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PSEG

December 2, 2009

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

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

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

Dear Secretary Izzo:

Enclosed for filing by Public Service Electric and Gas Company ("Company") please find an original and ten copies of tariff sheets and supporting exhibits filed to reflect changes to the PJM Open Access Transmission Tariff ("OATT") made in response to the annual formula rate update filing made by Public Service Electric and Gas ("PSE&G") in Federal Energy Regulatory Commission ("FERC") Docket No. ER09-1257, and in response to the annual formula rate update filings made by Potomac-Appalachian Transmission Highline, L.L.C. ("PATH") in Docket No. ER08-386 and Virginia Electric and Power Company ("VEPCo") in Docket No. ER-08-92.

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 Agreement ("SMA"). In the most recent Board Order (BPU Docket No. ER08050310), the Board discussed this issue at length, and concluded that such a "pass through" of FERC-approved transmission rate changes was in the best interests of BGS customers.

On September 30, 2008, in Docket ER08-1233, FERC approved PSE&G's filing to substitute a formula rate for its stated rates for Network Integration Transmission Service (NITS) and Point-to-Point transmission service. On November 14, 2008, PSE&G filed with the Board to recover the FERC-approved formula rates applicable to customers in PSE&G's transmission zone and authorized PSE&G to recover the transmission enhancement charges found in Schedule 12 of the OATT for the PATH and VEPCo projects. These Schedule 12 charges, also defined as Transmission Enhancement Charges ("TECs") are recovered by PJM through an additional transmission charge in the transmission zones assigned cost responsibility for Required Transmission Enhancement projects. On December 18, 2008 the Board approved the November 14, 2008 filing.

On October 7, 2009 PSE&G made a compliance filing with the FERC in Docket No. ER09-1275 for the annual update to the formula rate filed with the FERC in accordance with the Commission Order. Additionally, on or about October 15, 2009 VEPCo, and PATH made their annual formula rate update filings in Docket Nos. ER10-068 and ER08-386, respectively.

Request for Board Approval

PSE&G requests Board approval to implement revised Basic Generation Service-Fixed Price (BGS-FP) and Basic Generation Service-Commercial and Industrial Energy Price (BGS-CIEP) tariff rates as shown in Attachment 2. The attached pro-forma tariff sheets have an effective date of January 1, 2010. The BGS-FP and BGS-CIEP rates are revised to include the Network Integration Transmission Service (NITS) rates resulting from the FERC-approved PSE&G formula rate effective on January 1, 2010 and that are applicable to customers in the PSE&G service territory. Since costs for portions of certain Schedule 12 projects included in PSE&G's formula rate are borne by customers in other EDC service territories, the proposed BGS-FP and BGS-CIEP tariff rates are based on the transmission service costs allocable to PSE&G customers only. Details on these projects can be found in Attachments 1 and 7.

The amended tariff sheets also include revised BGS-FP and BGS-CIEP tariff rates resulting from the annual PATH and VEPCo formula updates which are effective on January 1, 2010. Copies of all formula rate updates are attached, but can also be found on the PJM website at www.pjm.com/services/formula-rates.html.

PSE&G also requests that the BGS Suppliers be compensated for the changes to the OATT resulting from the implementation of the PSE&G, PATH and VEPCo project annual formula updates effective on January 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 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 EDC 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,

Attachments

cc: Jerry May
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Attachment 1

Derivation of PSE&G Network Integration Transmission Service (NITS) Charge

Attachment 1 - PSE&G Network Integration Service Calculation.

Network Integration Service Rate Applicable to PSE&G customers - Effective January 1, 2010 through December 31, 2010

Line #	Description	Rate		Source
(1)	Transmission Service Annual Revenue Requirement	$ 251,064,988.00		Attachment 7 -Page 190 - Line 164
(2)	Total Schedule 12 TEC Included in above	$ (69,595,079.00)		Attachment 6a - Page 208 "Total Projects"
(3)	PSE&G Customer Share of Schedule 12 TEC	$ 24,091,671.32		Attachment 3a - Page 16 Column (n)
(4)	Total Transmission Costs Borne by PSE&G customers	$ 205,561,580.32		=(1) +(2) +(3)
(5)	2010 PSE&G Network Service Peak	9,686.7	MW	Attachment 7b -Page 4 -Line 165
(6)	2010 Network Integration Transmission Service Rate	$ 21,221.01	per MW-year	
	Resulting 2010 BGS Firm Transmission Service Supplier Rate	$ 58.14	per MW-day	= (6)/365

Notes -

Attachment 2 Tariffs and Rate Translation

Attachment 2a
Pro-forma PSE&G Tariff Sheets

Attachment 2b
Translation of NITS charge into Customer Rates

Attachment 2c
Translation of VEPCO Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 2d
Translation of PATH Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 2a
Pro-forma PSE&G Tariff Sheets

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 67**
Superseding
B.P.U.N.J. No. 14 ELECTRIC **XXX Revised Sheet No. 67**

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

APPLICABLE TO:

Default electric supply service for Rate Schedules RS, RSP, RHS, RLM, WH, WHS, HS, BPL, BPL-POF, PSAL, GLP and LPL-Secondary (less than 1,000 kilowatts).

BGS ENERGY CHARGES:

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

Charges per kilowatthour:

	For usage in each of the months of October through May		For usage in each of the months of June through September	
Rate Schedule	Charges	Charges Including SUT	Charges	Charges Including SUT
RS – first 600 kWh	11.2770 ¢	12.0664 ¢	12.0233 ¢	12.8649 ¢
RS – in excess of 600 kWh	11.2770 ¢	12.0664 ¢	12.9243 ¢	13.8290 ¢
RHS – first 600 kWh	10.3169 ¢	11.0391 ¢	11.8605 ¢	12.6907 ¢
RHS – in excess of 600 kWh	10.3169 ¢	11.0391 ¢	13.0652 ¢	13.9798 ¢
RLM On-Peak	14.4913 ¢	15.5057 ¢	15.8956 ¢	17.0083 ¢
RLM Off-Peak	7.6981 ¢	8.2370 ¢	8.1234 ¢	8.6920 ¢
WH	8.6773 ¢	9.2847 ¢	9.7344 ¢	10.4158 ¢
WHS	8.6875 ¢	9.2956 ¢	9.7888 ¢	10.4740 ¢
HS	10.3033 ¢	11.0245 ¢	13.5832 ¢	14.5340 ¢
BPL	8.0560 ¢	8.6199 ¢	8.4917 ¢	9.0861 ¢
BPL-POF	8.0560 ¢	8.6199 ¢	8.4917 ¢	9.0861 ¢
PSAL	8.0560 ¢	8.6199 ¢	8.4917 ¢	9.0861 ¢

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

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

Date of Issue: Effective:

Issued by FRANCES I. SUNDHEIM, Vice President and Corporate Rate Counsel
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 68**
Superseding
B.P.U.N.J. No. 14 ELECTRIC **XXX Revised Sheet No. 68**

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

BGS CAPACITY CHARGES:

Applicable to Rate Schedules GLP and LPL-Sec.

Charges per kilowatt of Generation Obligation:

Charge applicable in the months of June through September	$ 4.8077
Charge including New Jersey Sales and Use Tax (SUT)	$ 5.1442
Charge applicable in the months of October through May	$ 4.7880
Charge including New Jersey Sales and Use Tax (SUT)	$ 5.1232

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

BGS TRANSMISSION CHARGES

Applicable to Rate Schedules GLP and LPL-Sec.

Charges per kilowatt of Transmission Obligation:

Currently effective Annual Transmission Rate for Network Integration Transmission Service for the Public Service Transmission Zone as stated in the FERC Electric Tariff of the PJM Interconnection, LLC	$ 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	$ 25.09 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	$ 2.11 per MW per month
American Electric Power Service Corporation	$ 0.53 per MW per month
Atlantic City Electric Company.	$ 7.26 per MW per month
Delmarva Power and Light Company	$ 0.84 per MW per month
Potomac Electric Power Company.	$ 5.89 per MW per month

Above rates converted to a charge per kW of Transmission Obligation, applicable in all months	$ 1.8346
Charge including New Jersey Sales and Use Tax (SUT)	$ 1.9630

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).

Date of Issue: Effective:

Issued by FRANCES I. SUNDHEIM, Vice President and Corporate Rate Counsel
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

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 MW per year
PJM Seams Elimination Cost Assignment Charges	$ 0.00 per MW per month
PJM Reliability Must Run Charge	$ 0.00 per MW per month
PJM Transmission Enhancements	
Trans-Allegheny Interstate Line Company	$ 25.09 per MW per month
Virginia Electric and Power Company	$ 9.37 per MW per month
Potomac-Appalachian Transmission Highline L.L.C.	$ 15.09 per MW per month
PPL Electric Utilities Corporation	$ 2.11 per MW per month
American Electric Power Service Corporation	$ 0.53 per MW per month
Atlantic City Electric Company.	$ 7.26 per MW per month
Delmarva Power and Light Company	$ 0.84 per MW per month
Potomac Electric Power Company.	$ 5.89 per MW per month
Above rates converted to a charge per kW of Transmission Obligation, applicable in all months	$ 1.8346
Charge including New Jersey Sales and Use Tax (SUT)	$ 1.9630

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

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

Date of Issue: Effective:
Issued by FRANCES I. SUNDHEIM, Vice President and Corporate Rate Counsel
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

Attachment 2b
Translation of NITS charge into Customer Rates

Attachment 2b

Netork Integration Service Calculation - BGS-FP

NITS Charges for January 2010 - December 2011

TEC Charges for Jan 20010 - Dec 20010	$ 205,561,580.32		
PSE&G Zonal Transmission Load for Effective Yr. (MW)	9,686.70		
Term (Months)	12		
OATT rate	$ 1,768.42	/MW/month	all values show w/o NJ SUT
converted to $/MW/yr =	$ 21,221.01	/MW/yr	**New Rate From Rate Case**
	$ 17,631.00	/MW/yr	**Existing Rate**
Resulting Increase in Transmission Rate	$ 3,590.01	/MW/yr	
Resulting Increase in Transmission Rate	$ 299.17	/MW/month	

	RS	**RHS**	**RLM**	**WH**	**WHS**	**HS**	**PSAL**	**BPL**
Trans Obl - MW	4112.2	38.3	68.1	0.0	0.0	5.6	0.0	0.0
Total Annual Energy - MWh	13,496,224	185,200	301,068	4,190	65	28,180	166,110	327,488
Change in energy charge								
in $/MWh	$ 1.0939	$ 0.7424	$ 0.8120	$ -	$ -	$ 0.7134	$ -	$ -
in cents/kWh - rounded to 4 places	**0.1094**	**0.0742**	**0.0812**	**0**	**0**	**0.0713**	**0**	**0**

	GLP	**LPL-S**	
Change in Transmission Obligation Charge			
in $/kW/month - rounded to 4 places	**$ 0.2992**	**$ 0.2992**	<< same increase to BGS-CIEP Transmission Obligation Charges

Line #					
1	Total BGS-FP eligbile Trans Obl	7990	MW		= sum of BGS-FP eligible Trans Obl
2	Total BGS-FP eligbile energy @ cust	33,161,817	MWh		= sum of BGS-FP eligible kWh @ cust
3	Total BGS-FP eligbile energy @ trans nodes	35,480,591	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 28,684,199		unrounded	= Change in OATT rate * Total BGS-FP eligible Trans C
5	Change in Average Supplier Payment Rate	$ 0.8084	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ 0.81	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ 28,739,279		unrounded	= (6) * (3)
8	Difference due to rounding	$ 55,080		unrounded	= (7) - (4)

Attachment 2c

Translation of VEPCO Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 2c

Transmission Charge Adjustement - BGS-FP
PJM Schedule 12 - Transmission Enhancement Charges for January 2010 - December 2010
Calculation of costs and monthly PJM charges for PATH Projects

TEC Charges for Jan 2010 - Dec 2010	$ 1,754,332.16		
PSE&G Zonal Transmission Load for Effective Yr. (MW)	9,686.70		
Term (Months)	12		
OATT rate	$ 15.09	/MW/month	all values show w/o NJ SUT
converted to $/MW/yr =	$ 181.08	/MW/yr	

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4112.2	38.3	68.1	0.0	0.0	5.6	0.0	0.0
Total Annual Energy - MWh	13,496,224	185,200	301,068	4,190	65	28,180	166,110	327,488
Change in energy charge								
in $/MWh	$ 0.0552	$ 0.0374	$ 0.0410	$ -	$ -	$ 0.0360	$ -	$ -
in cents/kWh - rounded to 4 places	**0.0055**	**0.0037**	**0.0041**	**0**	**0**	**0.0036**	**0**	**0**

	GLP	LPL-S	
Change in Transmission Obligation Charge			
in $/kW/month - rounded to 4 places	**$ 0.0151**	**$ 0.0151**	<< same increase to BGS-CIEP Transmission Obligation Charges

Line #					
1	Total BGS-FP eligbile Trans Obl	7990	MW		= sum of BGS-FP eligible Trans Obl
2	Total BGS-FP eligbile energy @ cust	33,161,817	MWh		= sum of BGS-FP eligible kWh @ cust
3	Total BGS-FP eligbile energy @ trans nodes	35,480,591	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 1,446,829		unrounded	= Change in OATT rate * Total BGS-FP eligible Trans C
5	Change in Average Supplier Payment Rate	$ 0.0408	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ 0.04	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ 1,419,224		unrounded	= (6) * (3)
8	Difference due to rounding	$ (27,606)		unrounded	= (7) - (4)

Attachment 2d

Translation of PATH Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 2d

Transmission Charge Adjustement - BGS-FP

PJM Schedule 12 - Transmission Enhancement Charges for January 2010 - December 2010

Calculation of costs and monthly PJM charges for Virginia Power and Electric Company Projects

TEC Charges for Jan 2010 - Dec 2010	$ 1,089,697.36		
PSE&G Zonal Transmission Load for Effective Yr. (MW)	9,686.70		
Term (Months)	12		
OATT rate	$ 9.37	/MW/month	all values show w/o NJ SUT
converted to $/MW/yr =	$ 112.44	/MW/yr	

	RS	**RHS**	**RLM**	**WH**	**WHS**	**HS**	**PSAL**	**BPL**
Trans Obl - MW	4112.2	38.3	68.1	0.0	0.0	5.6	0.0	0.0
Total Annual Energy - MWh	13,496,224	185,200	301,068	4,190	65	28,180	166,110	327,488
Change in energy charge								
in $/MWh	$ 0.0343	$ 0.0233	$ 0.0254	$ -	$ -	$ 0.0223	$ -	$ -
in cents/kWh - rounded to 4 places	**0.0034**	**0.0023**	**0.0025**	**0**	**0**	**0.0022**	**0**	**0**

	GLP	**LPL-S**	
Change in Transmission Obligation Charge			
in $/kW/month - rounded to 4 places	**$ 0.0094**	**$ 0.0094**	<< same increase to BGS-CIEP Transmission Obligation Charges

Line #					
1	Total BGS-FP eligbile Trans Obl	7990	MW		= sum of BGS-FP eligible Trans Obl
2	Total BGS-FP eligbile energy @ cust	33,161,817	MWh		= sum of BGS-FP eligible kWh @ cust
3	Total BGS-FP eligbile energy @ trans nodes	35,480,591	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 898,396		unrounded	= Change in OATT rate * Total BGS-FP eligible Trans
5	Change in Average Supplier Payment Rate	$ 0.0253	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ 0.03	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ 1,064,418		unrounded	= (6) * (3)
8	Difference due to rounding	$ 166,022		unrounded	= (7) - (4)

Attachment 3 PJM Schedule 12 (Transmission Enhancement) Charges

Attachment 3a - PSE&G Project Charges

Attachment 3b – Potomac-Appalachian Transmission Highline Project Charges

Attachment 3c – Virginia Electric Power Company Project Charges

Attachment 3a - PSE&G Project Charges

		(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*	Jan - Dec 2010 Annual Revenue Requirement *per PJM website*	ACE Zone Share *per PJM Open Access Transmission Tariff*	JCP&L Zone Share	PSE&G Zone Share[1,2]	RE Zone Share	ACE Zone Charges	JCP&L Zone Charges	PSE&G Zone Charges	RE Zone Charges	Total NJ Zones Charges
Replace all Branchburg 500/230 kv txfrm	b0130	$ 4,089,600.00	1.36%	47.75%	50.89%	0.00%	$55,619	$1,952,784	$2,081,197	$0	$4,089,600
Reconductor Kittatinny - Newtown 230 kV	b0134	$ 1,693,708.00	0.00%	51.11%	45.96%	2.93%	$0	$865,654	$778,428	$49,626	$1,693,708
Build new Essex - Aldene 230 kV cable	b0145	$ 17,373,635.00	0.00%	73.45%	21.78%	4.77%	$0	$12,760,935	$3,783,978	$828,722	$17,373,635
Install 230-138kV transformer at Metuchen substation	b0161	$ 5,442,721.00	0.00%	0.00%	99.80%	0.20%	$0	$0	$5,431,836	$10,885	$5,442,721
New 230 kV section from Branchburg - Flagtown circuit	b0169	$ 4,637,505.00	1.72%	25.93%	59.59%	0.00%	$79,765	$1,202,505	$2,763,489	$0	$4,045,759
Reconductor the Flagtown-Somerville-Bridgewater 230 kV circuit	b0170	$ 1,464,701.00	0.00%	42.95%	38.36%	0.79%	$0	$629,089	$561,859	$11,571	$1,202,520
Replace wave trap at Branchburg 500kV substation	b0172.2	$ 7,560.00	1.89%	4.50%	7.61%	0.31%	$143	$340	$575	$23	$1,082
Replace both 230/138 kV txfrmrs at Roseland	b0274	$ 4,768,898.00	0.00%	0.00%	96.77%	0.00%	$0	$0	$4,614,863	$0	$4,614,863
Install 4th 500/230 kV transformer at New Freedom	b0411	$ 4,489,420.00	47.01%	7.04%	22.31%	0.00%	$2,110,476	$316,055	$1,001,590	$0	$3,428,121
New 500 kV transmission facilities from Pa - NJ border at Bushkill to Roseland (500kV and above elements)	b0489	$ 16,153,399.00	1.89%	4.50%	7.61%	0.31%	$305,299	$726,903	$1,229,274	$50,076	$2,311,551
New 500 kV transmission facilities from Pa - NJ border at Bushkill to Roseland (below 500 kV elements)	b0489.4	$ 2,250,890.00	5.23%	34.10%	42.21%	1.58%	$117,722	$767,553	$950,101	$35,564	$1,870,940
5021 circuit loop into New Freedom 500 kV substation	b0498	$ 6,772,194.00	1.89%	4.50%	7.61%	0.31%	$127,994	$304,749	$515,364	$20,994	$969,101
Reconductor Hudson - South Waterfront 230kV circuit	b0813	$ 450,848.00	0.00%	9.96%	84.09%	3.14%	$0	$44,904	$379,118	$14,157	$438,179
Totals		**$ 69,595,079.00**					**$2,797,018**	**$19,571,472**	**$24,091,671**	**$1,021,618**	**$47,481,780**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

	(k)	(l)	(m)	(n)	(o)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 2009**	**2009 TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**[3]	**2010 Impact (12 months)**	
PSE&G	$ 2,007,639.28	9,686.7	$ 207.26	$ 24,091,671	
JCP&L	$ 1,630,956.02	5,738.4	$ 284.22	$ 19,571,472	
ACE	$ 233,084.84	2,706.6	$ 86.12	$ 2,797,018	
RE	$ 85,134.84	371.1	$ 229.41	$ 1,021,618	
Total Impact on NJ Zones	**$ 3,956,814.98**			**$ 47,481,780**	
Notes on calculations >>>			= (k) / (l)	= (k) *12	

Notes:

1) Percentage for regional projects (e.g - 7.61% for PSE&G) will change on January 1, 2010
2) Percentage for "Below 500kV" portion of S/R Line was finalized by PJM
3) Uncompressed rate - assumes implementation on January 1, 2010

Attachment 3b – Potomac-Appalachian Transmission Highline Project Charges

Attachment 3b Potomac-Allegheny Transmission Highline (PATH)

PJM Schedule 12 - Transmission Enhancement Charges for January - December 2010

Calculation of costs and monthly PJM charges for PATH Project

		(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*	**Jan - Dec 2010 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share**	**JCP&L Zone Share**	**PSE&G Zone Share[1]**	**RE Zone Share**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
			per PJM Open Access Transmission Tariff								
Amos-Bedington 765 kV Circuit (AEP)	b0490	$ 12,480,138.00	1.89%	4.50%	7.61%	0.31%	$235,875	$561,606	$949,739	$38,688	$1,785,908
Amos-Bedington 765 kV Circuit (APS)	b0491	Included above	1.89%	4.50%	7.61%	0.31%	$0	$0	$0	$0	$0
Bedington-Kemptown 500 kV Circuit	b0492 & b560	$ 10,572,847.00	1.89%	4.50%	7.61%	0.31%	$199,827	$475,778	$804,594	$32,776	$1,512,974
Totals		**$ 23,052,985.00**					**$435,701**	**$1,037,384**	**$1,754,332**	**$71,464**	**$3,298,882**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

	(k)	(l)	(m)	(n)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 2010**	**2010 Trans. Peak Load**	**Rate in $/MW-mo. [2]**	**2010 Impact (12 months)**
PSE&G	$ 146,194.35	9,686.7	$15.09	$ 1,754,332
JCP&L	$ 86,448.69	5,738.4	$15.06	$ 1,037,384
ACE	$ 36,308.45	2,706.6	$13.41	$ 435,701
RE	$ 5,955.35	371.1	$16.05	$ 71,464
Total Impact on NJ Zones	**$ 274,906.85**	**18,502.8**		**$ 3,298,882**
Notes on calculations >>>			= (k) / (l)	= (k) *12

Notes:

1) Percentage for regional projects (7.61%) will change on January 1, 2010

2) Uncompressed rate - assumes implementation on January 1, 2010

Attachment 3c – Virginia Electric Power Company Project Charges

Attachment 3c - PJM Schedule 12 - Transmission Enhancement Charges for January 2010 - December 2010
Calculation of costs and monthly PJM charges for VEPCo Projects

			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
				Responsible Customers - Schedule 12 Appendix				Estimated New Jersey EDC Zone Charges by Project				
Required Transmission Enhancement	**PJM Upgrade ID**		**Jan - Dec 2010 Annual Revenue Requirement**	**ACE Zone Share**	**JCP&L Zone Share**	**PSE&G Zone Share[1]**	**RE Zone Share**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
per PJM website	*per PJM spreadsheet*		*per PJM website*	*per PJM Open Access Transmission Tariff*								
Mt Storm - Doubs 500kV	b0217	$	334,766.00	1.89%	4.50%	7.61%	0.31%	$6,327	$15,064	$25,476	$1,038	$47,905
Loudoun 150 MVA capacitor @ 500 kV	b0222	$	278,313.00	1.89%	4.50%	7.61%	0.31%	$5,260	$12,524	$21,180	$863	$39,827
500 kV breakers and bus work at Suffolk	b0231	$	686,436.00	1.89%	4.50%	7.61%	0.31%	$12,974	$30,890	$52,238	$2,128	$98,229
Meadowbrook-Loudon 500kV circuit	b0328.1	$	12,914,804.00	1.89%	4.50%	7.61%	0.31%	$244,090	$581,166	$982,817	$40,036	$1,848,108
Mt Storm - Replace MOD with breaker on 500kV side of Txfmr	b0837	$	104,963.00	1.89%	4.50%	7.61%	0.31%	$1,984	$4,723	$7,988	$325	$15,020
Totals		**$**	**14,319,282.00**					**$270,634**	**$644,368**	**$1,089,697**	**$44,390**	**$2,049,089**
Notes on calculations >>>								= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

		(k)	(l)		(m)	(n)
Zonal Cost Allocation for New Jersey Zones		**Average Monthly Impact on Zone Customers in 2010**	**2009 TX Peak Load** *per PJM website*		**Rate in $/MW-mo.[2]**	**2010 Impact (12 months)**
PSE&G	$	90,808.11	9,686.7	$	9.37	$ 1,089,697
JCP&L	$	53,697.31	5,738.4	$	9.36	$ 644,368
ACE	$	22,552.87	2,706.6	$	8.33	$ 270,634
RE	$	3,699.15	371.1	$	9.97	$ 44,390
Total Impact on NJ Zones	**$**	**170,757.44**				**$ 2,049,089**
Notes on calculations >>>					= (k) / (l)	= (k) *12

Notes:
1) Percentage for regional projects (7.61%) will change on January 1, 2010
2) Uncompressed rate - assumes implementation on January 1, 2010

Attachment 4 – Cost Allocations

Attachment 4a - Responsible Customer Shares for PSE&G Schedule 12 Projects
Source - PJM OATT - Sheet Nos. 270 E-10 through 270E16

Attachment 4b - Responsible Customer Shares for VEPCO Schedule 12 Projects
Source - PJM OATT - Sheet Nos. 270 F.03 through 270 F.08

Attachment 4c - Responsible Customer Shares for PATH Schedule 12 Projects
Source - PJM OATT - Sheet Nos.

Attachment 4a - Responsible Customer Shares for PSE&G Schedule 12 Projects
Source - PJM OATT - Sheet Nos. 270 E-10 through 270E16

(12) Public Service Electric and Gas Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0025	Convert the Bergen-Leonia 138 Kv circuit to 230 kV circuit.		PSEG (100%)
b0090	Add 150 MVAR capacitor at Camden 230 kV		PSEG (100%)
b0121	Add 150 MVAR capacitor at Aldene 230 kV		PSEG (100%)
b0122	Bypass the Essex 138 kV series reactors		PSEG (100%)
b0125	Add Special Protection Scheme at Bridgewater to automatically open 230 kV breaker for outage of Branchburg – Deans 500 kV and Deans 500/230 kV #1 transformer PSEG		(100%)
b0126	Replace wavetrap on Branchburg – Flagtown 230 kV		PSEG (100%)
b0127	Replace terminal equipment to increase Brunswick – Adams – Bennetts Lane 230 kV to conductor rating		PSEG (100%)
b0129	Replace wavetrap on Flagtown – Somerville 230 kV		PSEG (100%)
b0130	Replace all derated Branchburg 500/230 kV transformers		AEC (1.36%) / JCPL (47.75%) / PSEG (50.89%)
b0134	Upgrade or Retension PSEG portion of Kittatinny – Newton 230 kVcircuit		JCPL (51.11%) / PSEG (45.96%) / RE (2.93%)

The Annual Revenue Requirement for all Public Service Electric and Gas Company Projects (Required Transmission Enhancements) in this Section 12 shall be as specified in Attachment 7 of Attachment H-10A and under the procedures detailed in Attachment H-10B.

Issued By: Craig Glazer Effective: February 16, 2009
Vice President, Federal Government Policy
Issued On: December 17, 2008

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0145	Build new Essex – Aldene 230 kV cable connected through a phase angle regulator at Essex		PSEG (21.78%) / JCPL (73.45%) /RE (4.77%)
b0157	Add 100MVAR capacitor at West Orange 138kV substation		PSEG (100%)
b0158	Close the Sunnymeade " C" and "F" bus tie		PSEG (100%)
b0159	Make the Bayonne reactor permanent installation		PSEG (100%)
b0160	Relocate the X-2250 circuit from Hudson 1-6 bus to Hudson 7-12 bus		PSEG (100%)
b0161	Install 230/138kV transformer at Metuchen substation		PSEG (99.80%) / RE (0.20%)
b0162	Upgrade the Edison – Meadow Rd 138kV “Q” circuit		PSEG (100%)
b0163	Upgrade the Edison – Meadow Rd 138kV “R” circuit		PSEG (100%)
b0169	Build a new 230 kV section from Branchburg – Flagtown and move the Flagtown – Somerville 230 kV circuit to the new section		AEC (1.72%) / JCPL (25.93%) / Neptune* (10.63%) / PSEG (59.59%) / ECP** (2.13%)
b0170	Reconductor the Flagtown-Somerville-Bridgewater 230 kV circuit with 1590 ACSS		JCLP (42.95%) / Neptune* (17.90%) / PSEG (38.36%) RE (0.79%)

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0172.2	Replace wave trap at Branchburg 500kV substation		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)
b0184	Replace Hudson 230kV circuit breakers #1-2		PSEG (100%)
b0185	Replace Deans 230kV circuit breakers #9-10		PSEG (100%)
b0186	Replace Essex 230kV circuit breaker #5-6		PSEG (100%)

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0201	Branchburg substation: replace wave trap on Branchburg – Readington 230 kV circuit		PSEG (100%)
b0213.1	Replace New Freedo m 230 kV breaker BS2-6		PSEG (100%)
b0213.3	Replace New Freedo m 230 kV breaker BS2-8		PSEG (100%)
b0274	Replace both 230/138 kV transformers at Roseland		PSEG (96.77%) / ECP** (3.23%)
b0275	Upgrade the two 138 kV circuits bet ween Rosel and and West Orange		PSEG (100%)
b0278	Install 228 MVAR capacitor at Roseland 230 kV substation		PSEG (100%)
b0290	Install 400 MVAR capacitor in the Branchburg 500 kV vicinity		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%)
b0358	Reconductor the PSEG portion of Buckingham – Pleasant Valley 230 kV, replace wave trap and metering transformer		PSEG (100%)

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0368	Reconductor Tosco – G22_MTX 230 kV circuit with 1033 bundled ACSS		PSEG (100%)
b0371	Make the Metuchen 138 kV bus solid and upgrade 6 breakers at the Metuchen substation		PSEG (100%)
b0372	Make the Athenia 138 kV bus solid and upgrade 2 breakers at the Athenia substation		PSEG (100%)
b0395	Replace Hudson 230 kV breaker BS4-5		PSEG (100%)
b0396	Replace Hudson 230 kV breaker BS1-6		PSEG (100%)
b0397	Replace Hudson 230 kV breaker BS3-4		PSEG (100%)
b0398	Replace Hudson 230 kV breaker BS5-6		PSEG (100%)
b0401.1	Replace Roseland 230 kV breaker BS6-7		PSEG (100%)
b0401.2	Replace Roseland 138 kV breaker O-1315		PSEG (100%)
b0401.3	Replace Roseland 138 kV breaker S-1319		PSEG (100%)
b0401.4	Replace Roseland 138 kV breaker T-1320		PSEG (100%)
b0401.5	Replace Roseland 138 kV breaker G-1307		PSEG (100%)
b0401.6	Replace Roseland 138 kV breaker P-1316		PSEG (100%)
b0401.7	Replace Roseland 138 kV breaker 220-4		PSEG (100%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0401.8	Replace W. Orange 138 kV breaker 132-4		PSEG (100%)
b0411	Install 4th 500/ 230 kV transformer at New Freedom		AEC (47.01%) / JCPL (7.04%) / Neptune* (0.28%) / PECO (23.36%) / PSEG (22.31%)
b0423	Reconductor Readington (2555) – Branchburg (4962) 230 kV circuit w/1590 ACSS		PSEG (100%)
b0424	Replace Readington wavetrap on Readington (2555) – Roseland (5017) 230 kV circuit		PSEG (100%)
b0425	Reconductor Linden (4996) – Tosco (5190) 230 kV circuit w/1590 ACSS (Assumes operating at 220 degrees C)		PSEG (100%)
b0426	Reconductor Tosco (5190) – G22_MTX5 (90220) 230 kV circuit w/1590 ACSS (Assumes operation at 220 degrees C)		PSEG (100%)
b0427	Reconductor Athenia (4954) – Saddle Brook (5020) 230 kV circuit river section		PSEG (100%)
b0428	Replace Roseland wavetrap on Roseland (5019) – West Caldwell "G" (5089) 138 kV circuit		PSEG (100%)
b0429	Reconductor Kittatinny (2553) – Newton (2535) 230 kV circuit w/1590 ACSS		JCPL (41.91%) / Neptune* (3.59%) / PSEG (50.59%) / RE (2.23%) / ECP** (1.68%)
b0439	Spare Deans 500/230 kV transformer		PSEG (100%)
b0446.1	Upgrade Bayway 138 kV breaker #2-3		PSEG (100%)
b0446.2	Upgrade Bayway 138 kV breaker #3-4		PSEG (100%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0446.3	Upgrade Bay way 138 kV breaker #6-7		PSEG (100%)
b0446.4	Upgrade the breaker associated with TX 132-5 on Linden 138 kV		PSEG (100%)
b0470	Install 138 kV breaker at Roseland and close the Roseland 138 kV buses		PSEG (100%)
b0471	Replace the wave traps at both Lawrence and Pleasant Valley on the Lawrence – Pleasant Vallen 230 kV circuit		PSEG (100%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0472	Increase the emergency rating of Saddle Brook – Athenia 230 kV by 25% by adding forced cooling		ECP (1.04%) / PSEG (95.40%) / RE (3.56%)
b0473	Move the 150 MVAR mobile capacitor from Aldene 230 kV to Lawrence 230 kV substation		PSEG (100%)
b0489	Build new 500 kV transmission facilities from Pennsylvania – New Jersey border at Bushkill to Roseland		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%*)†
b489.1	Replace Athenia 230 kV breaker 31H		PSEG (100%)
b489.2	Replace Bergen 230 kV breaker 10H		PSEG (100%)
b489.3	Replace Saddlebrook 230 kV breaker 21P		PSEG (100%)
b0489.4	Install two Roseland 500/230 kV transformers as part of the Susquehanna – Roseland 500 kV project		AEC (5.23%) / ComEd (0.29%) / Dayton (0.03%) / DPL (1.81%) / JCPL (34.10%) / Neptune* (3.37%) / PECO (10.32%) / PENELEC (0.57%) / ECP** (0.49%) / PSEG (42.21%) / RE (1.58%) ††

* 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

Public Service Electric and Gas Company (cont.)

b0498	Loop the 5021 circuit into New Freedom 500 kV substation		AEC (*1.89%*) / AEP (*17.30%*) / APS (*6.02%*) / BGE (*4.95%*) / ComEd (*14.97%*) / Dayton (*2.50%*) / DL (*2.02%*) / DPL (*2.85%*) / Dominion (*13.61%*) / JCPL (*4.50%*) / ME (*2.18%*) / NEPTUNE* (*0.49%*) / PECO (*6.31%*) / PENELEC (*2.06%*) / PEPCO (*4.82%*) / PPL (*5.37%*) / PSEG (*7.61%*) / RE (*0.31%*) / ECP** (*0.24%*)
b0498.1	Upgrade the 20H circuit breaker		PSEG (100%)
b0498.2	Upgrade the 22H circuit breaker		PSEG (100%)
b0498.3	Upgrade the 30H circuit breaker		PSEG (100%)
b0498.4	Upgrade the 32H circuit breaker		PSEG (100%)
b0498.5	Upgrade the 40H circuit breaker		PSEG (100%)
b0498.6	Upgrade the 42H circuit breaker		PSEG (100%)

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512	MAPP Project – install new 500 kV transmission from Possum point to Calvert Cliffs to Salem		AEC (*1.89*%) / AEP (*17.30*%) / APS (*6.02*%) / BGE (*4.95*%) / ComEd (*14.97*%) / Dayton (*2.50*%) / DL (*2.02*%) / DPL (*2.85*%) / Dominion (*13.61*%) / JCPL (*4.50*%) / ME (*2.18*%) / NEPTUNE* (*0.49*%) / PECO (*6.31*%) / PENELEC (*2.06*%) / PEPCO (*4.82*%) / PPL (*5.37*%) / PSEG (*7.61*%) / RE (*0.31*%) / ECP** (*0.24*%)
b0565	Install 100 MVAR capacitor at Cox's Corner 230 kV substation		PSEG (100%)
b0578	Replace Essex 138 kV breaker 4LM (C1355 line to ECRRF) PSEG		(100%)
b0579	Replace Essex 138 kV breaker 1LM (220-1 TX)		PSEG (100%)
b0580	Replace Essex 138 kV breaker 1BM (BS1-3 tie)		PSEG (100%)
b0581	Replace Essex 138 kV breaker 2BM (BS3-4 tie)		PSEG (100%)
b0582	Replace Linden 138 kV breaker 3 (132-7 TX)		PSEG (100%)
b0592	Replace Metuchen 138 kV breaker '2-2 Transfer'		PSEG (100%)
b0664	Reconductor with 2x1033 ACSS conductor		JCPL (40.12%) / NEPTUNE* (10.37%) / PSEG (47.73%) / RE (1.78%)

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

Public Service Electric and Gas Company (cont.)

b0665	Reconductor with 2x1033 ACSS conductor		JCPL (40.12%) / NEPTUNE* (10.37%) / PSEG (47.73%) / RE (1.78%)
b0668	Reconductor with 2x1033 ACSS conductor		JCPL (43.88%) / NEPTUNE* (11.35%) / PSEG (43.16%) / RE (1.61%)
b0671	Replace terminal equipment at both ends of line		PSEG (100%)
b0743	Add a bus tie breaker at Roseland 138 kV		PSEG (100%)
b0812	Increase operating temperature on line for one year to get 925E MVA rating		PSEG (100%)
b0813	Reconductor Hudson – South Waterfront 230 kV circuit		BGE (1.25%) / JCPL (9.96%) / NEPTUNE* (0.44%) / PEPCO (1.12%) / PSEG (84.09%) / RE (3.14%)
b0814	New Essex – Kearney 138 kV circuit and Kearney 138 kV bus tie		JCPL (23.69%) / NEPTUNE* (0.81%) / PENELEC (5.41%) / PSEG (67.57%) / RE (2.52%)
b0829	Build Branchburg to Roseland 500 kV circuit as part of Branchburg – Hudson 500 kV project		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)

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

Public Service Electric and Gas Company (cont.)

b0830	Build Roseland - Hudson 500 kV circuit as part of Branchburg – Hudson 500 kV project		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%)
b0831	Replace 138/13 kV transformers with 230/13 kV units as part of Branchburg – Hudson 500 kV project		ComEd (2.54%) / Dayton (0.09%) / PENELEC (2.78%) / ECP** (1.24%) / PSEG (89.84%) / RE (3.51%)
b0832	Build Hudson 500 kV switching station as part of Branchburg – Hudson 500 kV project		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%)
b0833	Build Roseland 500 kV switching station as part of Branchburg – Hudson 500 kV project		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)

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

Public Service Electric and Gas Company (cont.)

b0834	Convert the E-1305/F-1306 to one 230 kV circuit as part of Branchburg – Hudson 500 kV project		ComEd (2.54%) / Dayton (0.09%) / PENELEC (2.78%) / ECP** (1.24%) / PSEG (89.84%) / RE (3.51%)
b0835	Build Hudson 230 kV transmission lines as part of Roseland – Hudson 500 kV project as part of Branchburg – Hudson 500 kV project		ComEd (2.54%) / Dayton (0.09%) / PENELEC (2.78%) / ECP** (1.24%) / PSEG (89.84%) / RE (3.51%)
b0836	Install transformation at new Hudson 500 kV switching station and perform Hudson 230 kV and 345 kV station work as part of Branchburg – Hudson 500 kV project		ComEd (2.54%) / Dayton (0.09%) / PENELEC (2.78%) / ECP** (1.24%) / PSEG (89.84%) / RE (3.51%)

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

(13) Rockland Electric Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0314	Install 35 MVAR capacitor at Closter 69 kV substation		RE (100%)

(14) UGI Utilities, Inc.

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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Attachment 4b - Responsible Customer Shares for VEPCO Schedule 12 Projects

Source - PJM OATT - Sheet Nos. 270 F.03 through 270 F.08

(19) [Reserved for Future Use]

(20) Virginia Electric and Power Company

Required Transmission Enhancements		Annual Revenue Requirement***	Responsible Customer(s)
b0217	Upgrade Mt. Storm - Doubs 500kV		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%)
b0222	Install 150 MVAR capacitor at Loudoun 500 kV		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)

* Neptune Regional Transmission System, LLC
** East Coast Power, L.L.C.
*** The Annual Revenue Requirement for all Virginia Electric and Power Company projects in this Section 20 shall be as specified in Attachment 7 to Appendix A of Attachment H-16A and under the procedures detailed in Attachment H-16B.

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0223	Install 150 MVAR capacitor at Asburn 230 kV		Dominion (100%)
b0224	Install 150 MVAR capacitor at Dranesville 230 kV		Dominion (100%)
b0225	Install 33 MVAR capacitor at Possum Pt. 115 kV		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0226	Install 500/230 kV transformer at Clifton and Clifton 500 kV 150 MVAR capacitor	As specified in Attachment 7 to Appendix A of Attachment H-16A and under the procedures detailed in Attachment H-16B	APS (3.69%) / BGE (3.54%) / Dominion (85.73%) / PEPCO (7.04%)
b0227	Install 500/230 kV transformer at Bristers; build new 230 kV Bristers-Gainsville circuit, upgrade two Loudoun-Brambleton circuits		AEC (0.71%) / APS (3.35%) / BGE (10.93%) / DPL (1.66%) / Dominion (67.38%) / ME (0.89%) / PECO (2.33%) / PEPCO (12.21%) / PPL (0.54%)
b0227.1	Loudoun Sub – upgrade 6-230 kV breakers		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0231	Install 500 kV breakers & 500 kV bus work at Suffolk		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%)
b0231.2	Install 500/230 kV Transformer, 230 kV breakers, & 230 kV bus work at Suffolk		Dominion (100%)
b0232	Install 150 MVAR capacitor at Lynnhaven 230 kV		Dominion (100%)
b0233	Install 150 MVAR capacitor at Landstown 230 kV		Dominion (100%)
b0234	Install 150 MVAR capacitor at Greenwich 230 kV		Dominion (100%)
b0235	Install 150 MVAR capacitor at Fentress 230 kV		Dominion (100%)

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0307	Reconductor Endless Caverns – Mt. Jackson 115 kV		Dominion (100%)
b0308	Replace L breaker and switches at Endless Caverns 115 kV		Dominion (100%)
b0309	Install SPS at Earleys 115 kV		Dominion (100%)
b0310	Reconductor Club House – South Hill and Chase City – South Hill 115 kV		Dominion (100%)
b0311	Reconductor Idylwood to Arlington 230 kV		Dominion (100%)
b0312	Reconductor Gallows to Ox 230 kV		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0325	Install a 2nd Everetts 230/115 kV transformer		Dominion (100%)
b0326	Uprate/resag Remington-Brandywine-Culppr 115 kV		Dominion (100%)
b0327	Build 2nd Harrisonburg – Valley 230 kV		APS (19.79%) / Dominion (76.18%) / PEPCO (4.03%)
b0328.1	Build new Meadow Brook – Loudoun 500 kV circuit (30 of 50 miles)		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0328.3	Upgrade Mt. Storm 500 kV substation		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)
b0328.4	Upgrade Loudoun 500 kV substation		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0329	Build Carson – Suffolk 500 kV, install 2nd Suffolk 500/230 kV transformer & build Suffolk – Fentress 230 kV circuit		AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)†
b0329	Build Carson – Suffolk 500 kV, install 2nd Suffolk 500/230 kV transformer & build Suffolk – Fentress 230 kV circuit		Dominion (100%)††
b0330	Install Crewe 115 kV breaker and shift load from line 158 to 98		Dominion (100%)
b0331	Upgrade/resag Shell Bank – Whealton 115 kV (Line 165)		Dominion (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

Attachment 4c - Responsible Customer Shares for PATH Schedule 12 Projects

Source - PJM OATT - Sheet Nos. 270F.02-270F.02a

(16) The Dayton Power and Light Company

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0318	Install a 765/138 kV transformer at Amos		AEP (99.00%) / PEPCO (1.00%)
b0324	Replace entrance conductors, wave traps, and risers at the Tidd 345 kV station on the Tidd – Canton Central 345 kV circuit		AEP (100%)
b0447	Replace Cook 345 kV breaker M2		AEP (100%)
b0448	Replace Cook 345 kV breaker N2		AEP (100%)
b0490	Construct an Amos – Bedington 765 kV circuit (AEP equipment)	As specified under the procedures detailed in Attachment H-19B	AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0460	Raise limiting structures on Albright – Bethelboro 138 kV to raise the rating to 175 MVA normal 214 MVA emergency		APS (100%)
b0491	Construct an Amos – Bedington 765 kV circuit (APS equipment)	As specified under the procedures detailed in Attachment H-19B	AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)
b0492	Construct a Bedington – Kemptown 500 kV circuit	As specified under the procedures detailed in Attachment H-19B	AEC (1.89%) / AEP (17.30%) / APS (6.02%) / BGE (4.95%) / ComEd (14.97%) / Dayton (2.50%) / DL (2.02%) / DPL (2.85%) / Dominion (13.61%) / JCPL (4.50%) / ME (2.18%) / NEPTUNE* (0.49%) / PECO (6.31%) / PENELEC (2.06%) / PEPCO (4.82%) / PPL (5.37%) / PSEG (7.61%) / RE (0.31%) / ECP** (0.24%)
b0492.3	Replace Eastalco 230 kV breaker D-26		APS (100%)
b0492.4	Replace Eastalco 230 kV breaker D-28		APS (100%)

*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.)

b0492.5	Replace Eastalco 230 kV breaker D-31		APS (100%)
b0495	Replace existing Kammer 765/500 kV transformer with a new larger transformer		AEC (*1.89*%) / AEP (*17.30*%) / APS (*6.02*%) / BGE (*4.95*%) / ComEd (*14.97*%) / Dayton (*2.50*%) / DL (*2.02*%) / DPL (*2.85*%) / Dominion (*13.61*%) / JCPL (*4.50*%) / ME (*2.18*%) / NEPTUNE* (*0.49*%) / PECO (*6.31*%) / PENELEC (*2.06*%) / PEPCO (*4.82*%) / PPL (*5.37*%) / PSEG (*7.61*%) / RE (*0.31*%) / ECP** (*0.24*%)
b0533	Reconductor the Powell Mountain – Sutton 138 kV line		APS (100%)
b0534	Install a 28.61 MVAR capacitor on Sutton 138 kV		APS (100%)
b0535	Install a 44 MVAR capacitor on Dutch Fork 138 kV		APS (100%)
b0536	Replace Doubs circuit breaker DJ1		APS (100%)
b0537	Replace Doubs circuit breaker DJ7		APS (100%)
b0538	Replace Doubs circuit breaker DJ10		APS (100%)

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

Attachment 5 – PATH Formula Update for January 1, 2010- December 31, 2010

POTOMAC-APPALACHIAN TRANSMISSION HIGHLINE, LLC

REVISED PROJECTED TRANSMISSION REVENUE REQUIREMENT FOR RATE YEAR 2010

For the 12 months ended 12/31/2010

SUMMARY

		PATH West Virginia Transmission Company, LLC (PATH-WV) (1)		PATH Allegheny Transmission Company, LLC (PATH-Allegheny) (2)		Potomac-Appalachian Transmission Highline, LLC (3) = (1) + (2)
1	NET REVENUE REQUIREMENT	$12,480,138	(A)	$10,572,847	(B)	$23,052,986
2	PJM Project No.					
3	b0490 & b0491	$12,480,138	(C)			$12,480,138
4	b0492 & b0560			$10,572,847	(D)	$10,572,847
5						
6	Total (Sum lines 3 to 5)	$12,480,138		$10,572,847		$23,052,986

Sources:		
	(A)	Rate Formula Template, page 2, line 5, col. (3)
	(B)	Rate Formula Template, page 7, line 5, col. (3)
	(C)	Rate Formula Template - Attachment 5, page 30 col., (6)
	(D)	Rate Formula Template - Attachment 5, page 31 col., (5)

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2010

PATH West Virginia Transmission Company, LLC

Line No.			(1)	(2)		(3) Allocated Amount
1	GROSS REVENUE REQUIREMENT	(line 86)		12 months		$ 18,125,035
	REVENUE CREDITS		Total	Allocator		
2	Total Revenue Credits	Attachment 1, line 12	0	TP	1.00000	-
3	True-up Adjustment with Interest	Protocols	$ (5,644,896)	DA	1.00000	(5,644,896)
4	Accelerated True-up Adjustment with Interest		0	DA	1.00000	-
5	NET REVENUE REQUIREMENT	(Lines 1 minus line 2 plus line 3 plus line 4)				$ 12,480,138

Formula Rate - Non-Levelized

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2010

PATH West Virginia Transmission Company, LLC

Line No.	(1)	(2) **Form No. 1 Page, Line, Col.**	(3) **Company Total**	(4) **Allocator**		(5) **Transmission** (Col 3 times Col 4)
	RATE BASE:					
	GROSS PLANT IN SERVICE					
6	Production	(Attachment 4)	-	NA	0.00000	-
7	Transmission	(Attachment 4)	-	TP	1.00000	-
8	Distribution	(Attachment 4)	-	NA	0.00000	-
9	General & Intangible	(Attachment 4)	-	W/S	1.00000	-
10	Common	(Attachment 4)	-	CE	1.00000	-
11	TOTAL GROSS PLANT (sum lines 6-10)	(GP=1 if plant =0)	-	GP=	1.00000	-
12	ACCUMULATED DEPRECIATION					
13	Production	(Attachment 4)	-	NA	0.00000	-
14	Transmission	(Attachment 4)	-	TP	1.00000	-
15	Distribution	(Attachment 4)	-	NA	0.00000	-
16	General & Intangible	(Attachment 4)	-	W/S	1.00000	-
17	Common	(Attachment 4)	-	CE	1.00000	-
18	TOTAL ACCUM. DEPRECIATION (sum lines 13-17)		-			-
19	NET PLANT IN SERVICE					
20	Production	(line 6- line 13)	-			-
21	Transmission	(line 7- line 14)	-			-
22	Distribution	(line 8- line 15)	-			-
23	General & Intangible	(line 9- line 16)	-			-
24	Common	(line 10- line 17)	-			-
25	TOTAL NET PLANT (sum lines 20-24)	(NP=1 if plant =0)	-	NP=	1.0000	-
26	ADJUSTMENTS TO RATE BASE (Note A)					
27	Account No. 281 (enter negative)	(Attachment 4)	-	NA	0.00000	-
28	Account No. 282 (enter negative)	(Attachment 4)	(364)	NP	1.00000	(364)
29	Account No. 283 (enter negative)	(Attachment 4)	890,828	NP	1.00000	890,828
30	Account No. 190	(Attachment 4)	3,294,376	NP	1.00000	3,294,376
31	Account No. 255 (enter negative)	(Attachment 4)	-	NP	1.00000	-
32	CWIP	(Attachment 4)	68,885,839	DA	1.00000	68,885,839
33	Unamortized Regulatory Asset	(Attachment 4)	3,296,685	DA	1.00000	3,296,685
34	Unamortized Abandoned Plant	(Attachment 4)	-	DA	1.00000	-
35	TOTAL ADJUSTMENTS (sum lines 27-34)		76,367,364			76,367,364
36	LAND HELD FOR FUTURE USE	(Attachment 4)	-	TP	1.00000	-
37	WORKING CAPITAL (Note C)					
38	CWC	calculated	785,212			785,212
39	Materials & Supplies (Note B)	(Attachment 4)	-	TE	1.00000	-
40	Prepayments (Account 165 - Note C)	(Attachment 4)	31,830	GP	1.00000	31,830
41	TOTAL WORKING CAPITAL (sum lines 38-40)		817,042			817,042
42	RATE BASE (sum lines 25, 35, 36, & 41)		77,184,406			77,184,406

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2010

PATH West Virginia Transmission Company, LLC

	(1)	(2)	(3)	(4)		(5)
		Form No. 1 Page, Line, Col.	**Company Total**	**Allocator**		**Transmission** (Col 3 times Col 4)
43	O&M					
44	Transmission	321.112.b	1,236,257	TE	1.00000	1,236,257
45	Less Account 565	321.96.b	-	TE	1.00000	-
46	Less Account 566 (Misc Trans Expense)	Line 56	1,236,257	DA	1.00000	1,236,257
47	A&G	323.197.b	5,040,341	W/S	1.00000	5,040,341
48	Less EPRI & Reg. Comm. Exp. & Other Ac	(Note D & Attach 4)	-	DA	1.00000	-
49	Plus Transmission Related Reg. Comm. E	(Note D & Attach 4)	-	TE	1.00000	-
50	PBOP Expense adjustment	(Attachment 4)	5,097			5,097
51	Common	(Attachment 4)	-	CE	1.00000	-
52	Transmission Lease Payments	200.4.c	-	DA	1.00000	-
53	Account 566					
54	Amortization of Regulatory Asset	Attachment 4	1,236,257	DA	1.00000	1,236,257
55	Miscellaneous Transmission Expense	Attachment 4	-	DA	1.00000	-
56	Total Account 566		1,236,257			1,236,257
57	TOTAL O&M (sum lines 44, 47, 49, 50, 51, 52, 56 less lines 45, 46 & 48		6,281,695			6,281,695
58	DEPRECIATION EXPENSE					
59	Transmission	336.7.b & c	-	TP	1.00000	-
60	General and Intangible	336.1.d&e + 336.10.b&c	-	W/S	1.00000	-
61	Common	336.11.b&c	-	CE	1.00000	-
62	Amortization of Abandoned Plant	(Attachment 4)	-	DA	1.00000	-
63	TOTAL DEPRECIATION (Sum lines 59-62)		-			-
64	TAXES OTHER THAN INCOME TAXES (Note E)					
65	LABOR RELATED					
66	Payroll	263i	-	W/S	1.00000	-
67	Highway and vehicle	263i	-	W/S	1.00000	-
68	PLANT RELATED					
69	Property	263i	-	GP	1.00000	-
70	Gross Receipts	263i	-	NA	0.00000	-
71	Other	263i	-	GP	1.00000	-
72	Payments in lieu of taxes		-	GP	1.00000	-
73	TOTAL OTHER TAXES (sum lines 66-72)		-			-
74	INCOME TAXES	(Note F)				
75	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		40.53%			
76	CIT=(T/1-T) * (1-(WCLTD/R)) =		46.52%			
77	where WCLTD=(line 118) and R= (line 121)					
78	and FIT, SIT & p are as given in footnote F.					
79	1 / (1 - T) = (T from line 75)		1.6814			
80	Amortized Investment Tax Credit (266.8f) (enter negative)		0			
81	Income Tax Calculation = line 76 * line 85		3,760,315	NA		3,760,315
82	ITC adjustment (line 79 * line 80)		0	NP	1.00000	-
83	Total Income Taxes	(line 81 plus line 82)	3,760,315			3,760,315
84	RETURN					
85	[Rate Base (line 42) * Rate of Return (line 121)]		8,083,025	NA		8,083,025
86	REV. REQUIREMENT (sum lines 57, 63, 73, 83, 85)		18,125,035			18,125,035

Attachment A
Formula Rate - Non-Levelized
Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2010

PATH West Virginia Transmission Company, LLC
SUPPORTING CALCULATIONS AND NOTES

87	TRANSMISSION PLANT INCLUDED IN ISO RATES								
88	Total transmission plant (line 7, column 3)						0		
89	Less transmission plant excluded from ISO rates (Note H)						0		
90	Less transmission plant included in OATT Ancillary Services (Note H)						0		
91	Transmission plant included in ISO rates (line 88 less lines 89 & 90)						0		
92	Percentage of transmission plant included in ISO Rates (line 91 divided by line 88) [If line 88 equal zero, enter 1)					TP=	1.0000		
93	TRANSMISSION EXPENSES								
94									
95	Total transmission expenses (line 44, column 3)						1,236,257		
96	Less transmission expenses included in OATT Ancillary Services (Note G)						0		
97	Included transmission expenses (line 95 less line 96)						1,236,257		
98	Percentage of transmission expenses after adjustment (line 97 divided by line 95) [If line 95 equal zero, enter 1)						1.00000		
99	Percentage of transmission plant included in ISO Rates (line 92)					TP	1.00000		
100	Percentage of transmission expenses included in ISO Rates (line 98 times line 99)					TE=	1.00000		
101	WAGES & SALARY ALLOCATOR (W&S)								
102		Form 1 Reference	$	TP	Allocation				
103	Production	354.20.b	0						
104	Transmission	354.21.b	431,862	1.00	431,862				
105	Distribution	354.23.b	0				W&S Allocator		
106	Other	354.24,25,26.b	0				($ / Allocation)		
107	Total (sum lines 103-106) [TP equals 1 if there are no wages & salaries		431,862		431,862	=	1.00000	=	WS
108	COMMON PLANT ALLOCATOR (CE) (Note I)								
109			**$**		% Electric		W&S Allocator		
110	Electric	200.3.c	0		(line 110 / line 113)		(line 107)		CE
111	Gas	201.3.d	0		1.00000	x	1.00000	=	1.00000
112	Water	201.3.e	0						
113	Total (sum lines 110 - 112)		0						
114	RETURN (R)						$		
115									
116									
117			$	%	Cost		Weighted		
118	Long Term Debt (Note K)	(Attachment 4)	0	50%	6.64%		0.0332	=WCLTD	
119	Preferred Stock	(Attachment 4)	0	0%	0.00%		0.0000		
120	Common Stock (Note J)	(Attachment 4)	0	50%	14.30%		0.0715		
121	Total (sum lines 118-120)		0				0.1047	=R	

SUPPORTING CALCULATIONS AND NOTES
Attachment A
Formula Rate - Non-Levelized
Rate Formula Template
Utilizing FERC Form 1 Data
For the 12 months ended 12/31/2010
PATH West Virginia Transmission Company, LLC

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter	
A	The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note F. Account 281 is not allocated.
B	Identified in Form 1 as being only transmission related.
C	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission Prepayments are the electric related prepayments booked to Account No. 165 and reported on Pages 110-111 line 57 in the Form 1.
D	EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, except safety, education and out-reach related advertising included in Account 930.1. Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
E	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
F	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 4, line 79). Inputs Required: FIT = 35.00% SIT= 8.50% (State Income Tax Rate or Composite SIT from Attachment 4) p = 0.00% (percent of federal income tax deductible for state purposes)
G	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, if any.
H	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
I	Enter dollar amounts
J	ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.
K	The percentage shown for Long Term Debt is subject to the Annual Update and Attachment 6 and Attachment 9.

Formula Rate - Non-Levelized

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2010

PATH Allegheny Transmission Company, LLC

Line No.			(1)	(2)		(3) Allocated Amount
1	GROSS REVENUE REQUIREMENT	(line 86)			12 months	$ 11,385,062
	REVENUE CREDITS		Total	Allocator		
2	Total Revenue Credits	Attachment 1, line 12	0	TP	1.00000	-
3	True-up Adjustment with Interest	Protocols	(812,214.29)	DA	1.00000	(812,214)
4	Accelerated True-up Adjustment with Interest		0	DA	1.00000	-
5	NET REVENUE REQUIREMENT	(Lines 1 minus line 2 plus line 3 plus line 4)				$ 10,572,847

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2010

PATH Allegheny Transmission Company, LLC

	(1)	(2)	(3)	(4)		(5)
		Form No. 1				**Transmission**
Line No.	**RATE BASE:**	**Page, Line, Col.**	**Company Total**	**Allocator**		(Col 3 times Col 4)
	GROSS PLANT IN SERVICE					
6	Production	(Attachment 4)	-	NA	0.00000	-
7	Transmission	(Attachment 4)	9,717,786	TP	1.00000	9,717,786
8	Distribution	(Attachment 4)	-	NA	0.00000	-
9	General & Intangible	(Attachment 4)	45,324	W/S	1.00000	45,324
10	Common	(Attachment 4)	-	CE	1.00000	-
11	TOTAL GROSS PLANT (sum lines 6-10)	(GP=1 if plant =0)	9,763,110	GP=	1.00000	9,763,110
12	ACCUMULATED DEPRECIATION					
13	Production	(Attachment 4)	-	NA	0.00000	-
14	Transmission	(Attachment 4)	-	TP	1.00000	-
15	Distribution	(Attachment 4)	-	NA	0.00000	-
16	General & Intangible	(Attachment 4)	1,606	W/S	1.00000	1,606
17	Common	(Attachment 4)	-	CE	1.00000	-
18	TOTAL ACCUM. DEPRECIATION (sum lines 13-17)		1,606			1,606
19	NET PLANT IN SERVICE					
20	Production	(line 6- line 13)	-			-
21	Transmission	(line 7- line 14)	9,717,786			9,717,786
22	Distribution	(line 8- line 15)	-			-
23	General & Intangible	(line 9- line 16)	43,718			43,718
24	Common	(line 10- line 17)	-			-
25	TOTAL NET PLANT (sum lines 20-24)	(NP=1 if plant =0)	9,761,504	NP=	1.0000	9,761,504
26	ADJUSTMENTS TO RATE BASE (Note A)					
27	Account No. 281 (enter negative)	(Attachment 4)	-	NA	0.00000	-
28	Account No. 282 (enter negative)	(Attachment 4)	(3,502)	NP	1.00000	(3,502)
29	Account No. 283 (enter negative)	(Attachment 4)	-	NP	1.00000	-
30	Account No. 190	(Attachment 4)	322,057	NP	1.00000	322,057
31	Account No. 255 (enter negative)	(Attachment 4)	-	NP	1.00000	-
32	CWIP	(Attachment 4)	42,306,210	DA	1.00000	42,306,210
33	Unamortized Regulatory Asset	(Attachment 4)	499,371	DA	1.00000	499,371
34	Unamortized Abandoned Plant	(Attachment 4)	-	DA	1.00000	-
35	TOTAL ADJUSTMENTS (sum lines 27-34)		43,124,136			43,124,136
36	LAND HELD FOR FUTURE USE	(Attachment 4)	-	TP	1.00000	-
37	WORKING CAPITAL (Note C)					
38	CWC	calculated	329,323			329,323
39	Materials & Supplies (Note B)	(Attachment 4)	-	TE	1.00000	-
40	Prepayments (Account 165 - Note C)	(Attachment 4)	5,733	GP	1.00000	5,733
41	TOTAL WORKING CAPITAL (sum lines 38-40)		335,056			335,056
42	RATE BASE (sum lines 25, 35, 36, & 41)		53,220,696			53,220,696

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2010

PATH Allegheny Transmission Company, LLC

	(1)	(2) **Form No. 1 Page, Line, Col.**	(3) **Company Total**	(4) **Allocator**		(5) **Transmission** (Col 3 times Col 4)
43	O&M					
44	Transmission	321.112.b	187,264	TE	1.00000	187,264
45	Less Account 565	321.96.b	-	TE	1.00000	-
46	Less Account 566	Line 56	187,264	DA	1.00000	187,264
47	A&G	323.197.b	2,446,116	W/S	1.00000	2,446,116
48	Less EPRI & Reg. Comm. Exp. & Other Ad.	(Note D & Attach 4)	35,029	DA	1.00000	35,029
49	Plus Transmission Related Reg. Comm. Exp.	(Note D & Attach 4)	35,029	TE	1.00000	35,029
50	PBOP Expense adjustment	(Attachment 4)	1,207			1,207
51	Common	(Attachment 4)	-	CE	1.00000	-
52	Transmission Lease Payments	200.4.c	-	DA	1.00000	-
53	Account 566					
54	Amortization of Regulatory Asset	Attachment 4	187,264	DA	1.00000	187,264
55	Miscellaneous Transmission Expense	Attachment 4	-	DA	1.00000	-
56	Total Account 566		187,264			187,264
57	TOTAL O&M (sum lines 44, 47, 49, 50, 51, 52, 56 less lines 45,46, 48)		2,634,587			2,634,587
58	DEPRECIATION EXPENSE					
59	Transmission	336.7.b & c	-	TP	1.00000	-
60	General and Intangible	336.1.d&e + 336.10.b&c	2,142	W/S	1.00000	2,142
61	Common	336.11.b & c	-	CE	1.00000	-
62	Amortization of Abandoned Plant	(Attachment 4)	-	DA	1.00000	-
63	TOTAL DEPRECIATION (Sum lines 59-62)		2,142			2,142
64	TAXES OTHER THAN INCOME TAXES (Note E)					
65	LABOR RELATED					
66	Payroll	263i	-	W/S	1.00000	-
67	Highway and vehicle	263i	-	W/S	1.00000	-
68	PLANT RELATED					
69	Property	263i	564,648	GP	1.00000	564,648
70	Gross Receipts	263i	-	NA	0.00000	-
71	Other	263i	-	GP	1.00000	-
72	Payments in lieu of taxes		-	GP	1.00000	-
73	TOTAL OTHER TAXES (sum lines 66-72)		564,648			564,648
74	INCOME TAXES	(Note F)				
75	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		40.41%			
76	CIT=(T/1-T) * (1-(WCLTD/R)) =		46.05%			
77	where WCLTD=(line 118) and R= (line 121)					
78	and FIT, SIT & p are as given in footnote F.					
79	1 / (1 - T) = (T from line 75)		1.6781			
80	Amortized Investment Tax Credit	(266.8f) (enter negative)	0			
81	Income Tax Calculation = line 76 * line 85		2,580,389	NA		2,580,389
82	ITC adjustment (line 79 * line 80)		0	NP	1.00000	-
83	Total Income Taxes	(line 81 plus line 82)	2,580,389			2,580,389
84	RETURN					
85	[Rate Base (line 42) * Rate of Return (line 121)]		5,603,296	NA		5,603,296
86	REV. REQUIREMENT (sum lines 57, 63, 73, 83, 85)		11,385,062			11,385,062

Attachment A
Formula Rate - Non-Levelized
Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2010

PATH Allegheny Transmission Company, LLC
SUPPORTING CALCULATIONS AND NOTES

87	TRANSMISSION PLANT INCLUDED IN ISO RATES		
88	Total transmission plant (line 7, column 3)		9,717,786
89	Less transmission plant excluded from ISO rates (Note H)		0
90	Less transmission plant included in OATT Ancillary Services (Note H)		0
91	Transmission plant included in ISO rates (line 88 less lines 89 & 90)		9,717,786
92	Percentage of transmission plant included in ISO Rates (line 91 divided by line 88) [If line 88 equal zero, enter 1)	TP=	1.0000
93	TRANSMISSION EXPENSES		
94			
95	Total transmission expenses (line 44, column 3)		187,264
96	Less transmission expenses included in OATT Ancillary Services (Note G)		0
97	Included transmission expenses (line 95 less line 96)		187,264
98	Percentage of transmission expenses after adjustment (line 97 divided by line 95) [If line 95 equal zero, enter 1)		1.00000
99	Percentage of transmission plant included in ISO Rates (line 92)	TP	1.00000
100	Percentage of transmission expenses included in ISO Rates (line 98 times line 99)	TE=	1.00000

101	WAGES & SALARY ALLOCATOR (W&S)								
102		Form 1 Reference	$	TP	Allocation				
103	Production	354.20.b	0						
104	Transmission	354.21.b	903	1.00	903				
105	Distribution	354.23.b	0				W&S Allocator		
106	Other	354.24,25,26.b	332,721	1.00	332,721		($ / Allocation)		
107	Total (sum lines 103-106) [TP equals 1 if there are no wages & salaries]		333,624		333,624	=	1.00000	=	WS

108	COMMON PLANT ALLOCATOR (CE) (Note I)							
109			**$**	% Electric		W&S Allocator		
110	Electric	200.3.c	0	(line 110 / line 113)		(line 107)		CE
111	Gas	201.3.d	0	1.00000	x	1.00000	=	1.00000
112	Water	201.3.e	0					
113	Total (sum lines 110 - 112)		0					

114	RETURN (R)					$	
115							
116							
117			$	%	Cost	Weighted	
118	Long Term Debt (Note K)	(Attachment 4)	0	50%	6.76%	0.0338	=WCLTD
119	Preferred Stock	(Attachment 4)	0	0%	0.00%	0.0000	
120	Common Stock (Note J)	(Attachment 4)	0	50%	14.30%	0.0715	
121	Total (sum lines 118-120)		0	0.1053			=R

SUPPORTING CALCULATIONS AND NOTES

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2010

PATH Allegheny Transmission Company, LLC

General Note: References to pages in this formulary rate are indicated as: (page#, line#, col.#)
References to data from FERC Form 1 are indicated as: #.y.x (page, line, column)

Note Letter	
A	The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note F. Account 281 is not allocated.
B	Identified in Form 1 as being only transmission related.
C	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission Prepayments are the electric related prepayments booked to Account No. 165 and reported on Pages 110-111 line 57 in the Form 1.
D	EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, except safety, education, siting and out-reach related advertising included in Account 930.1. Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
E	Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.
F	The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 9, line 79).

Inputs Required:	FIT =	35.00%	
	SIT=	8.32%	(State Income Tax Rate or Composite SIT from Attachment 4)
	p =	0.00%	(percent of federal income tax deductible for state purposes)

G	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, if any.
H	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
I	Enter dollar amounts
J	ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.
K	The percentage shown for Long Term Debt is subject to the Annual Update and Attachment 6 and Attachment 9.

Attachment 1 - Revenue Credit Workpaper
PATH West Virginia Transmission Company, LLC

	Account 454 - Rent from Electric Property		
1	Rent from FERC Form No. 1 - Note 6		-
2	Other Electric Revenues	See	-
3	Schedule 1A		-
4	PTP Serv revs for which the load is not included in the divisor received by TO		-
5	PJM Transitional Revenue Neutrality (Note 1)		-
6	PJM Transitional Market Expansion (Note 1)		-
7	Professional Services (Note 3)		-
8	Revenues from Directly Assigned Transmission Facility Charges (Note 2)		-
9	Rent or Attachment Fees associated with Transmission Facilities (Note 3)		-
10	Gross Revenue Credits	Sum lines 2-9 + line 1	-
11	Less line 20	less line 18	-
12	Total Revenue Credits	line 10 + line 11	-
13	Revenues associated with lines 13 thru 18 are to be included in lines 1-9 and total of those revenues entered here		-
14	Income Taxes associated with revenues in line 15		-
15	One half margin (line 13 - line 14)/2		-
16	All expenses (other than income taxes) associated with revenues in line 13 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.		-
17	Line 15 plus line 16		-
18	Line 13 less line 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 page 2, line 2 of Rate Formula Template.

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.

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). DLC will retain 50% of net revenues consistent with *Pacific Gas and Electric Company*, 90 FERC ¶ 61,314. Note: in order to use lines 15 - 20, 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).

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 are not included in the total above to the extent they are credited under Schedule 12.

Attachment 1 - Revenue Credit Workpaper
PATH West Virginia Transmission Company, LLC

Note 5 Other electric Revenues - includes revenues for various related electricity products/premium services such as surge protectors and appliance guards

Note 6 All Account 454 and 456 Revenues must be itemized below

Account 454	Include	$
Joint pole attachments - telephone	Include	-
Joint pole attachments - cable	Include	-
Underground rentals	Include	-
Transmission tower wireless rentals	Include	-
Other rentals	Include	-
Corporate headquarters sublease	Include	-
Misc non-transmission rentals	Include	-
Customer commitment services	Include	-
xxxx		
xxxx		
Total		-
Account 456	Include	-
Other electric revenues	Include	-
Transmission Revenue - Firm	Include	-
Transmission Revenue - Non-Firm	Include	-
xxxx		-
xxxx		-
xxxx		-
xxxx		-
xxxx		-
xxxx		-
xxxx		-
Total		-
Total Account 454 and 456 included		-
Payments by PJM of the revenue requirement calculated on Rate Formula Template	Exclude	-
Total Account 454 and 456 included and excluded		-

Attachment 1 - Revenue Credit Workpaper
PATH Allegheny Transmission Company, LLC

	Account 454 - Rent from Electric Property		
1	Rent from FERC Form No. 1 - Note 6		-
2	Other Electric Revenues	See Note 5	-
3	Schedule 1A		-
4	PTP Serv revs for which the load is not included in the divisor received by TO		-
5	PJM Transitional Revenue Neutrality (Note 1)		-
6	PJM Transitional Market Expansion (Note 1)		-
7	Professional Services (Note 3)		-
8	Revenues from Directly Assigned Transmission Facility Charges (Note 2)		-
9	Rent or Attachment Fees associated with Transmission Facilities (Note 3)		-
10	Gross Revenue Credits	Sum lines 2-9 + line 1	-
11	Less line 20	less line 18	-
12	Total Revenue Credits	line 10 + line 11	-
13	Revenues associated with lines 13 thru 18 are to be included in lines 1-9 and total of those revenues entered here		-
14	Income Taxes associated with revenues in line 15		-
15	One half margin (line 13 - line 14)/2		-
16	All expenses (other than income taxes) associated with revenues in line 13 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.		-
17	Line 15 plus line 16		-
18	Line 13 less line 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 page 7, line 2 of Rate Formula Template.

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.

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). DLC will retain 50% of net revenues consistent with *Pacific Gas and Electric Company*, 90 FERC ¶ 61,314. Note: in order to use lines 15 - 20, 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).

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 are not included in the total above to the extent they are credited under Schedule 12.

Note 5 Other electric Revenues - includes revenues for various related electricity products/premium services such as surge protectors and appliance guards

Attachment 1 - Revenue Credit Workpaper
PATH Allegheny Transmission Company, LLC

Note 6 All Account 454 and 456 Revenues must be itemized below

Account 454	Include	$
Joint pole attachments - telephone	Include	-
Joint pole attachments - cable	Include	-
Underground rentals	Include	-
Transmission tower wireless rentals	Include	-
Other rentals	Include	-
Corporate headquarters sublease	Include	-
Misc non-transmission rentals	Include	-
Customer commitment services	Include	-
xxxx		
xxxx		
Total		-
Account 456	Include	-
Other electric revenues	Include	-
Transmission Revenue - Firm	Include	-
Transmission Revenue - Non-Firm	Include	-
xxxx		-
xxxx		-
xxxx		-
xxxx		-
xxxx		-
xxxx		-
xxxx		-
Total		-
Total Account 454 and 456 included		-
Payments by PJM of the revenue requirement calculated on Rate Formula Template	Exclude	-
Total Account 454 and 456 included and excluded		-

Attachment 3 - Calculation of Carrying Charges
PATH West Virginia Transmission Company, LLC

1 Calculation of Composite Depreciation Rate

2	Transmission Plant @ Beginning of Period	(Attachment 4)	-
3	Transmission Plant @ End of Period	(Attachment 4)	-
4	Sum	(sum lines 2 & 3)	-
5	Average Balance of Transmission Investment	(line 4/2)	-
6	Depreciation Expense	Rate Formula Template	-
7	Composite Depreciation Rate	(line 6/ line 5)	0.00%
8	Depreciable Life for Composite Depreciation Rate	(1/line 7)	-
9	Round line 8 to nearest whole year		-

Attachment 3 - Calculation of Carrying Charges

PATH Allegheny Transmission Company, LLC

1 Calculation of Composite Depreciation Rate

2	Transmission Plant @ Beginning of Period	(Attachment 4)	$ 9,717,786
3	Transmission Plant @ End of Period	(Attachment 4)	9,717,786
4	Sum	(sum lines 2 & 3)	$ 19,435,572
5	Average Balance of Transmission Investment	(line 4/2)	$ 9,717,786
6	Depreciation Expense	Rate Formula Template	-
7	Composite Depreciation Rate	(line 6/ line 5)	0.00%
8	Depreciable Life for Composite Depreciation Rate	(1/line 7)	-
9	Round line 8 to nearest whole year		-

Attachment 4 - Cost Support
PATH West Virginia Transmission Company, LLC

Plant in Service Worksheet

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			
1	**Calculation of Transmission Plant In Service**	Source	Year	Balance
2	December	p206.58.b	2009	-
3	January	company records	2010	-
4	February	company records	2010	-
5	March	company records	2010	-
6	April	company records	2010	-
7	May	company records	2010	-
8	June compan	y records	2010	-
9	July	company records	2010	-
10	August	company records	2010	-
11	September	company records	2010	-
12	October compan	y records	2010	-
13	November	company records	2010	-
14	December	p207.58.g	2010	-
15	**Transmission Plant In Service**	(sum lines 2-14) /13		-
16	**Calculation of Distribution Plant In Service**	Source		
17	December	p206.75.b	2009	-
18	January	company records	2010	-
19	February	company records	2010	-
20	March	company records	2010	-
21	April	company records	2010	-
22	May	company records	2010	-
23	June compan	y records	2010	-
24	July	company records	2010	-
25	August	company records	2010	-
26	September	company records	2010	-
27	October	company records	2010	-
28	November	company records	2010	-
29	December	p207.75.g	2010	-
30	**Distribution Plant In Service**	(sum lines 17-29) /13		-
31	**Calculation of Intangible Plant In Service**	Source		
32	December	p204.5.b	2009	-
33	December	p205.5.g	2010	-
34	**Intangible Plant In Service**	(sum lines 32 & 33) /2		-
35	**Calculation of General Plant In Service**	Source		
36	December	p206.99.b	2009	-
37	December	p207.99.g	2010	-
38	**General Plant In Service**	(sum lines 36 & 37) /2		-
39	**Calculation of Production Plant In Service**	Source		
40	December	p204.46b	2009	-
41	January	company records	2010	-
42	February	company records	2010	-
43	March	company records	2010	-
44	April	company records	2010	-
45	May	company records	2010	-
46	March	Attachment 6	2010	-
47	April	company records	2010	-
48	August	company records	2010	-
49	September	company records	2010	-
50	October	company records	2010	-
51	November	company records	2010	-
52	December	p205.46.g	2010	-
53	**Production Plant In Service**	(sum lines 40-52) /13		-

Attachment 4 - Cost Support
PATH West Virginia Transmission Company, LLC

54	**Calculation of Common Plant In Service**	Source	Year	Balance
55	December (Electric Portion)	p356	2009	-
56	December (Electric Portion)	p356	2010	-
57	**Common Plant In Service**	(sum lines 55 & 56) /2		-
58	**Total Plant In Service**	(sum lines 15, 30, 34, 38, 53, & 57)		-

Accumulated Depreciation Worksheet

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions					Details
59	**Calculation of Transmission Accumulated Depreciation**	Source	Year	Balance	
60	December	Prior year p219.25	2009	-	
61	January	company records	2010	-	
62	February	company records	2010	-	
63	March	company records	2010	-	
64	April	company records	2010	-	
65	May	company records	2010	-	
66	June compan	y records	2010	-	
67	July	company records	2010	-	
68	August	company records	2010	-	
69	September	company records	2010	-	
70	October	company records	2010	-	
71	November	company records	2010	-	
72	December	p219.25	2010	-	
73	**Transmission Accumulated Depreciation**	(sum lines 60-72) /13		-	
74	**Calculation of Distribution Accumulated Depreciation**	Source			
75	December	Prior year p219.26	2009	-	
76	January	company records	2010	-	
77	February	company records	2010	-	
78	March	company records	2010	-	
79	April	company records	2010	-	
80	May	company records	2010	-	
81	June compan	y records	2010	-	
82	July	company records	2010	-	
83	August	company records	2010	-	
84	September	company records	2010	-	
85	October compan	y records	2010	-	
86	November	company records	2010	-	
87	December	p219.26	2010	-	
88	**Distribution Accumulated Depreciation**	(sum lines 75-87) /13		-	
89	**Calculation of Intangible Accumulated Depreciation**	Source			
90	December	Prior year p200.21.c	2009	-	
91	December	p200.21c	2010	-	
92	**Accumulated Intangible Depreciation**	(sum lines 90 & 91) /2		-	
93	**Calculation of General Accumulated Depreciation**	Source			
94	December	Prior year p219.28	2009	-	
95	December	p219.28	2010	-	
96	**Accumulated General Depreciation**	(sum lines 94 & 95) /2		-	

Attachment 4 - Cost Support
PATH West Virginia Transmission Company, LLC

97	**Calculation of Production Accumulated Depreciation**	Source	Year	Balance
98	December	Prior year p219	2009	-
99	January	company records	2010	-
100	February	company records	2010	-
101	March	company records	2010	-
102	April	company records	2010	-
103	May	company records	2010	-
104	June compan	y records	2010	-
105	July	company records	2010	-
106	August	company records	2010	-
107	September	company records	2010	-
108	October compan	y records	2010	-
109	November	company records	2010	-
110	December	p219.20 thru 219.24	2010	-
111	**Production Accumulated Depreciation**	(sum lines 98-110) /13		-
112	**Calculation of Common Accumulated Depreciation**	Source		
113	December (Electric Portion)	p356	2009	-
114	December (Electric Portion)	p356	2010	-
115	**Common Plant Accumulated Depreciation (Electric Only)**	(sum lines 113 & 114) /2		-
116	**Total Accumulated Depreciation**	(sum lines 73, 88, 92, 96, 111, & 115)		-

ADJUSTMENTS TO RATE BASE (Note A)

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Beginning of Year	End of Year	Average Balance	Details
117	Account No. 281 (enter negative)	273.8.k	-	-	0	
118	Account No. 282 (enter negative)	275.2.k	(364)	(364)	(364)	
119	Account No. 283 (enter negative)	277.9.k	890,828	890,828	890,828	
120	Account No. 190	234.8.c	3,294,376	3,294,376	3,294,376	
121	Account No. 255 (enter negative)	267.8.h	-	-	0	
122	Unamortized Abandoned Plant	Per FERC Order	-	-	0	
123	Prepayments (Account 165)	111.57.c	31,830	31,830	31,830	

Attachment 4 - Cost Support
PATH West Virginia Transmission Company, LLC

					Amos Substation Upgrade	Amos to Welton Spring Line	Welton Spring Substation and SVC	Welton Spring to Interconnection with PATH Allegheny	Total
124	**Calculation of Transmission CWIP**	Source							
125	December	216.b	2009	$ 41,575,099	$ 3,406,476	$ 23,894,176	$ 10,950,342	$ 3,324,105	41,575,099
126	January	company records	2010	45,032,544	3,493,837	26,645,323	11,035,525	3,857,858	45,032,544
127	February	company records	2010	48,514,721	3,579,806	29,420,169	11,118,349	4,396,398	48,514,721
128	March	company records	2010	53,946,730	5,609,353	32,195,391	11,206,973	4,935,013	53,946,730
129	April	company records	2010	57,955,368	6,000,559	35,151,489	11,293,025	5,510,295	57,955,368
130	May	company records	2010	62,282,651	6,827,187	38,013,782	11,375,413	6,066,270	62,282,651
131	June compan	y records	2010	68,404,614	9,332,434	40,970,991	11,459,862	6,641,328	68,404,614
132	July	company records	2010	73,439,197	10,781,766	43,901,532	11,543,271	7,212,628	73,439,197
133	August	company records	2010	77,093,282	10,842,364	46,836,050	11,630,151	7,784,717	77,093,282
134	September	company records	2010	82,067,477	12,206,930	49,783,040	11,718,202	8,359,305	82,067,477
135	October compan	y records	2010	86,034,375	12,362,897	52,838,423	11,877,333	8,955,722	86,034,375
136	November	company records	2010	90,257,062	12,404,209	56,273,472	11,950,907	9,628,474	90,257,062
137	December	216.b	2010	108,912,785	25,302,027	60,368,198	12,808,697	10,433,863	108,912,785
138	**Transmission CWIP**	(sum lines 125-137) /13		$ 68,885,839	$ 9,396,142	$ 41,253,233	$ 11,536,004	$ 6,700,460	68,885,839

LAND HELD FOR FUTURE USE

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Beg of year	End of Year	Average	Details
139	**LAND HELD FOR FUTURE USE**	p214	Total	-	-	-	
			Non-transmission Related	-	-		
			Transmission Related	-	-	-	

EPRI Dues Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions					Details
	Allocated General & Common Expenses					
		EPRI Dues	Common Expenses	EPRI Dues	Common Expenses	
140	EPRI Dues & Common Expenses	p352-353	p356	-	-	

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
	Directly Assigned A&G					
141	Regulatory Commission Exp Account 928	p323.189.b	-	-	-	

Attachment 4 - Cost Support
PATH West Virginia Transmission Company, LLC

Safety Related Advertising, Education and Out Reach Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Form 1 Amount	Safety, Education, Siting & Outreach Related	Other	Details
	Directly Assigned A&G					
142	General Advertising Exp Account 930.1	p323.191.b	1,643,192	1,643,192	-	None

Multi-state Workpaper

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	State 1	State 2	State 3	State 4	State 5	Weighed Average
	Income Tax Rates						
			WV				
143	SIT=State Income Tax Rate or Composite		8.500%				8.50%

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			
144	Excluded Transmission Facilities		-	**General Description of the Facilities**
	Instructions:		**Enter $**	**None**
1	Remove all investment below 69 kV facilities, including the investment allocated to distribution of a dual function substation, generator, interconnection and local and direct assigned facilities for which separate costs are charged and step-up generation substation included in transmission plant in service.		-	
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

Materials & Supplies

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Beg of year	End of Year	Average
145	Assigned to O&M	p227.6	-	-	-
146	Stores Expense Undistributed	p227.16	-	-	-
147	Undistributed Stores Exp		-	-	-
148	Transmission Materials & Supplies	p227.8	-	-	-

Regulatory Asset

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				
149	Beginning Balance of Regulatory Asset	p111.72.d (and notes)	$ 3,914,814	Uncapitalized costs as of date the rates become effective
150	Months Remaining in Amortization Period		38	As approved by FERC
151	Monthly Amortization	(line 149 - line 153) / 152	$ 103,021	
152	Months in Year to be amortized		12	Number of months rates are in effect during the calendar year
153	Ending Balance of Regulatory Asset	p111.72.c	$ 2,678,557	
154	Average Balance of Regulatory Asset	(line 149 + line 153)/2	$ 3,296,685	

Attachment 4 - Cost Support
PATH West Virginia Transmission Company, LLC

Capital Structure

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

155	Monthly Balances for Capital Structure				
156		Year	Debt	Preferred Stock	Common Stock
157	January	2010	0	-	0
158	February	2010	-	-	-
159	March	2010	-	-	-
160	April	2010	-	-	-
161	May	2010	-	-	-
162	June	2010	-	-	-
163	July	2010	-	-	-
164	August	2010	-	-	-
165	September	2010	-	-	-
166	October	2010	-	-	-
167	November	2010	-	-	-
168	December	2010	-	-	-
169	Average		0	-	0

Note: the amount outstanding for debt retired during the year is the outstanding amount as of the last month it was outstanding; the equity is less Account 216.1, Preferred Stock, and Account 219; and the capital structure is fixed at 50/50 until the first two lines are placed in servic

Detail of Account 566 Miscellaneous Transmission Expenses

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

			Total
170	Amortization Expense on Regulatory Asset		$ 1,236,257
171	Miscellaneous Transmission Expense		-
172	Total Account 566	Footnote Data: Schedule Page 320 b. 97	$ 1,236,257

PBOPs

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Details
173	**Calculation of PBOP Expenses**		
174	**PATH-WV - AEP Employees**		
175	Total PBOP expenses	$ 117,254,159	
176	Amount relating to retired personnel	$ -	
177	Amount allocated on Labor	$ 117,254,159	
178	Labor dollars	$ 1,151,954,661	
179	Cost per labor dollar	$ 0.102	
180	PATH WV labor (labor not capitalized) current year	$ 867,609	
181	PATH WV PBOP Expense for current year	$ 88,311	
182	PATH WV PBOP Expense in Account 926 for current year	$ 88,311	
183	PBOP Adjustment for Appendix A, Line 50	$ -	
184	Lines 175-179 cannot change absent approval or acceptance by FERC in a separate proceeding.		
184	**PATH-WV - Allegheny Employees**		
185	Total PBOP expenses	$ 22,856,433	
186	Amount relating to retired personnel	$ 8,786,372	
187	Amount allocated on FTEs	$ 14,070,061	
188	Number of FTEs	4,474	
189	Cost per FTE	$ 3,145	
190	PATH WV FTEs (labor not capitalized) current year	10.92	
191	PATH WV PBOP Expense for current year	$ 34,345	
192	PATH WV PBOP Expense in Account 926 for current year	$ 29,248	
193	PBOP Adjustment for Appendix A, Line 50	$ 5,097	
194	Lines 185-189 cannot change absent approval or acceptance by FERC in a separate proceeding.		

195	PBOP Expense adjustment	(sum lines 183 & 193)	$	5,097

Attachment 4 - Cost Support

PATH Allegheny Transmission Company, LLC

Plant in Service Worksheet

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

1	**Calculation of Transmission Plant In Service**	Source	Year		Balance
2	December	p206.58.b	2009	$	9,717,786
3	January	company records	2010		9,717,786
4	February	company records	2010		9,717,786
5	March	company records	2010		9,717,786
6	April	company records	2010		9,717,786
7	May	company records	2010		9,717,786
8	June company	records	2010		9,717,786
9	July	company records	2010		9,717,786
10	August	company records	2010		9,717,786
11	September	company records	2010		9,717,786
12	October company	records	2010		9,717,786
13	November	company records	2010		9,717,786
14	December	p207.58.g	2010		9,717,786
15	**Transmission Plant In Service**	(sum lines 2-14) /13		$	9,717,786
16	**Calculation of Distribution Plant In Service**	Source			
17	December	p206.75.b	2009		-
18	January	company records	2010		-
19	February	company records	2010		-
20	March	company records	2010		-
21	April	company records	2010		-
22	May	company records	2010		-
23	June company	records	2010		-
24	July	company records	2010		-
25	August	company records	2010		-
26	September	company records	2010		-
27	October	company records	2010		-
28	November	company records	2010		-
29	December	p207.75.g	2010		-
30	**Distribution Plant In Service**	(sum lines 17-29) /13			-
31	**Calculation of Intangible Plant In Service**	Source			
32	December	p204.5b	2009		-
33	December	p205.5.g	2010		-
34	**Intangible Plant In Service**	(sum lines 32 & 33) /2			-
35	**Calculation of General Plant In Service**	Source			
36	December	p206.99.b	2009	$	45,324
37	December	p207.99.g	2010		45,324
38	**General Plant In Service**	(sum lines 36 & 37) /2		$	45,324
39	**Calculation of Production Plant In Service**	Source			
40	December	p204.46b	2009		-
41	January	company records	2010		-
42	February	company records	2010		-
43	March	company records	2010		-
44	April	company records	2010		-
45	May	company records	2010		-
46	March	Attachment 6	2010		-
47	April	company records	2010		-
48	August	company records	2010		-
49	September	company records	2010		-
50	October	company records	2010		-
51	November	company records	2010		-
52	December	p205.46.g	2010		-
53	**Production Plant In Service**	(sum lines 40-52) /13			-

	A	B	C	D	E	F	G	H	I	J	K	L	M
64													
65													
66						**Attachment 4 - Cost Support**							
67						**PATH Allegheny Transmission Company, LLC**							
68													
69													
70	54		**Calculation of Common Plant In Service**	Source	Year	Balance							
71	55		December (Electric Portion)	p356	2009	-							
72	56		December (Electric Portion)	p356	2010	-							
73	57		**Common Plant In Service**	(sum lines 55 & 56) /2		-							
74													
75	58		**Total Plant In Service**	(sum lines 15, 30, 34, 38, 53, & 57)		$ 9,763,110							
76													
77													
78													
79	**Accumulated Depreciation Worksheet**												
80			Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions								Details		
81	59		**Calculation of Transmission Accumulated Depreciation**	Source	Year	Balance							
82	60		December	Prior year p219.25	2009	-							
83	61		January	company records	2010	-							
84	62		February	company records	2010	-							
85	63		March	company records	2010	-							
86	64		April	company records	2010	-							
87	65		May	company records	2010	-							
88	66		June company	records	2010	-							
89	67		July	company records	2010	-							
90	68		August	company records	2010	-							
91	69		September	company records	2010	-							
92	70		October	company records	2010	-							
93	71		November	company records	2010	-							
94	72		December	p219.25	2010	-							
95	73		**Transmission Accumulated Depreciation**	(sum lines 60-72) /13		-							
96													
97	74		**Calculation of Distribution Accumulated Depreciation**	Source									
98	75		December	Prior year p219.26	2009	-							
99	76		January	company records	2010	-							
100	77		February	company records	2010	-							
101	78		March	company records	2010	-							
102	79		April	company records	2010	-							
103	80		May	company records	2010	-							
104	81		June company	records	2010	-							
105	82		July	company records	2010	-							
106	83		August	company records	2010	-							
107	84		September	company records	2010	-							
108	85		October company	records	2010	-							
109	86		November	company records	2010	-							
110	87		December	p219.26	2010	-							
111	88		**Distribution Accumulated Depreciation**	(sum lines 75-87) /13		-							
112													
113	89		**Calculation of Intangible Accumulated Depreciation**	Source									
114	90		December	Prior year p200.21.c	2009								
115	91		December	p200.21c	2010								
116	92		**Accumulated Intangible Depreciation**	(sum lines 90 & 91) /2									
117													
118	93		**Calculation of General Accumulated Depreciation**	Source									
119	94		December	Prior year p219.28	2009	$ 535							
120	95		December	p219.28	2010	2,677							
121	96		**Accumulated General Depreciation**	(sum lines 94 & 95) /2		$ 1,606							
122													

	A	B	C	D	E	F	G	H	I	J	K	L	M
123													
124						**Attachment 4 - Cost Support**							
125						**PATH Allegheny Transmission Company, LLC**							
126													
127													
128	97		**Calculation of Production Accumulated Depreciation**	Source	Year	Balance							
129	98		December	Prior year p219	2009	-							
130	99		January	company records	2010	-							
131	100		February	company records	2010	-							
132	101		March	company records	2010	-							
133	102		April	company records	2010	-							
134	103		May	company records	2010	-							
135	104		June company	records	2010	-							
136	105		July	company records	2010	-							
137	106		August	company records	2010	-							
138	107		September	company records	2010	-							
139	108		October company	records	2010	-							
140	109		November	company records	2010	-							
141	110		December	p219.20 thru 219.24	2010	-							
142	111		**Production Accumulated Depreciation**	(sum lines 98-110) /13		-							
143													
144	112		**Calculation of Common Accumulated Depreciation**	Source									
145	113		December (Electric Portion)	p356	2009	-							
146	114		December (Electric Portion)	p356	2010	-							
147	115		**Common Plant Accumulated Depreciation (Electric Only)**	(sum lines 113 & 114) /2		-							
148													
149	116		**Total Accumulated Depreciation**	(sum lines 73, 88, 92, 96, 111, & 115)		$ 1,606							
150													
151													
152	**ADJUSTMENTS TO RATE BASE (Note A)**												
153			**Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions**								**Details**		
154					Beginning of Year	End of Year	Average Balance						
155	117		Account No. 281 (enter negative)	273.8.k	-	-	0						
156	118		Account No. 282 (enter negative)	275.2.k	(3,502)	(3,502)	(3,502)						
157	119		Account No. 283 (enter negative)	277.9.k	-	-	0						
158	120		Account No. 190	234.8.c	322,057	322,057	322,057						
159	121		Account No. 255 (enter negative)	267.8.h	-	-	0						
160													
161													
162	122		Unamortized Abandoned Plant	Per FERC Order	-	-	0						
163													
164	123		Prepayments (Account 165)	111.57.c	5,714	5,752	5,733						
165													

Attachment 4 - Cost Support
PATH Allegheny Transmission Company, LLC

	Calculation of Transmission CWIP	Source			Kemptown Substation	Kemptown to Interconnection with PATH West Virginia	Welton Spring Substation	**Total**
125	December	216.b	2009	$ 23,457,297	$ 4,169,044	$ 13,110,895	$ 6,177,359	$ 23,457,297
126	January	company records	2010	26,434,429	4,662,193	15,453,599	6,318,637	26,434,429
127	February	company records	2010	29,023,172	5,127,290	17,446,786	6,449,096	29,023,172
128	March	company records	2010	32,035,731	5,600,142	19,845,079	6,590,510	32,035,731
129	April	company records	2010	34,727,297	6,063,491	21,934,377	6,729,428	34,727,297
130	May	company records	2010	37,310,892	6,510,442	23,940,291	6,860,160	37,310,892
131	June company	records	2010	40,146,867	6,993,030	26,141,486	7,012,351	40,146,867
132	July	company records	2010	42,889,879	7,438,336	28,287,322	7,164,221	42,889,879
133	August	company records	2010	45,661,112	7,893,656	30,447,551	7,319,904	45,661,112
134	September	company records	2010	55,429,065	8,328,319	39,632,275	7,468,472	55,429,065
135	October company	records	2010	58,084,723	8,739,098	41,745,148	7,600,477	58,084,723
136	November	company records	2010	60,856,265	9,142,147	43,984,726	7,729,392	60,856,265
137	December	216.b	2010	63,923,996	9,555,441	46,506,094	7,862,460	63,923,996
138	**Transmission CWIP**	(sum lines 125-137) /13		$ 42,306,210	$ 6,940,202	$ 28,344,279	$ 7,021,728	$ 42,306,210

LAND HELD FOR FUTURE USE

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Beg of year	End of Year	Average	Details
139	**LAND HELD FOR FUTURE USE**	p214	Total	-	-	-	
			Non-transmission Related	-	-		
			Transmission Related	-	-	-	

EPRI Dues Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions					Details
	Allocated General & Common Expenses	EPRI Dues	Common Expenses	EPRI Dues	Common Expenses	
140	EPRI Dues & Common Expenses	p352-353	p356	-	-	

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	Details
	Directly Assigned A&G					
141	Regulatory Commission Exp Account 928	p323.189.b	35,029	35,029	-	

Attachment 4 - Cost Support

PATH Allegheny Transmission Company, LLC

Safety Related Advertising, Education and Out Reach Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Form 1 Amount	Safety, Education, Siting & Outreach Related	Other	Details
	Directly Assigned A&G					
142	General Advertising Exp Account 930.1	p323.191.b	136,313	136,313	-	None

Multi-state Workpaper

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	State 1	State 2	State 3	State 4	State 5	Weighed Average
	Income Tax Rates						
		MD	**WV**				
143	SIT=State Income Tax Rate or Composite	8.25%	8.50%				8.322%

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			
144	Excluded Transmission Facilities		-	**General Description of the Facilities**
	Instructions:		**Enter $**	**None**
1	Remove all investment below 69 kV facilities, including the investment allocated to distribution of a dual function substation, generator, interconnection and local and direct assigned facilities for which separate costs are charged and step-up generation substation included in transmission plant in service.		-	
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

Materials & Supplies

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Beg of year	End of Year	Average
145	Assigned to O&M	p227.6	-	-	-
146	Stores Expense Undistributed	p227.16	-	-	-
147	Undistributed Stores Exp		-	-	-
148	Transmission Materials & Supplies	p227.8	-	-	-

Regulatory Asset

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			
149	Beginning Balance of Regulatory Asset	p111.72.d (and notes)	$ 593,003	Uncapitalized costs as of date the rates become effective
150	Months Remaining in Amortization Period		38	As approved by FERC
151	Monthly Amortization	(line 149 - line 153) / 152	$ 15,605	
152	Months in Year to be Amortized		12	Number of months rates are in effect during the calendar year
153	Ending Balance of Regulatory Asset	p111.72.c	$ 405,739	
154	Average Balance of Regulatory Asset	(line 149 + line 153)/2	$ 499,371	

Attachment 4 - Cost Support
PATH Allegheny Transmission Company, LLC

Capital Structure

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

		Year	Debt	Preferred Stock	Common Stock
155	Monthly Balances for Capital Structure				
156					
157	January	2010	0	-	0
158	February	2010	-	-	-
159	March	2010	-	-	-
160	April	2010	-	-	-
161	May	2010	-	-	-
162	June	2010	-	-	-
163	July	2010	-	-	-
164	August	2010	-	-	-
165	September	2010	-	-	-
166	October	2010	-	-	-
167	November	2010	-	-	-
168	December	2010	-	-	-
169	Average		0	-	0

Note: the amount outstanding for debt retired during the year is the outstanding amount as of the last month it was outstanding; the equity is less Account 216.1, Preferred Stock, and Account 219; and the capital structure is fixed at 50/50 until the first two lines are placed in servic

Detail of Account 566 Miscellaneous Transmission Expenses

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

			Total
170	Amortization Expense on Regulatory Asset		$ 187,264
171	Miscellaneous Transmission Expense		-
172	Total Account 566	Footnote Data: Schedule Page 320 b. 97	$ 187,264

PBOPs

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Details
173	**Calculation of PBOP Expenses**		
174	**PATH - Allegheny - Allegheny Employees**		
175	Total PBOP expenses	$ 22,856,433	
176	Amount relating to retired personnel	$ 8,786,372	
177	Amount allocated on FTEs	$ 14,070,061	
178	Number of FTEs	4,475	
179	Cost per FTE	$ 3,144	
180	PATH Allegheny FTEs (labor not capitalized) current year	0.54	
181	PATH Allegheny PBOP Expense for current year	$ 1,711	
182	PATH Allegheny PBOP Expense in Account 926 for current year	$ 504	
183	PBOP Adjustment for Appendix A, Line 50	$ 1,207	
184	Lines 175-179 cannot change absent approval or acceptance by FERC in a separate proceeding.		

Attachment 5 - Transmission Enhancement Charge Worksheet

PATH West Virginia Transmission Company, LLC

1 New Plant Carrying Charge

	Formula Line	Item	
2	Formula Line	Item	
3	5	NET REVENUE REQUIREMENT	12,480,138
4	21	NET TRANSMISSION PLANT IN SERVICE	-
5	32	CWIP	68,885,839
6		**Carrying charge (line 3/sum of lines 4 and 5)**	**0.18117**

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

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

				(1)	(2)	(3)	(4)	(5)	(6)
				PJM Upgrade ID: b0490 & b0491					
9		Details		Amos Substation Upgrade - CWIP	Amos to Welton Spring Line - CWIP	Welton Spring Substation and SVC - CWIP	**Welton Spring to Interconnection with PATH Allegheny - CWIP**	Transmission Plant In Service	Totals
10	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes		Yes	
11		FCR for This Project		18.1%	18.1%	18.1%	18.1%	18.1%	
12	Forecast – Forecast of average 13 month current year net transmission plant plus 13-mo CWIP balances. Reconciliation – Average of 13 month prior year net transmission plant balances plus prior year 13-mo CWIP balances.	Investment		9,396,142	41,253,233	11,536,004	6,700,460	-	68,885,839
		Revenue Requirement		1,702,311.45	7,473,902.77	2,089,993.06	1,213,931.12	-	12,480,138.40

Attachment 5 - Transmission Enhancement Charge Worksheet

PATH Allegheny Transmission Company, LLC

1 New Plant Carrying Charge

	Formula Line	Item	
2	Formula Line	Item	
3	5	NET REVENUE REQUIREMENT	10,572,847
4	21	NET TRANSMISSION PLANT IN SERVICE	9,717,786
5	32	CWIP	42,306,210
6		**Carrying charge (line 3/sum of lines 4 and 5)**	**0.20323**

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

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

				(1)	(2)	(3)	(4)	(5)
				PJM Upgrade ID: b0492 & b0560				
9		Details		Kemptown Substation - CWIP	Kemptown to Interconnection with PATH West Virginia - CWIP	Welton Spring Substation - CWIP	Transmission Plant In Service	Totals
10	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes	
11		FCR for This Project		20.3%	20.3%	20.3%	20.3%	
12	Forecast – Forecast of average 13 month current year net transmission plant plus 13-mo CWIP balances. Reconciliation – Average of 13 month prior year net transmission plant balances plus prior year 13-mo CWIP balances.	Investment		6,940,202	28,344,279	7,021,728	9,717,786	52,023,995
		Revenue Requirement		1,410,458.71	5,760,413.68	1,427,027.27	1,974,947.60	10,572,847.27

Attachment 6 - Financing Costs for Long Term Debt using the Internal Rate of Return Methodology -- PATH-W\

HYPOTHETICAL EXAMPLE

PATH anticipates its financing will be a 7 year loan, where by PATH pays Origination Fees of $7.9 million and a Commitments Fee of 0.375% on the undrawn principle.
Consistent with GAAP, PATH will amortize the Origination Fees and Commitments Fees using the standard Internal Rate of Return formula below.
Each year, PATH will true up the amounts withdrawn, the interest paid in the year, Origination Fees, Commitments Fees, and total loan amount on this attachment.

Total Loan Amount	**$ 600,000,000**

Internal Rate of Return[1] **6.64%**

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

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

Origination Fees	
Underwriting Discount	-
Arrangement Fee	2,000,000
Upfront Fee	4,400,000
Rating Agency Fee	200,000
Legal Fees	1,250,000
Total Issuance Expense	**7,850,000**

Annual Rating Agency Fee	200,000
Annual Bank Agency Fee	75,000
Revolving Credit Commitment Fee	0.375%

	2008	2009	2010	2011	2012	2013	2014
LIBOR Rate	4.0610%	4.0610%	4.0610%	4.0610%	4.0610%	4.0610%	4.0610%
Spread	1.875%	1.875%	1.875%	1.875%	1.875%	1.875%	1.875%
Interest Rate	5.94%	5.94%	5.94%	5.94%	5.94%	5.94%	5.94%

(A) Year	(B)	(C) Capital Expenditures ($000's)	(D) Principle Drawn In Quarter ($000's)	(E) Principle Drawn To Date ($000's)	(F) Interest Expense ($000's)	(G) Origination Fees ($000's)	(H) Commitment & Utilization Fee ($000's)	(I) Net Cash Flows ($000's) (D-F-G-H)
Prior to 11/2008		16,529						
11/30/2008	Q4	8,923		-	-			-
2/15/2009	Q1	14,636	20,044	20,044	-	125		19,919
5/15/2009	Q2	17,119	8,560	28,604	297			8,262
8/15/2009	Q3	46,132	23,066	51,670	424			22,642
11/15/2009	Q4	62,740	31,370	83,040	767			30,603
2/15/2010	Q1	132,393	66,197	149,236	1,232	7,725	553	56,686
5/15/2010	Q2	132,393	66,197	215,433	2,215		491	63,490
8/15/2010	Q3	132,393	66,197	281,629	3,197		429	62,570
11/15/2010	Q4	132,393	66,197	347,826	4,179		367	61,650
2/15/2011	Q1	70,588	35,294	383,120	5,162		305	29,827
5/15/2011	Q2	70,588	35,294	418,414	5,685		272	29,336
8/15/2011	Q3	70,588	35,294	453,708	6,209		239	28,846
11/15/2011	Q4	70,588	35,294	489,002	6,733		206	28,355
2/15/2012	Q1	51,885	25,943	514,944	7,257		173	18,513
5/15/2012	Q2	51,885	25,943	540,887	7,642		148	18,152
8/15/2012	Q3	51,885	25,943	566,829	8,027		124	17,792
11/15/2012	Q4	51,885	25,943	592,772	8,412		100	17,431
2/15/2013	Q1	11,122	7,228	600,000	8,797		76	(1,644)
5/15/2013	Q2			600,000	8,904		69	(8,973)
8/15/2013	Q3			600,000	8,904		69	(8,973)
11/15/2013	Q4			600,000	8,904		69	(8,973)
2/15/2014	Q1			600,000	8,904		69	(8,973)
5/15/2014	Q2			600,000	8,904		69	(8,973)
8/15/2014	Q3			600,000	8,904		69	(8,973)
11/15/2014	Q4			600,000	8,904		69	(8,973)
2/15/2015	Q1			600,000	8,904		-	(608,903)

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1 The IRR is the Debt Cost shown on Page 5, Line 118 of Rate Formula Template.

[2] The IRR is a discount rate that makes the net present value of a series of cash flows equal to zero. The IRR equation can only be solved through iterations performed by a computer program (i.e.NPV function with goal seek in a spreadsheet program).

Attachment 6 - Financing Costs for Long Term Debt using the Internal Rate of Return Methodology -- PATH-Allegheny

HYPOTHETICAL EXAMPLE

PATH anticipates its financing will be a 7 year loan, where by PATH pays Origination Fees of $4.2 million and a Commitments Fee of 0.375% on the undrawn principle.
Consistent with GAAP, PATH will amortize the Origination Fees and Commitments Fees using the standard Internal Rate of Return formula below.
Each year, PATH will true up the amounts withdrawn, the interest paid in the year, Origination Fees, Commitments Fees, and total loan amount on this attachment.

Total Loan Amount	**$ 300,000,000**

Internal Rate of Return[1]	**6.76%**

Based on following Financial Formula[2]:

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

Origination Fees	
Underwriting Discount	-
Arrangement Fee	1,000,000
Upfront Fee	2,200,000
Rating Agency Fee	200,000
Legal Fees	750,000
Total Issuance Expense	**4,150,000**

Annual Rating Agency Fee	200,000
Annual Bank Agency Fee	75,000
Revolving Credit Commitment Fee	0.375%

	2008	2009	2010	2011	2012	2013	2014
LIBOR Rate	4.0610%	4.0610%	4.0610%	4.0610%	4.0610%	4.0610%	4.0610%
Spread	1.875%	1.875%	1.875%	1.875%	1.875%	1.875%	1.875%
Interest Rate	5.94%	5.94%	5.94%	5.94%	5.94%	5.94%	5.94%

(A) **Year**	(B)	(C) **Capital Expenditures ($000's)**	(D) **Principle Drawn In Quarter ($000's)**	(E) **Principle Drawn To Date ($000's)**	(F) **Interest Expense ($000's)**	(G) **Origination Fees ($000's)**	(H) **Commitment & Utilization Fee ($000's)**	(I) **Net Cash Flows ($000's) (D-F-G-H)**
Prior to 11/2008		8,672						
11/15/2008	Q4	13,079		-	-			-
2/15/2009	Q1	18,143	19,947	19,947	-	75		19,872
5/15/2009	Q2	17,756	8,878	28,825	296			8,582
8/15/2009	Q3	24,818	12,409	41,234	428			11,981
11/15/2009	Q4	33,644	16,822	58,056	612			16,210
2/15/2010	Q1	33,686	16,843	74,899	862	4,075	296	11,611
5/15/2010	Q2	30,717	15,359	90,258	1,112		280	13,967
8/15/2010	Q3	39,142	19,571	109,829	1,339		265	17,966
11/15/2010	Q4	41,965	20,983	130,811	1,630		247	19,106
2/15/2011	Q1	52,638	26,319	157,130	1,941		227	24,150
5/15/2011	Q2	47,999	24,000	181,130	2,332		203	21,465
8/15/2011	Q3	61,165	30,583	211,712	2,688		180	27,714
11/15/2011	Q4	65,576	32,788	244,500	3,142		152	29,495
2/15/2012	Q1	29,076	14,538	259,038	3,628		121	10,789
5/15/2012	Q2	26,514	13,257	272,295	3,844		107	9,306
8/15/2012	Q3	33,786	16,893	289,188	4,041		95	12,757
11/15/2012	Q4	21,624	10,812	300,000	4,292		79	6,442
2/15/2013	Q1			300,000	4,452		69	(4,521)
5/15/2013	Q2			300,000	4,452		69	(4,521)
8/15/2013	Q3			300,000	4,452		69	(4,521)
11/15/2013	Q4			300,000	4,452		69	(4,521)
2/15/2014	Q1			300,000	4,452		69	(4,521)
5/15/2014	Q2			300,000	4,452		69	(4,521)
8/15/2014	Q3			300,000	4,452		69	(4,521)
11/15/2014	Q4			300,000	4,452		69	(4,521)
2/15/2015	Q1			300,000	4,452		-	(304,452)

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[1] The IRR is the Debt Cost shown on Page 10, Line 118 of Rate Formula Template.

[2] The IRR is a discount rate that makes the net present value of a series of cash flows equal to zero. The IRR equation can only be solved through iterations performed by a computer program (i.e.NPV function with goal seek in a spreadsheet program).

Attachment 7

Potomac-Appalachian Transmission Highline, LLC

PATH West Virginia Transmission Company, LLC

CALCULATION OF COST OF DEBT AFTER CONSTRUCTION PHASE

YEAR ENDED 12/31/2014

(HYPOTHETICAL EXAMPLE)

	Amount Outstanding	Unamortized Debt Issue Expense	Unamortized Debt Premium/ (Discount)	Unamortized Losses on Reacquired Debt	Net Amount Outstanding	Effective Cost Rate[1]	Annualized Cost
Debt:							
First Mortgage Bonds:							
	$ 300,000,000	$2,900,000	($2,320,000)	$0	$294,780,000	7.237%	$ 21,333,422
Other Long Term Debt:							
6.600% Series Medium Term Notes Due 2021	$ 200,000,000	$1,800,000		-	$198,200,000	6.734%	$ 13,347,503
					-		
Total Debt	$ 500,000,000	$ 4,700,000	$ (2,320,000)	$ -	$ 492,980,000 7.035%		$ 34,680,924
Check with FERC Form 1 B/S pgs 110-113	$ 185,750,000	$ (1,131,082)	$ (1,595,909)	$ 17,075,452			

Development of Effective Cost Rates:

	Issue Date	Maturity Date	Amount Issued	(Discount) Premium at Issuance	Issuance Expense	Loss on Reacquired Debt	Net Proceeds	Net Proceeds Ratio	Coupon Rate	Effective Cost Rate	Annual Interest
First Mortgage Bonds											
7.090% Series Due 2041	1/1/2014	6/30/2044	$ 300,000,000	$ (2,400,000)	$ 3,000,000	-	$ 294,600,000	98.2000	0.07090	7.237%	$ 21,270,000
											-
Other Long Term Debt:											-
6.600% Series Medium Term Notes Due 2021	01/01/2014	06/30/2024	200,000,000		2,000,000		$ 198,000,000	99.0000	0.06600	6.734%	13,200,000
			$ 500,000,000	(2,400,000)	$ 5,000,000	-	$ 492,600,000				$ 34,470,000

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[1] The Effective Cost Rate is the Debt Cost shown on Page 5, Line 118 of Rate Formula Template.

Attachment 7
PATH Allegheny Transmission Company, LLC

Potomac-Appalachian Transmission Highline, LLC
CALCULATION OF COST OF DEBT AFTER CONSTRUCTION PHASE
YEAR ENDED 12/31/2014

(HYPOTHETICAL EXAMPLE)

	Amount Outstanding	Unamortized Debt Issue Expense	Unamortized Debt Premium/ (Discount)	Unamortized Losses on Reacquired Debt	Net Amount Outstanding	Effective Cost Rate[1]	Annualized Cost
Debt:							
First Mortgage Bonds:							
	$ 300,000,000	$2,900,000	($2,320,000)	$0	$294,780,000	7.237%	$ 21,333,422
Other Long Term Debt:							
6.600% Series Medium Term Notes Due 2021	$ 200,000,000	$1,800,000		-	$198,200,000	6.734%	$ 13,347,503
					-		
Total Debt	$ 500,000,000	$ 4,700,000	$ (2,320,000)	$ -	$ 492,980,000	**7.035%**	$ 34,680,924
Check with FERC Form 1 B/S pgs 110-113	$ 185,750,000	$ (1,131,082)	$ (1,595,909)	$ 17,075,452			

Development of Effective Cost Rates:	Issue Date	Maturity Date	Amount Issued	(Discount) Premium at Issuance	Issuance Expense	Loss on Reacquired Debt	Net Proceeds	Net Proceeds Ratio	Coupon Rate	Effective Cost Rate	Annual Interest
First Mortgage Bonds											
7.090% Series Due 2041	1/1/2014	6/30/2044	$ 300,000,000	$ (2,400,000)	$ 3,000,000	-	$ 294,600,000	98.2000	0.07090	7.237%	$ 21,270,000
											-
Other Long Term Debt:											-
6.600% Series Medium Term Notes Due 2021	01/01/2014	06/30/2024	200,000,000		2,000,000		$ 198,000,000	99.0000	0.06600	6.734%	13,200,000
			$ 500,000,000	(2,400,000)	$ 5,000,000	-	$ 492,600,000				$ 34,470,000

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[1] The Effective Cost Rate is the Debt Cost shown on Page 10, Line 118 of Rate Formula Template.

Attachment 8
Potomac-Appalachian Transmission Highline, LLC
Example of Interest Rates and Interest Calculations
PATH West Virginia Transmission Company, LLC

Reconciliation Revenue Requirement For Year 2008 Available May 31, 2009		2008 Revenue Requirement Forecast by March 1, 2008		True-up Adjustment - Over (Under) Recovery
$6,483,059	-	$11,575,595	=	$5,092,536

Interest Rate on Amount of Refunds or Surcharges		Over (Under) Recovery Plus Interest	Monthly Interest Rate	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
from 35.19a			0.4365%				
An over or under collection will be recovered prorata over 2008, held for 2009 and returned prorate over 2010							
		$			$		$
Calculation of Interest					Monthly		
January	Year 2008		0.4365%	12			
February	Year 2008		0.4365%	11			
March	Year 2008	509,254	0.4365%	10	(22,229)		(531,483)
April	Year 2008	509,254	0.4365%	9	(20,006)		(529,260)
May	Year 2008	509,254	0.4365%	8	(17,783)		(527,037)
June	Year 2008	509,254	0.4365%	7	(15,560)		(524,814)
July	Year 2008	509,254	0.4365%	6	(13,337)		(522,591)
August	Year 2008	509,254	0.4365%	5	(11,114)		(520,368)
September	Year 2008	509,254	0.4365%	4	(8,892)		(518,145)
October	Year 2008	509,254	0.4365%	3	(6,669)		(515,922)
November	Year 2008	509,254	0.4365%	2	(4,446)		(513,699)
December	Year 2008	509,254	0.4365%	1	(2,223)		(511,477)
					(122,259)		(5,214,795)
					Annual		
January through December	Year 2009	(5,214,795)	0.4365%	12	(273,151)		(5,487,946)
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					Monthly		
January	Year 2010	5,487,946	0.4365%		(23,955)	470,408	(5,041,493)
February	Year 2010	5,041,493	0.4365%		(22,006)	470,408	(4,593,091)
March	Year 2010	4,593,091	0.4365%		(20,049)	470,408	(4,142,732)
April	Year 2010	4,142,732	0.4365%		(18,083)	470,408	(3,690,407)
May	Year 2010	3,690,407	0.4365%		(16,109)	470,408	(3,236,108)
June	Year 2010	3,236,108	0.4365%		(14,126)	470,408	(2,779,825)
July	Year 2010	2,779,825	0.4365%		(12,134)	470,408	(2,321,551)
August	Year 2010	2,321,551	0.4365%		(10,134)	470,408	(1,861,277)
September	Year 2010	1,861,277	0.4365%		(8,124)	470,408	(1,398,993)
October	Year 2010	1,398,993	0.4365%		(6,107)	470,408	(934,692)
November	Year 2010	934,692	0.4365%		(4,080)	470,408	(468,364)
December	Year 2010	468,364	0.4365%		(2,044)	470,408	0
					(156,950)		

True-Up Adjustment with Interest	$	(5,644,896)
Less Over (Under) Recovery	$	5,092,536
Total Interest	$	(552,360)

Attachment 8
Potomac-Appalachian Transmission Highline, LLC
Interest Rates and Interest Calculations
PATH Allegheny Transmission Company, LLC

Reconciliation Revenue Requirement For Year 2008 Available May 31, 2009		2008 Revenue Requirement Forecast by March 1, 2008		True-up Adjustment - Over (Under) Recovery
$2,131,722	-	$2,864,460	=	$732,738

Interest Rate on Amount of Refunds or Surcharges		Over (Under) Recovery Plus Interest	Monthly Interest Rate	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
from 35.19a			0.4365%				
An over or under collection will be recovered prorata over 2008, held for 2009 and returned prorate over 2010							
		$			$		$
Calculation of Interest					Monthly		
January	Year 2008		0.4365%	12			
February	Year 2008		0.4365%	11			
March	Year 2008	73,274	0.4365%	10	(3,198)		(76,472)
April	Year 2008	73,274	0.4365%	9	(2,879)		(76,152)
May	Year 2008	73,274	0.4365%	8	(2,559)		(75,833)
June	Year 2008	73,274	0.4365%	7	(2,239)		(75,513)
July	Year 2008	73,274	0.4365%	6	(1,919)		(75,193)
August	Year 2008	73,274	0.4365%	5	(1,599)		(74,873)
September	Year 2008	73,274	0.4365%	4	(1,279)		(74,553)
October	Year 2008	73,274	0.4365%	3	(960)		(74,233)
November	Year 2008	73,274	0.4365%	2	(640)		(73,913)
December	Year 2008	73,274	0.4365%	1	(320)		(73,594)
					(17,591)		(750,329)
					Annual		
January through December	Year 2009	(750,329)	0.4365%	12	(39,302)		(789,632)
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					Monthly		
January	Year 2010	789,632	0.4365%		(3,447)	67,685	(725,394)
February	Year 2010	725,394	0.4365%		(3,166)	67,685	(660,876)
March	Year 2010	660,876	0.4365%		(2,885)	67,685	(596,076)
April	Year 2010	596,076	0.4365%		(2,602)	67,685	(530,993)
May	Year 2010	530,993	0.4365%		(2,318)	67,685	(465,626)
June	Year 2010	465,626	0.4365%		(2,032)	67,685	(399,974)
July	Year 2010	399,974	0.4365%		(1,746)	67,685	(334,036)
August	Year 2010	334,036	0.4365%		(1,458)	67,685	(267,809)
September	Year 2010	267,809	0.4365%		(1,169)	67,685	(201,294)
October	Year 2010	201,294	0.4365%		(879)	67,685	(134,488)
November	Year 2010	134,488	0.4365%		(587)	67,685	(67,390)
December	Year 2010	67,390	0.4365%		(294)	67,685	0
					(22,583)		

True-Up Adjustment with Interest	$	(812,214)
Less Over (Under) Recovery	$	732,738
Total Interest	$	(79,476)

Potomac-Appalachian Transmission Highline, LLC
Attachment 9 - Hypothetical Example of Final True-Up of Interest Rates and Interest Calculations for the Construction Loan

Applicable to both PATH West Virginia Transmission Company, LLC & PATH Allegheny Transmission Company, LLC

To be Prepared on 8/15/2013 (hypothetical date)

SUMMARY

			Hypothetical Revenue Requirement				
YEAR	**Estimated Effective cost of debt used in forecast/true up**	**Final Effective cost of debt for the construction loan:**	**Based on Estimated Effective cost of debt**	**Based on Actual Effective cost of debt**	Over (Under) Recovery	**Hypothetical Monthly Interest Rate applicable over the ATRR period**	Total Amount of Construction Loan Related True-Up included in rates effective Jan 2014 (Refund)/Owed
2008	7.18%	7.00%	$ 2,500,000.00	$ 2,400,000.00	$ 100,000.00	0.550%	$ (148,288.33)
2009	6.8%	7.00%	$5,000,000.00	$5,150,000.00	$ (150,000.00)	0.560%	$ 209,670.43
2010	7.2%	7.00%	$8,300,000.00	$8,200,000.00	$ 100,000.00	0.540%	$ (131,109.09)
2011	7.3%	7.00%	$12,300,000.00	$12,000,000.00	$ 300,000.00	0.580%	$ (368,656.73)
2012*	7.1%	6.83%	$18,000,000.00	$17,900,000.00	$ 100,000.00	0.570%	$ (114,946.28)
2013**	6.50%	6.50%	$25,000,000.00	$25,000,000.00	$ -		
2014**	6.50%	6.50%					$ (553,329.99)

** Assumes that the construction loan is retired on Sept 1, 2012*

*** Assumes permanent debt structure is put in place on Sept 1, 2012 with effective rate of 6.5%*

*Note: True-Up period is 2008 - 2012, with the true-up amount included in 2014 forecasted ATRR. Final effective cost of debt for 2012 is computed as follows: ((7%*243days)+(6.5%*122days))/365days*

Calculation of Applicable Interest Expense for each ATRR period

Interest Rate on Amount of Refunds or Surcharges from 35.19a		Over (Under) Recovery Plus Interest	Hypothetical Monthly Interest Rate	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
<u>Calculation of Interest for 2008 True-Up Period</u>							
An over or under collection will be recovered prorata over 2008, held for 2009, 2010, 2011, 2012, 2013 and returned prorate over 2014					Monthly		
January	Year 2008	-	0.5500%	12.00	-		-
February	Year 2008	-	0.5500%	11.00	-		-
March	Year 2008	10,000	0.5500%	10.00	(550)		(10,550)
April	Year 2008	10,000	0.5500%	9.00	(495)		(10,495)
May	Year 2008	10,000	0.5500%	8.00	(440)		(10,440)
June	Year 2008	10,000	0.5500%	7.00	(385)		(10,385)
July	Year 2008	10,000	0.5500%	6.00	(330)		(10,330)
August	Year 2008	10,000	0.5500%	5.00	(275)		(10,275)
September	Year 2008	10,000	0.5500%	4.00	(220)		(10,220)
October	Year 2008	10,000	0.5500%	3.00	(165)		(10,165)
November	Year 2008	10,000	0.5500%	2.00	(110)		(10,110)
December	Year 2008	10,000	0.5500%	1.00	(55)		(10,055)
					(3,025)		(103,025)
					Annual		
January through December	Year 2009	(103,025)	0.5600%	12.00	(6,923)		(109,948)
January through December	Year 2010	(109,948)	0.5400%	12.00	(7,125)		(117,073)
January through December	Year 2011	(117,073)	0.5800%	12.00	(8,148)		(125,221)
January through December	Year 2012	(125,221)	0.5700%	12.00	(8,565)		(133,786)
January through December	Year 2013	(133,786)	0.5700%	12.00	(9,151)		(142,937)
<u>Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months</u>					Monthly		
January	Year 2014	142,937	0.5700%		(815)	(12,357)	(131,395)
February	Year 2014	131,395	0.5700%		(749)	(12,357)	(119,786)
March	Year 2014	119,786	0.5700%		(683)	(12,357)	(108,112)
April	Year 2014	108,112	0.5700%		(616)	(12,357)	(96,371)
May	Year 2014	96,371	0.5700%		(549)	(12,357)	(84,563)
June	Year 2014	84,563	0.5700%		(482)	(12,357)	(72,687)
July	Year 2014	72,687	0.5700%		(414)	(12,357)	(60,744)
August	Year 2014	60,744	0.5700%		(346)	(12,357)	(48,733)
September	Year 2014	48,733	0.5700%		(278)	(12,357)	(36,653)
October	Year 2014	36,653	0.5700%		(209)	(12,357)	(24,505)
November	Year 2014	24,505	0.5700%		(140)	(12,357)	(12,287)
December	Year 2014	12,287	0.5700%		(70)	(12,357)	0
					(5,351)		
Total Amount of True-Up Adjustment for 2008 ATRR						$ (148,288)	
Less Over (Under) Recovery						$ 100,000	
Total Interest						$ (48,288)	

Potomac-Appalachian Transmission Highline, LLC
Attachment 9 - Hypothetical Example of Final True-Up of Interest Rates and Interest Calculations for the Construction Loan

Applicable to both PATH West Virginia Transmission Company, LLC & PATH Allegheny Transmission Company, LLC

Calculation of Interest for 2009 True-Up Period

An over or under collection will be recovered prorata over 2009, held for 2010, 2011, 2012, 2013 and returned prorate over 2014					Monthly		
January	Year 2009	(12,500)	0.5600%	12.00	840		13,340
February	Year 2009	(12,500)	0.5600%	11.00	770		13,270
March	Year 2009	(12,500)	0.5600%	10.00	700		13,200
April	Year 2009	(12,500)	0.5600%	9.00	630		13,130
May	Year 2009	(12,500)	0.5600%	8.00	560		13,060
June	Year 2009	(12,500)	0.5600%	7.00	490		12,990
July	Year 2009	(12,500)	0.5600%	6.00	420		12,920
August	Year 2009	(12,500)	0.5600%	5.00	350		12,850
September	Year 2009	(12,500)	0.5600%	4.00	280		12,780
October	Year 2009	(12,500)	0.5600%	3.00	210		12,710
November	Year 2009	(12,500)	0.5600%	2.00	140		12,640
December	Year 2009	(12,500)	0.5600%	1.00	70		12,570
					5,460		155,460
					Annual		
January through December	Year 2010	155,460	0.5400%	12.00	10,074		165,534
January through December	Year 2011	165,534	0.5800%	12.00	11,521		177,055
January through December	Year 2012	177,055	0.5700%	12.00	12,111		189,166
January through December	Year 2013	189,166	0.5700%	12.00	12,939		202,104
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					Monthly		
January	Year 2014	(202,104)	0.5700%		1,152	17,473	185,784
February	Year 2014	(185,784)	0.5700%		1,059	17,473	169,370
March	Year 2014	(169,370)	0.5700%		965	17,473	152,863
April	Year 2014	(152,863)	0.5700%		871	17,473	136,262
May	Year 2014	(136,262)	0.5700%		777	17,473	119,566
June	Year 2014	(119,566)	0.5700%		682	17,473	102,775
July	Year 2014	(102,775)	0.5700%		586	17,473	85,888
August	Year 2014	(85,888)	0.5700%		490	17,473	68,905
September	Year 2014	(68,905)	0.5700%		393	17,473	51,826
October	Year 2014	(51,826)	0.5700%		295	17,473	34,649
November	Year 2014	(34,649)	0.5700%		197	17,473	17,374
December	Year 2014	(17,374)	0.5700%		99	17,473	(0)
					7,566		
Total Amount of True-Up Adjustment for 2009 ATRR						$ 209,670	
Less Over (Under) Recovery						$ (150,000)	
Total Interest						$ 59,670	

Calculation of Interest for 2010 True-Up Period

An over or under collection will be recovered prorata over 2010, held for 2011, 2012, 2013 and returned prorate over 2014					Monthly		
January	Year 2010	8,333	0.5400%	12.00	(540)		(8,873)
February	Year 2010	8,333	0.5400%	11.00	(495)		(8,828)
March	Year 2010	8,333	0.5400%	10.00	(450)		(8,783)
April	Year 2010	8,333	0.5400%	9.00	(405)		(8,738)
May	Year 2010	8,333	0.5400%	8.00	(360)		(8,693)
June	Year 2010	8,333	0.5400%	7.00	(315)		(8,648)
July	Year 2010	8,333	0.5400%	6.00	(270)		(8,603)
August	Year 2010	8,333	0.5400%	5.00	(225)		(8,558)
September	Year 2010	8,333	0.5400%	4.00	(180)		(8,513)
October	Year 2010	8,333	0.5400%	3.00	(135)		(8,468)
November	Year 2010	8,333	0.5400%	2.00	(90)		(8,423)
December	Year 2010	8,333	0.5400%	1.00	(45)		(8,378)
					(3,510)		(103,510)
					Annual		
January through December	Year 2011	(103,510)	0.5800%	12.00	(7,204)		(110,714)
January through December	Year 2012	(110,714)	0.5700%	12.00	(7,573)		(118,287)
January through December	Year 2013	(118,287)	0.5700%	12.00	(8,091)		(126,378)
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					Monthly		
January	Year 2014	126,378	0.5700%		(720)	(10,926)	(116,173)
February	Year 2014	116,173	0.5700%		(662)	(10,926)	(105,909)
March	Year 2014	105,909	0.5700%		(604)	(10,926)	(95,587)
April	Year 2014	95,587	0.5700%		(545)	(10,926)	(85,206)
May	Year 2014	85,206	0.5700%		(486)	(10,926)	(74,766)
June	Year 2014	74,766	0.5700%		(426)	(10,926)	(64,266)
July	Year 2014	64,266	0.5700%		(366)	(10,926)	(53,707)
August	Year 2014	53,707	0.5700%		(306)	(10,926)	(43,087)
September	Year 2014	43,087	0.5700%		(246)	(10,926)	(32,407)
October	Year 2014	32,407	0.5700%		(185)	(10,926)	(21,666)
November	Year 2014	21,666	0.5700%		(123)	(10,926)	(10,864)
December	Year 2014	10,864	0.5700%		(62)	(10,926)	0
					(4,731)		
Total Amount of True-Up Adjustment for 2010 ATRR						$ (131,109)	
Less Over (Under) Recovery						$ 100,000	
Total Interest						$ (31,109)	

Potomac-Appalachian Transmission Highline, LLC
Attachment 9 - Hypothetical Example of Final True-Up of Interest Rates and Interest Calculations for the Construction Loan

Applicable to both PATH West Virginia Transmission Company, LLC & PATH Allegheny Transmission Company, LLC

Calculation of Interest for 2011 True-Up Period

An over or under collection will be recovered prorata over 2011, held for 2012, 2013 and returned prorate over 2014

					Monthly		
January	Year 2011	25,000	0.5800%	12.00	(1,740)		(26,740)
February	Year 2011	25,000	0.5800%	11.00	(1,595)		(26,595)
March	Year 2011	25,000	0.5800%	10.00	(1,450)		(26,450)
April	Year 2011	25,000	0.5800%	9.00	(1,305)		(26,305)
May	Year 2011	25,000	0.5800%	8.00	(1,160)		(26,160)
June	Year 2011	25,000	0.5800%	7.00	(1,015)		(26,015)
July	Year 2011	25,000	0.5800%	6.00	(870)		(25,870)
August	Year 2011	25,000	0.5800%	5.00	(725)		(25,725)
September	Year 2011	25,000	0.5800%	4.00	(580)		(25,580)
October	Year 2011	25,000	0.5800%	3.00	(435)		(25,435)
November	Year 2011	25,000	0.5800%	2.00	(290)		(25,290)
December	Year 2011	25,000	0.5800%	1.00	(145)		(25,145)
					(11,310)		(311,310)
					Annual		
January through December	Year 2012	(311,310)	0.5700%	12.00	(21,294)		(332,604)
January through December	Year 2013	(332,604)	0.5700%	12.00	(22,750)		(355,354)
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					Monthly		
January	Year 2014	355,354	0.5700%		(2,026)	(30,721)	(326,658)
February	Year 2014	326,658	0.5700%		(1,862)	(30,721)	(297,798)
March	Year 2014	297,798	0.5700%		(1,697)	(30,721)	(268,774)
April	Year 2014	268,774	0.5700%		(1,532)	(30,721)	(239,585)
May	Year 2014	239,585	0.5700%		(1,366)	(30,721)	(210,229)
June	Year 2014	210,229	0.5700%		(1,198)	(30,721)	(180,706)
July	Year 2014	180,706	0.5700%		(1,030)	(30,721)	(151,015)
August	Year 2014	151,015	0.5700%		(861)	(30,721)	(121,154)
September	Year 2014	121,154	0.5700%		(691)	(30,721)	(91,123)
October	Year 2014	91,123	0.5700%		(519)	(30,721)	(60,921)
November	Year 2014	60,921	0.5700%		(347)	(30,721)	(30,547)
December	Year 2014	30,547	0.5700%		(174)	(30,721)	0
					(13,303)		
Total Amount of True-Up Adjustment for 2011 ATRR						$ (368,657)	
Less Over (Under) Recovery						$ 300,000	
Total Interest						$ (68,657)	

Calculation of Interest for 2012 True-Up Period

An over or under collection will be recovered prorata over 2012, held for 2013 and returned prorate over 2014

					Monthly		
January	Year 2012	8,333	0.5700%	12.00	(570)		(8,903)
February	Year 2012	8,333	0.5700%	11.00	(523)		(8,856)
March	Year 2012	8,333	0.5700%	10.00	(475)		(8,808)
April	Year 2012	8,333	0.5700%	9.00	(428)		(8,761)
May	Year 2012	8,333	0.5700%	8.00	(380)		(8,713)
June	Year 2012	8,333	0.5700%	7.00	(333)		(8,666)
July	Year 2012	8,333	0.5700%	6.00	(285)		(8,618)
August	Year 2012	8,333	0.5700%	5.00	(238)		(8,571)
September	Year 2012	8,333	0.5700%	4.00	(190)		(8,523)
October	Year 2012	8,333	0.5700%	3.00	(143)		(8,476)
November	Year 2012	8,333	0.5700%	2.00	(95)		(8,428)
December	Year 2012	8,333	0.5700%	1.00	(48)		(8,381)
					(3,705)		(103,705)
					Annual		
January through December	Year 2013	(103,705)	0.5700%	12.00	(7,093)		(110,798)
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					Monthly		
January	Year 2014	110,798	0.5700%		(632)	(9,579)	(101,851)
February	Year 2014	101,851	0.5700%		(581)	(9,579)	(92,853)
March	Year 2014	92,853	0.5700%		(529)	(9,579)	(83,803)
April	Year 2014	83,803	0.5700%		(478)	(9,579)	(74,702)
May	Year 2014	74,702	0.5700%		(426)	(9,579)	(65,549)
June	Year 2014	65,549	0.5700%		(374)	(9,579)	(56,344)
July	Year 2014	56,344	0.5700%		(321)	(9,579)	(47,086)
August	Year 2014	47,086	0.5700%		(268)	(9,579)	(37,776)
September	Year 2014	37,776	0.5700%		(215)	(9,579)	(28,412)
October	Year 2014	28,412	0.5700%		(162)	(9,579)	(18,995)
November	Year 2014	18,995	0.5700%		(108)	(9,579)	(9,525)
December	Year 2014	9,525	0.5700%		(54)	(9,579)	0
					(4,148)		
Total Amount of True-Up Adjustment for 2012 ATRR						$ (114,946)	
Less Over (Under) Recovery						$ 100,000	
Total Interest						$ (14,946)	

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Potomac-Appalachian Transmission Highline, LLC
Attachment 10 - Depreciation Accrual Rates

Applicable to PATH West Virginia Transmission Company, LLC

TRANSMISSION PLANT		**Accrual Rate (Annual) Percent**	**Annual Depreciation Expense**
350.2	Land & Land Rights - Easements	1.43	-
352	Structures & Improvements	1.82	-
353	Station Equipment		
	Other	2.43	-
	SVC Dynamic Control Equipment	4.09	-
354	Towers & Fixtures	1.26	-
355	Poles & Fixtures	3.11	-
356	Overhead Conductors & Devices	1.13	-
Total Transmission Plant Depreciation			-
Total Transmission Depreciation Expense (must tie to p336.7.b & c)	-		

GENERAL PLANT		**Accrual Rate (Annual) Percent**	**Annual Depreciation Expense**
390	Structures & Improvements	2.00	-
391	Office Furniture & Equipment	5.00	-
	Information Systems	10.00	-
	Data Handling	10.00	
392	Transportation Equipment		
	Other	5.33	-
	Autos	11.43	-
	Light Trucks	6.96	-
	Medium Trucks	6.96	-
	Trailers	4.44	-
	ATV	5.33	-
393	Stores Equipment	5.00	-
394	Tools, Shop & Garage Equipment	5.00	-
395	Laboratory Equipment	5.00	-
396	Power Operated Equipment	4.17	-
397	Communication Equipment	6.67	-
398	Miscellaneous Equipment	6.67	-
Total General Plant			-
Total General Plant Depreciation Expense (must tie to p336.10.b & c)	-		

INTANGIBLE PLANT		**Accrual Rate (Annual) Percent**	**Annual Depreciation Expense**
303	Miscellaneous Intangible Plant	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.

Potomac-Appalachian Transmission Highline, LLC
Attachment 10 - Depreciation Accrual Rates

Applicable to PATH Allegheny Transmission Company, LLC

TRANSMISSION PLANT		**Accrual Rate (Annual) Percent**	**Annual Depreciation Expense**
350.2	Land & Land Rights - Easements	1.43	-
352	Structures & Improvements	1.82	-
353	Station Equipment		
	Other	2.43	-
	SVC Dynamic Control Equipment	4.09	-
354	Towers & Fixtures	1.26	-
355	Poles & Fixtures	3.11	-
356	Overhead Conductors & Devices	1.13	-
Total Transmission Plant Depreciation			-
Total Transmission Depreciation Expense (must tie to p336.7.b & c)	-		

GENERAL PLANT		**Accrual Rate (Annual) Percent**	**Annual Depreciation Expense**
390	Structures & Improvements	2.00	$ 83
391	Office Furniture & Equipment	5.00	2,059
	Information Systems	10.00	-
	Data Handling	10.00	
392	Transportation Equipment		
	Other	5.33	-
	Autos	11.43	-
	Light Trucks	6.96	-
	Medium Trucks	6.96	-
	Trailers	4.44	-
	ATV	5.33	-
393	Stores Equipment	5.00	-
394	Tools, Shop & Garage Equipment	5.00	-
395	Laboratory Equipment	5.00	-
396	Power Operated Equipment	4.17	-
397	Communication Equipment	6.67	-
398	Miscellaneous Equipment	6.67	-
Total General Plant			$ 2,142
Total General Plant Depreciation Expense (must tie to p336.10.b & c)	$ 2,142		

INTANGIBLE PLANT		**Accrual Rate (Annual) Percent**	**Annual Depreciation Expense**
303	Miscellaneous Intangible Plant	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.

Attachment 6 – VEPCO Formula Update for January 1, 2010 – December 31, 2010

VIRGINIA ELECTRIC AND POWER COMPANY
2010 ATRR with True-Up Adjustment

To: Interested Parties (as defined in Section 1.b. of the Formula Rate Implementation Protocols)

In accordance with Section 1.a. of the Formula Rate Implementation Protocols, Virginia Electric and Power Company ("VEPCO") is providing the following information to be posted on the www.pjm.com web site:

(i) VEPCO's Annual Transmission Revenue Requirement ("ATRR"), rate for Network Integration Transmission Service ("NITS"), based on applying its projected costs, revenues and credits, other than those credits that will be distributed to customers pursuant to section 2 of Attachment H-16, for the next calendar year, plus its True-up Adjustment calculated pursuant to the Formula Rate set out in Attachment H-16A,

(ii) an estimate of the Network Service Peak Load of the Dominion Zone that will be used by the Transmission Provider to determine each Network Customer's Zone Network Load pursuant to Section 34.1 and Attachment H-16 for the next calendar year; and

(iii) an explanation of any change in VEPCO's accounting policies and practices that took effect in the preceding twelve months ending August 31 that is reported in Notes 3 and 4 of VEPCO's Securities and Exchange Commission Form 10-Q ("Material Accounting Changes"). To the extent there are Material Accounting Changes, VEPCO's Form 10-Q will be posted on PJM's website at the time of the Annual Update.

VEPCO has estimated the Network Service Peak Load of the Dominion Zone that will be used by the Transmission Provider to determine each Network Customer's Zone Network Load pursuant to Section 34.1 and Attachment H-16 for the next calendar year. The estimated value is included on Page 4 of 5 at line 168.

The explanations pursuant to item (iii), above, are provided in the pages following the attachments to the rate formula.

Virginia Electric and Power Company
ATTACHMENT H-16A
Formula Rate -- Appendix A

Shaded cells are input cells

		Notes	FERC Form 1 Page # or Instruction (Note H)		2010 (000's)
	Allocators				
	Wages & Salary Allocation Factor				
1	Transmission Wages Expense		p354.21b/ Attachment 5	$	22,297
2	Less Generator Step-ups		Attachment 5		99
3	Net Transmission Wage Expenses		(Line 1 - 2)		22,198
4	Total Wages Expense		p354.28b/Attachment 5		592,988
5	Less A&G Wages Expense		p354.27b/Attachment 5		136,262
6	Total		(Line 4 - 5)	$	456,726
7	**Wages & Salary Allocator**	(Note B)	(Line 3 / 6)		**4.8603%**
	Plant Allocation Factors				
8	Electric Plant in Service	(Notes A& Q)	p207.104.g/Attachment 5	$	22,656,215
9	Common Plant In Service - Electric		(Line 26)		0
10	Total Plant In Service		(Sum Lines 8 & 9)		22,656,215
11	Accumulated Depreciation (Total Electric Plant)	(Notes A & Q)	(Line 15 - 14 - 13 -12)		9,177,693
12	Accumulated Intangible Amortization	(Notes A & Q)	p200.21c/Attachment 5		197,546
13	Accumulated Common Amortization - Electric	(Notes A & Q)	p356/Attachment 5		0
14	Accumulated Common Plant Depreciation - Electric	(Notes A & Q)	p356/Attachment 5		0
15	Total Accumulated Depreciation		p219.29c/Attachment 5		9,375,239
16	Net Plant		(Line 10 - 15)		13,280,976
17	Transmission Gross Plant		(Line 31 - 30)		2,448,913
18	**Gross Plant Allocator**	(Note B)	(Line 17 / 10)		**10.8090%**
19	Transmission Net Plant		(Line 44 - 30)	$	1,635,381
20	**Net Plant Allocator**	(Note B)	(Line 19 / 16)		**12.3137%**
	Plant Calculations				
	Plant In Service				
21	Transmission Plant In Service	(Notes A & Q)	p207.58.g/Attachment 5	$	2,597,286
22	Less: Generator Step-ups	(Notes A & Q)	Attachment 5		163,665
23	Less: Interconnect Facilities Installed After March 15, 2000	(Notes A & Q)	Attachment 5		23,814
24	**Total Transmission Plant In Service**		(Lines 21 - 22 - 23)		**2,409,806**
25	General & Intangible	(Notes A & Q)	p205.5.g + p207.99.g/Attachment 5		804,613
26	Common Plant (Electric Only)		p356/Attachment 5		0
27	Total General & Common		(Line 25 + 26)		804,613
28	Wage & Salary Allocation Factor		(Line 7)		4.8603%
29	**General & Common Plant Allocated to Transmission**		(Line 27 * 28)	**$**	**39,106**
30	**Plant Held for Future Use (Including Land)**	(Notes C & Q)	p214.47.d/Attachment 5	**$**	**3,517**
31	**TOTAL Plant In Service**		**(Line 24 + 29 + 30)**	**$**	**2,452,430**
	Accumulated Depreciation				
32	Transmission Accumulated Depreciation	(Notes A & Q)	p219.25.c/Attachment 5	$	831,499
33	Less Accumulated Depreciation for Generator Step-ups	(Notes A & Q)	Attachment 5		37,751
34	Less Accumulated Depreciation for Interconnect Facilities Installed After March 1	(Notes A & Q)	Attachment 5		4,607
35	Total Accumulated Depreciation for Transmission		(Line 32 - 33 - 34)		789,142
36	Accumulated General Depreciation	(Notes A & Q)	p219.28.b/Attachment 5		304,276
37	Accumulated Intangible Amortization	(Notes A & Q)	(Line 12)		197,546
38	Accumulated Common Amortization - Electric		(Line 13)		0
39	Common Plant Accumulated Depreciation (Electric Only)		(Line 14)		0
40	Total Accumulated Depreciation		(Sum Lines 36 to 39)		501,822
41	Wage & Salary Allocation Factor		(Line 7)		4.8603%
42	**General & Common Allocated to Transmission**		(Line 40 * 41)		**24,390**
43	**TOTAL Accumulated Depreciation**		**(Line 35 + 42)**	**$**	**813,532**
44	**TOTAL Net Property, Plant & Equipment**		**(Line 31 - 43)**	**$**	**1,638,898**

Virginia Electric and Power Company
ATTACHMENT H-16A
Formula Rate -- Appendix A

		Notes	FERC Form 1 Page # or Instruction (Note H)		2010
	Adjustment To Rate Base				
	Accumulated Deferred Income Taxes				
45	ADIT net of FASB 106 and 109		Attachment 1	$	(191,014)
46	**Accumulated Deferred Income Taxes Allocated To Transmission**		(Line 45)	**$**	**(191,014)**
	Transmission O&M Reserves				
47	**Total Balance Transmission Related Account 242 Reserves**	Enter Negative	Attachment 5	**$**	**(1,334)**
	Prepayments				
48	Prepayments	(Notes A & R)	Attachment 5	$	4,769
49	**Total Prepayments Allocated to Transmission**		(Line 48)	**$**	**4,769**
	Materials and Supplies				
50	Undistributed Stores Exp	(Notes A & R)	p227.6c & 16.c	$	-
51	Wage & Salary Allocation Factor		(Line 7)		4.8603%
52	Total Transmission Allocated Materials and Supplies		(Line 50 * 51)		0
53	Transmission Materials & Supplies		p227.8c/2		3,778
54	**Total Materials & Supplies Allocated to Transmission**		(Line 52 + 53)	**$**	**3,778**
	Cash Working Capital				
55	Transmission Operation & Maintenance Expense		(Line 85)	$	78,422
56	1/8th Rule		x 1/8		12.5%
57	**Total Cash Working Capital Allocated to Transmission**		(Line 55 * 56)	**$**	**9,803**
	Network Credits				
58	Outstanding Network Credits	(Note N)	Attachment 5 / From PJM		0
59	Less Accumulated Depreciation Associated with Facilities with Outstanding Net	(Note N)	Attachment 5 / From PJM		0
60	Net Outstanding Credits		(Line 58 - 59)		**0**
61	**TOTAL Adjustment to Rate Base**		(Line 46 + 47 + 49 + 54 + 57 - 60)	**$**	**(173,998)**
62	**Rate Base**		(Line 44 + 61)	**$**	**1,464,900**
	O&M				
	Transmission O&M				
63	Transmission O&M		p321.112.b/Attachment 5	$	57,558
64	Less GSU Maintenance		Attachment 5		332
65	Less Account 565 - Transmission by Others		p321.96.b/Attachment 5		0
66	Plus Schedule 12 Charges billed to Transmission Owner and booked to Accou	(Note O)	PJM Data		0
67	**Transmission O&M**		(Lines 63 - 64 + 65 + 66)	**$**	**57,226**
	Allocated General & Common Expenses				
68	Common Plant O&M	(Note A)	p356		0
69	Total A&G		Attachment 5		456,551
70	Less Property Insurance Account 924		p323.185b		7,052
71	Less Regulatory Commission Exp Account 928	(Note E)	p323.189b/Attachment 5		27,910
72	Less General Advertising Exp Account 930.1		p323.911b/Attachment 5		3,627
73	Less EPRI Dues	(Note D)	p352-353/Attachment 5		3,091
74	**General & Common Expenses**		(Lines 68 + 69) - Sum (70 to 73)	$	414,870
75	Wage & Salary Allocation Factor		(Line 7)		4.8603%
76	**General & Common Expenses Allocated to Transmission**		(Line 74 * 75)	**$**	**20,164**
	Directly Assigned A&G				
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b/Attachment 5	$	164
78	General Advertising Exp Account 930.1	(Note K)	p323.191b		0
79	Subtotal - Transmission Related		(Line 77 + 78)		**164**
80	Property Insurance Account 924		p323.185b		7,052
81	General Advertising Exp Account 930.1	(Note F)	Attachment 5		0
82	Total		(Line 80 + 81)		7,052
83	Net Plant Allocation Factor		(Line 20)		12.3137%
84	**A&G Directly Assigned to Transmission**		(Line 82 * 83)	**$**	**868**
85	**Total Transmission O&M**		**(Line 67 + 76 + 79 + 84)**	**$**	**78,422**

Virginia Electric and Power Company
ATTACHMENT H-16A
Formula Rate -- Appendix A

			Notes	FERC Form 1 Page # or Instruction (Note H)		2010
	Depreciation & Amortization Expense					
	Depreciation Expense					
86	Transmission Depreciation Expense		(Notes A and S)	p336.7b&c/Attachment 5	**$**	**51,167**
87	Less: GSU Depreciation			Attachment 5		**3,224**
88	Less Interconnect Facilities Depreciation			Attachment 5		**469**
89	Extraordinary Property Loss			Attachment 5		**0**
90	Total Transmission Depreciation			(Line 86 - 87 - 88 + 89)		**47,473**
91	General Depreciation		(Note A)	p336.10b&c&d/Attachment 5		24,909
92	Intangible Amortization		(Note A)	p336.1d&e/Attachment 5		30,253
93	Total			(Line 91 + 92)		**55,162**
94	Wage & Salary Allocation Factor			(Line 7)		4.8603%
95	**General and Intangible Depreciation Allocated to Transmission**			(Line 93 * 94)		**2,681**
96	Common Depreciation - Electric Only		(Note A)	p336.11.b		0
97	Common Amortization - Electric Only		(Note A)	p356 or p336.11d		0
98	Total			(Line 96 + 97)		0
99	Wage & Salary Allocation Factor			(Line 7)		4.8603%
100	**Common Depreciation - Electric Only Allocated to Transmission**			(Line 98 * 99)		**0**
101	**Total Transmission Depreciation & Amortization**			**(Line 90 + 95 + 100)**	**$**	**50,154**
	Taxes Other than Income					
102	**Taxes Other than Income**			Attachment 2	**$**	**14,281**
103	**Total Taxes Other than Income**			**(Line 102)**	**$**	**14,281**
	Return / Capitalization Calculations					
	Long Term Interest					
104	Long Term Interest		(Note T)	p117.62c through 67c	$	314,238
105	Less LTD Interest on Securitization Bonds		(Note P)	Attachment 8		0
106	**Long Term Interest**			(Line 104 - 105)	$	314,238
107	**Preferred Dividends**		(Note T), enter positive	p118.29c	$	16,659
	Common Stock					
108	Proprietary Capital			p112.16c,d/2	$	6,166,098
109	Less Preferred Stock		(Note T), enter negative	(Line 117)		-259,014
110	Less Account 219 - Accumulated Other Comprehensive Income		(Note T), enter negative	p112.15c,d/2		-15,590
111	**Common Stock**			(Sum Lines 108 to 110)	$	5,891,494
	Capitalization					
112	Long Term Debt			p112.24c,d/2	$	5,863,256
113	Less Loss on Reacquired Debt		(Note T), enter negative	p111.81c,d/2		-6,527
114	Plus Gain on Reacquired Debt		(Note T), enter positive	p113.61c,d/2		1,908
115	Less LTD on Securitization Bonds	(Note P)	(Note T), enter negative	Attachment 8		0
116	Total Long Term Debt			(Sum Lines 112 to 115)		5,858,638
117	Preferred Stock		(Note T), enter positive	p112.3c,d/2		259,014
118	Common Stock			(Line 111)		5,891,494
119	**Total Capitalization**			(Sum Lines 116 to 118)	$	12,009,146
120	Debt %	Total Long Term Debt		(Line 116 / 119)		48.8%
121	Preferred %	Preferred Stock		(Line 117 / 119)		2.2%
122	Common %	Common Stock		(Line 118 / 119)		49.1%
123	Debt Cost	Total Long Term Debt		(Line 106 / 116)		0.0536
124	Preferred Cost	Preferred Stock		(Line 107 / 117)		0.0643
125	Common Cost	Common Stock	(Note J)	Fixed		0.1140
126	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Line 120 * 123)		0.0262
127	Weighted Cost of Preferred	Preferred Stock		(Line 121 * 124)		0.0014
128	Weighted Cost of Common	Common Stock		(Line 122 * 125)		0.0559
129	**Total Return (R)**			(Sum Lines 126 to 128)		**0.0835**
130	**Investment Return = Rate Base * Rate of Return**			**(Line 62 * 129)**		**122,290**

Virginia Electric and Power Company
ATTACHMENT H-16A
Formula Rate -- Appendix A

Composite Income Taxes

		Notes	FERC Form 1 Page # or Instruction (Note H)		2010
	Income Tax Rates				
131	FIT=Federal Income Tax Rate		Attachment 5		35.00%
132	SIT=State Income Tax Rate or Composite	(Note I)	Attachment 5		6.13%
133	p	(percent of federal income tax deductible for s	Per State Tax Code		0.00%
134	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			38.98%
135	T/ (1-T)				63.89%
	ITC Adjustment	(Note I)			
136	Amortized Investment Tax Credit	enter negative	Attachment 1	$	(286)
137	T/(1-T)		(Line 135)		63.89%
138	**ITC Adjustment Allocated to Transmission**		(Line 136 * (1 + 137))	**$**	**(469)**
139	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WC	[Line 135 * 130 * (1-(126 / 129))]		**53,638**
140	**Total Income Taxes**		**(Line 138 + 139)**	**$**	**53,169**

REVENUE REQUIREMENT

		Notes	FERC Form 1 Page # or Instruction (Note H)		2010
	Summary				
141	Net Property, Plant & Equipment		(Line 44)	$	1,638,898
142	Adjustment to Rate Base		(Line 61)		-173,998
143	**Rate Base**		(Line 62)	**$**	**1,464,900**
144	O&M		(Line 85)		78,422
145	Depreciation & Amortization		(Line 101)		50,154
146	Taxes Other than Income		(Line 103)		14,281
147	Investment Return		(Line 130)		122,290
148	Income Taxes		(Line 140)		53,169
149					
150	**Revenue Requirement**		**(Sum Lines 144 to 149)**	**$**	**318,317**
	Net Plant Carrying Charge				
151	Revenue Requirement		(Line 150)	**$**	**318,317**
152	Net Transmission Plant		(Line 24 - 35)		**1,620,665**
153	Net Plant Carrying Charge		(Line 151 / 152)		**19.6411%**
154	Net Plant Carrying Charge without Depreciation		(Line 151 - 86) / 152		**16.4840%**
155	Net Plant Carrying Charge without Depreciation, Return or Income Taxes		(Line 151 - 86 - 130 - 140) / 152		**5.6576%**
	Net Plant Carrying Charge Calculation per 100 Basis Point increase in ROE				
156	Gross Revenue Requirement Less Return and Taxes		(Line 150 - 147 - 148)	**$**	**142,857**
157	Increased Return and Taxes		Attachment 4		**187,237**
158	Net Revenue Requirement per 100 Basis Point increase in ROE		(Line 156 + 157)		**330,094**
159	Net Transmission Plant		(Line 152)		**1,620,665**
160	Net Plant Carrying Charge per 100 Basis Point increase in ROE		(Line 158 / 159)		**20.3678%**
161	Net Plant Carrying Charge per 100 Basis Point increase in ROE without Depreciation		(Line 158 - 86) / 159		**17.2107%**
162	**Revenue Requirement**		(Line 150)	**$**	**318,317**
163	True-up Adjustment		Attachment 6		**3,664**
164	Plus any increased ROE calculated on Attachment 7 other than PJM Schedule 12 projects.		Attachment 7		**2,006**
165	Facility Credits under Section 30.9 of the PJM OATT.		Attachment 5		**-**
166	Revenue Credits		Attachment 3		**(9,195)**
167	Interest on Network Credits		PJM data		0
168	**Annual Transmission Revenue Requirement (ATRR)**		(Line 162 + 163 +164 + 165 + 166 + 167)	**$**	**314,792**
	Rate for Network Integration Transmission Service				
169	1 CP Peak	(Note L)	PJM Data - Attachment 5		**18,137.255**
170	Rate ($/MW-Year)		(Line 168 / 169)		**17,356.08**
171	**Rate for Network Integration Transmisson Service Rate ($/MW/Year)**		**(Line 170)**		**17,356.08**

Virginia Electric and Power Company ATTACHMENT H-16A Formula Rate -- Appendix A	Notes	FERC Form 1 Page # or Instruction (Note H)	2010

Notes

A Electric portion only - VEPCO does not have Common Plant.
B Excludes amounts for Generator Step-ups and Interconnection Facilities, when appropriate.
C Includes Transmission portion only.
D Excludes all EPRI Annual Membership Dues.
E Includes all regulatory commission expenses.
F Includes all safety related advertising included in Account 930.1.
G Includes all regulatory commission expenses directly related to transmission service, RTO filings, or transmission siting itemized in Form 1 at 351.h.
H The Form 1 reference incates only the end-of-year balance used to derive the amount beside the reference. Each plant balance with a Form 1 reference will include the Form 1 balance in an average of the 13 month blances for the year. Each non-plant balance included in rate base with a Form 1 reference will include Form 1 balances in the calculation of the average of the beginning and end of year balances for the year. See notes Q and R below.
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 ROE will be supported in the original filing and no change in ROE will be made absent a filing at FERC. The basis point increase in ROE for new investment will be set at 100 basis points in Attachment 4 but not applied to determine any of the charges resulting from this formula absent absent a filing at FERC.
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.
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) toward 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 on Line 167.
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 on Line 66.
P Securitization bonds may be included in the capital structure.
Q Calculated using 13 month average balance. Only beginning and end of year balances are from Form 1.
R Calculated using average of beginning and end of year balances. Beginning and end of year balances are from Form 1.
S The depreciation rates are included in Attachment 9.
T For the intial formula rate calculation, the projected capital structure shall reflect the capital structure from the 2006 FERC Form No. 1 data. For all other formula rate calculations, th projected capital structure and actual capital structure shall reflect the capital structure from the most recent FERC Form No. 1 data available.

END

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31, 2010

	Only Transmission Related	***Plant Related***	***Labor Related***	***Total ADIT***
ADIT- 282	(205,148)	(81,743)	(46,905)	
ADIT-283	0	(10,904)	(1,784)	
ADIT-190	0	108,368	68,731	
Subtotal	(205,148)	15,721	20,042	
Wages & Salary Allocator			4.8603%	
Gross Plant Allocator		10.8090%		
End of Year ADIT	(205,148)	1,699	974	(202,474)
End of Previous Year ADIT (from Sheet 1A-ADIT (3))	(183,989)	4,085	351	(179,554)
Average Beginning and End of Year ADIT	(194,568)	2,892	662	(191,014)

End of Year ADIT	(202,474)
End of Previous Year ADIT	(179,554)
Average Beginning and End of Year ADIT	(191,014)

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.

End of Year Balances :

A	**B**	**C**	**D**	**E**	**F**	**G**
ADIT-190	***Total***	***Production Or Other Related***	***Only Transmission Related***	***Plant Related***	***Labor Related***	***Justification***
BAD DEBTS	5,190	5,190				For tax purposes bad debts are deductible when they are deemed to be uncollectible / worthless.
CAPITAL LEASE	426	426				Not applicable to Transmission Cost of Service calculation.
CAPITALIZED BROKERS FEES	749	749				Not applicable to Transmission Cost of Service calculation.
CAPITALIZED INTEREST - NONOP CWIP	-					Not applicable to Transmission Cost of Service calculation.
CAPITALIZED INTEREST NONOP IN SERVICE	307	307				Not applicable to Transmission Cost of Service calculation.
CAPITALIZED INTEREST OPERATING CWIP	71,306	71,306				Represents tax capitalized interest on projects in CWIP - increase in taxable income.
CAPITALIZED INTEREST OPERATING IN SERVICE	105,501			105,501		Represents tax "In Service" capitalized Interest placed in service net of tax amortization.
CIAC NC - NONOP CWIP	7	7				Not applicable to Transmission Cost of Service calculation.
CIAC NC - NONOP IN SERVICE	2,679	2,679				Not applicable to Transmission Cost of Service calculation.
CIAC VA - NONOP CWIP	3,215	3,215				Not applicable to Transmission Cost of Service calculation.
CIAC VA - NONOP IN SERVICE	100,213	100,213				Not applicable to Transmission Cost of Service calculation.
CONTINGENT CLAIMS CURRENT	-					Not applicable to Transmission Cost of Service calculation.
CONTINGENT CLAIMS NONCURRENT	1,455	1,455				Not applicable to Transmission Cost of Service calculation.
DECOMMISSIONING & DECONTAMINATION	(0)	(0)				Book expensed as billed over 15 yr assessment period; tax deduct in year of assessment because all events test met as liability is based on prior facility use.
DEFERRED GAIN/LOSS NONOPERATING	(53)	(53)				Not applicable to Transmission Cost of Service calculation.
DEFERRED GAIN/LOSS OPERATING	(498)			(498)		Represents the ADIT on Book Gain/Loss as accrued.
DEFERRED GAIN/LOSS-FUTURE USE	(736)	(736)				Not applicable to Transmission Cost of Service calculation.
DEFERRED GAIN/LOSS-FUTURE USE NONOP	1,917	1,917				Not applicable to Transmission Cost of Service calculation.
DFIT 190 OPERATING NONCURRENT ASSET	(526)	(526)				Not applicable to Transmission Cost of Service calculation.
DFIT 282 NONOPERATING PLANT NONCURR LIAB	(3,368)	(3,368)				Not applicable to Transmission Cost of Service calculation.
DFIT 282 OPERATING PLANT NONCURR LIAB	94,973	94,973				Not applicable to Transmission Cost of Service calculation.
DFIT 283 NONOPERATING CURRENT LIAB	2	2				Not applicable to Transmission Cost of Service calculation.
DFIT 283 NONOPERATING NONCURRENT LIAB	5,650	5,650				Not applicable to Transmission Cost of Service calculation.
DFIT 283 OPERATING CURRENT LIABILITY	5,487	5,487				Not applicable to Transmission Cost of Service calculation.
DFIT 283 OPERATING NONCURRENT LIAB	46,626	46,626				Not applicable to Transmission Cost of Service calculation.
DFIT EFFECT ON SIT NONOP - OCI	225	225				Not applicable to Transmission Cost of Service calculation.
DIRECTOR CHARITABLE DONATION	175	175				Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP CURRENT ASSET N.C.	2	2				Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP CURRENT ASSET VA	22	22				Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP CURRENT ASSET W.V.	1	1				Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP NONCURRENT ASSET N.C.	3,786	3,786				Not applicable to Transmission Cost of Service calculation.
DSIT 190 N ONOP NONCURRENT ASSET VA	50,112	50,112				Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP NONCURRENT ASSET W.V.	1,725	1,725				Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP PLANT NONCURR ASSET N.C.	1,286	1,286				Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP PLANT NONCURR ASSET VA	16,992	16,992				Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP PLANT NONCURR ASSET W.V.	585	585				Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING CURRENT ASSET N.C.	(2,013)	(2,013)				Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING CURRENT ASSET VA	(26,588)	(26,588)				Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING CURRENT ASSET W.V.	(918)	(918)				Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING NONCURR ASSEST N.C.	451	451				Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING NONCURR ASSEST VA	5,888	5,888				Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING NONCURR ASSEST VA MIN	443	443				Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING NONCURR ASSEST W.V.	204	204				Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING PLANT NONCURR ASSET N.C.	5,356	5,356				Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING PLANT NONCURR ASSET VA	70,790	70,790				Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING PLANT NONCURR ASSET W.V.	2,439	2,439				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OP OTHER NONCURR LIAB N.C.	(17)	(17)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OP OTHER NONCURR LIAB VA	(230)	(230)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OP OTHER NONCURR LIAB W.V.	(8)	(8)				Not applicable to Transmission Cost of Service calculation.
DSM						Not applicable to Transmission Cost of Service calculation.
EARNEST MONEY						Not applicable to Transmission Cost of Service calculation.
EMISSIONS ALLOWANCES	0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DFIT DEFICIENCY (190)	6,480	6,480				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT DEFICIENCY N.C. (190)	83	83				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT DEFICIENCY VA (190)	1,086	1,086				Not applicable to Transmission Cost of Service calculation.

ATTACHMENT H-16A

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31, 2010

FAS 109 ITC DSIT DEFICIENCY W.V.(190)		38	38				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT GROSSUP N.C.		53	53				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT GROSSUP VA		693	693				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT GROSSUP W.V.		24	24				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC GROSSUP (190)		4,138	4,138				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC REG LIAB		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133		22,314	22,314				Not applicable to Transmission Cost of Service calculation.
FAS 143 ASSET OBLIGATION		11,912	11,839	73			Represents ARO accruals not deductible for tax.
FAS143 DECOMMISSIONING		284,921	284,921				Represents ARO accruals not deductible for tax.
FEDERAL TAX INTEREST EXPENSE NON CURRENT		860	860				Not applicable to Transmission Cost of Service calculation.
FLEET LEASE CREDIT - CURRENT		102			102		Books amortize the fleet lease extension credit over the new lease; tax takes the deduction when incurred.
FLEET LEASE CREDIT - NONCURRENT		154			154		Books amortizes the fleet lease extension credit over the new lease; tax takes the deduction when incurred.
GAIN SALE/LEASEBACK - SYSTEM OFFICE		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
GROSS REC-UNBILLED REV-NC		98	98				Books include income when meter is read; taxed when service is provided.
HEADWATER BENEFITS		461	461				Not applicable to Transmission Cost of Service calculation.
INT STOR NORTH ANNA		4,227	4,227				Books recognizes the expense as incurred. For tax the deduction is recognized when the casks are filled.
INT STOR SURRY		(778)	(778)				Books recognizes the expense as incurred. For tax the deduction is recognized when the casks are filled.
LONG TERM DISABILITY RESERVE		4,623				4,623	Book estimate accrued and expensed; tax deduction when paid.
METERS		6,995	6,995				Books pre-capitalize when purchased; tax purposes when installed.
NUCLEAR FUEL - PERMANENT DISPOSAL		19	19				Books estimate expense, tax deduction taken when paid.
OBSOLETE INVENTORY		425	425				Not applicable to Transmission Cost of Service calculation.
OPEB		24,839				24,839	Represents the difference between the book accrual expense and the actual funded amount.
PERFORMANCE ACHIEVEMENT PLAN		4	4				Not applicable to Transmission Cost of Service calculation.
POWER PURCHASE BUYOUT		499	499				Represents the difference between the book accrual expense and the actual funded amount.
PREMIUM, DEBT, DISCOUNT AND EXPENSE		3,108			3,108		Books record the yield to maturity method; taxes amortize staight line.
P'SHIP INCOME - NC ENTERPRISE		37	37				Not applicable to Transmission Cost of Service calculation.
P'SHIP INCOME - VIRGINIA CAPITAL		219	219				Not applicable to Transmission Cost of Service calculation.
QUALIFIED SETTLEMENT FUND		140	140				Not applicable to Transmission Cost of Service calculation.
REACTOR DECOMMISSIONING LIABILITY		350	350				Represents the difference between the accrual and payments.
REG ASSET FUEL HEDGE		1,543	1,543				Not applicable to Transmission Cost of Service calculation.
REG LIABILITY DECOMMISSIONING TRUST - NC		74,538	74,538				Not applicable to Transmission Cost of Service calculation.
REG LIABILITY HEDGES CAPACITY - NC		13,906	13,906				Not applicable to Transmission Cost of Service calculation.
REG LIABILITY HEDGES DEBT		3,862	3,862				Not applicable to Transmission Cost of Service calculation.
REGULATORY ASSET - D & D		4	4				Not applicable to Transmission Cost of Service calculation.
RESTRICTED STOCK AWARD		1,815	1,815				Not applicable to Transmission Cost of Service calculation.
RETIREMENT - (FASB 87)		57,275				57,275	Book estimate accrued and expensed; tax deduction when paid.
RETIREMENT - EXEC SUPP RET (ESRP) - NONOP		129	129				Not applicable to Transmission Cost of Service calculation.
RETIREMENT - SUPPLEMENTAL RETIREMENT		141	141				Not applicable to Transmission Cost of Service calculation.
SEPARATION/ERT		43				43	Book amount accrued and expensed; tax deduction when paid.
SUCCESS SHARE PLAN		6,789				6,789	Book amount accrued as its earned; tax deduction is actual payout.
VA SALES & USE TAX AUDIT (INCL. INT)		210	210				Not applicable to Transmission Cost of Service calculation.
VACATION ACCRUAL		13,116	13,116				Not applicable to Transmission Cost of Service calculation.
W.VA. STATE POLLUTION CONTROL - FEDERAL EFFECT		3,816	3,816				Federal effect of state deductions.
WEST VA PROPERTY TAX		1,558	1,558				Property tax expense is accrued for accounting purposes using the prior year's rates on the balance of the property located in the state at December 31 of the previous year. Tax takes a deduction when paid.
Subtotal - p234		1,128,101	926,091	73	108,368	93,569	
Less FASB 109 Above if not separately removed		73		73			
Less FASB 106 Above if not separately removed		24,839	0	0	0	24,839	
Total		1,103,190	926,091	0	108,368	68,731	

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

ATTACHMENT H-16A

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31, 2010

A	B	C	D	E	F	G
ADIT- 282	*Total*	*Production Or Other Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
AFC DEFERRED TAX - FUEL CWIP	(9)	(9)				Represents the amount of amortization of AFC in service not allowable for tax.
AFC DEFERRED TAX - FUEL IN SERVICE	(47)	(47)				Represents the amount of amortization of AFC in service not allowable for tax.
AFC DEFERRED TAX - PLANT CWIP	(7,130)	(7,130)				Represents the amount of amortization of AFC in service not allowable for tax.
AFC DEFERRED TAX - PLANT IN SERVICE	(9,804)	(5,452)	(4,353)			Represents the amount of amortization of AFC in service not allowable for tax.
AFUDC - DEBT - GENERATION RIDER	(2,051)	(2,051)				Not applicable to Transmission Cost of Service calculation.
BOOK CAPITALIZED INTEREST CWIP	(2,216)			(2,216)		Represents the unallowable amount of book interest.
CAP EXPENSE	(36,829)			(36,829)		Capitalized for books and current deduction for tax as repairs.
CAPITAL LEASE	(460)	(460)				Not applicable to Transmission Cost of Service calculation.
CASUALTY LOSS	(33,787)			(33,787)		Book varies in treatment; tax sec. 165 casualty loss for the decline in value (up to the adj. basis) and Sec 162 deduction for repairs to restore to pre-casualty condition.
COMPUTER SOFTWARE-BOOK AMORT	8,090				8,090	Represents total Book Computer Software Amortization Schedule M addition.
COMPUTER SOFTWARE-CWIP	(3,846)	(3,846)				Represents the allowable "In house" deduction for tax.
COMPUTER SOFTWARE-TAX AMORT	(20,645)				(20,645)	Total tax amortization shown as a schedule M deduction and add back total book amortization.
COST OF REMOVAL	(111,077)	(102,180)	(6,918)		(1,978)	Represents the actual cost of removal allowable for tax over the accrued amount.
DECOMMISSIONING	(0)	(0)				Tax deduction for funding decomm trust and tax deferral of book income generated by trust.
DECOMMISSIONING TRUST BOOK INCOME	(302,783)	(302,783)				Not applicable to Transmission Cost of Service calculation.
DFIT 190 NONOPERATING NONCURR ASSET	(6,603)	(6,603)				Not applicable to Transmission Cost of Service calculation.
DFIT 190 OPERATING NONCURR ASSET	(27,506)	(27,506)				Not applicable to Transmission Cost of Service calculation.
DSIT 282 NONOP PLANT NONCURR LIAB N.C.	268	268				Not applicable to Transmission Cost of Service calculation.
DSIT 282 NONOP PLANT NONCURR LIAB VA	3,837	3,837				Not applicable to Transmission Cost of Service calculation.
DSIT 282 NONOP PLANT NONCURR LIAB W.V.	122	122				Not applicable to Transmission Cost of Service calculation.
DSIT 282 OPERATING PLANT NONCURR LIAB N.C.	(31,476)	(31,476)				Not applicable to Transmission Cost of Service calculation.
DSIT 282 OPERATING PLANT NONCURR LIAB VA	(219,986)	(219,986)				Not applicable to Transmission Cost of Service calculation.
DSIT 282 OPERATING PLANT NONCURR LIAB W.V.	(14,827)	(14,827)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282)	(22,712)	(22,712)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - GENERATION R	(4,280)	(4,280)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282)	(79)	(79)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282)-GENERAT	(53)	(53)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282)	(1,050)	(1,050)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282) - GENERATIO	(725)	(725)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282)	(36)	(36)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282) - GENERAT	(25)	(25)				Not applicable to Transmission Cost of Service calculation.
FIXED ASSETS	(9,312)			(9,312)		Represents IRS audit adjustments to plant-related differences.
FIXED ASSETS - NC	27			27		Represents the state impact of IRS Audit adjustments to plant related differences.
FIXED ASSETS - VA	361			361		Represents the state impact of IRS Audit adjustments to plant related differences.
FIXED ASSETS - W.V.	13			13		Represents the state impact of IRS Audit adjustments to plant related differences.
GAIN(LOSS) INTERCO SALES - BOOK/TAX	(290)	(290)				Tax recognizes the intercompany gain/loss over the tax life of the assets.
INVOLUNTARY CONVERSION - TELECOMMUNICATIONS	(1,104)	(1,104)				Represents the difference between book and tax related to the disposal of telecommunication equipment. Recognized for tax purposes when utilized.
LIBERALIZED DEPRECIATION - FUEL	(3,559)	(3,559)				Represents difference between book burn of nuclear fuel based on usage vs. tax depreciation.
LIBERALIZED DEPRECIATION - PLANT ACUFILE	(2,114,153)	(1,889,657)	(193,877)		(30,619)	Difference between book and tax depreciation taking in consideration flow-through and ARAM.
LIBERALIZED DEPRECIATION - PLANT LAND FUTURE USE	228	228				Not applicable to Transmission Cost of Service calculation.
LIBERALIZED DEPRECIATION - PLANT LAND NON UTILITY	(532)	(532)				Not applicable to Transmission Cost of Service calculation.
LIBERALIZED DEPRECIATION - PLANT OPER LAND	707	707				Not applicable to Transmission Cost of Service calculation.
LIBERALIZED DEPRECIATION - PLANT OTHER	(232,500)	(232,500)				Not applicable to Transmission Cost of Service calculation.
LIBERALIZED DEPRECIATION - PLANT FUTURE USE	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
LIBERALIZED DEPRECIATION - PLANT NON UTILITY	7	7				Not applicable to Transmission Cost of Service calculation.
SUCCESS SHARE PLAN	(1,752)				(1,752)	Book amount accrued as it's earned; tax deduction is actual payout.
YORKTOWN IMPLOSION - TAX DEP.-LIB - NON OP	0	0				Not applicable to Transmission Cost of Service calculation.
Subtotal - p275 (Form 1-F filer: see note 6 below)	(3,209,585)	(2,875,790)	(205,148)	(81,743)	(46,905)	
Less FASB 109 Above if not separately removed	0		0	0	0	
Less FASB 106 Above if not separately removed	0					
Total	(3,209,585)	(2,875,790)	(205,148)	(81,743)	(46,905)	

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

ATTACHMENT H-16A

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31, 2010

A	B	C	D	E	F	G
ADIT-283	*Total*	*Production Or Other Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
CONTINGENT CLAIMS CURRENT	(2,406)	(2,406)				Not applicable to Transmission Cost of Service calculation.
DECOMMISSIONING TRUST - UNREALIZED GAIN/LOSS - NC	(8,280)	(8,280)				Not applicable to Transmission Cost of Service calculation.
DEFERRED FUEL EXPENSE	(283,143)	(283,143)				Not applicable to Transmission Cost of Service calculation.
DEFERRED FUEL EXPENSE - OTHER	(29,515)	(29,515)				Not applicable to Transmission Cost of Service calculation.
DFIT 190 NONOPERATING CURRENT ASSET	(9)	(9)				Not applicable to Transmission Cost of Service calculation.
DFIT 190 NONOPERATING NONCURR ASSET	(34,119)	(34,119)				Not applicable to Transmission Cost of Service calculation.
DFIT 190 OPERATING CURRENT ASSET	(4,153)	(4,153)				Not applicable to Transmission Cost of Service calculation.
DFIT 190 OPERATING NONCURR ASSET	(4,346)	(4,346)				Not applicable to Transmission Cost of Service calculation.
DFIT 190 OPERATING NONCURRENT ASSET	2,428	2,428				Not applicable to Transmission Cost of Service calculation.
DFIT 283 OPERATING NONCURRENT LIAB	89	89				Not applicable to Transmission Cost of Service calculation.
DSIT 283 NONOP CURRENT LIABILITY N.C.	(4)	(4)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 NONOP NONCURRENT LIABILITY N.C.	(627)	(627)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 NONOP NONCURRENT LIABILITY VA	(14,759)	(14,759)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 NONOP NONCURRENT LIABILITY W.V.	(278)	(278)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OP OTHER NONCURR LIAB N.C.	(3,433)	(3,433)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OP OTHER NONCURR LIAB VA	(45,441)	(45,441)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OP OTHER NONCURR LIAB VA MIN	(10)	(10)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OP OTHER NONCURR LIAB W.V.	(1,564)	(1,564)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OPERATING CURRENT LIABILITY N.C.	(1,067)	(1,067)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OPERATING CURRENT LIABILITY VA	(14,134)	(14,134)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OPERATING CURRENT LIABILITY W.V.	(474)	(474)				Not applicable to Transmission Cost of Service calculation.
EARNEST MONEY	-					Represents advances not recognized for tax.
EMISSIONS ALLOWANCES	(2,696)	(2,696)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283)	(12,857)	(12,857)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - GENERATION RIDE	(2,737)	(2,737)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC	(164)	(164)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - GENERATION RIDER	(34)	(34)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA	(2,158)	(2,158)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - GENERATION RIDER	(464)	(464)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV	(74)	(74)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - GENERATION RIDER	(16)	(16)				Not applicable to Transmission Cost of Service calculation.
FAS 109 REG ASSET	-					Represents tax gross-up on deferred tax deficiency related to previous flow-through and ARAM related ADIT.
FAS 133	(6,918)	(6,918)				Not applicable to Transmission Cost of Service calculation.
FAS 133	6,859	6,859				Not applicable to Transmission Cost of Service calculation.
FEDERAL TAX INTEREST EXPENSE	(3,818)	(3,818)				Not applicable to Transmission Cost of Service calculation.
FUEL HANDLING COSTS	(77)	(77)				IRS settlement required additional tax capitalization of handling costs.
GAIN(LOSS) INTERCO SALES -BOOK/TAX	-					Tax deferred recognition of intercompany gain/loss due to consolidated return rules.
GAIN(LOSS) INTERCO SALES -BOOK/TAX	-					Tax deferred recognition of intercompany gain/loss due to consolidated return rules.
GOODWILL AMORTIZATION	(3)	(3)				Not applicable to Transmission Cost of Service calculation.
NUCLEAR FUEL - PERMANENT DISPOSAL	(9)	(9)				Not applicable to Transmission Cost of Service calculation.
OBSOLETE INVENTORY	0	0				Not applicable to Transmission Cost of Service calculation.
PERFORMANCE ACHIEVEMENT PLAN	(4)	(4)				Not applicable to Transmission Cost of Service calculation.
POWERTREE CARBON CO, LLC.	(31)	(31)				Not applicable to Transmission Cost of Service calculation.
QUALIFIED SETTLEMENT FUND	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
REACQUIRED DEBT GAIN(LOSS)	(2,507)	(2,507)				Not applicable to Transmission Cost of Service calculation.
REG ASSET FUEL HEDGE	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
REG ASSET HEDGES CAPACITY	-					Not applicable to Transmission Cost of Service calculation.
REG ASSET POWER HEDGE	(2,960)	(2,960)				Not applicable to Transmission Cost of Service calculation.
REG LIABILITY - ARO	-					Not applicable to Transmission Cost of Service calculation.
REG LIABILITY FX FUEL HEDGE	-					Not applicable to Transmission Cost of Service calculation.
REG LIABILITY - FTR	(19,354)	(19,354)				Not applicable to Transmission Cost of Service calculation.
REGULATORY ASSET - D & D	(0)	(0)				Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
REGULATORY ASSET - FAS 112	(1,784)				(1,784)	Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
REGULATORY ASSET - ISABEL	-					Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
REGULATORY ASSET - NUG	(6,190)	(6,190)				Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
REGULATORY ASSET - PJM	(55,892)	(55,892)				Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
REGULATORY ASSET - VA SLS TAX	(5,753)	(5,753)				Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
SO2 ALLOWANCES - NONCURRENT	-					Book expense for emissions allowances based on moving-average-cost, tax expense based on specific identification.
W.VA. STATE NOL CFWD	-					Represents the deferred state tax impact related to WV NOL. This deferral will turn around when the pollution control projects are placed in service.
W.VA. STATE POLLUTION CONTROL	(10,904)			(10,904)		Represents the deferred state tax impact related to WV Pollution control projects. This deferral will turn around once placed in service.
ADFIT - OTHER COMPREHENSIVE INCOME	(1,187)	(1,187)				Not applicable to Transmission Cost of Service calculation.
ADFIT - OTHER COMPREHENSIVE INCOME	(2,479)	(2,479)				Not applicable to Transmission Cost of Service calculation.
DEFERRED N.C. SIT NONOP - OCI	(47)	(47)				Not applicable to Transmission Cost of Service calculation.
DEFERRED SIT NONOP - OCI	(208)	(208)				Not applicable to Transmission Cost of Service calculation.
DEFERRED SIT NONOP - OCI	(387)	(387)				Not applicable to Transmission Cost of Service calculation.
FAS 133	(16,651)	(16,651)				Not applicable to Transmission Cost of Service calculation.
Subtotal - p277 (Form 1-F filer: see note 6, below)	(596,754)	(584,066)	-	(10,904)	(1,784)	
Less FASB 109 Above if not separately removed	-		-	-	-	
Less FASB 106 Above if not separately removed	-				-	
Total	(596,754)	(584,066)	-	(10,904)	(1,784)	

Instructions for Account 283:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F

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

Attachment 1- Accumulated Deferred Income Taxes (ADIT) Worksheet
Amortization ITC-255

		Item	Balance	Amortization
1	Amortization			879
2	Amortization to line 136 of Appendix A	Total		286
3	Total		-	1,165
4	Total Form No. 1 (p 266 & 267)	Form No. 1 balance (p.266) for amortizat		1,165
5	Difference /1		-	-

/1 Difference must be zero

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31, 2009
(000's)

	Only Transmission Related	Plant Related	Labor Related	Total ADIT
ADIT- 282	(184,062)	(55,108)	(46,001)	
ADIT-283	0	(10,904)	(1,784)	
ADIT-190	73	108,368	56,831	
Subtotal	(183,989)	42,356	9,046	
Wages & Salary Allocator			3.8758%	
Gross Plant Allocator		9.6439%		
End of Year ADIT	(183,989)	4,085	351	(179,554)

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.

End of Year Balances :

A	B	C	D	E	F	G
ADIT-190	Total	Production Or Other Related	Only Transmission Related	Plant Related	Labor Related	Justification
BAD DEBTS	5,190	5,190				For tax purposes bad debts are deductible when they are deemed to be uncollectible / worthless.
CAPITAL LEASE	426	426				Not applicable to Transmission Cost of Service calculation.
CAPITALIZED BROKERS FEES	749	749				Not applicable to Transmission Cost of Service calculation.
CAPITALIZED INTEREST - NONOP CWIP	-	-				Not applicable to Transmission Cost of Service calculation.
CAPITALIZED INTEREST NONOP IN SERVICE	307	307				Not applicable to Transmission Cost of Service calculation.
CAPITALIZED INTEREST OPERATING CWIP	54,833	54,833				Represents tax capitalized interest on projects in CWIP - increase in taxable income.
CAPITALIZED INTEREST OPERATING IN SERVICE	105,501			105,501		Represents tax "In Service" capitalized Interest placed in service net of tax amortization.
CIAC NC - NONOP CWIP	7	7				Not applicable to Transmission Cost of Service calculation.
CIAC NC - NONOP IN SERVICE	2,679	2,679				Not applicable to Transmission Cost of Service calculation.
CIAC VA - NONOP CWIP	3,215	3,215				Not applicable to Transmission Cost of Service calculation.
CIAC VA - NONOP IN SERVICE	100,213	100,213				Not applicable to Transmission Cost of Service calculation.
CONTINGENT CLAIMS CURRENT	-	-				Not applicable to Transmission Cost of Service calculation.
CONTINGENT CLAIMS NONCURRENT	1,455	1,455				Not applicable to Transmission Cost of Service calculation.
DECOMMISSIONING & DECONTAMINATION	(2)	(2)				Book expensed as billed over 15 yr assessment period; tax deduct in year of assessment because all events test met as liability is based on prior facility use.
DEFERRED GAIN/LOSS NONOPERATING	(53)	(53)				Not applicable to Transmission Cost of Service calculation.
DEFERRED GAIN/LOSS OPERATING	(498)			(498)		Represents the ADIT on Book Gain/Loss as accrued.
DEFERRED GAIN/LOSS-FUTURE USE	(736)	(736)				Not applicable to Transmission Cost of Service calculation.
DEFERRED GAIN/LOSS-FUTURE USE NONOP	1,917	1,917				Not applicable to Transmission Cost of Service calculation.
DFIT - ITC ASSET FIT DEREGULATED	-	-				Not applicable to Transmission Cost of Service calculation.
DFIT 190 OPERATING NONCURRENT ASSET	(526)	(526)				Not applicable to Transmission Cost of Service calculation.
DFIT 282 NONOPERATING PLANT NONCURR LIAB	(3,368)	(3,368)				Not applicable to Transmission Cost of Service calculation.
DFIT 282 NONOPERATING PLANT NONCURR LIAB	-	0				Not applicable to Transmission Cost of Service calculation.
DFIT 282 OPERATING PLANT NONCURR LIAB	94,973	94,973				Not applicable to Transmission Cost of Service calculation.
DFIT 283 NONOPERATING CURRENT LIAB	2	2				Not applicable to Transmission Cost of Service calculation.
DFIT 283 NONOPERATING NONCURRENT LIAB	5,650	5,650				Not applicable to Transmission Cost of Service calculation.
DFIT 283 OPERATING CURRENT LIABILITY	5,487	5,487				Not applicable to Transmission Cost of Service calculation.
DFIT 283 OPERATING NONCURRENT LIAB	46,626	46,626				Not applicable to Transmission Cost of Service calculation.
DFIT EFFECT ON SIT NONOP - OCI	225	225				Not applicable to Transmission Cost of Service calculation.
DIRECTOR CHARITABLE DONATION	175	175				Not applicable to Transmission Cost of Service calculation.
DSIT - ITC SIT ASSET N.C. DEREGULATED	-	-				Not applicable to Transmission Cost of Service calculation.
DSIT - ITC SIT ASSET Va. DEREGULATED	-	-				Not applicable to Transmission Cost of Service calculation.
DSIT - ITC SIT ASSET W.V. DEREGULATED	-	-				Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP CURRENT ASSET N.C.	2	2				Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP CURRENT ASSET VA	22	22				Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP CURRENT ASSET W.V.	1	1				Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP NONCURRENT ASSET N.C.	3,786	3,786				Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP NONCURRENT ASSET VA	50,112	50,112				Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP NONCURRENT ASSET W.V.	1,725	1,725				Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP PLANT NONCURR ASSET N.C.	1,286	1,286				Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP PLANT NONCURR ASSET VA	16,992	16,992				Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP PLANT NONCURR ASSET W.V.	585	585				Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING CURRENT ASSET N.C.	(2,013)	(2,013)				Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING CURRENT ASSET VA	(26,588)	(26,588)				Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING CURRENT ASSET W.V.	(918)	(918)				Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING NONCURR ASSET N.C.	451	451				Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING NONCURR ASSET VA	5,888	5,888				Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING NONCURR ASSET VA MIN	443	443				Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING NONCURR ASSET W.V.	204	204				Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING PLANT NONCURR ASSET N.C.	5,356	5,356				Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING PLANT NONCURR ASSET VA	70,790	70,790				Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING PLANT NONCURR ASSET W.V.	2,439	2,439				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OP OTHER NONCURR LIAB NC	(17)	(17)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OP OTHER NONCURR LIAB VA	(230)	(230)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OP OTHER NONCURR LIAB W.V.	(8)	(8)				Not applicable to Transmission Cost of Service calculation.
EMISSIONS ALLOWANCES	0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DFIT DEFICIENCY (190)	6,480	6,480				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT DEFICIENCY N.C.(190)	83	83				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT DEFICIENCY VA (190)	1,086	1,086				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT DEFICIENCY W.V. (190)	38	38				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT GROSSUP NC	53	53				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT GROSSUP VA	693	693				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT GROSSUP WV	24	24				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC GROSSUP (190)	4,138	4,138				Not applicable to Transmission Cost of Service calculation.
FAS 133	22,314	22,314				Not applicable to Transmission Cost of Service calculation.
FAS 143 ASSET OBLIGATION	11,912	11,839	73			Represents ARO accruals not deductible for tax.
FAS143 DECOMMISSIONING	284,921	284,921				Represents ARO accruals not deductible for tax.
FEDERAL TAX INTEREST EXPENSE NON CURRENT	860	860				Not applicable to Transmission Cost of Service calculation.
FLEET LEASE CREDIT - CURRENT	102			102		Books amortize the fleet lease extension credit over the new lease; tax takes the deduction when incurred.
FLEET LEASE CREDIT - NONCURRENT	154			154		Books amortizes the fleet lease extension credit over the new lease; tax takes the deduction when incurred.
GAIN SALE/LEASEBACK - SYSTEM OFFICE	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
GROSS REC-UNBILLED REV-NC	98	98				Books include income when meter is read; taxed when service is provided.
HEADWATER BENEFITS	461	461				Not applicable to Transmission Cost of Service calculation.
INT STOR NORTH ANNA	4,227	4,227				filled.
INT STOR SURRY	(778)	(778)				filled.
LONG TERM DISABILITY RESERVE	4,623				4,623	Book estimate accrued and expensed; tax deduction when paid.
METERS	6,995	6,995				Books pre-capitalize when purchased; tax purposes when installed.
NUCLEAR FUEL - PERMANENT DISPOSAL	19	19				Books estimate expense, tax deduction taken when paid.
OBSOLETE INVENTORY	425	425				Not applicable to Transmission Cost of Service calculation.
OPEB	24,839				24,839	Represents the difference between the book accrual expense and the actual funded amount.
PERFORMANCE ACHIEVEMENT PLAN	4	4				Not applicable to Transmission Cost of Service calculation.
POWER PURCHASE BUYOUT	499	499				Represents the difference between the book accrual expense and the actual funded amount.
PREMIUM, DEBT, DISCOUNT AND EXPENSE	3,108			3,108		Books record the yield to maturity method; taxes amortize staight line.
P'SHIP INCOME - NC ENTERPRISE	37	37				Not applicable to Transmission Cost of Service calculation.
P'SHIP INCOME - VIRGINIA CAPITAL	219	219				Not applicable to Transmission Cost of Service calculation.
QUALIFIED SETTLEMENT FUND	140	140				Not applicable to Transmission Cost of Service calculation.
REACTOR DECOMMISSIONING LIABILITY	350	350				Represents the difference between the accrual and payments.
REG ASSET FUEL HEDGE	1,543	1,543				Not applicable to Transmission Cost of Service calculation.
REG LIABILITY DECOMMISSIONING TRUST - NC	74,538	74,538				Not applicable to Transmission Cost of Service calculation.
REGULATORY LIABILITY - ARO	-					Not applicable to Transmission Cost of Service calculation.
DSIT OPERATING	-					Not applicable to Transmission Cost of Service calculation.
DFIT OF STATE OPERATING	-					Not applicable to Transmission Cost of Service calculation.
REG LIABILITY HEDGES CAPACITY - NC	13,906	13,906				Not applicable to Transmission Cost of Service calculation.
REG LIABILITY HEDGES DEBT	3,862	3,862				Not applicable to Transmission Cost of Service calculation.
REGULATORY ASSET - D & D	4	4				Not applicable to Transmission Cost of Service calculation.
RESTRICTED STOCK AWARD	1,815	1,815				Not applicable to Transmission Cost of Service calculation.

RETIREMENT - (FASB 87)	45,375				45,375	Book estimate accrued and expensed; tax deduction when paid.
RETIREMENT - EXEC SUPP RET (ESRP) - NONOP	129	129				Not applicable to Transmission Cost of Service calculation.
RETIREMENT - SUPPLEMENTAL RETIREMENT	141	141				Not applicable to Transmission Cost of Service calculation.
SEPARATION/ERT	43				43	Book amount accrued and expensed; tax deduction when paid.
SUCCESS SHARE PLAN	6,789				6,789	Book amount accrued as its earned; tax deduction is actual payout.
VA SALES & USE TAX AUDIT (INCL. INT)	210	210				Not applicable to Transmission Cost of Service calculation.
VACATION ACCRUAL	13,116	13,116				Not applicable to Transmission Cost of Service calculation.
W.VA. STATE POLLUTION CONTROL - FEDERAL EFFECT	3,816	3,816				Federal effect of state deductions.
WEST VA PROPERTY TAX	1,558	1,558				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC REG LIABILITY	-					Represents the tax effect of ITC that will be refunded to the customer.
Subtotal - p234	1,099,726	909,616	73	108,368	81,669	
Less FASB 109 Above if not separately removed	-		-	-	-	
Less FASB 106 Above if not separately removed	24,839	0	0	0	24,839	
Total	1,074,888	909,616	73	108,368	56,831	

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,

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 **ADIT- 282**	**B** **Total**	**C** **Production Or Other Related**	**D** **Only Transmission Related**	**E** **Plant Related**	**F** **Labor Related**	**G** **Justification**
AFC DEFERRED TAX - FUEL CWIP	(9)	(9)				Not applicable to Transmission Cost of Service calculation.
AFC DEFERRED TAX - FUEL IN SERVICE	(47)	(47)				Represents the amount of amortization of AFC in service not allowable for tax.
AFC DEFERRED TAX - PLANT CWIP	(7,130)	(7,130)				Not applicable to Transmission Cost of Service calculation.
AFC DEFERRED TAX - PLANT IN SERVICE	(9,804)	(5,452)	(4,353)			Represents the amount of amortization of AFC in service not allowable for tax.
AFUDC - DEBT - GENERATION RIDER	(2,051)	(2,051)				Not applicable to Transmission Cost of Service calculation.
BOOK CAPITALIZED INTEREST CWIP	(2,216)			(2,216)		Represents the unallowable amount of book interest.
CAP EXPENSE	(21,044)			(21,044)		Capitalized for books and current deduction for tax as repairs.
CAPITAL LEASE	(460)	(460)				Not applicable to Transmission Cost of Service calculation.
CASUALTY LOSS	(22,937)			(22,937)		Book varies in treatment; tax sec. 165 casualty loss for the decline in value (up to the adj. basis) and Sec 162 deduction for repairs to restore to pre-casualty condition.
COMPUTER SOFTWARE-BOOK AMORT	8,090				8,090	Represents total Book Computer Software Amortization Schedule M addition.
COMPUTER SOFTWARE-CWIP	(3,846)	(3,846)				Represents the allowable "In house" deduction for tax.
COMPUTER SOFTWARE-TAX AMORT	(20,645)				(20,645)	Total tax amortization shown as a schedule M deduction and add back total book amortization.
COST OF REMOVAL	(101,137)	(93,247)	(5,912)		(1,978)	Represents the actual cost of removal allowable for tax over the accrued amount.
DECOMMISSIONING	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
DECOMMISSIONING TRUST BOOK INCOME	(302,783)	(302,783)				Not applicable to Transmission Cost of Service calculation.
DFIT 190 NONOPERATING NONCURR ASSET	(6,603)	(6,603)				Not applicable to Transmission Cost of Service calculation.
DFIT 190 OPERATING NONCURRENT ASSET	(27,506)	(27,506)				Not applicable to Transmission Cost of Service calculation.
DSIT 282 NONOP PLANT NONCURR LIAB N.C.	268	268				Not applicable to Transmission Cost of Service calculation.
DSIT 282 NONOP PLANT NONCURR LIAB VA	3,837	3,837				Not applicable to Transmission Cost of Service calculation.
DSIT 282 NONOP PLANT NONCURR LIAB W.V.	122	122				Not applicable to Transmission Cost of Service calculation.
DSIT 282 OPERATING PLANT NONCURR LIAB N.C.	(31,476)	(31,476)				Not applicable to Transmission Cost of Service calculation.
DSIT 282 OPERATING PLANT NONCURR LIAB VA	(219,986)	(219,986)				Not applicable to Transmission Cost of Service calculation.
DSIT 282 OPERATING PLANT NONCURR LIAB W.V.	(14,827)	(14,827)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282)	(22,712)	(22,712)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - GENERATION R	(4,280)	(4,280)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282)	(79)	(79)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282) - GENERAT	(53)	(53)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282)	(1,050)	(1,050)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282) - GENERATIO	(725)	(725)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282)	(36)	(36)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282) - GENERAT	(25)	(25)				Not applicable to Transmission Cost of Service calculation.
FIXED ASSETS	(9,312)			(9,312)		Represents IRS audit adjustments to plant-related differences.
FIXED ASSETS	-					Not applicable to Transmission Cost of Service calculation.
FIXED ASSETS - NC	27			27		Represents the state impact of IRS Audit adjustments to plant related differences.
FIXED ASSETS - VA	361			361		Represents the state impact of IRS Audit adjustments to plant related differences.
FIXED ASSETS - WV	13			13		Represents the state impact of IRS Audit adjustments to plant related differences.
GAIN(LOSS) INTERCO SALES - BOOK/TAX	(290)	(290)				Not applicable to Transmission Cost of Service calculation.
INVOLUNTARY CONVERSION - TELECOMMUNICATIONS	(1,104)	(1,104)				Represents the difference between book and tax related to the disposal of telecommunication equipment. Recognized for tax purposes when utilized.
LIBERALIZED DEPRECIATION - FUEL	(5,406)	(5,406)				Represents difference between book burn of nuclear fuel based on usage vs. tax depreciation.
LIBERALIZED DEPRECIATION - FUEL CWIP	-	-				Difference between book CWIP and Tax CWIP as a result of Euro exchange utilization.
LIBERALIZED DEPRECIATION - PLANT ACUFILE	(2,079,925)	(1,876,412)	(173,798)		(29,716)	Difference between book and tax depreciation taking in consideration flow-through and ARAM.
LIBERALIZED DEPRECIATION - PLANT LAND FUTURE USE	228	228				Not applicable to Transmission Cost of Service calculation.
LIBERALIZED DEPRECIATION - PLANT LAND NONUTILITY	(532)	(532)				Not applicable to Transmission Cost of Service calculation.
LIBERALIZED DEPRECIATION - PLAN OPER LAND	707	707				Not applicable to Transmission Cost of Service calculation.
LIBERALIZED DEPRECIATION - PLANT OTHER	(232,500)	(232,500)				Not applicable to Transmission Cost of Service calculation.
LIBERALIZED DEPRECIATION - PLANT FUTURE USE	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
LIBERALIZED DEPRECIATION - PLANT NON UTILITY	7	7				Not applicable to Transmission Cost of Service calculation.
SUCCESS SHARE PLAN	(1,752)				(1,752)	Book amount accrued as it's earned; tax deduction is actual payout.
YORKTOWN IMPLOSION - TAX DEP. - LIB - NONOP	0	0				Not applicable to Transmission Cost of Service calculation.
Subtotal - p275 (Form 1-F filer: see note 6 below)	(3,140,628)	(2,855,458)	(184,062)	(55,108)	(46,001)	
Less FASB 109 Above if not separately removed	0		0	0	0	
Less FASB 106 Above if not separately removed	0					
Total	(3,140,628)	(2,855,458)	(184,062)	(55,108)	(46,001)	

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,

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

A	B	C	D	E	F	G
ADIT-283	Total	Production Or Other Related	Only Transmission Related	Plant Related	Labor Related	Justification
ADFIT - OTHER COMPREHENSIVE INCOME	(3,667)	(3,667)				Not applicable to Transmission Cost of Service calculation.
CONTINGENT CLAIMS CURRENT	(2,406)	(2,406)				Not applicable to Transmission Cost of Service calculation.
DECOMMISSIONING TRUST - UNREALIZED GAIN/LOSS - NC	(8,280)	(8,280)				Not applicable to Transmission Cost of Service calculation.
DEFERRED FUEL EXPENSE	(283,143)	(283,143)				Not applicable to Transmission Cost of Service calculation.
DEFERRED FUEL EXPENSE - OTHER	(29,515)	(29,515)				Not applicable to Transmission Cost of Service calculation.
DEFERRED N.C. SIT NONOP - OCI	(47)	(47)				Not applicable to Transmission Cost of Service calculation.
DEFERRED SIT NONOP - OCI	(595)	(595)				Not applicable to Transmission Cost of Service calculation.
DFIT 190 NONOPERATING CURR ASSET	(9)	(9)				Not applicable to Transmission Cost of Service calculation.
DFIT 190 NONOPERATING NONCURR ASSET	(34,119)	(34,119)				Not applicable to Transmission Cost of Service calculation.
DFIT 190 OPERATING CURRENT ASSET	(4,153)	(4,153)				Not applicable to Transmission Cost of Service calculation.
DFIT 190 OPERATING NONCURR ASSET	(4,346)	(4,346)				Not applicable to Transmission Cost of Service calculation.
DFIT 190 OPERATING NONCURRENT ASSET	2,428	2,428				Not applicable to Transmission Cost of Service calculation.
DFIT 283 OPERATING NONCURRENT LIAB	89	89				Not applicable to Transmission Cost of Service calculation.
DSIT 283 NONOP CURRENT LIABILITY N.C.	-	-				Not applicable to Transmission Cost of Service calculation.
DSIT 283 NONOP CURRENT LIABILITY VA	-	-				Not applicable to Transmission Cost of Service calculation.
DSIT 283 NONOP CURRENT LIABILITY W.V.	(4)	(4)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 NONOP NONCURRENT LIABILITY N.C.	(627)	(627)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 NONOP NONCURRENT LIABILITY VA	(14,759)	(14,759)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 NONOP NONCURRENT LIABILITY W.V.	(278)	(278)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OP OTHER NONCURR LIAB N.C.	(3,433)	(3,433)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OP OTHER NONCURR LIAB VA	(45,441)	(45,441)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OP OTHER NONCURR LIAB VA MIN	(10)	(10)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OP OTHER NONCURR LIAB W.V.	(1,564)	(1,564)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OPERATING CURRENT LIABILITY N.C.	(1,067)	(1,067)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OPERATING CURRENT LIABILITY VA	(14,134)	(14,134)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OPERATING CURRENT LIABILITY W.V.	(474)	(474)				Not applicable to Transmission Cost of Service calculation.
DSM	-					Not applicable to Transmission Cost of Service calculation.
EMISSIONS ALLOWANCES	(2,696)	(2,696)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283)	(12,857)	(12,857)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - GENERATION RIDE	(2,737)	(2,737)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC	(164)	(164)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - GENERATION RIDER	(34)	(34)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA	(2,158)	(2,158)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - GENERATION RIDER	(464)	(464)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV	(74)	(74)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - GENERATION RIDER	(16)	(16)				Not applicable to Transmission Cost of Service calculation.
FAS 133	-					Not applicable to Transmission Cost of Service calculation.
FAS 133	(6,918)	(6,918)				Not applicable to Transmission Cost of Service calculation.
FAS 133	6,859	6,859				Not applicable to Transmission Cost of Service calculation.
FAS 133	(16,651)	(16,651)				Not applicable to Transmission Cost of Service calculation.
FAS 133	-					Not applicable to Transmission Cost of Service calculation.
FEDERAL TAX INTEREST EXPENSE	(3,818)	(3,818)				Not applicable to Transmission Cost of Service calculation.
FINANCIAL DERIVATIVES CURRENT ASSET	-					Not applicable to Transmission Cost of Service calculation.
FUEL HANDLING COSTS	(77)	(77)				IRS settlement required additional tax capitalization of handling costs.
GAIN SALE/LEASEBACK-SYSTEM OFFICE	-					Not applicable to Transmission Cost of Service calculation.
GOODWILL AMORTIZATION	(3)	(3)				Not applicable to Transmission Cost of Service calculation.
OBSOLETE INVENTORY	0	0				Not applicable to Transmission Cost of Service calculation.
NUCLEAR FUEL - PERMANENT DISPOSAL	(9)	(9)				Not applicable to Transmission Cost of Service calculation.
PERFORMANCE ACHIEVEMENT PLAN	(4)	(4)				Not applicable to Transmission Cost of Service calculation.
POWERTREE CARBON CO, LLC.	(31)	(31)				Not applicable to Transmission Cost of Service calculation.
QUALIFIED SETTLEMENT FUND	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
REACQUIRED DEBT GAIN(LOSS)	(2,507)	(2,507)				Not applicable to Transmission Cost of Service calculation.
REG ASSET FUEL HEDGE	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
REG ASSET HEDGES CAPACITY	-					Not applicable to Transmission Cost of Service calculation.
REG ASSET POWER HEDGE	(2,960)	(2,960)				Not applicable to Transmission Cost of Service calculation.
REG LIABILITY - FTR	(19,354)	(19,354)				Not applicable to Transmission Cost of Service calculation.
REG LIABILITY HEDGES DEBT	-					Not applicable to Transmission Cost of Service calculation.
REGULATORY ASSET - D & D	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
REGULATORY ASSET - FAS 112	(1,784)				(1,784)	Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
REGULATORY ASSET - NUG	(6,190)	(6,190)				Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
REGULATORY ASSET - PJM	(48,717)	(48,717)				Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
REGULATORY ASSET - VA SLS TAX	(5,753)	(5,753)				Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
REG LIABILITY - ARO	-	-				Not applicable to Transmission Cost of Service calculation.
DSIT OPERATING	-					Not applicable to Transmission Cost of Service calculation.
DFIT OF STATE OPERATING	-					Not applicable to Transmission Cost of Service calculation.
W.VA. STATE POLLUTION CONTROL	(10,904)			(10,904)		Represents the deferred state tax impact related to WV Pollution control projects. This deferral will turn around once placed in service.
Subtotal - p277 (Form 1-F filer: see note 6, below)	(589,579)	(576,891)	-	(10,904)	(1,784)	
Less FASB 109 Above if not separately removed	-					
Less FASB 106 Above if not separately removed	-					
Total	(589,579)	(576,891)	-	(10,904)	(1,784)	

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,

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

Attachment 1- Accumulated Deferred Income Taxes (ADIT) Worksheet

Amortization ITC-255

			Balance	Amortization
1	Amortization			879
2	Amortization to line 136 of Appendix A			286
3	Total		-	1,165
4	Total Form No. 1 (p 266 & 267)			1,165
5	Difference /1		-	-

/1 Difference must be zero

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 2 - Taxes Other Than Income Worksheet
2010 (000's)

	Other Taxes	***Page 263 Col (i)***	***Allocator***	***Allocated Amount***
	Plant Related		***Gross Plant Allocator***	
1	Transmission Personal Property Tax (directly assigned to Transmission)	$ 12,128	100.0000%	$ 12,128
1a	Other Plant Related Taxes	0	10.8090%	-
2				-
3				-
4				-
5				-
				-
	Total Plant Related	$ 12,128		$ 12,128
	Labor Related		***Wages & Salary Allocator***	
6	Federal FICA & Unemployment & State Unemployment	$ 44,300		
	Total Labor Related	$ 44,300	4.8603%	$ 2,153
	Other Included		***Gross Plant Allocator***	
7	Sales and Use Tax	$ -		
	Total Other Included	$ -	10.8090%	$ -
	Total Included			$ 14,281
	Currently Excluded			
8	Business and Occupation Tax - West Virginia	$ 18,600		
9	Gross Receipts Tax	11,300		
10	IFTA Fuel Tax			
11	Property Taxes - Other	121,020		
12	Property Taxes - Generator Step-Ups and Interconnects	922		
13	Sales and Use Tax - not allocated to Transmission	500		
14	Sales and Use Tax - Retail	8,000		
15	Other	(450)		
16		0		
17		0		
18		0		
19		0		
20		0		
21	Total "Other" Taxes (included on p. 263)	$ 159,892		
22	Total "Taxes Other Than Income Taxes" - acct 408.10 (p. 114.14)	$ 216,320		
23	Difference	$ (56,428)		

Criteria for Allocation:

A Other taxes that are incurred through ownership of plant including transmission plant will be either directly assigned or 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.

VEPCO
ATTACHMENT H-16A
Attachment 2A - Direct Assignment of Property Taxes Per Function
2010 (000's)

Directly Assigned Property Taxes	$	134,148
Production Property Tax		64,600
Transmission Property Tax		12,128
GSU/Interconnect Facilities		922
Distribution Property tax		54,900
General Property Tax		1,598
Total check		134,148

Allocation of General Property Tax to Transmission

General Property Tax	$	1,598.00
Wages & Salary Allocator		4.8603%
Trans General		78

Total Transmission Property Taxes		
Transmission	$	12,128
General		78
Total Transmission Property Taxes	$	12,206

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 3 - Revenue Credit Workpaper
2010 (000's)

			Transmission Related	Production/Other Related	Total
	Account 454 - Rent from Electric Property				
1	Rent from Electric Property - Transmission Related (Note 3)		7,124	-	7,124
2	Total Rent Revenues	(Sum Lines 1)	7,124	-	7,124
	Account 456 - Other Electric Revenues (Note 1)				
3	Schedule 1A				
4	Net revenues associated with Network Integration Transmission Service (NITS) and for the transmission component of the NCEMPA contract rate for which the load is not included in the divisor. (Note 4)		2,100		2,100
5	Point to Point Service revenues received by Transmission Owner for which the load is not included in the divisor (Note 4)				-
6	PJM Transitional Revenue Neutrality (Note 1)				-
7	PJM Transitional Market Expansion (Note 1)				-
8	Professional Services (Note 3)		4,683		4,683
9	Revenues from Directly Assigned Transmission Facility Charges (Note 2)		2,792		2,792
10	Rent or Attachment Fees associated with Transmission Facilities (Note 3)				-
11	Gross Revenue Credits (Accounts 454 and 456)	(Sum Lines 2-10)	16,699	-	16,699
12	Less line 14g		(7,504)	-	(7,504)
13	Total Revenue Credits		9,195	-	9,195
	Revenue Adjustment to Determine Revenue Credit				
14a	Revenues included in lines 1-11 which are subject to 50/50 sharing. (Lines 1 + 8 + 10)		11,807	-	11,807
14b	Costs associated with revenues in line 14a		3,200	-	3,200
14c	Net Revenues (14a - 14b)		8,607	-	8,607
14d	50% Share of Net Revenues (14c / 2)		4,304	-	4,304
14e	Cost associated with revenues in line 14b 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)		4,304	-	4,304
14g	Line 14f less line 14a		(7,504)	-	(7,504)

Revenue Adjustment to Determine Revenue Credit

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 169 of Appendix A.

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.

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). VEPCO will retain 50% of net revenues consistent with *Pacific Gas and Electric Company*, 90 FERC ¶ 61,314. 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).

Note 4: Revenues from Schedule 12 are not included in the total above to the extent they are credited under Schedule 12. In addition, revenues from Schedule 7, Schedule 8 and H-A are not included in the total above to the extent PJM credits VEPCO's share of these revenues monthly to network customers under Attachment H-16.

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 4 - Calculation of 100 Basis Point Increase in ROE
2010 (000's)

	Return and Taxes with Basis Point increase in ROE			
A	Basis Point increase in ROE and Income Taxes		(Line 130 + 140)	187,237
B	100 Basis Point increase in ROE	(Note J from Appendix A)	Fixed	1.00%

Return Calculation

Line Ref.				
62	Rate Base		(Line 44 + 61)	1,464,900
	Long Term Interest			
104	**Long Term Interest**		p117.62c through 67c	314,238
105	Less LTD Interest on Securitization Bonds	(Note P)	Attachment 8	0
106	Long Term Interest		(Line 104 - 105)	314,238
107	Preferred Dividends	enter positive	p118.29c	16,659
	Common Stock			
108	Proprietary Capital		p112.16c,d/2	6,166,098
109	Less Preferred Stock	enter negative	(Line 117)	-259,014
110	Less Account 219 - Accumulated Other Comprehensive Income	enter negative	p112.15c,d/2	-15,590
111	Common Stock		(Sum Lines 108 to 110)	5,891,494
	Capitalization			
112	Long Term Debt		p112.24c,d/2	5,863,256
113	Less Loss on Reacquired Debt	enter negative	p111.81c,d/2	-6,527
114	Plus Gain on Reacquired Debt	enter positive	p113.61c,d/2	1,908
115	Less LTD on Securitization Bonds	enter negative	Attachment 8	0
116	Total Long Term Debt		(Sum Lines 112 to 115)	5,858,638
117	Preferred Stock		p112.3c,d/2	259,014
118	Common Stock		(Line 111)	5,891,494
119	Total Capitalization		(Sum Lines 116 to 118)	12,009,146
120	Debt %	Total Long Term Debt	(Line 116 / 119)	48.8%
121	Preferred %	Preferred Stock	(Line 117 / 119)	2.2%
122	Common %	Common Stock	(Line 118 / 119)	49.1%
123	Debt Cost	Total Long Term Debt	(Line 106 / 116)	0.0536
124	Preferred Cost	Preferred Stock	(Line 107 / 117)	0.0643
125	Common Cost	Common Stock	Appendix A Line 125 + 100 Basis Points	0.1240
126	Weighted Cost of Debt	Total Long Term Debt (WCLTD)	(Line 120 * 123)	0.0262
127	Weighted Cost of Preferred	Preferred Stock	(Line 121 * 124)	0.0014
128	Weighted Cost of Common	Common Stock	(Line 122 * 125)	0.0608
129	Total Return (R)		**(Sum Lines 126 to 128)**	**0.0884**
130	Investment Return = Rate Base * Rate of Return		**(Line 62 * 129)**	**129,477**

Composite Income Taxes

	Income Tax Rates			
131	FIT=Federal Income Tax Rate			0.3500
132	SIT=State Income Tax Rate or Composite			0.0613
133	p = percent of federal income tax deductible for state purposes		Per State Tax Code	0.0000
134	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		0.3898
135	T/ (1-T)			0.6389
	ITC Adjustment			
136	Amortized Investment Tax Credit	enter negative	Attachment 1	-286
137	T/(1-T)		(Line 135)	0.6389
138	**ITC Adjustment Allocated to Transmission**	(Note I from Appendix A)	(Line 136 * (1 + 137))	**-469**
139	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		58,229
140	**Total Income Taxes**		**(Line 138 + 139)**	**57,760**

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 5 - Cost Support
2010 - Projected

Electric / Non-electric Cost Support

				Previous Year	Current Year														
Line #s	**Descriptions**	**Notes**	**Page #'s & Instructions**	**Form 1Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Form 1 Dec**	**Average**	**Non-electric Portion**	**Details**
	Plant Allocation Factors																		
8	Electric Plant in Service	(Notes A & Q)	p207.104g/Plant-Acc. Deprc Wkst	22,046,298	22,106,429	22,167,899	22,269,806	22,405,455	22,479,159	22,588,398	22,660,566	22,903,537	22,988,370	23,113,794	23,298,562	23,502,521	22,656,215	0	
15	Accumulated Depreciation (Total Electric Plant)	(Notes A & Q)	p219.29c	9,125,978	9,166,977	9,208,152	9,249,451	9,290,923	9,332,361	9,373,970	9,415,798	9,457,755	9,500,138	9,542,684	9,585,365	9,628,554	9,375,239	0	
12	Accumulated Intangible Amortization	(Notes A & Q)	p200.21c	183,971	186,492	189,013	191,534	194,055	194,055	196,577	199,098	201,619	204,140	206,661	209,182	211,703	197,546	0	Respondent is Electric Utility only.
13	Accumulated Common Amortization - Electric	(Notes A & Q)	p356	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	
14	Accumulated Common Plant Depreciation - Electric	(Notes A & Q)	p356	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	
	Plant In Service																		
21	Transmission Plant in Service	(Notes A & Q)	p207.58.g/Trans.Input Sht	2,430,495	2,437,058	2,446,424	2,465,946	2,472,691	2,479,144	2,497,227	2,516,332	2,718,877	2,760,877	2,800,637	2,819,194	2,919,817	2,597,286	0	
15	Generator Step-Ups		Trans. Input Sht	156,673	156,673	156,673	156,673	166,773	166,773	166,773	166,773	166,773	166,773	166,773	166,773	166,773	163,665	0	
23	Generator Interconnect Facilities		Input Sht	23,814	23,814	23,814	23,814	23,814	23,814	23,814	23,814	23,814	23,814	23,814	23,814	23,814	23,814		
25	General & Intangible		p205.5.g & p207.99.g/G&I Wksht	804,861	804,345	804,262	804,281	804,232	804,046	804,296	804,611	804,933	805,224	805,149	804,763	804,965	804,613	0	
26	Common Plant (Electric Only)	(Notes A & Q)	p356	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	
	Accumulated Depreciation																		
32	Transmission Accumulated Depreciation	(Notes A & Q)	p219.25.c/Trans.Input Sht	821,852	823,472	825,151	826,822	828,515	829,911	831,345	832,815	834,298	836,112	837,986	839,674	841,540	831,499	0	
33	Transmission Accumulated Depreciation - Generator Step-Ups		GSU Input Sht	36,108	36,372	36,636	36,900	37,181	37,462	37,743	38,024	38,305	38,587	38,868	39,149	39,430	37,751	0	
34	Transmission Accumulated Depreciation - Interconnection Facilities		Input Sht	4,365	4,405	4,445	4,486	4,526	4,566	4,607	4,647	4,687	4,727	4,768	4,808	4,848	4,607		
36	Accumulated General Depreciation	(Notes A & Q)	p219.28.b	296,686	297,833	299,123	300,416	301,727	302,828	304,102	305,439	306,793	308,161	309,543	310,755	312,179	304,276	0	
	Materials and Supplies																		
50	Undistributed Stores Exp	(Notes A & R)	p227.6c & 16.c	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	Respondent is Electric Utility only.
	Allocated General & Common Expenses																		
68	Common Plant O&M	(Note A)	p356	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	
	Depreciation Expense																	Electric		
86	Depreciation-Transmission	(Note A)	p336.7.b&c														51,167	0	
91	Depreciation-General	(Note A)															24,909	0	
92	Depreciation-Intangible	(Note A)	p336.1d&e/Attachment 5														30,253	0	Respondent is Electric Utility only.
87	Depreciation - Generator Step-Ups																3,224	0	
88	Depreciation - Interconnection Facilities																469	0	
96	Common Depreciation - Electric Only	(Note A)	p336.11.b														0	0	
97	Common Amortization - Electric Only	(Note A)	p356 or p336.11d														0	0	

O&M Expenses

				Previous Year	Current Year														
Line #s	**Descriptions**	**Notes**	**Page #'s & Instructions**	**Form 1Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Form 1 Dec**	**Totals**	**Non-electric Portion**	**Details**
63	Transmission O&M	(Note A)	p321.112.b/Trans. Input Sht	-	3,874	3,702	4,596	4,638	5,715	6,184	6,132	5,141	4,651	5,138	4,130	3,656	57,558	0	
64	Generator Step-Ups		Input Sheet														332	0	
65	Transmission by Others		p321.96.b	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	

Wages & Salary

				Previous Year	Current Year														
Line #s	**Descriptions**	**Notes**	**Page #'s & Instructions**	**Form 1Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Form 1 Dec**	**Totals**	**Non-electric Portion**	**Details**
4	Total Wage Expense	(Note A)	p354.28b/Trans. Wksht														592,988	0	
5	Total A&G Wages Expense	(Note A)	p354.27b/Trans. Wksht														136,262	0	
1	Transmission Wages	(Note A)	p354.21b/Trans. Wksht														22,297	0	
2	Generator Step-Ups		Trans. Wksht														99	0	

Transmission / Non-transmission Cost Support

				Previous Year	Current Year														
Line #s	**Descriptions**	**Notes**	**Page #'s & Instructions**	**Form 1Dec**	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Form 1 Dec**	**Average**	**Non-transmission Related**	**Details**
30	**Plant Held for Future Use (Including Land)**	(Notes C & Q)	p214.47.d	36,176	36,176	36,176	36,176	36,176	36,176	36,176	36,176	36,176	36,176	36,176	36,176	36,176	36176	32,659	Specific identification based on plant records: The following plant investments are included:
																Form 1 Amount	Transmission Related	Non-transmission Related	
																36,176	**3517**	**32,659**	**Enter Details**

EPRI Dues Cost Support

Line #s	**Descriptions**	**Notes**	**Page #'s & Instructions**	**Form 1 Amount**	**EPRI Dues**	**Details**
	Allocated General & Common Expenses					
73	Less EPRI Dues	(Note D)	p352-353/Attachment 5	$3,091	3,091	See Form 1

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 5 - Cost Support
2010 - Projected

Regulatory Expense Related to Transmission Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1 Amount	Transmission Related	Non-transmission Related	Details
	Allocated General & Common Expenses						
71	Less Regulatory Commission Exp Account 928	(Note E)	p323.189b/Attachment 5	$ 27,910	164	27,746	See FERC Form 1 pages 350-351.
	Directly Assigned A&G						
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b/Attachment 5		164		Transmission related - Includes three year amortization of cost of current case.

Safety Related Advertising Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1 Amount	Safety Related	Non-safety Related	Details
	Directly Assigned A&G						
81	General Advertising Exp Account 930.1	(Note F)	Attachment 5	3,627	-	3,627	

MultiState Workpaper

Line #s	Descriptions	Notes	Page #'s & Instructions	State 1	State 2	State 3	State 4	State 5	Details
	Income Tax Rates								
				Va	**NC**	**Wva**			**Enter Calculation**
132	SIT=State Income Tax Rate or Composite	(Note I)		5.52%	0.418%	0.19%			6.13%

Education and Out Reach Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1 Amount	Education & Outreach	Other	Details
	Directly Assigned A&G						
78	General Advertising Exp Account 930.1	(Note K)	p323.191b	3,627	0	3,627	-

Excluded Plant Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions		0	Description of the Facilities
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			Includes only the costs of any Interconnection Facilities constructed for VEPCO's own Generating Facilities after March 15, 2000 in accordance with Order 2003.	**0**	**General Description of the Facilities**
						None
						Add more lines if necessary

Instructions:

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**
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

Transmission Related Account 242 Reserves

Line #s	Descriptions	Notes	Page #'s & Instructions	Beginning Year Balance	End of Year Balance	Average Balance	Allocation	Transmission Related		Details
47	**Transmission Related Account 242 Reserves (exclude current year environmental site related reserves)**			Enter $	Enter $			Amount		
	Directly Assignable to Transmission			$ -	$ -	$ -	100%	-		
	Labor Related, General plant related or Common Plant related			$ 8,590	$ 9,173	$ 8,882	4.860%	432		
	Plant Related			7,474	9221	$ 8,348	10.81%	902		
	Other			$ 292	$ 292	$ 292	0.00%	-		
	Total Transmission Related Reserves			$ -	$ -	$ -		1,334	To line 49	

Prepayments

Line #s	Descriptions	Notes	Page #'s & Instructions	Beginning Year Balance	End of Year Balance	Average Balance		To Line 50	Description of the Prepayments
48	**Prepayments**								
	Wages & Salary Allocator						4.860%		
	Pension Liabilities, if any, in Account 242			$ 44	$ 45	$ 45	4.860%	2	
				$ -	$ -	$ -			
	Prepayments			$ 170,385	$ 25,759	$ 98,072	4.860%	4,767	
	Prepaid Pensions if not included in Prepayments					$ -	**4.860%**	-	

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 5 - Cost Support
2010 - Projected

Outstanding Network Credits Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Beginning Year Balance	End of Year Balance	Average Balance	Description of the Credits
	Network Credits						**General Description of the Credits**
58	**Outstanding Network Credits**	(Note N)	From PJM	$ -	$ -	$ -	**None**
59	**Less Accumulated Depreciation Associated with Facilities with Outstanding Network Credits**	(Note N)	From PJM	$ -	$ -	$ -	**Add more lines if necessary**

Extraordinary Property Loss

Line #s	Descriptions	Notes	Page #'s & Instructions	Amount	# of Years	Amortization	W/ interest	Amount	Number of years	Amortization
								$ -		
89									5	$ -

Interest on Outstanding Network Credits Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	0	Description of the Interest on the Credits
				0	**General Description of the Credits**
				Enter $	**None**
					Add more lines if necessary

Facility Credits under Section 30.9 of the PJM OATT.

Line #s	Descriptions	Notes	Page #'s & Instructions	Amount	Description & PJM Documentation
	Revenue Requirement				
165	Facility Credits under Section 30.9 of the PJM OATT.			-	

PJM Load Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	1 CP Peak	Description & PJM Documentation
	Network Zonal Service Rate			Enter	
169	1 CP Peak	(Note L)	PJM Data - Attachment 5	18,137.255	

A&G Expenses - Other Post Employment Benefits

Line #s	Descriptions	Notes	Page #'s & Instructions	Amount
	Total A&G Expenses		p323.197b	469,447
	Less OPEB Current Year			(40,555)
	Plus: Stated OPEB (2008 actual)		Fixed (2008 actual)	27,658
69	**Current Year Total A&G Expenses**			456,551

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 6 - True-up Adjustment for Network Integration Transmission Service

The True-Up Adjustment component of the Formula Rate for each Rate Year beginning with 2010 shall be determined as follows:[1]

(i) Beginning with 2009, no later than June 15 of each year VEPCO shall recalculate an adjusted Annual Transmission Revenue Requirement for the previous calendar year based on its actual costs as reflected in its Form No. 1 and its books and records for that calendar year, consistent with FERC accounting policies.[2]

(ii) VEPCO shall determine the difference between the recalculated Annual Transmission Revenue Requirement as determined in paragraph (i) above, and ATRR based on projected costs for the previous calendar year (True-Up Adjustment Before Interest).

(iii) The True-Up Adjustment shall be determined as follows:

True-Up Adjustment equals the True-Up Adjustment Before Interest multiplied by (1+i)^24 months

Where i = Sum of (the monthly rates for the 7 months ending July 31 of the current year and the monthly rates for the 12 months ending December 31 of the preceding year) divided by 19 months. 0.440%

Each monthly rate used to calculate i shall be calculated pursuant to the Commission's regulations at 18 C.F.R. § 35.19a.

Summary of Formula Rate Process including True-Up Adjustment

Month	Year	Action
Fall	2007	TO populates the formula with Year 2008 estimated data
Sept	2008	TO populates the formula with Year 2009 estimated data
June	2009	TO populates the formula with Year 2008 actual data and calculates the 2008 True-Up Adjustment Before Interest
Sept	2009	TO calculates the Interest to include in the 2008 True-Up Adjustment
Sept	2009	TO populates the formula with Year 2010 estimated data and 2008 True-Up Adjustment
June	2010	TO populates the formula with Year 2009 actual data and calculates the 2009 True-Up Adjustment Before Interest
Sept	2010	TO calculates the Interest to include in the 2009 True-Up Adjustment
Sept	2010	TO populates the formula with Year 2011 estimated data and 2009 True-Up Adjustment
June	(Year)	TO populates the formula with (Year -1) actual data and calculates the (Year-1) True-Up Adjustment Before Interest
Sept	(Year)	TO calculates the Interest to include in the (Year-1) True-Up Adjustment
Sept	(Year)	TO populates the formula with (Year +1) estimated data and (Year-1) True-Up Adjustment

[1] No True-Up Adjustment will be included in the Annual Transmission Revenue Requirement for 2008 or 2009 since the Formula Rate was not in effect for 2006 or 2007.

[2] To the extent possible each input to the Formula Rate used to calculate the actual Annual Transmission Revenue Requirement included in the True-Up Adjustment either will be taken directly from the FERC Form No. 1 or will be reconcilable to the FERC Form No. 1 by the application of clearly identified and supported information. If the reconciliation is provided through a worksheet included in the filed Formula Rate template, the inputs to the worksheet must meet this transparency standard, and doing so will satisfy this transparency requirement for the amounts that are output from the worksheet and input to the main body of the Formula Rate.

	Calendar Year Do for Each Calendar Year beginning in 2009	
A	ATRR based on actual costs included for the previous calendar year but excludes the true-up adjustment.	212,459.00
B	ATRR based on projected costs included for the previous calendar year but excludes the true-up adjustment.	209,161.00
C	Difference (A-B)	3,298
D	Future Value Factor (1+i)^24	1.11112
E	True-up Adjustment (C*D)	3,664

Where:
i = interest rate as described in (iii) above.

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 6A - True-up Adjustment for Annual Revenue Requirements recovered under Schedule 12

The True-Up Adjustment component of the annual revenue requirement for each project included in Attachment 7 for each Rate Year beginning with 2010 shall be determined as follows:[1]

(i) Beginning with 2009, no later than June 15 of each year VEPCO shall recalculate an adjusted Annual Revenue Requirement for the previous calendar year based on its actual costs as reflected in its Form No. 1 and its books and records for that calendar year, consistent with FERC accounting policies.[2]

(ii) VEPCO shall determine the difference between the recalculated Annual Revenue Requirement and the Annual Revenue Requirement based on its projections (True-Up Adjustment Before Interest).

(iii) The True-Up Adjustment for each project shall be determined as follows:

True-Up Adjustment equals the True-Up Adjustment Before Interest multiplied by (1+i)^24 months

Where i = Sum of (the monthly rates for the 7 months ending July 31 of the current year and the monthly rates for the 12 months ending December 31 of the proceeding year) divided by 19 months.

Each monthly rate used to calculate i shall be calculated pursuant to the Commission’s regulations at 18 C.F.R. § 35.19a.

Summary of Formula Rate Process including True-Up Adjustment

Month	Year	Action
Fall	2007	TO populates the formula with Year 2008 estimated data
Sept	2008	TO populates the formula with Year 2009 estimated data
June	2009	TO populates the formula with Year 2008 actual data and calculates the 2008 True-Up Adjustment Before Interest
Sept	2009	TO calculates the Interest to include in the 2008 True-Up Adjustment
Sept	2009	TO populates the formula with Year 2010 estimated data and 2008 True-Up Adjustment
June	2010	TO populates the formula with Year 2009 actual data and calculates the 2009 True-Up Adjustment Before Interest
Sept	2010	TO calculates the Interest to include in the 2009 True-Up Adjustment
Sept	2010	TO populates the formula with Year 2011 estimated data and 2009 True-Up Adjustment
June	(Year)	TO populates the formula with (Year -1) actual data and calculates the (Year-1) True-Up Adjustment Before Interest
Sept	(Year)	TO calculates the Interest to include in the (Year-1) True-Up Adjustment
Sept	(Year)	TO populates the formula with (Year +1) estimated data and (Year-1) True-Up Adjustment

[1] No True-Up Adjustment will be included in the annual revenue requirements for 2008 or 2009 since the Formula Rate was not in effect for 2006 or 2007. For all true-up calculations, the ATRR will be adjusted to exclude any true-up adjustment.

[2] To the extent possible, each input to the Formula Rate used to calculate the actual Annual Revenue Requirement included in the True-Up Adjustment either will be taken directly from the FERC Form No. 1 or will be reconcilable to the FERC Form No. 1 by the application of clearly identified and supported information. If the reconciliation is provided through a worksheet included in the filed Formula Rate template, the inputs to the worksheet must meet this transparency standard, and doing so will satisfy this transparency requirement for the amounts that are output from the worksheet and input to the main body of the Formula Rate.

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 7 - Transmission Enhancement Annual Revenue Requirement Worksheet
(dollars)

Per FERC order in Docket No. ER08-92, the ROE is 11.4%, which includes a 50 basis point RTO membership adder as authorized by FERC to become effective January 1, 2008. Per FERC order in Docket No. _______, the ROE for each specific project identified in that order will also include either an 150 or 125 basis point transmission incentive adder as authorized by the Commission.

1 New Plant Carrying Charge

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

		Formula Line		
3	A	154	Net Plant Carrying Charge without Depreciation	16.4840%
4	B	161	Net Plant Carrying Charge per 100 Basis Point increase in ROE without Depreciation	17.2107%
5	C		Line B less Line A	0.7267%

6 **FCR if a CIAC**

7	D	155	Net Plant Carrying Charge without Depreciation, Return, or Income Taxes	5.6576%

8 **The FCR resulting from Formula is for the rate period only.**
9 **Therefore actual revenues collected or the lack of revenues collected in other years are not applicable.**

10	Details		**Project A**				**Project B**			
11	Schedule 12	(Yes or No)	Yes	b0217			Yes	b0222		
12	Life		51	Upgrade Mt.Storm - Doubs 500 kV			51	Install 150 MVAR capacitor		
13	FCR W/O incentive	Line 3	16.4840%				16.4840%	at Loudoun		
14	Incentive Factor (Basis Points /100)		0				0			
15	FCR W incentive L.13 +(L.14*L.5)		16.4840%				16.4840%			
	Investment		1,911,923				1,671,324			
17	Annual Depreciation Exp		37,489				32,771			
18	In Service Month (1-12)		12				9			
19		**Invest Yr**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006					1,671,324	9,558	1,661,766	
21	W incentive	2006					1,671,324	9,558	1,661,766	
22	W / O incentive	2007	1,911,923	1,562	1,910,361		1,661,766	32,771	1,628,995	
23	W incentive	2007	1,911,923	1,562	1,910,361		1,661,766	32,771	1,628,995	
24	W / O incentive	2008	1,910,361	37,489	1,872,872		1,628,995	32,771	1,596,224	
25	W incentive	2008	1,910,361	37,489	1,872,872		1,628,995	32,771	1,596,224	
26	W / O incentive	2009	1,872,872	37,489	1,835,384		1,596,224	32,771	1,563,453	
27	W incentive	2009	1,872,872	37,489	1,835,384		1,596,224	32,771	1,563,453	
28	W / O incentive	2010	1,835,384	37,489	1,797,895	336,943	1,563,453	32,771	1,530,682	287,789
29	W incentive	2010	1,835,384	37,489	1,797,895	336,943	1,563,453	32,771	1,530,682	287,789

Lines continues as new rate years as added.

In the formulas used in the Columns for lines 19+ are as follows:
"In Service Month" is the first month during the first year that the project is placed in service or recovery is request for the project.
"Beginning" is the investment on line 16 for the first year and is the "Ending" for the prior year after the first year.
"Depreciation" is the annual depreciation in line 17 divided by twelve times the difference of 12.5 minus line 18 in the first year and line 17 thereafter.
"Ending" is "Beginning" less "Depreciation"
Revenue Requirement used for crediting is ("Beginning" plus "Ending") divided by two times line 13 times the quotient of 12.5 minus line 18 divided by 12 plus "Depreciation" for the first year and ("Beginning" plus "Ending") divided by two times line 13 plus "Depreciation" thereafter.
Revenue Requirement used for charging is ("Beginning" plus "Ending") divided by two times line 15 times the quotient of 12.5 minus line 18 divided by 12 plus "Depreciation" for the first year and ("Beginning" plus "Ending") divided by two times line 15 plus "Depreciation" thereafter.
Formula Logic to be copied on new lines added each year after line 25. Using 2009 as an example, the logic will be included in lines 26 and 27.
Beginning with the annual revenue requirements determined in 2009 for 2010, the annual revenue requirements based on projected costs will include a True-Up Adjustment for the previous calendar year in accordance with Attachment 6 A and as calculated in Lines A through I below
Projected Revenue Requirements are calculated using the logic described for lines 19 + but with projected data for the indicated year.
Actual Revenue Requirements are calculated using the logic described for lines 19 + but with actual data for the indicated year.

Calendar Year Do for Each Calendar Year beginning in 2009 for True-Up Adjustments applicable to 2010 annual revenue requirements.

A	Projected Revenue Requirement without Incentive for Previous Calendar Year*	347,423	303,849
B	Projected Revenue Requirement with Incentive for Previous Calendar Year*	347,423	303,849
C	Actual Revenue Requirement without Incentive for Previous Calendar Year *	345,463	295,320
D	Actual Revenue Requirement with Incentive for Previous Calendar Year *	345,463	295,320
E	True-Up Adjustment Before Interest without Incentive for Next Calendar Year (C-A)	(1,959)	(8,529)
F	True-Up Adjustment Before Interest with Incentive for Previous Calendar Year (B-D)	(1,959)	(8,529)
G	Future Value Factor (1+i)^24 months from Attachment 6	1.11112	1.11112
H	True-Up Adjustment without Incentive (E*G)	(2,177)	(9,476)
I	True-Up Adjustment with Incentive (F*G)	(2,177)	(9,476)

* These amounts do not include any True-Up Adjustments.

Additional columns to be inserted after the last project as new projects are added to formula.

Revenue Requirement including True-up Adjustment, if applicable			
W / O incentive	2010	334,766	278,313
W incentive	2010	334,766	278,313

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 7 - Transmission Enhancement Annual Revenue Requirement Worksheet
(dollars)

1

2

3
4
5

6

7

8
9

In 2008 and 2009 Project C-1 and Project C-2 were combined into Project C

10	**Project C-1**				**Project C-2**				**Project D**			
11	Yes	b0223			Yes	b0224			Yes	B0225		
12	51	Install 150 MVAR capacitor			51	Install 150 MVAR capacitor			51	Install 33 MVAR capacitor at		
13	16.4840%	at Asburn 230 kV			16.4840%	at Dranvesville 230 kV			16.4840%	Possum Pt. 115 kV		
14	0				0				0			
15	16.4840%				16.4840%				16.4840%			
	1,075,741				974,671				857,404			
17	21,093				19,111				16,812			
18	10				4				12			
19	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	1,075,741	4,394	1,071,347									
21	1,075,741	4,394	1,071,347									
22	1,071,347	21,093	1,050,254		974,671	13,537	961,134		857,404	700	856,704	
23	1,071,347	21,093	1,050,254		974,671	13,537	961,134		857,404	700	856,704	
24	1,050,254	21,093	1,029,161		961,134	19,111	942,023		856,704	16,812	839,892	
25	1,050,254	21,093	1,029,161		961,134	19,111	942,023		856,704	16,812	839,892	
26	1,029,161	21,093	1,008,068		942,023	19,111	922,912		839,892	16,812	823,080	
27	1,029,161	21,093	1,008,068		942,023	19,111	922,912		839,892	16,812	823,080	
28	1,008,068	21,093	986,975	185,524	922,912	19,111	903,800	169,669	823,080	16,812	806,268	151,103
29	1,008,068	21,093	986,975	185,524	922,912	19,111	903,800	169,669	823,080	16,812	806,268	151,103

Line

A	203,081	185,660	155,835
B	203,081	185,660	155,835
C	190,368	174,038	154,923
D	190,368	174,038	154,923
E	(12,713)	(11,622)	(912)
F	(12,713)	(11,622)	(912)
G	1.11112	1.11112	1.11112
H	(14,126)	(12,914)	(1,013)
I	(14,126)	(12,914)	(1,013)

The Projected 2008 Annual Revenue Requirement for Project C has been allocated to Project C-1 and Project C-2 based on the 2008 Actual Annual Revenue Requirement for each of these projects.

Project C Annual Revenue Requirement = 388,741

171,399	156,755	150,090
171,399	156,755	150,090

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 7 - Transmission Enhancement Annual Revenue Requirement Worksheet
(dollars)

1												
2												
3												
4												
5												
6												
7												
8									Project G-1 is labled as Project G in the 2008 and 2009			
9									Annual Updates			
10	**Project E**				**Project F**				**Project G-1**			
11	Yes	B0226			Yes	B0341			Yes	B0403		
12	51	Install 500/230 kV transformer at			51	Install a breaker at Northern Neck			51	2nd Dooms 500/230 kV transformer		
13	16.4840%	Clifton and Clifton 500 KV 150 MVAR			16.4840%	115 kV			16.4840%	addition		
14	0	capacitor			0				0			
15	16.4840%				16.4840%				16.4840%			
	8,219,365				748,850				6,434,160			
17	161,164				14,683				126,160			
18	9				9				11			
19	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20					748,850	4,283	744,567					
21					748,850	4,283	744,567					
22	8,219,365	47,006	8,172,359		744,567	14,683	729,884		6,434,160	15,770	6,418,390	
23	8,219,365	47,006	8,172,359		744,567	14,683	729,884		6,434,160	15,770	6,418,390	
24	8,172,359	161,164	8,011,195		729,884	14,683	715,201		6,418,390	126,160	6,292,230	
25	8,172,359	161,164	8,011,195		729,884	14,683	715,201		6,418,390	126,160	6,292,230	
26	8,011,195	161,164	7,850,031		715,201	14,683	700,517		6,292,230	126,160	6,166,070	
27	8,011,195	161,164	7,850,031		715,201	14,683	700,517		6,292,230	126,160	6,166,070	
28	7,850,031	161,164	7,688,867	1,441,879	700,517	14,683	685,834	128,946	6,166,070	126,160	6,039,910	1,132,176
29	7,850,031	161,164	7,688,867	1,441,879	700,517	14,683	685,834	128,946	6,166,070	126,160	6,039,910	1,132,176

Line

A	1,583,884	372,873	1,567,125
B	1,583,884	372,873	1,567,125
C	1,478,588	132,321	1,160,870
D	1,478,588	132,321	1,160,870
E	(105,295)	(240,553)	(406,255)
F	(105,295)	(240,553)	(406,255)
G	1.11112	1.11112	1.11112
H	(116,996)	(267,283)	(451,398)
I	(116,996)	(267,283)	(451,398)

1,324,883	(138,337)	680,777
1,324,883	(138,337)	680,777

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 7 - Transmission Enhancement Annual Revenue Requirement Worksheet
(dollars)

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	Project G-2				2008 Add-1				2008 Add-2			
11	Yes	B0403			Yes	B0232			Yes	B0308		
12	51	2nd Dooms 500/230 kV transformer			51	Install 150 MVAR capacitor at			51	Replace L breaker and switches at		
13	16.4840%	addition			16.4840%	Lynnhaven 230 kV			16.4840%	Endless Caverns 115kV		
14	0				0				0			
15	16.4840%	Spare Transformer Addition			16.4840%				16.4840%			
	2,396,741				998,394				166,396			
17	46,995				19,576				3,263			
18	4				8				11			
19	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20					998,394	7,341	991,053					
21					998,394	7,341	991,053					
22					991,053	19,576	971,477		166,396	408	165,988	
23					991,053	19,576	971,477		166,396	408	165,988	
24					971,477	19,576	951,900		165,988	3,263	162,726	
25					971,477	19,576	951,900		165,988	3,263	162,726	
26	2,396,741	33,288	2,363,453		951,900	19,576	932,324		162,726	3,263	159,463	
27	2,396,741	33,288	2,363,453		951,900	19,576	932,324		162,726	3,263	159,463	
28	2,396,741	46,995	2,349,746	438,200	932,324	19,576	912,747	171,647	159,463	3,263	156,200	29,280
29	2,396,741	46,995	2,349,746	438,200	932,324	19,576	912,747	171,647	159,463	3,263	156,200	29,280

Line

A		-	-
B		-	-
C		176,149	30,022
D		176,149	30,022
E	-	176,149	30,022
F	-	176,149	30,022
G	1.11112	1.11112	1.11112
H	-	195,723	33,358
I	-	195,723	33,358

438,200	367,370	62,637
438,200	367,370	62,637

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 7 - Transmission Enhancement Annual Revenue Requirement Worksheet
(dollars)

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9												
10	**2008 Add-3**				**2008 Add-4**				**2008 Add-5**			
11	Yes	B0309			Yes	B0333			Yes	B0339		
12	51	Install SPS at Earleys 115 kV			51	Replace wave trap on Elmont - Replace			51	Install Breaker at Dooms 230 kV Sub		
13	16.4840%				16.4840%	(line #231)			16.4840%			
14	0				0				0			
15	16.4840%				16.4840%				16.4840%			
	217,455				31,472				742,016			
17	4,264				617				14,549			
18	4				12				11			
19	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20												
21												
22	217,455	3,020	214,435		31,472	26	31,446		742,016	1,819	740,197	
23	217,455	3,020	214,435		31,472	26	31,446		742,016	1,819	740,197	
24	214,435	4,264	210,171		31,446	617	30,829		740,197	14,549	725,648	
25	214,435	4,264	210,171		31,446	617	30,829		740,197	14,549	725,648	
26	210,171	4,264	205,907		30,829	617	30,212		725,648	14,549	711,099	
27	210,171	4,264	205,907		30,829	617	30,212		725,648	14,549	711,099	
28	205,907	4,264	201,643	37,854	30,212	617	29,595	5,546	711,099	14,549	696,549	130,568
29	205,907	4,264	201,643	37,854	30,212	617	29,595	5,546	711,099	14,549	696,549	130,568

Line

A	-	-	-
B	-	-	-
C	38,829	5,687	133,877
D	38,829	5,687	133,877
E	38,829	5,687	133,877
F	38,829	5,687	133,877
G	1.11112	1.11112	1.11112
H	43,144	6,319	148,753
I	43,144	6,319	148,753

80,998	11,865	279,321
80,998	11,865	279,321

Virginia Electric and Power Company
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Attachment 7 - Transmission Enhancement Annual Revenue Requirement Worksheet
(dollars)

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10	**2008 Add-6**				**Project H-1**				**Project H-2**			
11	Yes	B0326			Yes	b0328.1			Yes	b0328.1		
12	51	Uprate-resag Remington - Brandywine -			51	Build new Meadowbrook-Loudon 500kV circuit			51	Meadowbrook-Loudon 500kV circuit		
13	16.4840%	Culppr 115 kV			16.4840%	(30 of 50 miles)			16.4840%	(30 of 50 miles)		
14	0				1.5				1.5			
15	16.4840%				17.5741%	line 2101 v11			17.5741%	Line 2030 & 559		
	2,932,626				21,850,320				45,093,650			
17	57,502				428,438				884,189			
18	12				6				12			
19	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20												
21												
22												
23												
24	2,932,626	2,396	2,930,230									
25	2,932,626	2,396	2,930,230									
26	2,930,230	57,502	2,872,728		21,850,320	232,070	21,618,250		45,093,650	36,841	45,056,809	
27	2,930,230	57,502	2,872,728		21,850,320	232,070	21,618,250		45,093,650	36,841	45,056,809	
28	2,872,728	57,502	2,815,225	526,303	21,618,250	428,438	21,189,812	3,956,674	45,056,809	884,189	44,172,620	8,238,471
29	2,872,728	57,502	2,815,225	526,303	21,618,250	428,438	21,189,812	4,189,996	45,056,809	884,189	44,172,620	8,724,808

Line

A	-		
B	-		
C	22,282		
D	22,282		
E	22,282	-	-
F	22,282	-	-
G	1.11112	1.11112	1.11112
H	24,758	-	-
I	24,758	-	-
	551,061	3,956,674	8,238,471
	551,061	4,189,996	8,724,808

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 7 - Transmission Enhancement Annual Revenue Requirement Worksheet
(dollars)

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6												
7												
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9												
10	**Project H-3**				**Project H-4**				**Project I**			
11	Yes	b0328.1			Yes	b0328.1			Yes	b0329		
12	51	Meadowbrook-Loudon 500kV circuit			51	Meadowbrook-Loudon 500kV circuit			51	Carson-Suffolk 500 kV line +		
13	16.4840%	(30 of 50 miles)			16.4840%	(30 of 50 miles)			16.4840%	Suffolk 500/230 # 2 transformer +		
14	1.5				1.5				1.5	Suffolk - Thrasher 230kV line		
15	17.5741%	Line 580			17.5741%	Line 124 & 535			17.5741%			
17	-				-				-			
18												
19	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20												
21												
22												
23												
24												
25												
26												
27												
28												
29												

Line

A			
B			
C			
D			
E	-	-	-
F	-	-	-
G	1.11112	1.11112	1.11112
H	-	-	-
I	-	-	-
	-	-	-
	-	-	-

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 7 - Transmission Enhancement Annual Revenue Requirement Worksheet
(dollars)

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8												
9												
10	**Project J**				**Project K-1**				**Project K-2**			
11	Yes	b0512			No				No			
12	51	MAPP Project -- Dominion Portion			51	Loudoun Bank # 1 transformer			51	Loudoun Bank # 2 transformer		
13	16.4840%				16.4840%	replacement			16.4840%	replacement		
14	1.5				1.5				1.5			
15	17.5741%				17.5741%				17.5741%			
					14,301,155				15,476,350			
17	-				280,415				303,458			
18					12				5			
19	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20												
21												
22												
23												
24												
25												
26					14,301,155	11,684	14,289,471					
27					14,301,155	11,684	14,289,471					
28					14,301,155	280,415	14,020,740	2,614,703	15,476,350	189,661	15,286,689	1,774,340
29					14,301,155	280,415	14,020,740	2,769,069	15,476,350	189,661	15,286,689	1,879,135

Line

A			
B			
C			
D			
E	-	-	-
F	-	-	-
G	1.11112	1.11112	1.11112
H	-	-	-
I	-	-	-

-	2,614,703	1,774,340
-	2,769,069	1,879,135

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 7 - Transmission Enhancement Annual Revenue Requirement Worksheet
(dollars)

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	Project L-1a				Project L-1b				Project L-2			
10												
11	No				No				No			
12	51	Ox Banks # 1 transformer			51	Ox Banks # 1 transformer			51	Ox Banks # 2 transformer		
13	16.4840%	replacement			16.4840%	replacement			16.4840%	replacement		
14	1.5				1.5				1.5			
15	17.5741%				17.5741%				17.5741%			
	10,401,447				2,786,626				10,312,963			
17	203,950				54,640				202,215			
18	7				12				3			
19	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20												
21												
22												
23												
24												
25												
26	10,401,447	93,477	10,307,970		2,786,626	2,277	2,784,349		10,312,963	160,087	10,152,876	
27	10,401,447	93,477	10,307,970		2,786,626	2,277	2,784,349		10,312,963	160,087	10,152,876	
28	10,401,447	203,950	10,197,497	1,901,713	2,786,626	54,640	2,731,986	509,483	10,312,963	202,215	10,110,748	1,885,535
29	10,401,447	203,950	10,197,497	2,013,986	2,786,626	54,640	2,731,986	539,562	10,312,963	202,215	10,110,748	1,996,853

Line

A			
B			
C			
D			
E	-	-	-
F	-	-	-
G	1.11112	1.11112	1.11112
H	-	-	-
I	-	-	-
	1,901,713	509,483	1,885,535
	2,013,986	539,562	1,996,853

Virginia Electric and Power Company
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Attachment 7 - Transmission Enhancement Annual Revenue Requirement Worksheet
(dollars)

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10	**Project M**				**Project N**				**Project O**			
11	No				No				No			
12	51	Yadkin Bank # 2 transformer			51	Carson Bank # 1 transformer			51	Lexington Bank # 1 transformer		
13	16.4840%	replacement			16.4840%	replacement			16.4840%	replacement		
14	1.5				1.5				1.5			
15	17.5741%				17.5741%				17.5741%			
	15,412,789				17,997,644				8,455,359			
17	302,212				352,895				165,791			
18	5				5				12			
19	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20												
21												
22												
23												
24												
25												
26												
27												
28	15,412,789	188,882	15,223,907	1,767,053	17,997,644	220,559	17,777,085	2,063,403	8,455,359	6,908	8,448,451	64,958
29	15,412,789	188,882	15,223,907	1,871,418	17,997,644	220,559	17,777,085	2,185,270	8,455,359	6,908	8,448,451	68,797

Line

A			
B			
C			
D			
E	-	-	-
F	-	-	-
G	1.11112	1.11112	1.11112
H	-	-	-
I	-	-	-

1,767,053	2,063,403	64,958
1,871,418	2,185,270	68,797

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 7 - Transmission Enhancement Annual Revenue Requirement Worksheet
(dollars)

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10	Project P				Project Q				Project R			
11	No				No				No			
12	51	Dooms Bank # 1 transformer			51	Valley Bank # 1 transformer			51	Garrisonville 230 kV UG line		
13	16.4840%	replacement			16.4840%	replacement			16.4840%			
14	1.5				1.5				1.25			
15	17.5741%				17.5741%				17.3924%			
	16,467,956				11,260,743				120,000,000			
17	322,901				220,799				2,352,941			
18	12				5				5			
19	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20												
21												
22												
23												
24												
25												
26												
27												
28	16,467,956	13,454	16,454,502	126,515	11,260,743	137,999	11,122,744	1,291,027	120,000,000	1,470,588	118,529,412	13,757,821
29	16,467,956	13,454	16,454,502	133,992	11,260,743	137,999	11,122,744	1,367,277	120,000,000	1,470,588	118,529,412	14,434,949

Line

A			
B			
C			
D			
E	-	-	-
F	-	-	-
G	1.11112	1.11112	1.11112
H	-	-	-
I	-	-	-

126,515	1,291,027	13,757,821
133,992	1,367,277	14,434,949

Virginia Electric and Power Company
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(dollars)

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10	**Project S**				**Project T1**				**Project T2**			
11	No	s0124			Yes	s0133			Yes	b0768		
12	51	Pleasant View Hamilton 230kV			51	Glen Carlyn Line 251 GIB substation project			51	Glen Carlyn Line 251 GIB substation project		
13	16.4840%	transmission line			16.4840%				16.4840%			
14	1.25				1.25	Glen Carlyn Line 251			1.25	Loop line # 251 Idylwwd - Arlington into the		
15	17.3924%				17.3924%				17.3924%	GIS sub		
	88,987,555				16,916,992				3,383,398			
17	1,744,854				331,706				66,341			
18	5				5				5			
19	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20												
21												
22												
23												
24												
25												
26												
27												
28	88,987,555	1,090,534	87,897,021	10,202,291	16,916,992	207,316	16,709,676	1,939,508	3,383,398	41,463	3,341,935	387,902
29	88,987,555	1,090,534	87,897,021	10,704,423	16,916,992	207,316	16,709,676	2,034,966	3,383,398	41,463	3,341,935	406,993

Line

A			
B			
C			
D			
E	-	-	-
F	-	-	-
G	1.11112	1.11112	1.11112
H	-	-	-
I	-	-	-
	10,202,291	1,939,508	387,902
	10,704,423	2,034,966	406,993

Virginia Electric and Power Company
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Attachment 7 - Transmission Enhancement Annual Revenue Requirement Worksheet
(dollars)

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10	**Project U**				**Project V**				**Project W**			
11	Yes	b0453.1			Yes	b0337			Yes	b0467.2		
12	51	Convert Remington - Sowego			51	Build Lexington 230kV ring bus			51	Reconductor the Dickerson - Pleasant		
13	16.4840%	115kV to 230kV			16.4840%				16.4840%	View 230 kV circuit		
14	1.25				1.25				1.25			
15	17.3924%				17.3924%				17.3924%			
					6,389,263							
17	-				125,280				-			
18					6							
19	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20												
21												
22												
23												
24												
25												
26					6,389,263	67,860	6,321,403		-	-	-	-
27					6,389,263	67,860	6,321,403		-	-	-	-
28					6,389,263	125,280	6,263,983	1,168,159	-	-	-	-
29					6,389,263	125,280	6,263,983	1,225,630	-	-	-	-

Line

A			
B			
C			
D			
E	-	-	-
F	-	-	-
G	1.11112	1.11112	1.11112
H	-	-	-
I	-	-	-

-	1,168,159	-
-	1,225,630	-

Virginia Electric and Power Company
ATTACHMENT H-16A
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(dollars)

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9												
10	**Project X**				**Project Y**				**Project Z**			
11	Yes	b0311			Yes	b0235			Yes	b0233		
12	51	Reconductor Idylwood to Arlington			51	Install 150 MVAR capacitor at Fentress 230			51	Install 150 MVAR capacitor at Landstown 230 kV		
13	16.4840%	230 kV			16.4840%	kV			16.4840%			
14	1.25				0				0			
15	17.3924%				16.4840%				16.4840%			
	3,364,891				1,210,360				1,015,296			
17	65,978				23,733				19,908			
18	8				6				6			
19	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20												
21												
22												
23												
24	3,364,891	24,742	3,340,149									
25	3,364,891	24,742	3,340,149									
26	3,340,149	65,978	3,274,171		1,210,360	12,855	1,197,505		1,015,296	10,783	1,004,513	
27	3,340,149	65,978	3,274,171		1,210,360	12,855	1,197,505		1,015,296	10,783	1,004,513	
28	3,274,171	65,978	3,208,193	600,254	1,197,505	23,733	1,173,772	219,173	1,004,513	19,908	984,605	183,851
29	3,274,171	65,978	3,208,193	629,697	1,197,505	23,733	1,173,772	219,173	1,004,513	19,908	984,605	183,851

Line:

A			
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D			
E	-	-	-
F	-	-	-
G	1.11112	1.11112	1.11112
H	-	-	-
I	-	-	-
	600,254	219,173	183,851
	629,697	219,173	183,851

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 7 - Transmission Enhancement Annual Revenue Requirement Worksheet
(dollars)

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10	Project AA - 1				Project AA - 2				Project AB-1			
11	Yes	b0231			Yes	b0231.2			Yes	b0307		
12	51	Install 500 kV breakers and			51	Install 500/230 kV Transformer, 230 kV breakers,			51	Re-Conductor Endless Caverns -		
13	16.4840%	500 kV bus work at Suffolk			16.4840%	& 230 kV bus work at Suffolk			16.4840%	Mt. Jackson 115 kV		
14	0				0				0			
15	16.4840%				16.4840%				16.4840%			
	3,768,349				11,687,723				12,097,976			
17	73,889				229,171				237,215			
18	10				10				9			
19	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20												
21												
22												
23												
24												
25												
26	3,768,349	15,394	3,752,955		11,687,723	47,744	11,639,979		12,097,976	69,188	12,028,788	
27	3,768,349	15,394	3,752,955		11,687,723	47,744	11,639,979		12,097,976	69,188	12,028,788	
28	3,752,955	73,889	3,679,066	686,436	11,639,979	229,171	11,410,808	2,129,015	12,028,788	237,215	11,791,573	2,200,487
29	3,752,955	73,889	3,679,066	686,436	11,639,979	229,171	11,410,808	2,129,015	12,028,788	237,215	11,791,573	2,200,487

Line

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E	-	-	-
F	-	-	-
G	1.11112	1.11112	1.11112
H	-	-	-
I	-	-	-

686,436	2,129,015	2,200,487
686,436	2,129,015	2,200,487

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 7 - Transmission Enhancement Annual Revenue Requirement Worksheet
(dollars)

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10	Project AB-2				Project AC-1a				Project AC-1b			
11	Yes	b0456			Yes	b0227			Yes	b0227		
12	51	Re-Conductor 9.4 miles of Edinburg - Mt. Jackson			51	Install 500/230 kV transformer at Bristers;			51	Install 500/230 kV transformer at Bristers;		
13	16.4840%	115 kV			16.4840%	build new 230 kV Bristers- Gainesville circuit,			16.4840%	build new 230 kV Bristers- Gainesville circuit,		
14	0				0	upgrade two Loudoun - Brmbleton circuits			0	upgrade two Loudoun - Brmbleton circuits		
15	16.4840%				16.4840%				16.4840%			
	1,331,288				17,119,737				3,769,319			
17	26,104				335,681				73,908			
18	11				6				11			
19	Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req
20												
21												
22												
23												
24												
25												
26	1,331,288	3,263	1,328,025		17,119,737	181,827	16,937,910		3,769,319	9,239	3,760,080	
27	1,331,288	3,263	1,328,025		17,119,737	181,827	16,937,910		3,769,319	9,239	3,760,080	
28	1,328,025	26,104	1,301,921	242,864	16,937,910	335,681	16,602,229	3,100,056	3,760,080	73,908	3,686,172	687,628
29	1,328,025	26,104	1,301,921	242,864	16,937,910	335,681	16,602,229	3,100,056	3,760,080	73,908	3,686,172	687,628

Line

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E	-	-	-
F	-	-	-
G	1.11112	1.11112	1.11112
H	-	-	-
I	-	-	-

242,864	3,100,056	687,628
242,864	3,100,056	687,628

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 7 - Transmission Enhancement Annual Revenue Requirement Worksheet
(dollars)

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10	Project AC - 2				Project AD				Project AE			
11	Yes	b0227.1			Yes	b0234			Yes	b0331		
12	51	Loudoun Sub-upgrade 6 - 230 kV breakers			51	Install 150 MVAR capacitor at Greenwich			51	Upgrade/resag Shell Bank - Whealton 115 kV		
13	16.4840%				16.4840%	230 kV			16.4840%	(Line 165)		
14	0				0				0			
15	16.4840%				16.4840%				16.4840%			
	774,776				1,303,064				4,563,260			
17	15,192				25,550				89,476			
18	4				6				12			
19	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20												
21												
22												
23												
24												
25												
26	774,776	10,761	764,015		1,303,064	13,840	1,289,224		4,563,260	3,728	4,559,532	
27	774,776	10,761	764,015		1,303,064	13,840	1,289,224		4,563,260	3,728	4,559,532	
28	764,015	15,192	748,824	139,880	1,289,224	25,550	1,263,674	235,960	4,559,532	89,476	4,470,056	833,694
29	764,015	15,192	748,824	139,880	1,289,224	25,550	1,263,674	235,960	4,559,532	89,476	4,470,056	833,694

Line

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E	-	-	-
F	-	-	-
G	1.11112	1.11112	1.11112
H	-	-	-
I	-	-	-

139,880	235,960	833,694
139,880	235,960	833,694

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 7 - Transmission Enhancement Annual Revenue Requirement Worksheet
(dollars)

1												
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9												
10	**Project AF**				**Project AG**				**2009 Add-1**			
11	Yes	b0338			Yes	b0455			Yes	B0453.3		
12	51	Replace Gordonsville 230/115kV transformer for			51	Add 2nd Endless Caverns 230/115kV			51	Add Sowego 230/115/ kV transformer		
13	16.4840%	larger one			16.4840%	transformer			16.4840%			
14	0				0				0			
15	16.4840%				16.4840%				16.4840%			
	2,520,955				2,237,628				1,396,704			
17	49,430				43,875				27,386			
18	10				5				9			
19	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20												
21												
22												
23												
24												
25												
26	2,520,955	10,298	2,510,657		2,237,628	27,422	2,210,206		1,396,704	7,988	1,388,716	
27	2,520,955	10,298	2,510,657		2,237,628	27,422	2,210,206		1,396,704	7,988	1,388,716	
28	2,510,657	49,430	2,461,226	459,213	2,210,206	43,875	2,166,331	404,589	1,388,716	27,386	1,361,330	254,045
29	2,510,657	49,430	2,461,226	459,213	2,210,206	43,875	2,166,331	404,589	1,388,716	27,386	1,361,330	254,045

Line

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E	-	-	-
F	-	-	-
G	1.11112	1.11112	1.11112
H	-	-	-
I	-	-	-
	459,213	404,589	254,045
	459,213	404,589	254,045

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 7 - Transmission Enhancement Annual Revenue Requirement Worksheet
(dollars)

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10	**2009 Add-2.1**				**2009 Add-2.2**				**2009 Add-3**			
11	Yes	B0340			Yes	B0340			Yes	B0761		
12	51	Reconductor one span Peninsula-			51	Reconductor one span Peninsula-			51	Install second 230 /115 kV transformer at		
13	16.4840%	magruder 115 kV close to Magruder			16.4840%	magruder 115 kV close to Magruder			16.4840%	Possum Point		
14	0	substation			0	substation			0			
15	16.4840%				16.4840%				16.4840%			
	1,097,479				116,600				4,436,608			
17	21,519				2,286				86,992			
18	4				10				7			
19	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20												
21												
22												
23												
24												
25												
26	1,097,479	15,243	1,082,236		116,600	476	116,124		4,436,608	39,871	4,396,737	
27	1,097,479	15,243	1,082,236		116,600	476	116,124		4,436,608	39,871	4,396,737	
28	1,082,236	21,519	1,060,717	198,141	116,124	2,286	113,837	21,240	4,396,737	86,992	4,309,744	804,580
29	1,082,236	21,519	1,060,717	198,141	116,124	2,286	113,837	21,240	4,396,737	86,992	4,309,744	804,580

Line

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E	-	-	-
F	-	-	-
G	1.11112	1.11112	1.11112
H	-	-	-
I	-	-	-

198,141	21,240	804,580
198,141	21,240	804,580

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 7 - Transmission Enhancement Annual Revenue Requirement Worksheet
(dollars)

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9												
10	2009 Add-4				2009 Add-5				2009 Add-6			
11	Yes	B0764			Yes	b0765			Yes	B0837		
12	51	Inrease the rating on 2.56 miles of the line			51	Add 2nd Bull Run 230/115kV			51	At Mt. Storm, replace the existing MOD on		
13	16.4840%	between Greenwich and Thompson Corner;			16.4840%	autotransformer			16.4840%	the 500 kV side of the transformer with a		
14	0	new rating to be 257 MVA			0				0	circuit breaker		
15	16.4840%				16.4840%				16.4840%			
	1,595,555				2,917,548				579,646			
17	31,285				57,207				11,366			
18	6				7				6			
19	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20												
21												
22												
23												
24												
25												
26	1,595,555	16,946	1,578,609		2,917,548	26,220	2,891,328		579,646	6,156	573,490	
27	1,595,555	16,946	1,578,609		2,917,548	26,220	2,891,328		579,646	6,156	573,490	
28	1,578,609	31,285	1,547,323	288,924	2,891,328	57,207	2,834,121	529,098	573,490	11,366	562,124	104,963
29	1,578,609	31,285	1,547,323	288,924	2,891,328	57,207	2,834,121	529,098	573,490	11,366	562,124	104,963

Line:

A			
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E	-	-	-
F	-	-	-
G	1.11112	1.11112	1.11112
H	-	-	-
I	-	-	-
	288,924	529,098	104,963
	288,924	529,098	104,963

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 7 - Transmission Enhancement Annual Revenue Requirement Worksheet
(dollars)

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10	2009 Add-7				Project AH				Project AI			
11	Yes	B0326			Yes	B0310			Yes	B0312		
12	51	Uprate - resag Remington-			51	Reconductor Club House - South Hill			51	Reconductor Gallows to Ox 230 kV		
13	16.4840%	Brandywine -			16.4840%	and Chase City -			16.4840%			
14	0	Culppr 115 kV			0	South Hill 115 kV			0			
15	16.4840%				16.4840%				16.4840%			
	13,597,725				20,295,858				3,062,627			
17	266,622				397,958				60,052			
18	10				5				12			
19	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20												
21												
22												
23												
24												
25												
26	13,597,725	55,546	13,542,179									
27	13,597,725	55,546	13,542,179									
28	13,542,179	266,622	13,275,557	2,476,937	20,295,858	248,724	20,047,134	2,326,890	3,062,627	2,502	3,060,125	23,529
29	13,542,179	266,622	13,275,557	2,476,937	20,295,858	248,724	20,047,134	2,326,890	3,062,627	2,502	3,060,125	23,529

Line

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D			
E	-	-	-
F	-	-	-
G	1.11112	1.11112	1.11112
H	-	-	-
I	-	-	-

2,476,937	2,326,890	23,529
2,476,937	2,326,890	23,529

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 7 - Transmission Enhancement Annual Revenue Requirement Worksheet
(dollars)

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9												
10	**Project AJ**				**Project AK**				**Project AL**			
11	Yes	B0327			Yes	B0342			Yes	B0762		
12	51	Build 2nd Harrisonburg - Valley 230 kV			51	Replace Trowbridge			51	Build a new Elko station and transfer		
13	16.4840%				16.4840%	230/115 kV transformer			16.4840%	load from Turner and Providence Forge		
14	0				0				0	stations		
15	16.4840%				16.4840%				16.4840%			
	5,978,225				4,045,221				94,877			
17	117,220				79,318				1,860			
18	5				6				5			
19	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20												
21												
22												
23												
24												
25												
26												
27												
28	5,978,225	73,263	5,904,962	685,395	4,045,221	42,964	4,002,257	402,237	94,877	1,163	93,714	10,878
29	5,978,225	73,263	5,904,962	685,395	4,045,221	42,964	4,002,257	402,237	94,877	1,163	93,714	10,878

Line:

A			
B			
C			
D			
E	-	-	-
F	-	-	-
G	1.11112	1.11112	1.11112
H	-	-	-
I	-	-	-
	685,395	402,237	10,878
	685,395	402,237	10,878

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 7 - Transmission Enhancement Annual Revenue Requirement Worksheet
(dollars)

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10	**Project AM**				**Project AN**				**Project AO**			
11	Yes	B0763			Yes	B0770			Yes	B0771		
12	51	Rebuild 17.5 miles of the line for a new			51	Add a second 230/115 kV			51	Build a parallel Chickahominy - Lanexa		
13	16.4840%	summer rating of 262 MVA			16.4840%	autotransformer at Lenexa			16.4840%	230 kV line		
14	0				0				0			
15	16.4840%				16.4840%				16.4840%			
	18,278,959				6,188,448				6,715,178			
17	358,411				121,342				131,670			
18	8				5				6			
19	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20												
21												
22												
23												
24												
25												
26												
27												
28	18,278,959	134,404	18,144,555	1,260,163	6,188,448	75,839	6,112,609	709,496	6,715,178	71,321	6,643,857	667,724
29	18,278,959	134,404	18,144,555	1,260,163	6,188,448	75,839	6,112,609	709,496	6,715,178	71,321	6,643,857	667,724

Line:

A			
B			
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D			
E	-	-	-
F	-	-	-
G	1.11112	1.11112	1.11112
H	-	-	-
I	-	-	-

1,260,163	709,496	667,724
1,260,163	709,496	667,724

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 7 - Transmission Enhancement Annual Revenue Requirement Worksheet
(dollars)

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10	Project AP				Project AQ						
11	Yes	B0772			Yes	B0773			If Yes for Schedule 12 Include in this Total.	If No for Schedule 12 include in this Sum.	
12	51	Install a second Elmont			51	Install dual primary protection schemes on lines					
13	16.4840%	230/115 kV autotransformer			16.4840%	#51 and #62 at remote terminals					
14	0				0						
15	16.4840%				16.4840%						
	4,838,680				460,000					Annual Revenue Requirement including Incentive if Applicable	Annual Revenue Requirement excluding Incentive
17	94,876				9,020						
18	6				11						
19	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Total**	**Sum**	**Sum**
20											
21											
22											
23											
24											
25											
26											
27											
28	4,838,680	51,391	4,787,289	481,134	460,000	1,127	458,873	10,594	44,243,204		37,958,845
29	4,838,680	51,391	4,787,289	481,134	460,000	1,127	458,873	10,594	45,164,327	39,964,732	

Line

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A		
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E	-	-
F	-	-
G	1.11112	1.11112
H	-	-
I	-	-

481,134	10,594
481,134	10,594

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 8 - Securitization Workpaper
(000's)

Line #		
	Long Term Interest	
105	**Less LTD Interest on Securitization Bonds**	0
	Capitalization	
115	**Less LTD on Securitization Bonds**	0

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 9 - Depreciation Rates[1]

Plant Type	Applied Depreciation Rate
Transmission	1.97%
General	
Structures and Improvements	1.86%
Communication Equipment	3.67%
Computer Equipment	16.51%
Furniture, Equipment and Office Machines	1.64%
Laboratory and Miscellaneous Equipment	4.10%
Stores and Power Operated Equipment	6.31%
Tools, Shop, Garage, and Other Tangible Equipment	4.93%

[1] Depreciation rates may be changed only pursuant to a Section 205 or Section 206 proceeding.

The following pages provide:

1. Explanations of change in VEPCO's accounting policies and practices that took effect in the preceding twelve months ending August 31 as reported in Notes 3 and 4 of VEPCO's Securities and Exchange Commission Form 10-Q ("Material Accounting Changes").

2. VEPCO's Form 10-Q filed July 31, 2009.

Note 3. Newly Adopted Accounting Standards

FSP FAS 115-2 and FAS 124-2

We adopted the provisions of FSP FAS 115-2 and FAS 124-2, *Recognition and Presentation of Other-Than-Temporary Impairments* (FSP FAS 115-2) effective April 1, 2009. This FSP amends the guidance for the recognition and presentation of other-than-temporary impairments and requires additional disclosures. The recognition provisions of FSP FAS 115-2 apply only to debt securities classified as available for sale or held to maturity, while the presentation and disclosure requirements apply to both debt and equity securities. Prior to the adoption of FSP FAS 115-2, as described in Note 2 in our Annual Report on Form 10-K for the year ended December 31, 2008, we considered all debt securities held by our nuclear decommissioning trusts with market values below their cost bases to be other-than-temporarily impaired as we did not have the ability to hold the investments through the anticipated recovery period.

Effective with the adoption of FSP FAS 115-2, using information obtained from our nuclear decommissioning trust fixed-income investment managers, we record in earnings any unrealized loss for a debt security when the manager intends to sell the debt security or it is more likely than not that the manager will have to sell the debt security before recovery of its fair value up to its cost basis. Additionally, for any debt security that is deemed to have experienced a credit loss, we record the credit loss in earnings and any remaining portion of the unrealized loss in other comprehensive income. We evaluate credit losses primarily by considering the credit ratings of the issuer, prior instances of non-performance by the issuer and other factors. For certain jurisdictions subject to cost-based regulation, all net realized and unrealized gains and losses on debt securities (including any other-than-temporary impairments) continue to be recorded to a regulatory liability.

Upon the adoption of FSP FAS 115-2 for debt investments held at April 1, 2009, we recorded a $3 million ($2 million after-tax) cumulative effect of a change in accounting principle to reclassify the non-credit related portion of previously recognized other-than-temporary impairments from retained earnings to AOCI, reflecting the fixed-income investment managers' intent and ability to hold the debt securities until the amortized cost bases are recovered.

Form 10-Q

VIRGINIA ELECTRIC & POWER CO - VELPRE

Filed: July 31, 2009 (period: June 30, 2009)

Quarterly report which provides a continuing view of a company's financial position

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark one)

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2009

or

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File Number 001-02255

VIRGINIA ELECTRIC AND POWER COMPANY
(Exact name of registrant as specified in its charter)

VIRGINIA *(State or other jurisdiction of incorporation or organization)*	**54-0418825** *(I.R.S. Employer Identification No.)*
120 TREDEGAR STREET **RICHMOND, VIRGINIA** *(Address of principal executive offices)*	**23219** *(Zip Code)*

(804) 819-2000
(Registrant's telephone number)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☐ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer	☐	Accelerated filer	☐
Non-accelerated filer	☒ (Do not check if a smaller reporting company)	Smaller reporting company	☐

Indicate by check mark whether the registrant is a shell company (as defined by Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

At June 30, 2009, the latest practicable date for determination, 209,833 shares of common stock, without par value, of the registrant were outstanding.

VIRGINIA ELECTRIC AND POWER COMPANY

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GLOSSARY OF TERMS

The following abbreviations or acronyms used in this Form 10-Q are defined below:

Abbreviation or Acronym	Definition
affiliates	Other Dominion subsidiaries
AOCI	Accumulated other comprehensive income (loss)
AROs	Asset retirement obligations
CEO	Chief Executive Officer
CFO	Chief Financial Officer
DOE	Department of Energy
Dominion	Dominion Resources, Inc.
DRS	Dominion Resources Services, Inc., a subsidiary of Dominion
DVP	Dominion Virginia Power operating segment
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation No.
FSP	FASB Staff Position
FTRs	Financial transmission rights
GAAP	U.S. generally accepted accounting principles
kWh	Kilowatt-hour
MD&A	Management’s Discussion and Analysis of Financial Condition and Results of Operations
Moody’s	Moody’s Investors Service
MW	Megawatt
MWh	Megawatt-hour
North Anna	North Anna power station
NRC	Nuclear Regulatory Commission
PJM	PJM Interconnection, LLC
ROE	Return on equity
RTO	Regional transmission organization
SEC	Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards
Standard & Poor’s	Standard & Poor’s Ratings Services, a division of the McGraw-Hill Companies, Inc.
U.S.	United States of America
VIEs	Variable interest entities
Virginia Commission	Virginia State Corporation Commission

VIRGINIA ELECTRIC AND POWER COMPANY
PART I. FINANCIAL INFORMATION
ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS

CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
(millions)				
Operating Revenue	**$ 1,675**	$ 1,546	**$ 3,534**	$ 3,070
Operating Expenses				
Electric fuel and other energy-related purchases	**685**	500	**1,479**	997
Purchased electric capacity	**104**	97	**212**	203
Other operations and maintenance:				
Affiliated suppliers	**100**	90	**201**	176
Other	**281**	274	**527**	493
Depreciation and amortization	**160**	150	**317**	299
Other taxes	**46**	45	**97**	94
Total operating expenses	**1,376**	1,156	**2,833**	2,262
Income from operations	**299**	390	**701**	808
Other income	**23**	9	**32**	18
Interest and related charges(1)	**87**	78	**174**	157
Income before income tax expense	**235**	321	**559**	669
Income tax expense	**86**	121	**206**	247
Net Income	**149**	200	**353**	422
Preferred dividends	**4**	4	**8**	8
Balance available for common stock	**$ 145**	$ 196	**$ 345**	$ 414

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(1) Includes $4 million and $12 million incurred with an affiliated trust for the three and six months ended June 30, 2008, respectively.

The accompanying notes are an integral part of the Consolidated Financial Statements.

VIRGINIA ELECTRIC AND POWER COMPANY
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(millions)	June 30, 2009	December 31, 2008 [1]
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 29**	$ 27
Customer accounts receivable (less allowance for doubtful accounts of $11 and $8)	**954**	940
Other receivables (less allowance for doubtful accounts of $6 and $7)	**43**	82
Inventories (average cost method)	**591**	547
Prepayments	**89**	28
Regulatory assets	**525**	212
Other	**62**	75
Total current assets	**2,293**	1,911
Investments		
Nuclear decommissioning trust funds	**1,074**	1,053
Other	**3**	3
Total investments	**1,077**	1,056
Property, Plant and Equipment		
Property, plant and equipment	**24,457**	23,476
Accumulated depreciation and amortization	**(9,153)**	(8,915)
Total property, plant and equipment, net	**15,304**	14,561
Deferred Charges and Other Assets		
Regulatory assets	**258**	921
Other	**348**	353
Total deferred charges and other assets	**606**	1,274
Total assets	**$ 19,280**	$ 18,802

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(1) Our Consolidated Balance Sheet at December 31, 2008 has been derived from the audited Consolidated Financial Statements at that date.

The accompanying notes are an integral part of the Consolidated Financial Statements.

VIRGINIA ELECTRIC AND POWER COMPANY
CONSOLIDATED BALANCE SHEETS—(Continued)
(Unaudited)

(millions)	June 30, 2009	December 31, 2008 [1]
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current Liabilities		
Securities due within one year	**$ 15**	$ 125
Short-term debt	**379**	297
Accounts payable	**390**	436
Payables to affiliates	**54**	132
Affiliated current borrowings	**522**	417
Accrued interest, payroll and taxes	**219**	236
Other	**450**	386
Total current liabilities	**2,029**	2,029
Long-Term Debt	**6,450**	6,000
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	**2,244**	2,485
Asset retirement obligations	**614**	715
Regulatory liabilities	**867**	760
Other	**361**	282
Total deferred credits and other liabilities	**4,086**	4,242
Total liabilities	**12,565**	12,271
Commitments and Contingencies (see Note 12)		
Preferred Stock Not Subject to Mandatory Redemption	**257**	257
Common Shareholder's Equity		
Common stock—no par, 300,000 shares authorized; 209,833 shares outstanding	**3,738**	3,738
Other paid-in capital	**1,110**	1,110
Retained earnings	**1,592**	1,421
Accumulated other comprehensive income	**18**	5
Total common shareholder's equity	**6,458**	6,274
Total liabilities and shareholder's equity	**$ 19,280**	$ 18,802

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(1) Our Consolidated Balance Sheet at December 31, 2008 has been derived from the audited Consolidated Financial Statements at that date.

The accompanying notes are an integral part of the Consolidated Financial Statements.

VIRGINIA ELECTRIC AND POWER COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

(millions)	Six Months Ended June 30, 2009	2008
Operating Activities		
Net income	**$ 353**	$ 422
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	**367**	346
Deferred income taxes and investment tax credits	**(103)**	223
Other adjustments	**(14)**	(35)
Changes in:		
Accounts receivable	**18**	(7)
Affiliated accounts receivable and payable	**(24)**	91
Inventories	**(44)**	8
Deferred fuel expenses	**331**	(382)
Accounts payable	**(27)**	(24)
Accrued interest, payroll and taxes	**(18)**	(10)
Prepayments	**(61)**	10
Other operating assets and liabilities	**133**	(55)
Net cash provided by operating activities	**911**	587
Investing Activities		
Plant construction and other property additions	**(1,125)**	(848)
Purchases of nuclear fuel	**(69)**	(66)
Purchases of securities	**(346)**	(243)
Proceeds from sales of securities	**330**	209
Other	**(47)**	67
Net cash used in investing activities	**(1,257)**	(881)
Financing Activities		
Issuance of short-term debt, net	**83**	433
Issuance (repayment) of affiliated current borrowings, net	**105**	(114)
Repayment of affiliated notes payable	**—**	(412)
Issuance of long-term debt	**460**	630
Repayment of long-term debt	**(119)**	(39)
Common dividend payments	**(176)**	(198)
Preferred dividend payments	**(8)**	(8)
Other	**3**	3
Net cash provided by financing activities	**348**	295
Increase in cash and cash equivalents	**2**	1
Cash and cash equivalents at beginning of period	**27**	49
Cash and cash equivalents at end of period	**$ 29**	$ 50
Supplemental Cash Flow Information		
Significant noncash investing activities:		
Accrued capital expenditures	**$ 103**	$ 10

The accompanying notes are an integral part of the Consolidated Financial Statements.

VIRGINIA ELECTRIC AND POWER COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

Note 1. Nature of Operations

Virginia Electric and Power Company (Virginia Power) is a regulated public utility that generates, transmits and distributes electricity for sale in Virginia and northeastern North Carolina. We are a member of PJM, a regional transmission organization (RTO), and our electric transmission facilities are integrated into the PJM wholesale electricity markets. All of our common stock is owned by our parent company, Dominion Resources, Inc. (Dominion).

We manage our daily operations through two primary operating segments: Dominion Virginia Power (DVP) and Generation. In addition, we also report a Corporate and Other segment that primarily includes specific items attributable to our operating segments that are not included in profit measures evaluated by executive management in assessing the segments' performance or allocating resources among the segments. See Note 15 for further discussion of our operating segments.

The terms "Company," "we," "our" and "us" are used throughout this report and, depending on the context of their use, may represent any of the following: the legal entity, Virginia Power, one or more of its consolidated subsidiaries or operating segments or the entirety of Virginia Power, including our Virginia and North Carolina operations and our consolidated subsidiaries.

Note 2. Significant Accounting Policies

As permitted by the rules and regulations of the SEC, our accompanying unaudited Consolidated Financial Statements contain certain condensed financial information and exclude certain footnote disclosures normally included in annual audited consolidated financial statements prepared in accordance with GAAP. These unaudited Consolidated Financial Statements should be read in conjunction with the Consolidated Financial Statements and Notes in our Annual Report on Form 10-K for the year ended December 31, 2008 and our Quarterly Report on Form 10-Q for the quarter ended March 31, 2009.

In our opinion, the accompanying unaudited Consolidated Financial Statements contain all adjustments necessary to present fairly our financial position as of June 30, 2009 and our results of operations for the three and six months ended June 30, 2009 and 2008, and our cash flows for the six months ended June 30, 2009 and 2008. Such adjustments are normal and recurring in nature unless otherwise noted.

We make certain estimates and assumptions in preparing our Consolidated Financial Statements in accordance with GAAP. These estimates and assumptions affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses for the periods presented. Actual results may differ from those estimates.

Our accompanying unaudited Consolidated Financial Statements include, after eliminating intercompany transactions and balances, our accounts and those of our majority-owned subsidiaries.

In accordance with GAAP, we report certain contracts and instruments at fair value. See Note 5 for further information on fair value measurements in accordance with SFAS No. 157, *Fair Value Measurements* .

The results of operations for interim periods are not necessarily indicative of the results expected for the full year. Information for quarterly periods is affected by seasonal variations in sales, electric fuel and other energy-related purchases and other factors.

We have evaluated subsequent events through July 31, 2009, the date our Consolidated Financial Statements were issued.

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Note 3. Newly Adopted Accounting Standards

FSP FAS 115-2 and FAS 124-2

We adopted the provisions of FSP FAS 115-2 and FAS 124-2, *Recognition and Presentation of Other-Than-Temporary Impairments* (FSP FAS 115-2) effective April 1, 2009. This FSP amends the guidance for the recognition and presentation of other-than-temporary impairments and requires additional disclosures. The recognition provisions of FSP FAS 115-2 apply only to debt securities classified as available for sale or held to maturity, while the presentation and disclosure requirements apply to both debt and equity securities. Prior to the adoption of FSP FAS 115-2, as described in Note 2 in our Annual Report on Form 10-K for the year ended December 31, 2008, we considered all debt securities held by our nuclear decommissioning trusts with market values below their cost bases to be other-than-temporarily impaired as we did not have the ability to hold the investments through the anticipated recovery period.

Effective with the adoption of FSP FAS 115-2, using information obtained from our nuclear decommissioning trust fixed-income investment managers, we record in earnings any unrealized loss for a debt security when the manager intends to sell the debt security or it is more likely than not that the manager will have to sell the debt security before recovery of its fair value up to its cost basis. Additionally, for any debt security that is deemed to have experienced a credit loss, we record the credit loss in earnings and any remaining portion of the unrealized loss in other comprehensive income. We evaluate credit losses primarily by considering the credit ratings of the issuer, prior instances of non-performance by the issuer and other factors. For certain jurisdictions subject to cost-based regulation, all net realized and unrealized gains and losses on debt securities (including any other-than-temporary impairments) continue to be recorded to a regulatory liability.

Upon the adoption of FSP FAS 115-2 for debt investments held at April 1, 2009, we recorded a $3 million ($2 million after-tax) cumulative effect of a change in accounting principle to reclassify the non-credit related portion of previously recognized other-than-temporary impairments from retained earnings to AOCI, reflecting the fixed-income investment managers' intent and ability to hold the debt securities until the amortized cost bases are recovered.

Note 4. Comprehensive Income

The following table presents total comprehensive income:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	**2008**	**2009**	**2008**
(millions)				
Net income	**$ 149**	$ 200	**$ 353**	$ 422
Other comprehensive income (loss):				
Net other comprehensive income associated with effective portion of changes in fair value of derivatives designated as cash flow hedges, net of taxes and amounts reclassified to earnings	**8**	—	**8**	1
Other, net of tax	**4**	(3)	**7**	(8)
Other comprehensive income (loss)	**12**	(3)	**15**	(7)
Total comprehensive income	**$ 161**	$ 197	**$ 368**	$ 415

Other comprehensive income for the three and six months ended June 30, 2009 excludes a $3 million ($2 million after-tax) adjustment representing the cumulative effect of the change in accounting principle related to the adoption of FSP FAS 115-2.

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Note 5. Fair Value Measurements

Our fair value measurements are made in accordance with the policies discussed in Note 6 to our Annual Report on Form 10-K for the year ended December 31, 2008. In addition, see Note 6 in this report for further information about our derivatives and hedge accounting activities.

The following table presents our assets and liabilities that are measured at fair value on a recurring basis for each hierarchy level, including both current and noncurrent portions:

(millions)	Level 1	Level 2	Level 3	Total
As of June 30, 2009				
Assets				
Derivatives	**$ —**	**$ 109**	**$ 8**	**$ 117**
Investments	**295**	**679**	**—**	**974**
Total assets	**$ 295**	**$ 788**	**$ 8**	**$ 1,091**
Liabilities				
Derivatives	**$ —**	**$ 9**	**$ 16**	**$ 25**
As of December 31, 2008				
Assets				
Derivatives	$ —	$ 60	$ 7	$ 67
Investments	225	714	—	939
Total assets	$ 225	$ 774	$ 7	$ 1,006
Liabilities				
Derivatives	$ —	$ 23	$ 76	$ 99

The following table presents the net changes in the assets and liabilities measured at fair value on a recurring basis and included in the Level 3 fair value category:

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions)	2009	2008	2009	2008
Beginning balance	**$ (41)**	$ 35	**$ (69)**	$ (4)
Total realized and unrealized gains or (losses):				
Included in earnings	**(87)**	70	**(138)**	89
Included in other comprehensive income (loss)	**—**	(3)	**—**	—
Included in regulatory assets/liabilities	**32**	167	**55**	200
Purchases, issuances and settlements	**88**	(59)	**142**	(75)
Transfers out of Level 3	**—**	—	**2**	—
Ending balance	**$ (8)**	$ 210	**$ (8)**	$ 210
The amount of gains (losses) for the period included in earnings attributable to the change in unrealized gains/losses relating to assets still held at the reporting date	**$ —**	$ 15	**$ —**	$ 15

The gains and losses included in earnings in the Level 3 fair value category, including those attributable to the change in unrealized gains and losses relating to assets still held at the reporting date, were classified in electric fuel and other energy-related purchases expense in our Consolidated Statements of Income for the three and six months ended June 30, 2009 and 2008.

As of June 30, 2009, our net balance of commodity derivatives categorized as Level 3 fair value measurements was a net liability of $8 million. A hypothetical 10% increase in commodity prices would increase the net liability by $2 million, while a hypothetical 10% decrease in commodity prices would decrease the net liability by $2 million.

There were no significant non-financial assets or liabilities that were measured at fair value on a nonrecurring basis during the six months ended June 30, 2009.

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Fair Value of Financial Instruments

Substantially all of our financial instruments are recorded at fair value, with the exception of the instruments described below that are reported at historical cost. Estimated fair values have been determined using available market information and valuation methodologies considered appropriate by management. At June 30, 2009 and December 31, 2008, the carrying amount of our cash and cash equivalents, customer and other receivables, short-term debt and accounts payable are representative of fair value due to the short-term nature of these instruments. The financial instruments' carrying amounts and fair values are as follows:

	June 30, 2009		December 31, 2008	
(millions)	**Carrying Amount**	**Estimated Fair Value (1)**	**Carrying Amount**	**Estimated Fair Value (1)**
Long-term debt(2)	**$ 6,465**	**$ 6,885**	$ 6,125	$ 6,231
Preferred stock(3)	**257**	**231**	257	231

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(1) Fair value is estimated using market prices, where available, and interest rates currently available for issuance of debt with similar terms and remaining maturities. The carrying amount of debt issues with short-term maturities and variable rates refinanced at current market rates is a reasonable estimate of their fair value.

(2) Includes securities due within one year and amounts which represent the unamortized discount and premium. Also includes the valuation of certain fair value hedges associated with our fixed rate debt of $1 million at June 30, 2009 and December 31, 2008.

(3) Includes issuance expenses of $2 million at June 30, 2009 and December 31, 2008.

Note 6. Derivatives and Hedge Accounting Activities

Our accounting policies and objectives and strategies for using derivative instruments are discussed in Note 2 to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2008.

The following table presents the volume of our derivative activity as of June 30, 2009. These volumes are based on open derivative positions and represent the combined absolute value of our long and short positions, except in the case of offsetting deals, for which we present the absolute value of the net volume of our long and short positions.

	Current	Noncurrent
Natural Gas (bcf):		
Fixed price	15.2	—
Basis	7.6	—
Electricity (MWh):		
Fixed price(1)	241,491	—
FTRs	97,202,239	—
Capacity (MW)	492,270	585,000
Interest rate	$ 370,000,000	$ 625,000,000
Foreign currency (euros)	9,847,638	4,000,000

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(1) Includes options.

For the three and six months ended June 30, 2009 and 2008, gains or losses on hedging instruments determined to be ineffective were not material. Amounts excluded from the assessment of effectiveness include gains or losses attributable to changes in the time value of options and changes in the differences between spot prices and forward prices and were not material for the three and six months ended June 30, 2009 and 2008.

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The following table presents selected information related to gains on cash flow hedges included in AOCI in our Consolidated Balance Sheet at June 30, 2009:

(millions)	AOCI After-Tax	Portion Expected to be Reclassified to Earnings During the Next 12 Months After-Tax	Maximum Term
Interest rate	$ 8	$ —	374 months
Other	4	2	65 months
Total	$ 12	$ 2	

The amounts that will be reclassified from AOCI to earnings will generally be offset by the recognition of the hedged transactions (e.g., anticipated purchases) in earnings, thereby achieving the realization of prices contemplated by the underlying risk management strategies and will vary from the expected amounts presented above as a result of changes in market prices, interest rates and foreign exchange rates.

Fair Value and Gains and Losses on Derivative Instruments

The following table presents the fair values of our derivatives as of June 30, 2009 and where they are presented on our Consolidated Balance Sheet:

(millions)	Fair Value – Derivatives under Hedge Accounting	Fair Value – Derivatives not under Hedge Accounting	Total Fair Value
ASSETS			
Current Assets			
Commodity	$ 16	$ 8	$ 24
Interest rate	23	—	23
Foreign currency	1	—	1
Total current derivative assets[1]	40	8	48
Noncurrent Assets			
Commodity	19	—	19
Interest rate	49	—	49
Foreign currency	1	—	1
Total noncurrent derivative assets[2]	69	—	69
Total derivative assets	$ 109	$ 8	$ 117
LIABILITIES			
Current Liabilities			
Commodity	$ 7	$ 16	$ 23
Total current derivative liabilities[3]	7	16	23
Noncurrent Liabilities			
Commodity	2	—	2
Total noncurrent derivative liabilities[4]	2	—	2
Total derivative liabilities	$ 9	$ 16	$ 25

---

(1) Current derivative assets are recorded in other current assets on our Consolidated Balance Sheet.
(2) Noncurrent derivative assets are recorded in other deferred charges and other assets on our Consolidated Balance Sheet.
(3) Current derivative liabilities are recorded in other current liabilities on our Consolidated Balance Sheet.
(4) Noncurrent derivative liabilities are recorded in other deferred credits and other liabilities on our Consolidated Balance Sheet.

The following tables present the gains and losses on our derivatives, as well as where the associated activity is presented on our Consolidated Balance Sheet and Consolidated Statements of Income:

Derivatives in SFAS No. 133 Cash Flow Hedging Relationships	Amount of Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion) [1]	Amount of Gain (Loss) Reclassified from AOCI to Income	Increase (Decrease) in Derivatives Subject to Regulatory Treatment [2]
(millions)			
Three months ended June 30, 2009			
Derivative Type and Location of Gains (Losses)			
Commodity:			
Electric fuel and other energy-related purchases		$ (1)	
Purchased electric capacity		2	
Total commodity	$ (1)	1	$ (4)
Interest rate[3]	14	—	86
Foreign currency[4]	1	—	2
Total	$ 14	$ 1	$ 84
Six months ended June 30, 2009			
Derivative Type and Location of Gains (Losses)			
Commodity:			
Electric fuel and other energy-related purchases		$ (6)	
Purchased electric capacity		3	
Total commodity	$ (2)	(3)	$ 1
Interest rate[3]	13	—	73
Foreign currency[4]	—	1	—
Total	$ 11	$ (2)	$ 74

---

(1) Amounts deferred into AOCI have no associated effect in our Consolidated Statements of Income.

(2) Represents net derivative activity deferred into and amortized out of regulatory assets/liabilities. Amounts deferred into regulatory assets/liabilities have no associated effect in our Consolidated Statements of Income.

(3) Amounts recorded in our Consolidated Statements of Income are classified in interest expense.

(4) Amounts recorded in our Consolidated Statements of Income are classified in electric fuel and other energy-related purchases.

Derivatives not designated as hedging instruments under SFAS No. 133	Amount of Gain (Loss) Recognized in Income on Derivatives [1]	
	Three Months Ended June 30, 2009	Six Months Ended June 30, 2009
(millions)		
Derivative Type and Location of Gains (Losses)		
Commodity[2]	$ (87)	$ (138)
Total	$ (87)	$ (138)

---

(1) Includes derivative activity amortized out of regulatory assets/liabilities. Amounts deferred into regulatory assets/liabilities have no associated effect on our Consolidated Statements of Income.

(2) Amounts are recorded in electric fuel and other energy-related purchases in our Consolidated Statements of Income.

For the three and six months ended June 30, 2009 there were no significant gains or losses recorded related to fair value hedging relationships.

See Note 5 for further information about fair value measurements and associated valuation methods for derivatives under SFAS No. 157.

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Note 7. Decommissioning Trust Investments

We hold marketable equity and debt securities and cash equivalents (classified as available-for-sale) and cost method investments in nuclear decommissioning trust funds to fund future decommissioning costs for our nuclear plants. Our decommissioning trust funds are summarized below.

(millions)	Amortized Cost	Total Unrealized Gains [1]	Total Unrealized Losses [1]	Fair Value
June 30, 2009				
Marketable equity securities	**$ 466**	**$ 70**	**$ —**	**$ 536**
Marketable debt securities:				
Corporate bonds	**149**	**5**	**(4)**	**150**
U.S. Treasury securities and agency debentures	**98**	**3**	**—**	**101**
State and municipal	**172**	**6**	**(3)**	**175**
Cost method investments	**96**	**—**	**—**	**96**
Cash equivalents and other[2]	**16**	**—**	**—**	**16**
Total	**$ 997**	**$ 84**	**$ (7)**[3]	$ 1,074
December 31, 2008				
Marketable equity securities	$ 459	$ 9	$ —	$ 468
Marketable debt securities:				
Corporate bonds	144	7	—	151
U.S. Treasury securities and agency debentures	122	4	—	126
State and municipal	177	6	—	183
Cost method investments	108	—	—	108
Cash equivalents and other[2]	17	—	—	17
Total	$ 1,027	$ 26	$ —	$ 1,053

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(1) Included in AOCI and the decommissioning trust regulatory liability.

(2) Includes net assets related to pending sales and purchases of securities of $5 million and $6 million at June 30, 2009 and December 31, 2008, respectively.

(3) The fair value of securities in an unrealized loss position was $118 million at June 30, 2009.

The fair value of our marketable debt securities at June 30, 2009, by contractual maturity is as follows:

(millions)	Amount
Due in one year or less	**$ 20**
Due after one year through five years	**97**
Due after five years through ten years	**155**
Due after ten years	**154**
Total	**$ 426**

Presented below is selected information regarding our marketable equity and debt securities.

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions)	2009	2008	2009	2008
Proceeds from sales[1]	**$ 193**	$ 89	**$ 330**	$ 209
Realized gains[2]	**15**	8	**23**	17
Realized losses[2]	**6**	23	**70**	50

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(1) The increase in proceeds primarily reflects changes in asset allocation and liquidation of positions in connection with changes in fund managers.

(2) Includes realized gains and losses recorded to the decommissioning trust regulatory liability.

We recorded other-than-temporary impairment losses on investments as follows:

(millions)	Three Months Ended June 30, 2009	Three Months Ended June 30, 2008	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
Total other-than-temporary impairment losses[1]	**$ 8**	$ 20	**$ 82**	$ 40
Losses recorded to decommissioning trust regulatory liability	**(7)**	(17)	**(70)**	(34)
Net impairment losses recognized in earnings	**$ 1**	$ 3	**$ 12**	$ 6

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(1) Amount includes other-than-temporary impairment losses for debt securities of $1 million and $4 million for the three months ended June 30, 2009 and 2008, respectively, and $5 million and $8 million for the six months ended June 30, 2009 and 2008, respectively.

Note 8. Regulatory Assets and Liabilities

Our regulatory assets and liabilities include the following:

(millions)	June 30, 2009	December 31, 2008
Regulatory assets		
Deferred cost of fuel used in electric generation[1]	**$ 463**	$ 133
Other	**62**	79
Regulatory assets –current	**525**	212
RTO start-up costs and administration fees[2]	**118**	122
Deferred cost of fuel used in electric generation[1]	**15**	676
Other	**125**	123
Regulatory assets –non-current	**258**	921
Total regulatory assets	**$ 783**	$ 1,133
Regulatory liabilities		
Provision for future cost of removal[3]	**$ 533**	$ 506
Decommissioning trust[4]	**221**	213
Other[5]	**128**	61
Total regulatory liabilities	**$ 882**	$ 780

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(1) As discussed under Virginia Fuel Expenses in Note 12, in March 2009 we filed our Virginia fuel factor application with the Virginia Commission which requested an annual decrease in fuel expense recovery of approximately $236 million for the period July 1, 2009 through June 30, 2010. The proposed fuel factor went into effect on July 1, 2009 on an interim basis and an evidentiary hearing on the Company's application was to be held on July 16, 2009. In a subsequent order, the Virginia Commission postponed the July 16th hearing until September 1, 2009.

(2) The FERC has approved our recovery of start-up costs incurred in connection with joining an RTO and on-going administrative charges paid to PJM through a Deferred Recovery Charge (DRC). As discussed in Note 12, in June 2009, the Virginia Commission approved full recovery of the DRC from retail customers. In July 2009, FERC issued an order denying requests for rehearing of its December 2008 order. The time to appeal FERC's orders has not yet expired. Recovery of the DRC, over a ten year period, will begin September 1, 2009. Approximately $19 million of these costs are included in other current regulatory assets.

(3) Rates charged to customers by our regulated business include a provision for the cost of future activities to remove assets that are expected to be incurred at the time of retirement.

(4) Primarily reflects a regulatory liability established in 2007 representing amounts previously collected from Virginia jurisdictional customers and placed in external trusts (including income, losses and changes in fair value thereon) for the future decommissioning of our utility nuclear generation stations, in excess of amounts recorded pursuant to SFAS No. 143, *Accounting for Asset Retirement Obligations.*

(5) Includes $15 million and $20 million reported in other current liabilities at June 30, 2009 and December 31, 2008, respectively.

At June 30, 2009, approximately $560 million of our regulatory assets represented past expenditures on which we do not earn a return. These expenditures consist primarily of deferred fuel costs that are expected to be recovered within two years.

Note 9. Asset Retirement Obligations

The following table describes the changes in our AROs during 2009:

(millions)	Amount
AROs at December 31, 2008[1]	$ 717
Revisions in estimated cash flows[2]	**(118)**
Accretion	**18**
AROs at June 30, 2009[1]	**$ 617**

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(1) Includes $2 million and $3 million reported in other current liabilities at December 31, 2008 and June 30, 2009, respectively.

(2) Primarily reflects updated decommissioning cost studies and applicable escalation rates received for each of our nuclear facilities during the second quarter of 2009.

Note 10. Variable Interest Entities

As discussed in Note 13 to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2008, certain variable pricing terms in some of our long-term power and capacity contracts cause them to be considered variable interests in the counterparties in accordance with FIN 46R, *Consolidation of Variable Interest Entities* .

We have long-term power and capacity contracts with four non-utility generators with an aggregate generation capacity of approximately 940 MW. These contracts contain certain variable pricing mechanisms in the form of partial fuel reimbursement that we consider to be variable interests. After an evaluation of the information provided to us by these entities, we were unable to determine whether they were variable interest entities (VIEs). However, the information they provided, as well as our knowledge of generation facilities in Virginia, enabled us to conclude that, if they were VIEs, we would not be the primary beneficiary. This conclusion was based primarily on a qualitative assessment of our variable interests as compared to the operations, commodity price and other risks retained by the equity and debt holders during the remaining terms of our contracts and for the years the entities are expected to operate after our contractual relationships expire. The contracts expire at various dates ranging from 2015 to 2021. We are not subject to any risk of loss from these potential VIEs other than our remaining purchase commitments which totaled $1.9 billion as of June 30, 2009. We paid $51 million and $50 million for electric capacity and $25 million and $46 million for electric energy to these entities for the three months ended June 30, 2009 and 2008, respectively. We paid $104 million and $102 million for electric capacity and $66 million and $92 million for electric energy to these entities for the six months ended June 30, 2009 and 2008, respectively.

We purchased shared services from Dominion Resources Services, Inc. (DRS), an affiliated VIE, of $99 million and $90 million for the three months ended June 30, 2009 and 2008, respectively, and $199 million and $176 million for the six months ended June 30, 2009 and 2008, respectively. We determined that we are not the most closely associated entity with DRS and therefore not the primary beneficiary. DRS provides accounting, legal, finance and certain administrative and technical services to all Dominion subsidiaries, including us. We have no obligation to absorb more than our allocated share of DRS costs.

Note 11. Significant Financing Transactions

Joint Credit Facilities and Short-Term Debt

We use short-term debt, primarily commercial paper, to fund working capital requirements and as a bridge to long-term debt financing. The level of our borrowings may vary significantly during the course of the year, depending upon the timing and amount of cash requirements not satisfied by cash from operations.

Our credit facility commitments are with a large consortium of banks, which included Lehman Brothers Holdings, Inc. (Lehman). In March 2009, we executed a consent agreement with the bank syndicates to reduce Lehman’s remaining commitment to zero in each of our credit facilities in which it had participated.

Our short-term financing is supported by a $2.9 billion five-year joint revolving credit facility with Dominion dated February 2006, which is scheduled to terminate in February 2011. This credit facility is being used for working capital, as support for the combined commercial paper programs of Dominion and us and for other general corporate purposes. This credit facility can also be used to support up to $1.5 billion of letters of credit.

At June 30, 2009, total outstanding commercial paper supported by the joint credit facility was $379 million, all of which were our borrowings, and the total outstanding letters of credit supported by the joint credit facility were $291 million, of which $226 million were issued on our behalf.

At June 30, 2009, capacity available under the joint credit facility was $2.2 billion.

In addition to the credit facility commitments of $2.9 billion disclosed above, we also have a five-year credit facility that supports certain of our tax-exempt financings. In June 2009, the committed amount was reduced from $182 million to $120 million. The reduced amount reflects the size necessary to cover outstanding variable rate tax-exempt financing.

Long-Term Debt

In May 2009, Virginia Power borrowed $40 million in connection with the Economic Development Authority of the County of Chesterfield Pollution Control Refunding Revenue Bonds, Series 2009 A, which mature in 2023 and bear a coupon rate of 5.0%. The proceeds were used to refund the principal amount of the Industrial Development Authority of the County of Chesterfield Money Market Municipals™ Pollution Control Revenue Bonds, Series 1985 that would otherwise have matured in October 2009.

In May 2009, Virginia Power borrowed $70 million in connection with the Economic Development Authority of York County, Virginia Pollution Control Refunding Revenue Bonds, Series 2009 A, which mature in 2033 and bear an initial coupon rate of 4.05% for the first five years, after which they will bear interest at a market rate to be determined at that time using a remarketing process. The proceeds were used to refund the principal amount of the Industrial Development Authority of York County, Virginia Money Market Municipals™ Pollution Control Revenue Bonds, Series 1985 that would otherwise have matured in July 2009.

In June 2009, we issued $350 million of 5.0% senior notes that mature in 2019. The proceeds were used for general corporate purposes and the repayment of short term debt, including commercial paper.

We repaid $119 million of long-term debt during the six months ended June 30, 2009.

Note 12. Commitments and Contingencies

Other than the following matters, there have been no significant developments regarding the commitments and contingencies disclosed in Note 20 to the Consolidated Financial Statements in our Annual Report on Form 10-K for the year ended December 31, 2008, or Note 8 to the Consolidated Financial Statements in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, nor have any significant new matters arisen during the three months ended June 30, 2009.

Electric Regulation in Virginia

2007 Virginia Regulation Act

Pursuant to the Virginia Electric Utility Regulation Act (the Regulation Act), the Virginia Commission entered an order in January 2009 initiating reviews of the base rates and terms and conditions of all investor-owned electric utilities in Virginia. Possible outcomes of the 2009 rate review, according to the Regulation Act, include a rate increase, a rate decrease, or a partial refund of 2008 earnings more than 50 basis points above the authorized return on equity (ROE).

In March 2009, we submitted our base rate filing and accompanying schedules to the Virginia Commission. Our filing proposed to increase our Virginia jurisdictional base rates by approximately $298 million annually. We also proposed a 12.5% ROE, plus an additional 100 basis point performance incentive pursuant to the Regulation Act based on our generating plant performance, customer service, and operating efficiency, resulting in a total ROE request of 13.5%. In April 2009, we submitted a revised filing that corrected certain plant balances. The corrected plant balances and related adjustments reduced the increase in our annual requirement by approximately $9 million, to $289 million. We proposed that the base rate increase become effective on an interim basis on September 1, 2009, subject to refund and adjustment by the Virginia Commission. In July 2009, in response to rulings by the Virginia Commission relating to the appropriate rate year and capital structure to be used in the Company's base rate review, we submitted a revised filing that further reduced the increase in our annual revenue requirement approximately $39 million, to $250 million. The proposed rate increase would increase a typical 1,000 kWh Virginia jurisdictional residential customer's bill by approximately $5.22 per month. The amended filing reflects an upward adjustment of 50 basis points in the proposed ROE. An evidentiary hearing on our base rate filing will be held in January 2010.

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In March 2009, we filed with the Virginia Commission, pursuant to the Regulation Act, a petition to recover from Virginia jurisdictional customers an annual net increase of approximately $78 million in costs related to FERC-approved transmission charges and PJM demand response programs. This amount also included a portion of costs discussed further in the *RTO Start-up Costs and Administrative Fees* section. In a final order in June 2009, the Virginia Commission approved a new rate adjustment clause (Rider T) to recover approximately $218 million over the 12-month period beginning September 1, 2009, subject to an annual review and re-set in 2010, if necessary. The approved amount to be recovered through Rider T includes approximately $150 million of transmission-related costs that were traditionally incorporated in base rates, plus an incremental increase of approximately $68 million. The Virginia Commission also ruled that approximately $10 million that the Company had proposed to collect in Rider T would be more appropriately recovered through base rates, and those costs have been incorporated into the Company's revised base rate filing that was submitted in July 2009. Once implemented, Rider T is expected to increase a typical 1,000 kWh Virginia jurisdictional residential customer's bill by approximately $1.11 per month.

In July 2009, we filed with the Virginia Commission an application for approval and cost recovery of twelve demand-side management (DSM) programs, including one peak-shaving program and eleven energy efficiency programs. We plan to use DSM, along with our traditional supply-side resources, to meet our projected load growth over the next 15 years. The DSM programs will also help to achieve Virginia's goal of reducing, by 2022, the electric energy consumption of the Company's retail customers by ten percent of what was consumed in 2006. Our application requests approval of the DSM programs by February 1, 2010 and two associated rate adjustment clauses for cost recovery to be effective April 1, 2010, although the Regulation Act gives the Virginia Commission until the end of March 2010 to act on our application. In the filing, we requested approval of the two rate adjustment clauses to recover from Virginia jurisdictional customers an annual net increase of approximately $51 million for the period April 1, 2010 to March 31, 2011. If approved by the Virginia Commission, the rate adjustment clauses will be expected, on a combined basis, to increase a typical 1,000 kWh residential bill by approximately $0.95 per month.

Virginia Fuel Expenses

In March 2009, we filed our Virginia fuel factor application with the Virginia Commission. The application requested an annual decrease in fuel expense recovery of approximately $236 million for the period July 1, 2009 through June 30, 2010, a decrease from 3.893 cents per kWh to 3.529 cents per kWh, or approximately $3.64 per month for the typical 1,000 kWh Virginia jurisdictional residential customer's average bill. The proposed fuel factor went into effect on July 1, 2009 on an interim basis and an evidentiary hearing on the Company's application was to be held on July 16, 2009. In a subsequent order, the Virginia Commission postponed the July 16th hearing until September 1, 2009.

Generation Expansion

In March 2009, we filed with the Virginia Commission our first annual update to the rate adjustment clause for the Virginia City Hybrid Energy Center requesting an increase of approximately $99 million for financing costs to be recovered through rates in 2010. As part of this filing we requested that the 13.5% ROE proposed in our March 31, 2009 base rate filing be applied to the Virginia City Hybrid Energy Center rate adjustment clause (Rider S), plus the 100 basis point enhancement for construction of a new coal-fired generation facility as previously authorized by the Virginia Commission pursuant to the Regulation Act, for a requested total ROE of 14.5%. If approved by the Virginia Commission, the revised Rider S could become effective as early as January 1, 2010 as requested by the Company and would increase a typical 1,000 kWh Virginia jurisdictional residential customer's bill by approximately $1.78 per month. An evidentiary hearing has been scheduled before a hearing examiner in August 2009.

In March 2009, the Virginia Commission authorized construction and operation of our proposed Bear Garden facility, a 580 MW (nominal) natural gas- and oil-fired combined-cycle electric generating facility and associated transmission interconnection facilities in Buckingham County, Virginia, estimated to cost $619 million, excluding financing costs. In March 2009, we also filed a petition with the Virginia Commission for the initiation of a rate adjustment clause for recovery of approximately $77 million in financing costs related to the construction of the Bear Garden facility to be recovered through rates in 2010. As part of this filing we requested that the 13.5% ROE proposed in our March 31, 2009 base rate filing be applied to the Bear Garden facility rate adjustment clause, with a 100 basis point enhancement for construction of a combined-cycle facility, as authorized by the Regulation Act, for a requested total ROE of 14.5%. If approved by the Virginia Commission, the rate adjustment clause could become effective as early as January 1, 2010 as requested by the Company, and would increase a typical 1,000 kWh Virginia jurisdictional residential customer's bill by approximately $1.40 per month. An evidentiary hearing has been scheduled before a hearing examiner in August 2009.

We are unable to predict the outcome of the Virginia Commission's future rate actions, including actions relating to our 2009 base rate review, our DSM program, our recovery of Virginia fuel expenses, and our additional rate adjustment clause filings; however, unfavorable future decisions by the Virginia Commission could adversely affect our results of operations, financial condition and cash flows.

RTO Start-up Costs and Administrative Fees

In December 2008, FERC approved our DRC request to become effective January 1, 2009, which allows recovery of approximately $153 million of RTO costs ($140 million of our costs and $13 million of Dominion's costs) that are being deferred due to a statutory base rate cap established under Virginia law. In June 2009, the Virginia Commission approved full recovery of the DRC from retail customers through Rider T. Recovery of the DRC will begin September 1, 2009. In July 2009, FERC issued an order denying requests for rehearing of its December 2008 order. The time to appeal FERC's orders has not yet expired. We cannot predict the status or outcome of a potential appeal, if any, of FERC's orders.

Guarantees and Surety Bonds

As of June 30, 2009, we had issued $16 million of guarantees primarily to support tax-exempt debt. We had also purchased $88 million of surety bonds for various purposes, including providing workers' compensation coverage. Under the terms of surety bonds, we are obligated to indemnify the respective surety bond company for any amounts paid.

Note 13. Credit Risk

We maintain a provision for credit losses based on factors surrounding the credit risk of our customers, historical trends and other information. We believe, based on our credit policies and our June 30, 2009 provision for credit losses, that it is unlikely a material adverse effect on our financial position, results of operations or cash flows would occur as a result of counterparty nonperformance.

We sell electricity and provide distribution and transmission services to customers in Virginia and northeastern North Carolina. Management believes that this geographic concentration risk is mitigated by the diversity of our customer base, which includes residential, commercial and industrial customers, as well as rural electric cooperatives and municipalities. Credit risk associated with trade accounts receivable from energy consumers is limited due to the large number of customers.

Our exposure to potential concentrations of credit risk results primarily from sales to wholesale customers. Our gross credit exposure for each counterparty is calculated as outstanding receivables plus any unrealized on or off-balance sheet exposure, taking into account contractual netting rights. Gross credit exposure is calculated prior to the application of collateral. At June 30, 2009, our gross credit exposure totaled $40 million. After the application of collateral, our credit exposure is reduced to $27 million. Of this amount, investment grade counterparties, including those internally rated, represented 67%, and no single counterparty exceeded 34%.

The majority of our derivative instruments contain credit-related contingent provisions. These provisions require us to provide collateral upon the occurrence of specific events, primarily a credit downgrade. If the credit-related contingent features underlying these instruments that are in a liability position and not fully collateralized with cash were fully triggered as of June 30, 2009, we would be required to post an additional $2 million of collateral to our counterparties. The collateral that would be required to be posted includes the impacts of any offsetting asset positions and any amounts already posted for derivatives, non-derivative contracts and derivatives elected under the normal purchases and normal sales exception, per contractual terms. As of June 30, 2009 we have not posted any collateral related to derivatives with credit-related contingent provisions that are in a liability position and not fully collateralized with cash. The aggregate fair value of all derivative instruments with credit-related contingent provisions that are in a liability position and not fully collateralized with cash as of June 30, 2009 is $1 million and does not include the impact of any offsetting asset positions. See Note 6 for further information about our derivative instruments.

Note 14. Related Party Transactions

We engage in related-party transactions primarily with other Dominion subsidiaries (affiliates). Our receivable and payable balances with affiliates are settled based on contractual terms or on a monthly basis, depending on the nature of the underlying transactions. We are included in Dominion's consolidated federal income tax return and participate in certain Dominion benefit plans. A discussion of significant related party transactions follows.

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Transactions with Affiliates

We transact with affiliates for certain quantities of natural gas and other commodities in the ordinary course of business. We also enter into certain commodity derivative contracts with affiliates. We use these contracts, which are principally comprised of commodity swaps and options, to manage commodity price risks associated with purchases of natural gas. We designate the majority of these contracts as cash flow hedges for accounting purposes.

We receive a variety of services from DRS and other affiliates, primarily for accounting, legal, finance and certain administrative and technical services. In addition, we provide certain services to affiliates, including charges for facilities and equipment usage.

Presented below are significant transactions with DRS and other affiliates:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	**2009**	2008
(millions)				
Commodity purchases from affiliates	**$ 55**	$ 121	**$ 154**	$ 186
Services provided by affiliates	**100**	90	**201**	176

The following table presents our borrowings from Dominion under short-term arrangements:

(millions)	**June 30, 2009**	December 31, 2008
Outstanding borrowings, net of repayments, under the Dominion money pool for our nonregulated subsidiaries	**$ 142**	$ 198
Short-term demand note borrowings from Dominion	**380**	219

Interest charges related to our borrowings from Dominion were not material for the three or six months ended June 30, 2009 and 2008.

Note 15. Operating Segments

We are organized primarily on the basis of the products and services we sell. The majority of our revenue is provided through tariff rates. Generally, such revenue is allocated for management reporting based on an unbundled rate methodology among our DVP and Generation segments. We manage our daily operations through the following segments:

DVP includes our transmission, distribution and customer service operations.

Generation includes our generation and energy supply operations.

Corporate and Other primarily includes specific items attributable to our operating segments. The contribution to net income by our primary operating segments is determined based on a measure of profit that management believes represents the segments' core earnings. As a result, certain specific items attributable to those segments are not included in profit measures evaluated by executive management, either in assessing the segment's performance or in allocating resources among the segments and are instead reported in the Corporate and Other segment.

In the six months ended June 30, 2009, our Corporate and Other segment included $9 million ($6 million after-tax) of expenses attributable to the Generation segment, reflecting net losses on investments in our nuclear decommissioning trusts. There were no specific items attributable to our operating segments included in the Corporate and Other segment in the six months ended June 30, 2008.

The following table presents segment information pertaining to our operations:

(millions)	DVP	Generation	Corporate and Other	Consolidated Total
Three Months Ended June 30, 2009				
Operating revenue	**$ 353**	**$ 1,322**	**$ —**	**$ 1,675**
Net income	**76**	**72**	**1**	**149**
Three Months Ended June 30, 2008				
Operating revenue	$ 357	$ 1,186	$ 3	$ 1,546
Net income (loss)	64	139	(3)	200
Six Months Ended June 30, 2009				
Operating revenue	**$ 733**	**$ 2,801**	**$ —**	**$ 3,534**
Net income (loss)	**166**	**193**	**(6)**	**353**
Six Months Ended June 30, 2008				
Operating revenue	$ 718	$ 2,346	$ 6	$ 3,070
Net income (loss)	143	282	(3)	422

VIRGINIA ELECTRIC AND POWER COMPANY
ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

MD&A discusses our results of operations and general financial condition. MD&A should be read in conjunction with our Consolidated Financial Statements. The terms "Company," "we," "our" and "us" are used throughout this report and, depending on the context of their use, may represent any of the following: the legal entity, Virginia Electric and Power Company, one or more of its consolidated subsidiaries or operating segments, or the entirety of Virginia Electric and Power Company and its consolidated subsidiaries. All of our common stock is owned by our parent company, Dominion.

Contents of MD&A

Our MD&A consists of the following information:

- Forward-Looking Statements
- Accounting Matters
- Results of Operations
- Segment Results of Operations
- Liquidity and Capital Resources
- Future Issues and Other Matters

Forward-Looking Statements

This report contains statements concerning expectations, plans, objectives, future financial performance and other statements that are not historical facts. These statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. In most cases, the reader can identify these forward-looking statements by such words as "anticipate," "estimate," "forecast," "expect," "believe," "should," "could," "plan," "may," "target" or other similar words.

We make forward-looking statements with full knowledge that risks and uncertainties exist that may cause actual results to differ materially from predicted results. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Additionally, other factors may cause actual results to differ materially from those indicated in any forward-looking statement. These factors include but are not limited to:

- Unusual weather conditions and their effect on energy sales to customers and energy commodity prices;
- Extreme weather events, including hurricanes, high winds and severe storms, that can cause outages and property damage to our facilities;
- State and federal legislative and regulatory developments and changes to environmental and other laws and regulations, including those related to climate change, greenhouse gas emissions and other emissions to which we are subject;
- Cost of environmental compliance, including those costs related to climate change;
- Risks associated with the operation of nuclear facilities;
- Fluctuations in energy-related commodity prices and the effect these could have on our liquidity position and the underlying value of our assets;
- Capital market conditions, including the availability of credit and our ability to obtain financing on reasonable terms;
- Risks associated with our membership and participation in PJM related to obligations created by the default of other participants;
- Price risk due to marketable securities held as investments in nuclear decommissioning trusts;
- Fluctuations in interest rates;
- Changes in federal and state tax laws and regulations;
- Changes in rating agency requirements or credit ratings and their effect on availability and cost of capital;
- Changes in financial or regulatory accounting principles or policies imposed by governing bodies;
- Employee workforce factors including collective bargaining agreements and labor negotiations with union employees;
- The risks of operating businesses in regulated industries that are subject to changing regulatory structures;
- Changes to regulated electric rates collected by the Company, including the outcome of our 2009 rate filings;
- Timing and receipt of regulatory approvals necessary for planned construction or expansion projects;
- The inability to complete planned construction or expansion projects within the terms and time frames initially anticipated;
- Changes in rules for the RTO in which we participate, including changes in rate designs and capacity models;

- Political and economic conditions, including the threat of domestic terrorism, inflation and deflation; and
- Adverse outcomes in litigation matters.

Additionally, other factors that could cause actual results to differ from predicted results are set forth in Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2008.

Our forward-looking statements are based on our beliefs and assumptions using information available at the time the statements are made. We caution the reader not to place undue reliance on our forward-looking statements because the assumptions, beliefs, expectations and projections about future events may, and often do, differ materially from actual results. We undertake no obligation to update any forward-looking statement to reflect developments occurring after the statement is made.

Accounting Matters

Critical Accounting Policies and Estimates

As of June 30, 2009, there have been no significant changes with regard to the critical accounting policies and estimates disclosed in MD&A in our Annual Report on Form 10-K for the year ended December 31, 2008, other than the impact of updated nuclear decommissioning cost studies on our AROs as discussed in Note 9 to our Consolidated Financial Statements. The policies disclosed included the accounting for derivative contracts and other instruments at fair value, regulated operations, AROs, unbilled revenue and income taxes.

Results of Operations

Presented below is a summary of our consolidated results:

	Second Quarter			Year-To-Date		
	2009	**2008**	**$ Change**	**2009**	**2008**	**$ Change**
(millions)						
Net income	**$ 149**	$ 200	$ (51)	**$ 353**	$ 422	$ (69)

Overview

Second Quarter and Year-To-Date 2009 vs. 2008

Our net income for the three and six months ended June 30, 2009 was lower than the comparable prior year periods, primarily reflecting a reduced benefit from financial transmission rights (FTRs) reflecting lower fuel prices, an increase in outage costs related to scheduled outages at certain of our generating facilities, and lower gains from sales of emissions allowances.

Analysis of Consolidated Operations

Presented below are selected amounts related to our results of operations:

	Second Quarter			Year-To-Date		
	2009	**2008**	**$ Change**	**2009**	**2008**	**$ Change**
(millions)						
Operating Revenue	**$ 1,675**	$ 1,546	$ 129	**$ 3,534**	$ 3,070	$ 464
Operating Expenses						
Electric fuel and other energy-related purchases	**685**	500	185	**1,479**	997	482
Purchased electric capacity	**104**	97	7	**212**	203	9
Other operations and maintenance	**381**	364	17	**728**	669	59
Depreciation and amortization	**160**	150	10	**317**	299	18
Other taxes	**46**	45	1	**97**	94	3
Other income	**23**	9	14	**32**	18	14
Interest and related charges	**87**	78	9	**174**	157	17
Income tax expense	**86**	121	(35)	**206**	247	(41)

An analysis of our results of operations follows:

Second Quarter 2009 vs. 2008

Operating Revenue increased 8%, primarily reflecting the combined effects of:

- A $198 million increase in fuel revenue primarily due to the impact of a comparatively higher fuel rate in certain customer jurisdictions, including the recovery of previously deferred fuel costs; and
- A $21 million increase due to the impact of a rate adjustment clause associated with the recovery of financing costs for the Virginia City Hybrid Energy Center; partially offset by
- A $54 million decrease in sales to wholesale customers due to decreased volumes ($29 million) and lower prices ($25 million);
- A $17 million decrease in base revenues from sales to retail customers due to an 8% decrease in cooling degree days, partially offset by a 12% increase in heating degree days; and
- A $9 million decrease reflecting the impact of unfavorable economic conditions on customer usage in base revenues and other factors.

Operating Expenses and Other Items

Electric fuel and other energy-related purchases expense increased 37%, primarily reflecting an increase due to a comparatively higher fuel rate in certain customer jurisdictions, including recovery of previously deferred fuel costs ($188 million) and a reduced benefit from FTRs ($38 million), partially offset by a decrease in fuel expenses associated with wholesale customers ($41 million).

Other operations and maintenance expense increased 5%, primarily reflecting:

- A $23 million increase in outage costs related to scheduled outages at certain fossil generating facilities; and
- A $16 million decrease in gains from the sale of emissions allowances; partially offset by
- A $13 million decrease reflecting lower storm damage and service restoration costs associated with our distribution operations; and
- A $12 million decrease due to the deferral of transmission-related expenditures collectible under certain rate adjustment clauses.

Other income increased 156%, primarily due to an increase in net realized gains on investments held in our nuclear decommissioning trusts for jurisdictions that are not subject to cost-based regulation ($4 million), greater charitable contributions in the comparable prior year period ($4 million) and an increase in amounts collectible from customers for taxes in connection with contributions in aid of construction (CIAC) ($3 million).

Interest and related charges increased 12%, largely due to the impact of additional borrowings.

Income tax expense decreased 29%, reflecting lower pre-tax income in 2009.

Year-To-Date 2009 vs. 2008

Operating Revenue increased 15%, primarily reflecting the combined effects of:

- A $500 million increase in fuel revenue primarily due to the impact of a comparatively higher fuel rate in certain customer jurisdictions, including the recovery of previously deferred fuel costs;
- A $53 million increase in base revenues from sales to retail customers due to a 19% increase in heating degree days, partially offset by an 8% decrease in cooling degree days; and
- A $43 million increase due to the impact of a rate adjustment clause associated with the recovery of financing costs for the Virginia City Hybrid Energy Center; partially offset by
- An $84 million decrease in sales to wholesale customers due to lower prices ($48 million) and decreased volumes ($36 million); and
- A $48 million decrease reflecting the impact of unfavorable economic conditions on customer usage in base revenues and other factors.

Operating Expenses and Other Items

Electric fuel and other energy-related purchases expense increased 48%, primarily reflecting an increase due to a comparatively higher fuel rate in certain customer jurisdictions, including recovery of previously deferred fuel costs ($490 million) and a reduced benefit from FTRs ($43 million), partially offset by a decrease in fuel expenses associated with wholesale customers ($51 million).

Other operations and maintenance expense increased 9%, primarily reflecting:

- A $44 million increase in outage costs related to scheduled outages at nuclear and fossil generating facilities; and
- A $27 million decrease in gains from the sale of emissions allowances; partially offset by
- A $17 million decrease due to the deferral of transmission-related expenditures collectible under certain rate adjustment clauses.

Other income increased 78%, primarily due to an increase in the equity component of AFUDC as a result of construction and expansion projects ($8 million) and an increase in amounts collectible from customers for taxes in connection with CIAC ($5 million).

Interest and related charges increased 11%, largely due to the impact of additional borrowings.

Income tax expense decreased 17%, reflecting lower pre-tax income in 2009.

Segment Results of Operations

Presented below is a summary of contributions by our operating segments to net income:

	Second Quarter			Year-To-Date		
(millions)	**2009**	**2008**	**$ Change**	**2009**	**2008**	**$ Change**
DVP	**$ 76**	$ 64	$ 12	**$ 166**	$ 143	$ 23
Generation	**72**	139	(67)	**193**	282	(89)
Primary operating segments	**148**	203	(55)	**359**	425	(66)
Corporate and Other	**1**	(3)	4	**(6)**	(3)	(3)
Consolidated	**$ 149**	$ 200	$ (51)	**$ 353**	$ 422	$ (69)

DVP

Presented below are operating statistics related to our DVP operations:

	Second Quarter			Year-To-Date		
	2009	**2008**	**% Change**	**2009**	**2008**	**% Change**
Electricity delivered (million MWh)	**19.0**	20.0	(5)%	**40.3**	40.8	(1)%
Degree days:						
Cooling(1)	**459**	501	(8)	**463**	504	(8)
Heating(2)	**294**	263	12	**2,457**	2,072	19
Average retail customer accounts (thousands)(3)	**2,401**	2,382	1	**2,400**	2,381	1

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(1) Cooling degree days are units measuring the extent to which the average daily temperature is greater than 65 degrees, and are calculated as the difference between 65 degrees and the average temperature for that day.

(2) Heating degree days are units measuring the extent to which the average daily temperature is less than 65 degrees, and are calculated as the difference between 65 degrees and the average temperature for that day.

(3) Period average.

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Presented below, on an after-tax basis, are the key factors impacting DVP's net income contribution:

(millions)	Second Quarter 2009 vs. 2008 Increase (Decrease)	Year-To-Date 2009 vs. 2008 Increase (Decrease)
Storm damage and service restoration – distribution operations	$ 8	$ 8
Regulated electric sales:		
Weather	(3)	13
Customer growth	1	3
Other(1)	(2)	(9)
Other(2)	8	8
Change in net income contribution	$ 12	$ 23

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(1) Decrease primarily reflects the impact of unfavorable economic conditions on customer usage and other factors.

(2) Primarily reflects the deferral of transmission-related expenditures collectible under certain rate adjustment clauses.

Generation

Presented below are operating statistics related to our Generation operations:

	Second Quarter			Year-To-Date		
	2009	2008	% Change	2009	2008	% Change
Electricity supplied (million MWh)	**19.0**	20.0	(5)%	**40.3**	40.8	(1)%
Degree days:						
Cooling	**459**	501	(8)	**463**	504	(8)
Heating	**294**	263	12	**2,457**	2,072	19

Presented below, on an after-tax basis, are the key factors impacting Generation's net income contribution:

(millions)	Second Quarter 2009 vs. 2008 Increase (Decrease)	Year-To-Date 2009 vs. 2008 Increase (Decrease)
Energy supply margin(1)	$ (17)	$ (20)
Outage costs	(14)	(27)
Sales of emissions allowances	(10)	(16)
Ancillary service revenue	(9)	(13)
Regulated electric sales:		
Weather	(8)	20
Rate adjustment clause(2)	13	27
Customer growth	3	6
Other(3)	(13)	(40)
Depreciation and amortization expense(4)	(4)	(8)
Other	(8)	(18)
Change in net income contribution	$ (67)	$ (89)

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(1) Reflects lower settlement gains on FTRs.

(2) Reflects the impact of a new rate adjustment clause associated with the recovery of financing costs for the Virginia City Hybrid Energy Center.

(3) Decrease reflects the impact of unfavorable economic conditions on customer usage and other factors, as well as lower sales to wholesale customers.

(4) Primarily due to incremental expense resulting from property additions.

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Liquidity and Capital Resources

We depend on both internal and external sources of liquidity to provide working capital and to fund capital requirements. Short-term cash requirements not met by cash provided by operations are generally satisfied with proceeds from short-term borrowings. Long-term cash needs are met through issuances of debt and/or equity securities.

At June 30, 2009, we had $2.2 billion of unused capacity under our joint credit facility.

A summary of our cash flows is presented below:

(millions)	2009	2008
Cash and cash equivalents at January 1,	**$ 27**	$ 49
Cash flows provided by (used in)		
Operating activities	**911**	587
Investing activities	**(1,257)**	(881)
Financing activities	**348**	295
Net increase in cash and cash equivalents	**2**	1
Cash and cash equivalents at June 30,	**$ 29**	$ 50

Operating Cash Flows

For the six months ended June 30, 2009, net cash provided by operating activities increased by $324 million as compared to the six months ended June 30, 2008. The increase is primarily due to a positive impact from deferred fuel cost recoveries in our Virginia jurisdiction due to increased fuel revenue and lower fuel costs, partially offset by higher income tax payments. We believe that our operations provide a stable source of cash flow to contribute to planned levels of capital expenditures and provide dividends to Dominion. However, our operations are subject to risks and uncertainties that may negatively impact the timing or amounts of operating cash flows, which are discussed in Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2008.

Credit Risk

As discussed in Note 13 to our Consolidated Financial Statements, our exposure to potential concentrations of credit risk results primarily from sales to wholesale customers. Presented below is a summary of our gross credit exposure as of June 30, 2009, for these activities. Our gross credit exposure for each counterparty is calculated as outstanding receivables plus any unrealized on or off-balance sheet exposure, taking into account contractual netting rights.

(millions)	Gross Credit Exposure	Credit Collateral	Net Credit Exposure
Investment grade(1)	$ 29	$ 13	$ 16
Non-investment grade(2)	9	—	9
No external ratings:			
Internally rated—investment grade(3)	2	—	2
Internally rated—non-investment grade	—	—	—
Total	$ 40	$ 13	$ 27

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(1) Designations as investment grade are based on minimum credit ratings assigned by Moody's and Standard & Poor's. The five largest counterparty exposures, combined, for this category represented approximately 60% of the total net credit exposure.

(2) The only counterparty exposure for this category represented approximately 32% of the total net credit exposure.

(3) The two largest counterparty exposures, combined, for this category represented approximately 8% of the total net credit exposure.

Investing Cash Flows

For the six months ended June 30, 2009, net cash used in investing activities increased by $376 million as compared to the six months ended June 30, 2008, primarily reflecting an increase in capital expenditures for generation and transmission construction projects, including our Virginia City Hybrid Energy Center.

Financing Cash Flows and Liquidity

We rely on banks and capital markets as significant sources of funding for capital requirements not satisfied by the cash provided by our operations. As discussed in *Credit Ratings and Debt Covenants* , our ability to borrow funds or issue securities and the return demanded by investors are affected by our credit ratings. In addition, the raising of external capital is subject to meeting certain regulatory requirements, including registration with the SEC and approval from the Virginia Commission.

For the six months ended June 30, 2009, net cash provided by financing activities increased by $53 million as compared to the six months ended June 30, 2008, primarily due to higher net debt issuances and a reduction in common dividend payments.

See Note 11 to our Consolidated Financial Statements for further information regarding our credit facilities, liquidity and significant financing transactions. Also, see Note 14 to our Consolidated Financial Statements for further information regarding our borrowings from Dominion.

Credit Ratings and Debt Covenants

Credit ratings are intended to provide banks and capital market participants with a framework for comparing the credit quality of securities and are not a recommendation to buy, sell or hold securities. In the *Credit Ratings* and *Debt Covenants* sections of MD&A in our Annual Report on Form 10-K for the year ended December 31, 2008, we discussed the use of capital markets and the impact of credit ratings on the accessibility and costs of using these markets, as well as various covenants present in the enabling agreements underlying our debt. As of June 30, 2009, there have been no changes in our credit ratings, nor have there been any changes to or events of default under our debt covenants. In April 2009, Moody’s revised its credit ratings outlook for the Company to positive from stable.

Future Cash Payments for Contractual Obligations and Planned Capital Expenditures

As of June 30, 2009, there have been no material changes outside the ordinary course of business to our contractual obligations nor any material changes to our planned capital expenditures disclosed in MD&A in our Annual Report on Form 10-K for the year ended December 31, 2008.

Future Issues and Other Matters

The following discussion of future issues and other information includes current developments of previously disclosed matters and new issues arising during the period covered by and subsequent to our Consolidated Financial Statements. This section should be read in conjunction with Item 1. Business and Future Issues and Other Matters in MD&A in our Annual Report on Form 10-K for the year ended December 31, 2008 and Future Issues and Other Matters in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2009. In addition, see Note 12 to our Consolidated Financial Statements and Part II, Item 1. Legal Proceedings for additional information on various environmental, regulatory, legal and other matters that may impact our future results of operations and/or financial condition, including a discussion of electric regulation in Virginia.

North Anna Power Station

In January 2008, the Nuclear Regulatory Commission (NRC) accepted and deemed complete our application for a Combined Construction Permit and Operating License (COL) that references a specific reactor design and which would allow us to build and operate a new nuclear unit at North Anna. In December 2008, we terminated a long-lead agreement with our vendor with respect to the reactor design identified in our COL application and certain related equipment. In March 2009, we commenced a competitive process to determine if vendors can provide an advanced technology reactor that could be licensed and built under terms acceptable to us. If, as a result of this process, we choose a different reactor design, we will amend our COL application, as necessary. We have not yet committed to building a new nuclear unit.

In May 2009, the Department of Energy (DOE) announced the names of four energy companies that have been selected to begin negotiations for federal loan guarantees for proposed new nuclear units in the U.S. Although, in a two-part process, we submitted an application for a federal loan guarantee for the proposed North Anna unit, the Company was not among those selected. While we can provide no assurance, because of the dynamic nature of the market for new nuclear units, there may be other opportunities to secure a loan guarantee with the DOE.

Environmental Matters

We are subject to costs resulting from a number of federal, state and local laws and regulations designed to protect human health and the environment. These laws and regulations affect future planning and existing operations. They can result in increased capital, operating and other costs as a result of compliance, remediation, containment and monitoring obligations.

Clean Water Act Compliance

In October 2007, the Virginia State Water Control Board (Water Board) issued a renewed water discharge (VPDES) permit for North Anna. The Blue Ridge Environmental Defense League, and other persons, appealed the Water Board's decision to the Richmond Circuit Court, challenging several permit provisions related to North Anna's discharge of cooling water. In February 2009, the court ruled that the Water Board was required to regulate the thermal discharge from North Anna into the waste heat treatment facility. We filed a motion for reconsideration with the court in February 2009, which was denied. We intend to appeal the court's decision and ask for a stay of the court's order. A final order is expected to be issued by the end of August 2009. It is expected that the order will allow North Anna to continue to operate pursuant to the currently issued VPDES permit. Until the final permit is reissued, it is not possible to predict any financial impact that may result.

Global Climate Change

In June 2009, the U.S. House of Representatives passed comprehensive legislation titled the "American Clean Energy and Security Act of 2009" to encourage the development of clean energy sources and reduce greenhouse gas (GHG) emissions. The legislation contains provisions establishing federal renewable energy standards for electric suppliers. The legislation also includes cap-and-trade provisions for the reduction of GHG emissions. Similar legislation is currently being considered in the U.S. Senate. The cost of compliance with future GHG emission reduction programs could be significant. Given the highly uncertain outcome and timing of future action by the U.S. federal government and states on this issue, we cannot predict the financial impact of future GHG emission reduction programs on our operations, shareholders or customers at this time.

VIRGINIA ELECTRIC AND POWER COMPANY
ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The matters discussed in this Item may contain "forward-looking statements" as described in the introductory paragraphs under Part I, Item 2. MD&A of this Form 10-Q. The reader's attention is directed to those paragraphs and Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2008 for discussion of various risks and uncertainties that may impact the Company.

Market Risk Sensitive Instruments and Risk Management

Our financial instruments, commodity contracts and related financial derivative instruments are exposed to potential losses due to adverse changes in commodity prices, interest rates and equity security prices as described below. Commodity price risk is due to our exposure to market shifts for prices paid for commodities. Interest rate risk is generally related to our outstanding debt and expected debt issuances. In addition, we are exposed to investment price risk through various portfolios of debt and equity securities.

The following sensitivity analysis estimates the potential loss of future earnings or fair value from market risk sensitive instruments over a selected time period due to a 10% unfavorable change in commodity prices and interest rates.

Commodity Price Risk

To manage price risk, we hold commodity-based financial derivative instruments for non-trading purposes associated with purchases of electricity, natural gas and other energy-related products. The derivatives used to manage our commodity price risk are executed within established policies and procedures and may include instruments such as futures, forwards, swaps, options and FTRs that are sensitive to changes in the related commodity prices. For sensitivity analysis purposes, the hypothetical change in market prices of commodity-based financial derivative instruments is determined based on models that consider the market prices of commodities in future periods, the volatility of the market prices in each period, as well as the time value factors of the derivative instruments. Prices and volatility are principally determined based on observable market prices.

A hypothetical 10% unfavorable change in commodity prices would have resulted in a decrease of approximately $2 million and $23 million in the fair value of our non-trading commodity-based financial derivatives as of June 30, 2009 and December 31, 2008, respectively. The decline in sensitivity is largely due to a decrease in commodity prices.

The impact of a change in energy commodity prices on our non-trading commodity-based financial derivative instruments at a point in time is not necessarily representative of the results that will be realized when such contracts are ultimately settled. For example, our expenses for power purchases, when combined with the settlement of commodity derivative instruments used for hedging purposes, will generally result in a range of prices for those purchases contemplated by the risk management strategy.

Interest Rate Risk

We manage our interest rate risk exposure predominantly by maintaining a balance of fixed and variable rate debt. We may also enter into interest-rate swaps when deemed appropriate to adjust our exposure based upon market conditions. At June 30, 2009 and December 31, 2008, a hypothetical 10% increase in market interest rates would have resulted in a decrease in annual earnings of approximately $1 million and $2 million, respectively.

Additionally, we may use forward-starting interest-rate swaps and treasury rate locks as anticipatory hedges of future financings. At June 30, 2009, we had $850 million in aggregate notional amounts of these interest-rate derivatives outstanding. A hypothetical 10% decrease in market interest rates would have resulted in a decrease of approximately $30 million in the fair value of these interest-rate derivatives at June 30, 2009. We did not have a significant amount of these interest-rate derivatives outstanding at December 31, 2008.

The impact of a change in market interest rates on these anticipatory hedges at a point in time is not necessarily representative of the results that will be realized when such contracts are settled. Net losses from interest-rate derivatives used for anticipatory hedging purposes, to the extent realized, will generally be amortized over the life of the respective debt issuance being hedged.

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Investment Price Risk

We are subject to investment price risk due to securities held as investments in decommissioning trust funds that are managed by third-party investment managers. These trust funds primarily hold marketable securities that are reported in our Consolidated Balance Sheets at fair value.

We recognized net realized losses (net of investment income) on nuclear decommissioning trust investments of $53 million, $9 million and $57 million for the six months ended June 30, 2009 and 2008 and for the year ended December 31, 2008, respectively. Net realized losses include gains and losses from the sale of investments as well as other-than-temporary impairments recognized in earnings. For the six months ended June 30, 2009, we recorded, in AOCI and regulatory liabilities, a net increase in unrealized gains on these investments of $72 million. For the six months ended June 30, 2008 and for the year ended December 31, 2008, we recorded, in AOCI and regulatory liabilities, a reduction in unrealized gains on these investments of $91 million and $233 million, respectively.

Dominion sponsors employee pension and other postretirement benefit plans, in which our employees participate, that hold investments in trusts to fund benefit payments. Investment-related declines in these trusts will result in future increases in the periodic cost recognized for such employee benefit plans and will be included in the determination of the amount of cash that we will provide to Dominion for our share of employee benefit plan contributions.

ITEM 4. CONTROLS AND PROCEDURES

Senior management, including our CEO and CFO, evaluated the effectiveness of our disclosure controls and procedures as of the end of the period covered by this report. Based on this evaluation process, the CEO and CFO have concluded that our disclosure controls and procedures are effective.

There were no changes in our internal control over financial reporting that occurred during the last fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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VIRGINIA ELECTRIC AND POWER COMPANY
PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

From time to time, we are alleged to be in violation or in default under orders, statutes, rules or regulations relating to the environment, compliance plans imposed upon or agreed to by us, or permits issued by various local, state and federal agencies for the construction or operation of facilities. Administrative proceedings may also be pending on these matters. In addition, in the ordinary course of business, we are involved in various legal proceedings. We believe that the ultimate resolution of these proceedings will not have a material adverse effect on our financial position, liquidity or results of operations. See *Future Issues and Other Matters* in MD&A and Note 12 to our Consolidated Financial Statements for discussions on various environmental, rate matters and other regulatory proceedings to which we are a party.

ITEM 1A. RISK FACTORS

Our business is influenced by many factors that are difficult to predict, involve uncertainties that may materially affect actual results and are often beyond our control. We have identified a number of these risk factors in our Annual Report on Form 10-K for the year ended December 31, 2008, which should be taken into consideration when reviewing the information contained in this report. There have been no material changes with regard to the risk factors previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2008. For other factors that may cause actual results to differ materially from those indicated in any forward-looking statement or projection contained in this report, see *Forward-Looking Statements* in MD&A.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

On April 24, 2009, by consent in lieu of the annual meeting, Dominion Resources, Inc., the sole holder of all the voting common stock of the Company, unanimously elected the following persons to serve as Directors: Thomas F. Farrell, II, Chairman of the Board, Thomas N. Chewning and Steven A. Rogers. On June 1, 2009, by consent in lieu of a special meeting, Dominion Resources, Inc., the sole holder of all the voting common stock of the Company, unanimously elected Mark F. McGettrick to serve as a Director, due to the retirement of Thomas N. Chewning. The names of the other Directors whose term of office continued after the meeting are: Thomas F. Farrell, II, Chairman of the Board and Steven A. Rogers.

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ITEM 6. EXHIBITS

(a) Exhibits:

3.1	Restated Articles of Incorporation, as in effect on October 28, 2003 (Exhibit 3.1, Form 10-Q for the quarter ended September 30, 2003, File No. 1-2255, incorporated by reference).
3.2	Bylaws, as amended and restated on June 1, 2009 (Exhibit 3.1, Form 8-K filed June 3, 2009, File No. 1-2255, incorporated by reference).
4.1	Form of Senior Indenture, dated as of June 1, 1998, between Virginia Electric and Power Company and The Bank of New York (as successor trustee to JP Morgan Chase Bank (formerly The Chase Manhattan Bank)) as supplemented by the First Supplemental Indenture (Exhibit 4.2, Form 8-K filed June 12, 1998, File No. 1-2255, incorporated by reference); Second Supplemental Indenture (Exhibit 4.2, Form 8-K filed June 4, 1999, File No. 1-2255, incorporated by reference); Third Supplemental Indenture (Exhibit 4.2, Form 8-K filed October 27, 1999, File No. 1-2255, incorporated by reference); Form of Fourth Supplemental Indenture (Exhibit 4.2, Form 8-K filed March 26, 2001, File No. 1-2255, incorporated by reference); Form of Fifth Supplemental Indenture (Exhibit 4.3, Form 8-K filed March 26, 2001, File No. 1-2255, incorporated by reference); Form of Sixth Supplemental Indenture (Exhibit 4.2, Form 8-K filed January 29, 2002, File No. 1-2255, incorporated by reference); Seventh Supplemental Indenture (Exhibit 4.4, Form 8-K filed September 11, 2002, File No. 1-2255, incorporated by reference); Form of Eighth Supplemental Indenture (Exhibit 4.2, Form 8-K filed February 27, 2003, File No. 1-2255, incorporated by reference); Form of Ninth Supplemental Indenture (Exhibit 4.2, Form 8-K filed December 4, 2003, File No. 1-2255, incorporated by reference); Form of Tenth Supplemental Indenture (Exhibit 4.3, Form 8-K filed December 4, 2003, File No. 1-2255, incorporated by reference); Form of Eleventh Supplemental Indenture (Exhibit 4.2, Form 8-K filed December 11, 2003, File No. 1-2255, incorporated by reference); Form of Twelfth Supplemental Indenture (Exhibit 4.2, Form 8-K filed January 12, 2006, File No. 1-2255, incorporated by reference); Form of Thirteenth Supplemental Indenture (Exhibit 4.3, Form 8-K filed January 12, 2006, File No. 1-2255, incorporated by reference); Form of Fourteenth Supplemental Indenture (Exhibit 4.2, Form 8-K filed May 16, 2007, File No. 1-2255, incorporated by reference); Form of Fifteenth Supplemental Indenture (Exhibit 4.2, Form 8-K filed September 10, 2007, File No. 1-2255, incorporated by reference); Form of Sixteenth Supplemental Indenture (Exhibit 4.2, Form 8-K filed November 30, 2007, File No. 1-2255, incorporated by reference); Form of Seventeenth Supplemental Indenture (Exhibit 4.3, Form 8-K filed November 30, 2007, File No. 1-2255, incorporated by reference); Form of Eighteenth Supplemental Indenture (Exhibit 4.2, Form 8-K filed April 15, 2008, File No. 1-2255, incorporated by reference); Nineteenth Supplemental Indenture (Exhibit 4.2, Form 8-K filed November 5, 2008, File No. 1-2255, incorporated by reference); Form of Twentieth Supplemental Indenture (Exhibit 4.3, Form 8-K filed June 24, 2009, File No. 1-2255, incorporated by reference).
10.1*	Dominion Resources, Inc. 2005 Incentive Compensation Plan, Originally Effective May 1, 2005, as Amended and Restated Effective May 5, 2009 (Exhibit 10, Form 8-K filed by Dominion Resources, Inc. on May 11, 2009, File No. 1-8489, incorporated by reference).
12.1	Ratio of earnings to fixed charges (filed herewith).
12.2	Ratio of earnings to fixed charges and preferred dividends (filed herewith).
31.1	Certification by Registrant’s CEO pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
31.2	Certification by Registrant’s CFO pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
32	Certification to the SEC by Registrant’s CEO and CFO, as required by Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).
99	Condensed consolidated earnings statements (unaudited) (filed herewith).

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* Indicates management contract or compensatory plan or agreement.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

VIRGINIA ELECTRIC AND POWER COMPANY
Registrant

July 31, 2009

/s/ Ashwini Sawhney
Ashwini Sawhney
Vice President and Controller
(Chief Accounting Officer)

EXHIBIT INDEX

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12.1 Ratio of earnings to fixed charges (filed herewith).

12.2 Ratio of earnings to fixed charges and preferred dividends (filed herewith).

31.1 Certification by Registrant’s CEO pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).

31.2 Certification by Registrant’s CFO pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).

32 Certification to the SEC by Registrant’s CEO and CFO, as required by Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).

99 Condensed consolidated earnings statements (unaudited) (filed herewith).

Exhibit 12.1

Virginia Electric and Power Company
Computation of Ratio of Earnings to Fixed Charges
(millions of dollars)

	Six Months Ended June 30, 2009	Twelve Months Ended June 30, 2009	Years Ended December 31,				
			2008	2007	2006	2005	2004
Earnings, as defined:							
Income from continuing operations before income taxes, extraordinary item and cumulative effect of change in accounting principle	$ 559	$ 1,254	$ 1,364	$ 977	$ 762	$ 754	$ 929
Fixed charges as defined	192	361	343	332	322	339	265
Capitalized interest	—	—	—	(4)	(9)	(6)	(7)
Total earnings, as defined	$ 751	$ 1,615	$ 1,707	$ 1,305	$ 1,075	$ 1,087	$ 1,187
Fixed charges, as defined:							
Interest charges	$ 185	$ 347	$ 330	$ 320	$ 311	$ 329	$ 256
Rental interest factor	7	14	13	12	11	10	9
Total fixed charges, as defined	$ 192	$ 361	$ 343	$ 332	$ 322	$ 339	$ 265
Ratio of Earnings to Fixed Charges	**3.91**	**4.47**	**4.98**	**3.93**	**3.34**	**3.21**	**4.48**

Exhibit 12.2

Virginia Electric and Power Company
Computation of Ratio of Earnings to Fixed Charges and Preferred Dividends
(millions of dollars)

	Six Months Ended June 30, 2009	Twelve Months Ended June 30, 2009	Years Ended December 31, 2008	2007	2006	2005	2004
Earnings, as defined:							
Income from continuing operations before income taxes, extraordinary item and cumulative effect of change in accounting principle	$ 559	$ 1,254	$ 1,364	$ 977	$ 762	$ 754	$ 929
Fixed charges as defined	205	387	369	357	347	364	290
Capitalized interest	—	—	—	(4)	(9)	(6)	(7)
Preference security dividend requirement	(13)	(26)	(26)	(25)	(25)	(25)	(25)
Total earnings, as defined	$ 751	$ 1,615	$ 1,707	$ 1,305	$ 1,075	$ 1,087	$ 1,187
Fixed charges, as defined:							
Interest charges	$ 185	$ 347	$ 330	$ 320	$ 311	$ 329	$ 256
Preference security dividend requirement	13	26	26	25	25	25	25
Rental interest factor	7	14	13	12	11	10	9
Total fixed charges, as defined	$ 205	$ 387	$ 369	$ 357	$ 347	$ 364	$ 290
Ratio of Earnings to Fixed Charges and Preferred Dividends	**3.66**	**4.17**	**4.63**	**3.66**	**3.10**	**2.99**	**4.09**

Exhibit 31.1

I, Thomas F. Farrell, II, certify that:

1. I have reviewed this report on Form 10-Q of Virginia Electric and Power Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: July 31, 2009

/s/ Thomas F. Farrell, II
Thomas F. Farrell, II
Chief Executive Officer

Exhibit 31.2

I, Mark F. McGettrick, certify that:

1. I have reviewed this report on Form 10-Q of Virginia Electric and Power Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 31, 2009

/s/ Mark F. McGettrick
Mark F. McGettrick
Executive Vice President and Chief Financial Officer

Exhibit 32

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, each of the undersigned officers of Virginia Electric and Power Company (the Company), certify that:

1. the Quarterly Report on Form 10-Q for the quarter ended June 30, 2009 (the "Report") of the Company to which this certification is an exhibit fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934 (15 U.S.C. 78m(a) or 78o(d)).

2. the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company as of June 30, 2009 and for the period then ended.

/s/ Thomas F. Farrell, II
Thomas F. Farrell, II
Chief Executive Officer
July 31, 2009

/s/ Mark F. McGettrick
Mark F. McGettrick
Executive Vice President and Chief Financial Officer
July 31, 2009

VIRGINIA ELECTRIC AND POWER COMPANY

CONDENSED CONSOLIDATED EARNINGS STATEMENT
(Unaudited)

(millions)	Twelve Months Ended June 30, 2009
Operating Revenue	$ 7,398
Operating Expenses	5,884
Income from operations	1,514
Other income	65
Interest and related charges	326
Income before income tax expense	1,253
Income tax expense	459
Net Income	**794**
Preferred dividends	17
Balance available for common stock	$ 777

Attachment 7 – PSE&G Formula Rate for January 1, 2010 to December 31, 2010

Public Service Electric and Gas Company

ATTACHMENT H-10A

	Formula Rate -- Appendix A	**Notes**	**FERC Form 1 Page # or Instruction**	**12 Months Ended 12/31/2010**
	Shaded cells are input cells			
	Allocators			
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense	(Note O)	Attachment 5	15,696,251
2	Total Wages Expense	(Note O)	Attachment 5	170,066,699
3	Less A&G Wages Expense	(Note O)	Attachment 5	11,575,685
4	Total Wages Less A&G Wages Expense		(Line 2 - Line 3)	158,491,014
5	**Wages & Salary Allocator**		(Line 1 / Line 4)	**9.9036%**
	Plant Allocation Factors			
6	Electric Plant in Service	(Note B)	Attachment 5	8,336,665,448
7	Common Plant in Service - Electric		(Line 22)	116,795,499
8	Total Plant in Service		(Line 6 + 7)	8,453,460,946
9	Accumulated Depreciation (Total Electric Plant)	(Note B & J)	Attachment 5	2,655,840,955
10	Accumulated Intangible Amortization - Electric	(Note B)	Attachment 5	7,064
11	Accumulated Common Plant Depreciation & Amortization - Electric	(Note B & J)	Attachment 5	33,229,278
12	Accumulated Common Amortization - Electric	(Note B)	Attachment 5	0
13	Total Accumulated Depreciation		(Line 9 + Line 10 + Line 11 + Line 12)	2,689,077,298
14	Net Plant		(Line 8 - Line 13)	5,764,383,649
15	Transmission Gross Plant		(Line 31)	2,020,322,379
16	**Gross Plant Allocator**		(Line 15 / Line 8)	**23.8994%**
17	Transmission Net Plant		(Line 43)	1,275,640,358
18	**Net Plant Allocator**		(Line 17 / Line 14)	**22.1297%**
	Plant Calculations			
	Plant In Service			
19	Transmission Plant In Service	(Note B)	Attachment 5	1,973,845,213
20	General	(Note B)	Attachment 5	230,325,363
21	Intangible - Electric	(Note B)	Attachment 5	34,473
22	Common Plant - Electric	(Note B)	Attachment 5	116,795,499
23	Total General, Intangible & Common Plant		(Line 20 + Line 21 + Line 22)	347,155,334
24	Less: General Plant Account 397 -- Communications	(Note B)	Attachment 5	31,433,904
25	Less: Common Plant Account 397 -- Communications	(Note B)	Attachment 5	14,283,433
26	General and Intangible Excluding Acct. 397		(Line 23 - Line 24 - Line 25)	301,437,997
27	Wage & Salary Allocator		(Line 5)	9.9036%
28	General and Intangible Plant Allocated to Transmission		(Line 26 * Line 27)	29,853,090
29	Account No. 397 Directly Assigned to Transmission	(Note B)	Attachment 5	16,624,076
30	Total General and Intangible Functionalized to Transmission		(Line 28 + Line 29)	46,477,166
31	**Total Plant In Rate Base**		(Line 19 + Line 30)	**2,020,322,379**
	Accumulated Depreciation			
32	Transmission Accumulated Depreciation	(Note B & J)	Attachment 5	727,556,076
33	Accumulated General Depreciation	(Note B & J)	Attachment 5	98,706,367
34	Accumulated Common Plant Depreciation - Electric	(Note B & J)	Attachment 5	33,229,278
35	Less: Amount of General Depreciation Associated with Acct. 397	(Note B & J)	Attachment 5	25,054,849
36	Balance of Accumulated General Depreciation		(Line 33 + Line 34 - Line 35)	106,880,797
37	Accumulated Intangible Amortization - Electric	(Note B)	(Line 10)	7,064
38	Accumulated General and Intangible Depreciation Ex. Acct. 397		(Line 36 + 37)	106,887,860
39	Wage & Salary Allocator		(Line 5)	9.9036%
40	Subtotal General and Intangible Accum. Depreciation Allocated to Transmission		(Line 38 * Line 39)	10,585,702
41	Accumulated General Depreciation Associated with Acct. 397 Directly Assigned to Transmission	(Note B & J)	Attachment 5	6,540,242
42	**Total Accumulated Depreciation**		(Lines 32 + 40 + 41)	**744,682,021**
43	**Total Net Property, Plant & Equipment**		(Line 31 - Line 42)	**1,275,640,358**

Public Service Electric and Gas Company

ATTACHMENT H-10A

	Formula Rate -- Appendix A	Notes	FERC Form 1 Page # or Instruction	12 Months Ended 12/31/2010
	Shaded cells are input cells			
	Adjustment To Rate Base			
	Accumulated Deferred Income Taxes			
44	**ADIT net of FASB 106 and 109**	(Note Q)	Attachment 1	-188,435,121
	CWIP for Incentive Transmission Projects			
45	CWIP Balances for Current Rate Year	(Note B & H)	Attachment 6	91,311,242
46	**Plant Held for Future Use**	(Note C & Q)	Attachment 5	4,096,903
	Prepayments			
47	Prepayments	(Note A & Q)	Attachment 5	874,374
	Materials and Supplies			
48	Undistributed Stores Expense	(Note Q)	Attachment 5	0
49	Wage & Salary Allocator		(Line 5)	9.9036%
50	Total Undistributed Stores Expense Allocated to Transmission		(Line 48 * Line 49)	0
51	Transmission Materials & Supplies	(Note N & Q))	Attachment 5	3,480,728
52	Total Materials & Supplies Allocated to Transmission		(Line 50 + Line 51)	3,480,728
	Cash Working Capital			
53	Operation & Maintenance Expense		(Line 80)	70,852,406
54	1/8th Rule		1/8	12.5%
55	Total Cash Working Capital Allocated to Transmission		(Line 53 * Line 54)	8,856,551
	Network Credits			
56	Outstanding Network Credits	(Note N & Q))	Attachment 5	0
57	**Total Adjustment to Rate Base**		(Lines 44 + 45 + 46 + 47 + 52 + 55 - 56)	**-79,815,322**
58	**Rate Base**		(Line 43 + Line 57)	**1,195,825,036**
	Operations & Maintenance Expense			
	Transmission O&M			
59	Transmission O&M	(Note O)	Attachment 5	45,589,226
60	Plus Transmission Lease Payments	(Note O)	Attachment 5	0
61	**Transmission O&M**		(Lines 59 + 60)	**45,589,226**
	Allocated Administrative & General Expenses			
62	Total A&G	(Note O)	Attachment 5	257,502,133
63	Plus: Fixed PBOP expense	(Note J)	Attachment 5	77,745,482
64	Less: Actual PBOP expense	(Note O)	Attachment 5	74,972,711
65	Less Property Insurance Account 924	(Note O)	Attachment 5	1,170,000
66	Less Regulatory Commission Exp Account 928	(Note E & O)	Attachment 5	12,832,629
67	Less General Advertising Exp Account 930.1	(Note O)	Attachment 5	3,279,688
68	Less EPRI Dues	(Note D & O)	Attachment 5	0
69	**Administrative & General Expenses**		Sum (Lines 62 to 63) - Sum (Lines 64 to 68)	242,992,587
70	Wage & Salary Allocator		(Line 5)	9.9036%
71	**Administrative & General Expenses Allocated to Transmission**		(Line 69 * Line 70)	**24,064,914**
	Directly Assigned A&G			
72	Regulatory Commission Exp Account 928	(Note G & O)	Attachment 5	939,349
73	General Advertising Exp Account 930.1	(Note K & O)	Attachment 5	0
74	Subtotal - Accounts 928 and 930.1 - Transmission Related		(Line 72 + Line 73)	939,349
75	Property Insurance Account 924		(Line 65)	1,170,000
76	General Advertising Exp Account 930.1	(Note F & O)	Attachment 5	0
77	Total Accounts 928 and 930.1 - General		(Line 75 + Line 76)	1,170,000
78	Net Plant Allocator		(Line 18)	22.1297%
79	**A&G Directly Assigned to Transmission**		(Line 77 * Line 78)	**258,917**
80	**Total Transmission O&M**		**(Lines 61 + 71 + 74 + 79)**	**70,852,406**

Public Service Electric and Gas Company

ATTACHMENT H-10A

	Formula Rate -- Appendix A		Notes	FERC Form 1 Page # or Instruction	12 Months Ended 12/31/2010
	Shaded cells are input cells				
	Depreciation & Amortization Expense				
	Depreciation Expense				
81	Transmission Depreciation Expense Including Amortization of Limited Term Plant		(Note J & O)	Attachment 5	45,499,229
82	General Depreciation Expense Including Amortization of Limited Term Plant		(Note J & O)	Attachment 5	27,533,975
83	Less: Amount of General Depreciation Expense Associated with Acct. 397		(Note J & O)	Attachment 5	3,714,034
84	Balance of General Depreciation Expense			(Line 82 - Line 83)	23,819,941
85	Intangible Amortization		(Note A & O)	Attachment 5	4,356,652
86	Total			(Line 84 + Line 85)	28,176,593
87	Wage & Salary Allocator			(Line 5)	9.9036%
88	General Depreciation & Intangible Amortization Allocated to Transmission			(Line 86 * Line 87)	2,790,485
89	General Depreciation Expense for Acct. 397 Directly Assigned to Transmission		(Note J & O)	Attachment 5	1,662,408
90	**General Depreciation and Intangible Amortization Functionalized to Transmission**			(Line 88 + Line 89)	**4,452,893**
91	**Total Transmission Depreciation & Amortization**			**(Lines 81 + 90)**	**49,952,122**
	Taxes Other than Income Taxes				
92	Taxes Other than Income Taxes		(Note O)	Attachment 2	9,634,702
93	**Total Taxes Other than Income Taxes**			(Line 92)	**9,634,702**
	Return \ Capitalization Calculations				
94	**Long Term Interest**			p117.62.c through 67.c	193,848,362
95	**Preferred Dividends**		enter positive	p118.29.d	3,987,876
	Common Stock				
96	Proprietary Capital		(Note P)	Attachment 5	3,549,490,730
97	Less Accumulated Other Comprehensive Income Account 219		(Note P)	Attachment 5	2,220,567
98	Less Preferred Stock			(Line 106)	79,523,400
99	Less Account 216.1		(Note P)	Attachment 5	4,006,682
100	**Common Stock**			(Line 96 - 97 - 98 - 99)	3,463,740,081
	Capitalization				
101	Long Term Debt		(Note P)	Attachment 5	3,438,111,677
102	Less Loss on Reacquired Debt		(Note P)	Attachment 5	95,892,748
103	Plus Gain on Reacquired Debt		(Note P)	Attachment 5	0
104	Less ADIT associated with Gain or Loss		(Note P)	Attachment 5	33,905,934
105	Total Long Term Debt			(Line 101 - 102 + 103 - 104)	3,308,312,995
106	Preferred Stock		(Note P)	Attachment 5	79,523,400
107	Common Stock			(Line 100)	3,463,740,081
108	**Total Capitalization**			(Sum Lines 105 to 107)	6,851,576,476
109	Debt %	Total Long Term Debt		(Line 105 / Line 108)	48.29%
110	Preferred %	Preferred Stock		(Line 106 / Line 108)	1.16%
111	Common %	Common Stock		(Line 107 / Line 108)	50.55%
112	Debt Cost	Total Long Term Debt		(Line 94 / Line 105)	0.0586
113	Preferred Cost	Preferred Stock		(Line 95 / Line 106)	0.0501
114	Common Cost	Common Stock	(Note J)	Fixed	0.1168
115	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Line 109 * Line 112)	0.0283
116	Weighted Cost of Preferred	Preferred Stock		(Line 110 * Line 113)	0.0006
117	Weighted Cost of Common	Common Stock		(Line 111 * Line 114)	0.0590
118	**Rate of Return on Rate Base (ROR)**			(Sum Lines 115 to 117)	**0.0879**
119	**Investment Return = Rate Base * Rate of Return**			**(Line 58 * Line 118)**	**105,138,765**

Public Service Electric and Gas Company

ATTACHMENT H-10A

	Formula Rate -- Appendix A		Notes	FERC Form 1 Page # or Instruction	12 Months Ended 12/31/2010
	Shaded cells are input cells				
	Composite Income Taxes				
	Income Tax Rates				
120	FIT=Federal Income Tax Rate		(Note I)		35.00%
121	SIT=State Income Tax Rate or Composite				9.00%
122	p	(percent of federal income tax deductible for state purposes)		Per State Tax Code	0.00%
123	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			40.85%
124	T / (1-T)				69.06%
	ITC Adjustment				
125	Amortized Investment Tax Credit	enter negative	(Note O)	Attachment 5	-1,198,000
126	1/(1-T)			1 / (1 - Line 123)	169.06%
127	Net Plant Allocation Factor			(Line 18)	22.1297%
128	**ITC Adjustment Allocated to Transmission**			(Line 125 * Line 126 * Line 127)	**-448,206**
129	**Income Tax Component =**	(T/1-T) * Investment Return * (1-(WCLTD/ROR)) =		[Line 124 * Line 119 * (1- (Line 115 / Line 118))]	**49,245,046**
130	**Total Income Taxes**			**(Line 128 + Line 129)**	**48,796,840**
	Revenue Requirement				
	Summary				
131	Net Property, Plant & Equipment			(Line 43)	1,275,640,358
132	Total Adjustment to Rate Base			(Line 57)	-79,815,322
133	**Rate Base**			(Line 58)	**1,195,825,036**
134	Total Transmission O&M			(Line 80)	70,852,406
135	Total Transmission Depreciation & Amortization			(Line 91)	49,952,122
136	Taxes Other than Income			(Line 93)	9,634,702
137	Investment Return			(Line 119)	105,138,765
138	Income Taxes			(Line 130)	48,796,840
139	**Gross Revenue Requirement**			**(Sum Lines 134 to 138)**	**284,374,836**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
140	Transmission Plant In Service			(Line 19)	1,973,845,213
141	Excluded Transmission Facilities		(Note B & M)	Attachment 5	0
142	Included Transmission Facilities			(Line 140 - Line 141)	1,973,845,213
143	Inclusion Ratio			(Line 142 / Line 140)	100.00%
144	Gross Revenue Requirement			(Line 139)	284,374,836
145	**Adjusted Gross Revenue Requirement**			(Line 143 * Line 144)	**284,374,836**
	Revenue Credits & Interest on Network Credits				
146	**Revenue Credits**		(Note O)	Attachment 3	30,529,264
147	**Interest on Network Credits**		(Note N & O)	Attachment 5	0
148	**Net Revenue Requirement**			**(Line 145 - Line 146 + Line 147)**	**253,845,573**
	Net Plant Carrying Charge				
149	Gross Revenue Requirement			(Line 144)	**284,374,836**
150	Net Transmission Plant			(Line 19 - Line 32)	**1,246,289,137**
151	Net Plant Carrying Charge			(Line 149 / Line 150)	**22.8177%**
152	Net Plant Carrying Charge without Depreciation			(Line 149 - Line 81) / Line 150	**19.1669%**
153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes			(Line 149 - Line 81 - Line 119 - Line 130) / Line 150	**6.8154%**
	Net Plant Carrying Charge Calculation per 100 Basis Point increase in ROE				
154	Gross Revenue Requirement Less Return and Taxes			(Line 144 - Line 137 - Line 138)	**130,439,230**
155	Increased Return and Taxes			Attachment 4	**164,156,001**
156	Net Revenue Requirement per 100 Basis Point increase in ROE			(Line 154 + Line 155)	**294,595,231**
157	Net Transmission Plant			(Line 19 - Line 32)	**1,246,289,137**
158	Net Plant Carrying Charge per 100 Basis Point increase in ROE			(Line 156 / Line 157)	**23.6378%**
159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation			(Line 156 - Line 81) / Line 157	**19.9870%**
160	**Net Revenue Requirement**			(Line 148)	**253,845,573**
161	True-up amount			Attachment 6	**-3,716,600**
162	Plus any increased ROE calculated on Attachment 7 other than PJM Sch. 12 projects not paid by other PJM transmission zones			Attachment 7	**936,016**
163	Facility Credits under Section 30.9 of the PJM OATT			Attachment 5	**0**
164	**Net Zonal Revenue Requirement**			(Line 160 + 161 + 162 + 163)	**251,064,988**
	Network Zonal Service Rate				
165	1 CP Peak		(Note L)	Attachment 5	**9,686.7**
166	Rate ($/MW-Year)			(Line 164 / 165)	**25,919**
167	**Network Service Rate ($/MW/Year)**			**(Line 166)**	**25,919**

Shaded cells are input cells

Notes

A Electric portion only
B Calculated using 13-month average balances.
C Includes Transmission portion only. At each annual informational filing, Company will identify for each parcel of land an intended use within a 15 year period.
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 351.h.
H CWIP can only be included 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.
J ROE will be supported in the original filing and 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 8 are fixed until changed as the result of a filing at FERC.
If book depreciation rates are different than the Attachment 8 rates, PSE&G will provide workpapers at the annual update to reconcile formula depreciation expense and depreciation accruals to FERC Form 1 amounts.
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; 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 Outstanding Network Credits is the balance of Network Facilities Upgrades Credits due Transmission Customers who have made lump-sum payments 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 147.
O Expenses reflect full year plan
P The projected capital structure shall reflect the capital structure from the FERC Form 1 data. For all other formula rate calculations, the projected capital structure and actual capital structure shall reflect the capital structure from the most recent FERC Form 1 data available.
Calculated using the average of the prior year and current year balances.
Q Calculated using beginning and year end projected balances.

END

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31,2010

	Only Transmission Related	Plant Related	Labor Related	Total ADIT	
ADIT- 282	0	(784,527,723)	(2,710,259)		From Acct. 282 total, below
ADIT-283	(1,781,312)	(93,325,145)	(23,265,958)		From Acct. 283 total, below
ADIT-190	1,617,015	14,216,746	8,333,773		From Acct. 190 total, below
Subtotal	(164,297)	(863,636,122)	(17,642,444)		
Wages & Salary Allocator			9.9036%		
Net Plant Allocator		22.1297%			
End of Year ADIT	(164,297)	(191,120,015)	(1,747,230)	**(193,031,542)**	
End of Previous Year ADIT (from Sheet 1A-ADIT (3))	(164,297)	(182,180,505)	(1,493,897)	**(183,838,699)**	
Average Beginning and End of Year ADIT	(164,297)	(186,650,260)	(1,620,563)	**(188,435,121)**	Appendix A, Line 44

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 108

(37,663,575) < From Acct 283, below

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

A	B	C	D	E	F	G
ADIT-190	***Total***	***Gas, Prod Or Other Related***	***Only Transmission Related***	***Plant Related***	***Labor Related***	***Justification***
Public Utility Realty Tax (PURTA)	1,617,015	-	1,617,015	-	-	Property Taxes for Transmission Switching Stations owned in Pennsylvania
Additional Maintenance Expense	1,348,125	1,348,125	-	-	-	Book estimate accrued expenses, generation related taxes
Newark Center Renovations	10,804	-	-	-	10,804	Amort of Renovations of Newark Plaza - General Property
New Jersey Corporate Business Tax(NJCBT)	8,767,009	-	-	8,767,009	-	New Jersey Corporate Income Tax Plant Related- Contra Account of 283 NJCBT
NJCBT - Step Up Basis	150,802,081	150,802,081	-	-	-	New Jersey Corporate Income Tax for Utility - Gets return on but no return of prior book vs tax timing differences
ADIT - Real Estate Taxes	2,289,737	-	-	2,289,737	-	Book estimate accrued and expensed, tax deduction when paid, related to plant
Gross Receipts & Franchise Tax(GRAFT)	756,443	756,443	-	-	-	Retail related
Market Transition Charge Revenue	17,485,019	17,485,019	-	-	-	Stranded cost recovery - generation related
Mine Closing Costs	1,357,594	1,357,594	-	-	-	Book estimate accrued and expensed, tax deduction when paid - Generation related
FIN 47	1,393	1,393	-	-	-	Asset Retirement Obligation - Legal liability for environmental removal costs
Vacation Pay	3,271,731	-	-	-	3,271,731	Vacation pay earned and expensed for books, tax deduction when paid - employees in all functions
OPEB	220,596,263	-	-	-	220,596,263	Fas 106 - Post Retirement Obligation, labor related.
Deferred Dividend Equivalents	2,645,151	-	-	-	2,645,151	Book accrual of dividends on employee stock options affecting all functions
Deferred Compensation	1,489,821	-	-	-	1,489,821	Book estimate accrued and expensed, tax deduction when paid - employees in all functions
ADIT - Interest/AFDC Debt	3,160,000	-	-	3,160,000	-	Capitalized Interest - Book vs Tax relates to all plant in all funtions
ADIT - Unallowable PIP Accrual	33,970	-	-	-	33,970	Book estimate accrued and expensed, tax deduction when paid - employees in all functions
ADIT - Legal Fees	637,144	637,144	-	-	-	Book estimate accrued and expensed, tax deduction when paid - employees in all functions
ADIT - Rev of 1985-1993 Settle Int Exp	(3,102,801)	(3,102,801)	-	-	-	Book estimate accrued and expensed, tax deduction when paid / audit settlement - Generation related
ADIT - Interest on Dismantling & Decommissioning	(1,940,681)	(1,940,681)	-	-	-	Book estimate accrued and expensed, tax deduction when paid / audit settlement - Generation related
ADIT - SETI Dissolution	60,619	60,619	-	-	-	Book estimate accrued and expensed, tax deduction when paid / audit settlement - Retail related
Minimum Pension Liability	137,435	137,435	-	-	-	Associated with Pension Liability not in rates
FIN 48 Services Allocation	(256,902)	(256,902)	-	-	-	Uncertain Tax Positions - Assets/(Liabilities) not in rates
Bankruptcies $ Acfc	(28,555)	(28,555)	-	-	-	Book estimate accrued and expensed, tax deduction when paid - Generation Related
Repair Allowance Deferred	(7,811,972)	(7,811,972)	-	-	-	Deferred recovery of lost repair allowance deductions-Retail Related
Fin Def. Energy competition Act CT	(5,750,974)	(5,750,974)	-	-	-	Restructuring Costs - Generation related
Def Tax Meter Equipment	202,155	202,155	-	-	-	Book estimate accrued and expensed, tax deduction when paid - Retail - Distribution Meters
Unrealized L/G Rabbi Trust	265,111	-	-	-	265,111	Book estimate accrued and expensed, tax deduction when paid for Executive Compensation
	-	-	-	-	-	
SECA Income Reversals Due to Reversals	(1,111,971)	(1,111,971)	-	-	-	Related to LSE SECA obligations - retail
Estimated Serverance Pay Accruals	617,185	-	-	-	617,185	Book estimate accrued and expensed, tax deduction when paid - employees in all functions
Federal Taxes Deferred	19,579,108	-	-	19,579,108	-	Fas109 - deferred tax asset primarily associated with items previously flowed through due to regulation
Federal Taxes Current	20,003,476	-	-	20,003,476	-	Fas109 - deferred tax asset primarily associated with items previously flowed through due to regulation
Fed Taxes Reg Requirement	16,292,691	-	-	16,292,691	-	Fas109 - deferred tax asset primarily associated with items previously flowed through due to regulation
		-	-	-	-	
Subtotal - p234	**453,423,224**	**152,784,152**	**1,617,015**	**70,092,021**	**228,930,036**	
Less FASB 109 Above if not separately removed	55,875,275			55,875,275		
Less FASB 106 Above if not separately removed	220,596,263				220,596,263	
Total	**176,951,686**	**152,784,152**	**1,617,015**	**14,216,746**	**8,333,773**	

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

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31,2008

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

A *ADIT- 282*	B *Total*	C *Gas, Prod Or Other Related*	D *Only Transmission Related*	E *Plant Related*	F *Labor Related*	G *Justification*
Depreciation - Liberalized Depreciation	(744,313,000)	-	-	744,313,000)	-	Basis difference resulting from accelerated tax depreciation versus depreciation used for ratemaking purposes - related to all functions
Depreciation - Non Utility Property	(87,752,986)	(87,752,986)	-	-	-	Inter-company gain on sale of non-regulated generation assets.
Cost of Removal	(37,304,000)	-	-	(37,304,000)	-	Book estimate accrued and expensed, tax deduction when paid. Retail related - Component of Liberlized Depreciation
FERC Normalization	(2,910,723)	-	-	(2,910,723)	-	Reverse South Georgia - Remaining Basis
Deffered Taxes on Rabbi Trust	(2,710,259)	-	-	-	(2,710,259)	Book estimate accrued and expensed, tax deduction when paid for Executive Compensation
Accounting for Income Taxes	(245,405,730)	-	-	245,405,730)	-	Fas109 - deferred tax liability primarily associated with plant related items previously flowed through due to regulation
Subtotal - p275	**(1,120,396,698)**	**(87,752,986)**	**0**	**(1,029,933,453)**	**(2,710,259)**	
Less FASB 109 Above if not separately removed	(245,405,730)			(245,405,730)		
Less FASB 106 Above if not separately removed	0					
Total	**(874,990,968)**	**(87,752,986)**	**0**	**(784,527,723)**	**(2,710,259)**	

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

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31,2008

A	B	C	D	E	F	G
	Total	Gas, Prod or Other Related	Only Transmission Related	Plant	Labor	
ADIT-283						
Fin 48	(26,140,626)	(26,140,626)	-	-	-	Uncertain Tax Positions - Assets/(Liabilities) not in rates
Securitization Regulatory Asset	975,438,224	975,438,224	-	-	-	Generation Related (Securitization of Stranded Costs)
Securitization - Federal	(1,292,307,692)	(1,292,307,692)	-	-	-	Generation Related (Securitization of Stranded Costs)
Securitization - State	(365,173,288)	(365,173,288)	-	-	-	Generation Related (Securitization of Stranded Costs)
Amortization of Hope Creek License Costs	(649,571)	(649,571)	-	-	-	Book vs Tax Difference - Generation Related
Environmental Cleanup Costs	19,891,668	19,891,668	-	-	-	Book estimate accrued and expensed, tax deduction when paid - Manufacturered Gas Plants
Company-Owned Life Insurance (COLI)	(3,746,320)	(3,746,320)	-	-	-	Related to Uncertain Tax Position (FIN 48) which will be reclassified and not in rates.
New Jersey Corporation Business Tax	(55,661,570)	-	-	(55,661,570)	-	New Jersey Corporate Income Tax - Plant Related- Contra Account of 190 NJCBT
Obsolete Material Write Off	5,751,926	5,751,926	-	-	-	Book accrued writeoff, tax deduction when actually disposed of - Generation Related
Fuel Cost Adjustment	(46,611,271)	(46,611,271)	-	-	-	Book deferral of Underrecovered Fuel Costs - Retail Related
Accelerated Acitivity Plan	(19,735,595)	(19,735,595)	-	-	-	Demand Side management and Associated Programs - Retail Related
Take-or-Pay Costs	913,793	913,793	-	-	-	Gas Supply Contracts
Other Contract Cancellations	(7,904,692)	(7,904,692)	-	-	-	Generation Related (Non-Utility Asset/Liability)
Other Computer Software	(13,135,754)	-	-	-	(13,135,754)	Accelerated Amortization of Computer Software - General Plant
Loss on Reacquired Debt	(37,663,575)	-	-	(37,663,575)	-	Tax deduction when reacquired, booked amortizes to expense
Additional Pension Deduction	(102,469,084)	(102,469,084)	-	-	-	Associated with Pension Liability not in rates
Amortization of Peach Bottom HWC	(689,765)	(689,765)	-	-	-	Generation Related (Non-Utility Asset/Liability)
Radioactive Waste Storage Costs	(1,092,677)	(1,092,677)	-	-	-	Generation Related (Non-Utility Asset/Liability)
Severance Pay Costs	(9,989,408)	-	-	-	(9,989,408)	Book estimate accrued and expensed, tax deduction when paid related to all employees
Repair Allowance-Reverse Amortization	(2,914,581)	(2,914,581)	-	-	-	Retail Related - Electric Distribution
Public Utility Realty Tax Assessment (PURPA)	(1,781,312)	-	(1,781,312)	-	-	Property Taxes for Transmission Switching Stations owned in Pennsylvania .
Federal Excise Tax Fuel Refunds	(137,133)	-	-	-	(137,133)	Vehicle Fuel Tax - General
Decommissioning and Decontamination Costs	12,603,383	12,603,383	-	-	-	Payments to DOE - Generation Related
Emission Allowance Sales	2,868,153	2,868,153	-	-	-	Sales of Emission Allowances - Generation Related
Interest Expense Ajustment	(2,001,557)	(2,001,557)	-	-	-	Generation Related (Non-Utility Asset/Liability)
Capitalization of Study Costs	(2,009,586)	(2,009,586)	-	-	-	Generation Related (Non-Utility Asset/Liability)
Budget Billing - Audit Settlement	6	6	-	-	-	Old Unbilled Revenue Issue - Retail Related
Lightnet Agreeement - Audit Settlement	123,968	123,968	-	-	-	Fiber Optics - Electric Distribution - Retail Related
Mescalero Radioactive Wast Storage Costs	158,378	158,378	-	-	-	Generation Related (Non-Utility Asset/Liability)
Sale of Call Option	(70)	(70)	-	-	-	Book amortization expensed, tax deduction when occurred. - Retail Related - distribution property
Vacation Pay Adjustment	(3,663)	-	-	-	(3,663)	Book estimate accrued and expensed, tax deduction when paid relating to all employees
Purchase Power - Audit Settlement	724,038	724,038	-	-	-	Puchased Power Settlements - Generation Related
Crude Oil Refunds	1,570,058	1,570,058	-	-	-	Generation Related (Non-Utility Asset/Liability)
	-	-	-	-	-	Generation Related (Non-Utility Asset/Liability)
Peach Bottom Interim Fuel Storage	(852,372)	(852,372)	-	-	-	Interim Nuclear Fuel Storage Costs - Generation Related
Amort UCUA Property Loss	15	15	-	-	-	Generation Related (Non-Utility Asset/Liability)
New Network Metering Equipment	(201,674)	(201,674)	-	-	-	New Upgraded Meter Equipments - Retail Related - Distribution Meters
Accounting for Income Taxes (FAS109) - Federal	(40,824,693)	-	-	(40,824,693)	-	Fas109 - deferred tax liability primarily non-plant related items previously flowed through due to regulation
Accounting for Income Taxes (FAS109) - State	(3,529,662)	-	-	(3,529,662)	-	Fas109 - deferred tax liability primarily non-plant related items previously flowed through due to regulation
Accounting for Income Taxes (FAS109) - Regulatory Requirement	(201,265,607)	-	-	(201,265,607)	-	Fas109 - gross-up
power (Deferred Project Costs)	(3,771,000)	(3,771,000)	-	-	-	Book Deferred Project Costs
Subtotal - p277	**(1,222,220,188)**	**(858,227,811)**	**(1,781,312)**	**(338,945,107)**	**(23,265,958)**	
Less FASB 109 Above if not separately removed	(245,619,962)			(245,619,962)		
Less FASB 106 Above if not separately removed	-					
Total	**(976,600,226)**	**(858,227,811)**	**(1,781,312)**	**(93,325,145)**	**(23,265,958)**	

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

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 1A - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31,2009

	Only Transmission Related	*Plant Related*	*Labor Related*	*Total ADIT*	
ADIT- 282	0	(740,486,723)	(2,710,259)		From Acct. 282 total, below
ADIT-283	(1,781,312)	(91,599,145)	(20,707,958)		From Acct. 283 total, below
ADIT-190	1,617,015	8,845,746	8,333,773		From Acct. 190 total, below
Subtotal	(164,297)	(823,240,122)	(15,084,444)		
Wages & Salary Allocator			9.9036%		
Net Plant Allocator		22.1297%			
End of Year ADIT	(164,297)	(182,180,505)	(1,493,897)	**(183,838,699)**	

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 108

(35,937,575) < From Acct 283, below

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

A	**B**	**C**	**D**	**E**	**F**	**G**
ADIT-190	***Total***	***Gas, Prod Or Other Related***	***Only Transmission Related***	***Plant Related***	***Labor Related***	***Justification***
Public Utility Realty Tax (PURTA)	1,617,015	-	1,617,015	-	-	Property Taxes for Transmission Switching Stations owned in Pennsylvania
Additional Maintenance Expense	1,348,125	1,348,125	-	-	-	Book estimate accrued expenses, generation related taxes
Newark Center Renovations	10,804	-	-	-	10,804	Amort of Renovations of Newark Plaza - General Property
New Jersey Corporate Business Tax(NJCBT)	3,396,009	-	-	3,396,009	-	New Jersey Corporate Income Tax Plant Related- Contra Account of 283 NJCBT
NJCBT - Step Up Basis	159,673,081	159,673,081	-	-	-	New Jersey Corporate Income Tax for Utility - Gets return on but no return of prior book vs tax timing differences
ADIT - Real Estate Taxes	2,289,737	-	-	2,289,737	-	Book estimate accrued and expensed, tax deduction when paid, related to plant
Gross Receipts & Franchise Tax(GRAFT)	756,443	756,443	-	-	-	Retail related
Market Transition Charge Revenue	17,485,019	17,485,019	-	-	-	Stranded cost recovery - generation related
Mine Closing Costs	1,357,594	1,357,594	-	-	-	Book estimate accrued and expensed, tax deduction when paid - Generation related
FIN 47	1,393	1,393	-	-	-	Asset Retirement Obligation - Legal liability for environmental removal costs
Vacation Pay	3,271,731	-	-	-	3,271,731	Vacation pay earned and expensed for books, tax deduction when paid - employees in all functions
OPEB	220,596,263	-	-	-	220,596,263	FASB 106 - Post Retirement Obligation, labor related.
Deferred Dividend Equivalents	2,645,151	-	-	-	2,645,151	Book accrual of dividends on employee stock options affecting all functions
Deferred Compensation	1,489,821	-	-	-	1,489,821	Book estimate accrued and expensed, tax deduction when paid - employees in all functions
ADIT - Interest/AFDC Debt	3,160,000	-	-	3,160,000	-	Capitalized Interest - Book vs Tax relates to all plant in all functions
ADIT - Unallowable PIP Accrual	33,970	-	-	-	33,970	Book estimate accrued and expensed, tax deduction when paid - employees in all functions
ADIT - Legal Fees	637,144	637,144	-	-	-	Book estimate accrued and expensed, tax deduction when paid - employees in all functions
ADIT - Rev of 1985-1993 Settle Int Exp	(3,102,801)	(3,102,801)	-	-	-	Book estimate accrued and expensed, tax deduction when paid / audit settlement - Generation related
ADIT - Interest on Dismantling & Decommissioning	(1,940,681)	(1,940,681)	-	-	-	Book estimate accrued and expensed, tax deduction when paid / audit settlement - Generation related
ADIT - SETI Dissolution	60,619	60,619	-	-	-	Book estimate accrued and expensed, tax deduction when paid / audit settlement - Retail related
Bankruptcies $ Acfc	137,435	137,435	-	-	-	Book estimate accrued and expensed, tax deduction when paid - Generation Related
Repair Allowance Deferred	(256,902)	(256,902)	-	-	-	Deferred recovery of lost repair allowance deductions-Retail Related
Fin Def. Energy competition Act CT	(28,555)	(28,555)	-	-	-	Restructuring Costs - Generation related
Def Tax Meter Equipment	(12,811,972)	(12,811,972)	-	-	-	Book estimate accrued and expensed, tax deduction when paid - Retail - Distribution Meters
Unrealized L/G Rabbi Trust	(5,750,974)	(5,750,974)	-	-	-	Book estimate accrued and expensed, tax deduction when paid for Executive Compensation
Reserve for SECA	202,155	202,155	-	-	-	Related to LSE SECA obligations - retail
Estimated Severance Pay Accruals	265,111	-	-	-	265,111	Book estimate accrued and expensed, tax deduction when paid - employees in all functions
Federal Taxes Deferred	19,579,108	-	-	19,579,108	-	FASB 109 - deferred tax asset primarily associated with items previously flowed through due to regulation
Federal Taxes Current	18,891,505	(1,111,971)	-	20,003,476	-	FASB 109 - deferred tax asset primarily associated with items previously flowed through due to regulation
Fed Taxes Reg Requirement	16,909,876	-	-	16,292,691	617,185	FASB 109 - deferred tax asset primarily associated with items previously flowed through due to regulation
Subtotal - p234	**451,923,224**	**156,655,152**	**1,617,015**	**64,721,021**	**228,930,036**	
Less FASB 109 Above if not separately removed	55,875,275			55,875,275		
Less FASB 106 Above if not separately removed	220,596,263				220,596,263	
Total	**175,451,686**	**156,655,152**	**1,617,015**	**8,845,746**	**8,333,773**	

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

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 1A - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31,2009

A	B	C	D	E	F	G
	Total	*Gas, Prod*	*Only*			
ADIT- 282		*Or Other*	*Transmission*	*Plant*	*Labor*	
		Related	*Related*	*Related*	*Related*	*Justification*
Depreciation - Liberalized Depreciation	(715,313,000)	-	-	(715,313,000)		Basis difference resulting from accelerated tax depreciation versus depreciation used for ratemaking purposes - related to all functions
Depreciation - Non Utility Property	(96,752,986)	(96,752,986)	-	-		nter-company gain on sale of non-regulated generation assets.
Cost of Removal	(22,263,000)	-	-	(22,263,000)		Book estimate accrued and expensed, tax deduction when paid. Retail related - Component of Liberalized Depreciation
FERC Normalization	(2,910,723)	-	-	(2,910,723)		Reverse South Georgia - Remaining Basis
Deferred Taxes on Rabbi Trust	(2,710,259)	-	-	-	(2,710,259)	Book estimate accrued and expensed, tax deduction when paid for Executive Compensation
Accounting for Income Taxes	(247,073,730)	-	-	(247,073,730)	-	FASB B 109 - deferred tax liability primarily associated with plant related items previously flowed through due to regulation
Subtotal - p275	**(1,087,023,698)**	**(96,752,986)**	**0**	**(987,560,453)**	**(2,710,259)**	
Less FASB 109 Above if not separately removed	(247,073,730)			(247,073,730)		
Less FASB 106 Above if not separately removed	0					
Total	**(839,949,968)**	**(96,752,986)**	**0**	**(740,486,723)**	**(2,710,259)**	

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

Public Service Electric and Gas Company

ATTACHMENT H-10A

Attachment 1A - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31,2009

A	B *Total*	C Gas, Prod or Other Related	D Only Transmission Related	E Plant	F Labor	G
Fin 48	(26,140,626)	(26,140,626)	-	-	-	Uncertain Tax Positions - Assets/(Liabilities) not in rates
Securitization Regulatory Asset	363,325,224	363,325,224	-	-	-	Generation Related (Securitization of Stranded Costs)
Securitization - Federal	(1,292,307,692)	(1,292,307,692)	-	-	-	Generation Related (Securitization of Stranded Costs)
Securitization - State	(365,173,288)	(365,173,288)	-	-	-	Generation Related (Securitization of Stranded Costs)
Amortization of Hope Creek License Costs	(649,571)	(649,571)	-	-	-	Book vs Tax Difference - Generation Related
Environmental Cleanup Costs	19,891,668	19,891,668	-	-	-	Book estimate accrued and expensed, tax deduction when paid - Manufactured Gas Plants
Company-Owned Life Insurance (COLI)	(3,746,320)	(3,746,320)	-	-	-	Related to Uncertain Tax Position (FIN 48), which will be reclassified and not in rates.
New Jersey Corporation Business Tax	(55,661,570)	-	-	(55,661,570)	-	New Jersey Corporate Income Tax - Plant Related- Contra Account of 190 NJCBT
Obsolete Material Write Off	5,751,926	5,751,926	-	-	-	Book accrued write-off, tax deduction when actually disposed of - Generation Related
Fuel Cost Adjustment	(46,611,271)	(46,611,271)	-	-	-	Book deferral of Underrecovered Fuel Costs - Retail Related
Accelerated Activity Plan	(19,735,595)	(19,735,595)	-	-	-	Demand Side management and Associated Programs - Retail Related
Take-or-Pay Costs	913,793	913,793	-	-	-	Gas Supply Contracts
Other Contract Cancellations	(7,904,692)	(7,904,692)	-	-	-	Generation Related (Non-Utility Asset/Liability)
Other Computer Software	(10,577,754)	-	-	-	(10,577,754)	Accelerated Amortization of Computer Software - General Plant
Loss on Reacquired Debt	(35,937,575)	-	-	(35,937,575)	-	Tax deduction when reacquired, booked amortizes to expense
Additional Pension Deduction	(99,469,084)	(99,469,084)	-	-	-	Associated with Pension Liability not in rates
Amortization of Peach Bottom HWC	(689,765)	(689,765)	-	-	-	Generation Related (Non-Utility Asset/Liability)
Radioactive Waste Storage Costs	(1,092,677)	(1,092,677)	-	-	-	Generation Related (Non-Utility Asset/Liability)
Severance Pay Costs	(9,989,408)	-	-	-	(9,989,408)	Book estimate accrued and expensed, tax deduction when paid related to all employees
Repair Allowance-Reverse Amortization	(2,914,581)	(2,914,581)	-	-	-	Retail Related - Electric Distribution
Public Utility Realty Tax Assessment (PURPA)	(1,781,312)	-	(1,781,312)	-	-	Property Taxes for Transmission Switching Stations owned in Pennsylvania
Federal Excise Tax Fuel Refunds	(137,133)	-	-	-	(137,133)	Vehicle Fuel Tax - General
Decommissioning and Decontamination Costs	12,603,383	12,603,383	-	-	-	Payments to DOE - Generation Related
Emission Allowance Sales	2,868,153	2,868,153	-	-	-	Sales of Emission Allowances - Generation Related
Interest Expense Adjustment	(2,001,557)	(2,001,557)	-	-	-	Generation Related (Non-Utility Asset/Liability)
Capitalization of Study Costs	(2,009,586)	(2,009,586)	-	-	-	Generation Related (Non-Utility Asset/Liability)
Budget Billing - Audit Settlement	6	6	-	-	-	Old Unbilled Revenue Issue - Retail Related
Lightnet Agreement - Audit Settlement	123,968	123,968	-	-	-	Fiber Optics - Electric Distribution - Retail Related
Mescalero Radioactive Waste Storage Costs	158,378	158,378	-	-	-	Generation Related (Non-Utility Asset/Liability)
Sale of Call Option	(70)	(70)	-	-	-	Book amortization expensed, tax deduction when occurred. - Retail Related - distribution property
Vacation Pay Adjustment	(3,663)	-	-	-	(3,663)	Book estimate accrued and expensed, tax deduction when paid relating to all employees
Purchase Power - Audit Settlement	724,038	724,038	-	-	-	Purchased Power Settlements - Generation Related
Crude Oil Refunds	1,570,058	1,570,058	-	-	-	Generation Related (Non-Utility Asset/Liability)
Loss of Union County Utility Authority	-	-	-	-	-	Generation Related (Non-Utility Asset/Liability)
Peach Bottom Interim Fuel Storage	(852,372)	(852,372)	-	-	-	Interim Nuclear Fuel Storage Costs - Generation Related
New Network Metering Equipment	15	15	-	-	-	New Upgraded Meter Equipments - Retail Related - Distribution Meters
Accounting for Income Taxes (FAS109) - Federal	(41,026,367)	(201,674)	-	(40,824,693)	-	FASB 109 - deferred tax liability primarily non-plant related items previously flowed through due to regulation
Accounting for Income Taxes (FAS109) - State	(3,529,662)	-	-	(3,529,662)	-	FASB 109 - deferred tax liability primarily non-plant related items previously flowed through due to regulation
Accounting for Income Taxes (FAS109) - Regulatory Requirement	(201,265,607)	-	-	(201,265,607)	-	FASB 109 - gross-up
Ipower (Deferred Project Costs)	(3,771,000)	(3,771,000)				Book Deferred Project Costs
Subtotal - p277	**(1,327,049,188)**	**(967,340,811)**	**(1,781,312)**	**(337,219,107)**	**(20,707,958)**	
Less FASB 109 Above if not separately removed	(245,821,636)			(245,619,962)		
Less FASB 106 Above if not separately removed	-					
Total	**(1,081,227,552)**	**(967,340,811)**	**(1,781,312)**	**(91,599,145)**	**(20,707,958)**	

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

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 2 - Taxes Other Than Income Worksheet - December 31, 2010

	Other Taxes	*Page 263 Col (i)*	*Allocator*	*Allocated Amount*	
	Plant Related				
1	Real Estate	18,720,000			Attachment #5
2	***Total Plant Related***	18,720,000	N/A	8,500,000	
	Labor Related		***Wages & Salary Allocator***		
3	FICA	10.247.766			
4	Federal Unemployment Tax	231,374			
5	New Jersey Unemployment Tax	494,106			
6	New Jersey Workforce Development	484,273			
7					
8	***Total Labor Related***	11,457,519	9.9036%	1,134,702	
	Other Included		***Net Plant Allocator***		
9					
10					
11					
12					
13	***Total Other Included***	0	22.1297%	0	
14	***Total Included (Lines 8 + 14 + 19)***	**30,177,519**		**9,634,702**	
	Currently Excluded				
15	Corporate Business Tax				
16	TEFA	97,756,177			
17	Use & Sales Tax				
18	Local Franchise Tax				
19	PA Corporate Income Tax				
20	Municipal Utility				
21	Public Utility Fund				
22	**Subtotal, Excluded**	97,756,177			
23	**Total, Included and Excluded (Line 20 + Line 28)**	127,933,696			
24	**Total Other Taxes from p114.14.g - Actual**	127,933,696			
25	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. Real Estate taxes are directly assigned to Transmission.

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 Net 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.

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 3 - Revenue Credit Workpaper - December 31, 2010

	Accounts 450 & 451		
1	Late Payment Penalties Allocated to Transmission		0
	Account 454 - Rent from Electric Property		
2	Rent from Electric Property - Transmission Related (Note 2)		516,000
	Account 456 - Other Electric Revenues		
3	Transmission for Others		0
4	Schedule 1A		5,065,000
5	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)		0
6	Point to Point Service revenues for which the load is not included in the divisor received by Transmission Owner		2,000,000
7	Professional Services (Note 2)		100,000
8	Revenues from Directly Assigned Transmission Facility Charges (Note 1)		22,063,000
9	Rent or Attachment Fees associated with Transmission Facilities (Note 2)		4,122,000
10	Gross Revenue Credits	(Sum Lines 1-9)	**33,866,000**
11	Less line 18	- line 18	(3,336,737)
12	Total Revenue Credits	line 10 + line 11	**30,529,264**
13	Revenues associated with lines 2, 7, and 9 (Note 2)		4,738,000
14	Income Taxes associated with revenues in line 13		1,935,473
15	One half margin (line 13 - line 14)/2		1,401,264
16	All expenses (other than income taxes) associated with revenues in line 13 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.		-
17	Line 15 plus line 16		1,401,264
18	Line 13 less line 17		3,336,737

Note 1 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.

Note 2 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). PSE&G will retain 50% of net revenues consistent with *Pacific Gas and Electric Company*, 90 FERC ¶ 61,314. Note: in order to use lines 13-18, 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).

Public Service Electric and Gas Company
ATTACHMENT H-10A
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 27 + Line 42 from below	164,156,001
B	100 Basis Point increase in ROE			1.00%

Return Calculation

			Appendix A Line or Source Reference	
1	**Rate Base**		(Line 43 + Line 57)	1,195,825,036
2	**Long Term Interest**		p117.62.c through 67.c	193,848,362
3	**Preferred Dividends**	enter positive	p118.29.d	3,987,876
	Common Stock			
4	Proprietary Capital		Attachment 5	3,549,490,730
5	Less Accumulated Other Comprehensive Income Account 219		p112.15.c	2,220,567
6	Less Preferred Stock		(Line 106)	79,523,400
7	Less Account 216.1		Attachment 5	4,006,682
8	Common Stock		(Line 96 - 97 - 98 - 99)	3,463,740,081
	Capitalization			
9	Long Term Debt		Attachment 5	3,438,111,677
10	Less Loss on Reacquired Debt		Attachment 5	95,892,748
11	Plus Gain on Reacquired Debt		Attachment 5	0
12	Less ADIT associated with Gain or Loss		Attachment 5	33,905,934
13	Total Long Term Debt		(Line 101 - 102 + 103 - 104)	3,308,312,995
14	Preferred Stock		Attachment 5	79,523,400
15	Common Stock		(Line 100)	3,463,740,081
16	Total Capitalization		(Sum Lines 105 to 107)	6,851,576,476
17	Debt %	Total Long Term Debt	(Line 105 / Line 108)	48.3%
18	Preferred %	Preferred Stock	(Line 106 / Line 108)	1.2%
19	Common %	Common Stock	(Line 107 / Line 108)	50.6%
20	Debt Cost	Total Long Term Debt	(Line 94 / Line 105)	0.0586
21	Preferred Cost	Preferred Stock	(Line 95 / Line 106)	0.0501
22	Common Cost	Common Stock	(Line 114 + 100 basis points)	0.1268
23	Weighted Cost of Debt	Total Long Term Debt (WCLTD)	(Line 109 * Line 112)	0.0283
24	Weighted Cost of Preferred	Preferred Stock	(Line 110 * Line 113)	0.0006
25	Weighted Cost of Common	Common Stock	(Line 111 * Line 114)	0.0641
26	**Rate of Return on Rate Base (ROR)**		**(Sum Lines 115 to 117)**	**0.0930**
27	**Investment Return = Rate Base * Rate of Return**		**(Line 58 * Line 118)**	**111,184,129**

Composite Income Taxes

	Income Tax Rates			
28	FIT=Federal Income Tax Rate			35.00%
29	SIT=State Income Tax Rate or Composite			9.00%
30	p = percent of federal income tax deductible for state purposes		Per State Tax Code	0.00%
31	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		40.85%
35	CIT = T / (1-T)			69.06%
36	1 / (1-T)			169.06%
	ITC Adjustment			
37	Amortized Investment Tax Credit	enter negative	Attachment 5	-1,198,000
38	1/(1-T)		1 / (1 - Line 123)	169%
39	Net Plant Allocation Factor		(Line 18)	22.1297%
40	**ITC Adjustment Allocated to Transmission**		(Line 125 * Line 126 * Line 127)	**-448,206**
41	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		53,420,077
42	**Total Income Taxes**			**52,971,872**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 5 - Cost Support - December 31, 2010

Electric / Non-electric Cost Support

				Previous Year	Current Year - 2010 Projected													
Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Form 1 Dec	Average	Non-electric Portion
	Plant Allocation Factors																	
6	Electric Plant in Service	(Note B)	p207.104g	8,020,657,074	8,054,589,466	8,093,743,442	8,136,043,723	8,181,990,037	8,223,548,638	8,347,822,352	8,410,205,802	8,459,928,681	8,508,036,154	8,567,896,375	8,620,004,723	8,752,184,351	8,336,665,448	
7	Common Plant in Service - Electric	(Note B)	p356	112,402,750	113,192,600	113,875,799	114,672,272	115,718,335	116,737,365	117,742,178	118,586,942	119,434,371	120,223,310	120,925,623	121,627,937	113,201,999	116,795,499	
9	Accumulated Depreciation (Total Electric Plant)	(Note B & J)	p219.29c	2,603,925,503	2,613,219,737	2,619,509,868	2,626,359,355	2,634,739,502	2,644,361,299	2,654,994,543	2,665,350,393	2,675,834,675	2,684,651,601	2,692,049,088	2,700,823,840	2,710,113,014	2,655,840,955	
10	Accumulated Intangible Amortization	(Note B)	p200.21c	3,616	4,191	4,766	5,340	5,915	6,489	7,064	7,638	8,213	8,788	9,362	9,937	10,511	7,064	
11	Accumulated Common Plant Depreciation - Electric	(Note B & J)	p356	30,752,623	31,330,267	31,808,278	32,314,893	32,832,753	33,307,195	33,847,886	34,397,269	34,955,360	35,522,125	36,096,215	36,677,630	28,138,125	33,229,278	
12	Accumulated Common Amortization - Electric	(Note B)	p356	0	-	-	-	-	-	-	-	-	-	-	-	-	0	
	Plant In Service																	
19	Transmission Plant in Service	(Note B)	p207.58.g	1,910,140,625	1,912,947,541	1,916,198,196	1,923,704,722	1,931,821,970	1,936,392,217	1,969,944,465	1,988,437,659	1,989,930,852	1,995,827,602	2,018,278,713	2,035,191,184	2,131,172,017	1,973,845,213	
20	General	(Note B)	p207.99.g	226,303,661	225,664,439	225,256,421	225,348,403	227,192,042	229,035,681	230,410,482	232,149,927	233,768,314	235,135,951	234,898,483	234,984,465	234,081,447	230,325,363	
21	Intangible - Electric	(Note B)	p205.5.g	34,473	34,473	34,473	34,473	34,473	34,473	34,473	34,473	34,473	34,473	34,473	34,473	34,473	34,473	
22	Common Plant in Service - Electric	(Note B)	p356	112,402,750	113,192,600	113,875,799	114,672,272	115,718,335	116,737,365	117,742,178	118,586,942	119,434,371	120,223,310	120,925,623	121,627,937	113,201,999	116,795,499	
24	General Plant Account 397 -- Communications	(Note B)	p207.94g	33,239,404	32,938,487	32,637,571	32,336,654	32,035,737	31,734,821	31,433,904	31,132,987	30,832,071	30,531,154	30,230,237	29,929,321	29,628,404	31,433,904	
25	Common Plant Account 397 -- Communications	(Note B)	p356	14,985,645	14,985,645	14,985,645	14,985,645	14,985,645	14,985,645	14,985,645	14,985,645	14,985,645	14,985,645	14,985,645	14,985,645	5,856,890	14,283,433	
29	Account No. 397 Directly Assigned to Transmission	(Note B)	Company Records	16,624,076	16,624,076	16,624,076	16,624,076	16,624,076	16,624,076	16,624,076	16,624,076	16,624,076	16,624,076	16,624,076	16,624,076	16,624,076	16,624,076	
	Accumulated Depreciation																	
32	Transmission Accumulated Depreciation	(Note B & J)	p219.25.c	721,456,048	722,931,704	721,790,781	721,411,632	722,279,159	724,008,777	726,490,949	728,910,803	731,317,144	732,866,905	733,895,598	734,846,098	736,023,390	727,556,076	
33	Accumulated General Depreciation	(Note B & J)	p219.28.b	101,543,330	101,351,499	100,890,672	100,431,902	99,911,042	99,409,849	98,924,924	98,462,050	98,016,125	97,584,887	96,012,654	95,581,466	95,062,379	98,706,367	
1	Accumulated Common Plant Depreciation - Electric	(Note B & J)	p356	30,752,623	31,330,267	31,808,278	32,314,893	32,832,753	33,307,195	33,847,886	34,397,269	34,955,360	35,522,125	36,096,215	36,677,630	28,138,125	33,229,278	
35	Amount of General Depreciation Associated with Acct. 397	(Note B & J)	Company Records	25,792,935	25,796,151	25,796,859	25,795,059	25,790,752	25,783,937	25,774,615	25,762,784	25,748,447	25,731,601	25,712,248	25,690,387	16,537,264	25,054,849	
41	Acc. Deprec. Acct. 397 Directly Assigned to Transmission	(Note B & J)	Company Records	5,717,813	5,854,885	5,991,956	6,129,028	6,266,099	6,403,171	6,540,242	6,677,314	6,814,385	6,951,457	7,088,528	7,225,600	7,362,671	6,540,242	

Wages & Salary

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
2	Total Wage Expense	(Note A)	p354.28b	170,066,699
3	Total A&G Wages Expense	(Note A)	p354.27b	11,575,685
1	Transmission Wages		p354.21b	15,696,251

Transmission / Non-transmission Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Beginning Year Balance	End of Year	Average
	Plant Held for Future Use (Including Land)	(Note C & Q)	p214.47.d	7,676,482	7,676,482	7,676,482
46	Transmission Only			4,096,903	4,096,903	4,096,903

Prepayments

Line #s	Descriptions	Notes	Page #'s & Instructions	Previous Year	Electric Beginning Year Balance	Electric End of Year Balance	Average Balance	Wage & Salary Allocator	To Line 47
	Prepayments								
47	Prepayments	(Note A & Q)	p111.57c	44,621,587	8,828,890	8,828,890	8,828,890	9.904%	874,374

Materials and Supplies

Line #s	Descriptions	Notes	Page #'s & Instructions	Beginning Year Balance	End of Year	Average
	Materials and Supplies					
48	Undistributed Stores Exp	(Note Q)	p227.16.b,c			
51	Transmission Materials & Supplies	(Note N & Q))	p227.8.b,c	3,480,728	3,480,728	3,480,728

Outstanding Network Credits Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Beginning Year Balance	End of Year	Average
	Network Credits					
56	**Outstanding Network Credits**	(Note N & Q))	From PJM	0	0	

O&M Expenses

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
59	Transmission O&M	(Note O)	p.321.112.b	45,589,226
60	Transmission Lease Payments		p321.96.b	-

Property Insurance Expenses

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
65	Property Insurance Account 924	(Note O)	p323.185b	1,170,000

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 5 - Cost Support - December 31, 2010

Adjustments to A & G Expense

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
32	Total A&G Expenses		p323.197b	257,502,133
33	Fixed PBOP expense	Note J)	Company Records	77,745,482
34	Actual PBOP expense	(Note O)	Company Records	74,972,711

Regulatory Expense Related to Transmission Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year	Transmission Related
	Allocated General & Common Expenses				
36	Regulatory Commission Exp Account 928	(Note E & O)	p323.189b	12,832,629	0
	Directly Assigned A&G				
72	Regulatory Commission Exp Account 928	(Note G & O)	p351.11-13h	939,349	939,349

General & Common Expenses

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year	EPRI Dues
38	Less EPRI Dues	(Note D & O)	p352-353	-	0

Safety Related Advertising Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year	Safety Related	Non-safety Related
	Directly Assigned A&G					
73	General Advertising Exp Account 930.1	(Note K & O)	p323.191b	3,279,688	0	3,279,688

Education and Out Reach Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year	Education & Outreach	Other
	Directly Assigned A&G					
76	General Advertising Exp Account 930.1	(Note K & O)	p323.191b	3,279,688		3,279,688

Depreciation Expense

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
	Depreciation Expense			
81	Depreciation-Transmission	(Note J & O)	p336.7.f	45,499,229
82	Depreciation-General & Common	(Note J & O)	p336.10&11.f	27,533,975
83	Depreciation-General Expense Associated with Acct. 397	(Note J & O)	Company Records	3,714,034
85	Depreciation-Intangible	(Note A & O)	p336.1.f	4,356,652
89	Transmission Depreciation Expense for Acct. 397	(Note J & O)	Company Records	1,662,408

Direct Assignment of Transmission Real Estate Taxes

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year	Transmission Related	Non-Transmission
92	Real Estate Taxes - Directly Assigned to Transmission		p263.38i	18,720,000	8,500,000	10,220,000

PSE&G's real estate taxes detail is in an access database which contains a list of the towns PSE&G pays taxes to, which are billed on a quarterly basis for various parcels of property by major classification. Every parcel is associated with a Lot & Block number. These Lot & Blocks are id ied to a particular type of propertyand are labeled. This is the breakout of transmission real estate taxes from

Return \ Capitalization

Line #s	Descriptions	Notes	Page #'s & Instructions	2007 End of Year	2008 End of Year	Average
96	Proprietary Capital	(Note P)	p112.16.c,d	3,369,975,183	3,729,006,276	3,549,490,730
97	Accumulated Other Comprehensive Income Account 219	(Note P)	p112.15.c,d	2,499,017	1,942,117	2,220,567
99	Account 216.1	(Note P)	p119.53.c&d	3,717,744	4,295,620	4,006,682
101	Long Term Debt	(Note P)	p112.18.c,d thru 23.c,d	3,352,517,129	3,523,706,225	3,438,111,677
102	Loss on Reacquired Debt	(Note P)	p111.81.c,d	79,689,473	112,096,023	95,892,748
103	Gain on Reacquired Debt	(Note P)	p113.61.c,d	0	0	0
104	ADIT associated with Gain or Loss on Reacquired Debt	(Note P)	p277.3.k (footnote)	30,140,293	37,671,575	33,905,934
106	Preferred Stock	(Note P)	p112.3.c,d	79,523,400	79,523,400	79,523,400

MultiState Workpaper

Line #s	Descriptions	Notes	Page #'s & Instructions	State 1	State 2	State 3
	Income Tax Rates					

Public Service Electric and Gas Company

ATTACHMENT H-10A

Attachment 5 - Cost Support - December 31, 2010

			NJ
121	SIT=State Income Tax Rate or Composite	(Note I)	9.00%

Amortized Investment Tax Credit

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
125	Amortized Investment Tax Credit	(Note O)	p266.8.f	1,198,000

Excluded Transmission Facilities

Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Form 1 Dec	Average
141	Excluded Transmission Facilities	(Note B & M)		0	0	0	0	0	0	0	0	0	0	0	0	0	0

Interest on Outstanding Network Credits Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
147	Interest on Network Credits	(Note N & O)		0

Facility Credits under Section 30.9 of the PJM OATT

Line #s	Descriptions	Notes	Page #'s &	End of Year
	Revenue Requirement			
163	Facility Credits under Section 30.9 of the PJM OATT			0

PJM Load Cost Support

Line #s	Descriptions	Notes	Page #'s &	1 CP Peak
	Network Zonal Service Rate			Enter
165	1 CP Peak	(Note L)	PJM Data	9,686.7

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6 - True-up Adjustment for Network Integration Transmission Service - December 31, 2010

The True-Up Adjustment component of the Formula Rate for each Rate Year beginning with 2010 shall be determined as follows:

(i) Beginning with 2009, no later than June 15 of each year PSE&G shall recalculate an adjusted Annual Transmission Revenue Requirement for the previous calendar year based on its actual costs as reflected in its Form No. 1 and its books and records for that calendar year, consistent with FERC accounting policies.[2]

(ii) PSE&G shall determine the difference between the recalculated Annual Transmission Revenue Requirement as determined in paragraph (i) above, and ATRR based on projected costs for the previous calendar year (True-Up Adjustment Before Interest).

(iii) The True-Up Adjustment shall be determined as follows:

True-Up Adjustment equals the True-Up Adjustment Before Interest multiplied by (1+i)^24 months

Where: i = Sum of (the monthly rates for the 10 months ending October 31 of the current year and the monthly rates for the 12 months ending December 31 of the preceding year) divided by 21 months.

Summary of Formula Rate Process including True-Up Adjustment

Month	Year	Action
July	2008	TO populates the formula with Year 2008 estimated data
October	2008	TO populates the formula with Year 2009 estimated data
June	2009	TO populates the formula with Year 2008 actual data and calculates the 2008 True-Up Adjustment Before Interest
October	2009	TO calculates the Interest to include in the 2008 True-Up Adjustment
October	2009	TO populates the formula with Year 2010 estimated data and 2008 True-Up Adjustment
June	2010	TO populates the formula with Year 2009 actual data and calculates the 2009 True-Up Adjustment Before Interest
October	2010	TO calculates the Interest to include in the 2009 True-Up Adjustment
October	2010	TO populates the formula with Year 2011 estimated data and 2009 True-Up Adjustment
June	(Year)	TO populates the formula with (Year -1) actual data and calculates the (Year-1) True-Up Adjustment Before Interest
October	(Year)	TO calculates the Interest to include in the (Year-1) True-Up Adjustment
October	(Year)	TO populates the formula with (Year +1) estimated data and (Year-1) True-Up Adjustment

[1] No True-Up Adjustment will be included in the Annual Transmission Revenue Requirement for 2008 or 2009 since the Formula Rate was not in effect for 2006 or 2007.

[2] To the extent possible each input to the Formula Rate used to calculate the actual Annual Transmission Revenue Requirement included in the True-Up Adjustment either will be taken directly from the FERC Form No. 1 or will be reconcilable to the FERC Form 1 by the application of clearly identified and supported information. If the reconciliation is provided through a worksheet included in the filed Formula Rate template, the inputs to the worksheet must meet this transparency standard, and doing so will satisfy this transparency requirement for the amounts that are output from the worksheet and input to the main body of the Formula Rate.

	Calendar Year	Complete for Each Calendar Year beginning in 2009	
A	ATRR based on actual costs included for the previous calendar year but excludes the true-up adjustment.	186,850,707	
B	ATRR based on projected costs included for the previous calendar year but excludes the true-up adjustment.	200,671,504	
C	Difference (A-B)	-3,455,199	<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.
D	Future Value Factor (1+i)^24	1.07565	
E	True-up Adjustment (C*D)	-3,716,600	

Where:
i = average interest rate as calculated below

Interest on Amount of Refunds or Surcharges

Interest 35.19a for Current Yr Month	Yr	Interest 35.19a for Month
January	Year 1	
February	Year 1	
March	Year 1	
April	Year 1	
May	Year 1	
June	Year 1	
July	Year 1	
August	Year 1	
September	Year 1	
October	Year 1	0.4200%
November	Year 1	0.4100%
December	Year 1	0.0420%
January	Year 2	0.3800%
February	Year 2	0.3400%
March	Year 2	0.3800%
April	Year 2	0.2800%
May	Year 2	0.2900%
June	Year 2	0.2800%
July	Year 2	0.2800%
August	Year 2	0.2800%
September	Year 2	0.2700%
Average Interest Rate		0.3043%

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2010

Estimated Additions - 2010

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	Other Projects PIS (Monthly additions)	Reconductor Hudson - South Waterfront B0813 (monthly additions)						Susquehanna Roseland >= 500KV (monthly additions)	Susquehanna Roseland < 500KV (monthly additions)
		(in service)	(in service)	(in service)	(in service)	(in service)		CWIP	CWIP
Dec								38,826,828	4,000,000
Jan	3,786,916		-					3,160,952	-
Feb	4,230,656	-	-					3,182,940	-
Mar	8,486,526	-	-					14,388,544	-
Apr	8,817,248	-	-					3,606,549	-
May	5,270,248	-	-	-				5,182,677	2,640,000
Jun	34,252,739		-			-	-	8,798,322	-
Jul	19,753,194		-				-	6,325,550	-
Aug	2,433,194	320,000	-				-	5,277,529	8,689,973
Sep	5,156,750	2,560,000	-				-	13,285,650	96,057
Oct	10,511,111	2,560,000	-				-	10,669,762	9,119,122
Nov	14,352,472	2,560,000	-		-		-	10,580,608	201,649
Dec	93,420,833	2,560,000	-					14,389,114	201,649
Total	**210,471,883**	**10,560,000**	**-**	**-**	**-**	**-**	**-**	**137,675,026**	**24,948,450**

	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
	Other Projects PIS (monthly balances)	Reconductor Hudson - South Waterfront B0813 (monthly balances)						Susquehanna Roseland >= 500KV (monthly balances)	Susquehanna Roseland < 500KV (monthly balances)
		(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	CWIP	CWIP
Dec	-							38,826,828	4,000,000
Jan	3,786,916	-	-	-	-	-	-	41,987,780	4,000,000
Feb	8,017,571	-	-	-	-	-	-	45,170,720	4,000,000
Mar	16,504,097	-	-	-	-	-	-	59,559,264	4,000,000
Apr	25,321,345	-	-	-	-	-	-	63,165,813	4,000,000
May	30,591,592	-	-	-	-	-	-	68,348,490	6,640,000
Jun	64,844,331	-	-	-	-	-	-	77,146,812	6,640,000
Jul	84,597,525	-	-	-	-	-	-	83,472,362	6,640,000
Aug	87,030,718	320,000	-	-	-	-	-	88,749,891	15,329,973
Sep	92,187,468	2,880,000	-	-	-	-	-	102,035,541	15,426,031
Oct	102,698,579	5,440,000	-	-	-	-	-	112,705,303	24,545,153
Nov	117,051,050	8,000,000	-	-	-	-	-	123,285,911	24,746,801
Dec	210,471,883	10,560,000	-	-	-	-	-	137,675,026	24,948,450
Total	**843,103,075**	**27,200,000**	**-**	**-**	**-**	**-**	**-**	**1,042,129,741**	**144,916,408**
Average 13 Month Balance	**64,854,083**	**2,092,308**	**-**	**-**	**-**	**-**	**-**		
Average 13 Month in service	**4.01**	**2.58**						**7.57**	**5.81**
13 Month Average CWIP to Appendix A, line 45								**80,163,826**	**11,147,416**

Estimated Transmission Enhancement Charges (Before True-Up) - 2010

Total Projects	Branchburg (B0130)	Kittany (B0134)	Essex Aldene (B0145)	New Freedom Trans.(B0411)	New Freedom Loop (B0498)	Flagtown Sommerville Bridgewater (B0170)	Wave Trap Branchburg (B0172.2)	Metuchen Transformer (B0161)	Branchburg-Flagtown-Sommerville (B0169)	Roseland Transformer (B0274)	Susquehanna Roseland (B0489) >= 500KV CWIP	Susquehanna Roseland (B0489.4) < 500KV CWIP	Reconductor Hudson - South Waterfront (B0813)
70,035,729	4,143,821	1,760,950	17,663,638	4,554,773	3,767,186	1,400,234	7,560	5,442,721	4,637,505	4,768,898	16,186,705	2,250,890	450,848

Actual Transmission Enhancement Charges - 2008

Total Projects	Branchburg (B0130)	Kittany (B0134)	Essex Aldene (B0145)	New Freedom Trans.(B0411)	New Freedom Loop (B0498)	Flagtown Sommerville Bridgewater (B0170)	Susquehanna Roseland (B0489) >= 500KV CWIP	Susquehanna Roseland (B0489.4) < 500KV CWIP
32,385,646	4,454,372	1,799,169	19,301,739	4,894,366	337,584	239,734	358,682	

True Up by Project (without interest) - 3 months 2008

Total Projects	Branchburg (B0130)	Kittany (B0134)	Essex Aldene (B0145)	New Freedom Trans.(B0411)	New Freedom Loop (B0498)	Flagtown Sommerville Bridgewater (B0170)	Susquehanna Roseland (B0489) >=500KV CWIP	Susquehanna Roseland (B0489.4) < 500KV CWIP
(409,656)	(50,408)	(62,512)	(269,606)	(60,756)	4,656	59,934	(30,964)	

Interest	***1.07565***	***1.07565***	***1.07565***	***1.07565***	***1.07565***	***1.07565***	***1.07565***	***1.07565***

True Up by Project (with interest) - 3 months 2008

Total Projects	Branchburg (B0130)	Kittany (B0134)	Essex Aldene (B0145)	New Freedom Trans.(B0411)	New Freedom Loop (B0498)	Flagtown Sommerville Bridgewater (B0170)	Susquehanna Roseland (B0489) > 500KV CWIP	Susquehanna Roseland (B0489.4) < 500KV CWIP
(440,648.06)	(54,221)	(67,241)	(290,003)	(65,352)	5,009	64,468	(33,307)	

Estimated Transmission Enhancement Charges (After True-Up) - 2010

Total Projects	Branchburg (B0130)	Kittany (B0134)	Essex Aldene (B0145)	New Freedom Trans.(B0411)	New Freedom Loop (B0498)	Flagtown Sommerville Bridgewater (B0170)	Wave Trap Branchburg (B0172.2)	Metuchen Transformer (B0161)	Branchburg-Flagtown-Sommerville (B0169)	Roseland Transformer (B0274)	Susquehanna Roseland (B0489) > 500KV CWIP	Susquehanna Roseland (B0489.4) < 500KV CWIP	Reconductor Hudson - South Waterfront (B0813)
69,595,081.16	4,089,599.54	1,693,708.21	17,373,635.41	4,489,420.35	6,772,194.45	1,464,701	7,560	5,442,721	4,637,505	4,768,898	16,153,398.74	2,250,889.81	450,848

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2010

	Actual Additions - 2010								
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	Other Projects PIS (Monthly additions)	Reconductor Hudson - South Waterfront B0813 (monthly additions) (in service)	(in service)	(in service)	in service)	(in service)	(in service)	Susquehanna Roseland (B0489) >= 500KV CWIP CWIP	Susquehanna Roseland (B0489.4) < 500KV CWIP CWIP
Dec									
Jan									
Feb									
Mar									
Apr									
May									
Jun									
Jul									
Aug									
Sep									
Oct									
Nov									
Dec									
Total	-	-	-	-	-	-	-	-	-

	Actual Additions - 2009								
	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
	Other Projects PIS (monthly balances)	Reconductor Hudson - South Waterfront B0813 (monthly balances) (in service)	(in service)	(in service)	(in service)	(in service)	(in service)	Susquehanna Roseland (B0489) >= 500KV CWIP CWIP	Susquehanna Roseland (B0489.4) < 500KV CWIP CWIP
Dec								-	-
Jan	-	-	-	-	-	-	-	-	-
Feb	-	-	-	-	-	-	-	-	-
Mar	-	-	-	-	-	-	-	-	-
Apr	-	-	-	-	-	-	-	-	-
May	-	-	-	-	-	-	-	-	-
Jun	-	-	-	-	-	-	-	-	-
Jul	-	-	-	-	-	-	-	-	-
Aug	-	-	-	-	-	-	-	-	-
Sep	-	-	-	-	-	-	-	-	-
Oct	-	-	-	-	-	-	-	-	-
Nov	-	-	-	-	-	-	-	-	-
Dec	-	.	-	.	-	.	-	-	-
Total	-	.	-	.	-	.	.	-	-
Average 13 Month Balance	-	-	-	-	-	-	-		-
Average 13 Month in service	#DIV/0!	#DIV/0!	#DIV/0!					#DIV/0!	
13 Month Average CWIP to Appendix A, line 45								-	

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2010

1 New Plant Carrying Charge

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

		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	19.1669%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	19.9870%
5	C		Line B less Line A	0.8201%

6 **FCR if a CIAC**

7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	6.8154%

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**

10		Details		**Branchburg (B0130)**			**Kittany (B0134)**			**Essex Aldene (B0145)**			**New Freedom Trans.(B0411)**			**New Freedom Loop (B0498)**		
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes			Yes			Yes			Yes			Yes		
12	Useful life of the project	Life		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		
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0			0			0			0			0		
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		19.1669%			19.1669%			19.1669%			19.1669%			19.1669%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		19.1669%			19.1669%			19.1669%			19.1669%			19.1669%		
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified - End of year	Investment		20,680,599			8,069,022			86,565,629			22,188,863			27,001,415		
18	Line 17 divided by line 12	Annual Depreciation Exp		492.395			192.120			2.061.086			528.306			642.891		
19	Months in service for depreciation expense from			13.00			13.00			13.00			13.00			13.00		
20	Year placed in Service (0 if CWIP)			2006			2007			2007			2007			2008		
21			**Invest Yr**	**Ending**	**Depreciation**	**Revenue**	**Ending**	**Depreciation**	**Revenue**	**Ending**	**Depreciation**	**Revenue**	**Ending**	**Depreciation**	**Revenue**	**Ending**	**Depreciation**	**Revenue**
22		W 11.68 % ROE	2006	20,680,597	492,395	4,652,471												
23		W Increased ROE	2006	20,680,597	492,395	4,652,471												
24		W 11.68 % ROE	2007	20,188,202	492,395	4,553,422	8,069,022	80,050	1,703,202	86,565,629	858,786	18,272,191	22,188,863	484,281	4,947,757			
25		W Increased ROE	2007	20,188,202	492,395	4,553,422	8,069,022	80,050	1,703,202	86,565,629	858,786	18,272,191	22,188,863	484,281	4,947,757			
26		W 11.68 % ROE	2008	19,695,807	492,395	4,454,372	7,988,972	192,120	1,799,169	85,706,843	2,061,086	19,301,739	21,704,582	528,306	4,894,366	24,921,237	88,646	837,584
27		W Increased ROE	2008	19,695,807	492,395	4,454,372	7,988,972	192,120	1,799,169	85,706,843	2,061,086	19,301,739	21,704,582	528,306	4,894,366	24,921,237	88,646	837,584
28		W 11.68 % ROE	2009	19,540,159	489,524	4,450,447	8,393,175	208,095	1,909,449	83,472,997	2,069,578	18,990,123	21,534,722	527,381	4,892,616	32,702,430	750,059	7,118,051
29		W Increased ROE	2009	19,540,159	489,524	4,450,447	8,393,175	208,095	1,909,449	83,472,997	2,069,578	18,990,123	21,534,722	527,381	4,892,616	32,702,430	750,059	7,118,051
30		W 11.68 % ROE	2010	19,050,635	492,395	4,143,821	8,185,079	192,120	1,760,950	81,403,418	2,061,086	17,663,638	21,007,341	528,306	4,554,773	31,952,371	642,891	6,767,186
31		W Increased ROE	2010	19,050,635	492,395	4,143,821	8,185,079	192,120	1,760,950	81,403,418	2,061,086	17,663,638	21,007,341	528,306	4,554,773	31,952,371	642,891	6,767,186

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2010

1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if not a CIAC**			
		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	19.1669%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	19.9870%
5	C		Line B less Line A	0.8201%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	6.8154%

8 **The FCR resulting from Formula in a giv**

9 **Therefore actual revenues collected in a**

				Flagtown Sommerville Bridgewater (B0170)	**Wave Trap Branchburg (B0172.2)**	**Metuchen Transformer (B0161)**	**Branchburg-Flagtown-Sommerville (B0169)**	**Roseland Transformer (B0274)**
10		Details						
11	"Yes" if a project under PJM OATT Schedule 12, otherwise 'No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42.00	42.00	42	42	42
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
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		19.1669%	19.1669%	19.17%	19.17%	19.17%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		19.1669%	19.1669%	19.17%	19.17%	19.17%
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified - End of year	Investment		6,961,495	36,369	25,085,218	22,815,697	21,122,893
18	Line 17 divided by line 12	Annual Depreciation Exp		165,750	866	597,267	543,231	502,926
19	Months in service for depreciation expense from			13.00	13.00	8.23	8.00	8.47
20	Year placed in Service (0 if CWIP)			2008	2008	2009	2009	2009

			Flagtown Sommerville Bridgewater (B0170)			Wave Trap Branchburg (B0172.2)			Metuchen Transformer (B0161)			Branchburg-Flagtown-Sommerville (B0169)			Roseland Transformer (B0274)		
21		**Invest Yr**	**Ending**	**Depreciation**	**Revenue**	**Ending**	**Depreciation**	**Revenue**	**Ending**	**Depreciation**	**Revenue**	**Ending**	**Depreciation**	**Revenue**	**Ending**	**Depreciation**	**Revenue**
22	W 11.68 % ROE	2006															
23	W Increased ROE	2006															
24	W 11.68 % ROE	2007															
25	W Increased ROE	2007															
26	W 11.68 % ROE	2008	6,961,495	25,372	239,734	36,369	577	5,114									
27	W Increased ROE	2008	6,961,495	25,372	239,734	36,369	577	5,114									
28	W 11.68 % ROE	2009	6,598,691	158,001	1,495,601	35,792	866	8,048	25,700,000	419,742	3,718,406	21,705,650	344,534	3,052,154	22,637,200	380,281	3,368,831
29	W Increased ROE	2009	6,598,691	158,001	1,495,601	35,792	866	8,048	25,700,000	419,742	3,718,406	21,705,650	344,534	3,052,154	22,637,200	380,281	3,368,831
30	W 11.68 % ROE	2010	6,440,689	165,750	1,400,234	34,926	866	7,560	25,280,258	597,267	5,442,721	21,361,116	543,231	4,637,505	22,256,919	502,926	4,768,898
31	W Increased ROE	2010	6,440,689	165,750	1,400,234	34,926	866	7,560	25,280,258	597,267	5,442,721	21,361,116	543,231	4,637,505	22,256,919	502,926	4,768,898

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2010

1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if not a CIAC**			
		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	19.1669%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	19.9870%
5	C		Line B less Line A	0.8201%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	6.8154%

8 **The FCR resulting from Formula in a give**

9 **Therefore actual revenues collected in a**

10		Details		**Susquehanna Roseland (B0489) >= 500KV CWIP**			**Susquehanna Roseland (B0489.4) < 500KV CWIP**			**Reconductor Hudson - South Waterfront (B0813)**						
11	"Yes" if a project under PJM OATT Schedule 12, otherwise 'No"	Schedule 12	(Yes or No)	Yes			Yes			Yes						
12	Useful life of the project	Life		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						
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		125			125			0						
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		19.1669%			19.1669%			19.1669%						
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		20.1920%			20.1920%			19.1669%						
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified - End of year	Investment		137,675,026			24,948,450			10,560,000						
18	Line 17 divided by line 12	Annual Depreciation Exp		3,277,977			594,011			251,429						
19	Months in service for depreciation expense from			7.57			5.81			2.58						
20	Year placed in Service (0 if CWIP)			2012			2012			2010						
21			**Invest Yr**	**Ending**	**Depreciation**	**Revenue**	**Ending**	**Depreciation**	**Revenue**				**Total**	**Incentive Charged**	**Revenue Credit**	
22		W 11.68 % ROE	2006										$ 4,652,471		$ 4,652,471	
23		W Increased ROE	2006										$ 4,652,471	$ 4,652,471		$ -
24		W 11.68 % ROE	2007										$ 29,476,571		$ 29,476,571	
25		W Increased ROE	2007										$ 29,476,571	$ 29,476,571		$ -
26		W 11.68 % ROE	2008	8,927,082	-	819,421	-	-	-				$ 32,351,499		$ 32,351,499	
27		W Increased ROE	2008	8,927,082	-	858,682	-	-	-				$ 32,390,760	$ 32,390,760		$ 39,261
28		W 11.68 % ROE	2009	36,193,521	-	4,719,582	4,000,000	-	686,085				$ 44,270,000		$ 44,270,000	
29		W Increased ROE	2009	36,193,521	-	4,947,559	4,000,000	-	719,226				$ 44,531,119	$ 44,531,119		$ 261,119
30		W 11.68 % ROE	2010	137,675,026	-	15,364,960	24,948,450	-	2,136,620	10,560,000	49,817	450,848	$ 69,099,714		$ 69,099,714	
31		W Increased ROE	2010	137,675,026	-	16,186,705	24,948,450	-	2,250,890	10,560,000	49,817	450,848	$ 70,035,729	$ 70,035,729		$ 936,016

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 8 - Depreciation Rates

Plant Type	PSE&G
Transmission	2.40
Distribution	
High Voltage Distribution	2.49
Meters	2.49
Line Transformers	2.49
All Other Distribution	2.49
General & Common	
Structures and Improvements	1.40
Office Furniture	5.00
Office Equipment	25.00
Computer Equipment	14.29
Personal Computers	33.33
Store Equipment	14.29
Tools, Shop, Garage and Other Tangible Equipment	14.29
Laboratory Equipment	20.00
Communications Equipment	10.00
Miscellaneous Equipment	14.29

Public Service Electric and Gas Company
Projected Costs of Plant in Forecasted Rate Base and In-Service Dates
12 Months Ended December 31, 2010

Required Transmission Enhancements

Upgrade ID	RTEP Baseline Project Description	Estimated/Actual Project Cost (thru 2010) *	Anticipated / Actual In-Service Date *
b0130	Replace all derated Branchburg 500/230 kv transformers	$ 20,680,599	Jan-06
b0134	Reconductor Kittatinny - Newtown 230 kV with 1590 ACSS	$ 8,069,022	Aug-07
b0145	Build new Essex - Aldene 230 kV cable connected through phase angle regulator at Essex	$ 86,565,629	Aug-07
b0411	Install 4th 500/230 kV transformer at New Freedom	$ 22,188,863	Feb-07
b0172.2	Replace wave trap at Branchburg 500kV substation	$ 36,369	May-08
b0170	Reconductor the Flagtown-Somerville-Bridgewater 230 kV circuit with 1590 ACSS	$ 6,961,495	Nov-08
b0498	Loop the 5021 circuit into New Freedom 500 kV substation	$ 27,001,415	Feb-09
b0161	Install 230-138kV transformer at Metuchen substation	$ 25,085,218	May-09
b0169	Build a new 230 kV section from Branchburg - Flagtown and move the Flagtown - Somerville 230 kV circuit to the new section	$ 22,815,697	May-09
b0274	Replace both 230/138 kV transformers at Roseland	$ 21,122,893	May-09
b0813	Reconductor Hudson - South Waterfront 230kV circuit	$ 10,560,000	Aug-10
b0489	Build new 500 kV transmission facilities from Pennsylvania - New Jersey border at Bushkill to Roseland (500kV and above elements of the project)	$ 137,675,026	Jun-12
b0489.4	Build new 500 kV transmission facilities from Pennsylvania - New Jersey border at Bushkill to Roseland (Below 500 kV elements of the project)	$ 24,948,450	Jun-12

**** May vary from original PJM Data due to updated information.***