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PSEG
Services Corporation

VIA ELECTRONIC MAIL & REGULAR MAIL

December 22, 2010

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

Docket Nos. EO03050394, ER07060379, ER08050310, EO09050351
++
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 a formula rate filing made by Public Service Electric and Gas ("PSE&G") in Federal Energy Regulatory Commission ("FERC") Docket No. ER08-1233, and in response to the annual formula rate update filings made by Potomac-Appalachian Transmission Highline, L.L.C. ("PATH") in Docket No. ER08-386-000 and Virginia Electric and Power Company ("VEPCo") in Docket No. ER-08-92-000.

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. ER10040287) the Board once again 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 ER08-1233-000, 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 December 18, 2008 the Board approved and authorized PSE&G to recover the FERC-approved formula rates applicable to customers in PSE&G's transmission zone and authorized the 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") in the PJM OATT were implemented to compensate transmission owners for the annual transmission revenue requirements for "Required Transmission Enhancements" (again, as defined in the PJM OATT) that are requested by PJM for reliability or economic purposes. TECs are recovered by PJM through an additional transmission charge in the transmission zones assigned cost responsibility for Required Transmission Enhancement projects.

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, 2011. The BGS-FP and BGS-CIEP rates are revised to include the PSE&G formula rate effective on January 1, 2011 and that is 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, 2011. Copies of all formula rate updates are attached, but can also be found on the PJM website at: http://www.pjm.com/markets-and-operations/transmission-service/formula-rates.aspx.

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, 2011. 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,

Original Signed by
Gregory Eisenstark, Esq.

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John Garvey, NJBPU
Frank Perrotti, NJBPU
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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
BGS TRANSMISSION CHARGE UPDATE - JUNE 2009
BPU DOCKET NO. EO09060440

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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, 2011 through December 31, 2011

Line #	Description	Rate		Source
(1)	Transmission Service Annual Revenue Requirement	$ 296,393,455.00		Attachment 7b -Page 141 - Line 164
(2)	Total Schedule 12 TEC Included in above	$ (74,754,882.00)		Attachment 7b - Page 158 Line 29
(3)	PSE&G Customer Share of Schedule 12 TEC	$ 24,456,661.36		Attachment 3a - Page 14 Column (n)
(4)	Total Transmission Costs Borne by PSE&G customers	$ 246,095,234.36		=(1) +(2) +(3)
(5)	2011 PSE&G Network Service Peak	10,761.4	MW	Attachment 7b -Page 4 -Line 165
(6)	2011 Network Integration Transmission Service Rate	$ 22,868.33	per MW-year	
	Resulting 2010 BGS Firm Transmission Service Supplier Rate	$ 62.65	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

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

APPLICABLE TO:

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

BGS ENERGY CHARGES:

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

Charges per kilowatthour:

	For usage in each of the months of October through May		For usage in each of the months of June through September	
Rate Schedule	Charges	Charges Including SUT	Charges	Charges Including SUT
RS – first 600 kWh	$ 0.115269	$ 0.123338	$ 0.114998	$ 0.123048
RS – in excess of 600 kWh	0.115269	0.123338	0.124119	0.132807
RHS – first 600 kWh	0.098536	0.105434	0.110206	0.117920
RHS – in excess of 600 kWh	0.098536	0.105434	0.122402	0.130970
RLM On-Peak	0.162208	0.173563	0.157618	0.168651
RLM Off-Peak	0.075315	0.080587	0.079418	0.084977
WH	0.095671	0.102368	0.107506	0.115031
WHS	0.077482	0.082906	0.089246	0.095493
HS	0.104362	0.111667	0.140262	0.150080
BPL	0.073379	0.078516	0.076450	0.081802
BPL-POF	0.073379	0.078516	0.076450	0.081802
PSAL	0.073379	0.078516	0.076450	0.081802

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

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

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

BGS CAPACITY CHARGES:

Applicable to Rate Schedules GLP and LPL-Sec.

Charges per kilowatt of Generation Obligation:

Charge applicable in the months of June through September	$ 4.5466
Charge including New Jersey Sales and Use Tax (SUT)	$ 4.8649
Charge applicable in the months of October through May	$ 4.5280
Charge including New Jersey Sales and Use Tax (SUT)	$ 4.8450

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

BGS TRANSMISSION CHARGES

Applicable to Rate Schedules GLP and LPL-Sec.

Charges per kilowatt of Transmission Obligation:

Currently effective Annual Transmission Rate for Network Integration Transmission Service for the Public Service Transmission Zone ~~as stated in~~ as derived from the FERC Electric Tariff of the PJM Interconnection, LLC	$ 22,868.33 per MW per year
PJM Seams Elimination Cost Assignment Charges	$ 0.00 per MW per month
PJM Reliability Must Run Charge	$ 0.00 per MW per month
PJM Transmission Enhancements	
Trans-Allegheny Interstate Line Company	$ 81.62 per MW per month
Virginia Electric and Power Company	$ 44.46 per MW per month
Potomac-Appalachian Transmission Highline L.L.C.	$ 20.34 per MW per month
PPL Electric Utilities Corporation	$ 5.35 per MW per month
American Electric Power Service Corporation	$ 0.86 per MW per month
Atlantic City Electric Company.	$ 5.50 per MW per month
Delmarva Power and Light Company	$ 2.23 per MW per month
Potomac Electric Power Company.	$ 4.06 per MW per month

Above rates converted to a charge per kW of Transmission Obligation, applicable in all months	$ 2.0702
Charge including New Jersey Sales and Use Tax (SUT)	$ 2.2151

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

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

BGS TRANSMISSION CHARGES

Charges per kilowatt of Transmission Obligation:

Currently effective Annual Transmission Rate for Network Integration Transmission Service for the Public Service Transmission Zone ~~as stated in~~ as derived from the FERC Electric Tariff of the PJM Interconnection, LLC	$ 22,868.33 per MW per year
PJM Seams Elimination Cost Assignment Charges	$ 0.00 per MW per month
PJM Reliability Must Run Charge	$ 0.00 per MW per month
PJM Transmission Enhancements	
Trans-Allegheny Interstate Line Company	$ 81.62 per MW per month
Virginia Electric and Power Company	$ 44.46 per MW per month
Potomac-Appalachian Transmission Highline L.L.C.	$ 20.34 per MW per month
PPL Electric Utilities Corporation	$ 5.35 per MW per month
American Electric Power Service Corporation	$ 0.86 per MW per month
Atlantic City Electric Company.	$ 5.50 per MW per month
Delmarva Power and Light Company	$ 2.23 per MW per month
Potomac Electric Power Company.	$ 4.06 per MW per month

Above rates converted to a charge per kW of Transmission Obligation, applicable in all months	$ 2.0702
Charge including New Jersey Sales and Use Tax (SUT)	$ 2.2151

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.

Attachment 2b
Translation of NITS Charge into Customer Rates

Attachment 2b

Network Integration Service Calculation - BGS-FP
NITS Charges for January 2011 - December 2011

NITS Charges for Jan 2011 - Dec 2011	$	246,095,234.36		
PSE&G Zonal Transmission Load for Effective Yr. (MW) (1/1/11)		10,761.40		
Term (Months)		12		
OATT rate	$	1,905.6941	/MW/month	all values show w/o NJ SUT
converted to $/MW/yr =	$	22,868.33	/MW/yr	
	$	18,958.15	/MW/yr	**Jan 11 - May 11 Weighted Average of 17,631.00 18,054.72 21,221.02**
	$	20,683.39	/MW/yr	**June 11 - Dec 11 Weighted Average of 18,054.72 21,221.01 22,868.33**
	$	19,964.54	/MW/yr	**Jan 11 - Dec 11 Weighted Average**
Resulting Increase in Transmission Rate	$	2,903.79	/MW/yr	
Resulting Increase in Transmission Rate	$	241.98	/MW/month	

	RS	**RHS**	**RLM**	**WH**	**WHS**	**HS**	**PSAL**	**BPL**
Trans Obl - MW	4,329.6	33.1	83.6	0.5	0.0	6.0	0.0	0.0
Total Annual Energy - MWh	13,307,205	169,112	276,689	2,802	35	22,768	175,734	334,793
Change in energy charge								
in $/MWh	$ 0.9448	$ 0.5684	$ 0.8774	$ 0.5182	$ -	$ 0.7652	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000945**	**$ 0.000568**	**$ 0.000877**	**$ 0.000518**	**$ -**	**$ 0.000765**	**$ -**	**$ -**

Line #						
1	Total BGS-FP eligbile Trans Obl		8,930.9	MW		= sum of BGS-FP eligible Trans Obl
2	Total BGS-FP eligbile energy @ cust		32,518,909	MWh		= sum of BGS-FP eligible kWh @ cust
3	Total BGS-FP eligbile energy @ trans nodes		34,759,755	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	25,933,451		unrounded	= Change in OATT rate * Total BGS-FP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.7461	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	0.75	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	26,069,816		unrounded	= (6) * (3)
8	Difference due to rounding	$	136,365		unrounded	= (7) - (4)

Attachment 2c

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

Attachment 2c

Transmission Charge Adjustment - BGS-FP
PJM Schedule 12 - Transmission Enhancement Charges for January 2011 - December 2011
Calculation of costs and monthly PJM charges for VEPCO Projects

TEC Charges for Jan 2011 - Dec 2011	$	5,741,429		
PSE&G Zonal Transmission Load for Effective Yr. (MW) (1/1/11)		10,761.40		
Term (Months)		12		
OATT rate	$	44.4601	/MW/month	all values show w/o NJ SUT
Resulting Increase in Transmission Rate	$	533.52	/MW/yr	

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4,329.6	33.1	83.6	0.5	0.0	6.0	0.0	0.0
Total Annual Energy - MWh	13,307,205	169,112	276,689	2,802	35	22,768	175,734	334,793
Change in energy charge								
in $/MWh	$ 0.1736	$ 0.1044	$ 0.1612	$ 0.0952	$ -	$ 0.1406	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000174**	**$ 0.000104**	**$ 0.000161**	**$ 0.000095**	**$ -**	**$ 0.000141**	**$ -**	**$ -**

Line #						
1	Total BGS-FP eligbile Trans Obl		8,930.9	MW		= sum of BGS-FP eligible Trans Obl
2	Total BGS-FP eligbile energy @ cust		32,518,909	MWh		= sum of BGS-FP eligible kWh @ cust
3	Total BGS-FP eligbile energy @ trans nodes		34,759,755	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	4,764,824		unrounded	= Change in OATT rate * Total BGS-FP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.1371	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	0.14	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	4,866,366		unrounded	= (6) * (3)
8	Difference due to rounding	$	101,541		unrounded	= (7) - (4)

Attachment 2d

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

Attachment 2d

Transmission Charge Adjustment - BGS-FP
PJM Schedule 12 - Transmission Enhancement Charges for January 2011 - December 2011
Calculation of costs and monthly PJM charges for PATH Project

TEC Charges for Jan 2011 - Dec 2011	$	2,626,959		
PSE&G Zonal Transmission Load for Effective Yr. (MW) (1/1/11)		10,761.40		
Term (Months)		12		
OATT rate	$	20.3425	/MW/month	all values show w/o NJ SUT
Resulting Increase in Transmission Rate	$	244.11	/MW/yr	

	RS	**RHS**	**RLM**	**WH**	**WHS**	**HS**	**PSAL**	**BPL**
Trans Obl - MW	4,329.6	33.1	83.6	0.5	0.0	6.0	0.0	0.0
Total Annual Energy - MWh	13,307,205	169,112	276,689	2,802	35	22,768	175,734	334,793
Change in energy charge								
in $/MWh	$ 0.0794	$ 0.0478	$ 0.0738	$ 0.0436	$ -	$ 0.0643	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000079**	**$ 0.000048**	**$ 0.000074**	**$ 0.000044**	**$ -**	**$ 0.000064**	**$ -**	**$ -**

Line #						
1	Total BGS-FP eligbile Trans Obl		8,930.9	MW		= sum of BGS-FP eligible Trans Obl
2	Total BGS-FP eligbile energy @ cust		32,518,909	MWh		= sum of BGS-FP eligible kWh @ cust
3	Total BGS-FP eligbile energy @ trans nodes		34,759,755	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	2,180,122		unrounded	= Change in OATT rate * Total BGS-FP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.0627	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	0.06	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	2,085,585		unrounded	= (6) * (3)
8	Difference due to rounding	$	(94,537)		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

Attachment 3a -PJM Schedule 12 - Transmission Enhancement Charges for January 2011 - December 2011
Calculation of costs and monthly PJM charges for PSE&G 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 2011 Annual Revenue Requirement**	**ACE Zone Share**	**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**
per PJM website	*per PJM spreadsheet*	*per PJM website*	*per PJM Open Access Transmission Tariff*								
Replace all derated Branchburg 500/230 kV transformers	b0130	$ 4,037,838.00	1.36%	47.75%	50.89%	0.00%	$54,915	$1,928,068	$2,054,856	$0	$4,037,838
Upgrade or Retension PSEG portion of Kittatinny – Newton 230 kV circuit	b0134	$ 1,599,150.00	0.00%	51.11%	45.96%	2.93%	$0	$817,326	$734,969	$46,855	$1,599,150
Build new Essex – Aldene 230 kV cable connected through a phase angle regulator at Essex	b0145	$ 17,558,470.00	0.00%	73.45%	21.78%	4.77%	$0	$12,896,696	$3,824,235	$837,539	$17,558,470
Install 230/138kV transformer at Metuchen substation	b0161	$ 4,276,941.00	0.00%	0.00%	99.80%	0.20%	$0	$0	$4,268,387	$8,554	$4,276,941
Build a new 230 kV section from Branchburg – Flagtown and move the Flagtown – Somerville 230 kV circuit to the new section	b0169	$ 3,462,908.00	1.72%	25.93%	59.59%	0.00%	$59,562	$897,932	$2,063,547	$0	$3,021,041
Reconductor the Flagtown-Somerville-Bridgewater 230 kV circuit with 1590 ACSS	b0170	$ 1,473,114.00	0.00%	42.95%	38.36%	0.79%	$0	$632,702	$565,087	$11,638	$1,209,427
Replace wave trap at Branchburg 500kV substation	b0172.2	$ 16,033.00	1.99%	4.22%	7.12%	0.27%	$319	$677	$1,142	$43	$2,180
Replace both 230/138 kV txfrmrs at Roseland	b0274	$ 3,779,831.00	0.00%	0.00%	96.77%	0.00%	$0	$0	$3,657,742	$0	$3,657,742
Install 4th 500/230 kV transformer at New Freedom	b0411	$ 4,441,046.00	47.01%	7.04%	22.31%	0.00%	$2,087,736	$312,650	$990,797	$0	$3,391,183
Build new 500 kV transmission facilities from Pa - NJ border at Bushkill to Roseland (500kV and above elements)	b0489	$ 20,146,965.00	1.99%	4.22%	7.12%	0.27%	$400,925	$850,202	$1,434,464	$54,397	$2,739,987
New 500 kV transmission facilities from Pa - NJ border at Bushkill to Roseland (below 500 kV elements)	b0489.4	$ 2,426,077.00	5.23%	34.10%	42.21%	1.58%	$126,884	$827,292	$1,024,047	$38,332	$2,016,555
Replace Roseland breakers	b0489.5-.9	$ 1,468,395.00	1.99%	4.22%	7.12%	0.27%	$29,221	$61,966	$104,550	$3,965	$199,702
Loop the 5021 circuit into New Freedom 500 kV substation	b0498	$ 5,609,858.00	1.99%	4.22%	7.12%	0.27%	$111,636	$236,736	$399,422	$15,147	$762,941
Reconductor Hudson - South Waterfront 230 kV circuit	b0813	$ 2,157,553.00	0.00%	9.96%	84.09%	3.14%	$0	$214,892	$1,814,286	$67,747	$2,096,926
Reconductor South Mahwah - Waldwick 345 kV J-3410 circuit	b1017	$ 2,031,996.00	0.00%	29.53%	66.05%	2.58%	$0	$600,048	$1,342,133	$52,425	$1,994,607
Reconductor South Mahwah - Waldwick 345 kV K-3411 circuit	b1018	$ 268,707.00	0.00%	29.71%	65.87%	2.57%	$0	$79,833	$176,997	$6,906	$263,736
Totals		**$ 74,754,882.00**					**$2,871,197**	**$20,357,020**	**$24,456,661**	**$1,143,547**	**$48,828,426**
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 2011**	**2011 TX Peak Load** *per PJM website*	**Rate in $/MW-mo.** ^{3}	**2011 Impact (12 months)**	
PSE&G	$ 2,038,055.11	10,761.4	$ 189.39	$ 24,456,661	
JCP&L	$ 1,696,418.35	6,420.1	$ 264.24	$ 20,357,020	
ACE	$ 239,266.42	2,936.3	$ 81.49	$ 2,871,197	
RE	$ 95,295.62	430.4	$ 221.41	$ 1,143,547	
Total Impact on NJ Zones	**$ 4,069,035.50**			**$ 48,828,426**	
Notes on calculations >>>			= (k) / (l)	= (k) *12	

Attachment 3b
Potomac-Appalachian Transmission Highline Project Charges

Attachment 3b Potomac-Allegheny Transmission Highline (PATH)

PJM Schedule 12 - Transmission Enhancement Charges for January 2011 - December 2011

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	**PJM Upgrade ID**		**Jan - Dec 2011 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*								
Amos-Bedington 765 kV Circuit (AEP)	b0490	$	16,266,358.00	1.99%	4.22%	7.12%	0.27%	$323,701	$686,440	$1,158,165	$43,919	$2,212,225
Amos-Bedington 765 kV Circuit (APS)	b0491	Included above		1.99%	4.22%	7.12%	0.27%	$0	$0	$0	$0	$0
Bedington-Kemptown 500 kV Circuit	b0492 & b560	$	20,629,134.00	1.99%	4.22%	7.12%	0.27%	$410,520	$870,549	$1,468,794	$55,699	$2,805,562
Totals		**$**	**36,895,492.00**					**$734,220**	**$1,556,990**	**$2,626,959**	**$99,618**	**$5,017,787**
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 2011**	**2011 Trans. Peak Load**	**Rate in $/MW-mo.[2]**	**2011 Impact (12 months)**
PSE&G	$	218,913.25	10,761.4	$20.34	$ 2,626,959
JCP&L	$	129,749.15	6,420.1	$20.21	$ 1,556,990
ACE	$	61,185.02	2,936.3	$20.84	$ 734,220
RE	$	8,301.49	430.4	$19.29	$ 99,618
Total Impact on NJ Zones	**$**	**418,148.91**	**20,548.2**		**$ 5,017,787**
Notes on calculations >>>				= (k) / (l)	= (k) *12

Attachment 3c
Virginia Electric Power Company Project Charges

Attachment 3c - PJM Schedule 12 - Transmission Enhancement Charges for January 2011 - December 2011
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 *per PJM website*	**PJM Upgrade ID** *per PJM spreadsheet*	**Jan - Dec 2011 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								
Upgrade Mt Storm - Doubs 500kV	b0217	$ 315,968.00	1.99%	4.22%	7.12%	0.27%	$6,288	$13,334	$22,497	$853	$42,972
Loudoun 150 MVA capacitor @ 500 kV	b0222	$ 269,894.00	1.99%	4.22%	7.12%	0.27%	$5,371	$11,390	$19,216	$729	$36,706
500 kV breakers and bus work at Suffolk	b0231	$ 3,725,678.00	1.99%	4.22%	7.12%	0.27%	$74,141	$157,224	$265,268	$10,059	$506,692
Meadowbrook-Loudon 500kV circuit	b0328.1	$ 38,097,077.00	1.99%	4.22%	7.12%	0.27%	$758,132	$1,607,697	$2,712,512	$102,862	$5,181,202
Build Carson – Suffolk 500 kV, install 2nd Suffolk 500/230 kV transformer & build Suffolk – Fentress 230 kV circuit	b0329	$ 19,034,374.00	1.99%	4.22%	7.12%	0.27%	$758,132	$1,607,697	$2,712,512	$102,862	$5,181,202
Mt Storm - Replace MOD with breaker on 500kV side of Txfmr	b0837	$ 132,354.00	1.99%	4.22%	7.12%	0.27%	$2,634	$5,585	$9,424	$357	$18,000
Totals		**$ 61,575,345.00**					**$1,604,697**	**$3,402,926**	**$5,741,429**	**$217,723**	**$10,966,775**
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 2011**	**2011 TX Peak Load** *per PJM website*	**Rate in $/MW-mo.[2]**	**2011 Impact (12 months)**
PSE&G	$ 478,452.42	10,761.4	$ 44.46	$ 5,741,429
JCP&L	$ 283,577.14	6,420.1	$ 44.17	$ 3,402,926
ACE	$ 133,724.76	2,936.3	$ 45.54	$ 1,604,697
RE	$ 18,143.56	430.4	$ 42.16	$ 217,723
Total Impact on NJ Zones	**$ 913,897.88**			**$ 10,966,775**
Notes on calculations >>>			= (k) / (l)	= (k) *12

Attachment 4 – Cost Allocations

Attachment 4a – Responsible Customer Shares for PSE&G Schedule 12 Projects
Source – PJM OATT – Sheet Nos. 270E.10 through 270E.21

Attachment 4b – Responsible Customer Shares for VEPCO Schedule 12 Projects
Source – PJM OATT – Sheet Nos. 270F.03 through 270F.11

Attachment 4c – Responsible Customer Shares for PATH Schedule 12 Projects
Source – PJM OATT Sheet Nos. 270F.02.01 through 270F.01i

Attachment 4a – Responsible Customer Shares for PSE&G Schedule 12 Projects
Source – PJM OATT – Sheet Nos. 270E.10 through 270E.21

(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.

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 (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
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%)
b1082	Install 230/138 kV transformer at Bergen substation		PENELEC (16.52%) / PSEG (80.29%) / RE (3.19%)

* 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 Freedom 230 kV breaker BS2-6		PSEG (100%)
b0213.3	Replace New Freedom 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 between Roseland 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 (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
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 Bayway 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 (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)†
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
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†Cost allocations associated with Regional Facilities and Necessary Lower Voltage Facilities associated with the project
††Cost allocations associated with below 500 kV elements of the project

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0489.5	Replace Roseland 230 kV breaker '42H' with 80 kA		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0489.6	Replace Roseland 230 kV breaker '51H' with 80 kA		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0489.7	Replace Roseland 230 kV breaker '71H' with 80 kA		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0489.8	Replace Roseland 230 kV breaker '31H' with 80 kA		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0489.9	Replace Roseland 230 kV breaker '11H' with 80 kA		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0498	Loop the 5021 circuit into New Freedom 500 kV substation		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
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%)

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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 and install a DC line from Calvert Cliffs to Vienna and a DC line from Calvert Cliffs to Indian River		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
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%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
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%)

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Issued By: Craig Glazer Effective: February 11, 2010
Vice President, Federal Government Policy
Issued On: November 13, 2009

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
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%)
b0814.1	Replace Kearny 138 kV breaker '1-SHT' with 80 kA breaker		JCPL (23.69%) / NEPTUNE* (0.81%) / PENELEC (5.41%) / PSEG (67.57%) / RE (2.52%)
b0814.2	Replace Kearny 138 kV breaker '15HF' with 80 kA breaker		JCPL (23.69%) / NEPTUNE* (0.81%) / PENELEC (5.41%) / PSEG (67.57%) / RE (2.52%)
b0814.3	Replace Kearny 138 kV breaker '14HF' with 80 kA breaker		JCPL (23.69%) / NEPTUNE* (0.81%) / PENELEC (5.41%) / PSEG (67.57%) / RE (2.52%)
b0814.4	Replace Kearny 138 kV breaker '10HF' with 80 kA breaker		JCPL (23.69%) / NEPTUNE* (0.81%) / PENELEC (5.41%) / PSEG (67.57%) / RE (2.52%)
b0814.5	Replace Kearny 138 kV breaker '2HT' with 80 kA breaker		JCPL (23.69%) / NEPTUNE* (0.81%) / PENELEC (5.41%) / PSEG (67.57%) / RE (2.52%)
b0814.6	Replace Kearny 138 kV breaker '22HF' with 80 kA breaker		JCPL (23.69%) / NEPTUNE* (0.81%) / PENELEC (5.41%) / PSEG (67.57%) / RE (2.52%)
b0814.7	Replace Kearny 138 kV breaker '4HT' with 80 kA breaker		JCPL (23.69%) / NEPTUNE* (0.81%) / PENELEC (5.41%) / PSEG (67.57%) / RE (2.52%)
b0814.8	Replace Kearny 138 kV breaker '25HF' with 80 kA breaker		JCPL (23.69%) / NEPTUNE* (0.81%) / PENELEC (5.41%) / PSEG (67.57%) / RE (2.52%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0814.9	Replace Essex 138 kV breaker '2LM' with 63 kA breaker and 2.5 cycle contact parting time		JCPL (23.69%) / NEPTUNE* (0.81%) / PENELEC (5.41%) / PSEG (67.57%) / RE (2.52%)
b0814.10	Replace Essex 138 kV breaker '1BT' with 63 kA breaker and 2.5 cycle contact parting time		JCPL (23.69%) / NEPTUNE* (0.81%) / PENELEC (5.41%) / PSEG (67.57%) / RE (2.52%)
b0814.11	Replace Essex 138 kV breaker '2PM' with 63 kA breaker and 2.5 cycle contact parting time		JCPL (23.69%) / NEPTUNE* (0.81%) / PENELEC (5.41%) / PSEG (67.57%) / RE (2.52%)
b0814.12	Replace Marion 138 kV breaker '2HM' with 63 kA breaker		JCPL (23.69%) / NEPTUNE* (0.81%) / PENELEC (5.41%) / PSEG (67.57%) / RE (2.52%)
b0814.13	Replace Marion 138 kV breaker '2LM' with 63 kA breaker		JCPL (23.69%) / NEPTUNE* (0.81%) / PENELEC (5.41%) / PSEG (67.57%) / RE (2.52%)
b0814.14	Replace Marion 138 kV breaker '1LM' with 63 kA breaker		JCPL (23.69%) / NEPTUNE* (0.81%) / PENELEC (5.41%) / PSEG (67.57%) / RE (2.52%)
b0814.15	Replace Marion 138 kV breaker '6PM' with 63 kA breaker		JCPL (23.69%) / NEPTUNE* (0.81%) / PENELEC (5.41%) / PSEG (67.57%) / RE (2.52%)
b0814.16	Replace Marion 138 kV breaker '3PM' with 63 kA breaker		JCPL (23.69%) / NEPTUNE* (0.81%) / PENELEC (5.41%) / PSEG (67.57%) / RE (2.52%)
b0814.17	Replace Marion 138 kV breaker '4LM' with 63 kA breaker		JCPL (23.69%) / NEPTUNE* (0.81%) / PENELEC (5.41%) / PSEG (67.57%) / RE (2.52%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0814.18	Replace Marion 138 kV breaker '3LM' with 63 kA breaker		JCPL (23.69%) / NEPTUNE* (0.81%) / PENELEC (5.41%) / PSEG (67.57%) / RE (2.52%)
b0814.19	Replace Marion 138 kV breaker '1HM' with 63 kA breaker		JCPL (23.69%) / NEPTUNE* (0.81%) / PENELEC (5.41%) / PSEG (67.57%) / RE (2.52%)
b0814.20	Replace Marion 138 kV breaker '2PM3' with 63 kA breaker		JCPL (23.69%) / NEPTUNE* (0.81%) / PENELEC (5.41%) / PSEG (67.57%) / RE (2.52%)
b0814.21	Replace Marion 138 kV breaker '2PM1' with 63 kA breaker		JCPL (23.69%) / NEPTUNE* (0.81%) / PENELEC (5.41%) / PSEG (67.57%) / RE (2.52%)
b0814.22	Replace ECRR 138 kV breaker '903'		JCPL (23.69%) / NEPTUNE* (0.81%) / PENELEC (5.41%) / PSEG (67.57%) / RE (2.52%)
b0814.23	Replace Foundry 138 kV breaker '21P'		JCPL (23.69%) / NEPTUNE* (0.81%) / PENELEC (5.41%) / PSEG (67.57%) / RE (2.52%)
b0814.24	Change the contact parting time on Essex 138 kV breaker '3LM' to 2.5 cycles		JCPL (23.69%) / NEPTUNE* (0.81%) / PENELEC (5.41%) / PSEG (67.57%) / RE (2.52%)
b0814.25	Change the contact parting time on Essex 138 kV breaker '2BM' to 2.5 cycles		JCPL (23.69%) / NEPTUNE* (0.81%) / PENELEC (5.41%) / PSEG (67.57%) / RE (2.52%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0814.26	Change the contact parting time on Essex 138 kV breaker '1BM' to 2.5 cycles		JCPL (23.69%) / NEPTUNE* (0.81%) / PENELEC (5.41%) / PSEG (67.57%) / RE (2.52%)
b0814.27	Change the contact parting time on Essex 138 kV breaker '3PM' to 2.5 cycles		JCPL (23.69%) / NEPTUNE* (0.81%) / PENELEC (5.41%) / PSEG (67.57%) / RE (2.52%)
b0814.28	Change the contact parting time on Essex 138 kV breaker '4LM' to 2.5 cycles		JCPL (23.69%) / NEPTUNE* (0.81%) / PENELEC (5.41%) / PSEG (67.57%) / RE (2.52%)
b0814.29	Change the contact parting time on Essex 138 kV breaker '1PM' to 2.5 cycles		JCPL (23.69%) / NEPTUNE* (0.81%) / PENELEC (5.41%) / PSEG (67.57%) / RE (2.52%)
b0814.30	Change the contact parting time on Essex 138 kV breaker '1LM' to 2.5 cycles		JCPL (23.69%) / NEPTUNE* (0.81%) / PENELEC (5.41%) / PSEG (67.57%) / RE (2.52%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0829	Build Branchburg to Roseland 500 kV circuit as part of Branchburg – Hudson 500 kV project		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0829.6	Replace Branchburg 500 kV breaker 91X		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0829.9	Replace Branchburg 230 kV breaker 102H		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0829.11	Replace Branchburg 230 kV breaker 32H		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0829.12	Replace Branchburg 230 kV breaker 52H		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0830	Build Roseland - Hudson 500 kV circuit as part of Branchburg – Hudson 500 kV project		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0830.1	Replace Roseland 230 kV breaker '82H' with 80 kA		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0830.2	Replace Roseland 230 kV breaker '91H' with 80 kA		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0830.3	Replace Roseland 230 kV breaker '22H' with 80 kA		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
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 (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0833	Build Roseland 500 kV switching station as part of Branchburg – Hudson 500 kV project		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
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%)
b0882	Replace Hudson 230 kV breaker 1HA with 80 kA		PSEG (100%)
b0883	Replace Hudson 230 kV breaker 2HA with 80 kA		PSEG (100%)
b0884	Replace Hudson 230 kV breaker 3HB with 80 kA		PSEG (100%)
b0885	Replace Hudson 230 kV breaker 4HA with 80 kA		PSEG (100%)
b0886	Replace Hudson 230 kV breaker 4HB with 80 kA		PSEG (100%)
b0889	Replace Bergen 230 kV breaker '21H'		PSEG (100%)
b0890	Upgrade New Freedom 230 kV breaker '21H'		PSEG (100%)
b0891	Upgrade New Freedom 230 kV breaker '31H'		PSEG (100%)
b0899	Replace ECRR 138 kV breaker 901		PSEG (100%)
b0900	Replace ECRR 138 kV breaker 902		PSEG (100%)

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1013	Replace Linden 138 kV breaker '7PB'		PSEG (100%)
b1017	Reconductor South Mahwah - Waldwick 345 kV J-3410 circuit		JCPL (29.53%) / NEPTUNE* (1.40%) / PSEG (66.05%) / RE (2.58%) / ECP** (0.44%)
b1018	Reconductor South Mahwah - Waldwick 345 kV K-3411 circuit		JCPL (29.71%) / NEPTUNE* (1.41%) / PSEG (65.87%) / RE (2.57%) / ECP** (0.44%)
b1019.1	Replace wave trap, line disconnect and ground switch at Roseland on the F-2206 circuit		PSEG (100%)
b1019.2	Replace wave trap, line disconnect and ground switch at Roseland on the B-2258 circuit		PSEG (100%)
b1019.3	Replace 1-2 and 2-3 section disconnect and ground switches at Cedar Grove on the F-2206 circuit		PSEG (100%)
b1019.4	Replace 1-2 and 2-3 section disconnect and ground switches at Cedar Grove on the B-2258 circuit		PSEG (100%)
b1019.5	Replace wave trap, line disconnect and ground switch at Cedar Grove on the F-2206 circuit		PSEG (100%)
b1019.6	Replace line disconnect and ground switch at Cedar Grove on the K-2263 circuit		PSEG (100%)
b1019.7	Replace 2-4 and 4-5 section disconnect and ground switches at Clifton on the B-2258 circuit		PSEG (100%)
b1019.8	Replace 1-2 and 2-3 section disconnect and ground switches at Clifton on the K-2263 circuit		PSEG (100%)
b1019.9	Replace line, ground, 230 kV main bus disconnects at Athenia on the B-2258 circuit		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)
b1019.10	Replace wave trap, line, ground 230 kV breaker disconnect and 230 kV main bus disconnects at Athenia on the K-2263 circuit		PSEG (100%)
b1098	Re-configure the Bayway 138 kV substation and install three new 138 kV breakers		PSEG (100%)
b1099	Build a new 230 kV substation by tapping the Aldene – Essex circuit and install three 230/26 kV transformers, and serve some of the Newark area load from the new station		PSEG (100%)
b1100	Build a new 138 kV circuit from Bayonne to Marion		PSEG (100%)
b1101	Re-configure the Cedar Grove substation with breaker and half scheme and build a new 69 kV circuit from Cedar Grove to Hinchman		PSEG (100%)
b1154	Convert the West Orange 138 kV substation, the two Roseland – West Orange 138 kV circuits, and the Roseland – Sewaren 138 kV circuit from 138 kV to 230 kV		PSEG (96.18%) / RE (3.82%)
b1155	Build a new 230 kV circuit from Branchburg to Middlesex Sw. Rack. Build a new 230 kV substation at Middlesex		JCPL (4.61%) / PSEG (91.75%) / RE (3.64%)
b1156	Convert the Burlington, Camden, and Cuthbert Blvd 138 kV substations, the 138 kV circuits from Burlington to Camden, and the 138 kV circuit from Camden to Cuthbert Blvd. from 138 kV to 230 kV		PSEG (96.18%) / RE (3.82%)

Attachment 4b – Responsible Customer Shares for VEPCO Schedule 12 Projects
Source – PJM OATT – Sheet Nos. 270F.03 through 270F.11

(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 (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0222	Install 150 MVAR capacitor at Loudoun 500 kV		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)

* 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)
b0231	Install 500 kV breakers & 500 kV bus work at Suffolk		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
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)
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 (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0785	Rebuild the Chase City – Crewe 115 kV line		Dominion (100%)
b0786	Reconductor the Moran DP – Crewe 115 kV segment		Dominion (100%)
b0787	Upgrade the Chase City – Twitty's Creek 115 kV segment		Dominion (100%)
b0788	Reconductor the line from Farmville – Pamplin 115 kV		Dominion (100%)
b0793	Close switch 145T183 to network the lines. Rebuild the section of the line #145 between Possum Point – Minnieville DP 115 kV		Dominion (100%)
b0815	Replace Elmont 230 kV breaker '22192'		Dominion (100%)
b0816	Replace Elmont 230 kV breaker '21692'		Dominion (100%)
b0817	Replace Elmont 230 kV breaker '200992'		Dominion (100%)
b0818	Replace Elmont 230 kV breaker '2009T2032'		Dominion (100%)
b0837	At Mt. Storm, replace the existing MOD on the 500 kV side of the transformer with a circuit breaker		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)

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

Attachment 4c – Responsible Customer Shares for PATH Schedule 12 Projects
Source – PJM OATT Sheet Nos. 270F.02.01 through 270F.01i

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1078	Reconductor Greene - Alpha 138 kV		Dayton (100%)
b1079	Perform sag study on Bath - Trebein 138 kV line to ensure clearance for rating increase		Dayton (100%)

(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 (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0460	Raise limiting structures on Albright – Bethelboro 138 kV to raise the rating to 175 MVA normal 214 MVA emergency		APS (100%)
b0491	Construct an Amos – Bedington 765 kV circuit (APS equipment)	As specified under the procedures detailed in Attachment H-19B	AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0492	Construct a Bedington – Kemptown 500 kV circuit	As specified under the procedures detailed in Attachment H-19B	AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0492.3	Replace Eastalco 230 kV breaker D-26		APS (100%)
b0492.4	Replace Eastalco 230 kV breaker D-28		APS (100%)

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0539	Replace Doubs circuit breaker DJ11		APS (100%)
b0540	Replace Doubs circuit breaker DJ12		APS (100%)
b0541	Replace Doubs circuit breaker DJ13		APS (100%)
b0542	Replace Doubs circuit breaker DJ20		APS (100%)
b0543	Replace Doubs circuit breaker DJ21		APS (100%)
b0544	Remove instantaneous reclose from Eastalco circuit breaker D-26		APS (100%)
b0545	Remove instantaneous reclose from Eastalco circuit breaker D-28		APS (100%)
b0559	Install 200 MVAR capacitor at Meadow Brook 500 kV substation		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)
b0560	Install 250 MVAR capacitor at Kemptown 500 kV substation		AEC (1.99%) / AEP (17.96%) / APS (6.27%) / BGE (4.85%) / ComEd (15.61%) / Dayton (2.46%) / DL (2.01%) / DPL (2.83%) / Dominion (13.34%) / JCPL (4.22%) / ME (2.09%) / NEPTUNE* (0.50%) / PECO (5.88%) / PENELEC (2.11%) / PEPCO (4.65%) / PPL (5.60%) / PSEG (7.12%) / RE (0.27%) / ECP** (0.24%)

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

Issued By: Craig Glazer Effective: February 11, 2010
Vice President, Federal Government Policy
Issued On: December 30, 2009

Attachment 5

PATH Formula Rate for January 1, 2011 to December 31, 2011

POTOMAC-APPALACHIAN TRANSMISSION HIGHLINE, LLC

PROJECTED TRANSMISSION REVENUE REQUIREMENT FOR RATE YEAR 2011

For the 12 months ended 12/31/2011

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	$16,266,358	(A)	$20,629,134	(B)	$36,895,492
2	PJM Project No.					
3	b0490 & b0491	$16,266,358	(C)			$16,266,358
4	b0492 & b0560			$20,629,134	(D)	$20,629,134
5						
6	Total (Sum lines 3 to 5)	$16,266,358		$20,629,134		$36,895,492

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)

Formula Rate - Non-Levelized

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2011

PATH West Virginia Transmission Company, LLC

Line No.			(1)		(2)	(3) Allocated Amount
1	GROSS REVENUE REQUIREMENT	(line 86)			12 months	$ 21,029,095
	REVENUE CREDITS		Total	Allocator		
2	Total Revenue Credits	Attachment 1, line 12	0	TP	1.00000	$ -
3	True-up Adjustment with Interest	Protocols	-4,762,736	DA	1.00000	$ (4,762,736)
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)				$ 16,266,358

Attachment A

Formula Rate - Non-Levelized

Rate Formula Template

Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2011

PATH West Virginia Transmission Company, LLC

Line No.	(1) **RATE BASE:**	(2) **Form No. 1 Page, Line, Col.**	(3) **Company Total**	(4) **Allocator**		(5) **Transmission** (Col 3 times Col 4)
	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)	-	NP	1.00000	-
30	Account No. 190	(Attachment 4)	5,060,630	NP	1.00000	5,060,630
31	Account No. 255 (enter negative)	(Attachment 4)	-	NP	1.00000	-
32	CWIP	(Attachment 4)	84,873,806	DA	1.00000	84,873,806
33	Unamortized Regulatory Asset	(Attachment 4)	2,060,428	DA	1.00000	2,060,428
34	Unamortized Abandoned Plant	(Attachment 4)	-	DA	1.00000	-
35	TOTAL ADJUSTMENTS (sum lines 27-34)		91,994,500			91,994,500
36	LAND HELD FOR FUTURE USE	(Attachment 4)	9,393,949	TP	1.00000	9,393,949
37	WORKING CAPITAL (Note C)					
38	CWC	calculated	670,288			670,288
39	Materials & Supplies (Note B)	(Attachment 4)	-	TE	1.00000	-
40	Prepayments (Account 165 - Note C)	(Attachment 4)	43,540	GP	1.00000	43,540
41	TOTAL WORKING CAPITAL (sum lines 38-40)		713,828			713,828
42	RATE BASE (sum lines 25, 35, 36, & 41)		102,102,277			102,102,277

Attachment A

Formula Rate - Non-Levelized

Rate Formula Template

Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2011

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	4,120,949	W/S	1.00000	4,120,949
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		5,362,303			5,362,303
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		4,974,278	NA		4,974,278
82	ITC adjustment (line 79 * line 80)		0	NP	1.00000	-
83	Total Income Taxes	(line 81 plus line 82)	4,974,278			4,974,278
84	RETURN					
85	[Rate Base (line 42) * Rate of Return (line 121)]		10,692,513	NA		10,692,513
86	REV. REQUIREMENT (sum lines 57, 63, 73, 83, 85)		21,029,095			21,029,095

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2011

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	0	1.00	0				
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		0		0	=	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

Formula Rate - Non-Levelized

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2011

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 12/31/2011

PATH Allegheny Transmission Company, LLC

			(1)	(2)		(3)
Line No.						Allocated Amount
1	GROSS REVENUE REQUIREMENT	(line 86)		12 months		$ 19,477,085
	REVENUE CREDITS		Total	Allocator		
2	Total Revenue Credits	Attachment 1, line 12	0	TP	1.00000	-
3	True-up Adjustment with Interest	Protocols	1,152,049	DA	1.00000	1,152,049
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)				$ 20,629,134

Attachment A

Formula Rate - Non-Levelized

Rate Formula Template

Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2011

PATH Allegheny 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)	19,690,413	TP	1.00000	19,690,413
8	Distribution	(Attachment 4)	-	NA	0.00000	-
9	General & Intangible	(Attachment 4)	58,135	W/S	1.00000	58,135
10	Common	(Attachment 4)	-	CE	1.00000	-
11	TOTAL GROSS PLANT (sum lines 6-10)	(GP=1 if plant =0)	19,748,548	GP=	1.00000	19,748,548
12	ACCUMULATED DEPRECIATION					
13	Production	(Attachment 4)	-	NA	0.00000	-
14	Transmission	(Attachment 4)	13,171	TP	1.00000	13,171
15	Distribution	(Attachment 4)	-	NA	0.00000	-
16	General & Intangible	(Attachment 4)	6,126	W/S	1.00000	6,126
17	Common	(Attachment 4)	-	CE	1.00000	-
18	TOTAL ACCUM. DEPRECIATION (sum lines 13-17)		19,296			19,296
19	NET PLANT IN SERVICE					
20	Production	(line 6- line 13)	-			-
21	Transmission	(line 7- line 14)	19,677,242			19,677,242
22	Distribution	(line 8- line 15)	-			-
23	General & Intangible	(line 9- line 16)	52,010			52,010
24	Common	(line 10- line 17)	-			-
25	TOTAL NET PLANT (sum lines 20-24)	(NP=1 if plant =0)	19,729,252	NP=	1.0000	19,729,252
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)	2,240,240	NP	1.00000	2,240,240
29	Account No. 283 (enter negative)	(Attachment 4)	(781,152)	NP	1.00000	(781,152)
30	Account No. 190	(Attachment 4)	866,176	NP	1.00000	866,176
31	Account No. 255 (enter negative)	(Attachment 4)	-	NP	1.00000	-
32	CWIP	(Attachment 4)	80,466,541	DA	1.00000	80,466,541
33	Unamortized Regulatory Asset	(Attachment 4)	312,107	DA	1.00000	312,107
34	Unamortized Abandoned Plant	(Attachment 4)	-	DA	1.00000	-
35	TOTAL ADJUSTMENTS (sum lines 27-34)		83,103,912			83,103,912
36	LAND HELD FOR FUTURE USE	(Attachment 4)	-	TP	1.00000	-
37	WORKING CAPITAL (Note C)					
38	CWC	calculated	330,472			330,472
39	Materials & Supplies (Note B)	(Attachment 4)	-	TE	1.00000	-
40	Prepayments (Account 165 - Note C)	(Attachment 4)	12,448	GP	1.00000	12,448
41	TOTAL WORKING CAPITAL (sum lines 38-40)		342,920			342,920
42	RATE BASE (sum lines 25, 35, 36, & 41)		103,176,083			103,176,083

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2011

PATH Allegheny 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	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	2,456,114	W/S	1.00000	2,456,114
48	Less EPRI & Reg. Comm. Exp. & Other Ad.	(Note D & Attach 4)	4,108	DA	1.00000	4,108
49	Plus Transmission Related Reg. Comm. Exp.	(Note D & Attach 4)	4,108	TE	1.00000	4,108
50	PBOP Expense adjustment	(Attachment 4)	394			394
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)		2,643,772			2,643,772
58	DEPRECIATION EXPENSE					
59	Transmission	336.7.b & c	8,318	TP	1.00000	8,318
60	General and Intangible	336.1.d&e + 336.10.b.c.d&e	3,500	W/S	1.00000	3,500
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)		11,818			11,818
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	921,989	GP	1.00000	921,989
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)		921,989			921,989
74	INCOME TAXES	(Note F)				
75	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		40.57%			
76	CIT=(T/1-T) * (1-(WCLTD/R)) =		46.37%			
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)		1.6827			
80	Amortized Investment Tax Credit	(266.8f) (enter negative)	0			
81	Income Tax Calculation = line 76 * line 85		5,036,700	NA		5,036,700
82	ITC adjustment (line 79 * line 80)		0	NP	1.00000	-
83	Total Income Taxes	(line 81 plus line 82)	5,036,700			5,036,700
84	RETURN					
85	[Rate Base (line 42) * Rate of Return (line 121)]		10,862,806	NA		10,862,806
86	REV. REQUIREMENT (sum lines 57, 63, 73, 83, 85)		19,477,085			19,477,085

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

For the 12 months ended 12/31/2011

PATH Allegheny Transmission Company, LLC
SUPPORTING CALCULATIONS AND NOTES

87	TRANSMISSION PLANT INCLUDED IN ISO RATES								
88	Total transmission plant (line 7, column 3)						19,690,413		
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)						19,690,413		
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	9,322	1.00	9,322				
105	Distribution	354.23.b	0				W&S Allocator		
106	Other	354.24,25,26.b	0	1.00	0		($ / Allocation)		
107	Total (sum lines 103-106) [TP equals 1 if there are no wages & salaries]		9,322		9,322	=	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

Formula Rate - Non-Levelized

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2011

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=	8.57%	(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)	19,690,413
3	Transmission Plant @ End of Period	(Attachment 4)	19,690,413
4	Sum	(sum lines 2 & 3)	39,380,826
5	Average Balance of Transmission Investment	(line 4/2)	19,690,413
6	Depreciation Expense	Rate Formula Template	8,318
7	Composite Depreciation Rate	(line 6/ line 5)	0.04%
8	Depreciable Life for Composite Depreciation Rate	(1/line 7)	2,367.21
9	Round line 8 to nearest whole year		2,367

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	2010	-
3	January	company records	2011	-
4	February	company records	2011	-
5	March	company records	2011	-
6	April	company records	2011	-
7	May	company records	2011	-
8	June	company records	2011	-
9	July	company records	2011	-
10	August	company records	2011	-
11	September	company records	2011	-
12	October	company records	2011	-
13	November	company records	2011	-
14	December	p207.58.g	2011	-
15	**Transmission Plant In Service**	(sum lines 2-14) /13		-
16	**Calculation of Distribution Plant In Service**	Source		
17	December	p206.75.b	2010	-
18	January	company records	2011	-
19	February	company records	2011	-
20	March	company records	2011	-
21	April	company records	2011	-
22	May	company records	2011	-
23	June	company records	2011	-
24	July	company records	2011	-
25	August	company records	2011	-
26	September	company records	2011	-
27	October	company records	2011	-
28	November	company records	2011	-
29	December	p207.75.g	2011	-
30	**Distribution Plant In Service**	(sum lines 17-29) /13		-
31	**Calculation of Intangible Plant In Service**	Source		
32	December	p204.5.b	2010	-
33	December	p205.5.g	2011	-
34	**Intangible Plant In Service**	(sum lines 32 & 33) /2		-
35	**Calculation of General Plant In Service**	Source		
36	December	p206.99.b	2010	-
37	December	p207.99.g	2011	-
38	**General Plant In Service**	(sum lines 36 & 37) /2		-
39	**Calculation of Production Plant In Service**	Source		
40	December	p204.46b	2010	-
41	January	company records	2011	-
42	February	company records	2011	-
43	March	company records	2011	-
44	April	company records	2011	-
45	May	company records	2011	-
46	March	Attachment 6	2011	-
47	April	company records	2011	-
48	August	company records	2011	-
49	September	company records	2011	-
50	October	company records	2011	-
51	November	company records	2011	-
52	December	p205.46.g	2011	-
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	2010	-	
56	December (Electric Portion)	p356	2011	-	
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	2010	-	
61	January	company records	2011	-	
62	February	company records	2011	-	
63	March	company records	2011	-	
64	April	company records	2011	-	
65	May	company records	2011	-	
66	June	company records	2011	-	
67	July	company records	2011	-	
68	August	company records	2011	-	
69	September	company records	2011	-	
70	October	company records	2011	-	
71	November	company records	2011	-	
72	December	p219.25	2011	-	
73	**Transmission Accumulated Depreciation**	(sum lines 60-72) /13		-	
74	**Calculation of Distribution Accumulated Depreciation**	Source			
75	December	Prior year p219.26	2010	-	
76	January	company records	2011	-	
77	February	company records	2011	-	
78	March	company records	2011	-	
79	April	company records	2011	-	
80	May	company records	2011	-	
81	June	company records	2011	-	
82	July	company records	2011	-	
83	August	company records	2011	-	
84	September	company records	2011	-	
85	October	company records	2011	-	
86	November	company records	2011	-	
87	December	p219.26	2011	-	
88	**Distribution Accumulated Depreciation**	(sum lines 75-87) /13		-	
89	**Calculation of Intangible Accumulated Depreciation**	Source			
90	December	Prior year p200.21.c	2010	-	
91	December	p200.21c	2011	-	
92	**Accumulated Intangible Depreciation**	(sum lines 90 & 91) /2		-	
93	**Calculation of General Accumulated Depreciation**	Source			
94	December	Prior year p219.28	2010	-	
95	December	p219.28	2011	-	
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	2010	-
99	January	company records	2011	-
100	February	company records	2011	-
101	March	company records	2011	-
102	April	company records	2011	-
103	May	company records	2011	-
104	June	company records	2011	-
105	July	company records	2011	-
106	August	company records	2011	-
107	September	company records	2011	-
108	October	company records	2011	-
109	November	company records	2011	-
110	December	p219.20 thru 219.24	2011	-
111	**Production Accumulated Depreciation**	(sum lines 98-110) /13		-
112	**Calculation of Common Accumulated Depreciation**	Source		
113	December (Electric Portion)	p356	2010	-
114	December (Electric Portion)	p356	2011	-
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					Details
			Beginning of Year	End of Year	Average Balance
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	-	-	0
120	Account No. 190	234.8.c	5,060,630	5,060,630	5,060,630
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	43,540	43,540	43,540

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

									Welton Spring to Interconnection with PATH Allegheny	
124	**Calculation of Transmission CWIP**	Source				Amos Substation Upgrade	Amos to Welton Spring Line	Welton Spring Substation and SVC		**Total**
125	December	216.b	2010	$	49,802,901	1,318,981.65	39,942,340.82	1,214,082.85	7,327,495.71	49,802,901.03
126	January	company records	2011		52,816,694	1,370,537.65	42,272,558.82	1,387,103.85	7,786,493.71	52,816,694.03
127	February	company records	2011		56,074,855	1,422,093.65	44,803,639.82	1,557,294.85	8,291,826.71	56,074,855.03
128	March	company records	2011		60,266,058	2,577,905.65	47,194,923.82	1,728,325.85	8,764,902.71	60,266,058.03
129	April	company records	2011		64,647,181	3,656,611.65	49,804,656.82	1,903,928.85	9,281,983.71	64,647,181.03
130	May	company records	2011		69,007,134	4,735,388.65	52,415,383.82	2,057,070.85	9,799,290.71	69,007,134.03
131	June	company records	2011		73,495,670	5,882,482.65	55,091,319.82	2,190,228.85	10,331,638.71	73,495,670.03
132	July	company records	2011		78,809,590	6,953,266.65	58,493,149.82	2,351,247.85	11,011,925.71	78,809,590.03
133	August	company records	2011		87,494,681	7,002,475.65	65,465,048.82	2,512,260.85	12,514,895.71	87,494,681.03
134	September	company records	2011		103,968,390	7,115,367.65	78,711,910.82	2,674,521.85	15,466,589.71	103,968,390.03
135	October	company records	2011		122,086,026	7,149,056.65	93,418,878.82	2,831,465.85	18,686,624.71	122,086,026.03
136	November	company records	2011		136,536,795	7,182,641.65	############	2,970,855.85	21,222,815.71	136,536,795.03
137	December	216.b	2011		148,353,499	7,349,250.65	############	3,113,558.85	23,240,044.71	148,353,499.03
138	**Transmission CWIP**	(sum lines 125-137) /13			84,873,806	4,901,235.42	65,186,533.74	2,191,688.23	12,594,348.33	84,873,805.72

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	9,393,949	9,393,949	**9,393,949**	
			Non-transmission Related	-	-		
			Transmission Related	9,393,949	9,393,949	**9,393,949**	

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	400,000	400,000	-	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				
				Reference FERC Form 1 page 232 for details.
149	Beginning Balance of Regulatory Asset	p111.72.d (and notes)	2,678,557	Uncapitalized costs as of date the rates become effective
150	Months Remaining in Amortization Period		46	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	1,442,300	
154	Average Balance of Regulatory Asset	(line 149 + line 153)/2	2,060,428	

Attachment 4 - Cost Support
PATH West Virginia 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		Year	Debt	Preferred Stock	Common Stock
157	January	2009	0	-	0
158	February	2009	-	-	-
159	March	2009	-	-	-
160	April	2009	-	-	-
161	May	2009	-	-	-
162	June	2009	-	-	-
163	July	2009	-	-	-
164	August	2009	-	-	-
165	September	2009	-	-	-
166	October	2009	-	-	-
167	November	2009	-	-	-
168	December	2009	-	-	-
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 service

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		1,236,257.00
171	Miscellaneous Transmission Expense		-
172	Total Account 566	Footnote Data: Schedule Page 320 b. 97	1,236,257.00

PBOPs

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

			Details
173	**Calculation of PBOP Expenses**		
174	**PATH-WV - AEP Employees**		
175	Total PBOP expenses	$117,254,159	
176	Amount relating to retired personnel	$0	
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	1,147,921	
181	PATH WV PBOP Expense for current year	$116,844	
182	PATH WV PBOP Expense in Account 926 for current year	$116,844	
183	PBOP Adjustment for Appendix A, Line 50	$0	
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	1.81	
191	PATH WV PBOP Expense for current year	$5,676	
192	PATH WV PBOP Expense in Account 926 for current year	$5,812	
193	PBOP Adjustment for Appendix A, Line 50	-$136	
194	Lines 185-189 cannot change absent approval or acceptance by FERC in a separate proceeding.		

195	PBOP Expense adjustment	(sum lines 183 & 193)	-$136

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	2010	19,690,413
3	January	company records	2011	19,690,413
4	February	company records	2011	19,690,413
5	March	company records	2011	19,690,413
6	April	company records	2011	19,690,413
7	May	company records	2011	19,690,413
8	June	company records	2011	19,690,413
9	July	company records	2011	19,690,413
10	August	company records	2011	19,690,413
11	September	company records	2011	19,690,413
12	October	company records	2011	19,690,413
13	November	company records	2011	19,690,413
14	December	p207.58.g	2011	19,690,413
15	**Transmission Plant In Service**	(sum lines 2-14) /13		19,690,413
16	**Calculation of Distribution Plant In Service**	Source		
17	December	p206.75.b	2010	-
18	January	company records	2011	-
19	February	company records	2011	-
20	March	company records	2011	-
21	April	company records	2011	-
22	May	company records	2011	-
23	June	company records	2011	-
24	July	company records	2011	-
25	August	company records	2011	-
26	September	company records	2011	-
27	October	company records	2011	-
28	November	company records	2011	-
29	December	p207.75.g	2011	-
30	**Distribution Plant In Service**	(sum lines 17-29) /13		-
31	**Calculation of Intangible Plant In Service**	Source		
32	December	p204.5b	2010	-
33	December	p205.5.g	2011	-
34	**Intangible Plant In Service**	(sum lines 32 & 33) /2		-
35	**Calculation of General Plant In Service**	Source		
36	December	p206.99.b	2010	58,135
37	December	p207.99.g	2011	58,135
38	**General Plant In Service**	(sum lines 36 & 37) /2		58,135
39	**Calculation of Production Plant In Service**	Source		
40	December	p204.46b	2010	-
41	January	company records	2011	-
42	February	company records	2011	-
43	March	company records	2011	-
44	April	company records	2011	-
45	May	company records	2011	-
46	March	Attachment 6	2011	-
47	April	company records	2011	-
48	August	company records	2011	-
49	September	company records	2011	-
50	October	company records	2011	-
51	November	company records	2011	-
52	December	p205.46.g	2011	-
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	2010	-							
72	56		December (Electric Portion)	p356	2011	-							
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)		19,748,548							
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	2010	9,012							
83	61		January	company records	2011	9,705							
84	62		February	company records	2011	10,398							
85	63		March	company records	2011	11,091							
86	64		April	company records	2011	11,784							
87	65		May	company records	2011	12,478							
88	66		June	company records	2011	13,171							
89	67		July	company records	2011	13,864							
90	68		August	company records	2011	14,557							
91	69		September	company records	2011	15,250							
92	70		October	company records	2011	15,944							
93	71		November	company records	2011	16,637							
94	72		December	p219.25	2011	17,330							
95	73		**Transmission Accumulated Depreciation**	(sum lines 60-72) /13		13,171							
96													
97	74		**Calculation of Distribution Accumulated Depreciation**	Source									
98	75		December	Prior year p219.26	2010	-							
99	76		January	company records	2011	-							
100	77		February	company records	2011	-							
101	78		March	company records	2011	-							
102	79		April	company records	2011	-							
103	80		May	company records	2011	-							
104	81		June	company records	2011	-							
105	82		July	company records	2011	-							
106	83		August	company records	2011	-							
107	84		September	company records	2011	-							
108	85		October	company records	2011	-							
109	86		November	company records	2011	-							
110	87		December	p219.26	2011	-							
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	2010	4,375							
115	91		December	p200.21c	2011	7,876							
116	92		**Accumulated Intangible Depreciation**	(sum lines 90 & 91) /2		6,126							
117													
118	93		**Calculation of General Accumulated Depreciation**	Source									
119	94		December	Prior year p219.28	2008	-							
120	95		December	p219.28	2009	-							
121	96		**Accumulated General Depreciation**	(sum lines 94 & 95) /2		-							
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	2010	-							
130	99		January	company records	2011	-							
131	100		February	company records	2011	-							
132	101		March	company records	2011	-							
133	102		April	company records	2011	-							
134	103		May	company records	2011	-							
135	104		June	company records	2011	-							
136	105		July	company records	2011	-							
137	106		August	company records	2011	-							
138	107		September	company records	2011	-							
139	108		October	company records	2011	-							
140	109		November	company records	2011	-							
141	110		December	p219.20 thru 219.24	2011	-							
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	2008	-							
146	114		December (Electric Portion)	p356	2009	-							
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)		19,296							
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	2,240,240	2,240,240	2,240,240						
157	119		Account No. 283 (enter negative)	277.9.k	(781,152)	(781,152)	(781,152)						
158	120		Account No. 190	234.8.c	866,176	866,176	866,176						
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	12,448	12,448	12,448						
165													

Attachment 4 - Cost Support
PATH Allegheny Transmission Company, LLC

						Kemptown Substation	Kemptown to Interconnection with PATH West Virginia	Welton Spring Substation and SVC	Total
124	**Calculation of Transmission CWIP**	Source							
125	December	216.b	2010	$	48,679,709	7,383,051	36,148,502	5,148,156	48,679,709
126	January	company records	2011		51,260,243	7,790,696	38,209,555	5,259,992	51,260,243
127	February	company records	2011		53,828,395	8,192,548	40,265,898	5,369,949	53,828,395
128	March	company records	2011		56,513,948	8,596,057	42,437,429	5,480,462	56,513,948
129	April	company records	2011		62,737,703	9,003,114	45,086,800	8,647,789	62,737,703
130	May	company records	2011		65,574,410	9,385,335	47,442,829	8,746,246	65,574,410
131	June	company records	2011		68,379,663	9,750,807	49,794,150	8,834,706	68,379,663
132	July	company records	2011		72,939,385	11,238,358	52,731,622	8,969,405	72,939,385
133	August	company records	2011		81,290,331	12,607,909	59,618,287	9,064,135	81,290,331
134	September	company records	2011		96,506,335	13,958,542	73,390,718	9,157,075	96,506,335
135	October	company records	2011		116,512,987	15,653,758	91,526,854	9,332,375	116,512,987
136	November	company records	2011		131,010,354	16,996,095	104,591,836	9,422,423	131,010,354
137	December	216.b	2011		140,831,565	18,342,239	112,971,353	9,517,973	140,831,565
138	**Transmission CWIP**	(sum lines 125-137) /13			80,466,541	11,453,731	61,093,526	7,919,284	80,466,541

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	4,108	4,108	-	

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	-	-	-	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	VA			
143	SIT=State Income Tax Rate or Composite	8.250%	8.500%	6.000%			8.575%

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			
				Reference FERC Form 1 page 232 for details.
149	Beginning Balance of Regulatory Asset	p111.72.d (and notes)	405,739	Uncapitalized costs as of date the rates become effective
150	Months Remaining in Amortization Period		26	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	218,475	
154	Average Balance of Regulatory Asset	(line 149 + line 153)/2	312,107	

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	2009	0	-	0
158	February	2009	-	-	-
159	March	2009	-	-	-
160	April	2009	-	-	-
161	May	2009	-	-	-
162	June	2009	-	-	-
163	July	2009	-	-	-
164	August	2009	-	-	-
165	September	2009	-	-	-
166	October	2009	-	-	-
167	November	2009	-	-	-
168	December	2009	-	-	-
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	1.64
181	PATH Allegheny PBOP Expense for current year	$5,144
182	PATH Allegheny PBOP Expense in Account 926 for current year	$4,750
183	PBOP Adjustment for Appendix A, Line 50	394
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	16,266,358
4	21	NET TRANSMISSION PLANT IN SERVICE	-
5	32	CWIP	84,873,806
6		**Carrying charge (line 3/sum of lines 4 and 5)**	**0.19165**

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 Midpoint Line - CWIP	Midpoint Substation and SVC - CWIP	**Midpoint 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		19.2%	19.2%	19.2%	19.2%	19.2%	
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		4,901,235	65,186,534	2,191,688	12,594,348	-	84,873,806
		Revenue Requirement		939,338.71	12,493,224.57	420,044.63	2,413,750.40	-	16,266,358

Attachment 5 - Transmission Enhancement Charge Worksheet

PATH Allegheny Transmission Company, LLC

1 New Plant Carrying Charge

Line	Formula Line	Item	
2	Formula Line	Item	
3	5	NET REVENUE REQUIREMENT	20,629,134
4	21	NET TRANSMISSION PLANT IN SERVICE	19,677,242
5	32	CWIP	80,466,541
6		**Carrying charge (line 3/sum of lines 4 and 5)**	**0.20600**

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**

Line		Details		(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 and SVC - 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		20.6%	20.6%	20.6%	20.6%	
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		11,453,731	61,093,526	7,919,284	19,677,242	100,143,783
		Revenue Requirement		2,359,413.14	12,584,970.09	1,631,334.01	4,053,416.47	20,629,133.71

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)

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)

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

PATH West Virginia 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 5, Line 118 of Rate Formula Template.

Attachment 7

PATH Allegheny Transmission Company, LLC

(HYPOTHETICAL EXAMPLE)

Potomac-Appalachian Transmission Highline, LLC

CALCULATION OF COST OF DEBT AFTER CONSTRUCTION PHASE

YEAR ENDED 12/31/2014

	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
Interest Rates and Interest Calculations
PATH West Virginia Transmission Company, LLC

Reconciliation Revenue Requirement For Year 2009 Available May 31, 2010		2009 Revenue Requirement Forecast by September 1, 2008		True-up Adjustment - Over (Under) Recovery
$10,668,849	-	$15,102,249	=	$4,433,400

Interest Rate on Amount of Refunds or Surcharges		Over (Under) Recovery Plus Interest	Average Monthly Interest Rate	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
from 35.19a			0.2900%				
An over or under collection will be recovered prorata over 2009, held for 2010 and returned prorate over 2011							
Calculation of Interest					Monthly		
January	Year 2009	369,450	0.2900%	12	(12,857)		(382,307)
February	Year 2009	369,450	0.2900%	11	(11,785)		(381,235)
March	Year 2009	369,450	0.2900%	10	(10,714)		(380,164)
April	Year 2009	369,450	0.2900%	9	(9,643)		(379,093)
May	Year 2009	369,450	0.2900%	8	(8,571)		(378,021)
June	Year 2009	369,450	0.2900%	7	(7,500)		(376,950)
July	Year 2009	369,450	0.2900%	6	(6,428)		(375,878)
August	Year 2009	369,450	0.2900%	5	(5,357)		(374,807)
September	Year 2009	369,450	0.2900%	4	(4,286)		(373,736)
October	Year 2009	369,450	0.2900%	3	(3,214)		(372,664)
November	Year 2009	369,450	0.2900%	2	(2,143)		(371,593)
December	Year 2009	369,450	0.2900%	1	(1,071)		(370,521)
					(83,570)		(4,516,970)
					Annual		
January through December	Year 2010	(4,516,970)	0.2900%	12	(157,191)		(4,674,161)
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					Monthly		
January	Year 2011	4,674,161	0.2900%		(13,555)	396,895	(4,290,821)
February	Year 2011	4,290,821	0.2900%		(12,443)	396,895	(3,906,370)
March	Year 2011	3,906,370	0.2900%		(11,328)	396,895	(3,520,803)
April	Year 2011	3,520,803	0.2900%		(10,210)	396,895	(3,134,119)
May	Year 2011	3,134,119	0.2900%		(9,089)	396,895	(2,746,313)
June	Year 2011	2,746,313	0.2900%		(7,964)	396,895	(2,357,383)
July	Year 2011	2,357,383	0.2900%		(6,836)	396,895	(1,967,325)
August	Year 2011	1,967,325	0.2900%		(5,705)	396,895	(1,576,135)
September	Year 2011	1,576,135	0.2900%		(4,571)	396,895	(1,183,811)
October	Year 2011	1,183,811	0.2900%		(3,433)	396,895	(790,350)
November	Year 2011	790,350	0.2900%		(2,292)	396,895	(395,747)
December	Year 2011	395,747	0.2900%		(1,148)	396,895	0
					(88,576)		
True-Up Adjustment with Interest						(4,762,736)	
Less Over (Under) Recovery						4,433,400	
Total Interest						(329,336)	

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

Reconciliation Revenue Requirement For Year 2009 Available May 31, 2010		2009 Revenue Requirement Forecast by Sept 1, 2008		True-up Adjustment - Over (Under) Recovery
$7,516,266	-	$6,443,879	=	($1,072,387)

Interest Rate on Amount of Refunds or Surcharges		Over (Under) Recovery Plus Interest	Average Monthly Interest Rate	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
from 35.19a			0.2900%				
An over or under collection will be recovered prorata over 2009, held for 2010 and returned prorate over 2011							
Calculation of Interest					Monthly		
January	Year 2009	(89,366)	0.2900%	12	3,110		92,475
February	Year 2009	(89,366)	0.2900%	11	2,851		92,216
March	Year 2009	(89,366)	0.2900%	10	2,592		91,957
April	Year 2009	(89,366)	0.2900%	9	2,332		91,698
May	Year 2009	(89,366)	0.2900%	8	2,073		91,439
June	Year 2009	(89,366)	0.2900%	7	1,814		91,180
July	Year 2009	(89,366)	0.2900%	6	1,555		90,921
August	Year 2009	(89,366)	0.2900%	5	1,296		90,661
September	Year 2009	(89,366)	0.2900%	4	1,037		90,402
October	Year 2009	(89,366)	0.2900%	3	777		90,143
November	Year 2009	(89,366)	0.2900%	2	518		89,884
December	Year 2009	(89,366)	0.2900%	1	259		89,625
					20,214		1,092,601
					Annual		
January through December	Year 2010	1,092,601	0.2900%	12	38,023		1,130,624
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					Monthly		
January	Year 2011	(1,130,624)	0.2900%		3,279	(96,004)	1,037,898
February	Year 2011	(1,037,898)	0.2900%		3,010	(96,004)	944,904
March	Year 2011	(944,904)	0.2900%		2,740	(96,004)	851,640
April	Year 2011	(851,640)	0.2900%		2,470	(96,004)	758,106
May	Year 2011	(758,106)	0.2900%		2,199	(96,004)	664,300
June	Year 2011	(664,300)	0.2900%		1,926	(96,004)	570,223
July	Year 2011	(570,223)	0.2900%		1,654	(96,004)	475,872
August	Year 2011	(475,872)	0.2900%		1,380	(96,004)	381,248
September	Year 2011	(381,248)	0.2900%		1,106	(96,004)	286,350
October	Year 2011	(286,350)	0.2900%		830	(96,004)	191,176
November	Year 2011	(191,176)	0.2900%		554	(96,004)	95,726
December	Year 2011	(95,726)	0.2900%		278	(96,004)	(0)
					21,425		

True-Up Adjustment with Interest	$	1,152,049
Less Over (Under) Recovery	$	(1,072,387)
Total Interest	$	79,662

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	8,318
Total Transmission Plant Depreciation			8,318
Total Transmission Depreciation Expense (must tie to p336.7.b & c)	8,318		

GENERAL PLANT		**Accrual Rate (Annual) Percent**	**Annual Depreciation Expense**
390	Structures & Improvements	2.00	1,130
391	Office Furniture & Equipment	5.00	2,370
	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			3,500
Total General Plant Depreciation Expense (must tie to p336.10.b.c.d&e)	3,500		

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 Rate for January 1, 2011 to December 31, 2011

VIRGINIA ELECTRIC AND POWER COMPANY
2011 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 169.

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

		Notes	FERC Form 1 Page # or Instruction (Note H)		2011
	Shaded cells are input cells				**(000's)**
	Allocators				
	Wages & Salary Allocation Factor				
1	Transmission Wages Expense		p354.21b/ Attachment 5	$	24,180
2	Less Generator Step-ups		Attachment 5		62
3	Net Transmission Wage Expenses		(Line 1 - 2)		24,118
4	Total Wages Expense		p354.28b/Attachment 5		604,538
5	Less A&G Wages Expense		p354.27b/Attachment 5		150,521
6	Total		(Line 4 - 5)	$	454,017
7	**Wages & Salary Allocator**	(Note B)	(Line 3 / 6)		**5.3121%**
	Plant Allocation Factors				
8	Electric Plant in Service	(Notes A& Q)	p207.104.g/Attachment 5	$	25,707,324
9	Common Plant In Service - Electric		(Line 26)		0
10	Total Plant In Service		(Sum Lines 8 & 9)		25,707,324
11	Accumulated Depreciation (Total Electric Plant)	(Notes A & Q)	(Line 15 - 14 - 13 -12)		10,781,110
12	Accumulated Intangible Amortization	(Notes A & Q)	p200.21c/Attachment 5		175,213
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		10,956,323
16	Net Plant		(Line 10 - 15)		14,751,002
17	Transmission Gross Plant		(Line 31 - 30)		3,255,505
18	**Gross Plant Allocator**	(Note B)	(Line 17 / 10)		**12.6637%**
19	Transmission Net Plant		(Line 44 - 30)	$	2,426,464
20	**Net Plant Allocator**	(Note B)	(Line 19 / 16)		**16.4495%**
	Plant Calculations				
	Plant In Service				
21	Transmission Plant In Service	(Notes A & Q)	p207.58.g/Attachment 5	$	3,402,466
22	Less: Generator Step-ups	(Notes A & Q)	Attachment 5		163,460
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)		**3,215,191**
25	General & Intangible	(Notes A & Q)	p205.5.g + p207.99.g/Attachment 5		758,913
26	Common Plant (Electric Only)		p356/Attachment 5		0
27	Total General & Common		(Line 25 + 26)		758,913
28	Wage & Salary Allocation Factor		(Line 7)		5.3121%
29	**General & Common Plant Allocated to Transmission**		(Line 27 * 28)	**$**	**40,315**
30	**Plant Held for Future Use (Including Land)**	(Notes C & Q)	p214.47.d/Attachment 5	**$**	**2,858**
31	**TOTAL Plant In Service**		**(Line 24 + 29 + 30)**	**$**	**3,258,364**
	Accumulated Depreciation				
32	Transmission Accumulated Depreciation	(Notes A & Q)	p219.25.c/Attachment 5	$	847,347
33	Less Accumulated Depreciation for Generator Step-ups	(Notes A & Q)	Attachment 5		40,241
34	Less Accumulated Depreciation for Interconnect Facilities Installed After March 15, 2000	(Notes A & Q)	Attachment 5		4,984
35	Total Accumulated Depreciation for Transmission		(Line 32 - 33 - 34)		802,122
36	Accumulated General Depreciation	(Notes A & Q)	p219.28.b/Attachment 5		331,541
37	Accumulated Intangible Amortization	(Notes A & Q)	(Line 12)		175,213
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)		506,754
41	Wage & Salary Allocation Factor		(Line 7)		5.3121%
42	**General & Common Allocated to Transmission**		(Line 40 * 41)		**26,920**
43	**TOTAL Accumulated Depreciation**		**(Line 35 + 42)**	**$**	**829,041**
44	**TOTAL Net Property, Plant & Equipment**		**(Line 31 - 43)**	**$**	**2,429,322**

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

	Formula Rate -- Appendix A	**Notes**	**FERC Form 1 Page # or Instruction (Note H)**		**2011**
	Adjustment To Rate Base				
	Accumulated Deferred Income Taxes				
45	ADIT net of FASB 106 and 109		Attachment 1	$	(195,047)
46	**Accumulated Deferred Income Taxes Allocated To Transmission**		(Line 45)	**$**	**(195,047)**
	Transmission O&M Reserves				
47	**Total Balance Transmission Related Account 242 Reserves**	Enter Negative	Attachment 5	**$**	**(6,068)**
	Prepayments				
48	Prepayments	(Notes A & R)	Attachment 5	$	2,136
49	**Total Prepayments Allocated to Transmission**		(Line 48)	**$**	**2,136**
	Materials and Supplies				
50	Undistributed Stores Exp	(Notes A & R)	p227.6c & 16.c	$	-
51	Wage & Salary Allocation Factor		(Line 7)		5.3121%
52	Total Transmission Allocated Materials and Supplies		(Line 50 * 51)		0
53	Transmission Materials & Supplies		p227.8c/2		7,200
54	**Total Materials & Supplies Allocated to Transmission**		(Line 52 + 53)	**$**	**7,200**
	Cash Working Capital				
55	Transmission Operation & Maintenance Expense		(Line 85)	$	80,784
56	1/8th Rule		x 1/8		12.5%
57	**Total Cash Working Capital Allocated to Transmission**		(Line 55 * 56)	**$**	**10,098**
	Network Credits				
58	Outstanding Network Credits	(Note N)	Attachment 5 / From PJM		0
59	Less Accumulated Depreciation Associated with Facilities with Outstanding Network Credits	(Note N)	Attachment 5 / From PJM		0
60	Net Outstanding Credits		(Line 58 - 59)		**0**
61	**TOTAL Adjustment to Rate Base**		(Line 46 + 47 + 49 + 54 + 57 - 60)	**$**	**(181,681)**
62	**Rate Base**		(Line 44 + 61)	**$**	**2,247,641**
	O&M				
	Transmission O&M				
63	Transmission O&M		p321.112.b/Attachment 5	$	70,598
64	Less GSU Maintenance		Attachment 5		193
65	Less Account 565 - Transmission by Others		p321.96.b/Attachment 5		14,280
66	Plus Schedule 12 Charges billed to Transmission Owner and booked to Account 565	(Note O)	PJM Data		0
67	**Transmission O&M**		(Lines 63 - 64 + 65 + 66)	**$**	**56,125**
	Allocated General & Common Expenses				
68	Common Plant O&M	(Note A)	p356		0
69	Total A&G		Attachment 5		480,698
70	Less Property Insurance Account 924		p323.185b		10,879
71	Less Regulatory Commission Exp Account 928	(Note E)	p323.189b/Attachment 5		33,899
72	Less General Advertising Exp Account 930.1		p323.911b/Attachment 5		2,662
73	Less EPRI Dues	(Note D)	p352-353/Attachment 5		2,738
74	**General & Common Expenses**		(Lines 68 + 69) - Sum (70 to 73)	$	430,519
75	Wage & Salary Allocation Factor		(Line 7)		5.3121%
76	**General & Common Expenses Allocated to Transmission**		(Line 74 * 75)	**$**	**22,870**
	Directly Assigned A&G				
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b/Attachment 5	$	-
78	General Advertising Exp Account 930.1	(Note K)	p323.191b		0
79	Subtotal - Transmission Related		(Line 77 + 78)		**0**
80	Property Insurance Account 924		p323.185b		10,879
81	General Advertising Exp Account 930.1	(Note F)	Attachment 5		0
82	Total		(Line 80 + 81)		10,879
83	Net Plant Allocation Factor		(Line 20)		16.4495%
84	**A&G Directly Assigned to Transmission**		(Line 82 * 83)	**$**	**1,790**
85	**Total Transmission O&M**		**(Line 67 + 76 + 79 + 84)**	**$**	**80,784**

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

			Notes	FERC Form 1 Page # or Instruction (Note H)		2011
	Depreciation & Amortization Expense					
	Depreciation Expense					
86	Transmission Depreciation Expense		(Notes A and S)	p336.7b&c/Attachment 5	$	**67,029**
87	Less: GSU Depreciation			Attachment 5		**3,309**
88	Less Interconnect Facilities Depreciation			Attachment 5		**482**
89	Extraordinary Property Loss			Attachment 5		**0**
90	Total Transmission Depreciation			(Line 86 - 87 - 88 + 89)		**63,237**
91	General Depreciation		(Note A)	p336.10b&c&d/Attachment 5		22,008
92	Intangible Amortization		(Note A)	p336.1d&e/Attachment 5		22,140
93	Total			(Line 91 + 92)		**44,147**
94	Wage & Salary Allocation Factor			(Line 7)		5.3121%
95	**General and Intangible Depreciation Allocated to Transmission**			(Line 93 * 94)		**2,345**
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)		5.3121%
100	**Common Depreciation - Electric Only Allocated to Transmission**			(Line 98 * 99)		**0**
101	**Total Transmission Depreciation & Amortization**			**(Line 90 + 95 + 100)**	**$**	**65,582**
	Taxes Other than Income					
102	**Taxes Other than Income**			Attachment 2	**$**	**18,853**
103	**Total Taxes Other than Income**			**(Line 102)**	**$**	**18,853**
	Return / Capitalization Calculations					
	Long Term Interest					
104	Long Term Interest		(Note T)	p117.62c through 67c/Attachment 5	$	367,601
105	Less LTD Interest on Securitization Bonds		(Note P)	Attachment 8		0
106	**Long Term Interest**			(Line 104 - 105)	$	367,601
107	**Preferred Dividends**		(Note T), enter positive	p118.29c	$	16,659
	Common Stock					
108	Proprietary Capital			p112.16c,d/2	$	6,981,788
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		-15,036
111	**Common Stock**			(Sum Lines 108 to 110)	$	6,707,738
	Capitalization					
112	Long Term Debt			p112.24c,d/2	$	6,291,289
113	Less Loss on Reacquired Debt		(Note T), enter negative	p111.81c,d/2		-11,255
114	Plus Gain on Reacquired Debt		(Note T), enter positive	p113.61c,d/2		3,788
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)		6,283,822
117	Preferred Stock		(Note T), enter positive	p112.3c,d/2		259,014
118	Common Stock			(Line 111)		6,707,738
119	**Total Capitalization**			(Sum Lines 116 to 118)	$	13,250,574
120	Debt %	Total Long Term Debt		(Line 116 / 119)		47.4%
121	Preferred %	Preferred Stock		(Line 117 / 119)		2.0%
122	Common %	Common Stock		(Line 118 / 119)		50.6%
123	Debt Cost	Total Long Term Debt		(Line 106 / 116)		0.0585
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)		0.0277
127	Weighted Cost of Preferred	Preferred Stock		(Line 121 * 124)		0.0013
128	Weighted Cost of Common	Common Stock		(Line 122 * 125)		0.0577
129	**Total Return (R)**			(Sum Lines 126 to 128)		**0.0867**
130	**Investment Return = Rate Base * Rate of Return**			**(Line 62 * 129)**		**194,890**

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

		Notes	FERC Form 1 Page # or Instruction (Note H)		2011
	Composite Income Taxes				
	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		6.22%
133	p	(percent of federal income tax deductible for state purposes)	Per State Tax Code		0.00%
134	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			39.04%
135	T/ (1-T)				64.05%
	ITC Adjustment	(Note I)			
136	Amortized Investment Tax Credit	enter negative	Attachment 1	$	(163)
137	T/(1-T)		(Line 135)		64.05%
138	**ITC Adjustment Allocated to Transmission**		(Line 136 * (1 + 137))	**$**	**(267)**
139	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =	[Line 135 * 130 * (1-(126 / 129))]		**84,888**
140	**Total Income Taxes**		**(Line 138 + 139)**	**$**	**84,621**
	REVENUE REQUIREMENT				
	Summary				
141	Net Property, Plant & Equipment		(Line 44)	$	2,429,322
142	Adjustment to Rate Base		(Line 61)		-181,681
143	**Rate Base**		(Line 62)	**$**	**2,247,641**
144	O&M		(Line 85)		80,784
145	Depreciation & Amortization		(Line 101)		65,582
146	Taxes Other than Income		(Line 103)		18,853
147	Investment Return		(Line 130)		194,890
148	Income Taxes		(Line 140)		84,621
149					
150	**Revenue Requirement**		**(Sum Lines 144 to 149)**	**$**	**444,730**
	Net Plant Carrying Charge				
151	Revenue Requirement		(Line 150)	**$**	**444,730**
152	Net Transmission Plant		(Line 24 - 35)		**2,413,069**
153	Net Plant Carrying Charge		(Line 151 / 152)		**18.4301%**
154	Net Plant Carrying Charge without Depreciation		(Line 151 - 86) / 152		**15.6523%**
155	Net Plant Carrying Charge without Depreciation, Return or Income Taxes		(Line 151 - 86 - 130 - 140) / 152		**4.0691%**
	Net Plant Carrying Charge Calculation with 100 Basis Point increase in ROE				
156	Gross Revenue Requirement Less Return and Taxes		(Line 150 - 147 - 148)	**$**	**165,219**
157	Increased Return and Taxes		Attachment 4		**298,177**
158	Net Revenue Requirement with 100 Basis Point increase in ROE		(Line 156 + 157)		**463,396**
159	Net Transmission Plant		(Line 152)		**2,413,069**
160	Net Plant Carrying Charge with 100 Basis Point increase in ROE		(Line 158 / 159)		**19.2036%**
161	Net Plant Carrying Charge with 100 Basis Point increase in ROE without Depreciation		(Line 158 - 86) / 159		**16.4259%**
162	**Revenue Requirement**		(Line 150)	**$**	**444,730**
163	True-up Adjustment		Attachment 6		**28,192**
164	Plus any increased ROE calculated on Attachment 7 other than PJM Schedule 12 projects.		Attachment 7		**2,932**
165	Facility Credits under Section 30.9 of the PJM OATT.		Attachment 5		**-**
166	Revenue Credits		Attachment 3		**(8,607)**
167	Interest on Network Credits		PJM data		0
168	**Annual Transmission Revenue Requirement (ATRR)**		(Line 162 + 163 +164 + 165 + 166 + 167)	**$**	**467,247**
	Rate for Network Integration Transmission Service				
169	1 CP Peak	(Note L)	PJM Data - Attachment 5		**19,140**
170	Rate ($/MW-Year)		(Line 168 / 169)		**24,412.04**
171	**Rate for Network Integration Transmission Service ($/MW/Year)**		**(Line 170)**		**24,412.04**

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 indicates 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 balances 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	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.
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 initial 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, the projected capital structure and actual capital structure shall reflect the capital structure from the most recent FERC Form No. 1 data available.

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31, 2011

	Only Transmission Related	*Plant Related*	*Labor Related*	*Total ADIT*
ADIT- 282	(196,888)	(51,765)	(43,311)	
ADIT-283	0	(7,249)	(1,607)	
ADIT-190	77	113,272	80,015	
Subtotal	(196,811)	54,258	35,096	
Wages & Salary Allocator			5.3121%	
Gross Plant Allocator		12.6637%		
End of Year ADIT	(196,811)	6,871	1,864	(188,075)
End of Previous Year ADIT (from Sheet 1A-ADIT (3))	(205,074)	1,991	1,065	(202,019)
Average Beginning and End of Year ADIT	(200,942)	4,431	1,465	(195,047)

End of Year ADIT	(188,075)
End of Previous Year ADIT	(202,019)
Average Beginning and End of Year ADIT	(195,047)

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***
ADFIT - OTHER COMPREHENSIVE INCOME	123	123				Not applicable to Transmission Cost of Service calculation.
BAD DEBTS	7,271	7,271				For tax purposes bad debts are deductible when they are deemed to be uncollectible / worthless.
CAPITAL LEASE	439	439				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	171,951	171,951				Represents tax capitalized interest on projects in CWIP - increase in taxable income.
CAPITALIZED INTEREST OPERATING IN SERVICE	107,763			107,763		Represents tax "In Service" capitalized Interest placed in service net of tax amortization.
CIAC DC - NONOP IN SERVICE	2,016	2,016				Not applicable to Transmission Cost of Service calculation.
CIAC NC - NONOP CWIP	65	65				Not applicable to Transmission Cost of Service calculation.
CIAC NC - NONOP IN SERVICE	2,491	2,491				Not applicable to Transmission Cost of Service calculation.
CIAC VA - NONOP CWIP	31,826	31,826				Not applicable to Transmission Cost of Service calculation.
CIAC VA - NONOP IN SERVICE	95,521	95,521				Not applicable to Transmission Cost of Service calculation.
CONTINGENT CLAIMS CURRENT	2,732	2,732				Not applicable to Transmission Cost of Service calculation.
CONTINGENT CLAIMS NONCURRENT	3,201	3,201				Not applicable to Transmission Cost of Service calculation.
CUSTOMER ACCOUNTS-RESERVE & REFUND	172,809	172,809				Not applicable to Transmission Cost of Service calculation.
CUSTOMER ACCOUNTS INTEREST-RESERVE & REFUND	(154)	(154)				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	(56)	(56)				Not applicable to Transmission Cost of Service calculation.
DEFERRED GAIN/LOSS OPERATING	366			366		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.
DEFERRED N.C. SIT NONOP - OCI	22	22				Not applicable to Transmission Cost of Service calculation.
DFIT 190 OPERATING NONCURRENT ASSET	342	342				Not applicable to Transmission Cost of Service calculation.
DFIT 282 NONOPERATING PLANT NONCURR LIAB	4,439	4,439				Not applicable to Transmission Cost of Service calculation.
DFIT 282 OPERATING PLANT NONCURR LIAB	107,002	107,002				Not applicable to Transmission Cost of Service calculation.
DFIT 283 NONOPERATING OTHER NONCURRENT LIAB	11	11				Not applicable to Transmission Cost of Service calculation.
DFIT 283 NONOPERATING NONCURRENT LIAB	2,227	2,227				Not applicable to Transmission Cost of Service calculation.
DFIT 283 OPERATING CURRENT LIABILITY	3,967	3,967				Not applicable to Transmission Cost of Service calculation.
DFIT 283 OPERATING NONCURRENT CURRENT LIAB	380	380				Not applicable to Transmission Cost of Service calculation.
DFIT 283 OPERATING NONCURRENT LIAB	7,337	7,337				Not applicable to Transmission Cost of Service calculation.
DFIT 283 OPERATING OTHER NONCURRENT LIABILITY	(63)	(63)				Not applicable to Transmission Cost of Service calculation.
DFIT EFFECT ON SIT NONOP - OCI	495	495				Not applicable to Transmission Cost of Service calculation.
DIRECTOR CHARITABLE DONATION	105	105				Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP CURRENT ASSET D.C.	0	0				Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP CURRENT ASSET N.C.	52	52				Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP CURRENT ASSET VA	804	804				Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP CURRENT ASSET W.V.	35	35				Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP NONCURRENT ASSET D.C.	0	0				Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP NONCURRENT ASSET N.C.	(60)	(60)				Not applicable to Transmission Cost of Service calculation.
DSIT 190 N ONOP NONCURRENT ASSET VA	90	90				Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP NONCURRENT ASSET W.V.	(5)	(5)				Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP NONCURRENT ASSET D.C.	1	1				Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP NONCURRENT ASSET N.C.	3,641	3,641				Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP NONCURRENT ASSET VA	56,589	56,589				Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP NONCURRENT ASSET W.V.	1,876	1,876				Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP PLANT NONCURR ASSET D.C.	0	0				Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP PLANT NONCURR ASSET N.C.	1,162	1,162				Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP PLANT NONCURR ASSET VA	18,108	18,108				Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP PLANT NONCURR ASSET W.V.	600	600				Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING CURRENT ASSET D.C.	0	0				Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING CURRENT ASSET N.C.	1,659	1,659				Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING CURRENT ASSET VA	25,969	25,969				Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING CURRENT ASSET W.V.	1,007	1,007				Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING NONCURR ASSEST D.C.	1	1				Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING NONCURR ASSEST N.C.	(1,552)	(1,552)				Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING NONCURR ASSEST VA	(16,754)	(16,754)				Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING NONCURR ASSEST VA MIN	(702)	(702)				Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING NONCURR ASSEST W.V.	(615)	(615)				Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING PLANT NONCURR ASSET D.C.	1	1				Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING PLANT NONCURR ASSET N.C.	5,154	5,154				Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING PLANT NONCURR ASSET VA	81,415	81,415				Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING PLANT NONCURR ASSET W.V.	2,689	2,689				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)	5,744	5,744				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT DEFICIENCY D.C. (190)	0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT DEFICIENCY N.C. (190)	61	61				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT DEFICIENCY VA (190)	983	983				Not applicable to Transmission Cost of Service calculation.

ATTACHMENT H-16A

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31, 2011

FAS 109 ITC DSIT DEFICIENCY W.V.(190)		32	32				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT GROSSUP D.C.		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT GROSSUP N.C.		39	39				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT GROSSUP VA		628	628				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT GROSSUP W.V.		21	21				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC GROSSUP (190)		3,673	3,673				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC REG LIAB		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133		5,014	5,014				Not applicable to Transmission Cost of Service calculation.
FAS 133 - DEFERRED GAIN/LOSS CAPAC HEDGE NON CURRE		1,058	1,058				Not applicable to Transmission Cost of Service calculation.
FAS 133 - FTR HEDGE CURRENT ASSET		(2,904)	(2,904)				Not applicable to Transmission Cost of Service calculation.
FAS 133 - POWER HEDGE CURRENT ASSET		123	123				Not applicable to Transmission Cost of Service calculation.
FAS 133 REG FTR CURRENT		2,904	2,904				Not applicable to Transmission Cost of Service calculation.
FAS 133 REG GL POWER HEDGE CURRENT		(3)	(3)				Not applicable to Transmission Cost of Service calculation.
FAS 133 REG HEDGE DEBT CURRENT		(598)	(598)				Not applicable to Transmission Cost of Service calculation.
FAS 143 ASSET OBLIGATION		13,569	13,492	77			Represents ARO accruals not deductible for tax.
FAS143 DECOMMISSIONING		297,634	297,634				Represents ARO accruals not deductible for tax.
FEDERAL TAX INTEREST EXPENSE NON CURRENT		-	-				Not applicable to Transmission Cost of Service calculation.
FIXED ASSETS		341	341				Not applicable to Transmission Cost of Service calculation.
FLEET LEASE CREDIT - CURRENT		60			60		Books amortize the fleet lease extension credit over the new lease; tax takes the deduction when incurred.
FLEET LEASE CREDIT - NONCURRENT		56			56		Books amortizes the fleet lease extension credit over the new lease; tax takes the deduction when incurred.
FUEL DEF CURRENT LIAB		2,594	2,594				Not applicable to Transmission Cost of Service calculation.
FUEL DEF NON CUR LIAB		7,273	7,273				Not applicable to Transmission Cost of Service calculation.
GAIN SALE/LEASEBACK - SYSTEM OFFICE		-	-				Not applicable to Transmission Cost of Service calculation.
GROSS REC-UNBILLED REV-NC		125	125				Books include income when meter is read; taxed when service is provided.
HEADWATER BENEFITS		523	523				Not applicable to Transmission Cost of Service calculation.
INT STOR NORTH ANNA		2,977	2,977				Books recognizes the expense as incurred. For tax the deduction is recognized when the casks are filled.
INT STOR SURRY		552	552				Books recognizes the expense as incurred. For tax the deduction is recognized when the casks are filled.
LONG TERM DISABILITY RESERVE		6,377				6,377	Book estimate accrued and expensed; tax deduction when paid.
METERS		7,162	7,162				Books pre-capitalize when purchased; tax purposes when installed.
NUCLEAR FUEL - PERMANENT DISPOSAL		(1)	(1)				Books estimate expense, tax deduction taken when paid.
OBSOLETE INVENTORY		425	425				Not applicable to Transmission Cost of Service calculation.
OPEB		23,960				23,960	Represents the difference between the book accrual expense and the actual funded amount.
PERFORMANCE ACHIEVEMENT PLAN		-	-				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		5,027			5,027		Books record the yield to maturity method; taxes amortize staight line.
P'SHIP INCOME - NC ENTERPRISE		32	32				Not applicable to Transmission Cost of Service calculation.
P'SHIP INCOME - VIRGINIA CAPITAL		208	208				Not applicable to Transmission Cost of Service calculation.
QUALIFIED SETTLEMENT FUND		140	140				Not applicable to Transmission Cost of Service calculation.
REACTOR DECOMMISSIONING LIABILITY		-	-				Represents the difference between the accrual and payments.
REG FUEL HEDGE		(611)	(611)				Not applicable to Transmission Cost of Service calculation.
REG HEDGES CAPACITY		5,175	5,175				Not applicable to Transmission Cost of Service calculation.
REG HEDGES CAPACITY NC		2,094	2,094				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 VCHEC AFUDC DEBT		4	4				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 VCHEC COST RESERVE		368	368				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 BEAR GARDEN COST RESERVE		3,503	3,503				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 VCHEC AFUDC DEBT		2,085	2,085				Not applicable to Transmission Cost of Service calculation.
REG FUEL HEDGE		766	766				Not applicable to Transmission Cost of Service calculation.
REG HEDGES DEBT		29,884	29,884				Not applicable to Transmission Cost of Service calculation.
REG LIAB - DEBT VALUATION - MTM - CURRENT		1,259	1,259				Not applicable to Transmission Cost of Service calculation.
REG LIAB - DEFERRED G/L CAPACITY HEDGE - CURRENT		410	410				Not applicable to Transmission Cost of Service calculation.
REG LIAB - DEFERRED G/L CAPACITY HEDGE - NON CUR		(2,094)	(2,094)				Not applicable to Transmission Cost of Service calculation.
REG LIAB - DEFERRED G/L POWER HEDGE CURRENT		11	11				Not applicable to Transmission Cost of Service calculation.
REG LIAB - DEFERRED VALUATION - MTM - NON CURRENT		(9,611)	(9,611)				Not applicable to Transmission Cost of Service calculation.
REG LIAB - FTR CURRENT		1,219	1,219				Not applicable to Transmission Cost of Service calculation.
REG LIAB CURRENT RIDER A6 BEAR GARDEN AFUDC DEBT		0	0				Not applicable to Transmission Cost of Service calculation.
REG LIAB OTHER NON CURR DOE SETTLEMENT		2,228	2,228				Not applicable to Transmission Cost of Service calculation.
REG LIAB PLANT CONTRA VASLSTX		1,568	1,568				Not applicable to Transmission Cost of Service calculation.
REG LIABILITY DECOMMISSIONING		99,337	99,337				Not applicable to Transmission Cost of Service calculation.
REG LIABILITY HEDGES DEBT		3,862	3,862				Not applicable to Transmission Cost of Service calculation.
REG RATE REFUND - CURRENT		(142,942)	(142,942)				Not applicable to Transmission Cost of Service calculation.
REG RATE REFUND INTEREST - CURRENT		(124)	(124)				Not applicable to Transmission Cost of Service calculation.
REGULATORY ASSET - D & D		4	4				Not applicable to Transmission Cost of Service calculation.
REGULATORY ASSET - VA SLS TAX		4,962	4,962				Not applicable to Transmission Cost of Service calculation.
RESTRICTED STOCK AWARD		819	819				Not applicable to Transmission Cost of Service calculation.
RETIREMENT - (FASB 87)		85,432				85,432	Book estimate accrued and expensed; tax deduction when paid.
RETIREMENT - EXEC SUPP RET (ESRP) - NONOP		(23)	(23)				Not applicable to Transmission Cost of Service calculation.
RETIREMENT - SUPPLEMENTAL RETIREMENT		132	132				Not applicable to Transmission Cost of Service calculation.
SEPARATION/ERT		(11,794)				(11,794)	Book amount accrued and expensed; tax deduction when paid.
SEPARATION/ERT - NON CURRENT		4	4				Not applicable to Transmission Cost of Service calculation.
SUCCESS SHARE PLAN		0				0	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		10,891	10,891				Not applicable to Transmission Cost of Service calculation.
W.VA. STATE POLLUTION CONTROL - FEDERAL EFFECT		2,537	2,537				Federal effect of state deductions.
WEST VA PROPERTY TAX		1,951	1,951				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.
ROUNDING		0	0				
Subtotal - p234		1,387,603	1,170,279	77	113,272	103,975	
Less FASB 109 Above if not separately removed		11,181	11,181	0	0	0	
Less FASB 106 Above if not separately removed		23,960	0	0	0	23,960	
Total		1,352,462	1,159,098	77	113,272	80,015	

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, 2011

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	33	33				Represents the amount of amortization of AFC in service not allowable for tax.
AFC DEFERRED TAX - FUEL IN SERVICE	(71)	(71)				Represents the amount of amortization of AFC in service not allowable for tax.
AFC DEFERRED TAX - PLANT CWIP	(22,638)	(22,638)				Represents the amount of amortization of AFC in service not allowable for tax.
AFC DEFERRED TAX - PLANT IN SERVICE	(14,646)	(5,758)	(8,889)			Represents the amount of amortization of AFC in service not allowable for tax.
AFUDC - DEBT - GENERATION RIDER	(1,787)	(1,787)				Not applicable to Transmission Cost of Service calculation.
BOOK CAPITALIZED INTEREST CWIP	(1,457)			(1,457)		Represents the unallowable amount of book interest.
CAP EXPENSE	(44,510)	(45,489)	980			Capitalized for books and current deduction for tax as repairs.
CAPITAL LEASE	(460)	(460)				Not applicable to Transmission Cost of Service calculation.
CASUALTY LOSS	(52,111)			(52,111)		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	18,731				18,731	Represents total Book Computer Software Amortization Schedule M addition.
COMPUTER SOFTWARE-CWIP	(7,669)	(7,669)				Represents the allowable "In house" deduction for tax.
COMPUTER SOFTWARE-TAX AMORT	(26,144)				(26,144)	Total tax amortization shown as a schedule M deduction and add back total book amortization.
COST OF REMOVAL	(77,660)	(70,501)	(5,210)		(1,949)	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	(335,496)	(335,496)				Not applicable to Transmission Cost of Service calculation.
DFIT 190 NONOPERATING NONCURR ASSET	(6,955)	(6,955)				Not applicable to Transmission Cost of Service calculation.
DFIT 190 OPERATING NONCURR ASSET	(30,105)	(30,105)				Not applicable to Transmission Cost of Service calculation.
DFIT 190 OPERATING PLANT NONCURRENT ASSET	(1,144)	(1,144)				Not applicable to Transmission Cost of Service calculation.
DSIT 282 NONOP NONCURR PLAN LIABLITY - D.C.	0	0				Not applicable to Transmission Cost of Service calculation.
DSIT 282 NONOP NONCURR PLAN LIABLITY - N.C.	(16)	(16)				Not applicable to Transmission Cost of Service calculation.
DSIT 282 NONOP NONCURR PLAN LIABLITY - VA.	28	28				Not applicable to Transmission Cost of Service calculation.
DSIT 282 NONOP NONCURR PLAN LIABLITY - W.V.	(1)	(1)				Not applicable to Transmission Cost of Service calculation.
DSIT 282 NONOP PLANT NONCURR LIAB D.C.	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
DSIT 282 NONOP PLANT NONCURR LIAB N.C.	(371)	(371)				Not applicable to Transmission Cost of Service calculation.
DSIT 282 NONOP PLANT NONCURR LIAB VA	(12,231)	(12,231)				Not applicable to Transmission Cost of Service calculation.
DSIT 282 NONOP PLANT NONCURR LIAB W.V.	(195)	(195)				Not applicable to Transmission Cost of Service calculation.
DSIT 282 OPERATING PLANT NONCURR LIAB D.C.	(8)	(8)				Not applicable to Transmission Cost of Service calculation.
DSIT 282 OPERATING PLANT NONCURR LIAB N.C.	(28,720)	(28,720)				Not applicable to Transmission Cost of Service calculation.
DSIT 282 OPERATING PLANT NONCURR LIAB VA	(262,924)	(262,924)				Not applicable to Transmission Cost of Service calculation.
DSIT 282 OPERATING PLANT NONCURR LIAB W.V.	(15,488)	(15,488)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT DEFICIENCY (282)	(3,734)	(3,734)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282)	(35,113)	(35,113)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - BEAR GARDEN	(1,423)	(1,423)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - BREMO RIDER	(10)	(10)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - GENERATION R	(6,518)	(6,518)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - NAIII RIDER	(1,678)	(1,678)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - PPT RIDER	(8)	(8)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - VCHEC RIDER	510	510				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - WARREN RIDER	(31)	(31)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY D.C. (282)	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY D.C. (282) - BEAR GA	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY D.C. (282) - BREMO R	-	-				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY D.C. (282) - GENERAT	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY D.C. (282) - NAIII	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY D.C. (282) - PP7 RIDER	-	-				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY D.C. (282) - VCHEC R	0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY D.C. (282) - WARREN	-	-				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282)	(234)	(234)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282) - BEAR GA	(15)	(15)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282) - BREMO R	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282) - GENERAT	(73)	(73)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282) - NAIII R	(18)	(18)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282) - PP7 RID	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282) - VCHEC R	4	4				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282) - WARREN	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282)	(3,480)	(3,480)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282) - BEAR GARD	(243)	(243)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282) - BREMO RID	(2)	(2)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282) - GENERATIO	(1,110)	(1,110)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282) - NAIII RID	(287)	(287)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282) - PP7 RIDER	(1)	(1)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282) - VCHEC RID	89	89				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282) - WARREN RI	(5)	(5)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282)	(117)	(117)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282) - BEAR GA	(8)	(8)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282) - BREMO R	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282) - GENERAT	(37)	(37)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282) - NAIII R	(9)	(9)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282) - PP7 RID	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282) - VCHEC R	3	3				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282) - WARREN	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FIXED ASSETS	290			290		Represents IRS audit adjustments to plant-related differences.
FIXED ASSETS - D.C.	(0)			(0)		Represents the state impact of IRS Audit adjustments to plant related differences.
FIXED ASSETS - NC	111			111		Represents the state impact of IRS Audit adjustments to plant related differences.
FIXED ASSETS - VA	1,354			1,354		Represents the state impact of IRS Audit adjustments to plant related differences.
FIXED ASSETS - W.V.	49			49		Represents the state impact of IRS Audit adjustments to plant related differences.
GAIN(LOSS) INTERCO SALES - BOOK/TAX	(197)	(197)				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	5,070	5,070				Represents difference between book burn of nuclear fuel based on usage vs. tax depreciation.
LIBERALIZED DEPRECIATION - FUEL CWIP	(30)	(30)				Represents the difference between book CWIP and Tax CWIP.
LIBERALIZED DEPRECIATION - PLANT ACUFILE	(2,188,247)	(1,970,528)	(183,769)		(33,950)	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	690	690				Not applicable to Transmission Cost of Service calculation.
LIBERALIZED DEPRECIATION - PLANT OTHER	(211,736)	(211,736)				Not applicable to Transmission Cost of Service calculation.
LIBERALIZED DEPRECIATION - PLANT FUTURE USE	(1)	(1)				Not applicable to Transmission Cost of Service calculation.
LIBERALIZED DEPRECIATION - PLANT NON UTILITY	15	15				Not applicable to Transmission Cost of Service calculation.
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)	(3,371,605)	(3,079,641)	(196,888)	(51,765)	(43,311)	
Less FASB 109 Above if not separately removed	(53,549)	(53,549)	0	0	0	
Less FASB 106 Above if not separately removed	0					
Total	(3,318,055)	(3,026,092)	(196,888)	(51,765)	(43,311)	

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, 2011

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	(8,052)	(8,052)				Not applicable to Transmission Cost of Service calculation.
AFUDC - DEBT - VCHEC RIDER CURRENT	(1,191)	(1,191)				Not applicable to Transmission Cost of Service calculation.
CONTINGENT CLAIMS CURRENT	-					Not applicable to Transmission Cost of Service calculation.
DECOMM POUR OVER	(5,482)	(5,482)				Not applicable to Transmission Cost of Service calculation.
DECOMMISSIONING TRUST - UNREALIZED GAIN/LOSS - NC	(28,170)	(28,170)				Not applicable to Transmission Cost of Service calculation.
DEFERRED FUEL EXPENSE	0	0				Not applicable to Transmission Cost of Service calculation.
DEFERRED FUEL EXPENSE - OTHER CURRENT	(1,573)	(1,573)				Not applicable to Transmission Cost of Service calculation.
DEFERRED FUEL EXPENSE - CURRENT	9,750	9,750				Not applicable to Transmission Cost of Service calculation.
DEFERRED N.C. SIT NONOP - OCI	(336)	(336)				Not applicable to Transmission Cost of Service calculation.
DEFERRED SIT NONOP - OCI	(1,079)	(1,079)				Not applicable to Transmission Cost of Service calculation.
DFIT 190 NONOP NONCURRENT ASSET	(11)	(11)				Not applicable to Transmission Cost of Service calculation.
DFIT 190 NONOPERATING CURRENT ASSET	(312)	(312)				Not applicable to Transmission Cost of Service calculation.
DFIT 190 NONOPERATING NONCURR ASSET	(21,928)	(21,928)				Not applicable to Transmission Cost of Service calculation.
DFIT 190 OPERATING CURRENT ASSET	(10,135)	(10,135)				Not applicable to Transmission Cost of Service calculation.
DFIT 190 OPERATING NONCURR ASSET	(10,373)	(10,373)				Not applicable to Transmission Cost of Service calculation.
DFIT 190 OPERATING NONCURRENT ASSET	16,909	16,909				Not applicable to Transmission Cost of Service calculation.
DFIT 283 NONOP OTHER NONCURRENT LIABILITY	18	18				Not applicable to Transmission Cost of Service calculation.
DFIT 283 OPERATING NONCURRENT LIAB	89	89				Not applicable to Transmission Cost of Service calculation.
DFIT EFFECT ON SIT NONOP - OCI	(8)	(8)				Not applicable to Transmission Cost of Service calculation.
DOE SETTLEMENT	(49,972)	(49,972)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 NONOP NONCURR OTHER LIABILITY - D.C.	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 NONOP NONCURR OTHER LIABILITY - N.C.	74	74				Not applicable to Transmission Cost of Service calculation.
DSIT 283 NONOP NONCURR OTHER LIABILITY - VA.	(111)	(111)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 NONOP NONCURR OTHER LIABILITY - W.V.	6	6				Not applicable to Transmission Cost of Service calculation.
DSIT 283 NONOP NONCURRENT LIABILITY D.C.	0	0				Not applicable to Transmission Cost of Service calculation.
DSIT 283 NONOP NONCURRENT LIABILITY N.C.	(398)	(398)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 NONOP NONCURRENT LIABILITY VA	(5,201)	(5,201)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 NONOP NONCURRENT LIABILITY W.V.	(180)	(180)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OP OTHER NONCURR ASSET VA MIN	10	10				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OP OTHER NONCURR LIAB D.C.	(1)	(1)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OP OTHER NONCURR LIAB N.C.	(761)	(761)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OP OTHER NONCURR LIAB VA.	(19,442)	(19,442)				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.	(584)	(584)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OPERATING CURRENT LIABILITY D.C.	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OPERATING CURRENT LIABILITY N.C.	(673)	(673)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OPERATING CURRENT LIABILITY VA	(10,089)	(10,089)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OPERATING CURRENT LIABILITY W.V.	(573)	(573)				Not applicable to Transmission Cost of Service calculation.
EARNEST MONEY	-	-				Represents advances not recognized for tax.
EMISSIONS ALLOWANCES	(273)	(273)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283)	(22,980)	(22,980)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - BEAR GARDEN RID	(910)	(910)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - BREMO RIDER	(7)	(7)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - GENERATION RIDE	(4,166)	(4,166)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - NAIII RIDER	(1,073)	(1,073)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - PP7 RIDER	(5)	(5)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - VCHEC RIDER	3,599	3,599				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - VCHEC RIDER CUR	(2,534)	(2,534)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - VCHEC RIDER NON	(739)	(739)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - WARREN RIDER	(20)	(20)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP DC	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP DC - BEAR GARDEN RIDER	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP DC - BREMO RIDER	-	-				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP DC - GENERATION RIDER	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP DC - NAIII RIDER	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP DC - PP7 RIDER	-	-				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP DC - VCHEC RIDER	0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP DC - VCHEC RIDER CURR	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP DC - WARREN RIDER	-	-				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC	(256)	(256)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - BEAR GARDEN RIDER	(10)	(10)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - BREMO RIDER	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - GENERATION RIDER	(47)	(47)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - NAIII RIDER	(12)	(12)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - PP7 RIDER	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - VCHEC RIDER	40	40				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - VCHEC RIDER CURR	(28)	(28)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - VCHEC RIDER NONCURR	(9)	(9)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - WARREN RIDER	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA	(3,915)	(3,915)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - BEAR GARDEN RIDER	(155)	(155)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - BREMO RIDER	(1)	(1)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - GENERATION RIDER	(709)	(709)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - NAIII RIDER	(183)	(183)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - PP7 RIDER	(1)	(1)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - VCHEC RIDER	613	613				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - VCHEC RIDER CURR	(432)	(432)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - VCHEC RIDER NONCUR	(124)	(124)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - WARREN RIDER	(3)	(3)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV	(130)	(130)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - BEAR GARDEN RIDER	(5)	(5)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - BREMO RIDER	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - GENERATION RIDER	(24)	(24)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - NAIII RIDER	(6)	(6)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - PP7 RIDER	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - VCHEC RIDER	20	20				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - VCHEC RIDER CURR	(14)	(14)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - VCHEC RIDER NONCURR	(4)	(4)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - WARREN RIDER	(0)	(0)				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	(4,829)	(4,829)				Not applicable to Transmission Cost of Service calculation.
FAS 133-REG-GL HEDGE CAPACITY CURRENT	(5,595)	(5,595)				Not applicable to Transmission Cost of Service calculation.
FAS 133 REG FUEL HEDGE NONCURRENT	358	358				Not applicable to Transmission Cost of Service calculation.
FAS 133 REG GL CAPACITY HEDGE NONCURRENT	(2,094)	(2,094)				Not applicable to Transmission Cost of Service calculation.
FAS 133 REG HEDGE DEBT NONCURRENT	(33,627)	(33,627)				Not applicable to Transmission Cost of Service calculation.
FAS 133-DEBT VALUATION - MTM - CURRENT LIAB	(1,259)	(1,259)				Not applicable to Transmission Cost of Service calculation.
FAS 133-DEBFERRED B/L CAPACITY HEDGE - NON CURRENT	2,094	2,094				Not applicable to Transmission Cost of Service calculation.
FAS 133-DEFERRED B/L CAPACITY HEDGE CURRENT LIAB	(410)	(410)				Not applicable to Transmission Cost of Service calculation.
FAS 133-DEFERRED G/L POWER HEDGE - CURRENT LIAB	(11)	(11)				Not applicable to Transmission Cost of Service calculation.
FAS 133-DEFERRED VALUATION - MTM NON CURRENT LIAB	9,611	9,611				Not applicable to Transmission Cost of Service calculation.
FAS 133-FTR CURRENT LIAB	(1,219)	(1,219)				Not applicable to Transmission Cost of Service calculation.
FEDERAL TAX INTEREST EXPENSE	(1,206)	(1,206)				Not applicable to Transmission Cost of Service calculation.
FEDERAL TAX INTEREST EXPENSE NON CURRENT	(603)	(603)				Not applicable to Transmission Cost of Service calculation.
FIXED ASSETS	(336)	(336)				Not applicable to Transmission Cost of Service calculation.
FUEL DEF OTHER CURRENT LIAB	(8,166)	(8,166)				Not applicable to Transmission Cost of Service calculation.
FUEL HANDLING COSTS	(173)	(173)				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	-	-				Not applicable to Transmission Cost of Service calculation.
OBSOLETE INVENTORY	-	-				Not applicable to Transmission Cost of Service calculation.
PERFORMANCE ACHIEVEMENT PLAN	-	-				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.

ATTACHMENT H-16A

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31, 2011

REACQUIRED DEBT GAIN(LOSS)		(2,010)	(2,010)				Not applicable to Transmission Cost of Service calculation.
REG FTR		0	0				Not applicable to Transmission Cost of Service calculation.
REG FTR CURRENT		(2,280)	(2,280)				Not applicable to Transmission Cost of Service calculation.
REG HEDGES CAPACITY		420	420				Not applicable to Transmission Cost of Service calculation.
REG ASSET - A4 RAC COSTS NONCURRENT		(24,422)	(24,422)				Not applicable to Transmission Cost of Service calculation.
REG ASSET - DEFERRED G/L POWER HEDGE CURRENT		(123)	(123)				Not applicable to Transmission Cost of Service calculation.
REG ASSET - FTR - CURRENT		2,904	2,904				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A5 DSM		(866)	(866)				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 BEAR GARDEN AFUDC DEBT		226	226				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 BEAR GARDEN COST RESERV		(3,761)	(3,761)				Not applicable to Transmission Cost of Service calculation.
REG ASSET - DEBT VALUATION - MTM - NON CURRENT		-	-				Not applicable to Transmission Cost of Service calculation.
REG ASSET - DEFERRED GAIN/LOSS CAPAC HEDGE NONCUR		(1,058)	(1,058)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 BEAR GARDEN AFUDC DEBT		(1,103)	(1,103)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 BREMO AFUDC DEBT		(4)	(4)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 NAIII AFUDC DEBT		(718)	(718)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 PP7 AFUDC DEBT		(4)	(4)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 VCHEC COST RESERVE		(605)	(605)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 WARREN AFUDC DEBT		(14)	(14)				Not applicable to Transmission Cost of Service calculation.
REG ATRR NON CURRENT		(11,110)	(11,110)				Not applicable to Transmission Cost of Service calculation.
REG FTR		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
REG FTR CURRENT		(624)	(624)				Not applicable to Transmission Cost of Service calculation.
REG HEDGE DEBT - CURRENT		598	598				Not applicable to Transmission Cost of Service calculation.
REG NON CURRENT DSM A5 RIDER		(635)	(635)				Not applicable to Transmission Cost of Service calculation.
REG POWER HEDGE - CURRENT		3	3				Not applicable to Transmission Cost of Service calculation.
REG POWER HEDGE		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
REGULATORY ASSET - D & D		-	-				Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
REGULATORY ASSET - FAS 112		(1,607)				(1,607)	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		(5,073)	(5,073)				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		(354)	(354)				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 CURRENT		(12,745)	(12,745)				Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
REGULATORY ASSET PJM - CURRENT		(12,557)	(12,557)				Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
RETIREMENT - EXEC SUPP RET (ESRP) - NONOP		(219)	(219)				Not applicable to Transmission Cost of Service calculation.
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		(7,249)			(7,249)		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		-					Not applicable to Transmission Cost of Service calculation.
DEFERRED SIT NONOP - OCI		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133		-	-				Not applicable to Transmission Cost of Service calculation.
Subtotal - p277 (Form 1-F filer: see note 6, below)		(316,783)	(307,927)	-	(7,249)	(1,607)	
Less FASB 109 Above if not separately removed		(34,231)	(34,231)	-	-	-	
Less FASB 106 Above if not separately removed		-					
Total		(282,552)	(273,696)	-	(7,249)	(1,607)	

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				809
2	Amortization to line 136 of Appendix A		Total		163
3	Total			-	972
4	Total Form No. 1 (p 266 & 267)		Form No. 1 balance (p.266) for amortiza		972
5	Difference /1			-	-

/1 Difference must be zero

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

	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	73	108,368	68,731	
Subtotal	(205,074)	15,721	20,042	
Wages & Salary Allocator			5.3121%	
Gross Plant Allocator		12.6637%		
End of Year ADIT	(205,074)	1,991	1,065	(202,019)

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 ADIT-190	B Total	C Production Or Other Related	D Only Transmission Related	E Plant Related	F Labor Related	G 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 - 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.
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				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	1,128,102	926,091	73	108,368	93,569	
Less FASB 109 Above if not separately removed	12,595	12,595	-	-	-	
Less FASB 106 Above if not separately removed	24,839	0	0	0	24,839	
Total	1,090,668	913,496	73	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.

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	(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)				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	-					Represents IRS audit adjustments to plant-related differences.
FIXED ASSETS - NC	27			27		Represents IRS audit adjustments to plant-related differences.
FIXED ASSETS - VA	361			361		Represents IRS audit adjustments to plant-related differences.
FIXED ASSETS - WV	13			13		Represents 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	(3,559)	(3,559)				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	(2,114,153)	(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 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)	(3,209,585)	(2,875,790)	(205,148)	(81,743)	(46,905)	
Less FASB 109 Above if not separately removed	(28,960)	(28,960)	0	0	0	
Less FASB 106 Above if not separately removed	0					
Total	(3,180,626)	(2,846,831)	(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.

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	(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.
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	(46,598)	(46,598)				Not applicable to Transmission Cost of Service calculation.
DEFERRED FUEL EXPENSE	(236,545)	(236,545)				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	-	-				Not applicable to Transmission Cost of Service calculation.
DEFERRED SIT NONOP - OCI	-	-				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	(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	-	-				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.
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 - 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)				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 - 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.
REG LIABILITY - ARO	-	-				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.
FAS 133	(16,651)	(16,651)				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)	(596,754)	(584,066)	0	(10,904)	(1,784)	
Less FASB 109 Above if not separately removed	(18,504)	(18,504)	-	-	-	
Less FASB 106 Above if not separately removed	-					
Total	(578,250)	(565,562)	-	(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.

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 2 - Taxes Other Than Income Worksheet
2011 (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)	$ 16,632	100.0000%	$ 16,632
1a	Other Plant Related Taxes	0	12.6637%	-
2				-
3				-
4				-
5				-
				-
	Total Plant Related	$ 16,632		$ 16,632
	Labor Related		***Wages & Salary Allocator***	
6	Federal FICA & Unemployment & State Unemployment	$ 41,808		
	Total Labor Related	$ 41,808	5.3121%	$ 2,221
	Other Included		***Gross Plant Allocator***	
7	Sales and Use Tax	$ -		
	Total Other Included	$ -	12.6637%	$ -
	Total Included	$ 58,440		$ 18,853
	Currently Excluded			
8	Business and Occupation Tax - West Virginia	$ 19,494		
9	Gross Receipts Tax	10,755		
10	IFTA Fuel Tax			
11	Property Taxes - Other	121,266		
12	Property Taxes - Generator Step-Ups and Interconnects	1,087		
13	Sales and Use Tax - not allocated to Transmission	756		
14	Sales and Use Tax - Retail	0		
15	Other	300		
16		0		
17		0		
18		0		
19		0		
20		0		
21	Total "Other" Taxes (included on p. 263)	$ 153,659		
22	Total "Taxes Other Than Income Taxes" - acct 408.10 (p. 114.14)	$ 212,099		
23	Difference	$ (58,440)		

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
2011 (000's)

Directly Assigned Property Taxes	$	138,986
Production Property Tax		65,009
Transmission Property Tax		16,541
GSU/Interconnect Facilities		1,087
Distribution Property tax		54,631
General Property Tax		1,717
Total check		138,986

Allocation of General Property Tax to Transmission

General Property Tax	$	1,717
Wages & Salary Allocator		5.3121%
Trans General		91

Total Transmission Property Taxes

Transmission	$	16,541
General		91
Total Transmission Property Taxes	$	16,632

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 3 - Revenue Credit Workpaper
2011 (000's)

			Transmission Related	Production/Other Related	Total
	Account 454 - Rent from Electric Property				
1	Rent from Electric Property - Transmission Related (Note 3)		7,436		7,436
2	Total Rent Revenues	(Sum Lines 1)	7,436	-	7,436
	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)		1,800		1,800
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)		4,241		4,241
9	Revenues from Directly Assigned Transmission Facility Charges (Note 2)		2,495		2,495
10	Rent or Attachment Fees associated with Transmission Facilities (Note 3)				-
11	Gross Revenue Credits (Accounts 454 and 456)	(Sum Lines 2-10)	15,972	-	15,972
12	Less line 14g		(7,365)	-	(7,365)
13	Total Revenue Credits		8,607	-	8,607
	Revenue Adjustment to Determine Revenue Credit				
14a	Revenues included in lines 1-11 which are subject to 50/50 sharing. (Lines 1 + 8 + 10)		11,677	-	11,677
14b	Costs associated with revenues in line 14a		3,053		3,053
14c	Net Revenues (14a - 14b)		8,624	-	8,624
14d	50% Share of Net Revenues (14c / 2)		4,312	-	4,312
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)		4,312	-	4,312
14g	Line 14f less line 14a		(7,365)	-	(7,365)

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
2011 (000's)

	Return and Taxes with Basis Point increase in ROE			
A	Basis Point increase in ROE and Income Taxes		(Line 130 + 140)	298,177
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)	2,247,641
	Long Term Interest			
104	**Long Term Interest**		p117.62c through 67c/Attachment 5	367,601
105	Less LTD Interest on Securitization Bonds	(Note P)	Attachment 8	0
106	Long Term Interest		(Line 104 - 105)	367,601
107	Preferred Dividends	enter positive	p118.29c	16,659
	Common Stock			
108	Proprietary Capital		p112.16c,d/2	6,981,788
109	Less Preferred Stock	enter negative	(Line 117)	-259,014
110	Less Account 219 - Accumulated Other Comprehensive Income	enter negative	p112.15c,d/2	-15,036
111	Common Stock		(Sum Lines 108 to 110)	6,707,738
	Capitalization			
112	Long Term Debt		p112.24c,d/2	6,291,289
113	Less Loss on Reacquired Debt	enter negative	p111.81c,d/2	-11,255
114	Plus Gain on Reacquired Debt	enter positive	p113.61c,d/2	3,788
115	Less LTD on Securitization Bonds	enter negative	Attachment 8	0
116	Total Long Term Debt		(Sum Lines 112 to 115)	6,283,822
117	Preferred Stock		p112.3c,d/2	259,014
118	Common Stock		(Line 111)	6,707,738
119	Total Capitalization		(Sum Lines 116 to 118)	13,250,574
120	Debt %	Total Long Term Debt	(Line 116 / 119)	47.4%
121	Preferred %	Preferred Stock	(Line 117 / 119)	2.0%
122	Common %	Common Stock	(Line 118 / 119)	50.6%
123	Debt Cost	Total Long Term Debt	(Line 106 / 116)	0.0585
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)	0.0277
127	Weighted Cost of Preferred	Preferred Stock	(Line 121 * 124)	0.0013
128	Weighted Cost of Common	Common Stock	(Line 122 * 125)	0.0628
129	Total Return (R)		**(Sum Lines 126 to 128)**	**0.0918**
130	Investment Return = Rate Base * Rate of Return		**(Line 62 * 129)**	**206,268**

Composite Income Taxes

	Income Tax Rates			
131	FIT=Federal Income Tax Rate			0.3500
132	SIT=State Income Tax Rate or Composite			0.0622
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)} =		0.3904
135	T/ (1-T)			0.6405
	ITC Adjustment			
136	Amortized Investment Tax Credit	enter negative	Attachment 1	-163
137	T/(1-T)		(Line 135)	0.6405
138	**ITC Adjustment Allocated to Transmission**	(Note I from Appendix A)	(Line 136 * (1 + 137))	**-267**
139	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		92,175
140	**Total Income Taxes**		**(Line 138 + 139)**	**91,909**

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 5 - Cost Support
2011 - Projection

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	24,380,905	24,486,521	24,562,266	24,682,861	25,499,086	25,688,567	26,111,685	26,182,480	26,256,522	26,356,983	26,463,116	26,559,198	26,965,025	25,707,324	0	
15	Accumulated Depreciation (Total Electric Plant)	(Notes A & Q)	p219.29c	10,621,818	10,673,030	10,729,370	10,787,083	10,835,949	10,893,274	10,953,127	11,007,863	11,069,041	11,127,706	11,182,300	11,244,341	11,307,291	10,956,323	0	
12	Accumulated Intangible Amortization	(Notes A & Q)	p200.21c	164,143	165,988	167,833	169,678	171,523	173,368	175,213	177,058	178,903	180,748	182,593	184,438	186,283	175,213	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	3,034,737	3,084,228	3,100,657	3,141,191	3,270,383	3,274,237	3,568,585	3,577,472	3,587,348	3,621,503	3,633,533	3,670,756	3,667,421	3,402,466	0	
15	Generator Step-Ups		Trans. Input Sht	163,460	163,460	163,460	163,460	163,460	163,460	163,460	163,460	163,460	163,460	163,460	163,460	163,460	163,460	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	756,640	756,640	756,640	756,640	756,640	756,640	756,640	756,640	756,640	761,140	761,140	761,140	772,695	758,913	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	835,454	836,959	838,721	840,501	842,358	844,147	846,141	848,709	851,296	853,899	856,560	859,000	861,764	847,347	0	
33	Transmission Accumulated Depreciation - Generator Step-Ups		GSU Input Sht	39,087	39,279	39,472	39,664	39,856	40,049	40,241	40,434	40,626	40,818	41,011	41,203	41,396	40,241	0	
34	Transmission Accumulated Depreciation - Interconnection Facilities		Input Sht	4,791	4,823	4,855	4,887	4,919	4,952	4,984	5,016	5,048	5,080	5,112	5,145	5,177	4,984		
36	Accumulated General Depreciation	(Notes A & Q)	p219.28.b	322,956	324,387	325,818	327,249	328,680	330,111	331,541	332,972	334,403	335,834	337,265	338,696	340,126	331,541	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														67,029	0	
91	Depreciation-General	(Note A)															22,008	0	
92	Depreciation-Intangible	(Note A)	p336.1d&e/Attachment 5														22,140	0	Respondent is Electric Utility only.
87	Depreciation - Generator Step-Ups																3,309	0	
88	Depreciation - Interconnection Facilities																482	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	-	4,564	4,464	5,562	5,651	7,207	7,852	7,818	6,367	5,641	6,367	4,915	4,190	70,598	0	
64	Generator Step-Ups		Input Sheet														193	0	
65	Transmission by Others		p321.96.b	-	1,190	1,190	1,190	1,190	1,190	1,190	1,190	1,190	1,190	1,190	1,190	1,190	14,280	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														604,538	0	
5	Total A&G Wages Expense	(Note A)	p354.27b/Trans. Wksht														150,521	0	
1	Transmission Wages	(Note A)	p354.21b/Trans. Wksht														24,180	0	
2	Generator Step-Ups		Trans. Wksht														62	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	35,540	35,540	35,540	35,540	35,540	35,540	35,540	35,540	35,540	35,540	35,540	35,540	35,540	35,540	32,682	Specific identification based on plant records: The following plant investments are included:
																Form 1 Amount	Transmission Related	Non-transmission Related	
																35,540	**2,858**	**32,682**	**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	$2,738	2,738	See Form 1

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	$ 33,899		33,899	See FERC Form 1 pages 350-351.
	Directly Assigned A&G						
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b/Attachment 5		0		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	2,662	-	2,662	

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)		5.61%	0.365%	0.24%			6.22%

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	2,662	0	2,662	-

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

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

Add more lines if necessary

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			$ 5,501	$ 5,698	$ 5,599	100%	5,599		
	Labor Related, General plant related or Common Plant related			$ 354	$ 1,347	$ 851	5.312%	45		
	Plant Related			$ 3,123	$ 3,573	$ 3,348	12.66%	424		
	Other			$ 58,728	$ 153,628	$ 106,178	0.00%	-		
	Total Transmission Related Reserves			$ -	$ -	$ -		6,068	To line 47	

Prepayments

Line #s	Descriptions	Notes	Page #'s & Instructions	Beginning Year Balance	End of Year Balance	Average Balance		To Line 48	Description of the Prepayments
48	**Prepayments**								
	Wages & Salary Allocator						5.312%		
	Pension Liabilities, if any, in Account 242			$ 45	$ 45	$ 45	5.312%	2	
				$ -	$ -	$ -			
	Prepayments			$ 25,759	$ 54,581	$ 40,170	5.312%	2,134	
	Prepaid Pensions if not included in Prepayments					$ -	**5.312%**	-	

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	19,140.038	

A&G Expenses - Other Post Employment Benefits

Line #s	Descriptions	Notes	Page #'s & Instructions	Amount
	Total A&G Expenses		p323.197b	490,234
	Less OPEB Current Year			(37,194)
	Plus: Stated OPEB (2008 actual)		Fixed (2008 actual)	27,658
69	**Current Year Total A&G Expenses**			480,698

Interest on Long-Term Debt

Line #s	Descriptions	Notes	Page #'s & Instructions	Amount
	Interest on Long-Term Debt		p117.62c through 67c	371,772
	Less Interest on Short-Term Debt Included in Account 430			(4,171)
104	**Total Interest on Long-Term Debt**			367,601

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. 0.2900%

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.	278,688.00
B	ATRR based on projected costs included for the previous calendar year but excludes the true-up adjustment.	252,389.00
C	Difference (A-B)	26,299
D	Future Value Factor (1+i)^24	1.07197
E	True-up Adjustment (C*D)	28,192

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.

An Annual Revenue Requirement will not be determined in this Attachment 7 for RTEP projects that have not been identified as qualifying for an incentive and for which 100% of the cost is allocated to the Dominion zone. To the extent the cost allocation of such RTEP projects changes to be other than 100% allocated to the Dominion zone, the Annual Revenue Requirements will be determined in this Attachment 7 for such RTEP projects.

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	15.6523%
4	B	161	Net Plant Carrying Charge with 100 Basis Point increase in ROE without Depreciation	16.4259%
5	C		Line B less Line A	0.7735%

6 **FCR if a CIAC**

7	D	155	Net Plant Carrying Charge without Depreciation, Return, or Income Taxes	4.0691%

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	15.6523%		15.6523%	at Loudoun
14	Incentive Factor (Basis Points /100)		0		0	
15	FCR W incentive L.13 +(L.14*L.5)		15.6523%		15.6523%	
	Investment		1,911,923		1,671,946	
17	Annual Depreciation Exp		37,489		32,783	
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					1,671,946	9,562	1,662,384	
21	W incentive	2006					1,671,946	9,562	1,662,384	
22	W / O incentive	2007	1,911,923	1,562	1,910,361		1,662,384	32,783	1,629,601	
23	W incentive	2007	1,911,923	1,562	1,910,361		1,662,384	32,783	1,629,601	
24	W / O incentive	2008	1,910,361	37,489	1,872,872		1,629,601	32,783	1,596,818	
25	W incentive	2008	1,910,361	37,489	1,872,872		1,629,601	32,783	1,596,818	
26	W / O incentive	2009	1,872,872	37,489	1,835,384		1,596,818	32,783	1,564,034	
27	W incentive	2009	1,872,872	37,489	1,835,384		1,596,818	32,783	1,564,034	
28	W / O incentive	2010	1,835,384	37,489	1,797,895		1,564,034	32,783	1,531,251	
29	W incentive	2010	1,835,384	37,489	1,797,895		1,564,034	32,783	1,531,251	
30	W / O incentive	2011	1,797,895	37,489	1,760,406	315,968	1,531,251	32,783	1,498,468	269,894
31	W incentive	2011	1,797,895	37,489	1,760,406	315,968	1,531,251	32,783	1,498,468	269,894

Lines continue as new rate years are 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*	341,325	298,517
B	Projected Revenue Requirement with Incentive for Previous Calendar Year*	341,325	298,517
C	Actual Revenue Requirement without Incentive for Previous Calendar Year *	377,960	322,995
D	Actual Revenue Requirement with Incentive for Previous Calendar Year *	377,960	322,995
E	True-Up Adjustment Before Interest without Incentive for Previous Calendar Year (C-A)	36,635	24,478
F	True-Up Adjustment Before Interest with Incentive for Previous Calendar Year (B-D)	36,635	24,478
G	Future Value Factor (1+i)^24 months from Attachment 6	1.07197	1.07197
H	True-Up Adjustment without Incentive (E*G)	39,272	26,240
I	True-Up Adjustment with Incentive (F*G)	39,272	26,240

* 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.

Projected Revenue Requirement including True-up Adjustment, if applicable			
W / O incentive	2011	355,239	296,134
W incentive	2011	355,239	296,134

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

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8 Project G-1 is labled as Project G in the 2008 and 2009
9 Annual Updates

10	Project E				Project G-1				Project G-2			
11	Yes	B0226			Yes	B0403			Yes	B0403		
12	51	Install 500/230 kV transformer at			51	2nd Dooms 500/230 kV transformer			51	2nd Dooms 500/230 kV transformer		
13	15.6523%	Clifton and Clifton 500 KV 150 MVAR			15.6523%	addition			15.6523%	addition		
14	0	capacitor			0				0			
15	15.6523%				15.6523%				15.6523%	Spare Transformer Addition		
	8,241,202				7,173,623				2,414,294			
17	161,592				140,659				47,339			
18	9				11				4			
19	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20												
21												
22	8,241,202	47,131	8,194,071		7,173,623	17,582	7,156,041					
23	8,241,202	47,131	8,194,071		7,173,623	17,582	7,156,041					
24	8,194,071	161,592	8,032,479		7,156,041	140,659	7,015,381					
25	8,194,071	161,592	8,032,479		7,156,041	140,659	7,015,381					
26	8,032,479	161,592	7,870,887		7,015,381	140,659	6,874,722		2,414,294	33,532	2,380,762	
27	8,032,479	161,592	7,870,887		7,015,381	140,659	6,874,722		2,414,294	33,532	2,380,762	
28	7,870,887	161,592	7,709,294		6,874,722	140,659	6,734,063		2,380,762	47,339	2,333,423	
29	7,870,887	161,592	7,709,294		6,874,722	140,659	6,734,063		2,380,762	47,339	2,333,423	
30	7,709,294	161,592	7,547,702	1,355,631	6,734,063	140,659	6,593,403	1,183,690	2,333,423	47,339	2,286,084	408,870
31	7,709,294	161,592	7,547,702	1,355,631	6,734,063	140,659	6,593,403	1,183,690	2,333,423	47,339	2,286,084	408,870

Line

			Note: G=G1+G2	
A	1,556,087	1,238,134	1,540,136	302,002
B	1,556,087	1,238,134	1,540,136	302,002
C	1,619,278	1,415,971	1,761,350	345,379
D	1,619,278	1,415,971	1,761,350	345,379
E	63,191	177,837	221,214	43,377
F	63,191	177,837	221,214	43,377
G	1.07197	1.07197		1.07197
H	67,739	190,636	237,135	46,499
I	67,739	190,636	237,135	46,499

1,423,370	1,374,326	455,369
1,423,370	1,374,326	455,369

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

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10	Project H-1				Project H-2				Project H-3			
11	Yes	b0328.1			Yes	b0328.1			Yes	b0328.1		
12	51	Build new Meadowbrook-Loudon 500kV circuit			51	Build new Meadowbrook-Loudon 500kV circuit			51	Build new Meadowbrook-Loudon 500kV circuit		
13	15.6523%	(30 of 50 miles)			15.6523%	(30 of 50 miles)			15.6523%	(30 of 50 miles)		
14	1.5				1.5				1.5			
15	16.8126%	line 2101 v11			16.8126%	Line 2030 & 559			16.8126%	Line 580 - Phase 1		
	21,850,320				45,089,768				13,581,000			
17	428,438				884,113				266,294			
18	6				12				7			
19	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20												
21												
22												
23												
24												
25												
26	21,850,320	232,070	21,618,250		45,089,768	36,838	45,052,930					
27	21,850,320	232,070	21,618,250		45,089,768	36,838	45,052,930					
28	21,618,250	428,438	21,189,812		45,052,930	884,113	44,168,817		13,581,000	122,051	13,458,949	
29	21,618,250	428,438	21,189,812		45,052,930	884,113	44,168,817		13,581,000	122,051	13,458,949	
30	21,189,812	428,438	20,761,374	3,711,611	44,168,817	884,113	43,284,704	7,728,378	13,458,949	266,294	13,192,654	2,352,095
31	21,189,812	428,438	20,761,374	3,954,986	44,168,817	884,113	43,284,704	8,235,731	13,458,949	266,294	13,192,654	2,506,712

Line

A	-		
B	-		
C	2,393,884	381,681	
D	2,525,568	402,686	
E	2,393,884	381,681	-
F	2,525,568	402,686	-
G	1.07197	1.07197	1.07197
H	2,566,175	409,151	-
I	2,707,337	431,668	-
	6,277,786	8,137,529	2,352,095
	6,662,323	8,667,400	2,506,712

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

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10	Project H-4				Project H-5				Project H-6			
11	Yes	b0328.1			Yes	b0328.1			Yes	b0328.1		
12	51	Meadowbrook-Loudon 500kV circuit			51	Build new Meadowbrook-Loudon 500kV circuit			51	Meadowbrook-Loudon 500kV circuit		
13	15.6523%	(30 of 50 miles)			15.6523%	(30 of 50 miles)			15.6523%	(30 of 50 miles)		
14	1.5				1.5				1.5			
15	16.8126%	Line 124			16.8126%	Line 114			16.8126%	Clevenger DP/580		
	11,317,500				14,682,570				15,814,622			
17	221,912				287,894				310,091			
18	4				6				9			
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	11,317,500	157,188	11,160,313		14,682,570	155,942	14,526,628		15,814,622	90,443	15,724,179	
29	11,317,500	157,188	11,160,313		14,682,570	155,942	14,526,628		15,814,622	90,443	15,724,179	
30	11,160,313	221,912	10,938,401	1,951,396	14,526,628	287,894	14,238,734	2,539,121	15,724,179	310,091	15,414,088	2,747,026
31	11,160,313	221,912	10,938,401	2,079,599	14,526,628	287,894	14,238,734	2,706,000	15,724,179	310,091	15,414,088	2,927,671

Line

A			
B			
C			
D			
E	-	-	-
F	-	-	-
G	1.07197	1.07197	1.07197
H	-	-	-
I	-	-	-
	1,951,396	2,539,121	2,747,026
	2,079,599	2,706,000	2,927,671

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												
10	Project H-7				Project H-8				Project H-9			
11	Yes	b0328.1			Yes	b0328.1			Yes	b0328.1		
12	51	Build new Meadowbrook-Loudon 500kV circuit			51	Meadowbrook-Loudon 500kV circuit			51	Build new Meadowbrook-Loudon 500kV circuit		
13	15.6523%	(30 of 50 miles)			15.6523%	(30 of 50 miles)			15.6523%	(30 of 50 miles)		
14	1.5				1.5				1.5			
15	16.8126%	Line 580 - Phase 2			16.8126%	Line 535			16.8126%	Expansion work at Mt Storm and Loudoun Substations		
	11,362,770				91,300,800				14,900,000			
17	222,799				1,790,212				292,157			
18	12				4				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	11,362,770	9,283	11,353,487									
29	11,362,770	9,283	11,353,487									
30	11,353,487	222,799	11,130,687	1,982,450	91,300,800	1,268,067	90,032,733	11,320,364	14,900,000	158,252	14,741,748	1,414,818
31	11,353,487	222,799	11,130,687	2,112,890	91,300,800	1,268,067	90,032,733	12,065,523	14,900,000	158,252	14,741,748	1,507,965

Line

A			
B			
C			
D			
E	-	-	-
F	-	-	-
G	1.07197	1.07197	1.07197
H	-	-	-
I	-	-	-
	1,982,450	11,320,364	1,414,818
	2,112,890	12,065,523	1,507,965

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												
10	**Project I**				**Project J**				**Project K-1**			
11	Yes	b0329			Yes	b0512			No			
12	51	Carson-Suffolk 500 kV line +			51	MAPP Project -- Dominion Portion			51	Loudoun Bank # 1 transformer		
13	15.6523%	Suffolk 500/230 # 2 transformer +			15.6523%				15.6523%	replacement		
14	1.5	Suffolk - Thrasher 230kV line			1.5				1.5			
15	16.8126%				16.8126%				16.8126%			
	188,076,091								13,583,694			
17	3,687,766				-				266,347			
18	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									13,583,694	11,098	13,572,596	
27									13,583,694	11,098	13,572,596	
28									13,572,596	266,347	13,306,249	
29									13,572,596	266,347	13,306,249	
30	188,076,091	1,997,540	186,078,551	17,858,620					13,306,249	266,347	13,039,902	2,328,243
31	188,076,091	1,997,540	186,078,551	19,034,374					13,306,249	266,347	13,039,902	2,481,087

Line

A			612,586
B			648,566
C			118,369
D			124,884
E	-	-	(494,217)
F	-	-	(523,682)
G	1.07197	1.07197	1.07197
H	-	-	(529,786)
I	-	-	(561,372)

17,858,620	-	1,798,457
19,034,374	-	1,919,715

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												
10	Project K-2				Project L-1a				Project L-1b			
11	No				No				No			
12	51	Loudoun Bank # 2 transformer replacement			51	Ox Bank # 1 transformer replacement			51	Ox Bank # 1 transformer replacement		
13	15.6523%				15.6523%				15.6523%			
14	1.5				1.5				1.5			
15	16.8126%				16.8126%				16.8126%			
	14,317,903				11,059,957				2,913,908			
17	280,743				216,862				57,135			
18	5				7				12			
19	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20												
21												
22												
23												
24												
25												
26					11,059,957	99,395	10,960,562		2,913,908	2,381	2,911,527	
27					11,059,957	99,395	10,960,562		2,913,908	2,381	2,911,527	
28	14,317,903	175,464	14,142,439		10,960,562	216,862	10,743,700		2,911,527	57,135	2,854,392	
29	14,317,903	175,464	14,142,439		10,960,562	216,862	10,743,700		2,911,527	57,135	2,854,392	
30	14,142,439	280,743	13,861,695	2,472,396	10,743,700	216,862	10,526,838	1,881,531	2,854,392	57,135	2,797,256	499,443
31	14,142,439	280,743	13,861,695	2,634,859	10,743,700	216,862	10,526,838	2,004,930	2,854,392	57,135	2,797,256	532,231

Line

A	-	924,542	
B	-	978,826	
C	-	1,026,054	
D	-	1,082,500	
E	-	101,512	-
F	-	103,674	-
G	1.07197	1.07197	1.07197
H	-	108,818	-
I	-	111,135	-

2,472,396	1,990,349	499,443
2,634,859	2,116,065	532,231

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

1												
2												
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4												
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7												
8												
9												
10	**Project L-2**				**Project M**				**Project N**			
11	No				No				No			
12	51	Ox Bank # 2 transformer			51	Yadkin Bank # 2 transformer			51	Carson Bank # 1 transformer		
13	15.6523%	replacement			15.6523%	replacement			15.6523%	replacement		
14	1.5				1.5				1.5			
15	16.8126%				16.8126%				16.8126%			
	11,501,538				16,069,103				18,798,600			
17	225,520				315,080				368,600			
18	3				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	11,501,538	178,537	11,323,001									
27	11,501,538	178,537	11,323,001									
28	11,323,001	225,520	11,097,481		16,069,103	170,669	15,898,434		18,798,600	230,375	18,568,225	
29	11,323,001	225,520	11,097,481		16,069,103	170,669	15,898,434		18,798,600	230,375	18,568,225	
30	11,097,481	225,520	10,871,960	1,944,887	15,898,434	315,080	15,583,354	2,778,900	18,568,225	368,600	18,199,625	3,246,116
31	11,097,481	225,520	10,871,960	2,072,341	15,898,434	315,080	15,583,354	2,961,539	18,568,225	368,600	18,199,625	3,459,421

Line

	Note L=L-1a +L-1b+L1-2			
A	2,580,314	1,655,772		306,293
B	2,731,788	1,752,962		324,283
C	2,863,625	1,837,571		
D	3,021,129	1,938,629		
E	283,311	181,799	-	(306,293)
F	289,341	185,667	-	(324,283)
G		1.07197	1.07197	1.07197
H	303,701	194,883	-	(328,337)
I	310,165	199,030	-	(347,622)

	2,139,770	2,778,900	2,917,779
	2,271,370	2,961,539	3,111,799

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

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10	Project O				Project P				Project Q			
11	No				No				No			
12	51	Lexington Bank # 1 transformer			51	Dooms Bank # 7 transformer			51	Valley Bank # 1 transformer		
13	15.6523%	replacement			15.6523%	replacement			15.6523%	replacement		
14	1.5				1.5				1.5			
15	16.8126%				16.8126%				16.8126%			
	-				18,678,014				11,830,354			
17	-				366,236				231,968			
18	12				9				1			
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	-	-	-	-								
30	-	-	-	-	18,678,014	106,819	18,571,195	957,082	11,830,354	222,302	11,608,052	1,980,202
31	-	-	-	-	18,678,014	106,819	18,571,195	1,020,110	11,830,354	222,302	11,608,052	2,110,512

Line

A			
B			
C			
D			
E	-	-	-
F	-	-	-
G	1.07197	1.07197	1.07197
H	-	-	-
I	-	-	-

-	957,082	1,980,202
-	1,020,110	2,110,512

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

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9												
10	**Project R-1**				**Project R-2**				**Project S**			
11	No	s0124			No	s0124			No	s0133		
12	51	Garrisonville 230 kV UG line			51	Garrisonville 230 kV UG line			51	Pleasant View Hamilton 230kV		
13	15.6523%	Phase 1			15.6523%	Phase 2			15.6523%	transmission line		
14	1.25				1.25				1.25			
15	16.6192%				16.6192%				16.6192%			
	93,000,000				35,000,000				85,969,995			
17	1,823,529				686,275				1,685,686			
18	6				11				11			
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	93,000,000	987,745	92,012,255						85,969,995	210,711	85,759,284	
29	93,000,000	987,745	92,012,255						85,969,995	210,711	85,759,284	
30	92,012,255	1,823,529	90,188,725	16,082,896	35,000,000	85,784	34,914,216	769,735	85,759,284	1,685,686	84,073,598	14,977,103
31	92,012,255	1,823,529	90,188,725	16,963,747	35,000,000	85,784	34,914,216	811,985	85,759,284	1,685,686	84,073,598	15,798,161

Line

A	943,131		
B	989,296		
C			
D			
E	(943,131)	-	-
F	(989,296)	-	-
G	1.07197	1.07197	1.07197
H	(1,011,009)	-	-
I	(1,060,497)	-	-
	15,071,886	769,735	14,977,103
	15,903,250	811,985	15,798,161

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

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10	**Project T**				**Project U**				**Project V**			
11	Yes	b0768			Yes	b0453.1			Yes	b0337		
12	51	Glen Carlyn Line 251 GIB substation project			51	Convert Remington - Sowego			51	Build Lexington 230kV ring bus		
13	15.6523%				15.6523%	115kV to 230kV			15.6523%			
14	1.25	Glen Carlyn Line 251			1.25				1.25			
15	16.6192%				16.6192%				16.6192%			
	20,745,794								6,407,258			
17	406,780				-				125,633			
18	6								3			
19	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20												
21												
22												
23												
24												
25												
26									6,407,258	99,459	6,307,799	
27									6,407,258	99,459	6,307,799	
28									6,307,799	125,633	6,182,166	
29									6,307,799	125,633	6,182,166	
30	20,745,794	220,339	20,525,455	1,969,901					6,182,166	125,633	6,056,534	1,083,455
31	20,745,794	220,339	20,525,455	2,077,977					6,182,166	125,633	6,056,534	1,142,623

Line

A			465,822
B			488,610
C			1,023,671
D			1,070,585
E	-	-	557,849
F	-	-	581,975
G	1.07197	1.07197	1.07197
H	-	-	597,998
I	-	-	623,861

1,969,901	-	1,681,453
2,077,977	-	1,766,483

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

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10	**Project W**				**Project X**				**Project AA - 1**			
11	Yes	b0467.2			Yes	b0311			Yes	b0231		
12	51	Reconductor the Dickerson - Pleasant			51	Reconductor Idylwood to Arlington			51	Install 500 kV breakers and		
13	15.6523%	View 230 kV circuit			15.6523%	230 kV			15.6523%	500 kV bus work at Suffolk		
14	1.25				1.25				0			
15	16.6192%				16.6192%				15.6523%			
	5,074,691				3,196,608				21,769,250			
17	99,504				62,679				426,848			
18	6				8				11			
19	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20												
21												
22												
23												
24												
25												
26					3,196,608	23,504	3,173,104		21,769,250	53,356	21,715,894	
27					3,196,608	23,504	3,173,104		21,769,250	53,356	21,715,894	
28					3,173,104	62,679	3,110,425		21,715,894	426,848	21,289,046	
29					3,173,104	62,679	3,110,425		21,715,894	426,848	21,289,046	
30	5,074,691	53,898	5,020,793	481,863	3,110,425	62,679	3,047,746	544,628	21,289,046	426,848	20,862,198	3,725,678
31	5,074,691	53,898	5,020,793	508,300	3,110,425	62,679	3,047,746	574,400	21,289,046	426,848	20,862,198	3,725,678
Line												
A								716,012				590,133
B								751,022				590,133
C								242,022				178,690
D								253,118				178,690
E				-				(473,990)				(411,443)
F				-				(497,904)				(411,443)
G				1.07197				1.07197				1.07197
H				-				(508,104)				(441,055)
I				-				(533,739)				(441,055)
				481,863				36,524				3,284,623
				508,300				40,661				3,284,623

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 AB-2**				**Project AC**				**Project AG**			
11	Yes	b0456			Yes	b0227			Yes	b0455		
12	51	Re-Conductor 9.4 miles of Edinburg - Mt. Jackson			51	Install 500/230 kV transformer at Bristers;			51	Add 2nd Endless Caverns 230/115kV		
13	15.6523%	115 kV			15.6523%	build new 230 kV Bristers- Gainesville circuit,			15.6523%	transformer		
14	0				0	upgrade two Loudoun - Brambleton circuits			0			
15	15.6523%				15.6523%				15.6523%			
	10,821,688				21,403,678				3,554,673			
17	212,190				419,680				69,699			
18	11				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	10,821,688	26,524	10,795,164		21,403,678	227,327	21,176,351		3,554,673	43,562	3,511,111	
27	10,821,688	26,524	10,795,164		21,403,678	227,327	21,176,351		3,554,673	43,562	3,511,111	
28	10,795,164	212,190	10,582,974		21,176,351	419,680	20,756,671		3,511,111	69,699	3,441,411	
29	10,795,164	212,190	10,582,974		21,176,351	419,680	20,756,671		3,511,111	69,699	3,441,411	
30	10,582,974	212,190	10,370,784	1,852,068	20,756,671	419,680	20,336,991	3,635,742	3,441,411	69,699	3,371,712	602,906
31	10,582,974	212,190	10,370,784	1,852,068	20,756,671	419,680	20,336,991	3,635,742	3,441,411	69,699	3,371,712	602,906

Line

A	529,247	3,659,045	500,033
B	529,247	3,659,045	500,033
C	121,982	2,333,161	449,843
D	121,982	2,333,161	449,843
E	(407,265)	(1,325,884)	(50,190)
F	(407,265)	(1,325,884)	(50,190)
G	1.07197	1.07197	1.07197
H	(436,577)	(1,421,309)	(53,802)
I	(436,577)	(1,421,309)	(53,802)
	1,415,491	2,214,432	549,104
	1,415,491	2,214,432	549,104

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

1												
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9												
10	**2009 Add-1**				**2009 Add-6**				**Project AJ**			
11	Yes	B0453.3			Yes	B0837			Yes	B0327		
12	51	Add Sowego 230/115/ kV transformer			51	At Mt. Storm, replace the existing MOD on the 500 kV side of the transformer with a circuit breaker			51	Build 2nd Harrisonburg - Valley 230 kV		
13	15.6523%				15.6523%				15.6523%			
14	1.25				0				0			
15	16.6192%				15.6523%				15.6523%			
	3,555,513				779,172				6,531,740			
17	69,716				15,278				128,073			
18	9				6				7			
19	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20												
21												
22												
23												
24												
25												
26	3,555,513	20,334	3,535,179		779,172	8,276	770,896					
27	3,555,513	20,334	3,535,179		779,172	8,276	770,896					
28	3,535,179	69,716	3,465,463		770,896	15,278	755,619		6,531,740	58,700	6,473,040	
29	3,535,179	69,716	3,465,463		770,896	15,278	755,619		6,531,740	58,700	6,473,040	
30	3,465,463	69,716	3,395,747	606,686	755,619	15,278	740,341	132,354	6,473,040	128,073	6,344,966	1,131,233
31	3,465,463	69,716	3,395,747	639,857	755,619	15,278	740,341	132,354	6,473,040	128,073	6,344,966	1,131,233

Line

A			
B			
C	198,203	85,365	-
D	207,290	85,365	-
E	198,203	85,365	-
F	207,290	85,365	-
G	1.07197	1.07197	1.07197
H	212,467	91,509	-
I	222,209	91,509	-
	819,154	223,863	1,131,233
	862,066	223,863	1,131,233

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

1			
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9			
10			
11	If Yes for Schedule	If No for Schedule 12 include in	
12	12 Include in this	this Sum.	
13	Total.		
14			
15			
		Annual Revenue	Annual Revenue
17		Requirement	Requirement
18		including Incentive	excluding
		if Applicable	Incentive
19	**Total**	**Sum**	**Sum**
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30	72,906,444		49,918,535
31	76,688,642	52,850,924	

Line

-

A
B
C
D
E
F
G
H
I

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 Plant	
Land	
Land Rights	1.36%
Structures and Improvements	1.41%
Station and Equipment	2.02%
Towers and Fixtures	2.36%
Poles and Fixtures	1.89%
Overhead conductors and Devices	1.90%
Underground Conduit	1.74%
Underground Conductors and Devices	2.50%
Roads and Trails	1.17%
General Plant	
Land Rights	1.70%
Structures and Improvements - Major	1.82%
Structures and Improvements - Other	2.26%
Communication Equipment	3.20%
Communication Equipment - Clearing	6.22%
Communication Equipment - Massed	6.22%
Communication Equipment - 25 Years	3.72%
Office Furniture and Equipment - EDP Hardware	27.38%
Office Furniture and Equipment - EDP Fixed Location	12.21%
Office Furniture and Equipment	1.64%
Laboratory Equipment	4.23%
Micellaneous Equipment	2.53%
Stores Equipment	5.08%
Power Operated Equipment	8.16%
Tools, Shop and Garage Equipment	4.76%
Electric Vehicle Recharge Equirment	13.23%

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

The following pages provide:

1. Explanations of changes 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”).

   For the 12-month period ended August 31, 2010, the only material accounting changes reported were in the 2009 Form 10-K, which are included here.

2. VEPCO’s Form 10-Q filed August 2, 2010.

From 2009 Dominion Virginia Power Form 10-K

NOTE 3. NEWLY ADOPTED ACCOUNTING STANDARDS

2009

NONCONTROLLING INTERESTS IN CONSOLIDATED FINANCIAL STATEMENTS

Effective January 1, 2009, Dominion adopted new accounting guidance for noncontrolling interests that requires retrospective application of presentation and disclosure changes including that noncontrolling interests be reported as a component of equity and that net income attributable to the parent and noncontrolling interests be separately identified in the income statement.

As discussed in Note 25, Dominion previously consolidated an investment in the subordinated notes of a third-party CDO entity held by DCI, which was deconsolidated as of March 31, 2008. The noncontrolling interest income from the CDO entity was previously reported in minority interest in Dominion's Consolidated Statements of Income and in operating activities in its Consolidated Statements of Cash Flows. Dominion's subsidiary preferred dividends were previously included in interest and related charges in its Consolidated Statements of Income and in operating activities in its Consolidated Statements of Cash Flows. Due to the application of new accounting guidance for noncontrolling interests, Dominion now reflects its interest in the previously held CDO entity's income and its subsidiary preferred dividends as an adjustment (noncontrolling interests) to arrive at net income attributable to Dominion in its Consolidated Statements of Income and reflects its subsidiary preferred dividends in financing activities in its Consolidated Statements of Cash Flows. Since Dominion's subsidiary preferred stock does not qualify as permanent equity, Dominion continues to report these amounts as mezzanine equity in its Consolidated Balance Sheets.

RECOGNITION AND PRESENTATION OF OTHER-THAN-TEMPORARY IMPAIRMENTS

The FASB amended its guidance for the recognition and presentation of other-than-temporary impairments, which Dominion and Virginia Power adopted effective April 1, 2009. The recognition provisions of this guidance 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 this guidance, as described in Note 2, the Companies considered all debt securities held by their nuclear decommissioning trusts with market values below their cost bases to be other-than-temporarily impaired as they did not have the ability to ensure the investments were held through the anticipated recovery period.

Upon the adoption of this guidance for debt investments held at April 1, 2009, Dominion recorded a $20 million ($12 million after-tax) and Virginia Power 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.

SEC FINAL RULE, *MODERNIZATION OF OIL AND GAS REPORTING*

Effective December 31, 2009, Dominion adopted the SEC Final Rule, *Modernization of Oil and Gas Reporting*, which revised the existing Regulation S-K and Regulation S-X reporting requirements. Under the new requirements, the ceiling test is calculated using an average price based on the prior 12-month period rather than period-end prices. Going forward, Dominion will be less likely to experience a ceiling test impairment based solely on a sudden decrease in gas and oil prices.

2008

FAIR VALUE MEASUREMENTS

Dominion and Virginia Power adopted new FASB guidance effective January 1, 2008, which defines fair value, establishes a framework for measuring fair value and expands disclosures related to fair value measurements. The guidance applies broadly to financial and non-financial assets and liabilities that are measured at fair value under other authoritative accounting pronouncements, but does not expand the application of fair value accounting to any new circumstances.

Generally, the provisions of this guidance were applied prospectively. Certain situations, however, required retrospective application as of the beginning of the year of adoption through the recognition of a cumulative effect of accounting change. Such retrospective application was required for financial instruments, including derivatives and certain hybrid instruments with limitations on initial gains or losses. Retrospective application resulted in an immaterial amount recognized through a cumulative effect of accounting change adjustment to retained earnings as of January 1, 2008 for Dominion and no adjustment for Virginia Power.

In February 2008, the FASB amended the fair value measurements guidance to exclude leasing transactions. However, the exclusion does not apply to fair value measurements of assets and liabilities recorded as a result of a lease transaction but measured pursuant to other pronouncements within the scope of the fair value measurements guidance.

See Note 7 for further information on fair value measurements.

ENDORSEMENT SPLIT-DOLLAR LIFE INSURANCE ARRANGEMENTS

Effective January 1, 2008, Dominion adopted new accounting guidance for deferred compensation and postretirement benefit aspects of endorsement split-dollar life insurance arrangements. This guidance specifies that if an employer provides a benefit to an employee under the endorsement split-dollar life insurance arrangement that extends to post-retirement periods, it should recognize a liability for future benefits based on the substantive agreement with the employee. Dominion's adoption of this guidance resulted in an immaterial amount recognized through a cumulative effect of accounting change adjustment to retained earnings as of January 1, 2008.

2007

ACCOUNTING FOR UNCERTAINTY IN INCOME TAXES

Effective January 1, 2007, Dominion and Virginia Power adopted new FASB guidance for accounting for uncertainty in income taxes. As a result of the implementation of this guidance, Dominion recorded a $58 million charge and Virginia Power recorded a $5 million benefit to beginning retained earnings, representing the cumulative effect of the change in accounting principle. At January 1, 2007, Dominion and Virginia Power had unrecognized tax benefits of $625 million and $225 million, respectively. For the majority of unrecognized tax benefits, the ultimate deductibility is highly certain, but there is uncertainty about the timing of such deductibility.

VIRGINIA ELECTRIC & POWER CO (VELPM)

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RICHMOND, VA, 23219
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10−Q

Quarterly report pursuant to sections 13 or 15(d)
Filed on 8/2/2010
Filed Period 6/30/2010

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, 2010

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	Exact name of registrants as specified in their charters, address of principal executive offices and registrants' telephone number	I.R.S. Employer Identification Number
001−08489	**DOMINION RESOURCES, INC.**	**54−1229715**
001−02255	**VIRGINIA ELECTRIC AND POWER COMPANY**	**54−0418825**

120 Tredegar Street
Richmond, Virginia 23219
(804) 819−2000

State or other jurisdiction of incorporation or organization of the registrants: Virginia

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.

Dominion Resources, Inc. Yes ☒ No ☐ Virginia Electric and Power Company 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).

Dominion Resources, Inc. Yes ☒ No ☐ Virginia Electric and Power Company 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.

Dominion Resources, Inc.
Large accelerated filer ☒ Accelerated filer ☐
Non−accelerated filer ☐ (Do not check if a smaller reporting company) Smaller reporting company ☐

Virginia Electric and Power Company
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 in Rule 12b−2 of the Exchange Act).

Dominion Resources, Inc. Yes ☐ No ☒ Virginia Electric and Power Company Yes ☐ No ☒

At June 30, 2010, the latest practicable date for determination, Dominion Resources, Inc. had 589,130,663 shares of common stock outstanding and Virginia Electric and Power Company had 256,310 shares of common stock outstanding. Dominion Resources, Inc. is the sole holder of Virginia Electric and Power Company's common stock.

This combined Form 10−Q represents separate filings by Dominion Resources, Inc. and Virginia Electric and Power Company. Information contained herein relating to an individual registrant is filed by that registrant on its own behalf. Virginia Electric and Power Company makes no representations as to the information relating to Dominion Resources, Inc.'s other operations.

COMBINED INDEX

GLOSSARY OF TERMS

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

Abbreviation or Acronym	Definition
AOCI	Accumulated other comprehensive income (loss)
AMR	Automated meter reading program deployed by Dominion East Ohio
ARO	Asset retirement obligation
bcf	Billion cubic feet
bcfe	Billion cubic feet equivalent
Bear Garden	A 580 MW combined cycle, natural gas−fired power station under construction in Buckingham County, Virginia
BREDL	Blue Ridge Environmental Defense League
BP	BP Alternative Energy, Inc.
Brayton Point	Brayton Point power station
CAA	Clean Air Act
CEO	Chief Executive Officer
CFO	Chief Financial Officer
COL	Combined Construction Permit and Operating License
CONSOL	CONSOL Energy, Inc.
DD&A	Depreciation, depletion and amortization expense
DEI	Dominion Energy, Inc.
Dodd−Frank Act	the Dodd−Frank Wall Street Reform and Consumer Protection Act of 2010
DOE	Department of Energy
Dominion	The legal entity, Dominion Resources, Inc., one or more of Dominion Resources, Inc.'s consolidated subsidiaries (other than Virginia Power) or operating segments or the entirety of Dominion Resources, Inc. and its consolidated subsidiaries
Dominion Direct®	A dividend reinvestment and open enrollment direct stock purchase plan
DRS	Dominion Resources Services, Inc.
DSM	Demand−side management
DTI	Dominion Transmission, Inc.
DVP	Dominion Virginia Power operating segment
ECCP	Energy Conservation Council of Pennsylvania
E&P	Exploration & production
EPA	Environmental Protection Agency
EPS	Earnings per share
Fairless	Fairless power station
Fowler Ridge	A wind−turbine facility joint venture between Dominion and BP in Benton County, Indiana
FERC	Federal Energy Regulatory Commission
FTRs	Financial transmission rights
GAAP	U.S. generally accepted accounting principles
GHG	Greenhouse gas
Hope	Hope Gas, Inc.
Kewaunee	Kewaunee power station
kV	Kilovolt
kWh	Kilowatt−hour
LNG	Liquefied natural gas
Local 69	Utility Workers' Union of America, AFL−CIO, Local 69
mcfe	Thousand cubic feet equivalent
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
Meadow Brook−to−Loudoun line	Project to construct an approximately 270−mile 500−kV transmission line that begins in southwestern Pennsylvania, crosses West Virginia, and terminates in northern Virginia, of which Virginia Power will construct approximately 65 miles in Virginia and Trans−Allegheny Interstate Line Company will construct the remainder
Millstone	Millstone power station
Moody's	Moody's Investors Service
MW	Megawatt
MWh	Megawatt hour

Abbreviation or Acronym	Definition
NAAQS	National Ambient Air Quality Standard
NedPower	A wind−turbine facility joint venture between Dominion and Shell WindEnergy Inc. in Grant County, West Virginia
NGLs	Natural gas liquids
North Anna	North Anna power station
NO_X	Nitrogen oxide
NO_2	Nitrogen dioxide
NRC	Nuclear Regulatory Commission
ODEC	Old Dominion Electric Cooperative
Pennsylvania Commission	Pennsylvania Public Utility Commission
Peoples	The Peoples Natural Gas Company
PIR	Pipeline infrastructure replacement program deployed by Dominion East Ohio
PJM	PJM Interconnection, LLC
PNG Companies LLC	An indirect subsidiary of SteelRiver Infrastructure Fund North America
RCRA	Resource Conservation and Recovery Act
Riders C1 and C2	Rate adjustment clauses associated with the recovery of costs related to certain DSM programs
Rider R	A rate adjustment clause associated with recovery of costs related to Bear Garden
Rider S	A rate adjustment clause associated with the recovery of costs related to the Virginia City Hybrid Energy Center
Rider T	A rate adjustment clause associated with the recovery of certain transmission−related expenditures
ROE	Return on equity
RTEP	Regional transmission expansion plan
RTO	Regional transmission organization
Salem Harbor	Salem Harbor power station
SEC	Securities and Exchange Commission
SELC	Southern Environmental Law Center
SO_2	Sulfur dioxide
Standard & Poor’s	Standard & Poor’s Ratings Services, a division of the McGraw−Hill Companies, Inc.
State Line	State Line power station
Surry	Surry power station
the Companies	Dominion and Virginia Power, collectively
U.S.	United States of America
US−APWR	Mitsubishi Heavy Industry’s Advanced Pressurized Water Reactor
VIE	Variable interest entity
Virginia Commission	Virginia State Corporation Commission
Virginia City Hybrid Energy Center	A 585 MW (nominal) carbon−capture compatible, clean coal powered electric generation facility under construction in Wise County, Virginia
Virginia Power	The legal entity, Virginia Electric and Power Company, one or more of its consolidated subsidiaries or operating segments or the entirety of Virginia Power and its consolidated subsidiaries
VPDES	Virginia Pollutant Discharge Elimination System
VPP	Volumetric production payment
West Virginia Commission	Public Service Commission of West Virginia

PART I. FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS

DOMINION RESOURCES, INC.
CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009[1]	2010	2009[1]
(millions, except per share amounts)				
Operating Revenue	**$ 3,333**	$ 3,406	**$7,501**	$7,992
Operating Expenses				
Electric fuel and other energy−related purchases	**956**	998	**1,984**	2,139
Purchased electric capacity	**109**	105	**217**	213
Purchased gas	**391**	351	**1,183**	1,358
Other operations and maintenance	**853**	685	**1,921**	1,919
Depreciation, depletion and amortization	**262**	271	**531**	550
Other taxes	**119**	107	**288**	260
Total operating expenses	**2,690**	2,517	**6,124**	6,439
Gain on sale of Appalachian E&P operations	**2,467**	—	**2,467**	—
Income from operations	**3,110**	889	**3,844**	1,553
Other income (loss)	**(25)**	69	**46**	8
Interest and related charges	**188**	220	**371**	439
Income from continuing operations including noncontrolling interests before income tax expense	**2,897**	738	**3,519**	1,122
Income tax expense	**1,134**	265	**1,429**	406
Income from continuing operations including noncontrolling interests	**1,763**	473	**2,090**	716
Income (loss) from discontinued operations[2]	**2**	(15)	**(147)**	(6)
Net Income Including Noncontrolling Interests	**1,765**	458	**1,943**	710
Noncontrolling Interests	**4**	4	**8**	8
Net Income Attributable to Dominion	**$ 1,761**	$ 454	**$1,935**	$ 702
Amounts Attributable to Dominion:				
Income from continuing operations, net of tax	**$ 1,759**	$ 469	**$2,082**	$ 708
Income (loss) from discontinued operations, net of tax	**2**	(15)	**(147)**	(6)
Net income attributable to Dominion	**$ 1,761**	$ 454	**$1,935**	$ 702
Earnings Per Common Share – Basic and Diluted				
Income from continuing operations	**$ 2.98**	$ 0.79	**$ 3.50**	$ 1.20
Income (loss) from discontinued operations	**—**	(0.03)	**(0.25)**	(0.01)
Net income attributable to Dominion	**$ 2.98**	$ 0.76	**$ 3.25**	$ 1.19
Dividends paid per common share	**$0.4575**	$0.4375	**$0.915**	$0.875

(1) Our Consolidated Statements of Income for the three and six months ended June 30, 2009 have been recast to reflect Peoples as discontinued operations, as discussed in Note 3.

(2) Includes income tax expense of $1 million and $28 million for the three months ended June, 2010 and 2009, respectively, and $13 million and $54 million for the six months ended June 30, 2010 and 2009, respectively.

The accompanying notes are an integral part of Dominion’s Consolidated Financial Statements.

DOMINION RESOURCES, INC.
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(millions)	June 30, 2010	December 31, 2009(1)
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 411**	$ 48
Customer receivables (less allowance for doubtful accounts of $32 and $31)	**1,739**	2,050
Other receivables (less allowance for doubtful accounts of $9 and $14)	**135**	130
Inventories	**1,107**	1,185
Derivative assets	**1,029**	1,128
Assets held for sale	**—**	1,018
Prepayments	**107**	405
Other investments	**900**	—
Other	**947**	853
Total current assets	**6,375**	6,817
Investments		
Nuclear decommissioning trust funds	**2,558**	2,625
Investment in equity method affiliates	**581**	595
Other	**275**	272
Total investments	**3,414**	3,492
Property, Plant and Equipment		
Property, plant and equipment	**38,350**	39,036
Accumulated depreciation, depletion and amortization	**(12,892)**	(13,444)
Total property, plant and equipment, net	**25,458**	25,592
Deferred Charges and Other Assets		
Goodwill	**3,141**	3,354
Regulatory assets	**1,271**	1,390
Other	**2,129**	1,909
Total deferred charges and other assets	**6,541**	6,653
Total assets	**$ 41,788**	$ 42,554

(1) Dominion's Consolidated Balance Sheet at December 31, 2009 has been derived from the audited Consolidated Financial Statements at that date.

The accompanying notes are an integral part of Dominion's Consolidated Financial Statements.

DOMINION RESOURCES, INC.
CONSOLIDATED BALANCE SHEETS—(Continued)
(Unaudited)

(millions)	June 30, 2010	December 31, 2009[1]
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Securities due within one year	**$ 895**	$ 1,137
Short−term debt	**—**	1,295
Accounts payable	**1,286**	1,401
Accrued taxes	**1,083**	152
Accrued interest and payroll	**392**	524
Derivative liabilities	**717**	679
Liabilities held for sale	**—**	428
Regulatory liabilities	**362**	536
Other	**936**	681
Total current liabilities	**5,671**	6,833
Long−Term Debt		
Long−term debt	**13,614**	13,730
Junior subordinated notes payable to affiliates	**268**	268
Enhanced junior subordinated notes	**1,467**	1,483
Total long−term debt	**15,349**	15,481
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	**4,000**	4,244
Asset retirement obligations	**1,540**	1,605
Pension and other postretirement benefit liabilities	**1,145**	1,260
Regulatory liabilities	**1,198**	1,215
Other	**482**	474
Total deferred credits and other liabilities	**8,365**	8,798
Total liabilities	**29,385**	31,112
Commitments and Contingencies (see Note 15)		
Subsidiary Preferred Stock Not Subject to Mandatory Redemption	**257**	257
Common Shareholders' Equity		
Common stock – no par[2]	**6,079**	6,525
Other paid−in capital	**190**	185
Retained earnings	**6,077**	4,686
Accumulated other comprehensive loss	**(200)**	(211)
Total common shareholders' equity	**12,146**	11,185
Total liabilities and shareholders' equity	**$41,788**	$ 42,554

(1) Dominion's Consolidated Balance Sheet at December 31, 2009 has been derived from the audited Consolidated Financial Statements at that date.
(2) 1 billion shares authorized; 589 million and 599 million shares outstanding at June 30, 2010 and December 31, 2009, respectively.

The accompanying notes are an integral part of Dominion's Consolidated Financial Statements.

DOMINION RESOURCES, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

Six Months Ended June 30, (millions)	2010	2009
Operating Activities		
Net income including noncontrolling interests	$ 1,943	$ 710
Adjustments to reconcile net income including noncontrolling interests to net cash provided by operating activities:		
Gain from sale of Appalachian E&P operations	(2,467)	—
Loss from sale of Peoples	113	—
Accrued charges related to workforce reduction program	288	—
Impairment of merchant generation facility	163	—
Impairment of gas and oil properties	21	455
Depreciation, depletion and amortization (including nuclear fuel)	629	640
Deferred income taxes and investment tax credits	(210)	(447)
Contribution to employee pension plans	(250)	—
Base rate case refunds	(203)	—
Other adjustments	96	33
Changes in:		
Accounts receivable	312	623
Inventories	91	40
Deferred fuel and purchased gas costs	(46)	490
Prepayments	299	(13)
Accounts payable	(131)	(529)
Accrued interest, payroll and taxes	791	(43)
Margin deposit assets and liabilities	5	(137)
Other operating assets and liabilities	(38)	80
Net cash provided by operating activities	1,406	1,902
Investing Activities		
Plant construction and other property additions	(1,654)	(1,788)
Proceeds from the sale of Appalachian E&P operations	3,450	—
Proceeds from the sale of Peoples	741	—
Proceeds from sale of securities	1,140	727
Purchases of securities	(2,064)	(760)
Other	48	33
Net cash provided by (used in) investing activities	1,661	(1,788)
Financing Activities		
Repayment of short−term debt, net	(1,295)	(951)
Issuance of long−term debt	—	1,195
Repayment of long−term debt	(411)	(133)
Issuance of common stock	48	314
Repurchase of common stock	(500)	—
Common dividend payments	(544)	(516)
Subsidiary preferred dividend payments	(8)	(8)
Other	4	(20)
Net cash used in financing activities	(2,706)	(119)
Increase (decrease) in cash and cash equivalents	361	(5)
Cash and cash equivalents at beginning of period (1)	50	71
Cash and cash equivalents at end of period (2)	$ 411	$ 66
Supplemental Cash Flow Information:		
Significant noncash investing and financing activities		
Accrued capital expenditures	$ 215	$ 189
Debt for equity exchange	—	56

(1) 2010 and 2009 amounts include $2 million and $5 million, respectively, of cash classified as held for sale in Dominion’s Consolidated Balance Sheets.

(2) 2009 amount includes $2 million of cash classified as held for sale in Dominion’s Consolidated Balance Sheet.

The accompanying notes are an integral part of Dominion’s Consolidated Financial Statements.

VIRGINIA ELECTRIC AND POWER COMPANY
CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions)	**2010**	2009	**2010**	2009
Operating Revenue	**$ 1,711**	$ 1,675	**$3,450**	$3,534
Operating Expenses				
Electric fuel and other energy−related purchases	**589**	685	**1,221**	1,479
Purchased electric capacity	**108**	104	**215**	212
Other operations and maintenance:				
Affiliated suppliers	**88**	100	**208**	201
Other	**229**	281	**628**	527
Depreciation and amortization	**165**	160	**328**	317
Other taxes	**53**	46	**117**	97
Total operating expenses	**1,232**	1,376	**2,717**	2,833
Income from operations	**479**	299	**733**	701
Other income	**28**	23	**42**	32
Interest and related charges	**83**	87	**171**	174
Income before income tax expense	**424**	235	**604**	559
Income tax expense	**157**	86	**242**	206
Net Income	**267**	149	**362**	353
Preferred dividends	**4**	4	**8**	8
Balance available for common stock	**$ 263**	$ 145	**$ 354**	$ 345

The accompanying notes are an integral part of Virginia Power’s Consolidated Financial Statements.

VIRGINIA ELECTRIC AND POWER COMPANY
CONSOLIDATED BALANCE SHEETS
(Unaudited)

(millions)	June 30, 2010	December 31, 2009(1)
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 15**	$ 19
Customer accounts receivable (less allowance for doubtful accounts of $10 and $12)	**859**	880
Other receivables (less allowance for doubtful accounts of $6 at both dates)	**64**	72
Inventories (average cost method)	**590**	614
Prepayments	**171**	52
Other	**347**	459
Total current assets	**2,046**	2,096
Investments		
Nuclear decommissioning trust funds	**1,178**	1,204
Other	**3**	4
Total investments	**1,181**	1,208
Property, Plant and Equipment		
Property, plant and equipment	**26,666**	25,643
Accumulated depreciation and amortization	**(9,567)**	(9,314)
Total property, plant and equipment, net	**17,099**	16,329
Deferred Charges and Other Assets		
Intangible assets	**220**	217
Regulatory assets	**236**	200
Other	**236**	68
Total deferred charges and other assets	**692**	485
Total assets	**$ 21,018**	$ 20,118

(1) Virginia Power’s Consolidated Balance Sheet at December 31, 2009 has been derived from the audited Consolidated Financial Statements at that date.

The accompanying notes are an integral part of Virginia Power’s Consolidated Financial Statements.

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

(millions)	June 30, 2010	December 31, 2009(1)
LIABILITIES AND SHAREHOLDER'S EQUITY		
Current Liabilities		
Securities due within one year	**$ 363**	$ 245
Short−term debt	**—**	442
Accounts payable	**436**	390
Payables to affiliates	**83**	67
Affiliated current borrowings	**763**	2
Accrued interest, payroll and taxes	**189**	213
Regulatory liabilities	**322**	491
Other	**439**	358
Total current liabilities	**2,595**	2,208
Long−Term Debt	**6,086**	6,213
Deferred Credits and Other Liabilities		
Deferred income taxes and investment tax credits	**2,397**	2,359
Asset retirement obligations	**651**	636
Regulatory liabilities	**977**	995
Other	**296**	277
Total deferred credits and other liabilities	**4,321**	4,267
Total liabilities	**13,002**	12,688
Commitments and Contingencies (see Note 15)		
Preferred Stock Not Subject to Mandatory Redemption	**257**	257
Common Shareholder's Equity		
Common stock—no par(2)	**5,171**	4,738
Other paid−in capital	**1,110**	1,110
Retained earnings	**1,464**	1,299
Accumulated other comprehensive income	**14**	26
Total common shareholder's equity	**7,759**	7,173
Total liabilities and shareholder's equity	**$21,018**	$ 20,118

(1) Virginia Power's Consolidated Balance Sheet at December 31, 2009 has been derived from the audited Consolidated Financial Statements at that date.

(2) 300,000 shares authorized; 256,310 and 241,710 shares outstanding at June 30, 2010 and December 31, 2009, respectively.

The accompanying notes are an integral part of Virginia Power's Consolidated Financial Statements.

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

Six Months Ended June 30, (millions)	2010	2009
Operating Activities		
Net income	**$ 362**	$ 353
Adjustments to reconcile net income to net cash provided by operating activities:		
Accrued charges related to workforce reduction program	**114**	—
Depreciation and amortization (including nuclear fuel)	**383**	367
Deferred income taxes and investment tax credits	**129**	(103)
Base rate case refunds	**(203)**	—
Other adjustments	**(29)**	(14)
Changes in:		
Accounts receivable	**28**	18
Affiliated accounts receivable and payable	**18**	(24)
Inventories	**23**	(44)
Deferred fuel expenses	**(51)**	331
Accounts payable	**20**	(27)
Accrued interest, payroll and taxes	**(24)**	(18)
Prepayments	**(119)**	(61)
Other operating assets and liabilities	**(92)**	133
Net cash provided by operating activities	**559**	911
Investing Activities		
Plant construction and other property additions	**(1,041)**	(1,125)
Purchases of nuclear fuel	**(63)**	(69)
Purchases of securities	**(724)**	(346)
Proceeds from sales of securities	**711**	330
Other	**5**	(47)
Net cash used in investing activities	(1,112)	(1,257)
Financing Activities		
Issuance (repayment) of short−term debt, net	**(442)**	83
Issuance of affiliated current borrowings, net	**1,194**	105
Issuance of long−term debt	**—**	460
Repayment of long−term debt	**(9)**	(119)
Common dividend payments	**(189)**	(176)
Preferred dividend payments	**(8)**	(8)
Other	**3**	3
Net cash provided by financing activities	549	348
Increase (decrease) in cash and cash equivalents	(4)	2
Cash and cash equivalents at beginning of period	19	27
Cash and cash equivalents at end of period	$ 15	$ 29
Supplemental Cash Flow Information		
Significant noncash investing and financing activities:		
Accrued capital expenditures	$ 160	$ 103
Conversion of short−term borrowings payable to Dominion to equity	433	—

The accompanying notes are an integral part of Virginia Power’s Consolidated Financial Statements.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

Note 1. Nature of Operations

Dominion, headquartered in Richmond, Virginia, is one of the nation's largest producers and transporters of energy. Dominion's operations are conducted through various subsidiaries, including Virginia Power, a regulated public utility that generates, transmits and distributes electricity for sale in Virginia and northeastern North Carolina.

As discussed in Note 3, Dominion completed the sales of its Pennsylvania gas distribution operations and substantially all of its Appalachian E&P operations in February and April 2010, respectively.

Note 2. Significant Accounting Policies

As permitted by the rules and regulations of the SEC, Dominion's and Virginia Power's 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 Dominion's and Virginia Power's Annual Report on Form 10−K for the year ended December 31, 2009 and their Quarterly Report on Form 10−Q for the quarter ended March 31, 2010. Due to the sale of substantially all of Dominion's Appalachian E&P operations during the second quarter of 2010, accounting for gas and oil operations is no longer considered a significant accounting policy. There have been no other material changes with regard to the significant accounting policies previously disclosed in Dominion's and Virginia Power's Annual Report on Form 10−K for the year ended December 31, 2009.

In Dominion's and Virginia Power's opinion, the accompanying unaudited Consolidated Financial Statements contain all adjustments necessary to present fairly their financial position as of June 30, 2010, their results of operations for the three and six months ended June 30, 2010 and 2009 and their cash flows for the six months ended June 30, 2010 and 2009. Such adjustments are normal and recurring in nature unless otherwise noted.

The Companies make certain estimates and assumptions in preparing their 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 revenues and expenses for the periods presented. Actual results may differ from those estimates.

Dominion's and Virginia Power's accompanying unaudited Consolidated Financial Statements include, after eliminating intercompany transactions and balances, their accounts and those of their respective majority−owned subsidiaries.

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, rate changes, electric fuel and other energy−related purchases, purchased gas expenses and other factors.

Certain amounts in Dominion's and Virginia Power's 2009 Consolidated Financial Statements and Notes have been recast to conform to the 2010 presentation.

Amounts disclosed for Dominion are inclusive of Virginia Power, where applicable.

Note 3. Dispositions

Sale of Appalachian E&P Operations

In April 2010, Dominion completed the sale of substantially all of its Appalachian E&P operations to a newly−formed subsidiary of CONSOL for approximately $3.5 billion, subject to adjustments pursuant to the terms of the sale agreement.

The transaction includes the mineral rights to approximately 491,000 acres in the Marcellus Shale formation. Dominion retained certain oil and natural gas wells located on or near its natural gas storage fields. The transaction generated after−tax proceeds of approximately $2.2 billion and resulted in an after−tax gain of approximately $1.4 billion, which includes a $134 million write−off of goodwill. Proceeds from the sale will be used to pay taxes on the gain and to offset substantially all of Dominion's equity needs for 2010 and its market equity issuances for 2011, repurchase common stock, fund contributions to Dominion's pension plans and the Dominion Foundation, reduce debt and offset the majority of the impact of Virginia Power's rate case settlement.

The results of operations for Dominion's Appalachian E&P business are not reported as discontinued operations in the Consolidated Statements of Income since Dominion did not sell its entire U.S. cost pool.

Due to the sale, hedge accounting was discontinued for certain cash flow hedges since it became probable that the forecasted sales of gas would not occur. In connection with the discontinuance of hedge accounting for these contracts, Dominion recognized a $42 million ($25 million after−tax) benefit, recorded in operating revenue in its Consolidated Statement of Income, reflecting the reclassification of gains from AOCI to earnings for these contracts for the three months ended March 31, 2010.

Sale of Peoples

In February 2010, Dominion completed the sale of Peoples to PNG Companies LLC and netted after−tax proceeds of approximately $542 million. The sale resulted in an after−tax loss of approximately $132 million, which included a $79 million write−off of goodwill and post−closing adjustments. The sale also resulted in after−tax expenses of approximately $27 million, including transaction and benefit−related costs. In addition, Peoples had income from operations of $12 million after−tax during 2010.

Prior to March 31, 2010, Dominion did not report Peoples as discontinued operations since it expected to have significant continuing cash flows related primarily to the sale of natural gas production from its Appalachian E&P business to Peoples. Due to the sale of its Appalachian E&P business, Dominion will not have significant continuing cash flows with Peoples; therefore, the results of Peoples were reclassified to discontinued operations in the Consolidated Statements of Income for all periods presented.

The carrying amounts of the major classes of assets and liabilities classified as held for sale in Dominion's Consolidated Balance Sheet were as follows:

(millions)	December 31, 2009
ASSETS	
Current Assets	
Customer receivables	$ 87
Other	56
Total current assets	143
Property, Plant and Equipment	
Property, plant and equipment	985
Accumulated depreciation, depletion and amortization	(284)
Total property, plant and equipment, net	701
Deferred Charges and Other Assets	
Regulatory assets	125
Other	49
Total deferred charges and other assets	174
Assets held for sale	$ 1,018
LIABILITIES	
Current Liabilities	$ 133
Deferred Credits and Other Liabilities	
Deferred income taxes and investment tax credits	238
Other	57
Total deferred credits and other liabilities	295
Liabilities held for sale	$ 428

The following table presents selected information regarding the results of operations of Peoples, which are reported as discontinued operations in the Consolidated Statements of Income:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
(millions)				
Operating revenue	**$ —**	$ 63	**$ 67**	$290
Income (loss) before income taxes	**3**	13	**(134)**	48

Note 4. Ceiling Test

Dominion follows the full cost method of accounting for its gas and oil E&P activities, which subjects capitalized costs to a quarterly ceiling test using hedge−adjusted prices.

At March 31, 2010, Dominion recorded a ceiling test impairment charge of $21 million ($13 million after−tax) in other operations and maintenance expense in its Consolidated Statement of Income primarily due to a decline in hedge−adjusted prices reflecting the discontinuance of hedge accounting for certain cash flow hedges, as discussed in Note 3.

During the six months ended June 30, 2009, Dominion recorded a ceiling test impairment charge of $455 million ($281 million after−tax) in other operations and maintenance expense in its Consolidated Statement of Income. Excluding the effects of hedge−adjusted prices in calculating the ceiling limitation, the impairment would have been $631 million ($378 million after−tax).

Note 5. Operating Revenue

The Companies’ operating revenue consists of the following:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
(millions)				
Dominion				
Electric sales:				
Regulated	**$ 1,688**	$ 1,647	**$3,405**	$3,472
Nonregulated	**840**	924	**1,785**	1,918
Gas sales:				
Regulated	**39**	47	**184**	377
Nonregulated	**345**	389	**1,127**	1,320
Gas transportation and storage	**316**	289	**781**	682
Other	**105**	110	**219**	223
Total operating revenue	**$ 3,333**	$ 3,406	**$7,501**	$7,992
Virginia Power				
Regulated electric sales	**$ 1,688**	$ 1,647	**$3,405**	$3,472
Other	**23**	28	**45**	62
Total operating revenue	**$ 1,711**	$ 1,675	**$3,450**	$3,534

Note 6. Income Taxes

Continuing Operations

For continuing operations, including noncontrolling interests, the statutory U.S. federal income tax rate reconciles to Dominion's and Virginia Power's effective income tax rate as follows:

	Dominion		Virginia Power	
Six Months Ended June 30,	**2010**	**2009**	**2010**	**2009**
U.S. statutory rate	**35.0%**	35.0%	**35.0%**	35.0%
Increases (reductions) resulting from:				
Legislative changes	**1.6**	—	**2.6**	—
State taxes, net of federal benefit	**4.5**	4.0	**3.9**	3.8
Domestic production activities deduction	**(0.6)**	(0.5)	**(0.9)**	(0.7)
Non−deductible goodwill	**0.9**	—	**—**	—
Other, net	**(0.8)**	(2.3)	**(0.5)**	(1.3)
Effective tax rate	**40.6%**	36.2%	**40.1%**	36.8%

Dominion's and Virginia Power's effective tax rates in 2010 reflect a reduction of deferred tax assets resulting from the enactment of the Patient Protection and Affordable Care Act and the Health Care and Education Affordability Reconciliation Act of 2010 which eliminated the employer's deduction, beginning in 2013, for that portion of its retiree prescription drug coverage cost that is being reimbursed by the Medicare Part D subsidy. In addition, Dominion's effective tax rate in 2010 includes the impact of goodwill written off with the sale of the Appalachian E&P operations that is not deductible for tax purposes.

As of June 30, 2010, there have been no material changes in Dominion's and Virginia Power's unrecognized tax benefits. See Note 6 to the Consolidated Financial Statements in Dominion's and Virginia Power's Annual Report on Form 10−K for the year ended December 31, 2009, for a discussion of these unrecognized tax benefits, including possible changes that could reasonably occur during the next twelve months.

Discontinued Operations

Income tax expense in 2010 for Dominion's discontinued operations primarily reflects the impact of goodwill written off in the sale of Peoples that is not deductible for tax purposes and the reversal of deferred taxes for which the benefit was offset by the reversal of income tax−related regulatory assets.

Income tax expense in 2009 for Dominion's discontinued operations also reflects the impact of these items. Since the sale of Peoples was expected to occur later in 2009, the tax effects related to the sale were included in the determination of Dominion's estimated annual effective tax rate in 2009.

Note 7. Earnings Per Share

The following table presents the calculation of Dominion's basic and diluted EPS:

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions, except EPS)	**2010**	**2009**	**2010**	**2009**
Net income attributable to Dominion	**$ 1,761**	$ 454	**$1,935**	$ 702
Average shares of common stock outstanding – Basic	**590.4**	593.7	**595.1**	589.5
Net effect of potentially dilutive securities(1)	**1.0**	0.3	**1.0**	0.4
Average shares of common stock outstanding – Diluted	**591.4**	594.0	**596.1**	589.9
Earnings Per Common Share – Basic and Diluted	**$ 2.98**	$ 0.76	**$ 3.25**	$ 1.19

(1) Potentially dilutive securities consist of options, goal−based stock and contingently convertible senior notes.

Potentially dilutive securities with the right to acquire approximately 2.7 million and 2.2 million common shares for the three and six months ended June 30, 2009, respectively, were not included in the period's calculation of diluted EPS because the exercise or purchase prices of those instruments were greater than the average market price of Dominion's common shares. There were no potentially dilutive securities excluded from the calculation of diluted EPS for the three and six months ended June 30, 2010.

Note 8. Comprehensive Income

The following table presents Dominion's total comprehensive income:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
(millions)				
Net income including noncontrolling interests	**$1,765**	$ 458	**$1,943**	$710
Other comprehensive income (loss):				
Net other comprehensive income (loss) associated with effective portion of changes in fair value of derivatives designated as cash flow hedges, net of taxes and amounts reclassified to earnings	**(111)(1)**	(112)(2)	**(5)**	39
Other, net of tax	**(48)(3)**	53(4)	**16**	77(4)
Other comprehensive income (loss)	**(159)**	(59)	**11**	116
Comprehensive income including noncontrolling interests	**1,606**	399	**1,954**	826
Noncontrolling interests	**4**	4	**8**	8
Total comprehensive income attributable to Dominion	**$1,602**	$ 395	**$1,946**	$818

(1) Reflects the impact of changes in commodity prices and the reclassification of gains related to interest rate derivatives to earnings.
(2) Principally reflects the reclassification of electricity−related derivative activity to earnings.
(3) Primarily represents a net reduction in unrealized gains on investments held in nuclear decommissioning trusts.
(4) Principally represents a net increase in unrealized gains on investments held in nuclear decommissioning trusts.

The following table presents Virginia Power's total comprehensive income:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	**2009**	**2010**	**2009**
(millions)				
Net income	**$ 267**	$ 149	**$362**	$353
Other comprehensive income (loss):				
Net other comprehensive income (loss) associated with effective portion of changes in fair value of derivatives designated as cash flow hedges, net of taxes and amounts reclassified to earnings	**(3)**	8	**(8)**	8
Other, net of tax	**(6)**	4	**(4)**	7
Other comprehensive income (loss)	**(9)**	12	**(12)**	15
Total comprehensive income	**$ 258**	$ 161	**$350**	$368

Note 9. Fair Value Measurements

Dominion's and Virginia Power's fair value measurements are made in accordance with the policies discussed in Note 7 to the Consolidated Financial Statements in their Annual Report on Form 10−K for the year ended December 31, 2009. See Note 10 in this report for further information about their derivatives and hedge accounting activities.

Fair values are based on inputs and assumptions that market participants would use when pricing an asset or liability, including assumptions about risk and the risks inherent in valuation techniques and the inputs to valuations. The inputs and assumptions include the following:

For commodity and foreign currency derivative contracts:

- Forward commodity prices
- Forward foreign currency prices
- Price volatility
- Volumes
- Commodity location
- Interest rates
- Credit quality of counterparties and Dominion and Virginia Power
- Credit enhancements
- Time value

For interest rate derivative contracts:

- Interest rate curves
- Credit quality of counterparties and Dominion and Virginia Power
- Credit enhancements
- Time value

For investments:

- Quoted securities prices
- Securities trading information including volume and restrictions
- Maturity
- Interest rates
- Credit quality
- Net asset value (only for investments in partnerships)

Dominion and Virginia Power regularly evaluate and validate the inputs used to estimate fair value by a number of methods, including review and verification of models, as well as various market price verification procedures such as the use of pricing services and multiple broker quotes to support the market price of the various commodities in which the Companies transact.

For derivative contracts, Dominion and Virginia Power recognize transfers among Level 1, Level 2 and Level 3 based on fair values as of the first day of the month in which the transfer occurs. Transfers out of Level 3 represent assets and liabilities that were previously classified as Level 3 for which the inputs became observable based on the criteria discussed in Note 7 to the Consolidated Financial Statements in Dominion's and Virginia Power's Annual Report on Form 10−K for the year ended December 31, 2009 for classification in either Level 1 or Level 2. Because the activity and liquidity of commodity markets vary substantially between regions and time periods, the availability of observable inputs for substantially the full term and value of the Companies' over−the−counter derivative contracts is subject to change.

At June 30, 2010, Dominion's and Virginia Power's net balance of commodity derivatives categorized as Level 3 fair value measurements was a net asset of $32 million and $5 million, respectively. A hypothetical 10% increase in commodity prices would decrease Dominion's and Virginia Power's Level 3 net asset by $54 million and $2 million, respectively, while a hypothetical 10% decrease in commodity prices would increase Dominion's and Virginia Power's Level 3 net asset by $54 million and $2 million, respectively.

Non−recurring Fair Value Measurements

In June 2010, Dominion evaluated State Line, a coal−fired merchant power station with minimal environmental controls, for impairment due to the station's relatively low level of profitability combined with the EPA's issuance in June 2010 of a new stringent 1−hour primary NAAQS for SO_2 that will likely require significant environmental capital expenditures in the future. As a result of this evaluation, Dominion recorded an impairment charge of $163 million ($95 million after−tax) in other operations and maintenance expense in its Consolidated Statement of Income, to write down State Line's long−lived assets to their estimated fair value of $59 million. As management is not aware of any recent market transactions for comparable assets with sufficient transparency to develop a market approach to fair value, Dominion relied on the income approach (discounted cash flows) to estimate the fair value of State Line's long−lived assets. This is considered a Level 3 fair value measurement due to the use of significant unobservable inputs including estimates of future power and other commodity prices.

During the first quarter of 2009, Dominion evaluated an equity method investment for impairment and recorded a $23 million impairment in other income (loss) in its Consolidated Statement of Income. The resulting fair value of $10 million was estimated using an expected present value cash flow model and was considered a Level 3 fair value measurement due to the use of significant unobservable inputs related to the timing and amount of future equity distributions based on the investee's future financing structure, contractual and market based revenues and operating costs.

Recurring Fair Value Measurements

Dominion

The following table presents Dominion’s 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, 2010				
Assets				
Derivatives:				
Commodity	**$ 106**	**$1,038**	**$ 104**	**$1,248**
Interest rate	**—**	**56**	**—**	**56**
Investments(1):				
Marketable equity securities	**1,458**	**—**	**—**	**1,458**
Marketable debt securities:				
Corporate bonds	**—**	**323**	**—**	**323**
U.S. Treasury securities and agency debentures	**269**	**152**	**—**	**421**
State and municipal	**—**	**263**	**—**	**263**
Other	**—**	**28**	**—**	**28**
Cash equivalents and other	**—**	**79**	**—**	**79**
Total assets	**$1,833**	**$1,939**	**$ 104**	**$3,876**
Liabilities				
Derivatives:				
Commodity	**$ 11**	**$ 778**	**$ 72**	**$ 861**
Interest rate	**—**	**24**	**—**	**24**
Total liabilities	**$ 11**	**$ 802**	**$ 72**	**$ 885**
As of December 31, 2009				
Assets				
Derivatives:				
Commodity	$ 85	$1,058	$ 41	$1,184
Interest rate	—	176	—	176
Foreign currency	—	2	—	2
Investments(1):				
Marketable equity securities	1,575	1	—	1,576
Marketable debt securities:				
Corporate bonds	—	253	—	253
U.S. Treasury securities and agency debentures	216	78	—	294
State and municipal	—	434	—	434
Other	—	4	—	4
Cash equivalents and other	—	54	—	54
Total assets	$1,876	$2,060	$ 41	$3,977
Liabilities				
Derivatives:				
Commodity	$ 17	$ 736	$ 107	$ 860
Interest rate	—	1	—	1
Total liabilities	$ 17	$ 737	$ 107	$ 861

(1) Includes investments held in the nuclear decommissioning and rabbi trusts.

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

(millions)	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Beginning balance	**$(60)**	$ 98	**$(66)**	$ 99
Total realized and unrealized gains (losses):				
Included in earnings	**12**	(69)	**13**	(131)
Included in other comprehensive income (loss)	**61**	(108)	**85**	(88)
Included in regulatory assets/liabilities	**19**	32	**14**	55
Purchases, issuances and settlements	**(3)**	78	**(18)**	112
Transfers out of Level 3	**3**	—	**4**	(16)
Ending balance	**$ 32**	$ 31	**$ 32**	$ 31
The amount of gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets/liabilities still held at the reporting date	**$ 3**	$ 3	**$(11)**	$ (10)

The following table presents Dominion's gains and losses included in earnings in the Level 3 fair value category:

(millions)	Operating revenue	Electric fuel and other energy−related purchases	Purchased gas	Total
Three Months Ended June 30, 2010				
Total gains (losses) included in earnings	**$ 6**	**$ 6**	**$ —**	**$ 12**
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets/liabilities still held at the reporting date	**3**	**—**	**—**	**3**
Three Months Ended June 30, 2009				
Total gains (losses) included in earnings	$ 18	$ (87)	$ —	$ (69)
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets/liabilities still held at the reporting date	3	—	—	3
Six Months Ended June 30, 2010				
Total gains (losses) included in earnings	**$ (10)**	**$ 26**	**$ (3)**	**$ 13**
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets/liabilities still held at the reporting date	**(9)**	**—**	**(2)**	**(11)**
Six Months Ended June 30, 2009				
Total gains (losses) included in earnings	$ 14	$ (138)	$ (7)	$(131)
The amount of total gains (losses) for the period included in earnings attributable to the change in unrealized gains (losses) relating to assets/liabilities still held at the reporting date	(4)	(1)	(5)	(10)

Virginia Power

The following table presents Virginia Power's 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, 2010				
Assets				
Derivatives:				
Commodity	**$ —**	**$ 22**	**$ 9**	**$ 31**
Interest rate	**—**	**3**	**—**	**3**
Investments[1]:				
Marketable equity securities	**579**	**—**	**—**	**579**
Marketable debt securities:				
Corporate bonds	**—**	**216**	**—**	**216**
U.S. Treasury securities and agency debentures	**103**	**52**	**—**	**155**
State and municipal	**—**	**83**	**—**	**83**
Other	**—**	**25**	**—**	**25**
Cash equivalents and other	**—**	**47**	**—**	**47**
Total assets	**$ 682**	**$ 448**	**$ 9**	**$1,139**
Liabilities				
Derivatives:				
Commodity	**$ —**	**$ 8**	**$ 4**	**$ 12**
Interest rate	**—**	**7**	**—**	**7**
Total liabilities	**$ —**	**$ 15**	**$ 4**	**$ 19**
As of December 31, 2009				
Assets				
Derivatives:				
Commodity	$ —	$ 30	$ 2	$ 32
Interest rate	—	86	—	86
Foreign currency	—	2	—	2
Investments[1]:				
Marketable equity securities	634	—	—	634
Marketable debt securities:				
Corporate bonds	—	161	—	161
U.S. Treasury securities and agency debentures	90	8	—	98
State and municipal	—	189	—	189
Other	—	3	—	3
Cash equivalents and other	—	16	—	16
Total assets	$ 724	$ 495	$ 2	$1,221
Liabilities				
Derivatives:				
Commodity	$ —	$ 3	$ 12	$ 15
Total liabilities	$ —	$ 3	$ 12	$ 15

(1) Includes investments held in the nuclear decommissioning and rabbi trusts.

The following table presents the net change in Virginia Power’s 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,	
	2010	**2009**	**2010**	**2009**
(millions)				
Beginning balance	**$ (15)**	$ (41)	**$ (10)**	$ (69)
Total realized and unrealized gains (losses):				
Included in earnings	**6**	(87)	**26**	(138)
Included in regulatory assets/liabilities	**20**	32	**15**	55
Purchases, issuances and settlements	**(6)**	88	**(26)**	142
Transfers out of Level 3	**—**	—	**—**	2
Ending balance	**$ 5**	$ (8)	**$ 5**	$ (8)

The gains and losses included in earnings in the Level 3 fair value category were classified in electric fuel and other energy−related purchases expense in Virginia Power’s Consolidated Statements of Income for the three and six months ended June 30, 2010 and 2009. There were no unrealized gains and losses included in earnings in the Level 3 fair value category relating to assets/liabilities still held at the reporting date for the three and six months ended June 30, 2010 and 2009.

Fair Value of Financial Instruments

Substantially all of Dominion’s and Virginia Power’s 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. The carrying amount of cash and cash equivalents, customer and other receivables, short−term debt and accounts payable are representative of fair value because of the short−term nature of these instruments. For Dominion’s and Virginia Power’s financial instruments that are not recorded at fair value, the carrying amounts and estimated fair values are as follows:

	June 30, 2010		**December 31, 2009**	
(millions)	**Carrying Amount**	**Estimated Fair Value(1)**	**Carrying Amount**	**Estimated Fair Value(1)**
Dominion				
Long−term debt, including securities due within one year(2)	**$14,509**	**$ 16,265**	$14,867	$ 15,970
Junior subordinated notes payable to affiliates	**268**	**264**	268	255
Enhanced junior subordinated notes	**1,467**	**1,517**	1,483	1,487
Subsidiary preferred stock(3)	**257**	**255**	257	251
Virginia Power				
Long−term debt, including securities due within one year(2)	**$ 6,449**	**$ 7,320**	$ 6,458	$ 6,977
Preferred stock(3)	**257**	**255**	257	251

(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 amounts which represent the unamortized discount and premium. At June 30, 2010 and December 31, 2009, includes the valuation of certain fair value hedges associated with Dominion’s fixed rate debt of approximately $54 million and $23 million, respectively.

(3) Includes issuance expenses of $2 million at June 30, 2010 and December 31, 2009.

Note 10. Derivatives and Hedge Accounting Activities

Dominion’s and Virginia Power’s accounting policies and objectives and strategies for using derivative instruments are discussed in Note 2 to the Consolidated Financial Statements in their Annual Report on Form 10−K for the year ended December 31, 2009. See Note 9 in this report for further information about fair value measurements and associated valuation methods for derivatives.

Dominion

The following table presents the volume of Dominion’s derivative activity as of June 30, 2010. These volumes are based on open derivative positions and represent the combined absolute value of their long and short positions, except in the case of offsetting deals, for which they represent the absolute value of the net volume of their long and short positions.

	Current	**Noncurrent**
Natural Gas (bcf):		
Fixed price(1)	568	146
Basis(1)	1,229	591
Electricity (MWh):		
Fixed price	19,001,154	11,021,011
FTRs	105,571,139	2,599,872
Capacity (MW)	1,512,600	4,659,850
Liquids (gallons)(2)	154,476,000	415,212,000
Interest rate	$850,000,000	$825,000,000
Foreign currency (euros)	4,301,400	—

(1) Includes options.

(2) Includes NGL and oil derivatives.

For the three and six months ended June 30, 2010 and 2009, 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, 2010 and 2009.

The following table presents selected information related to gains (losses) on cash flow hedges included in AOCI in Dominion's Consolidated Balance Sheet at June 30, 2010:

(millions)	**AOCI After−Tax**	**Amounts Expected to be Reclassified to Earnings during the next 12 Months After−Tax**	**Maximum Term**
Commodities:			
Gas	$ (15)	$ (6)	54 months
Electricity	214	177	35 months
NGLs	34	9	54 months
Other	10	3	59 months
Interest rate	33	(1)	342 months
Total	$ 276	$ 182	

The amounts that will be reclassified from AOCI to earnings will generally be offset by the recognition of the hedged transactions (e.g., anticipated sales) 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.

The sale of the majority of Dominion's remaining E&P operations resulted in the discontinuance of hedge accounting for certain cash flow hedges, as discussed in Note 3.

In addition, changes to Dominion's financing needs during the first and second quarters of 2010 resulted in the discontinuance of hedge accounting for certain cash flow hedges since it became probable that forecasted interest payments would not occur. In connection with the discontinuance of hedge accounting for these contracts, Dominion recognized a benefit recorded to interest and related charges reflecting the reclassification of gains from AOCI to earnings of $70 million ($43 million after−tax) in the three months ended June 30, 2010 and $110 million ($67 million after−tax) in the six months ended June 30, 2010. The reclassification of gains from AOCI to earnings was partially offset by subsequent changes in fair value of $37 million ($23 million after−tax) for the three and six months ended June 30, 2010.

Fair Value and Gains and Losses on Derivative Instruments

The following table presents the fair values of Dominion's derivatives and where they are presented in its Consolidated Balance Sheets:

(millions)	Fair Value – Derivatives under Hedge Accounting	Fair Value – Derivatives not under Hedge Accounting	Total Fair Value
June 30, 2010			
ASSETS			
Current Assets			
Commodity	**$ 465**	**$ 542**	**$ 1,007**
Interest rate	**22**	**—**	**22**
Total current derivative assets	**487**	**542**	**1,029**
Noncurrent Assets			
Commodity	**158**	**83**	**241**
Interest rate	**34**	**—**	**34**
Total noncurrent derivative assets[1]	**192**	**83**	**275**
Total derivative assets	**$ 679**	**$ 625**	**$ 1,304**
LIABILITIES			
Current Liabilities			
Commodity	**$ 142**	**$ 551**	**$ 693**
Interest rate	**—**	**24**	**24**
Total current derivative liabilities	**142**	**575**	**717**
Noncurrent Liabilities			
Commodity	**61**	**107**	**168**
Total noncurrent derivative liabilities[2]	**61**	**107**	**168**
Total derivative liabilities	**$ 203**	**$ 682**	**$ 885**
December 31, 2009			
ASSETS			
Current Assets			
Commodity	$ 445	$ 507	$ 952
Interest rate	174	—	174
Foreign currency	2	—	2
Total current derivative assets	621	507	1,128
Noncurrent Assets			
Commodity	132	100	232
Interest rate	2	—	2
Total noncurrent derivative assets[1]	134	100	234
Total derivative assets	$ 755	$ 607	$ 1,362
LIABILITIES			
Current Liabilities			
Commodity	$ 147	$ 532	$ 679
Total current derivative liabilities	147	532	679
Noncurrent Liabilities			
Commodity	61	120	181
Interest rate	1	—	1
Total noncurrent derivative liabilities[2]	62	120	182
Total derivative liabilities	$ 209	$ 652	$ 861

(1) Noncurrent derivative assets are presented in other deferred charges and other assets in Dominion's Consolidated Balance Sheets.

(2) Noncurrent derivative liabilities are presented in other deferred credits and other liabilities in Dominion's Consolidated Balance Sheets.

Derivatives in cash flow hedging relationships (millions)	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)
Three Months Ended June 30, 2010			
Derivative Type and Location of Gains (Losses)			
Commodity:			
Operating revenue		**$ 114**	
Purchased gas		**(19)**	
Electric fuel and other energy−related purchases		**(5)**	
Purchased electric capacity		**1**	
Total commodity	**$ (16)**	**91**	**$ 2**
Interest rate(3)	**—**	**70**	**(23)**
Foreign currency(4)	**—**	**(1)**	**(1)**
Total	**$ (16)**	**$ 160**	**$ (22)**
Three Months Ended June 30, 2009			
Derivative Type and Location of Gains (Losses)			
Commodity:			
Operating revenue		$ 284	
Purchased gas		(35)	
Electric fuel and other energy−related purchases		(2)	
Purchased electric capacity		1	
Total commodity	$ (57)	248	$ (4)
Interest rate(3)	138	(1)	86
Foreign currency(4)	1	—	2
Total	$ 82	$ 247	$ 84
Six Months Ended June 30, 2010			
Derivative Type and Location of Gains (Losses)			
Commodity:			
Operating revenue		**$ 295**	
Purchased gas		**(116)**	
Electric fuel and other energy−related purchases		**(8)**	
Purchased electric capacity		**2**	
Total commodity	**$ 283**	**173**	**$ (11)**
Interest rate(3)	**(3)**	**110**	**(24)**
Foreign currency(4)	**—**	**—**	**(2)**
Total	**$ 280**	**$ 283**	**$ (37)**
Six Months Ended June 30, 2009			
Derivative Type and Location of Gains (Losses)			
Commodity:			
Operating revenue		$ 522	
Purchased gas		(83)	
Electric fuel and other energy−related purchases		(7)	
Purchased electric capacity		3	
Total commodity	$ 374	435	$ 1
Interest rate(3)	124	(2)	73
Foreign currency(4)	1	1	—
Total	$ 499	$ 434	$ 74

(1) Amounts deferred into AOCI have no associated effect in Dominion’s 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 Dominion's Consolidated Statements of Income.
(3) Amounts recorded in Dominion's Consolidated Statements of Income are classified in interest and related charges.
(4) Amounts recorded in Dominion's Consolidated Statements of Income are classified in electric fuel and other energy−related purchases.

Derivatives not designated as hedging instruments (millions)	Amount of Gain (Loss) Recognized in Income on Derivatives[1] Three Months Ended June 30, 2010	2009	Six Months Ended June 30, 2010	2009
Derivative Type and Location of Gains (Losses)				
Commodity				
Operating revenue	**$ (14)**	$ 13	**$ 26**	$ 46
Purchased gas	**2**	(14)	**(29)**	(46)
Electric fuel and other energy−related purchases	**5**	(86)	**26**	(137)
Interest Rate[2]	**(37)**	—	**(37)**	—
Total	**$ (44)**	$ (87)	**$(14)**	$(137)

(1) Includes derivative activity amortized out of regulatory assets/liabilities. Amounts deferred into regulatory assets/liabilities have no associated effect in Dominion's Consolidated Statements of Income.
(2) Amounts are recorded in interest and related charges in Dominion's Consolidated Statements of Income.

Virginia Power

The following table presents the volume of Virginia Power's derivative activity as of June 30, 2010. These volumes are based on open derivative positions and represent the combined absolute value of their long and short positions, except in the case of offsetting deals, for which they represent the absolute value of the net volume of their long and short positions.

	Current	Noncurrent
Natural Gas (bcf):		
Fixed price	10	—
Basis	5	—
Electricity (MWh):		
Fixed price	723,200	—
FTRs	104,879,135	2,599,872
Capacity (MW)	417,000	350,500
Interest rate	$300,000,000	$75,000,000
Foreign currency (euros)	4,301,400	—

For the three and six months ended June 30, 2010 and 2009, 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, 2010 and 2009.

The following table presents selected information related to gains on cash flow hedges included in AOCI in Virginia Power's Consolidated Balance Sheet at June 30, 2010:

(millions)	AOCI After−Tax	Amounts Expected to be Reclassified to Earnings during the next 12 Months After−Tax	Maximum Term
Interest rate	$ 3	$ —	342 months
Other	2	2	47 months
Total	$ 5	$ 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 sales) 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 Virginia Power's derivatives and where they are presented in its Consolidated Balance Sheets:

(millions)	Fair Value – Derivatives under Hedge Accounting	Fair Value – Derivatives not under Hedge Accounting	Total Fair Value
June 30, 2010			
ASSETS			
Current Assets			
Commodity	**$ 22**	**$ 9**	**$ 31**
Interest rate	**3**	**—**	**3**
Total current derivative assets[1]	**25**	**9**	**34**
Total derivative assets	**$ 25**	**$ 9**	**$ 34**
LIABILITIES			
Current Liabilities			
Commodity	**$ 4**	**$ 4**	**$ 8**
Interest rate	**—**	**7**	**7**
Total current derivative liabilities[3]	**4**	**11**	**15**
Noncurrent Liabilities			
Commodity	**4**	**—**	**4**
Total noncurrent derivative liabilities[4]	**4**	**—**	**4**
Total derivative liabilities	**$ 8**	**$ 11**	**$ 19**
December 31, 2009			
ASSETS			
Current Assets			
Commodity	$ 20	$ 2	$ 22
Interest rate	86	—	86
Foreign currency	2	—	2
Total current derivative assets[1]	108	2	110
Noncurrent Assets			
Commodity	10	—	10
Total noncurrent derivative assets[2]	10	—	10
Total derivative assets	$ 118	$ 2	$ 120
LIABILITIES			
Current Liabilities			
Commodity	$ 1	$ 12	$ 13
Total current derivative liabilities[3]	1	12	13
Noncurrent Liabilities			
Commodity	2	—	2
Total noncurrent derivative liabilities[4]	2	—	2
Total derivative liabilities	$ 3	$ 12	$ 15

(1) Current derivative assets are presented in other current assets in Virginia Power's Consolidated Balance Sheets.
(2) Noncurrent derivative assets are presented in other deferred charges and other assets in Virginia Power's Consolidated Balance Sheets.
(3) Current derivative liabilities are presented in other current liabilities in Virginia Power's Consolidated Balance Sheets.
(4) Noncurrent derivative liabilities are presented in other deferred credits and other liabilities in Virginia Power's Consolidated Balance Sheets.

Derivatives in cash flow hedging relationships (millions)	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)
Three Months Ended June 30, 2010			
Derivative Type and Location of Gains (Losses)			
Commodity:			
Purchased electric capacity		**$ 1**	
Total commodity	**$ 1**	**1**	**$ 2**
Interest rate(3)	**—**	**6**	**(23)**
Foreign currency(4)	**—**	**—**	**(1)**
Total	**$ 1**	**$ 7**	**$ (22)**
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, 2010			
Derivative Type and Location of Gains (Losses)			
Commodity:			
Electric fuel and other energy−related purchases		**$ (1)**	
Purchased electric capacity		**2**	
Total commodity	**$ (2)**	**1**	**$ (11)**
Interest rate(3)	**(1)**	**9**	**(24)**
Foreign currency(4)	**—**	**—**	**(2)**
Total	**$ (3)**	**$ 10**	**$ (37)**
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 Virginia Power’s 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 Virginia Power’s Consolidated Statements of Income.

(3) Amounts recorded in Virginia Power’s Consolidated Statements of Income are classified in interest and related charges.

(4) Amounts recorded in Virginia Power’s Consolidated Statements of Income are classified in electric fuel and other energy−related purchases.

Derivatives not designated as hedging instruments (millions)	Amount of Gain (Loss) Recognized in Income on Derivatives(1) Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Derivative Type and Location of Gains (Losses)				
Commodity(2)	**$ 5**	$ (87)	**$ 26**	$ (138)
Interest Rate(3)	**(3)**	—	**(3)**	—
Total	**$ 2**	$ (87)	**$ 23**	$ (138)

(1) Includes derivative activity amortized out of regulatory assets/liabilities. Amounts deferred into regulatory assets/liabilities have no associated effect in Virginia Power's Consolidated Statements of Income.
(2) Amounts are recorded in electric fuel and other energy−related purchases in Virginia Power's Consolidated Statements of Income.
(3) Amounts are recorded in interest and related charges in Virginia Power's Consolidated Statements of Income.

Note 11. Investments

Dominion

Rabbi Trust Securities

Marketable equity and debt securities and cash equivalents held in Dominion's rabbi trusts and classified as trading totaled $91 million and $96 million at June 30, 2010 and December 31, 2009, respectively. Cost method investments held in Dominion's rabbi trusts totaled $18 million and $17 million at June 30, 2010 and December 31, 2009, respectively.

Decommissioning Trust Securities

Dominion holds marketable equity and debt securities (classified as available−for−sale), cash equivalents and cost method investments in nuclear decommissioning trust funds in order to fund future decommissioning costs for its nuclear plants. Dominion's decommissioning trust funds are summarized below.

(millions)	Amortized Cost	Total Unrealized Gains(1)	Total Unrealized Losses(1)	Fair Value
June 30, 2010				
Marketable equity securities	**$ 1,184**	**$ 230**	**$ (1)**	**$1,413**
Marketable debt securities:				
Corporate bonds	**308**	**16**	**(1)**	**323**
U.S. Treasury securities and agency debentures	**403**	**18**	**—**	**421**
State and municipal	**208**	**11**	**(2)**	**217**
Other	**28**	**—**	**—**	**28**
Cost method investments	**105**	**—**	**—**	**105**
Cash equivalents and other(2)	**51**	**—**	**—**	**51**
Total	**$ 2,287**	**$ 275**	**$ (4)(3)**	**$2,558**
December 31, 2009				
Marketable equity securities	$ 1,191	$ 338	$ —	$1,529
Marketable debt securities:				
Corporate bonds	241	13	(1)	253
U.S. Treasury securities and agency debentures	281	13	(1)	293
State and municipal	371	21	(3)	389
Other	4	—	—	4
Cost method investments	97	—	—	97
Cash equivalents and other(2)	60	—	—	60
Total	$ 2,245	$ 385	$ (5)(3)	$2,625

(1) Included in AOCI and the decommissioning trust regulatory liability.
(2) At June 30, 2010 and December 31, 2009, reflects $28 million and $11 million, respectively, related to net pending sales and purchases of securities.
(3) The fair value of securities in an unrealized loss position was $86 million and $169 million at June 30, 2010 and December 31, 2009, respectively.

The fair value of Dominion's marketable debt securities (classified as available for sale) at June 30, 2010 by contractual maturity is as follows:

(millions)	Amount
Due in one year or less	$ 81
Due after one year through five years	317
Due after five years through ten years	275
Due after ten years	316
Total	$ 989

Presented below is selected information regarding Dominion's marketable equity and debt securities.

(millions)	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Trading securities:				
Net unrealized gain (loss)	**$ (3)**	$ 6	**$ (1)**	$ 2
Available−for−sale securities:				
Proceeds from sales(1)	**627**	438	**1,140**	727
Realized gains(2)	**17**	45	**73**	61
Realized losses(2)	**28**	16	**54**	159

(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 or losses recorded to the decommissioning trust regulatory liability.

Dominion recorded other−than−temporary impairment losses on investments as follows:

(millions)	Three Months Ended June 30, 2010	Three Months Ended June 30, 2009	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Total other−than−temporary impairment losses(1)	**$ 41**	$ 15	**$ 48**	$156
Losses recorded to decommissioning trust regulatory liability	**(13)**	(7)	**(16)**	(70)
Losses recognized in other comprehensive income (before taxes)	**(1)**	(1)	**(2)**	(1)
Net impairment losses recognized in earnings	**$ 27**	$ 7	**$ 30**	$ 85

(1) Amount includes other−than−temporary impairment losses for debt securities of $1 million and $2 million for the three months ended June 30, 2010 and 2009, respectively, and $3 million and $8 million for the six months ended June 30, 2010 and 2009, respectively.

Other Investments

In May 2010, using proceeds from the sale of the Appalachian E&P business, Dominion acquired $1.4 billion of short−term investments consisting of $700 million in time deposits and $700 million in Treasury Bills. As of June 30, 2010, $900 million of these investments are still held and are classified as other current investments on Dominion's Consolidated Balance Sheet. There were no unrealized gains or losses for these investments as of June 30, 2010 and their amortized cost approximates fair value. Proceeds from the sale of these investments are expected to be used largely to pay the tax liability on the gain from the sale of the Appalachian E&P business.

Virginia Power

Decommissioning Trust Securities

Virginia Power holds marketable equity and debt securities (classified as available−for−sale), cash equivalents and cost method investments in nuclear decommissioning trust funds in order to fund future decommissioning costs for its nuclear plants. Virginia Power's decommissioning trust funds are summarized below.

(millions)	Amortized Cost	Total Unrealized Gains(1)	Total Unrealized Losses(1)	Fair Value
June 30, 2010				
Marketable equity securities	**$ 488**	**$ 91**	**$ —**	**$ 579**
Marketable debt securities:				
Corporate bonds	**208**	**9**	**(1)**	**216**
U.S. Treasury securities and agency debentures	**151**	**4**	**—**	**155**
State and municipal	**80**	**2**	**—**	**82**
Other	**24**	**1**	**—**	**25**
Cost method investments	**105**	**—**	**—**	**105**
Cash equivalents and other(2)	**16**	**—**	**—**	**16**
Total	**$ 1,072**	**$ 107**	**$ (1)(3)**	**$1,178**

(millions)	Amortized Cost	Total Unrealized Gains(1)	Total Unrealized Losses(1)	Fair Value
December 31, 2009				
Marketable equity securities	$ 499	$ 135	$ —	$ 634
Marketable debt securities:				
Corporate bonds	153	9	(1)	161
U.S. Treasury securities and agency debentures	95	3	—	98
State and municipal	181	9	(1)	189
Other	3	—	—	3
Cost method investments	97	—	—	97
Cash equivalents and other (2)	22	—	—	22
Total	$ 1,050	$ 156	$ (2)(3)	$1,204

(1) Included in AOCI and the decommissioning trust regulatory liability.
(2) At June 30, 2010 and December 31, 2009, reflects $31 million and $6 million, respectively, related to net pending sales and purchases of securities.
(3) The fair value of securities in an unrealized loss position was $60 million and $88 million at June 30, 2010, and December 31, 2009, respectively.

The fair value of Virginia Power’s marketable debt securities at June 30, 2010, by contractual maturity is as follows:

(millions)	Amount
Due in one year or less	**$ 10**
Due after one year through five years	**167**
Due after five years through ten years	**160**
Due after ten years	**141**
Total	**$ 478**

Presented below is selected information regarding Virginia Power’s marketable equity and debt securities.

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions)	2010	2009	2010	2009
Proceeds from sales (1)	**$ 407**	$ 193	**$ 711**	$ 330
Realized gains (2)	**8**	15	**37**	23
Realized losses (2)	**2**	6	**20**	70

(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 or losses recorded to the decommissioning trust regulatory liability.

Virginia Power recorded other−than−temporary impairment losses on investments as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
(millions)	2010	2009	2010	2009
Total other−than−temporary impairment losses (1)	**$ 16**	$ 8	**$ 19**	$ 82
Losses recorded to decommissioning trust regulatory liability	**(13)**	(7)	**(16)**	(70)
Net impairment losses recognized in earnings	**$ 3**	$ 1	**$ 3**	$ 12

(1) Amount includes other−than−temporary impairment losses for debt securities of $1 million for the three months ended June 30, 2010 and 2009, and $2 million and $5 million for the six months ended June 30, 2010 and 2009, respectively.

Note 12. Regulatory Matters

Other than the following matters, there have been no significant developments regarding the pending regulatory matters disclosed in Note 14 to the Consolidated Financial Statements in Dominion’s and Virginia Power’s Annual Report on Form 10−K for the year ended December 31, 2009 and Note 12 to the Consolidated Financial Statements in Dominion’s and Virginia Power’s Quarterly Report on Form 10−Q for the quarter ended March 31, 2010.

Virginia Regulation

Virginia Fuel Expenses

In April 2010, Virginia Power filed its Virginia fuel factor application with the Virginia Commission. The application requested an annual decrease in fuel expense recovery of approximately $82 million for the period July 1, 2010 through June 30, 2011. The proposed fuel factor went into effect on July 1, 2010 on an interim basis and an evidentiary hearing on the Company's application is to be held in September 2010.

Generation Riders R and S

In June 2010, Virginia Power filed annual updates for Riders R and S with the Virginia Commission. The proposed revenue requirements under Riders R and S, effective April 1, 2011, for the rate year ending March 31, 2012 are approximately $86 million and $200 million, respectively. The ROE utilized in both rider filings is 12.3%, consistent with the terms of the rate settlement approved by the Virginia Commission in March 2010. The proposed updates to Riders R and S are subject to the approval of the Virginia Commission.

Transmission Rider T

In June 2010, the Virginia Commission approved Virginia Power's annual update to Rider T to be effective September 1, 2010, reflecting the revenue requirement of approximately $338 million recommended by Virginia Commission Staff and agreed to by Virginia Power.

Approval of DSM Programs – Riders C1 and C2

In March 2010, the Virginia Commission approved Virginia Power's application for the recovery of approximately $28 million for five DSM programs through initiation of Riders C1 and C2, effective May 1, 2010.

North Anna Power Station

Virginia Power is considering the construction of a third nuclear unit at a site located at North Anna, which Virginia Power owns along with ODEC. Virginia Power and ODEC have obtained an Early Site Permit for the North Anna site from the NRC. In November 2007, Virginia Power, along with ODEC, filed an application with the NRC for a COL that references a specific reactor design and which would allow Virginia Power to build and operate a new nuclear unit at North Anna. In January 2008, the NRC accepted Virginia Power's application for the COL and deemed it complete. In December 2008, Virginia Power terminated a long−lead agreement with its vendor with respect to the reactor design identified in its COL application and certain related equipment. A competitive process was initiated in 2009 to determine if vendors could provide an advanced technology reactor that could be licensed and built under terms acceptable to Virginia Power. In May 2010, Virginia Power announced its selection of US−APWR technology for the potential third nuclear unit.

In June 2010, Virginia Power and ODEC amended the COL application to reflect the selection of the US−APWR technology. Virginia Power has a cooperative agreement, scheduled to terminate September 30, 2010, with the DOE to share equally the cost of developing a COL that references the technology previously selected by Virginia Power. Funding is not available under the agreement for activities related to the US−APWR technology. Program activities to close out the agreement will continue to be funded by the DOE.

Virginia Power has not yet committed to building a new nuclear unit at North Anna. If Virginia Power decides to build the new unit, it must first receive a COL from the NRC and the approval of the Virginia Commission. The US−APWR design is currently undergoing the NRC certification process.

The NRC is required to conduct a hearing in all COL proceedings. In August 2008, the Atomic Safety and Licensing Board of the NRC granted a request for a hearing on one of eight contentions filed by the BREDL. In August 2009, the Atomic Safety and Licensing Board dismissed this contention as moot, but in November 2009 admitted a new contention filed by the BREDL. Virginia Power's motion for reconsideration of this ruling was denied by the Atomic Safety and Licensing Board in March 2010. In June 2010, the BREDL filed a new proposed contention concerning Virginia Power's change in reactor technology. Virginia Power and the NRC staff oppose the admission of this contention. In July 2010, Virginia Power also filed a motion to dismiss BREDL's admitted contention as moot based on the change in the reactor technology. Absent additional admitted contentions, the mandatory NRC hearing will be uncontested with respect to other issues. In March 2010, the NRC completed its final supplemental environmental impact statement, finding that there are no environmental impacts that would preclude issuing a COL for the new nuclear unit. However, further safety and environmental review is now expected as a result of the change in reactor technology.

Electric Transmission Projects

In October 2008, the Virginia Commission authorized construction of the Meadow Brook−to−Loudoun line and affirmed the 65−mile route proposed for the line which is adjacent to, or within, existing transmission line right−of−ways. The Virginia Commission's approval of the Meadow Brook−to−Loudoun line was conditioned on the respective state commission approvals of both the West Virginia and Pennsylvania portions of the transmission line. The West Virginia Commission's approval of Trans−Allegheny Interstate Line Company's application became effective in February 2009 and the Pennsylvania Commission granted approval in December 2008. On appeal by the ECCP, the Pennsylvania Commonwealth Court affirmed in May 2010 the Pennsylvania Commission's approval and subsequently denied a request for reargument by the ECCP in June 2010. The Meadow Brook−to−Loudoun line is expected to cost approximately $255 million and be completed in June 2011.

In December 2008, as part of PJM's RTEP process, the Hayes−to−Yorktown 230 kV line was authorized by PJM. In June 2010, the Virginia Commission authorized the construction of the Hayes−to−Yorktown line along the proposed eight−mile route utilizing existing easements and property previously acquired for the transmission line right−of−way. In accordance with the Virginia Commission's approval, approximately 4.2 miles of the Hayes−to−Yorktown line will be constructed overhead and approximately 3.8 miles will be installed underground in order to cross under the York River. The Hayes−to−Yorktown line is expected to cost approximately $63 million and, subject to receipt of all regulatory approvals, is expected to be completed by June 2012.

DTI Appalachian Gateway Project

In August 2008, DTI announced the proposed development of the Appalachian Gateway gas pipeline project. In June 2010, DTI filed a certificate application with the FERC seeking approval for the Appalachian Gateway project. The project is expected to provide approximately 484,000 dekatherms per day of firm transportation services for new Appalachian gas supplies from the supply areas in the Appalachian Basin in West Virginia and southwestern Pennsylvania to an interconnection with Texas Eastern Transmission, LP at Oakford, Pennsylvania. Plans call for construction to start in 2011, with transportation services to begin by September 2012. DTI estimates the cost of the Appalachian Gateway project to be approximately $634 million.

Note 13. Variable Interest Entities

As discussed in Note 16 to the Consolidated Financial Statements in Dominion's and Virginia Power's Annual Report on Form 10−K for the year ended December 31, 2009, certain variable pricing terms in some of the Companies' long−term power and capacity contracts cause them to be considered variable interests in the counterparties.

Virginia Power has long−term power and capacity contracts with four non−utility generators with an aggregate generation capacity of approximately 947 MW at June 30, 2010. These contracts contain certain variable pricing mechanisms in the form of partial fuel reimbursement that Virginia Power considers to be variable interests. After an evaluation of the information provided by these entities, Virginia Power was unable to determine whether they were VIEs. However, the information they provided, as well as Virginia Power's knowledge of generation facilities in Virginia, enabled Virginia Power to conclude that, if they were VIEs, it would not be the primary beneficiary. This conclusion reflects Virginia Power's determination that its variable interests do not convey the power to direct the most significant activities that impact the economic performance of the entity during the remaining terms of Virginia Power's contracts and for the years the entities are expected to operate after its contractual relationships expire. The contracts expire at various dates ranging from 2015 to 2021. Virginia Power is not subject to any risk of loss from these potential VIEs other than its remaining purchase commitments which totaled $1.7 billion as of June 30, 2010. Virginia Power paid $53 million and $51 million for electric capacity and $34 million and $25 million for electric energy to these entities for the three months ended June 30, 2010 and 2009, respectively. Virginia Power paid $107 million and $104 million for electric capacity and $75 million and $66 million for electric energy to these entities for the six months ended June 30, 2010 and 2009, respectively.

Virginia Power purchased shared services from DRS, an affiliated VIE, of approximately $107 million and $99 million for the three months ended June 30, 2010 and 2009, respectively, and $248 million and $199 million for the six months ended June 30, 2010 and 2009, respectively. Virginia Power determined that it is 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 Virginia Power. Virginia Power has no obligation to absorb more than its allocated share of DRS costs.

Note 14. Significant Financing Transactions

Credit Facilities and Short−Term Debt

Dominion and Virginia Power use short−term debt to fund working capital requirements, as a bridge to long−term debt financing and as bridge financing for acquisitions, if applicable. The levels of borrowing may vary significantly during the course of the year, depending upon the timing and amount of cash requirements not satisfied by cash from operations. In addition, Dominion utilizes cash and letters of credit to fund collateral requirements under its commodities hedging program. Collateral requirements are impacted by commodity prices, hedging levels, Dominion's credit quality and the credit quality of its counterparties.

At June 30, 2010, commercial paper, bank loans and letters of credit outstanding, as well as capacity available under credit facilities, were as follows:

(millions)	Facility Limit	Outstanding Commercial Paper	Outstanding Bank Borrowings	Outstanding Letters of Credit	Facility Capacity Available
Five−year joint revolving credit facility(1)	$2,872	$ —	$ —	$ 140	$ 2,732
Five−year Dominion credit facility(2)	1,700	—	—	8	1,692
Five−year Dominion bilateral facility(3)	200	—	—	21	179
Totals	$4,772	$ —	$ —	$ 169	$ 4,603

(1) This credit facility was entered into in February 2006 and terminates in February 2011. This credit facility can be used to support bank borrowings and the issuance of commercial paper, as well as to support up to $1.5 billion of letters of credit.

(2) This credit facility was entered into in August 2005 and terminates in August 2010. This credit facility can be used to support bank borrowings, commercial paper and letter of credit issuances.

(3) This facility was entered into in December 2005 and terminates in December 2010. This facility can be used to support bank borrowings, commercial paper and letter of credit issuances.

In addition to the credit facility commitments disclosed above, Virginia Power also has a five−year $120 million credit facility that terminates in February 2011, which supports certain of its tax−exempt financings.

Dominion and Virginia Power plan to replace their existing credit facilities during the third quarter of 2010. They expect to operate with credit facilities of $3.0 to $3.5 billion, comprised of two joint credit facilities. The Companies expect one facility to be approximately $3.0 billion, which would be used principally to support the issuance of commercial paper but could also support bank borrowings and the issuance of letters of credit. The second facility of approximately $500 million also would support bank borrowings and the issuance of commercial paper, but would be the primary source for the issuance of letters of credit. In addition to these two facilities, Virginia Power expects to replace its existing $120 million credit facility that supports certain tax−exempt financings with a facility of a similar size. All three facilities should be for a three−year term. The Companies do not expect the overall reduction in the size and tenor of their credit facilities to negatively impact their ability to fund their operations.

Dominion repaid $411 million of long−term debt during the six months ended June 30, 2010.

Convertible Securities

At June 30, 2010, Dominion had $202 million of outstanding contingent convertible senior notes that are convertible by holders into a combination of cash and shares of Dominion's common stock under certain circumstances. The conversion feature requires that the principal amount of each note be repaid in cash, while amounts payable in excess of the principal amount will be paid in common stock. The conversion rate is subject to adjustment upon certain events such as subdivisions, splits, combinations of common stock or the issuance to all common stock holders of certain common stock rights, warrants or options and certain dividend increases. As of June 30, 2010, the conversion rate has been adjusted, primarily due to individual dividend payments above the level paid at issuance, to 28.3226 shares of common stock per $1,000 principal amount of senior notes, which represents a conversion price of $35.31.

The senior notes have not been eligible for conversion during 2010 and as of June 30, 2010, the closing price of Dominion's common stock was not equal to $42.37 per share or higher for at least 20 out of the last 30 consecutive trading days; therefore, the senior notes are not eligible for conversion during the third quarter of 2010.

Enhanced Junior Subordinated Notes

In the second quarter of 2010, Dominion purchased and cancelled $16 million of its $500 million 2006 Series B Enhanced Junior Subordinated Notes, which mature in 2066 and bear a coupon rate of 6.3%. These purchases were conducted in compliance with the Replacement Capital Covenant as disclosed in the *Debt Covenants* section of MD&A in Dominion’s and Virginia Power’s Annual Report on Form 10−K for the year ended December 31, 2009.

Issuance of Common Stock

During the six months ended June 30, 2010, Dominion issued 1.5 million shares of common stock and received cash proceeds of $48 million. The shares issued and cash proceeds received during the six months ended June 30, 2010 were through Dominion Direct ®, employee savings plans and the exercise of employee stock options. In February 2010, Dominion began purchasing its common stock on the open market with proceeds received through Dominion Direct® and employee savings plans, rather than issuing additional new common shares.

In March 2010, Virginia Power issued 14,600 shares of its common stock to Dominion reflecting the conversion of approximately $433 million of short−term demand note borrowings from Dominion to equity.

Repurchase of Common Stock

In March 2010, Dominion began repurchasing common shares on the open market in anticipation of proceeds from the sale of its Appalachian E&P operations. During the six months ended June 30, 2010, Dominion repurchased 12.2 million shares of its common stock for approximately $500 million.

Note 15. Commitments and Contingencies

Other than the following matters, there have been no significant developments regarding the commitments and contingencies disclosed in Note 23 to the Consolidated Financial Statements in Dominion’s and Virginia Power’s Annual Report on Form 10−K for the year ended December 31, 2009, or Note 15 to the Consolidated Financial Statements in Dominion’s and Virginia Power’s Quarterly Report on Form 10−Q for the quarter ended March 31, 2010.

Guarantees

Dominion

At June 30, 2010, Dominion had issued $126 million of guarantees, primarily to support equity method investees. No significant amounts related to these guarantees have been recorded. As of June 30, 2010, Dominion’s exposure under these guarantees was $49 million, primarily related to certain reserve requirements associated with non−recourse financing.

Dominion also enters into guarantee arrangements on behalf of its consolidated subsidiaries, primarily to facilitate their commercial transactions with third parties. To the extent that a liability subject to a guarantee has been incurred by one of Dominion’s consolidated subsidiaries, that liability is included in Dominion’s Consolidated Financial Statements. Dominion is not required to recognize liabilities for guarantees issued on behalf of its subsidiaries unless it becomes probable that it will have to perform under the guarantees. Dominion currently believes it is unlikely that it would be required to perform or otherwise incur any losses associated with guarantees of its subsidiaries’ obligations.

At June 30, 2010, Dominion had issued the following subsidiary guarantees:

(millions)	Stated Limit	Value(1)
Subsidiary debt(2)	$ 126	$ 126
Commodity transactions(3)	2,833	266
Lease obligation for power generation facility(4)	784	784
Nuclear obligations(5)	231	52
Other(6)	499	124
Total	$ 4,473	$ 1,352

(1) Represents the estimated portion of the guarantee’s stated limit that is utilized as of June 30, 2010 based upon prevailing economic conditions and fact patterns specific to each guarantee arrangement. For those guarantees related to obligations that are recorded as liabilities by Dominion’s subsidiaries, the value includes the recorded amount.

(2) Guarantees of debt of certain DEI subsidiaries. In the event of default by the subsidiaries, Dominion would be obligated to repay such amounts.

(3) Guarantees related to energy trading and marketing activities and other commodity commitments of certain subsidiaries, including subsidiaries of Virginia Power and DEI. These guarantees were provided to counterparties in order to facilitate

physical and financial transactions in gas, oil, electricity, pipeline capacity, transportation and related commodities and services. If any of these subsidiaries fail to perform or pay under the contracts and the counterparties seek performance or payment, Dominion would be required to satisfy such obligation. Dominion and its subsidiaries receive similar guarantees as collateral for credit extended to others.

(4) Guarantee of a DEI subsidiary's leasing obligation for Fairless.

(5) Guarantees related to certain DEI subsidiaries' potential retrospective premiums that could be assessed if there is a nuclear incident under Dominion's nuclear insurance programs and guarantees for a DEI subsidiary's and Virginia Power's commitment to buy nuclear fuel. Additionally, as of June 30, 2010, Dominion had agreements to provide up to $150 million and $60 million to two DEI subsidiaries to pay the operating expenses of Millstone and Kewaunee, respectively, in the event of a prolonged outage, as part of satisfying certain NRC requirements concerned with ensuring adequate funding for the operations of nuclear power stations.

(6) Guarantees related to other miscellaneous contractual obligations such as leases, environmental obligations and construction projects. Also includes guarantees related to certain DEI subsidiaries' obligations for equity capital contributions and energy generation associated with Fowler Ridge and NedPower.

Virginia Power

As of June 30, 2010, Virginia Power had issued $16 million of guarantees primarily to support tax−exempt debt issued through conduits. No significant amounts related to these guarantees have been recorded.

Spent Nuclear Fuel

Under provisions of the Nuclear Waste Policy Act of 1982, Dominion and Virginia Power entered into contracts with the DOE for the disposal of spent nuclear fuel. The DOE failed to begin accepting the spent fuel on January 31, 1998, the date provided by the Nuclear Waste Policy Act and by the Companies' contracts with the DOE.

In January 2004, Dominion and Virginia Power filed lawsuits in the U.S. Court of Federal Claims against the DOE requesting damages in connection with its failure to commence accepting spent nuclear fuel. In October 2008, the court issued an opinion and order for Dominion in the amount of approximately $155 million, which includes approximately $112 million in damages incurred by Virginia Power for spent nuclear fuel−related costs at Surry and North Anna and approximately $43 million in damages incurred for spent nuclear fuel−related costs at Millstone through June 30, 2006. In December 2008, the government appealed the judgment to the U. S. Court of Appeals for the Federal Circuit and the appeal was docketed. In March 2009, the Federal Circuit granted the government's request to stay the appeal. In May 2010, the stay was lifted, and the government's initial brief in the appeal was filed in June 2010. The issues raised by the government on appeal pertain to the damages awarded to Dominion for Millstone. The government did not take issue with the damages awarded to Virginia Power for Surry or North Anna. As a result, Virginia Power recognized a receivable in the amount of $174 million, largely offset against property, plant and equipment and regulatory assets and liabilities, representing certain spent nuclear fuel−related costs incurred through June 30, 2010. Briefing on the appeal and oral argument before the court is expected to be concluded in 2010. Payment of any damages will not occur until the appeal process has been resolved.

A lawsuit was also filed for Kewaunee, and that lawsuit is presently stayed through August 25, 2010. In June 2010, Dominion Energy Kewaunee, Inc. made a formal offer of settlement to the Authorized Representative of the Attorney General for resolution of claims incurred at Kewaunee prior to December 31, 2008. That offer has not yet been formally accepted by the government, and will not be effective until such formal acceptance is received. Dominion, however, believes it is probable that its offer will be accepted by the government. As a result, Dominion recognized a receivable in the amount of $23 million, largely offset against property, plant and equipment, for certain spent nuclear fuel−related costs incurred through June 30, 2010.

The recognition of these receivables did not materially impact the Companies' results of operations. The Companies will continue to manage their spent nuclear fuel until it is accepted by the DOE.

Surety Bonds and Letters of Credit

As of June 30, 2010, Dominion had purchased $91 million of surety bonds, including $40 million at Virginia Power, and authorized the issuance of standby letters of credit by financial institutions of $169 million, including $88 million at Virginia Power, to facilitate commercial transactions by its subsidiaries with third parties. Under the terms of the surety bonds, the Companies are obligated to indemnify the respective surety bond company for any amounts paid.

Environmental Matters

In December 2009, the EPA issued *Final Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act*, finding that GHGs "endanger both the public health and the public welfare of current and future generations." In April 2010, the EPA and the U.S. Department of Transportation issued final rules *(Final Rulemaking To Establish Light−Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards)* that will reduce GHG emissions and improve fuel economy for new cars and trucks sold in the U.S. When these rules take effect in January 2011, they will establish GHG emissions as regulated pollutants under the CAA. In May 2010, the EPA issued the *Final Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule* that, combined with these prior actions, will require Dominion and Virginia Power to obtain permits for GHG emissions for new and modified facilities over certain size thresholds, and meet best available control technology for GHG emissions beginning in 2011. The EPA is planning to establish guidance for GHG permitting, including best available control technology. These regulations may affect capital costs, or create significant permitting delays, for new or modified facilities that emit GHGs.

In June 2008, the Virginia State Air Pollution Control Board approved and issued an air permit to construct and operate the Virginia City Hybrid Energy Center and also approved and issued another air permit for hazardous emissions. Construction of the Virginia City Hybrid Energy Center commenced and the facility is expected to be in operation by 2012. In August 2008, SELC, on behalf of four environmental groups, filed Petitions for Appeal in Richmond Circuit Court challenging the approval of both of the air permits. The Richmond Circuit Court issued an Order in September 2009 upholding the initial air permit and upholding the second air permit for hazardous emissions except for one condition related to the permit limit for mercury emissions. In September 2009, the hazardous emissions air permit was amended by the Virginia Department of Environmental Quality to comply with the Richmond Circuit Court Order. The permit amendment does not impact the project. In October 2009, SELC filed a Notice of Appeal of the court's Order regarding the initial air permit with the Richmond Circuit Court, initiating the appeals process to the Virginia Court of Appeals. In May 2010, the Court of Appeals affirmed the Circuit Court's opinion in the appeal of the Virginia City Hybrid Energy Center's air permit. SELC did not further appeal the Court of Appeals decision to the Supreme Court of Virginia. These actions do not impact the project's construction.

In May 2010, Dominion received a request for information pursuant to Section 114 of the CAA from the EPA. The request concerns historical operating changes and capital improvements undertaken at Brayton Point and Salem Harbor. Dominion is currently in the process of responding to the request and cannot predict the outcome of this matter.

The EPA has finalized rules establishing a new 1−hour NAAQS for NO_2 (January 2010) and a new 1−hour NAAQS for SO_2 (June 2010), which could require additional NO_X and SO_2 controls in certain areas where the Companies operate. Until the states have developed implementation plans for these standards, the impact on Dominion's or Virginia Power's facilities that emit NO_X and SO_2 is uncertain. However, based on a preliminary assessment, Dominion has determined that the new 1−hour SO_2 NAAQS will likely require significant future capital expenditures at State Line, and has recorded an impairment charge on this facility as detailed in Note 9. In January 2010, the EPA proposed a new, more stringent NAAQS for ozone and in July 2010, the EPA announced a proposed new rule, called the "Transport Rule," which will eventually replace the current "Clean Air Interstate Rule" and as proposed requires significant reductions in SO_2 and NO_X emissions. Until the ozone rulemaking is complete and states have developed implementation plans for the new standard, it is not possible to determine the impact on Dominion's or Virginia Power's facilities that emit NO_X. The Companies are studying the newly proposed Transport Rule and cannot currently predict whether the new proposed rule will ultimately require additional controls.

In June 2010, the EPA proposed regulations for coal combustion byproducts. The EPA is considering two possible options for the regulation of coal combustion byproducts. Both options fall under the RCRA. Under the first proposal, the EPA would list these byproducts as special wastes subject to regulation under subtitle C, the hazardous waste provisions of the RCRA, when destined for disposal at landfills or surface impoundments. Under the second proposal, the EPA would regulate coal combustion byproducts under subtitle D of the RCRA, the section for non−hazardous wastes. Regulation under either option will affect Dominion's and Virginia Power's disposal facilities and potentially require material investments. The Companies cannot currently predict the outcome of this matter.

In June 2010, the Conservation Law Foundation and Healthlink, Inc., filed a Complaint in the District Court of Massachusetts against Dominion Energy New England, Inc. alleging that Salem Harbor Units 1, 2, 3, and 4 have been and are in violation of visible emissions standards and monitoring requirements of the Massachusetts State Implementation Plan and the station's state and federal operating permits. Dominion is evaluating the claims and cannot predict the outcome of this lawsuit at this time.

In October 2007, the Virginia State Water Control Board issued a VPDES permit for North Anna. The BREDL, and other persons, appealed the Virginia State Water Control 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 Virginia State Water Control Board was required to regulate the thermal discharge from North Anna into the waste heat treatment facility. Virginia Power filed a motion for reconsideration with the court in February 2009, which was denied. The final order was issued by the court in September 2009. The court's order allows North Anna to continue to operate pursuant to the currently issued VPDES permit. In October 2009, Virginia Power filed a Notice of Appeal of the court's Order with the Richmond Circuit Court, initiating the appeals process to the Virginia Court of Appeals. In June 2010, the Virginia Court of Appeals reversed the Richmond Circuit Court's September 2009 order. The Virginia Court of Appeals held that the lower court had applied the wrong standard of review, and that the Virginia State Water Control Board's determination not to regulate the station's thermal discharge into the waste heat treatment facility was lawful. BREDL and the other original appellants can seek review of the Court of Appeals' decision by the Supreme Court of Virginia within thirty days.

Note 16. Credit Risk

Credit risk is the risk of financial loss if counterparties fail to perform their contractual obligations. In order to minimize overall credit risk, credit policies are maintained, including the evaluation of counterparty financial condition, collateral requirements and the use of standardized agreements that facilitate the netting of cash flows associated with a single counterparty. In addition, counterparties may make available collateral, including letters of credit or cash held as margin deposits, as a result of exceeding agreed−upon credit limits, or may be required to prepay the transaction. Dominion and Virginia Power maintain a provision for credit losses based on factors surrounding the credit risk of their customers, historical trends and other information. Management believes, based on credit policies and the provision for credit losses, that it is unlikely that a material adverse effect on financial position, results of operations or cash flows would occur as a result of counterparty nonperformance.

Dominion

As a diversified energy company, Dominion transacts primarily with major companies in the energy industry and with commercial and residential energy consumers. These transactions principally occur in the Northeast, mid−Atlantic and Midwest regions of the U.S. and Texas. Dominion does not believe that this geographic concentration contributes significantly to its overall exposure to credit risk. In addition, as a result of its large and diverse customer base, Dominion is not exposed to a significant concentration of credit risk for receivables arising from electric and gas utility operations.

Dominion's exposure to credit risk is concentrated primarily within its energy marketing and price risk management activities, as Dominion transacts with a smaller, less diverse group of counterparties and transactions may involve large notional volumes and potentially volatile commodity prices. Energy marketing and price risk management activities include trading of energy−related commodities, marketing of merchant generation output, structured transactions and the use of financial contracts for enterprise−wide hedging purposes. 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, 2010, Dominion's gross credit exposure totaled $749 million. After the application of collateral, credit exposure is reduced to $651 million. Of this amount, investment grade counterparties, including those internally rated, represented 87%. Two counterparty exposures are greater than 10% of Dominion's total exposure, one representing 10% and the other 11%, both of which are large financial institutions rated investment grade.

The majority of Dominion's derivative instruments contain credit−related contingent provisions. These provisions require Dominion 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, 2010 and December 31, 2009, Dominion would have been required to post an additional $58 million and $36 million, respectively, of collateral to its 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. Dominion had posted $36 million in collateral, including $13 million of letters of credit at June 30, 2010 and $62 million in collateral, including $48 million of letters of credit at December 31, 2009, related to derivatives with credit−related contingent provisions that are in a liability position and not fully collateralized with cash. The collateral posted includes any amounts paid related to non−derivative contracts and derivatives elected under the normal purchases and normal sales exception, per contractual terms. 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, 2010 and December 31, 2009 is $170 million and $181 million, respectively, and does not include the impact of any offsetting asset positions. See Note 10 for further information about derivative instruments.

Virginia Power

Virginia Power sells electricity and provides 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 Virginia Power's 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. Virginia Power's exposure to potential concentrations of credit risk results primarily from sales to wholesale customers. Virginia Power's 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, 2010, Virginia Power's gross credit exposure totaled $25 million. After the application of collateral, credit exposure is reduced to $12 million. Of this amount, investment grade counterparties, including those internally rated, represented $3 million, and no single counterparty, whether investment grade or non−investment grade, exceeded $7 million of exposure.

Certain of Virginia Power's derivative instruments contain credit−related contingent provisions. These provisions require Virginia Power 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, 2010 and December 31, 2009, Virginia Power would have been required to post an additional $2 million of collateral to its 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, 2010 and December 31, 2009, Virginia Power had 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, 2010 and December 31, 2009 is $3 million and $2 million, respectively, and does not include the impact of any offsetting asset positions. See Note 10 for further information about derivative instruments.

Note 17. Related Party Transactions

Virginia Power engages in related party transactions primarily with other Dominion subsidiaries (affiliates). Virginia Power's 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. Virginia Power is included in Dominion's consolidated federal income tax return and participates in certain Dominion benefit plans. A discussion of other significant related party transactions follows.

Transactions with Affiliates

Virginia Power transacts with affiliates for certain quantities of natural gas and other commodities in the ordinary course of business. Virginia Power also enters into certain commodity derivative contracts with affiliates. Virginia Power uses these contracts, which are principally comprised of commodity swaps, to manage commodity price risks associated with purchases of natural gas. Virginia Power designates the majority of these contracts as cash flow hedges for accounting purposes.

DRS provides accounting, legal, finance and certain administrative and technical services to Virginia Power.

Presented below are significant Virginia Power transactions with DRS and other affiliates:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
(millions)				
Commodity purchases from affiliates	**$ 89**	$ 55	**$ 156**	$ 154
Services provided by affiliates	**108**	100	**249**	201

Virginia Power’s short−term demand note borrowings from Dominion were $763 million at June 30, 2010.

In March 2010, Virginia Power issued 14,600 shares of its common stock to Dominion reflecting the conversion of approximately $433 million of short−term demand note borrowings from Dominion to equity.

Note 18. Employee Benefit Plans

The components of the provision for net periodic benefit cost were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2010	2009	2010	2009
(millions)				
Three Months Ended June 30,				
Service cost	**$ 25**	$ 27	**$ 14**	$ 15
Interest cost	**68**	62	**25**	25
Expected return on plan assets	**(106)**	(102)	**(18)**	(14)
Amortization of prior service cost (credit)	**1**	1	**(1)**	(2)
Amortization of net loss	**15**	10	**3**	8
Settlements and curtailments	**—**	2	**(1)**	—
Special termination benefits	**1**	2	**—**	—
Net periodic benefit cost	**$ 4**	$ 2	**$ 22**	$ 32
Six Months Ended June 30,				
Service cost	**$ 52**	$ 53	**$ 28**	$ 30
Interest cost	**134**	125	**50**	50
Expected return on plan assets	**(205)**	(203)	**(35)**	(28)
Amortization of prior service cost (credit)	**2**	2	**(3)**	(4)
Amortization of net loss	**30**	19	**6**	15
Settlements and curtailments(1)	**84**	2	**37**	—
Special termination benefits(2)	**10**	2	**1**	—
Net periodic benefit cost	**$ 107**	$ —	**$ 84**	$ 63

(1) Relates to the sale of Peoples and a workforce reduction program.

(2) Represents a one−time special termination benefit for certain employees in connection with a workforce reduction program.

Employer Contributions

During the six months ended June 30, 2010, Dominion contributed $250 million to its defined benefit pension plans. Virginia Power’s portion of this contribution was $119 million. Dominion made no contributions to its other postretirement benefit plans during the six months ended June 30, 2010, but expects to contribute approximately $56 million, of which Virginia Power’s portion is expected to be $35 million, to its other postretirement benefit plans through Voluntary Employees’ Beneficiary Associations during the remainder of 2010.

Note 19. Operating Segments

Dominion and Virginia Power are organized primarily on the basis of products and services sold in the U.S. A description of the operations included in the Companies' primary operating segments is as follows:

Primary Operating Segment	Description of Operations	Dominion	Virginia Power
DVP	Regulated electric distribution	X	X
	Regulated electric transmission	X	X
	Nonregulated retail energy marketing (electric and gas)	X	
Dominion Generation	Regulated electric fleet	X	X
	Merchant electric fleet	X	
Dominion Energy	Gas transmission and storage	X	
	Gas distribution	X	
	LNG import and storage	X	
	Producer services	X	

In addition to the operating segments above, the Companies also report a Corporate and Other segment.

The Corporate and Other Segment of Dominion includes its corporate, service company and other functions (including unallocated debt) and certain specific items that are not included in profit measures evaluated by executive management in assessing segment performance or allocating resources among the segments.

In the six months ended June 30, 2010, Dominion reported after−tax net benefits of $933 million for specific items in the Corporate and Other segment, with $1.1 billion of these net benefits attributable to its operating segments. In the six months ended June 30, 2009, Dominion reported after−tax net expenses of $276 million for specific items in the Corporate and Other segment, with $274 million of these net expenses attributable to its operating segments.

The net benefits for specific items in 2010 primarily related to the impact of the following items:

- A $2.5 billion ($1.4 billion after−tax) benefit resulting from the gain on the sale of substantially all of Dominion's Appalachian E&P operations net of charges related to the divestiture, attributable to Dominion Energy; partially offset by
- A $338 million ($206 million after−tax) charge primarily reflecting severance pay and other benefits related to a workforce reduction program, attributable to:
  - DVP ($67 million after−tax);
  - Dominion Energy ($24 million after−tax); and
  - Dominion Generation ($115 million after−tax);
- A $134 million ($147 million after−tax) loss from the discontinued operations of Peoples primarily reflecting a net loss on the sale; attributable to the Corporate and Other segment; and
- A $163 million ($95 million after−tax) impairment charge at State Line to reflect the estimated fair value of the power station, attributable to Dominion Generation.

The net expenses for specific items in 2009 primarily related to the impact of the following items:

- A $455 million ($281 million after−tax) ceiling test impairment charge related to the carrying value of Dominion's E&P properties, attributable to Dominion Energy;
- A $64 million ($38 million after−tax) net loss on investments held in nuclear decommissioning trust funds, attributable to Dominion Generation; partially offset by
- A $103 million ($62 million after−tax) reduction in other operations and maintenance expense due to a downward revision in the nuclear decommissioning ARO for a power station unit that is no longer in service, attributable to Dominion Generation.

The Corporate and Other Segment of Virginia Power primarily includes certain specific items that are not included in profit measures evaluated by executive management in assessing segment performance or allocating resources among the segments. In the six months ended June 30, 2010 and 2009, Virginia Power reported after−tax net expenses of $141 million and $6 million, respectively, for specific items attributable to its operating segments in the Corporate and Other segment.

The net expenses for specific items in 2010 primarily related to the impact of the following:

- A $202 million ($123 million after−tax) charge primarily reflecting severance pay and other benefits related to a workforce reduction program, attributable to:
  - DVP ($63 million after−tax); and
  - Dominion Generation ($60 million after−tax).

The following table presents segment information pertaining to Dominion's operations:

(millions)	DVP	Dominion Generation	Dominion Energy	Corporate and Other	Adjustments/ Eliminations	Consolidated Total
Three Months Ended June 30, 2010						
Total revenue from external customers	**$ 787**	**$ 1,831**	**$ 450**	**$ (6)**	**$ 271**	**$ 3,333**
Intersegment revenue	**19**	**108**	**294**	**167**	**(588)**	**—**
Total operating revenue	**806**	**1,939**	**744**	**161**	**(317)**	**3,333**
Income from discontinued operations, net of tax	**—**	**—**	**—**	**2**	**—**	**2**
Net income attributable to Dominion	**112**	**276**	**86**	**1,287**	**—**	**1,761**
2009						
Total revenue from external customers	$ 660	$ 2,019	$ 457	$ (1)	$ 271	$ 3,406
Intersegment revenue	20	95	328	162	(605)	—
Total operating revenue	680	2,114	785	161	(334)	3,406
Loss from discontinued operations, net of tax	—	—	—	(15)	—	(15)
Net income attributable to Dominion	82	270	102	—	—	454
Six Months Ended June 30, 2010						
Total revenue from external customers	**$1,790**	**$ 3,809**	**$ 1,300**	**$ 34**	**$ 568**	**$ 7,501**
Intersegment revenue	**107**	**210**	**567**	**399**	**(1,283)**	**—**
Total operating revenue	**1,897**	**4,019**	**1,867**	**433**	**(715)**	**7,501**
Loss from discontinued operations, net of tax	**—**	**—**	**—**	**(147)**	**—**	**(147)**
Net income attributable to Dominion	**226**	**601**	**261**	**847**	**—**	**1,935**
2009						
Total revenue from external customers	$1,649	$ 4,281	$ 1,493	$ (22)	$ 591	$ 7,992
Intersegment revenue	83	161	641	350	(1,235)	—
Total operating revenue	1,732	4,442	2,134	328	(644)	7,992
Loss from discontinued operations, net of tax	—	—	—	(6)	—	(6)
Net income (loss) attributable to Dominion	197	639	279	(413)	—	702

Intersegment sales and transfers for Dominion are based on contractual arrangements and may result in intersegment profit or loss that is eliminated in consolidation.

The following table presents segment information pertaining to Virginia Power's operations:

(millions)	DVP	Dominion Generation	Corporate and Other	Consolidated Total
Three Months Ended June 30,				
2010				
Operating revenue	**$398**	**$ 1,313**	**$ —**	**$ 1,711**
Net income	**105**	**160**	**2**	**267**
2009				
Operating revenue	$353	$ 1,322	$ —	$ 1,675
Net income	76	72	1	149
Six Months Ended June 30,				
2010				
Operating revenue	**$800**	**$ 2,650**	**$ —**	**$ 3,450**
Net income (loss)	**198**	**303**	**(139)**	**362**
2009				
Operating revenue	$733	$ 2,801	$ —	$ 3,534
Net income (loss)	166	193	(6)	353

ITEM 2. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

MD&A discusses Dominion’s and Virginia Power’s results of operations and general financial condition. MD&A should be read in conjunction with the Companies’ Consolidated Financial Statements.

Contents of MD&A

MD&A consists of the following information:

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

Forward−Looking Statements

This report contains statements concerning Dominion’s and Virginia Power’s 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.

Dominion and Virginia Power 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 facilities;
- Federal, state and local legislative and regulatory developments;
- Changes to federal, state and local environmental laws and regulations, including those related to climate change, the tightening of emission or discharge limits for GHGs and other emissions, more extensive permitting requirements and the regulation of additional substances;
- Cost of environmental compliance, including those costs related to climate change;
- Risks associated with the operation of nuclear facilities;
- Unplanned outages of the Companies’ generation facilities;
- Fluctuations in energy−related commodity prices and the effect these could have on Dominion’s earnings and Dominion’s and Virginia Power’s liquidity position and the underlying value of their assets;
- Counterparty credit risk;
- Capital market conditions, including the availability of credit and the ability to obtain financing on reasonable terms;
- Risks associated with Virginia Power’s membership and participation in PJM related to obligations created by the default of other participants;
- Price risk due to investments held in nuclear decommissioning trusts by Dominion and Virginia Power and in benefit plan trusts by Dominion;
- 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;
- Receipt of approvals for, and timing of, closing dates for acquisitions and divestitures;

- Changes in rules for RTOs and independent system operators in which Dominion and Virginia Power participate, including changes in rate designs and new and evolving capacity models;
- Political and economic conditions, including the threat of domestic terrorism, inflation and deflation;
- Changes to regulated electric rates collected by Virginia Power;
- Changes to regulated electric transmission rates collected by Virginia Power and regulated gas distribution, transportation and storage rates, including LNG storage, collected by Dominion;
- Timing and receipt of regulatory approvals necessary for planned construction or expansion projects;
- The inability to complete planned construction projects within the terms and time frames initially anticipated; and
- Adverse outcomes in litigation matters.

Additionally, other risks that could cause actual results to differ from predicted results are set forth in Item 1A. Risk Factors in Dominion's and Virginia Power's Annual Report on Form 10−K for the year ended December 31, 2009.

Dominion's and Virginia Power's forward−looking statements are based on beliefs and assumptions using information available at the time the statements are made. The Companies caution the reader not to place undue reliance on their forward−looking statements because the assumptions, beliefs, expectations and projections about future events may, and often do, differ materially from actual results. Dominion and Virginia Power 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, 2010, there have been no significant changes with regard to the critical accounting policies and estimates disclosed in MD&A in Dominion's and Virginia Power's Annual Report on Form 10−K for the year ended December 31, 2009, other than the accounting for gas and oil operations, which is no longer a critical accounting policy due to the sale of substantially all of Dominion's Appalachian E&P operations. The other policies disclosed included the accounting for regulated operations, AROs, income taxes, derivative contracts and other instruments at fair value, goodwill and long−lived asset impairment testing, employee benefit plans and unbilled revenue.

Other

See Note 9 to Dominion's and Virginia Power's Consolidated Financial Statements for information on fair value measurements.

Dominion

Results of Operations

Presented below is a summary of Dominion's consolidated results:

(millions, except EPS)	2010	2009	$ Change
Second Quarter			
Net income attributable to Dominion	**$1,761**	$ 454	$ 1,307
Diluted EPS	**2.98**	0.76	2.22
Year−To−Date			
Net income attributable to Dominion	**$1,935**	$ 702	$ 1,233
Diluted EPS	**3.25**	1.19	2.06

Overview

Second Quarter 2010 vs. 2009

Net income attributable to Dominion increased by $1.3 billion. Favorable drivers include a gain on the sale of Dominion's Appalachian E&P operations and the impact of favorable weather on electric utility operations. Unfavorable drivers include an impairment charge related to State Line and lower margins from merchant generation operations.

Year−to−Date 2010 vs. 2009

Net income attributable to Dominion increased by $1.2 billion. Favorable drivers include a gain on the sale of Dominion's Appalachian E&P operations and lower ceiling test impairment charges related to these properties. Unfavorable drivers include charges related to a workforce reduction program, a loss on the sale of Peoples, lower margins from merchant generation operations and an impairment charge related to State Line.

Analysis of Consolidated Operations

Presented below are selected amounts related to Dominion's results of operations.

	Second Quarter			Year−To−Date		
	2010	**2009**	**$ Change**	**2010**	**2009**	**$ Change**
(millions)						
Operating revenue	**$3,333**	$3,406	$ (73)	**$7,501**	$7,992	$ (491)
Electric fuel and other energy−related purchases	**956**	998	(42)	**1,984**	2,139	(155)
Purchased electric capacity	**109**	105	4	**217**	213	4
Purchased gas	**391**	351	40	**1,183**	1,358	(175)
Net revenue	**1,877**	1,952	(75)	**4,117**	4,282	(165)
Other operations and maintenance	**853**	685	168	**1,921**	1,919	2
Depreciation, depletion and amortization	**262**	271	(9)	**531**	550	(19)
Other taxes	**119**	107	12	**288**	260	28
Gain on sale of Appalachian E&P operations	**2,467**	—	2,467	**2,467**	—	2,467
Other income (loss)	**(25)**	69	(94)	**46**	8	38
Interest and related charges	**188**	220	(32)	**371**	439	(68)
Income tax expense	**1,134**	265	869	**1,429**	406	1,023
Income (loss) from discontinued operations	**2**	(15)	17	**(147)**	(6)	(141)

An analysis of Dominion's results of operations follows:

Second Quarter 2010 vs. 2009

Net revenue decreased 4%, primarily reflecting:

- A $142 million decrease from merchant generation operations, primarily reflecting a $109 million decrease due to lower volumes resulting primarily from higher scheduled nuclear refueling outage days and a $30 million decrease in realized prices;
- A $44 million decrease from E&P operations primarily reflecting the sale of Dominion's Appalachian E&P business in April 2010; and
- A $30 million decrease from producer services primarily related to unfavorable price changes on economic hedging positions and lower physical margins all associated with natural gas aggregation, marketing and trading activities.

These decreases were partially offset by:

- A $128 million increase from electric utility operations primarily due to an increase in cooling degree days ($65 million) and the impact of Riders C1 and C2, R, S and T ($57 million); and
- A $22 million increase from regulated gas distribution operations, primarily reflecting increased rider revenue associated with the recovery of deferred bad debt expense which is offset in other operations and maintenance expense.

Other operations and maintenance increased 25%, primarily reflecting a $163 million impairment charge related to State Line.

Other taxes increased 11% primarily due to additional property tax from increased investments and higher rates, as well as an increase in gross receipts tax due to new non−regulated retail energy customers.

Gain on sale of Appalachian E&P operations reflects a gain on the sale of Dominion's Appalachian E&P business in April 2010, as described in Note 3 to the Consolidated Financial Statements in this report.

Other income (loss) was a loss of $25 million for the second quarter of 2010 versus income of $69 million for the second quarter of 2009 primarily due to lower net realized gains (including investment income) on nuclear decommissioning trust funds ($42 million) and a $50 million charitable contribution in 2010.

Interest and related charges decreased 15%, primarily due to a benefit resulting from the discontinuance of hedge accounting for certain interest rate hedges ($70 million) partially offset by subsequent changes in fair value of these interest rate derivatives ($37 million).

Income tax expense increased $869 million, primarily reflecting higher federal and state taxes largely due to the gain on the sale of Dominion's Appalachian E&P business.

Income (loss) from discontinued operations reflects income of $2 million for the second quarter of 2010 versus a loss of $15 million for the second quarter of 2009, primarily reflecting the net impact of Peoples' 2009 interim income tax provision and income from operations.

Year−to−Date 2010 vs. 2009

Net revenue decreased 4%, primarily reflecting:

- A $240 million decrease from merchant generation operations, primarily reflecting a $116 million decrease due to lower volumes resulting primarily from higher scheduled nuclear refueling outage days and a $103 million decrease in realized prices;
- A $68 million decrease from E&P operations primarily reflecting the sale of Dominion's Appalachian E&P business and the February 2009 expiration of VPP royalty interests; and
- A $56 million decrease from producer services primarily related to less favorable price changes on economic hedging positions and lower physical margins all associated with natural gas aggregation, marketing and trading activities.

These decreases were partially offset by:

- A $171 million increase from electric utility operations, primarily due to the net impact of Riders C1 and C2, R, S and T ($118 million), and an increase in cooling degree days ($83 million), partially offset by a $28 million decrease due to the impact of unfavorable economic conditions on customer usage and other factors; and
- A $32 million increase related to gas transmission operations largely due to the completion of the Cove Point expansion project.

Other operations and maintenance primarily reflects costs related to a workforce reduction program ($274 million) and an impairment charge related to State Line ($163 million), offset by a decrease in ceiling test impairment charges related to the carrying value of Dominion's E&P properties ($434 million).

Other taxes increased 11% primarily due to higher payroll taxes associated with a workforce reduction program and additional property tax due to increased investments and higher rates.

Gain on sale of Appalachian E&P operations reflects a gain on the sale of Dominion's Appalachian E&P operations, as described in Note 3 to the Consolidated Financial Statements in this report.

Other income (loss) increased $38 million, primarily reflecting higher net realized gains (including investment income) on nuclear decommissioning trust funds ($62 million) and the absence of an impairment loss on an equity method investment ($23 million), partially offset by an increase in charitable contributions ($48 million).

Interest and related charges decreased 15%, primarily due to a benefit resulting from the discontinuance of hedge accounting for certain interest rate hedges ($110 million) partially offset by subsequent changes in fair value of these interest rate derivatives ($37 million).

Income tax expense increased $1 billion, primarily reflecting higher federal and state taxes largely due to the gain on the sale of Dominion's Appalachian E&P business.

Income (loss) from discontinued operations primarily reflects a loss on the sale of Peoples.

Segment Results of Operations

Segment results include the impact of intersegment revenues and expenses, which may result in intersegment profit and loss. Presented below is a summary of contributions by Dominion's operating segments to net income attributable to Dominion:

Second Quarter	Net Income attributable to Dominion			Diluted EPS		
	2010	2009	$ Change	2010	2009	$ Change
(millions, except EPS)						
DVP	**$ 112**	$ 82	$ 30	**$0.19**	$ 0.14	$ 0.05
Dominion Generation	**276**	270	6	**0.47**	0.46	0.01
Dominion Energy	**86**	102	(16)	**0.14**	0.17	(0.03)
Primary operating segments	**474**	454	20	**0.80**	0.77	0.03
Corporate and Other	**1,287**	—	1,287	**2.18**	(0.01)	2.19
Consolidated	**$1,761**	$ 454	$ 1,307	**$2.98**	$ 0.76	$ 2.22
Year−To−Date						
DVP	**$ 226**	$ 197	$ 29	**$0.38**	$ 0.33	$ 0.05
Dominion Generation	**601**	639	(38)	**1.01**	1.08	(0.07)
Dominion Energy	**261**	279	(18)	**0.44**	0.48	(0.04)
Primary operating segments	**1,088**	1,115	(27)	**1.83**	1.89	(0.06)
Corporate and Other	**847**	(413)	1,260	**1.42**	(0.70)	2.12
Consolidated	**$1,935**	$ 702	$ 1,233	**$3.25**	$ 1.19	$ 2.06

DVP

Presented below are selected operating statistics related to DVP's operations:

	Second Quarter			Year−To−Date		
	2010	2009	% Change	2010	2009	% Change
Electricity delivered (million MWh)	**20.0**	19.0	5 %	**41.2**	40.3	2 %
Degree days (electric distribution service area):						
Cooling (1)	**724**	459	58	**724**	463	56
Heating (2)	**197**	294	(33)	**2,323**	2,457	(5)
Average electric distribution customer accounts (thousands) (3)	**2,420**	2,401	1	**2,419**	2,400	1
Average retail energy marketing customer accounts (thousands) (3)	**2,046**	1,725	19	**1,996**	1,679	19

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

(3) Period average.

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

	Second Quarter 2010 vs. 2009 Increase (Decrease)		Year−To−Date 2010 vs. 2009 Increase (Decrease)	
(millions, except EPS)	**Amount**	**EPS**	**Amount**	**EPS**
Regulated electric sales:				
Weather	$ 13	$0.02	$ 17	$ 0.03
FERC transmission rates	10	0.02	19	0.03
Other	—	—	(5)	(0.01)
Interest expense	2	—	3	—
Storm damage and service restoration – electric distribution operations	(1)	—	(7)	(0.01)
Retail energy marketing operations	—	—	(3)	—
Other(1)	6	0.01	5	0.01
Change in net income contribution	$ 30	$0.05	$ 29	$ 0.05

(1) Primarily reflects lower operations and maintenance largely due to a reduction in salaries, wages and benefits expense associated with a workforce reduction program.

Dominion Generation

Presented below are selected operating statistics related to Dominion Generation's operations:

	Second Quarter			Year−To−Date		
	2010	**2009**	**% Change**	**2010**	**2009**	**% Change**
Electricity supplied (million MWh):						
Utility	**20.0**	19.0	5 %	**41.2**	40.3	2 %
Merchant	**10.5**	12.1	(13)	**22.9**	24.7	(7)
Degree days (electric utility service area):						
Cooling	**724**	459	58	**724**	463	56
Heating	**197**	294	(33)	**2,323**	2,457	(5)

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

	Second Quarter 2010 vs. 2009 Increase (Decrease)		Year−To−Date 2010 vs. 2009 Increase (Decrease)	
(millions, except EPS)	**Amount**	**EPS**	**Amount**	**EPS**
Regulated electric sales:				
Weather	$ 27	$ 0.05	$ 34	$ 0.06
Rate adjustment clauses	20	0.03	45	0.08
Other	—	—	(8)	(0.02)
Outage costs	13	0.02	22	0.04
PJM ancillary service revenue	12	0.02	13	0.02
Interest expense	5	0.01	9	0.02
Merchant generation margin	(92)	(0.16)	(163)	(0.28)
Other(1)	21	0.04	10	0.02
Share dilution	—	—	—	(0.01)
Change in net income contribution	$ 6	$ 0.01	$ (38)	$(0.07)

(1) Primarily reflects lower operations and maintenance largely due to a reduction in salaries, wages and benefits expense associated with a workforce reduction program.

Dominion Energy

Presented below are selected operating statistics related to Dominion Energy’s operations:

	Second Quarter			Year−To−Date		
	2010	**2009**	**% Change**	**2010**	**2009**	**% Change**
Gas distribution throughput (bcf):						
Sales	**4**	4	— %	**19**	31	(39)%
Transportation	**37**	32	16	**136**	119	14
Heating degree days (gas distribution service area)	**436**	649	(33)	**3,383**	3,749	(10)
Average gas distribution customer accounts (thousands)[1]:						
Sales	**257**	293	(12)	**260**	371	(30)
Transportation	**1,047**	1,019	3	**1,050**	946	11
Production[2] (bcfe):	**5.2**	12.0	(57)	**17.4**	26.4	(34)
Average realized prices without hedging results (per mcfe)	**$ 4.10**	$ 3.58	15	**$ 4.99**	$ 4.37	14
Average realized prices with hedging results (per mcfe)	**6.49**	7.14	(9)	**6.51**	7.55	(14)
DD&A (unit of production rate per mcfe)	**1.06**	1.39	(24)	**1.26**	1.67	(25)
Average production (lifting) cost (per mcfe)	**1.33**	1.26	6	**1.34**	1.25	7

(1) Period average.

(2) Includes natural gas, NGLs and oil. Production includes 2.3 bcfe for the year−to−date period ended June 30, 2009 associated with the VPP royalty interests. There was no production related to VPPs for the quarter ended June 30, 2009 or the quarter and year−to−date periods ended June 30, 2010 due to the expiration of these interests in February 2009.

Presented below, on an after−tax basis, are the key factors impacting Dominion Energy’s net income contribution:

	Second Quarter		**Year−To−Date**	
	2010 vs. 2009 Increase (Decrease)		**2010 vs. 2009 Increase (Decrease)**	
(millions, except EPS)	**Amount**	**EPS**	**Amount**	**EPS**
Producer services	$ (12)	$(0.02)	$ (28)	$(0.05)
E&P disposed operations	(9)	(0.02)	(9)	(0.02)
Expired E&P VPP royalty interests	—	—	(12)	(0.02)
Cove Point expansion revenue	—	—	20	0.03
Gas distribution margin:				
Weather	(1)	—	(3)	—
AMR and PIR revenue[1]	3	—	5	0.01
Other	6	0.01	5	0.01
Other	(3)	—	4	—
Change in net income contribution	$ (16)	$(0.03)	$ (18)	$(0.04)

(1) Primarily reflects an allowed return on investment through the AMR and PIR programs.

Corporate and Other

Presented below are the Corporate and Other segment's after−tax results:

	Second Quarter			Year−To−Date		
	2010	2009	$ Change	2010	2009	$ Change
(millions, except EPS)						
Specific items attributable to operating segments	**$1,280**	$ 61	$ 1,219	**$1,065**	$ (274)	$ 1,339
Specific items attributable to corporate operations:						
Peoples discontinued operations	**2**	(15)	17	**(147)**	(6)	(141)
Other	**53**	4	49	**15**	4	11
Total specific items	**1,335**	50	1,285	**933**	(276)	1,209
Other corporate operations	**(48)**	(50)	2	**(86)**	(137)	51
Total net benefit (expense)	**$1,287**	$ —	$ 1,287	**$ 847**	$ (413)	$ 1,260
EPS impact	**$ 2.18**	$(0.01)	$ 2.19	**$ 1.42**	$(0.70)	$ 2.12

Total Specific Items

Corporate and Other includes specific items that are not included in profit measures evaluated by management in assessing segment performance or in allocating resources among the segments. See Note 19 to the Consolidated Financial Statements for discussion of these items.

Other Corporate Operations

Second Quarter 2010 vs. 2009

Net expenses decreased $2 million primarily reflecting a $14 million benefit resulting largely from the discontinuance of hedge accounting and subsequent changes in fair value of certain interest rate derivatives, partially offset by a $12 million reduction in consolidated tax benefits that are not attributed to the operating segments.

Year−to−Date 2010 vs. 2009

Net expenses decreased $51 million primarily due to a $41 million benefit resulting from the discontinuance of hedge accounting and subsequent changes in fair value of certain interest rate derivatives and a $14 million increase in consolidated tax benefits that are not attributed to the operating segments.

Virginia Power

Results of Operations

Presented below is a summary of Virginia Power's consolidated results:

	Second Quarter			Year−To−Date		
	2010	2009	$ Change	2010	2009	$ Change
(millions)						
Net income	**$267**	$149	$ 118	**$362**	$353	$ 9

Overview

Second Quarter 2010 vs. 2009

Net income increased 79%, primarily reflecting the impact of favorable weather and lower outage costs.

Year−To−Date 2010 vs. 2009

Net income increased 3%, primarily reflecting the combined effects of favorable weather and lower outage costs, partially offset by charges related to a workforce reduction program.

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Analysis of Consolidated Operations

Presented below are selected amounts related to Virginia Power's results of operations:

	Second Quarter			Year−To−Date		
	2010	**2009**	**$ Change**	**2010**	**2009**	**$ Change**
(millions)						
Operating revenue	**$1,711**	$1,675	$ 36	**$3,450**	$3,534	$ (84)
Electric fuel and other energy−related purchases	**589**	685	(96)	**1,221**	1,479	(258)
Purchased electric capacity	**108**	104	4	**215**	212	3
Net revenue	**1,014**	886	128	**2,014**	1,843	171
Other operations and maintenance	**317**	381	(64)	**836**	728	108
Depreciation and amortization	**165**	160	5	**328**	317	11
Other taxes	**53**	46	7	**117**	97	20
Other income	**28**	23	5	**42**	32	10
Interest and related charges	**83**	87	(4)	**171**	174	(3)
Income tax expense	**157**	86	71	**242**	206	36

An analysis of Virginia Power's results of operations follows:

Second Quarter 2010 vs. 2009

Net revenue increased 14%, primarily reflecting an increase in sales to retail customers due to an increase in cooling degree days ($65 million) and the impact from Riders C1 and C2, R, S and T ($57 million).

Other operations and maintenance decreased 17%, primarily reflecting lower outage costs due to fewer scheduled outage days as compared to the prior year ($47 million) and a decrease in salaries, wages and benefits related to a workforce reduction program ($13 million).

Income tax expense increased 83%, primarily reflecting higher pre−tax income in 2010.

Year−to−Date 2010 vs. 2009

Net revenue increased 9%, primarily due to the net impact of Riders C1 and C2, R, S and T ($118 million) and an increase in cooling degree days ($83 million), partially offset by a $28 million decrease due to the impact of unfavorable economic conditions on customer usage and other factors.

Other operations and maintenance increased 15%, primarily reflecting costs related to a workforce reduction program ($177 million), partially offset by a decrease in outage costs due to fewer scheduled outage days as compared to the prior year ($57 million) and a decrease in bad debt expense ($12 million).

Other taxes increased 21% primarily due to higher payroll taxes associated with a workforce reduction program and additional property tax due to increased investments and higher rates.

Other income increased 31% primarily reflecting higher net realized gains (including investment income) on nuclear decommissioning trust funds ($8 million) and an increase in the equity component of allowance for funds used during construction as a result of construction and expansion projects ($6 million), partially offset by a decrease in other miscellaneous income ($4 million).

Income tax expense increased 17%, primarily reflecting higher pretax income ($17 million) and a charge related to 2010 health care law changes that eliminated tax deductions for a portion of certain retiree health care costs ($16 million).

Segment Results of Operations

Presented below is a summary of contributions by Virginia Power's operating segments to net income:

	Second Quarter			Year−To−Date		
	2010	**2009**	**$ Change**	**2010**	**2009**	**$ Change**
(millions)						
DVP	**$105**	$ 76	$ 29	**$ 198**	$166	$ 32
Dominion Generation	**160**	72	88	**303**	193	110
Primary operating segments	**265**	148	117	**501**	359	142
Corporate and Other	**2**	1	1	**(139)**	(6)	(133)
Consolidated	**$267**	$149	$ 118	**$ 362**	$353	$ 9

DVP

Presented below are operating statistics related to Virginia Power's DVP segment:

	Second Quarter			Year−To−Date		
	2010	**2009**	**% Change**	**2010**	**2009**	**% Change**
Electricity delivered (million MWh)	**20.0**	19.0	5%	**41.2**	40.3	2%
Degree days (electric distribution service area):						
Cooling	**724**	459	58	**724**	463	56
Heating	**197**	294	(33)	**2,323**	2,457	(5)
Average electric distribution customer accounts (thousands)(1)	**2,420**	2,401	1	**2,419**	2,400	1

(1) Period average.

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

	Second Quarter 2010 vs. 2009 Increase (Decrease)	Year−to−Date 2010 vs. 2009 Increase (Decrease)
(millions)		
Regulated electric sales:		
Weather	$ 13	$ 17
FERC transmission rates	10	19
Other	—	(5)
Interest expense	2	3
Storm damage and service restoration – electric distribution operations	(1)	(7)
Other(1)	5	5
Change in net income contribution	$ 29	$ 32

(1) Primarily reflects lower operations and maintenance largely due to a reduction in salaries, wages and benefits expense associated with a workforce reduction program.

Dominion Generation

Presented below are operating statistics related to Virginia Power's Dominion Generation segment:

	Second Quarter			Year−To−Date		
	2010	**2009**	**% Change**	**2010**	**2009**	**% Change**
Electricity supplied (million MWh):	**20.0**	19.0	5%	**41.2**	40.3	2%
Degree days (electric utility service area):						
Cooling	**724**	459	58	**724**	463	56
Heating	**197**	294	(33)	**2,323**	2,457	(5)

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

(millions)	Second Quarter 2010 vs. 2009 Increase (Decrease)	Year−To−Date 2010 vs. 2009 Increase (Decrease)
Regulated electric sales:		
Weather	$ 27	$ 34
Rate adjustment clauses	20	45
Other	—	(8)
Outage costs	29	35
PJM ancillary service revenue	12	13
Other	—	(9)
Change in net income contribution	$ 88	$ 110

Corporate and Other

Corporate and Other includes specific items that are not included in profit measures evaluated by management in assessing segment performance or in allocating resources among the segments. See Note 19 to the Consolidated Financial Statements for discussion of these items.

Liquidity and Capital Resources

Dominion and Virginia Power 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. Net proceeds from the sale of Dominion's Appalachian E&P operations will be used to offset substantially all of Dominion's equity needs for 2010 and its market equity issuances for 2011, repurchase common stock, fund contributions to Dominion's pension plans and the Dominion Foundation, reduce debt and offset the majority of the impact of Virginia Power's rate case settlement.

At June 30, 2010, Dominion had $4.6 billion of unused capacity under its credit facilities, including $2.7 billion of unused capacity under a joint credit facility available to Virginia Power.

A summary of Dominion's cash flows is presented below:

(millions)	2010	2009
Cash and cash equivalents at January 1[(1)]	**$ 50**	$ 71
Cash flows provided by (used in):		
Operating activities	**1,406**	1,902
Investing activities	**1,661**	(1,788)
Financing activities	**(2,706)**	(119)
Net increase (decrease) in cash and cash equivalents	**361**	(5)
Cash and cash equivalents at June 30[(2)]	**$ 411**	$ 66

(1) 2010 and 2009 amounts include $2 million and $5 million, respectively, of cash classified as held for sale in Dominion's Consolidated Balance Sheets.

(2) 2009 amount includes $2 million of cash classified as held for sale in Dominion's Consolidated Balance Sheet.

A summary of Virginia Power's cash flows is presented below:

(millions)	2010	2009
Cash and cash equivalents at January 1	**$ 19**	$ 27
Cash flows provided by (used in):		
Operating activities	**559**	911
Investing activities	**(1,112)**	(1,257)
Financing activities	**549**	348
Net increase (decrease) in cash and cash equivalents	**(4)**	2
Cash and cash equivalents at June 30	**$ 15**	$ 29

Operating Cash Flows

Net cash provided by Dominion's operating activities decreased by $496 million primarily due to lower deferred fuel and gas cost recoveries, a contribution to Dominion's pension plans, lower margins in merchant generation operations and refunds related to the rate case settlement, partially offset by lower income tax payments, lower margin collateral requirements and the favorable impact of weather on electric utility operations.

Net cash provided by Virginia Power's operating activities decreased by $352 million, primarily due to lower deferred fuel cost recoveries, the refunds related to the rate case settlement and a contribution to the Dominion pension plan, partially offset by the favorable impact of weather, lower outage costs, and lower income tax payments in 2010. Virginia Power believes that its operations provide a stable source of cash flow to contribute to planned levels of capital expenditures and provide dividends to Dominion.

The Companies' 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 Dominion's and Virginia Power's Annual Report on Form 10−K for the year ended December 31, 2009.

Credit Risk

Dominion's exposure to potential concentrations of credit risk results primarily from its energy marketing and price risk management activities. Presented below is a summary of Dominion's credit exposure as of June 30, 2010 for these activities. 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]	$ 587	$ 85	$ 502
Non−investment grade[2]	24	11	13
No external ratings:			
Internally rated—investment grade[3]	64	2	62
Internally rated—non−investment grade[4]	74	—	74
Total	$ 749	$ 98	$ 651

(1) Designations as investment grade are based upon minimum credit ratings assigned by Moody's and Standard & Poor's. The five largest counterparty exposures, combined, for this category represented approximately 37% of the total net credit exposure.
(2) The five largest counterparty exposures, combined, for this category represented approximately 2% of the total net credit exposure.
(3) The five largest counterparty exposures, combined, for this category represented approximately 6% of the total net credit exposure.
(4) The five largest counterparty exposures, combined, for this category represented approximately 7% of the total net credit exposure.

Virginia Power's exposure to potential concentrations of credit risk results primarily from sales to wholesale customers. Presented below is a summary of Virginia Power's gross credit exposure as of June 30, 2010, for these activities. 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]	$ 6	$ 3	$ 3
Non−investment grade[2]	17	10	7
No external ratings:			
Internally rated—non−investment grade[3]	2	—	2
Total	$ 25	$ 13	$ 12

(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 25% of the total net credit exposure.
(2) The only counterparty exposure for this category represented 58% of the total net credit exposure.
(3) The only two counterparty exposures for this category represented 17% of the total net credit exposure.

Investing Cash Flows

For the six months ended June 30, 2010, net cash provided by Dominion's investing activities was approximately $1.7 billion as compared to net cash used in investing activities of $1.8 billion in 2009, primarily reflecting the proceeds received from the sale of Dominion's Appalachian E&P operations in April 2010 and the sale of Peoples in February 2010. Portions of the proceeds from the E&P sale were invested in time deposit certificates and other short−term securities.

Net cash used in Virginia Power's investing activities decreased by $145 million as compared to 2009, primarily due to lower capital expenditures.

Financing Cash Flows and Liquidity

Dominion and Virginia Power rely on banks and capital markets as significant sources of funding for capital requirements not satisfied by cash provided by their operations. As discussed further in *Credit Ratings and Debt Covenants* in Dominion's and Virginia Power's Annual Report on Form 10−K for the year ended December 31, 2009, the Companies' ability to borrow funds or issue securities and the return demanded by investors are affected by credit ratings. In addition, the raising of external capital is subject to certain regulatory requirements, including registration with the SEC and, in the case of Virginia Power, approval by the Virginia Commission.

Each of the Companies meets the definition of a well−known seasoned issuer under SEC rules governing the registration, communications and offering processes under the Securities Act of 1933. The rules provide for a streamlined shelf registration process to provide registrants with timely access to capital. This allows the Companies to use automatic shelf registration statements to register any offering of securities, other than those for business combination transactions.

Net cash used in Dominion’s financing activities increased by $2.6 billion, primarily due to net debt repayments in 2010 as compared to net debt issuances in 2009, and net repurchases of common stock in 2010 as compared to issuances of common stock in 2009. This reflects the use of proceeds from the sales of Dominion’s Appalachian E&P operations and Peoples.

Net cash provided by Virginia Power’s financing activities increased by $201 million, primarily due to higher net debt issuances in 2010 as compared to 2009, as a result of lower cash flow from operations.

See Note 14 to the Consolidated Financial Statements for further information regarding Dominion’s and Virginia Power’s credit facilities, liquidity and significant financing transactions, including stock repurchases.

Credit Ratings

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* section of MD&A in Dominion’s and Virginia Power’s Annual Report on Form 10−K for the year ended December 31, 2009, there is a discussion on the use of capital markets by the Companies, as well as the impact of credit ratings on the accessibility and costs of using these markets. As of June 30, 2010, there have been no changes in the Companies’ credit ratings.

Debt Covenants

In the *Debt Covenants* section of MD&A in Dominion’s and Virginia Power’s Annual Report on Form 10−K for the year ended December 31, 2009, there is a discussion on the various covenants present in the enabling agreements underlying the Companies’ debt. As of June 30, 2010, there have been no changes to, or events of default under, the Companies’ debt covenants.

Future Cash Payments for Contractual Obligations and Planned Capital Expenditures

As of June 30, 2010, there have been no material changes outside the ordinary course of business to Dominion’s or Virginia Power’s contractual obligations as disclosed in MD&A in the Companies’ Annual Report on Form 10−K for the year ended December 31, 2009. As of June 30, 2010, Dominion’s planned capital expenditures for 2010, 2011 and 2012 are expected to total approximately $3.6 billion, $3.4 billion and $3.8 billion, respectively. The decrease in planned capital expenditures, as compared to the amounts originally forecasted in Dominion’s Annual Report on Form 10−K for the year ended December 31, 2009, primarily reflects the sale of Dominion’s Appalachian E&P operations. As of June 30, 2010, there have been no material changes to Virginia Power’s planned capital expenditures as disclosed in MD&A in the Companies’ Annual Report on Form 10−K for the year ended December 31, 2009.

Use of Off−Balance Sheet Arrangements

Other than a $135 million reduction in guarantees issued to third parties and equity method investees, as of June 30, 2010, there have been no material changes in the off−balance sheet arrangements disclosed in MD&A in Dominion’s Annual Report on Form 10−K for the year ended December 31, 2009.

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, the dates of Dominion’s and Virginia Power’s Consolidated Financial Statements that may impact the Companies’ future results of operations and/or financial condition. This section should be read in conjunction with Item 1. Business and Future Issues and Other Matters in MD&A in Dominion’s and Virginia Power’s Annual Report on Form 10−K for the year ended December 31, 2009 and Future Issues and Other Matters in their Quarterly Report on Form 10−Q for the quarter ended March 31, 2010.

Regulatory Matters

See Note 14 to the Consolidated Financial Statements in Dominion’s and Virginia Power’s Annual Report on Form 10−K for the year ended December 31, 2009, Note 12 to the Consolidated Financial Statements in their Quarterly Report on Form 10−Q for the quarter ended March 31, 2010 and Note 12 to the Consolidated Financial Statements in this report for additional information on various regulatory matters.

Environmental Matters

Dominion and Virginia Power 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. See Note 23 to the Consolidated Financial Statements in Dominion's and Virginia Power's Annual Report on Form 10−K for the year ended December 31, 2009, Note 15 to the Consolidated Financial Statements in their Quarterly Report on Form 10−Q for the quarter ended March 31, 2010 and Note 15 to the Consolidated Financial Statements in this report for additional information on various environmental matters.

Legal Matters

See Item 3. Legal Proceedings in Dominion's and Virginia Power's Annual Report on Form 10−K for the year ended December 31, 2009 and Part II, Item 1. Legal Proceedings in their Quarterly Report on Form 10−Q for the quarter ended March 31, 2010 and this report for additional information on various legal matters.

Sale of Appalachian E&P Operations

In April 2010, Dominion completed the sale of substantially all of its Appalachian E&P operations to CONSOL for approximately $3.5 billion, subject to adjustments pursuant to the terms of the sale agreement. A more detailed description of the sale can be found in Note 3 to the Consolidated Financial Statements in this report.

Net proceeds of the sale will be used to offset substantially all of Dominion's equity needs for 2010 and its market equity issuances for 2011, repurchase common stock, fund contributions to Dominion's pension plans and the Dominion Foundation, reduce debt and offset the majority of the impact of Virginia Power's rate case settlement. Dominion has projected that approximately $910 million of such proceeds will be used to repurchase common shares in 2010. From March 2010 to June 30, 2010, 12.2 million common shares have been repurchased for approximately $500 million.

Collective Bargaining Agreement

In May 2010, members of the Local 69 ratified a new three−year labor contract with Dominion. The new contract is retroactive to April 1, 2010 and runs through April 1, 2013. Local 69 represents about 870 DTI employees in West Virginia, New York, Pennsylvania, Ohio and Virginia and about 160 Hope employees in West Virginia.

DTI Firm Transportation Agreement

In June 2010, DTI entered into a 15−year firm transportation agreement with the gas subsidiary of CONSOL. The project is expected to provide approximately 200,000 dekatherms per day of firm transportation services for CONSOL's Marcellus Shale natural gas production from various receipt points in central and southwestern Pennsylvania to a nexus of market pipelines and storage facilities in Leidy, Pennsylvania. The project will involve the construction by DTI of new compression facilities at three existing compressor stations in central Pennsylvania, subject to the receipt of regulatory approval. Dominion plans to apply for a FERC certificate in December 2010. If the project is approved, construction is expected to begin in March 2012, with a projected in−service date of November 2012.

Dodd−Frank Act

In July 2010, the Dodd−Frank Act was signed into law in an effort to improve regulation of financial markets. Dominion and Virginia Power are currently evaluating the Act and cannot yet predict the impact it may have on Dominion's and Virginia Power's financial condition, results of operations or cash flows.

Issuance of Common Stock

In July 2010, the Virginia Commission approved Dominion and Virginia Power's joint request allowing Virginia Power to issue and sell up to $500 million of common stock to Dominion. This request was necessitated by the impact that the recently approved rate case settlement had on Virginia Power's common equity.

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 for discussion of various risks and uncertainties that may impact Dominion and Virginia Power.

Market Risk Sensitive Instruments and Risk Management

Dominion’s and Virginia Power’s 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 present in Dominion’s and Virginia Power’s electric operations, Dominion’s gas production and procurement operations, and Dominion’s energy marketing and trading operations due to the exposure to market shifts in prices received and paid for electricity, natural gas and other commodities. The Companies use commodity derivative contracts to manage price risk exposures for these operations. Interest rate risk is generally related to their outstanding debt. In addition, they are exposed to investment price risk through various portfolios of equity and debt 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, Dominion and Virginia Power primarily hold commodity−based financial derivative instruments held for non−trading purposes associated with purchases and sales of electricity, natural gas and other energy−related products. As part of its strategy to market energy and to manage related risks, Dominion also holds commodity−based financial derivative instruments for trading purposes.

The derivatives used to manage 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 market prices of Dominion’s non−trading commodity−based financial derivative instruments would have resulted in a decrease in fair value of approximately $161 million and $150 million as of June 30, 2010 and December 31, 2009, respectively. A hypothetical 10% unfavorable change in commodity prices would have resulted in a decrease of approximately $14 million and $11 million in the fair value of Dominion’s commodity−based financial derivative instruments held for trading purposes as of June 30, 2010 and December 31, 2009, respectively.

A hypothetical 10% unfavorable change in commodity prices would have resulted in a decrease of approximately $4 million and $3 million in the fair value of Virginia Power’s non−trading commodity−based financial derivatives as of June 30, 2010 and December 31, 2009, respectively.

The impact of a change in commodity prices on Dominion’s and Virginia Power’s 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. Net losses from commodity derivative instruments used for hedging purposes, to the extent realized, will generally be offset by recognition of the hedged transaction, such as revenue from physical sales of the commodity.

Interest Rate Risk

Dominion and Virginia Power may use forward−starting interest rate swaps and interest rate lock agreements as anticipatory hedges. At December 31, 2009, Dominion and Virginia Power had $1.7 billion and $850 million, respectively, in aggregate notional amounts of these interest rate derivatives outstanding. At December 31, 2009, a hypothetical 10% decrease in market interest rates would have resulted in a decrease of approximately $62 million and $33 million in the fair value of these interest rate derivatives held by Dominion and Virginia Power, respectively. Subsequent to June 30, 2010, all forward−starting interest rate swap contracts were terminated; therefore, Dominion and Virginia Power have no sensitivity to changes in interest rates related to these interest rate swaps. In the six months ended June 30, 2010, Dominion recognized a $67 million after−tax benefit, recorded in interest and related charges in its Consolidated Statement of Income, reflecting the discontinuance of hedge accounting for certain of these interest rate derivatives since it became probable that the forecasted interest payments would not occur.

Investment Price Risk

Dominion and Virginia Power 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 the Consolidated Balance Sheets at fair value.

Dominion recognized net realized gains (including investment income) on nuclear decommissioning trust investments of $41 million and $29 million for the six months ended June 30, 2010 and for the year ended December 31, 2009, respectively. Dominion recognized net realized losses (net of investment income) on nuclear decommissioning trust investments of $89 million for the six months ended June 30, 2009. Net realized gains and losses include gains and losses from the sale of investments as well as any other−than−temporary declines in fair value. For the six months ended June 30, 2010 and 2009 and the year ended December 31, 2009, Dominion recorded, in AOCI and regulatory liabilities, a net increase in unrealized losses on these investments of $108 million, and a net increase in unrealized gains on these investments of $152 million and $349 million, respectively.

Virginia Power recognized net realized gains (including investment income) on nuclear decommissioning trust investments of $20 million for the six months ended June 30, 2010. Virginia Power recognized net realized losses (net of investment income) on nuclear decommissioning trust investments of $53 million and $3 million for the six months ended June 30, 2009 and for the year ended December 31, 2009, respectively. Net realized gains and losses include gains and losses from the sale of investments as well as any other−than−temporary declines in fair value. Virginia Power recorded, in AOCI and regulatory liabilities, a net increase in unrealized losses on these investments of $48 million, and a net increase in unrealized gains on these investments of $72 million and $149 million for the six months ended June 30, 2010 and 2009 and for the year ended December 31, 2009, respectively.

Dominion sponsors employee pension and other postretirement benefit plans, in which Dominion’s and Virginia Power’s employees participate, that hold investments in trusts to fund benefit payments. If the values of investments held in these trusts decline, it 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 contributions to be made to the employee benefit plans.

ITEM 4. CONTROLS AND PROCEDURES

Senior management of each of Dominion and Virginia Power, including Dominion’s and Virginia Power’s CEO and CFO, evaluated the effectiveness of each of their respective Companies’ disclosure controls and procedures as of the end of the period covered by this report. Based on this evaluation process, both Dominion’s and Virginia Power’s CEO and CFO have concluded that each of the Companies’ disclosure controls and procedures are effective.

There were no changes in either Dominion’s or Virginia Power’s internal control over financial reporting that occurred during the last fiscal quarter that have materially affected, or are reasonably likely to materially affect, either of the Companies’ internal control over financial reporting.

The Dodd−Frank Act permanently exempts small public companies with less than $75 million in market capitalization (nonaccelerated filers) from the requirement to obtain an external audit on the effectiveness of internal financial reporting controls provided in Section 404(b) of the Sarbanes−Oxley Act. As a result, Virginia Power will be permanently exempt from providing an attestation report on internal controls over financial reporting by an independent registered public accounting firm. Disclosure of management attestations on internal controls over financial reporting under existing Section 404(a) is still required.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

From time to time, Dominion and Virginia Power 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 the Companies, or permits issued by various local, state and/or 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, the Companies and their subsidiaries are involved in various legal proceedings. Dominion and Virginia Power believe that the ultimate resolution of these proceedings will not have a material adverse effect on their financial position, liquidity or results of operations. See Notes 12 and 15 to the Consolidated Financial Statements and Dominion's and Virginia Power's Annual Report on Form 10−K for the year ended December 31, 2009 and their Quarterly Report on Form 10−Q for the quarter ended March 31, 2010 for discussions on various environmental and other regulatory proceedings to which Dominion and/or Virginia Power are a party.

In May 2010, Dominion received a request for information pursuant to Section 114 of the CAA from the EPA. The request concerns historical operating changes and capital improvements undertaken at Brayton Point and Salem Harbor. Dominion is currently in the process of responding to the request and cannot predict the outcome of this matter.

ITEM 1A. RISK FACTORS

Dominion's and Virginia Power's businesses are influenced by many factors that are difficult to predict, involve uncertainties that may materially affect actual results and are often beyond the Companies' control. A number of these risk factors have been identified in Dominion's and Virginia Power's Annual Report on Form 10−K for the year ended December 31, 2009, which should be taken into consideration when reviewing the information contained in this report. Except for the risk factor on credit rating agency requirements below, which has been amended to delete the references to Dominion's and Virginia Power's current credit ratings due to the Dodd−Frank Act, there have been no material changes with regard to the risk factors previously disclosed in Dominion's and Virginia Power's Annual Report on Form 10−K for the year ended December 31, 2009 or their Quarterly Report on Form 10−Q for the quarter ended March 31, 2010. 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.

Changing rating agency requirements could negatively affect Dominion's and Virginia Power's growth and business strategy. In order to maintain current credit ratings in light of existing or future requirements, Dominion and Virginia Power may find it necessary to take steps or change their business plans in ways that may adversely affect their growth and earnings. A reduction in Dominion's credit ratings or the credit ratings of Virginia Power could result in an increase in borrowing costs, loss of access to certain markets, or both, thus adversely affecting operating results and could require Dominion to post additional collateral in connection with some of its price risk management activities.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Dominion

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares (or Units) Purchased(1)	(b) Average Price Paid per Share (or Unit)(2)	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased under the Plans or Programs(3)
4/1/10−4/30/10	6,672,030	$ 41.43	6,474,700	42,762,448 shares/ $ 2.22 billion
5/1/10−5/31/10	987,050	41.54	979,028	41,783,420 shares/ $ 2.18 billion
6/1/10−6/30/10	4,348	38.96	N/A	41,783,420 shares/ $ 2.18 billion
Total	7,663,428	$ 41.44	7,453,728	41,783,420 shares/ $ 2.18 billion

(1) In April, May and June 2010, 197,330 shares, 8,022 shares and 4,348 shares, respectively, were tendered by employees to satisfy tax withholding obligations on vested restricted and goal−based stock.

(2) Represents the weighted−average price paid per share.

(3) The remaining repurchase authorization is pursuant to repurchase authority granted by the Dominion Board of Directors in February 2005, as modified in June 2007. The aggregate authorization granted by the Dominion Board of Directors was 86 million shares (as adjusted to reflect a two−for−one stock split distributed in November 2007) not to exceed $4 billion.

ITEM 6. EXHIBITS

Exhibit Number	Description	Dominion	Virginia Power
3.1.a	Dominion Resources, Inc. Articles of Incorporation, as amended and restated effective May 20, 2010 (Exhibit 3.1, Form 8−K filed May 20, 2010, File No. 1−8489).	X	
3.1.b	Virginia Electric and Power Company Restated Articles of Incorporation, as in effect on October 28, 2003 (Exhibit 3.1, Form 10−Q for the quarter ended September 30, 2003 filed November 7, 2003, File No. 1−2255).		X
3.2.a	Dominion Resources, Inc. Bylaws, as amended and restated effective May 18, 2010 (Exhibit 3.2, Form 8−K filed May 20, 2010, File No. 1−8489).	X	
3.2.b	Virginia Electric and Power Company Amended and Restated Bylaws, effective June 1, 2009 (Exhibit 3.1, Form 8−K filed June 3, 2009, File No. 1−2255).		X
4	Dominion Resources, Inc. and Virginia Electric and Power Company agree to furnish to the Securities and Exchange Commission upon request any other instrument with respect to long−term debt as to which the total amount of securities authorized does not exceed 10% of either of their total consolidated assets.	X	X
10.1	Supplemental retirement agreement dated May 19, 2010 between Dominion and Mark F. McGettrick (Exhibit 10.1, Form 8−K filed May 20, 2010, File No. 1−8489).	X	
10.2*	$3.0 billion Five−Year Credit Agreement dated February 28, 2006 among Dominion Resources, Inc., Virginia Electric and Power Company, Consolidated Natural Gas Company, JP Morgan Chase Bank, N.A., as Administrative Agent, Citibank, N.A. as Syndication Agent and Barclay's Bank PLC, The Bank of Nova Scotia and Wachovia Bank, National Association, as Co−Documentation Agents and other lenders named therein (filed herewith) (Portions of this exhibit have been omitted pursuant to a request for confidential treatment).	X	X
10.3*	$1.70 billion Amended and Restated Five−Year Credit Agreement dated February 28, 2006 among Consolidated Natural Gas Company, Barclay's Bank PLC, as Administrative Agent, Barclays Bank PLC and KeyBank National Association, as Syndication Agents, and SunTrust Bank, The Bank of Nova Scotia and ABN AMRO Bank, N.V., as Co−Documentation Agents and other lenders as named therein (filed herewith) (Portions of this exhibit have been omitted pursuant to a request for confidential treatment).	X	
10.4*	$500 million 364−Day Revolving Credit Agreement dated July 30, 2008, among Dominion Resources, Inc., The Royal Bank of Scotland PLC, as Administrative Agent, Barclays Bank PLC and Morgan Stanley Bank, as Co−Syndication Agents, Citibank N.A. and The Bank of Nova Scotia, as Co−Documentation Agents and other lenders named therein (filed herewith) (Portions of this exhibit have been omitted pursuant to a request for confidential treatment).	X	
10.5*	Offshore Package Purchase Agreement dated April 27, 2007 between Dominion Exploration & Production, Inc. and Eni Petroleum Co. Inc. (Exhibit 99.1, Form 8−K filed August 2, 2010, File No. 1−8489).	X	
10.6*	Alabama/Michigan/Permian Package Purchase Agreement dated as of June 1, 2007 between Dominion Resources, Inc., through certain of its wholly owned subsidiaries, and L O & G Acquisition Corp. (Exhibit 99.2, Form 8−K filed August 2, 2010, File No. 1−8489).	X	
10.7*	Gulf Coast/Rockies/San Juan Package Purchase Agreement dated as of June 1, 2007 between Dominion Resources, Inc., through certain of its wholly owned subsidiaries, and XTO Energy, Inc. (Exhibit 99.1, Form 8−K filed August 2, 2010, File No. 1−8489).	X	
12.1	Ratio of earnings to fixed charges for Dominion Resources, Inc. (filed herewith).	X	
12.2a	Ratio of earnings to fixed charges for Virginia Electric and Power Company (filed herewith).		X
12.2b	Ratio of earnings to fixed charges and preferred dividends for Virginia Electric and Power Company (filed herewith).		X

Exhibit Number	Description	Dominion	Virginia Power
31.a	Certification by Chief Executive Officer of Dominion Resources, Inc. pursuant to Section 302 of the Sarbanes−Oxley Act of 2002 (filed herewith).	X	
31.b	Certification by Chief Financial Officer of Dominion Resources, Inc. pursuant to Section 302 of the Sarbanes−Oxley Act of 2002 (filed herewith).	X	
31.c	Certification by Chief Executive Officer of Virginia Electric and Power Company pursuant to Section 302 of the Sarbanes−Oxley Act of 2002 (filed herewith).		X
31.d	Certification by Chief Financial Officer of Virginia Electric and Power Company pursuant to Section 302 of the Sarbanes−Oxley Act of 2002 (filed herewith).		X
32.a	Certification to the Securities and Exchange Commission by Chief Executive Officer and Chief Financial Officer of Dominion Resources, Inc. as required by Section 906 of the Sarbanes−Oxley Act of 2002 (furnished herewith).	X	
32.b	Certification to the Securities and Exchange Commission by Chief Executive Officer and Chief Financial Officer of Virginia Electric and Power Company as required by Section 906 of the Sarbanes−Oxley Act of 2002 (furnished herewith).		X
99	Condensed consolidated earnings statements (unaudited) (filed herewith).	X	X
101^	The following financial statements from Dominion Resources, Inc. and Virginia Electric and Power Company Quarterly Report on Form 10−Q for the quarter ended June 30, 2010, filed on July 29, 2010, formatted in XBRL: (i) Consolidated Statements of Income; (ii) Consolidated Balance Sheets; (iii) Consolidated Statements of Cash Flows; and (iv) the Notes to Consolidated Financial Statements.	X	

* This exhibit is being re−filed to include certain previously omitted schedules and/or exhibits.

^ This exhibit will not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934 (15 U.S.C. 78r), or otherwise subject to the liability of that section. Such exhibit will not be deemed to be incorporated by reference into any filing under the Securities Act or Securities Exchange Act, except to the extent that the Company specifically incorporates it by reference.

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.

DOMINION RESOURCES, INC.
Registrant

August 2, 2010

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

VIRGINIA ELECTRIC AND POWER COMPANY
Registrant

August 2, 2010

/s/ Ashwini Sawhney
Ashwini Sawhney
Vice President − Accounting
(Chief Accounting Officer)

EXHIBIT INDEX

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3.1.a	Dominion Resources, Inc. Articles of Incorporation, as amended and restated effective May 20, 2010 (Exhibit 3.1, Form 8−K filed May 20, 2010, File No. 1−8489).	X	
3.1.b	Virginia Electric and Power Company Restated Articles of Incorporation, as in effect on October 28, 2003 (Exhibit 3.1, Form 10−Q for the quarter ended September 30, 2003 filed November 7, 2003, File No. 1−2255).		X
3.2.a	Dominion Resources, Inc. Bylaws, as amended and restated effective May 18, 2010 (Exhibit 3.2, Form 8−K filed May 20, 2010, File No. 1−8489).	X	
3.2.b	Virginia Electric and Power Company Amended and Restated Bylaws, effective June 1, 2009 (Exhibit 3.1, Form 8−K filed June 3, 2009, File No. 1−2255).		X
4	Dominion Resources, Inc. and Virginia Electric and Power Company agree to furnish to the Securities and Exchange Commission upon request any other instrument with respect to long−term debt as to which the total amount of securities authorized does not exceed 10% of either of their total consolidated assets.	X	X
10.1	Supplemental retirement agreement dated May 19, 2010 between Dominion and Mark F. McGettrick (Exhibit 10.1, Form 8−K filed May 20, 2010, File No. 1−8489).	X	
10.2	$3.0 billion Five−Year Credit Agreement dated February 28, 2006 among Dominion Resources, Inc., Virginia Electric and Power Company, Consolidated Natural Gas Company, JP Morgan Chase Bank, N.A., as Administrative Agent, Citibank, N.A. as Syndication Agent and Barclay's Bank PLC, The Bank of Nova Scotia and Wachovia Bank, National Association, as Co−Documentation Agents and other lenders named therein (filed herewith) (Portions of this exhibit have been omitted pursuant to a request for confidential treatment).	X	X
10.3	$1.70 billion Amended and Restated Five−Year Credit Agreement dated February 28, 2006 among Consolidated Natural Gas Company, Barclay's Bank PLC, as Administrative Agent, Barclays Bank PLC and KeyBank National Association, as Syndication Agents, and SunTrust Bank, The Bank of Nova Scotia and ABN AMRO Bank, N.V., as Co−Documentation Agents and other lenders as named therein (filed herewith) (Portions of this exhibit have been omitted pursuant to a request for confidential treatment).	X	
10.4	$500 million 364−Day Revolving Credit Agreement dated July 30, 2008, among Dominion Resources, Inc., The Royal Bank of Scotland PLC, as Administrative Agent, Barclays Bank PLC and Morgan Stanley Bank, as Co−Syndication Agents, Citibank N.A. and The Bank of Nova Scotia, as Co−Documentation Agents and other lenders named therein (filed herewith) (Portions of this exhibit have been omitted pursuant to a request for confidential treatment).	X	
10.5	Offshore Package Purchase Agreement dated April 27, 2007 between Dominion Exploration & Production, Inc. and Eni Petroleum Co. Inc. (Exhibit 99.1, Form 8−K filed August 2, 2010, File No. 1−8489).	X	
10.6	Alabama/Michigan/Permian Package Purchase Agreement dated as of June 1, 2007 between Dominion Resources, Inc., through certain of its wholly owned subsidiaries, and L O & G Acquisition Corp. (Exhibit 99.2, Form 8−K filed August 2, 2010, File No. 1−8489).	X	
10.7	Gulf Coast/Rockies/San Juan Package Purchase Agreement dated as of June 1, 2007 between Dominion Resources, Inc., through certain of its wholly owned subsidiaries, and XTO Energy, Inc. (Exhibit 99.1, Form 8−K filed August 2, 2010, File No. 1−8489).	X	
12.1	Ratio of earnings to fixed charges for Dominion Resources, Inc. (filed herewith).	X	
12.2a	Ratio of earnings to fixed charges for Virginia Electric and Power Company (filed herewith).		X
12.2b	Ratio of earnings to fixed charges and preferred dividends for Virginia Electric and Power Company (filed herewith).		X

Exhibit Number	Description	Dominion	Virginia Power
31.a	Certification by Chief Executive Officer of Dominion Resources, Inc. pursuant to Section 302 of the Sarbanes−Oxley Act of 2002 (filed herewith).	X	
31.b	Certification by Chief Financial Officer of Dominion Resources, Inc. pursuant to Section 302 of the Sarbanes−Oxley Act of 2002 (filed herewith).	X	
31.c	Certification by Chief Executive Officer of Virginia Electric and Power Company pursuant to Section 302 of the Sarbanes−Oxley Act of 2002 (filed herewith).		X
31.d	Certification by Chief Financial Officer of Virginia Electric and Power Company pursuant to Section 302 of the Sarbanes−Oxley Act of 2002 (filed herewith).		X
32.a	Certification to the Securities and Exchange Commission by Chief Executive Officer and Chief Financial Officer of Dominion Resources, Inc. as required by Section 906 of the Sarbanes−Oxley Act of 2002 (furnished herewith).	X	
32.b	Certification to the Securities and Exchange Commission by Chief Executive Officer and Chief Financial Officer of Virginia Electric and Power Company as required by Section 906 of the Sarbanes−Oxley Act of 2002 (furnished herewith).		X
99	Condensed consolidated earnings statements (unaudited) (filed herewith).	X	X
101	The following financial statements from Dominion Resources, Inc. and Virginia Electric and Power Company Quarterly Report on Form 10−Q for the quarter ended June 30, 2010, filed on July 29, 2010, formatted in XBRL: (i) Consolidated Statements of Income; (ii) Consolidated Balance Sheets; (iii) Consolidated Statements of Cash Flows; and (iv) the Notes to Consolidated Financial Statements.	X	

Exhibit 12.1

Dominion Resources Inc. and Subsidiaries
Computation of Ratio of Earnings to Fixed Charges
(millions of dollars)

	Six Months Ended June 30, 2010 (a)	**Twelve Months Ended June 30, 2010 (b)**	**Years Ended December 31,**				
			2009 (c)	**2008 (d)**	**2007 (e)**	**2006 (f)**	**2005 (g)**
Earnings, as defined:							
Income from continuing operations including noncontrolling interest before income taxes, extraordinary item and cumulative effect of change in accounting principle	$ 3,519	$3,021	$1,874	$ 2,613	$4,442	$2,609	$1,561
Distributed income from unconsolidated investees, less equity in earnings	(18)	(34)	(30)	(39)	(20)	(16)	(15)
Fixed charges, as defined	438	956	1,022	990	1,325	1,271	1,099
Capitalized interest	(12)	(22)	(18)	(44)	(73)	(118)	(96)
Preference security dividend requirement of consolidated subsidiary	(14)	(25)	(24)	(26)	(26)	(24)	(24)
Total earnings, as defined	$ 3,913	$3,896	$2,824	$ 3,494	$5,648	$3,722	$2,525
Fixed charges, as defined:							
Interest charges	$ 396	$ 874	$ 941	$ 911	$1,238	$1,190	$1,023
Preference security dividend requirement of consolidated subsidiary	14	25	24	26	26	24	24
Rental interest factor	28	57	57	53	61	57	52
Total fixed charges, as defined	$ 438	$ 956	$1,022	$ 990	$1,325	$1,271	$1,099
Ratio of Earnings to Fixed Charges	**8.93**	**4.08**	**2.76**	**3.53**	**4.26**	**2.93**	**2.30**

(a) Earnings for the six months ended June 30, 2010 include a $2.4 billion benefit resulting from the sale of our Appalachian E&P operations—primarily reflecting the gain on the sale partially offset by certain transaction costs and other related charges. Earnings for the period also include a $338 million charge related to the workforce reduction program primarily reflecting severance pay and other benefits to affected employees and a $163 million charge related to our State Line coal−fired merchant power stations. Excluding these items from the calculation would result in a lower ratio of earnings to fixed charges for the six months ended June 30, 2010.

(b) Earnings for the twelve months ended June 30, 2010 include a $2.4 billion benefit resulting from the sale of our Appalachian E&P operations—primarily reflecting the gain on the sale partially offset by certain transaction costs and other related charges and a $67 million net gain related to our investments in nuclear decommissioning trust funds. Earnings for the period also include a $712 million charge in connection with the proposed settlement of Virginia Power's 2009 rate case proceeding, a $338 million charge related to the workforce reduction program primarily reflecting severance pay and other benefits to affected employees, a $163 million charge related to our State Line coal−fired merchant power stations and a $8 million net charge related to other items. Excluding these items from the calculation would result in a lower ratio of earnings to fixed charges for the twelve months ended June 30, 2010.

(c) Earnings for the twelve months ended December 31, 2009 include a $455 million impairment charge as a result of the quarterly ceiling test performed on our gas and oil properties under the full cost method of accounting, a $712 million charge in connection with the proposed settlement of Virginia Power's 2009 rate case proceeding and a $41 million net charge related to other items. Earnings for the period also include a $103 million reduction in other operation and maintenance expense due to a downward revision in the nuclear decommissioning asset retirement obligation for a power station that is no longer in service. Excluding these items from the calculation would result in a higher ratio of earnings to fixed charges for the twelve months ended December 31, 2009.

(d) Earnings for the twelve months ended December 31, 2008 include $180 million of impairment charges reflecting other−than−temporary declines in the fair value of securities held in nuclear decommissioning trust funds, $59 million of impairment charges related to Dominion Capital, Inc. (DCI) assets, a $42 million reduction in the gain recognized in 2007 from the sale of the majority of our U.S. exploration and production (E&P) businesses as a result of post−closing adjustments, and a $30 million net charge related to other items. Excluding these items from the calculation would result in a higher ratio of earnings to fixed charges for the twelve months ended December 31, 2008.

(e) Earnings for the twelve months ended December 31, 2007 include a $3.6 billion gain from the disposition of the majority of our U.S. E&P operations, partially offset by $1 billion of charges related to the disposition which are comprised of $541 million related to the discontinuance of hedge accounting for certain gas and oil derivatives and subsequent changes in the fair value of these derivatives, $171 million primarily related to the settlement of volumetric production payment agreements, $242 million of charges related to the early retirement of debt, and $91 million of employee−related expenses. Earnings for the period also include a $387 million charge related to the impairment of the partially−completed Dresden generation facility; a $231 million charge due to the termination of a power sales agreement at our State Line generating facility; $88 million of impairment charges related to DCI assets; $48 million of charges related to litigation reserves, and $70 million of charges related to other items. Fixed charges for the twelve months ended December 31, 2007 include $234 million of costs related to the early retirement of debt associated with our debt tender offer completed in July 2007. Excluding these items from the calculation would result in a lower ratio of earnings to fixed charges for the twelve months ended December 31, 2007.

(f) Earnings for the twelve months ended December 31, 2006 include $90 million of impairment charges related to DCI assets, a $60 million charge due to an adjustment eliminating the application of hedge accounting related to certain interest rate swaps associated with our junior subordinated notes payable to affiliated trusts, a $27 million charge resulting from the termination of a pipeline project in West Virginia, a $26 million impairment charge resulting from a change in method of assessing other−than−temporary decline in the fair value of certain securities, $17 million of incremental charges related to hurricanes Katrina and Rita, and $12 million of net charges related to other items. Fixed charges for the twelve months ended December 31, 2006 include a $60 million charge due to an adjustment eliminating the application of hedge accounting related to certain interest rate swaps associated with our junior subordinated notes payable to affiliated trusts. Excluding these items from the calculation would result in a higher ratio of earnings to fixed charges for the twelve months ended December 31, 2006.

(g) Earnings for the twelve months ended December 31, 2005 include a $423 million charge reflecting the de−designation of hedge contracts resulting from the delay of natural gas and oil production following Hurricanes Katrina and Rita, $73 million in charges resulting from the termination of certain long−term power purchase contracts, $21 million in net charges related to trading activities discontinued in 2004, including the Batesville long−term power−tolling contract divested in the second quarter of 2005 and other activities, $35 million of impairment charges related to DCI assets, a $76 million charge related to miscellaneous asset impairments, a $28 million charge related to expenses following Hurricanes Katrina and Rita and $5 million of charges related to other items. Excluding these items from the calculation would result in a higher ratio of earnings to fixed charges for the twelve months ended December 31, 2005.

Exhibit 12.2.a

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

	Six Months Ended June 30, 2010	Twelve Months Ended June 30, 2010	Years Ended December 31, 2009	2008	2007	2006	2005
Earnings, as defined:							
Income from continuing operations before income taxes, extraordinary item and cumulative effect of change in accounting principle	$ 604	$ 1,450	$ 503	$1,364	$ 977	$ 762	$ 754
Fixed charges as defined	188	387	392	343	332	322	339
Capitalized interest	—	—	—	—	(4)	(9)	(6)
Total earnings, as defined	$ 792	$ 1,837	$ 895	$1,707	$1,305	$1,075	$1,087
Fixed charges, as defined:							
Interest charges	$ 180	$ 371	$ 376	$ 330	$ 320	$ 311	$ 329
Rental interest factor	8	16	16	13	12	11	10
Total fixed charges, as defined	$ 188	$ 387	$ 392	$ 343	$ 332	$ 322	$ 339
Ratio of Earnings to Fixed Charges	**4.21**	**4.75**	**2.28**	**4.98**	**3.93**	**3.34**	**3.21**

Exhibit 12.2.b

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

	Six Months Ended June 30, 2010	Twelve Months Ended June 30, 2010	Years Ended December 31, 2009	2008	2007	2006	2005
Earnings, as defined:							
Income from continuing operations before income taxes, extraordinary item and cumulative effect of change in accounting principle	$ 604	$1,450	$ 503	$1,364	$ 977	$ 762	$ 754
Fixed charges as defined	202	413	416	369	357	347	364
Capitalized interest	—	—	—	—	(4)	(9)	(6)
Preference security dividend requirement	(14)	(26)	(24)	(26)	(25)	(25)	(25)
Total earnings, as defined	$ 792	$1,837	$ 895	$1,707	$1,305	$1,075	$1,087
Fixed charges, as defined:							
Interest charges	$ 180	$ 371	$ 376	$ 330	$ 320	$ 311	$ 329
Preference security dividend requirement	14	26	24	26	25	25	25
Rental interest factor	8	16	16	13	12	11	10
Total fixed charges, as defined	$ 202	$ 413	$ 416	$ 369	$ 357	$ 347	$ 364
Ratio of Earnings to Fixed Charges and Preferred Dividends	**3.92**	**4.45**	**2.15**	**4.63**	**3.66**	**3.10**	**2.99**

Exhibit 31.a

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

1. I have reviewed this report on Form 10−Q of Dominion Resources, Inc.;
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: August 2, 2010

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

Exhibit 31.b

I, Mark F. McGettrick, certify that:

1. I have reviewed this report on Form 10−Q of Dominion Resources, Inc.;
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: August 2, 2010

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

Exhibit 31.c

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: August 2, 2010

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

Exhibit 31.d

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: August 2, 2010

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

Exhibit 32.a

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 Dominion Resources, Inc. (the Company), certify that:

1. the Quarterly Report on Form 10−Q for the quarter ended June 30, 2010 (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, 2010 and for the period then ended.

/s/ Thomas F. Farrell, II
Thomas F. Farrell, II
President and Chief Executive Officer
August 2, 2010

/s/ Mark F. McGettrick
Mark F. McGettrick
Executive Vice President and
Chief Financial Officer
August 2, 2010

Exhibit 32.b

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, 2010 (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, 2010 and for the period then ended.

/s/ Thomas F. Farrell, II
Thomas F. Farrell, II
Chief Executive Officer
August 2, 2010

/s/ Mark F. McGettrick
Mark F. McGettrick
Executive Vice President and Chief Financial Officer
August 2, 2010

Exhibit 99

DOMINION RESOURCES, INC.

CONDENSED CONSOLIDATED EARNINGS STATEMENT
(Unaudited)

(millions, except per share amounts)	Twelve Months Ended June 30, 2010
Operating Revenue	$14,306
Operating Expenses	9,446
Income from operations	4,860
Other income	232
Interest and related charges	821
Income before income tax expense including noncontrolling interests	$ 4,271
Income tax expense	1,619
Net income including noncontrolling interests	2,652
Loss from discontinued operations (including income tax benefit of $25)	(114)
Noncontrolling interests	17
Net income attributable to Dominion	$ 2,521
Amounts attributable to Dominion:	
Income from continuing operations	$ 2,635
Loss from discontinued operations	(114)
Net income attributable to Dominion	$ 2,521
Earnings Per Common Share – Basic	
Income from continuing operations	$ 4.45
Loss from discontinued operations	(0.19)
Noncontrolling interests	(0.03)
Net income attributable to Dominion	$ 4.23
Earnings Per Common Share – Diluted	
Income from continuing operations	$ 4.44
Loss from discontinued operations	(0.19)
Noncontrolling interests	(0.03)
Net income attributable to Dominion	$ 4.22

Exhibit 99

VIRGINIA ELECTRIC AND POWER COMPANY

CONDENSED CONSOLIDATED EARNINGS STATEMENT
(Unaudited)

(millions)	Twelve Months Ended June 30, 2010
Operating Revenue	$ 6,500
Operating Expenses	5,720
Income from operations	780
Other income	115
Interest and related charges	345
Income before income tax expense	550
Income tax expense	184
Net Income	366
Preferred dividends	17
Balance available for common stock	$ 349

Attachment 7

PSE&G Formula Rate for January 1, 2011 to December 31, 2011

Gregory Eisenstark
Associate General Regulatory Counsel

Law Department
80 Park Plaza, T5G, Newark, NJ 07102-4194
tel: 973.430.6281 fax: 973.430.5983
email: gregory.eisenstark@pseg.com

PSEG
Services Corporation

October 15, 2010

VIA ELECTRONIC FILING

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

Re: Informational Filing Public Service Electric and Gas Company,
Docket No. ER09-1257-000
2011 Formula Rate Annual Update

Dear Ms. Bose:

Attached for informational purposes, please find the 2011 Annual Update of Public Service Electric and Gas Company ("PSE&G") in the above referenced docket.

This annual Update is being filed in accordance with the Commission Order at 124 FERC ¶ 61,303 (2008).[1] The attachment has been submitted to PJM for posting on its Internet website.

This filing requires no action by the Commission. Thank you for your attention to this matter and please advise the undersigned of any questions.

Very truly yours,

Gregory Eisenstark

Attachments

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[1] As amended by errata issued by the Commission, 125 FERC ¶ 61,024 (2008)

Public Service Electric and Gas Company

ATTACHMENT H-10A

Shaded cells are input cells

	Formula Rate -- Appendix A	Notes	FERC Form 1 Page # or Instruction	12 Months Ended 12/31/2011
	Allocators			
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense	(Note O)	Attachment 5	19,944,198
2	Total Wages Expense	(Note O)	Attachment 5	149,963,118
3	Less A&G Wages Expense	(Note O)	Attachment 5	3,751,396
4	Total Wages Less A&G Wages Expense		(Line 2 - Line 3)	146,211,722
5	**Wages & Salary Allocator**		(Line 1 / Line 4)	**13.6406%**
	Plant Allocation Factors			
6	Electric Plant in Service	(Note B)	Attachment 5	9,126,016,804
7	Common Plant in Service - Electric		(Line 22)	115,602,277
8	Total Plant in Service		(Line 6 + 7)	9,241,619,081
9	Accumulated Depreciation (Total Electric Plant)	(Note B & J)	Attachment 5	2,696,477,596
10	Accumulated Intangible Amortization - Electric	(Note B)	Attachment 5	140,077
11	Accumulated Common Plant Depreciation & Amortization - Electric	(Note B & J)	Attachment 5	35,760,011
12	Accumulated Common Amortization - Electric	(Note B)	Attachment 5	0
13	Total Accumulated Depreciation		(Line 9 + Line 10 + Line 11 + Line 12)	2,732,377,684
14	Net Plant		(Line 8 - Line 13)	6,509,241,397
15	Transmission Gross Plant		(Line 31)	2,273,703,088
16	**Gross Plant Allocator**		(Line 15 / Line 8)	**24.6029%**
17	Transmission Net Plant		(Line 43)	1,493,849,153
18	**Net Plant Allocator**		(Line 17 / Line 14)	**22.9497%**
	Plant Calculations			
	Plant In Service			
19	Transmission Plant In Service	(Note B)	Attachment 5	2,214,586,954
20	General	(Note B)	Attachment 5	222,010,874
21	Intangible - Electric	(Note B)	Attachment 5	903,473
22	Common Plant - Electric	(Note B)	Attachment 5	115,602,277
23	Total General, Intangible & Common Plant		(Line 20 + Line 21 + Line 22)	338,516,624
24	Less: General Plant Account 397 -- Communications	(Note B)	Attachment 5	27,862,984
25	Less: Common Plant Account 397 -- Communications	(Note B)	Attachment 5	5,854,998
26	General and Intangible Excluding Acct. 397		(Line 23 - Line 24 - Line 25)	304,798,642
27	Wage & Salary Allocator		(Line 5)	13.6406%
28	General and Intangible Plant Allocated to Transmission		(Line 26 * Line 27)	41,576,451
29	Account No. 397 Directly Assigned to Transmission	(Note B)	Attachment 5	17,539,684
30	Total General and Intangible Functionalized to Transmission		(Line 28 + Line 29)	59,116,135
31	**Total Plant In Rate Base**		(Line 19 + Line 30)	**2,273,703,088**
	Accumulated Depreciation			
32	Transmission Accumulated Depreciation	(Note B & J)	Attachment 5	755,736,953
33	Accumulated General Depreciation	(Note B & J)	Attachment 5	94,483,550
34	Accumulated Common Plant Depreciation - Electric	(Note B & J)	Attachment 5	35,760,011
35	Less: Amount of General Depreciation Associated with Acct. 397	(Note B & J)	Attachment 5	14,955,958
36	Balance of Accumulated General Depreciation		(Line 33 + Line 34 - Line 35)	115,287,604
37	Accumulated Intangible Amortization - Electric	(Note B)	(Line 10)	140,077
38	Accumulated General and Intangible Depreciation Ex. Acct. 397		(Line 36 + 37)	115,427,681
39	Wage & Salary Allocator		(Line 5)	13.6406%
40	Subtotal General and Intangible Accum. Depreciation Allocated to Transmission		(Line 38 * Line 39)	15,745,061
41	Accumulated General Depreciation Associated with Acct. 397 Directly Assigned to Transmission	(Note B & J)	Attachment 5	8,371,921
42	**Total Accumulated Depreciation**		(Lines 32 + 40 + 41)	**779,853,936**
43	**Total Net Property, Plant & Equipment**		(Line 31 - Line 42)	**1,493,849,153**

Public Service Electric and Gas Company

ATTACHMENT H-10A

	Formula Rate -- Appendix A	**Notes**	**FERC Form 1 Page # or Instruction**	**12 Months Ended 12/31/2011**
	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	-297,608,508
	CWIP for Incentive Transmission Projects			
45	CWIP Balances for Current Rate Year	(Note B & H)	Attachment 6	118,390,650
46	**Plant Held for Future Use**	(Note C & Q)	Attachment 5	1,778,167
	Prepayments			
47	Prepayments	(Note A & Q)	Attachment 5	5,831,232
	Materials and Supplies			
48	Undistributed Stores Expense	(Note Q)	Attachment 5	0
49	Wage & Salary Allocator		(Line 5)	13.6406%
50	Total Undistributed Stores Expense Allocated to Transmission		(Line 48 * Line 49)	0
51	Transmission Materials & Supplies	(Note N & Q))	Attachment 5	3,514,264
52	Total Materials & Supplies Allocated to Transmission		(Line 50 + Line 51)	3,514,264
	Cash Working Capital			
53	Operation & Maintenance Expense		(Line 80)	81,707,455
54	1/8th Rule		1/8	12.5%
55	Total Cash Working Capital Allocated to Transmission		(Line 53 * Line 54)	10,213,432
	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)	**-157,880,762**
58	**Rate Base**		(Line 43 + Line 57)	**1,335,968,391**
	Operations & Maintenance Expense			
	Transmission O&M			
59	Transmission O&M	(Note O)	Attachment 5	52,212,698
60	Plus Transmission Lease Payments	(Note O)	Attachment 5	0
61	**Transmission O&M**		(Lines 59 + 60)	**52,212,698**
	Allocated Administrative & General Expenses			
62	Total A&G	(Note O)	Attachment 5	199,116,808
63	Plus: Fixed PBOP expense	(Note J)	Attachment 5	77,745,482
64	Less: Actual PBOP expense	(Note O)	Attachment 5	52,639,903
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	11,425,582
67	Less General Advertising Exp Account 930.1	(Note O)	Attachment 5	1,919,371
68	Less EPRI Dues	(Note D & O)	Attachment 5	0
69	**Administrative & General Expenses**		Sum (Lines 62 to 63) - Sum (Lines 64 to 68)	209,707,434
70	Wage & Salary Allocator		(Line 5)	13.6406%
71	**Administrative & General Expenses Allocated to Transmission**		(Line 69 * Line 70)	**28,605,412**
	Directly Assigned A&G			
72	Regulatory Commission Exp Account 928	(Note G & O)	Attachment 5	620,834
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)	620,834
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)	22.9497%
79	**A&G Directly Assigned to Transmission**		(Line 77 * Line 78)	**268,511**
80	**Total Transmission O&M**		**(Lines 61 + 71 + 74 + 79)**	**81,707,455**

Public Service Electric and Gas Company

ATTACHMENT H-10A

Formula Rate -- Appendix A

Shaded cells are input cells

			Notes	**FERC Form 1 Page # or Instruction**	**12 Months Ended 12/31/2011**
	Depreciation & Amortization Expense				
	Depreciation Expense				
81	Transmission Depreciation Expense Including Amortization of Limited Term Plant		(Note J & O)	Attachment 5	51,290,500
82	General Depreciation Expense Including Amortization of Limited Term Plant		(Note J & O)	Attachment 5	26,429,391
83	Less: Amount of General Depreciation Expense Associated with Acct. 397		(Note J & O)	Attachment 5	3,364,772
84	Balance of General Depreciation Expense			(Line 82 - Line 83)	23,064,619
85	Intangible Amortization		(Note A & O)	Attachment 5	5,044,689
86	Total			(Line 84 + Line 85)	28,109,308
87	Wage & Salary Allocator			(Line 5)	13.6406%
88	General Depreciation & Intangible Amortization Allocated to Transmission			(Line 86 * Line 87)	3,834,286
89	General Depreciation Expense for Acct. 397 Directly Assigned to Transmission		(Note J & O)	Attachment 5	1,753,968
90	**General Depreciation and Intangible Amortization Functionalized to Transmission**			(Line 88 + Line 89)	**5,588,255**
91	**Total Transmission Depreciation & Amortization**			**(Lines 81 + 90)**	**56,878,754**
	Taxes Other than Income Taxes				
92	Taxes Other than Income Taxes		(Note O)	Attachment 2	9,342,688
93	**Total Taxes Other than Income Taxes**			(Line 92)	**9,342,688**
	Return \ Capitalization Calculations				
94	**Long Term Interest**			p117.62.c through 67.c	195,974,631
95	**Preferred Dividends**		enter positive	p118.29.d	3,987,874
	Common Stock				
96	Proprietary Capital		(Note P)	Attachment 5	4,015,559,296
97	Less Accumulated Other Comprehensive Income Account 219		(Note P)	Attachment 5	3,524,080
98	Less Preferred Stock			(Line 106)	79,523,400
99	Less Account 216.1		(Note P)	Attachment 5	3,941,456
100	**Common Stock**			(Line 96 - 97 - 98 - 99)	3,928,570,361
	Capitalization				
101	Long Term Debt		(Note P)	Attachment 5	3,547,156,489
102	Less Loss on Reacquired Debt		(Note P)	Attachment 5	109,213,413
103	Plus Gain on Reacquired Debt		(Note P)	Attachment 5	0
104	Less ADIT associated with Gain or Loss		(Note P)	Attachment 5	36,995,999
105	Total Long Term Debt			(Line 101 - 102 + 103 - 104)	3,400,947,077
106	Preferred Stock		(Note P)	Attachment 5	79,523,400
107	Common Stock			(Line 100)	3,928,570,361
108	**Total Capitalization**			(Sum Lines 105 to 107)	7,409,040,838
109	Debt %	Total Long Term Debt		(Line 105 / Line 108)	45.90%
110	Preferred %	Preferred Stock		(Line 106 / Line 108)	1.07%
111	Common %	Common Stock		(Line 107 / Line 108)	53.02%
112	Debt Cost	Total Long Term Debt		(Line 94 / Line 105)	0.0576
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)	0.0265
116	Weighted Cost of Preferred	Preferred Stock		(Line 110 * Line 113)	0.0005
117	Weighted Cost of Common	Common Stock		(Line 111 * Line 114)	0.0619
118	**Rate of Return on Rate Base (ROR)**			(Sum Lines 115 to 117)	**0.0889**
119	**Investment Return = Rate Base * Rate of Return**			**(Line 58 * Line 118)**	**118,795,682**

Public Service Electric and Gas Company

ATTACHMENT H-10A

Formula Rate -- Appendix A

Shaded cells are input cells

Composite Income Taxes

Line	Description		Notes	FERC Form 1 Page # or Instruction	12 Months Ended 12/31/2011
	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	-1,265,000
126	1/(1-T)			1 / (1 - Line 123)	169.06%
127	Net Plant Allocation Factor			(Line 18)	22.9497%
128	**ITC Adjustment Allocated to Transmission**			(Line 125 * Line 126 * Line 127)	**-490,809**
129	**Income Tax Component =**	(T/1-T) * Investment Return * (1-(WCLTD/ROR)) =		[Line 124 * Line 119 * (1- (Line 115 / Line 118))]	**57,637,745**
130	**Total Income Taxes**			**(Line 128 + Line 129)**	**57,146,936**

Revenue Requirement

Line	Description		Notes	FERC Form 1 Page # or Instruction	12 Months Ended 12/31/2011
	Summary				
131	Net Property, Plant & Equipment			(Line 43)	1,493,849,153
132	Total Adjustment to Rate Base			(Line 57)	-157,880,762
133	**Rate Base**			(Line 58)	**1,335,968,391**
134	Total Transmission O&M			(Line 80)	81,707,455
135	Total Transmission Depreciation & Amortization			(Line 91)	56,878,754
136	Taxes Other than Income			(Line 93)	9,342,688
137	Investment Return			(Line 119)	118,795,682
138	Income Taxes			(Line 130)	57,146,936
139	**Gross Revenue Requirement**			**(Sum Lines 134 to 138)**	**323,871,516**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
140	Transmission Plant In Service			(Line 19)	2,214,586,954
141	Excluded Transmission Facilities		(Note B & M)	Attachment 5	0
142	Included Transmission Facilities			(Line 140 - Line 141)	2,214,586,954
143	Inclusion Ratio			(Line 142 / Line 140)	100.00%
144	Gross Revenue Requirement			(Line 139)	323,871,516
145	**Adjusted Gross Revenue Requirement**			(Line 143 * Line 144)	**323,871,516**
	Revenue Credits & Interest on Network Credits				
146	**Revenue Credits**		(Note O)	Attachment 3	32,598,264
147	**Interest on Network Credits**		(Note N & O)	Attachment 5	0
148	**Net Revenue Requirement**			**(Line 145 - Line 146 + Line 147)**	**291,273,252**
	Net Plant Carrying Charge				
149	Gross Revenue Requirement			(Line 144)	**323,871,516**
150	Net Transmission Plant			(Line 19 - Line 32)	**1,458,850,000**
151	Net Plant Carrying Charge			(Line 149 / Line 150)	**22.2005%**
152	Net Plant Carrying Charge without Depreciation			(Line 149 - Line 81) / Line 150	**18.6846%**
153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes			(Line 149 - Line 81 - Line 119 - Line 130) / Line 150	**6.6243%**
	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)	**147,928,898**
155	Increased Return and Taxes			Attachment 4	**187,918,679**
156	Net Revenue Requirement per 100 Basis Point increase in ROE			(Line 154 + Line 155)	**335,847,576**
157	Net Transmission Plant			(Line 19 - Line 32)	**1,458,850,000**
158	Net Plant Carrying Charge per 100 Basis Point increase in ROE			(Line 156 / Line 157)	**23.0214%**
159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation			(Line 156 - Line 81) / Line 157	**19.5056%**
160	**Net Revenue Requirement**			(Line 148)	**291,273,252**
161	True-up amount			Attachment 6	**3,835,973**
162	Plus any increased ROE calculated on Attachment 7 other than PJM Sch. 12 projects not paid by other PJM transmission zones			Attachment 7	**1,284,229**
163	Facility Credits under Section 30.9 of the PJM OATT			Attachment 5	**0**
164	**Net Zonal Revenue Requirement**			(Line 160 + 161 + 162 + 163)	**296,393,455**
	Network Zonal Service Rate				
165	1 CP Peak		(Note L)	Attachment 5	**10,761.4**
166	Rate ($/MW-Year)			(Line 164 / 165)	**27,542**
167	**Network Service Rate ($/MW/Year)**			**(Line 166)**	**27,542**

Public Service Electric and Gas Company

ATTACHMENT H-10A

Formula Rate -- Appendix A **Notes** **FERC Form 1 Page # or Instruction**

12 Months Ended 12/31/2011

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 31,2011

	Only Transmission Related	*Plant Related*	*Labor Related*	*Total ADIT*	
ADIT- 282	0	(1,131,309,811)	(87,798)		From Acct. 282 total, below
ADIT-283	(1,781,312)	(102,007,901)	(57,025,936)		From Acct. 283 total, below
ADIT-190	1,617,015	(85,112,549)	7,819,143		From Acct. 190 total, below
Subtotal	(164,297)	(1,318,430,261)	(49,294,591)		
Wages & Salary Allocator			13.6406%		
Net Plant Allocator		22.9497%			
End of Year ADIT	(164,297)	(302,575,340)	(6,724,092)	**(309,463,729)**	
End of Previous Year ADIT (from Sheet 1A-ADIT (3))	(164,297)	(282,670,292)	(2,918,698)	**(285,753,286)**	
Average Beginning and End of Year ADIT	(164,297)	(292,622,816)	(4,821,395)	**(297,608,508)**	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

(32,950,573) < 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 taxe
Newark Center Renovations	10,804	-	-	-	10,804	Amort of Renovations of Newark Plaza - General Property
New Jersey Corporate Business Tax(NJCBT)	(89,404,672)	-	-	(89,404,672)	-	New Jersey Corporate Income Tax Plant Related- Contra Account of 283 NJCBT
NJCBT - Step Up Basis	141,931,340	141,931,340	-	-	-	New Jersey Corporate Income Tax for Utility - Gets return on but no return of prior book vs tax timing difference
ADIT - Real Estate Taxes	2,769,110	-	-	2,769,110	-	Book estimate accrued and expensed, tax deduction when paid related to plan
Gross Receipts & Franchise Tax(GRAFT)	756,443	756,443	-	-	-	Retail related
Market Transition Charge Revenue	51,871,037	51,871,037	-	-	-	Stranded cost recovery - generation related
Mine Closing Costs	1,357,594	1,357,594	-	-	-	Book estimate accrued and expensed, tax deduction when paid - Generation relate
FIN 47	11,354	11,354	-	-	-	Asset Retirement Obligation - Legal liability for environmental removal costs
Vacation Pay	2,995,169	-	-	-	2,995,169	Vacation pay earned and expensed for books, tax deduction when paid - employees in all function
OPEB	162,415,318	-	-	-	162,415,318	FASB 106 - Post Retirement Obligation, labor related
Deferred Dividend Equivalents	3,862,689	-	-	-	3,862,689	Book accrual of dividends on employee stock options affecting all functions
Deferred Compensation	462,421	-	-	-	462,421	Book estimate accrued and expensed, tax deduction when paid - employees in all function
ADIT - Interest/AFDC Debt	1,523,013	-	-	1,523,013	-	Capitalized Interest - Book vs Tax relates to all plant in all functions
ADIT - Unallowable PIP Accrua	(792,552)	-	-	-	(792,552)	Book estimate accrued and expensed, tax deduction when paid - employees in all function
ADIT - Legal Fees	637,144	637,144	-	-	-	Book estimate accrued and expensed, tax deduction when paid - employees in all function
ADIT - Rev of 1985-1993 Settle Int Exp	(3,180,712)	(3,180,712)	-	-	-	Book estimate accrued and expensed, tax deduction when paid / audit settlement - Generation relate
ADIT - Interest on Dismantling & Decommissioning	(1,940,681)	(1,940,681)	-	-	-	Book estimate accrued and expensed, tax deduction when paid / audit settlement - Generation relate
ADIT - SETI Dissolution	60,619	60,619	-	-	-	Book estimate accrued and expensed, tax deduction when paid / audit settlement - Retail relate
Minimum Pension Liability	137,435	137,435	-	-	-	Associated with Pension Liability not in rates
FIN 48 Services Allocation	(649,220)	(649,220)	-	-	-	Uncertain Tax Positions - Assets/(Liabilities) not in rates
Bankruptcies $ Acfc	(5,845)	(5,845)	-	-	-	Book estimate accrued and expensed, tax deduction when paid - Generation Relate
Repair Allowance Deferred	(6,515,037)	(6,515,037)	-	-	-	Deferred recovery of lost repair allowance deductions-Retail Related
Fin Def. Energy competition Act CT	(1,748,958)	(1,748,958)	-	-	-	Restructuring Costs - Generation related
Def Tax Meter Equipment	201,647	201,647	-	-	-	Book estimate accrued and expensed, tax deduction when paid - Retail - Distribution Meter
Unrealized L/G Rabbi Trust	436,479	-	-	-	436,479	Book estimate accrued and expensed, tax deduction when paid for Executive Compensation
Reserve for SECA	(1,111,579)	(1,111,579)	-	-	-	Related to LSE SECA obligations - retai
Estimated Serverance Pay Accruals	844,133	-	-	-	844,133	Book estimate accrued and expensed, tax deduction when paid - employees in all function
Federal Taxes Deferred	23,030,494	-	-	23,030,494	-	FASB 109 - deferred tax asset primarily associated with items previously flowed through due to regulatio
Federal Taxes Current	27,158,392	-	-	27,158,392	-	FASB 109 - deferred tax asset primarily associated with items previously flowed through due to regulatio
Fed Taxes Reg Requirement	23,760,554	-	-	23,760,554	-	FASB 109 - deferred tax asset primarily associated with items previously flowed through due to regulation
Subtotal - p234	**343,849,073**	**183,160,706**	**1,617,015**	**(11,163,109)**	**170,234,461**	
Less FASB 109 Above if not separately removed	73,949,440			73,949,440		
Less FASB 106 Above if not separately removed	162,415,318				162,415,318	
Total	**107,484,315**	**183,160,706**	**1,617,015**	**(85,112,549)**	**7,819,143**	

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 31,2011

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	(954,201,440)	-	-	(954,201,440)	-	Basis difference resulting from accelerated tax depreciation versus depreciation used for ratemaking purposes - related to all functions
Depreciation - Non Utility Property	(78,501,105)	(78,501,105)	-	-	-	Inter-company gain on sale of non-regulated generation assets.
Cost of Removal	(56,582,328)	-	-	(56,582,328)	-	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
Deffered Taxes on Rabbi Trust	(87,798)	-	-	-	(87,798)	Book estimate accrued and expensed, tax deduction when paid for Executive Compensation
Accounting for Income Taxes	(246,194,931)	-	-	(246,194,931)	-	FASB 109 - deferred tax liability primarily associated with plant related items previously flowed through due to regulation
Repair Deduction	(117,615,320)	-	-	(117,615,320)	-	Basis difference resulting from repair deduction versus depreciation used for ratemaking purposes - related to all functions
Subtotal - p275	**(1,456,093,645)**	**(78,501,105)**		**(1,377,504,742)**	**(87,798)**	
Less FASB 109 Above if not separately removed	(246,194,931)			(246,194,931)		
Less FASB 106 Above if not separately removed						
Total	**(1,209,898,714)**	**(78,501,105)**		**(1,131,309,811)**	**(87,798)**	

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 31,2011

A	B	C	D	E	F	G
ADIT-283	*Total*	Gas, Prod or Other Related	Only Transmission Related	Plant	Labor	
Fin 48	(17,958,042)	(17,958,042)	-	-	-	Uncertain Tax Positions - Assets/(Liabilities) not in rates
Securitization Regulatory Asset	1,137,456,772	1,137,456,772	-	-	-	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 Relatec
Environmental Cleanup Costs	19,635,923	19,635,923	-	-	-	Book estimate accrued and expensed, tax deduction when paid - Manufactured Gas Plant
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	(38,625,328)	-	-	(38,625,328)	-	New Jersey Corporate Income Tax - Plant Related- Contra Account of 190 NJCBT
Obsolete Material Write Ofl	5,751,926	5,751,926	-	-	-	Book accrued write-off, tax deduction when actually disposed of - Generation Relatec
Energy Cost Adjustment	(48,480,219)	(48,480,219)	-	-	-	Book deferral of Underrecovered Fuel Costs - Retail Relatec
Accelerated Acitivity Plan	(52,270,844)	(52,270,844)	-	-	-	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	(14,844,638)	-	-	-	(14,844,638)	Accelerated Amortization of Computer Software - General Plar
Loss on Reacquired Debt	(32,950,573)	-	-	(32,950,573)	-	Tax deduction when reacquired, booked amortizes to expens(
Additional Pension Deduction	(95,612,551)	(95,612,551)	-	-	0	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	(11,608,502)	-	-	-	(11,608,502)	Book estimate accrued and expensed, tax deduction when paid related to all employee
Repair Allowance-Reverse Amortizatior	(2,347,178)	(2,347,178)	-	-	-	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 - Genera
Decommissioning and Decontamination Costs	12,603,383	12,603,383	-	-	-	Payments to DOE - Generation Relatec
Emission Allowance Sales	2,547,897	2,547,897	-	-	-	Sales of Emission Allowances - Generation Relatec
Interest Expense Ajustment		-	-	-	-	Generation Related (Non-Utility Asset/Liability)
Capitalization of Study Costs	(2,009,586)	(2,009,586)	-	-	-	Generation Related (Non-Utility Asset/Liability)
Lightnet Agreeement - Audit Settlement		-	-	-	-	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 propert
Vacation Pay Adjustment	(3,663)	0	-	-	(3,663)	Book estimate accrued and expensed, tax deduction when paid relating to all employee
Purchase Power - Audit Settlement	848,012	848,012	-	-	-	Purchased Power Settlements - Generation Relatec
Crude Oil Refunds	1,570,058	1,570,058	-	-	-	Generation Related (Non-Utility Asset/Liability)
Peach Bottom Interim Fuel Storage	(852,372)	(852,372)	-	-	-	Interim Nuclear Fuel Storage Costs - Generation Relatec
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) - Federa	(42,858,665)	-	-	(42,858,665)	-	FASB 109 - deferred tax liability primarily non-plant related items previously flowed through due to regulatio
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 regulatio
Accounting for Income Taxes (FAS109) - Regulatory Requiremen	(200,681,760)	-	-	(200,681,760)	-	FASB 109 - gross-up
iPower (Deferred Project Costs)	(4,052,970)	(4,052,970)	-	-	-	Deferred Customer Information System Costs
Casualty Loss	(60,864,000)	-	-	(30,432,000)	(30,432,000)	Storm Related Loss
Subtotal - p277	**(1,121,748,590)**	**(713,863,354)**	**(1,781,312)**	**(349,077,988)**	**(57,025,936)**	
Less FASB 109 Above if not separately removed	(247,070,087)			(247,070,087)		
Less FASB 106 Above if not separately removed						
Total	**(874,678,503)**	**(713,863,354)**	**(1,781,312)**	**(102,007,901)**	**(57,025,936)**	

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

	Only Transmission Related	*Plant Related*	*Labor Related*	*Total ADIT*
ADIT- 282	0	(1,079,099,811)	(87,798)	
ADIT-283	(1,781,312)	(82,153,401)	(29,128,436)	
ADIT-190	1,617,015	(70,443,549)	7,819,143	
Subtotal	(164,297)	(1,231,696,761)	(21,397,091)	
Wages & Salary Allocator			13.6406%	
Net Plant Allocator		22.9497%		
End of Year ADIT	(164,297)	(282,670,292)	(2,918,698)	**(285,753,286)**

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

(34,571,573) < 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 taxe
Newark Center Renovations	10,804	-	-	-	10,804	Amort of Renovations of Newark Plaza - General Property
New Jersey Corporate Business Tax(NJCBT)	(74,735,672)	-	-	(74,735,672)	-	New Jersey Corporate Income Tax Plant Related- Contra Account of 283 NJCBT
NJCBT - Step Up Basis	150,802,340	150,802,340	-	-	-	New Jersey Corporate Income Tax for Utility - Gets return on but no return of prior book vs tax timing difference
ADIT - Real Estate Taxes	2,769,110	-	-	2,769,110	-	Book estimate accrued and expensed, tax deduction when paid related to plar
Gross Receipts & Franchise Tax(GRAFT)	756,443	756,443	-	-	-	Retail related
Market Transition Charge Revenue	51,871,037	51,871,037	-	-	-	Stranded cost recovery - generation relatec
Mine Closing Costs	1,357,594	1,357,594	-	-	-	Book estimate accrued and expensed, tax deduction when paid - Generation relate
FIN 47	11,354	11,354	-	-	-	Asset Retirement Obligation - Legal liability for environmental removal costs
Vacation Pay	2,995,169	-	-	-	2,995,169	Vacation pay earned and expensed for books, tax deduction when paid - employees in all function
OPEB	160,013,318	-	-	-	160,013,318	Fas 106 - Post Retirement Obligation, labor related
Deferred Dividend Equivalents	3,862,689	-	-	-	3,862,689	Book accrual of dividends on employee stock options affecting all functions
Deferred Compensation	462,421	-	-	-	462,421	Book estimate accrued and expensed, tax deduction when paid - employees in all function
ADIT - Interest/AFDC Debt	1,523,013	-	-	1,523,013	-	Capitalized Interest - Book vs Tax relates to all plant in all funtions
ADIT - Unallowable PIP Accrua	(792,552)	-	-	-	(792,552)	Book estimate accrued and expensed, tax deduction when paid - employees in all function
ADIT - Legal Fees	637,144	637,144	-	-	-	Book estimate accrued and expensed, tax deduction when paid - employees in all function
ADIT - Rev of 1985-1993 Settle Int Exp	(3,180,712)	(3,180,712)	-	-	-	Book estimate accrued and expensed, tax deduction when paid / audit settlement - Generation relate
ADIT - Interest on Dismantling & Decommissioning	(1,940,681)	(1,940,681)	-	-	-	Book estimate accrued and expensed, tax deduction when paid / audit settlement - Generation relate
ADIT - SETI Dissolution	60,619	60,619	-	-	-	Book estimate accrued and expensed, tax deduction when paid / audit settlement - Retail relate
Minimum Pension Liability	137,435	137,435	-	-	-	Associated with Pension Liability not in rates
FIN 48 Services Allocation	(649,220)	(649,220)	-	-	-	Uncertain Tax Positions - Assets/(Liabilities) not in rates
Bankruptcies $ Acfc	(5,845)	(5,845)	-	-	-	Book estimate accrued and expensed, tax deduction when paid - Generation Relate
Repair Allowance Deferred	(9,515,037)	(9,515,037)	-	-	-	Deferred recovery of lost repair allowance deductions-Retail Related
Fin Def. Energy competition Act CT	(4,062,958)	(4,062,958)	-	-	-	Restructuring Costs - Generation related
Def Tax Meter Equipment	201,647	201,647	-	-	-	Book estimate accrued and expensed, tax deduction when paid - Retail - Distribution Meter
Unrealized L/G Rabbi Trust	436,479	-	-	-	436,479	Book estimate accrued and expensed, tax deduction when paid for Executive Compensation
SECA Income Reversals Due to Reversals	(1,111,579)	(1,111,579)	-	-	-	Related to LSE SECA obligations - retai
Estimated Serverance Pay Accruals	844,133	-	-	-	844,133	Book estimate accrued and expensed, tax deduction when paid - employees in all function
Federal Taxes Deferred	23,030,494	-	-	23,030,494	-	Fas109 - deferred tax asset primarily associated with items previously flowed through due to regulatio
Federal Taxes Current	27,158,392	-	-	27,158,392	-	Fas109 - deferred tax asset primarily associated with items previously flowed through due to regulatio
Fed Taxes Reg Requirement	23,760,554	-	-	23,760,554	-	Fas109 - deferred tax asset primarily associated with items previously flowed through due to regulation
Subtotal - p234	**359,673,073**	**186,717,706**	**1,617,015**	**3,505,891**	**167,832,461**	
Less FASB 109 Above if not separately removed	73,949,440			73,949,440		
Less FASB 106 Above if not separately removed	160,013,318				160,013,318	
Total	**125,710,315**	**186,717,706**	**1,617,015**	**(70,443,549)**	**7,819,143**	

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 31,2010

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

A	B	C	D	E	F	G
ADIT- 282	*Total*	*Gas, Prod Or Other Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
Depreciation - Liberalized Depreciation	(915,650,440)	-	-	(915,650,440)	-	Basis difference resulting from accelerated tax depreciation versus depreciation used for ratemaking purposes - related to all functior
Depreciation - Non Utility Property	(87,501,105)	(87,501,105)	-	-	-	Inter-company gain on sale of non-regulated generation assets
Cost of Removal	(46,923,328)	-	-	(46,923,328)	-	Book estimate accrued and expensed, tax deduction when paid. Retail related - Component of Liberalized Depreciatic
FERC Normalization	(2,910,723)	-	-	(2,910,723)	-	Reverse South Georgia - Remaining Basis
Deffered Taxes on Rabbi Trust	(87,798)	-	-	-	(87,798)	Book estimate accrued and expensed, tax deduction when paid for Executive Compensatior
Accounting for Income Taxes	(244,194,931)	-	-	(244,194,931)	-	FASB 109 - deferred tax liability primarily associated with plant related items previously flowed through due to regulatio
Repair Deduction	(113,615,320)	-	-	(113,615,320)	-	Basis difference resulting from repair deduction versus depreciation used for ratemaking purposes - related to all function
Subtotal - p275	**(1,410,883,645)**	**(87,501,105)**		**(1,323,294,742)**	**(87,798)**	
Less FASB 109 Above if not separately removed	(244,194,931)			(244,194,931)		
Less FASB 106 Above if not separately removed						
Total	**(1,166,688,714)**	**(87,501,105)**		**(1,079,099,811)**	**(87,798)**	

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 31,2010

A	B	C	D	E	F	G
ADIT-283	*Total*	Gas, Prod or Other Related	Only Transmission Related	Plant	Labor	
Fin 48	(17,958,042)	(17,958,042)	-	-	-	Uncertain Tax Positions - Assets/(Liabilities) not in rates
Securitization Regulatory Asset	997,889,772	997,889,772	-	-	-	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	19,841,923	19,841,923	-	-	-	Book estimate accrued and expensed, tax deduction when paid - Manufactured Gas Plant
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	(42,489,328)	-	-	(42,489,328)	-	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	(51,245,219)	(51,245,219)	-	-	-	Book deferral of Underrecovered Fuel Costs - Retail Related
Accelerated Acitivity Plan	(40,838,844)	(40,838,844)	-	-	-	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	(12,286,638)	-	-	-	(12,286,638)	Accelerated Amortization of Computer Software - General Plan
Loss on Reacquired Debt	(34,571,573)	-	-	(34,571,573)	-	Tax deduction when reacquired, booked amortizes to expense
Additional Pension Deduction	(98,380,551)	(98,380,551)	-	-	-	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	(11,608,502)	-	-	-	(11,608,502)	Book estimate accrued and expensed, tax deduction when paid related to all employee
Repair Allowance-Reverse Amortization	(2,347,178)	(2,347,178)	-	-	-	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 - Genera
Decommissioning and Decontamination Costs	12,603,383	12,603,383	-	-	-	Payments to DOE - Generation Related
Emission Allowance Sales	2,547,897	2,547,897	-	-	-	Sales of Emission Allowances - Generation Related
Interest Expense Ajustment		-	-	-	-	Generation Related (Non-Utility Asset/Liability)
Capitalization of Study Costs	(2,009,586)	(2,009,586)	-	-	-	Generation Related (Non-Utility Asset/Liability)
Lightnet Agreeement - Audit Settlement		-	-	-	-	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 propert
Vacation Pay Adjustment	(3,663)	-	-	-	(3,663)	Book estimate accrued and expensed, tax deduction when paid relating to all employee
Purchase Power - Audit Settlement	848,012	848,012	-	-	-	Purchased Power Settlements - Generation Related
Crude Oil Refunds	1,570,058	1,570,058	-	-	-	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) - Federa	(42,858,665)	-	-	(42,858,665)	-	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 Requiremen	(200,681,760)	-	-	(200,681,760)	-	FASB 109 - gross-up
iPower (Deferred Project Costs)	(4,052,970)	(4,052,970)	-	-	-	Deferred Customer Information System
Casualty Loss	(10,185,000)	-	-	(5,092,500)	(5,092,500)	Storm Related Loss
Subtotal - p277	**(1,207,458,590)**	**(847,325,354)**	**(1,781,312)**	**(329,223,488)**	**(29,128,436)**	
Less FASB 109 Above if not separately removed	(247,070,087)	-	-	(247,070,087)		
Less FASB 106 Above if not separately removed						
Total	**(960,388,503)**	**(847,325,354)**	**(1,781,312)**	**(82,153,401)**	**(29,128,436)**	

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, 2011

	Other Taxes	*Page 263 Col (i)*	*Allocator*	*Allocated Amount*	
	Plant Related				
1	Real Estate	18,597,320			Attachment #5
2	***Total Plant Related***	18,597,320	N/A	7,765,813	
	Labor Related		***Wages & Salary Allocator***		
3	FICA	10,956,557			
4	Federal Unemployment Tax	87,196			
5	New Jersey Unemployment Tax	273,523			
6	New Jersey Workforce Development	242,857			
7					
8	***Total Labor Related***	11,560,133	13.6406%	1,576,875	
	Other Included		***Net Plant Allocator***		
9					
10					
11					
12					
13	***Total Other Included***	0	22.9497%	0	
14	***Total Included (Lines 8 + 14 + 19)***	**30,157,453**		**9,342,688**	
	Currently Excluded				
15	Corporate Business Tax				
16	TEFA	$ 93,922,733			
17	Use & Sales Tax				
18	Local Franchise Tax				
19	PA Corporate Income Tax				
20	Municipal Utility				
21	Public Utility Fund				
22	**Subtotal, Excluded**	93,922,733			
23	**Total, Included and Excluded (Line 20 + Line 28)**	124,080,186			
24	**Total Other Taxes from p114.14.g - Actual**	124,080,186			
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, 2011

	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		5,121,000
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		3,600,000
7	Professional Services (Note 2)		100,000
8	Revenues from Directly Assigned Transmission Facility Charges (Note 1)		22,476,000
9	Rent or Attachment Fees associated with Transmission Facilities (Note 2)		4,122,000
10	Gross Revenue Credits	(Sum Lines 1-9)	**35,935,000**
11	Less line 18	- line 18	(3,336,737)
12	Total Revenue Credits	line 10 + line 11	**32,598,264**
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	187,918,679
B	100 Basis Point increase in ROE			1.00%

Return Calculation

			Appendix A Line or Source Reference	
1	**Rate Base**		(Line 43 + Line 57)	1,335,968,391
2	**Long Term Interest**		p117.62.c through 67.c	195,974,631
3	**Preferred Dividends**	enter positive	p118.29.d	3,987,874
	Common Stock			
4	Proprietary Capital		Attachment 5	4,015,559,296
5	Less Accumulated Other Comprehensive Income Account 219		p112.15.c	3,524,080
6	Less Preferred Stock		(Line 106)	79,523,400
7	Less Account 216.1		Attachment 5	3,941,456
8	Common Stock		(Line 96 - 97 - 98 - 99)	3,928,570,361
	Capitalization			
9	Long Term Debt		Attachment 5	3,547,156,489
10	Less Loss on Reacquired Debt		Attachment 5	109,213,413
11	Plus Gain on Reacquired Debt		Attachment 5	0
12	Less ADIT associated with Gain or Loss		Attachment 5	36,995,999
13	Total Long Term Debt		(Line 101 - 102 + 103 - 104)	3,400,947,077
14	Preferred Stock		Attachment 5	79,523,400
15	Common Stock		(Line 100)	3,928,570,361
16	Total Capitalization		(Sum Lines 105 to 107)	7,409,040,838
17	Debt %	Total Long Term Debt	(Line 105 / Line 108)	45.9%
18	Preferred %	Preferred Stock	(Line 106 / Line 108)	1.1%
19	Common %	Common Stock	(Line 107 / Line 108)	53.0%
20	Debt Cost	Total Long Term Debt	(Line 94 / Line 105)	0.0576
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)	0.0265
24	Weighted Cost of Preferred	Preferred Stock	(Line 110 * Line 113)	0.0005
25	Weighted Cost of Common	Common Stock	(Line 111 * Line 114)	0.0672
26	**Rate of Return on Rate Base (ROR)**		**(Sum Lines 115 to 117)**	**0.0942**
27	**Investment Return = Rate Base * Rate of Return**		**(Line 58 * Line 118)**	**125,879,522**

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	-1,265,000
38	1/(1-T)		1 / (1 - Line 123)	169%
39	Net Plant Allocation Factor		(Line 18)	22.9497%
40	**ITC Adjustment Allocated to Transmission**		(Line 125 * Line 126 * Line 127)	**-490,809**
41	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		62,529,966
42	**Total Income Taxes**			**62,039,157**

Public Service Electric and Gas Company

ATTACHMENT H-10A

Attachment 5 - Cost Support - December 31, 2011

Electric / Non-electric Cost Support

				Previous Year	Current Year - 2011 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	8,807,983,182	8,852,733,871	8,890,929,347	8,928,061,240	9,021,777,977	9,059,526,438	9,165,260,608	9,216,072,246	9,242,487,923	9,280,757,139	9,316,159,230	9,353,524,948	9,502,944,301	9,126,016,804	
7	Common Plant in Service - Electric	(Note B)	p356	110,189,604	112,311,865	113,027,398	113,742,931	114,457,883	115,172,835	115,887,786	116,600,898	117,315,849	118,030,801	118,491,887	118,992,824	118,607,036	115,602,277	
9	Accumulated Depreciation (Total Electric Plant)	(Note B & J)	p219.29c	2,619,713,874	2,631,664,340	2,644,070,067	2,656,362,804	2,669,456,785	2,682,882,488	2,697,161,713	2,708,848,829	2,722,630,384	2,735,283,458	2,748,499,087	2,761,685,677	2,775,949,239	2,696,477,596	
10	Accumulated Intangible Amortization	(Note B)	p200.21c	49,729	64,787	79,845	94,903	109,961	125,019	140,077	155,135	170,193	185,251	200,308	215,366	230,424	140,077	
11	Accumulated Common Plant Depreciation - Electric	(Note B & J)	p356	31,537,644	32,225,783	32,944,515	33,670,568	34,403,350	35,143,443	35,890,848	36,643,701	37,405,706	38,175,022	38,692,702	39,254,771	38,892,092	35,760,011	
12	Accumulated Common Amortization - Electric	(Note B)	p356	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
	Plant In Service																	
19	Transmission Plant in Service	(Note B)	p207.58.g	2,138,762,276	2,141,963,446	2,145,326,968	2,151,101,255	2,156,800,434	2,166,657,022	2,233,337,839	2,239,593,985	2,240,982,218	2,247,771,691	2,257,037,071	2,274,109,325	2,396,186,867	2,214,586,954	
20	General	(Note B)	p207.99.g	218,628,843	224,358,307	224,231,294	224,104,280	223,977,267	223,850,254	223,723,240	220,390,980	220,263,967	220,136,953	220,435,341	220,825,327	221,215,314	222,010,874	
21	Intangible - Electric	(Note B)	p205.5.g	903,473	903,473	903,473	903,473	903,473	903,473	903,473	903,473	903,473	903,473	903,473	903,473	903,473	903,473	
22	Common Plant in Service - Electric	(Note B)	p356	110,189,604	112,311,865	113,027,398	113,742,931	114,457,883	115,172,835	115,887,786	116,600,898	117,315,849	118,030,801	118,491,887	118,992,824	118,607,036	115,602,277	
24	General Plant Account 397 -- Communications	(Note B)	p207.94g	28,701,984	28,562,151	28,422,317	28,282,484	28,142,651	28,002,817	27,862,984	27,723,151	27,583,317	27,443,484	27,303,651	27,163,817	27,023,984	27,862,984	
25	Common Plant Account 397 -- Communications	(Note B)	p356	5,859,190	5,859,132	5,858,317	5,857,502	5,856,687	5,855,872	5,855,057	5,854,242	5,853,427	5,852,611	5,851,796	5,850,981	5,850,166	5,854,998	
29	Account No. 397 Directly Assigned to Transmission	(Note B)	Company Records	17,539,684	17,539,684	17,539,684	17,539,684	17,539,684	17,539,684	17,539,684	17,539,684	17,539,684	17,539,684	17,539,684	17,539,684	17,539,684	17,539,684	
	Accumulated Depreciation																	
32	Transmission Accumulated Depreciation	(Note B & J)	p219.25.c	743,070,086	745,157,735	747,236,264	749,207,129	751,593,869	753,631,057	756,391,577	759,444,324	761,429,937	762,265,623	763,564,586	764,695,747	766,892,456	755,736,953	
33	Accumulated General Depreciation	(Note B & J)	p219.28.b	94,914,243	94,822,987	95,054,179	95,286,299	95,519,347	95,753,321	95,988,223	93,042,637	93,241,224	93,440,739	93,554,398	93,766,740	93,901,817	94,483,550	
1	Accumulated Common Plant Depreciation - Electric	(Note B & J)	p356	31,537,644	32,225,783	32,944,515	33,670,568	34,403,350	35,143,443	35,890,848	36,643,701	37,405,706	38,175,022	38,692,702	39,254,771	38,892,092	35,760,011	
35	Amount of General Depreciation Associated with Acct. 397	(Note B & J)	Company Records	14,103,870	14,250,823	14,395,847	14,539,698	14,682,378	14,823,885	14,964,220	15,103,384	15,241,375	15,378,194	15,513,841	15,648,316	15,781,619	14,955,958	
41	Acc. Deprec. Acct. 397 Directly Assigned to Transmission	(Note B & J)	Company Records	7,494,937	7,641,101	7,787,265	7,933,429	8,079,593	8,225,757	8,371,921	8,518,085	8,664,249	8,810,413	8,956,577	9,102,741	9,248,905	8,371,921	

Wages & Salary

Line #s	**Descriptions**	**Notes**	**Page #'s & Instructions**	**End of Year**
2	Total Wage Expense	(Note A)	p354.28b	149,963,118
3	Total A&G Wages Expense	(Note A)	p354.27b	3,751,396
1	Transmission Wages		p354.21b	19,944,198

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	5,357,746	5,357,746	5,357,746
46	Transmission Only			1,778,167	1,778,167	1,778,167

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	42,749,000	42,749,000	42,749,000	42,749,000	13.641%	5,831,232

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	0	0	-
51	Transmission Materials & Supplies	(Note N & Q))	p227.8.b,c	3,514,264	3,514,264	3,514,264

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	52,212,698
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

Adjustments to A & G Expense

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
62	Total A&G Expenses		p323.197b	199,116,808
63	Fixed PBOP expense	(Note J)	Company Records	77,745,482
64	Actual PBOP expense	(Note O)	Company Records	52,639,903

Regulatory Expense Related to Transmission Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year	Transmission Related
	Allocated General & Common Expenses				
66	Regulatory Commission Exp Account 928	(Note E & O)	p323.189b	11,425,582	0
	Directly Assigned A&G				
72	Regulatory Commission Exp Account 928	(Note G & O)	p351.11-13h	620,834	620,834

General & Common Expenses

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year	EPRI Dues
68	Less EPRI Dues	(Note D & O)	p352-353	0	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	1,919,371	0	1,919,371

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	1,919,371	0	1,919,371

Depreciation Expense

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
	Depreciation Expense			
81	Depreciation-Transmission	(Note J & O)	p336.7.f	51,290,500
82	Depreciation-General & Common	(Note J & O)	p336.10&11.f	26,429,391
83	Depreciation-General Expense Associated with Acct. 397	(Note J & O)	Company Records	3,364,772
85	Depreciation-Intangible	(Note A & O)	p336.1.f	5,044,689
89	Transmission Depreciation Expense for Acct. 397	(Note J & O)	Company Records	1,753,968

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	18,597,320	7,765,813	10,831,507

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 identified to a particular type of property and are labeled. This is the breakout of transmission real estate taxes from total

Return \ Capitalization

Line #s	Descriptions	Notes	Page #'s & Instructions	2008 End of Year	2009 End of Year	Average
96	Proprietary Capital	(Note P)	p112.16.c,d	3,729,006,276	4,302,112,315	4,015,559,296
97	Accumulated Other Comprehensive Income Account 219	(Note P)	p112.15.c,d	1,942,117	5,106,042	3,524,080
99	Account 216.1	(Note P)	p119.53.c&d	4,295,618	3,587,293	3,941,456
101	Long Term Debt	(Note P)	p112.18.c,d thru 23.c,d	3,523,706,225	3,570,606,752	3,547,156,489
102	Loss on Reacquired Debt	(Note P)	p111.81.c,d	112,096,023	106,330,803	109,213,413
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)	37,671,575	36,320,422	36,995,999
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					
				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 Credi	(Note O)	p266.8.f	1,265,000

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 & Instructions	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 & Instructions	1 CP Peak
	Network Zonal Service Rate			Enter
165	1 CP Peak	(Note L)	PJM Data	10,761.4

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6 - True-up Adjustment for Network Integration Transmission Service - December 31, 2011

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.	231,567,232	
B	ATRR based on projected costs included for the previous calendar year but excludes the true-up adjustment.	227,983,090	
C	Difference (A-B)	3,584,143	<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	1.07026	
E	True-up Adjustment (C*D)	3,835,973	

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	0.3800%
February	Year 1	0.3400%
March	Year 1	0.3800%
April	Year 1	0.2800%
May	Year 1	0.2900%
June	Year 1	0.2800%
July	Year 1	0.2800%
August	Year 1	0.2800%
September	Year 1	0.2700%
October	Year 1	0.2700%
November	Year 1	0.2300%
December	Year 1	0.2800%
January	Year 2	0.2300%
February	Year 2	0.2300%
March	Year 2	0.2800%
April	Year 2	0.2700%
May	Year 2	0.2800%
June	Year 2	0.2700%
July	Year 2	0.2800%
August	Year 2	0.2800%
September	Year 2	0.2700%
Average Interest Rate		0.2833%

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2011

Estimated Additions - 2011

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	Other Projects PIS (Monthly additions)	Reconductor South Mahwah 345 kV J-3410 Circuit (B1017) (monthly additiions)	Reconductor South Mahwah 345 kV K-3411 Circuit (B1018) (monthly additiions)	Susquehanna Roseland Breakers (monthly additions)				Susquehanna Roseland (B0489) >= 500KV (monthly additions)	Susquehanna Roseland (B0489.4)< 500KV (monthly additions)
		(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	CWIP	CWIP
Dec				2,662,585				82,971,548	8,615,789
Jan	2,136,137			1,065,034				3,332,091	-
Feb	1,765,971			1,597,551				3,386,466	-
Mar	5,241,770			532,517				5,715,992	-
Apr	4,634,145			1,065,034				3,983,634	-
May	9,324,071			532,517				3,054,938	-
Jun	47,248,299	18,900,000		532,518				2,683,840	-
Jul	6,256,146							3,514,067	-
Aug	1,388,233							3,527,989	-
Sep	6,789,473							6,838,989	-
Oct	9,265,381							6,336,634	496,202
Nov	17,072,253							4,465,869	12,884,444
Dec	103,563,542		18,514,000					1,025,525	12,662,877
Total	**214,685,421**	**18,900,000**	**18,514,000**	**7,987,756**				**130,837,583**	**34,659,312**

	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
	Other Projects PIS (monthly balances)	Reconductor South Mahwah 345 kV J-3410 Circuit (B1017) (monthly balances)	Reconductor South Mahwah 345 kV K-3411 Circuit (B1018) (monthly balances)	Susquehanna Roseland Breakers (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	-	-		2,662,585				82,971,548	8,615,789
Jan	2,136,137	-	-	3,727,619				86,303,639	8,615,789
Feb	3,902,108	-	-	5,325,170				89,690,105	8,615,789
Mar	9,143,878	-	-	5,857,687				95,406,097	8,615,789
Apr	13,778,023	-	-	6,922,721				99,389,731	8,615,789
May	23,102,094	-	-	7,455,238				102,444,669	8,615,789
Jun	70,350,393	18,900,000	-	7,987,756				105,128,509	8,615,789
Jul	76,606,539	18,900,000	-	7,987,756				108,642,577	8,615,789
Aug	77,994,772	18,900,000	-	7,987,756				112,170,565	8,615,789
Sep	84,784,245	18,900,000	-	7,987,756				119,009,555	8,615,789
Oct	94,049,626	18,900,000	-	7,987,756				125,346,189	9,111,991
Nov	111,121,879	18,900,000	-	7,987,756				129,812,058	21,996,435
Dec	214,685,421	18,900,000	18,514,000	7,987,756				130,837,583	34,659,312
Total	**781,655,115**	**132,300,000**	**18,514,000**	**87,865,312**				**1,387,152,826**	**151,925,630**
Average 13 Month Balance	**60,127,317**	**10,176,923**	**1,424,154**	**6,758,870**					
Average 13 Month in service	**3.64**	**7.00**	**1.00**	**11.00**				**10.60**	**4.38**
13 Month Average CWIP to Appendix A, line 45								**106,704,064**	**11,686,587**

Estimated Transmission Enhancement Charges (Before True-Up) - 2011

Total Projects	Branchburg (B0130)	Kittany (B0134)	Essex Aldene (B0145)	New Freedom Trans.(B0411)	New Freedom Loop (B0498)	Metuchen Transformer (B0161)	Branchburg-Flagtown-Sommerville (B0169)	Flagtown Sommerville Bridgewater (B0170)	Roseland Transformer (B0274)	Wave Trap Branchburg (B0172.2)	Susquehanna Roseland (B0489) >= 500KV CWIP	Susquehanna Roseland (B0489.4) < 500KV CWIP	Reconductor Hudson - South Waterfront (B0813)	Reconductor South Mahwah 345 kV J-3410 Circuit (B1017)	Reconductor South Mahwah 345 kV K-3411 Circuit (B1018)	Susquehanna Roseland Breakers
78,044,417	3,959,937	1,685,576	16,885,923	4,354,742	6,493,054	5,225,977	4,265,317	1,338,200	4,566,222	7,065	21,032,231	2,303,520	2,157,553	2,031,996	268,707	1,468,395

Actual Transmission Enhancement Charges - 2009

Total Projects	Branchburg (B0130)	Kittany (B0134)	Essex Aldene (B0145)	New Freedom Trans.(B0411)	New Freedom Loop (B0498)	Metuchen Transformer (B0161)	Branchburg-Flagtown-Somerville (B0169)	Flagtown-Somerville-Bridgewater (B0170)	Roseland Transformer (B0274)	Wave Trap Branchburg (B0172.2)	Susquehanna Roseland (B0489) >= 500KV CWIP	Susquehanna Roseland (B0489.4) < 500KV CWIP
51,588,883	4,523,234	1,828,696	19,618,517	4,973,254	6,292,837	2,831,673	2,302,423	1,621,657	2,634,066	8,379	4,120,411	833,737

True Up by Project (without interest) - 2009

Total Projects	Branchburg (B0130)	Kittany (B0134)	Essex Aldene (B0145)	New Freedom Trans.(B0411)	New Freedom Loop (B0498)	Metuchen Transformer (B0161)	Branchburg-Flagtown-Somerville (B0169)	Flagtown-Somerville-Bridgewater (B0170)	Roseland Transformer (B0274)	Wave Trap Branchburg (B0172.2)	Susquehanna Roseland (B0489) >= 500KV CWIP	Susquehanna Roseland (B0489.4) < 500KV CWIP
(3,073,579)	72,787	(80,753)	628,394	80,638	(825,214)	(886,732)	(749,732)	126,057	(734,765)	8,379	(827,148)	114,511

Interest	1.07026	1.07026	1.07026	1.07026	1.07026	1.07026	1.07026	1.07026	1.07026	1.07026	1.07026	1.07026

True Up by Project (with interest) - 2009

Total Projects	Branchburg (B0130)	Kittany (B0134)	Essex Aldene (B0145)	New Freedom Trans.(B0411)	New Freedom Loop (B0498)	Metuchen Transformer (B0161)	Branchburg-Flagtown-Somerville (B0169)	Flagtown-Somerville-Bridgewater (B0170)	Roseland Transformer (B0274)	Wave Trap Branchburg (B0172.2)	Susquehanna Roseland (B0489) >= 500KV CWIP	Susquehanna Roseland (B0489.4) < 500KV CWIP
(3,289,537)	77,901	(86,426)	672,546	86,304	(883,196)	(949,036)	(802,410)	134,914	(786,391)	8,967	(885,266)	122,557

Estimated Transmission Enhancement Charges (After True-Up) - 2011

Total Projects	Branchburg (B0130)	Kittany (B0134)	Essex Aldene (B0145)	New Freedom Trans.(B0411)	New Freedom Loop (B0498)	Metuchen Transformer (B0161)	Branchburg-Flagtown-Sommerville (B0169)	Flagtown Sommerville Bridgewater (B0170)	Roseland Transformer (B0274)	Wave Trap Branchburg (B0172.2)	Susquehanna Roseland (B0489) >= 500KV CWIP	Susquehanna Roseland (B0489.4) < 500KV CWIP	Reconductor Hudson - South Waterfront (B0813)	Reconductor South Mahwah 345 kV J-3410 Circuit (B1017)	Reconductor South Mahwah 345 kV K-3411 Circuit (B1018)	Susquehanna Roseland Breakers
74,754,880	4,037,838	1,599,150	17,558,470	4,441,046	5,609,858	4,276,941	3,462,908	1,473,114	3,779,831	16,033	20,146,965	2,426,077	2,157,553	2,031,996	268,707	1,468,395

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2011

	Actual Additions - 2011								
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	Other Projects PIS (Monthly additions)	0 (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 - 2011								
	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)
	Other Projects PIS (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									
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, 2011

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	18.6846%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	19.5056%
5	C		Line B less Line A	0.8209%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	6.6243%

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)**	**Kittatinny (B0134)**	**Essex Aldene (B0145)**	**New Freedom Trans.(B0411)**
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12 (Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life	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
14	Input the allowed increase in ROE	Increased ROE (Basis Points)	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	18.6846%	18.6846%	18.6846%	18.6846%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project	18.6846%	18.6846%	18.6846%	18.6846%
17	in Service Account 101 or 106 if not yet classified - End of year balance	Investment	20,680,597	8,069,022	86,565,629	22,188,863
18	Line 17 divided by line 12	Annual Depreciation Exp	492,395	192,120	2,061,086	528,306
19	depreciation expense from Attachment 6		13.00	13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)		2006	2007	2007	2007

21		**Invest Yr**	**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
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
28	W 11.68 % ROE	2009	19,203,412	492,395	4,523,234	7,796,853	192,120	1,828,696	83,645,756	2,061,086	19,618,517	21,176,276	528,306	4,973,254
29	W Increased ROE	2009	19,203,412	492,395	4,523,234	7,796,853	192,120	1,828,696	83,645,756	2,061,086	19,618,517	21,176,276	528,306	4,973,254
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	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
32	W 11.68 % ROE	2011	18,558,240	492,395	3,959,937	7,992,960	192,120	1,685,576	79,342,332	2,061,086	16,885,923	20,479,035	528,306	4,354,742
33	W Increased ROE	2011	18,558,240	492,395	3,959,937	7,992,960	192,120	1,685,576	79,342,332	2,061,086	16,885,923	20,479,035	528,306	4,354,742

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2011

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	18.6846%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	19.5056%
5	C		Line B less Line A	0.8209%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	6.6243%

8 **The FCR resulting from Formula in a give**

9 **Therefore actual revenues collected in a**

				New Freedom Loop (B0498)	Metuchen Transformer (B0161)	Branchburg-Flagtown-Somerville (B0169)	Flagtown Somerville Bridgewater (B0170)
10		Details					
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42.00	42.00	42	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
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		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		18.6846%	18.6846%	18.6846%	18.6846%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		18.6846%	18.6846%	18.6846%	18.6846%
17	in Service Account 101 or 106 if not yet classified - End of year balance	Investment		27,005,442	25,789,958	15,773,869	6,961,495
18	Line 17 divided by line 12	Annual Depreciation Exp		642,987	614,047	375,568	165,750
19	depreciation expense from Attachment 6			13.00	13.00	13.00	8.12
20	Year placed in Service (0 if CWIP)			2008	2009	2009	2008

21		Invest Yr	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	24,921,237	88,646	837,584							6,961,495	25,372	239,734
27	W Increased ROE	2008	24,921,237	88,646	837,584							6,961,495	25,372	239,734
28	W 11.68 % ROE	2009	26,916,602	642,982	6,292,837	19,700,217	288,478	2,831,673	15,773,880	234,561	2,302,423	6,936,122	165,750	1,621,657
29	W Increased ROE	2009	26,916,602	642,982	6,292,837	19,700,217	288,478	2,831,673	15,773,880	234,561	2,302,423	6,936,122	165,750	1,621,657
30	W 11.68 % ROE	2010	31,952,371	642,891	6,767,186	25,280,258	597,267	5,442,721	21,361,116	543,231	4,637,505	6,440,689	165,750	1,400,234
31	W Increased ROE	2010	31,952,371	642,891	6,767,186	25,280,258	597,267	5,442,721	21,361,116	543,231	4,637,505	6,440,689	165,750	1,400,234
32	W 11.68 % ROE	2011	31,309,481	642,987	6,493,054	24,682,991	614,047	5,225,977	20,817,885	375,568	4,265,317	6,274,940	165,750	1,338,200
33	W Increased ROE	2011	31,309,481	642,987	6,493,054	24,682,991	614,047	5,225,977	20,817,885	375,568	4,265,317	6,274,940	165,750	1,338,200

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2011

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	18.6846%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	19.5056%
5	C		Line B less Line A	0.8209%

6 **FCR if a CIAC**

7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	6.6243%

8 **The FCR resulting from Formula in a give**

9 **Therefore actual revenues collected in a**

		Details		**Roseland Transformers (B0274)**	**Wave Trap Branchburg (B0172.2)**	**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	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	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		18.6846%	18.6846%	18.6846%	18.6846%	18.6846%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		18.6846%	18.6846%	19.7108%	19.7108%	18.6846%
17	in Service Account 101 or 106 if not yet classified - End of year balance	Investment		21,065,727	29,460	130,837,583	34,659,312	8,138,000
18	Line 17 divided by line 12	Annual Depreciation Exp		501,565	701			193,762
19	depreciation expense from Attachment 6			13.00	13.00	10.60	4.38	2.84
20	Year placed in Service (0 if CWIP)			2009	2008	2014	2014	2010

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				36,369	577	5,114	8,927,082		819,421						
27	W Increased ROE	2008				36,369	577	5,114	8,927,082		858,682						
28	W 11.68 % ROE	2009	21,092,458	268,347	2,634,066	35,792	866	8,379	33,993,795		3,927,226	8,601,534		794,647			
29	W Increased ROE	2009	21,092,458	268,347	2,634,066	35,792	866	8,379	33,993,795		4,120,411	8,601,534		833,737			
30	W 11.68 % ROE	2010	22,256,919	502,926	4,768,898	34,926	866	7,560	137,675,026		15,364,960	24,948,450		2,136,620	10,560,000	49,817	450,848
31	W Increased ROE	2010	22,256,919	502,926	4,768,898	34,926	866	7,560	137,675,026		16,186,705	24,948,450		2,250,890	10,560,000	49,817	450,848
32	W 11.68 % ROE	2011	21,753,993	501,565	4,566,222	34,060	701	7,065	130,837,583		19,937,281	34,659,312		2,183,598	10,510,183	193,762	2,157,553
33	W Increased ROE	2011	21,753,993	501,565	4,566,222	34,060	701	7,065	130,837,583		21,032,231	34,659,312		2,303,520	10,510,183	193,762	2,157,553

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2011

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	18.6846%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	19.5056%
5	C		Line B less Line A	0.8209%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	6.6243%

8 **The FCR resulting from Formula in a give**
9 **Therefore actual revenues collected in a**

10		Details		**Reconductor South Mahwah J-3410 Circuit (B1017)**			**Reconductor South Mahwah K-3410 Circuit (B1018)**			**Susquehanna Roseland Breakers**						
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)		0			0			125						
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		18.6846%			18.6846%			18.6846%						
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		18.6846%			18.6846%			19.7108%						
17	in Service Account 101 or 106 if not yet classified - End of year balance	Investment		18,900,000			18,514,000			7,987,756						
18	Line 17 divided by line 12	Annual Depreciation Exp		450,000			440,810			190,185						
19	depreciation expense from Attachment 6			7.00			1.00			11.00						
20	Year placed in Service (0 if CWIP)			2011			2011			2011						
21			**Invest Yr**	**Ending**	**Depreciation**	**Revenue**	**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										$ 32,351,499		$ 32,351,499	
27		W Increased ROE	2008										$ 32,390,760	$ 32,390,760		$ 39,261
28		W 11.68 % ROE	2009										$ 51,356,608		$ 51,356,608	
29		W Increased ROE	2009										$ 51,588,883	$ 51,588,883		$ 232,275
30		W 11.68 % ROE	2010										$ 69,099,713		$ 69,099,713	
31		W Increased ROE	2010										$ 70,035,729	$ 70,035,729		$ 936,016
32		W 11.68 % ROE	2011	18,900,000	242,308	2,031,996	18,514,000	33,908	268,707	7,987,756	160,925	1,399,039	$ 76,760,188		$ 76,760,188	$ -
33		W Increased ROE	2011	18,900,000	242,308	2,031,996	18,514,000	33,908	268,707	7,987,756	160,925	1,468,395	$ 78,044,417	$ 78,044,417		$ 1,284,229

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, 2011

Required Transmission Enhancements

Upgrade ID	RTEP Baseline Project Description	Estimated/Actual Project Cost (thru 2011) *	Anticipated / Actual In-Service Date *
b0130	Replace all derated Branchburg 500/230 kv transformers	$ 20,680,597	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	$ 29,460	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	$ 27,005,442	Feb-09
b0161	Install 230-138kV transformer at Metuchen substation	$ 25,789,958	May-09
b0169	Build a new 230 kV section from Branchburg - Flagtown and move the Flagtown - Somerville 230 kV circuit to the new section	$ 15,773,869	May-09
b0274	Replace both 230/138 kV transformers at Roseland	$ 21,065,727	May-09
b0489.5-.9	Susquehanna Roseland Breakers	$ 7,987,756	Nov-10
b0813	Reconductor Hudson - South Waterfront 230kV circuit	$ 8,138,000	Dec-10
b1017	Reconductor South Mahwah 345 kV J-3410 Circuit	$ 18,900,000	Jun-11
b1018	Reconductor South Mahwah 345 kV K-3411 Circuit	$ 18,514,000	Dec-11
b0489.4	Build new 500 kV transmission facilities from Pennsylvania - New Jersey border at Bushkill to Roseland (Below 500 kV elements of the project)	$ 34,659,312	Jun-14
b0489	Build new 500 kV transmission facilities from Pennsylvania - New Jersey border at Bushkill to Roseland (500kV and above elements of the project)	$ 130,837,583	Jun-15

**** May vary from original PJM Data due to updated information.***

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon the official service list in accordance with the requirement of Rule 2010 of the Commission's Rules of Practice.

Dated at Newark, New Jersey, this 15th day of October 2010.

James E. Wrynn
James E. Wrynn
Paralegal