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PSEG
Services Corporation

VIA ELECTRONIC MAIL & OVERNIGHT MAIL

December 9, 2016

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, 2014
-and-
In the Matter of the Provision of
Basic Generation Service for the Period Beginning June 1, 2015
-and-
In the Matter of the Provision of
Basic Generation Service for the Period Beginning June 1, 2016

Docket Nos. EO03050394, ER13050378, ER14040370, ER15040482
++
Compliance Tariff Filing Reflecting Changes to Schedule 12 Charges in PJM Open Access
Transmission Tariff Docket No. _______________

Irene Kim Asbury, Esquire
Secretary of the Board
Board of Public Utilities
44 South Clinton Ave.
3rd Floor, Suite 314
Trenton, New Jersey 08625-0350

Dear Secretary Asbury:

Enclosed for filing on behalf of Jersey Central Power & Light Company ("JCP&L"), Atlantic City Electric Company ("ACE"), Public Service Electric and Gas Company ("PSE&G"), and Rockland Electric Company ("RECO") (collectively, the "EDCs"), enclosed please find an original and ten copies of tariff sheets and supporting exhibits that reflect changes to the PJM Open Access Transmission Tariff ("OATT") made in response to the annual formula rate update filings made by

Potomac-Appalachian Transmission Highline, L.L.C. (“PATH”) in Federal Energy Regulatory Commission (“FERC”) Docket No. ER08-386-000, Virginia Electric and Power Company (“VEPCo”) in FERC Docket No. ER-08-92-000 and by PSE&G in FERC Docket No. ER09-1257-000.

Background

In its Orders dated October 22, 2003 (BPU Docket No. EO03050394) and October 22, 2004 (BPU Docket No. EO04040288), the Board of Public Utilities (“Board”) authorized the EDCs to recover FERC-approved changes in firm transmission service-related charges. The Board has also authorized recovery of FERC-approved changes in firm transmission service-related charges in subsequent orders approving the Basic Generation Service (“BGS”) supply procurement process and the associated Supplier Master Agreement (“SMA”). In the Board Order dated July 29, 2016 in BPU Docket No. ER16060527, the Board again concluded that such a "pass through" of FERC-approved transmission rate changes was appropriate.

The EDCs' pro-forma tariff sheets, included as Attachment 2a (PSE&G), Attachment 3a (JCP&L), Attachment 4a (ACE), and Attachment 5a (RECO), propose effective dates of January 1, 2017, and specifically reflect changes to BGS rates applicable to Basic Generation Service – Residential Small Commercial Pricing (“BGS-RSCP”), and Commercial and Industrial Energy Pricing ("BGS-CIEP") customers resulting from the PATH, PSE&G, and VEPCo annual formula rate updates filed with FERC on or about September 1, 2016, October 17, 2016, and September 15, 2016, respectively. The specific additional PJM transmission charges related to the PATH, PSE&G, and VEPCo filings are found in Schedule 12 of the PJM OATT. On August 5, 2016, PJM updated its Schedule 12 Transmission Enhancement Worksheet, which, along with Schedule 12 of the PJM OATT, is utilized in developing this filing and incorporates the formula rate updates referenced herein. Because BGS suppliers will begin paying these increased transmission charges in January 2017, the EDCs request a waiver of the 30-day filing requirement.

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

The EDCs respectfully request approval to implement these revised tariff rates effective January 1, 2017. In support of this request, the EDCs have included pro-forma tariff sheets as noted above. The BGS rates have been modified in accordance with the Board-approved methodology contained in each EDC's Company-Specific Addendum in the above-referenced BGS proceedings and in conformance with each EDC's Board-approved BGS tariff sheets.

The determinants for calculation of the PJM charges are set forth in Schedule 12 of the PJM OATT and on the Formula Rates page of the PJM website. 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/billing-settlements-and-credit/formula-rates.aspx.

Attachment 1 shows the derivation of the PSE&G Network Integration Transmission Service Charge. The translation of the transmission zone rate impact to the BGS rates of each of the EDCs, assuming implementation on January 1, 2017, is included as Attachments 2, 3, 4, and 5 for PSE&G, JCP&L, ACE, and RECO, respectively. Attachment 6 shows the cost impact for the January through December 2017 period for each of the EDCs. These costs were allocated to the various transmission zones using the cost information from the formula rates for the PATH, PSE&G, and VEPCo projects posted on the PJM website. Attachment 7 provides excerpts of the Schedule 12 OATT indicating responsible share of projects. Attachments 8, 9, and 10 provide the formula rate updates for PATH, VEPCo, and PSE&G, respectively.

The EDCs also request that 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, 2017. Suppliers will be compensated subject to the terms and conditions of the applicable SMAs. Any differences between payments to BGS-RSCP and BGS-CIEP Suppliers and charges to customers will flow through BGS Reconciliation Charges.

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

We thank the Board for all courtesies extended.

Respectfully submitted,

Attachments

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

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
BGS TRANSMISSION ENHANCEMENT CHARGE
BPU Docket No.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
BGS TRANSMISSION ENHANCEMENT CHARGE
BPU Docket No.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
BGS TRANSMISSION ENHANCEMENT CHARGE
BPU Docket No.

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Attachment 1

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

Attachment 1 - PSE&G Network Integration Service Calculation.

Derived Network Integration Service Rate Applicable to PSE&G customers - Effective January 1, 2017 through December 31, 2017

Line #	Description	Rate			Source
(1)	Transmission Service Annual Revenue Requirement	$	1,185,164,918.44		Page 4 of Attachment 10 - Line 164
(2)	Total Schedule 12 TEC Included in above	$	(483,133,849.00)		Attachment 6a Column (a)
(3)	PSE&G Customer Share of Schedule 12 TEC	$	191,993,249.06		Attachment 6a Column (h)
(4)	Total Transmission Costs Borne by PSE&G customers	$	894,024,318.49		=(1) +(2) +(3)
(5)	2017 PSE&G Network Service Peak		9,800.3	MW	Page 4 of Attachment 10 - -Line 165
(6)	2017 Derived Network Integration Transmission Service Rate	$	91,224.18	per MW-year	
	Resulting 2017 BGS Firm Transmission Service Supplier Rate	$	249.93	per MW-day	= (6)/365

Attachment 2 – PSE&G Tariffs and Rate Translation

Attachment 2a
Pro-forma PSE&G Tariff Sheets

Attachment 2b
PSE&G Translation of NITS Charge into
Customer Rates

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

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

Attachment 2a
Pro-forma PSE&G Tariff Sheets

BASIC GENERATION SERVICE – RESIDENTIAL SMALL COMMERCIAL PRICING (BGS-RSCP) ELECTRIC SUPPLY CHARGES

APPLICABLE TO:

Default electric supply service for Rate Schedules RS, RHS, RLM, WH, WHS, HS, BPL, BPL-POF, PSAL, GLP and LPL-Secondary (less than 500 kilowatts).

BGS ENERGY CHARGES:

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

Charges per kilowatthour:

	For usage in each of the months of October through May		For usage in each of the months of June through September	
Rate Schedule	Charges	Charges Including SUT	Charges	Charges Including SUT
RS – first 600 kWh	$0.117493	$0.125571	$0.119322	$0.127525
RS – in excess of 600 kWh	0.117493	0.125571	0.128430	0.137260
RHS – first 600 kWh	0.089878	0.096057	0.086286	0.092218
RHS – in excess of 600 kWh	0.089878	0.096057	0.098465	0.105234
RLM On-Peak	0.204958	0.219049	0.219396	0.234479
RLM Off-Peak	0.053331	0.056998	0.050248	0.053703
WH	0.054613	0.058368	0.053331	0.056998
WHS	0.054808	0.058576	0.053437	0.057111
HS	0.094585	0.101088	0.097987	0.104724
BPL	0.051584	0.055130	0.047370	0.050627
BPL-POF	0.051584	0.055130	0.047370	0.050627
PSAL	0.051584	0.055130	0.047370	0.050627

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

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

BASIC GENERATION SERVICE – RESIDENTIAL SMALL COMMERCIAL PRICING (BGS-RSCP)
ELECTRIC SUPPLY CHARGES
(Continued)

BGS CAPACITY CHARGES:

Applicable to Rate Schedules GLP and LPL-Sec.

Charges per kilowatt of Generation Obligation:

Charge applicable in the months of June through September	$6.7319
Charge including New Jersey Sales and Use Tax (SUT)	$7.2031
Charge applicable in the months of October through May	$6.7319
Charge including New Jersey Sales and Use Tax (SUT)	$7.2031

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

BGS TRANSMISSION CHARGES

Applicable to Rate Schedules GLP and LPL-Sec.

Charges per kilowatt of Transmission Obligation:

Currently effective Annual Transmission Rate for Network Integration Transmission Service for the Public Service Transmission Zone as derived from the FERC Electric Tariff of the PJM Interconnection, LLC	$ 91,224.18 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	$104.68 per MW per month
Virginia Electric and Power Company	$ 82.20 per MW per month
Potomac-Appalachian Transmission Highline L.L.C.	$ 10.72 per MW per month
PPL Electric Utilities Corporation	$ 53.39 per MW per month
American Electric Power Service Corporation	$ 26.91 per MW per month
Atlantic City Electric Company.	$ 11.09 per MW per month
Delmarva Power and Light Company	$ 0.33 per MW per month
Potomac Electric Power Company.	$ 3.37 per MW per month

Above rates converted to a charge per kW of Transmission Obligation, applicable in all months	$ 7.8947
Charge including New Jersey Sales and Use Tax (SUT)	$ 8.4375

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).

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 83**
Superseding
B.P.U.N.J. No. 15 ELECTRIC **XXX Revised Sheet No. 83**

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

BGS TRANSMISSION CHARGES

Charges per kilowatt of Transmission Obligation:

Currently effective Annual Transmission Rate for Network Integration Transmission Service for the Public Service Transmission Zone as derived from the FERC Electric Tariff of the PJM Interconnection, LLC	$ 91,224.18 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	$ 104.68 per MW per month
Virginia Electric and Power Company	$ 82.20 per MW per month
Potomac-Appalachian Transmission Highline L.L.C.	$ 10.72 per MW per month
PPL Electric Utilities Corporation	$ 53.39 per MW per month
American Electric Power Service Corporation	$ 26.91 per MW per month
Atlantic City Electric Company.	$ 11.09 per MW per month
Delmarva Power and Light Company	$ 0.33 per MW per month
Potomac Electric Power Company.	$ 3.37 per MW per month

Above rates converted to a charge per kW of Transmission Obligation, applicable in all months	$ 7.8947
Charge including New Jersey Sales and Use Tax (SUT)	$ 8.4375

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

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

Date of Issue: Effective:

Issued by SCOTT S. JENNINGS, Vice President Finance – PSE&G
80 Park Plaza, Newark, New Jersey 07102
Filed pursuant to Order of Board of Public Utilities dated
in Docket No.

Attachment 2b
PSE&G Translation of NITS Charge into Customer Rates

Attachment 2b

Network Integration Service Calculation - BGS-RSCP
NITS Charges for January 2017 - December 2017

			Effective 1/1/17 - 12/31/17				
PSE&G Annual Transmission Service Revenue Rec	$	1,185,164,918.00					
Total Schedule 12 TEC Included in above	$	(483,133,850.00)					
PSE&G Customer Share of Schedule 12 NITS	$	191,993,305.00					
NITS Charges for Jan 2017 - Dec 2017	$	894,024,373.00					
PSE&G Zonal Transmission Load for Effective Yr. (MW) (1/1/17)		9,800.30					
Term (Months)		12					
OATT rate	$	7,602.02	/MW/month	all values show w/o NJ SUT			
converted to $/MW/yr =	$	91,224.18	/MW/yr	**Jan 17 - Dec 17 NITS Charge**			
	$	70,337.03	/MW/yr	**Jan 17 - May 17 Weighted Average of:**	**$ 55,722.38**	**$ 72,688.29**	**$ 82,516.44**
	$	82,031.74	/MW/yr	**Jun 17 - Dec 17 Weighted Average of:**	**$ 72,688.29**	**$ 82,516.44**	**$ 91,224.18**
	$	77,158.94	/MW/yr	**Jan 17 - Dec 17 Weighted Average**			
Resulting Increase in Transmission Rate	$	14,065.24	/MW/yr				
Resulting Increase in Transmission Rate	$	1,172.10	/MW/month				

	RS	**RHS**	**RLM**	**WH**	**WHS**	**HS**	**PSAL**	**BPL**
Trans Obl - MW	3,756.9	25.7	72.3	0.0	0.0	3.0	0.0	0.0
Total Annual Energy - MWh	12,371,327.1	159,712.7	220,782.8	1,426.0	30.0	16,697.1	160,628.0	287,511.0
Change in energy charge								
in $/MWh	$ 4.2713	$ 2.2637	$ 4.6030	$ -	$ -	$ 2.5113	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.004271**	**$ 0.002264**	**$ 0.004603**	**$ -**	**$ -**	**$ 0.002511**	**$ -**	**$ -**

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

Line #						
1	Total BGS-RSCP Trans Obl		6,633.6	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust		24,216,290	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes		25,990,884	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	93,303,177		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl adjusted for migration
5	Change in Average Supplier Payment Rate	$	3.5898	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	3.59	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	93,307,273		unrounded	= (6) * (3)
8	Difference due to rounding	$	4,097		unrounded	= (7) - (4)

Attachment 2c

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

Attachment 2c

Transmission Charge Adjustment - BGS-RSCP
Attachment 6c - PJM Schedule 12 - Transmission Enhancement Charges for January 2017 - December 2017
Calculation of costs and monthly PJM charges for VEPCO Projects

TEC Charges for Jan 2017 - Dec 2017	$	9,666,468.12		
PSE&G Zonal Transmission Load for Effective Yr. (MW) (1/1/17)		9,800.30		
Term (Months)		12		
OATT rate	$	82.20	/MW/month	all values show w/o NJ SUT
Resulting Increase in Transmission Rate	$	986.40	/MW/yr	

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	3,756.9	25.7	72.3	0.0	0.0	3.0	0.0	0.0
Total Annual Energy - MWh	12,371,327.1	159,712.7	220,782.8	1,426.0	30.0	16,697.1	160,628.0	287,511.0
Change in energy charge								
in $/MWh	$ 0.2995	$ 0.1588	$ 0.3228	$ -	$ -	$ 0.1761	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000300**	**$ 0.000159**	**$ 0.000323**	**$ -**	**$ -**	**$ 0.000176**	**$ -**	**$ -**

Line #						
1	Total BGS-RSCP Trans Obl		6,633.6	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust		24,216,290.0	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes		25,990,883.9	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	6,543,383		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.2518	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	0.25	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	6,497,721		unrounded	= (6) * (3)
8	Difference due to rounding	$	(45,662)		unrounded	= (7) - (4)

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

Attachment 2d

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges for January 2017 - December 2017
Calculation of costs and monthly PJM charges for PATH Project

TEC Charges for Jan 2017 - Dec 2017	$	1,261,026.71		
PSE&G Zonal Transmission Load for Effective Yr. (MW) (1/1/17)		9,800.30		
Term (Months)		12		
OATT rate	$	10.72	/MW/month	all values show w/o NJ SUT
Resulting Increase in Transmission Rate	$	128.64	/MW/yr	

	RS	**RHS**	**RLM**	**WH**	**WHS**	**HS**	**PSAL**	**BPL**
Trans Obl - MW	3,756.9	25.7	72.3	0.0	0.0	3.0	0.0	0.0
Total Annual Energy - MWh	12,371,327.1	159,712.7	220,782.8	1,426.0	30.0	16,697.1	160,628.0	287,511.0
Change in energy charge								
in $/MWh	$ 0.0391	$ 0.0207	$ 0.0421	$ -	$ -	$ 0.0230	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000039**	**$ 0.000021**	**$ 0.000042**	**$ -**	**$ -**	**$ 0.000023**	**$ -**	**$ -**

Line #						
1	Total BGS-RSCP Trans Obl		6,633.6	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust		24,216,290	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes		25,990,884	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	853,346		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.0328	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	0.03	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	779,727		unrounded	= (6) * (3)
8	Difference due to rounding	$	(73,620)		unrounded	= (7) - (4)

Attachment 3 – JCP&L Tariffs and Rate Translation

Attachment 3a
Pro-forma JCP&L Tariff Sheets

Attachment 3b
JCP&L Translation of PSE&G Schedule 12 (Transmission Enhancement)
Charges into Customer Rates

Attachment 3c
JCP&L Translation of VEPCO Schedule 12 (Transmission Enhancement)
Charges into Customer Rates

Attachment 3d
JCP&L Translation of PATH Schedule 12 (Transmission Enhancement)
Charges into Customer Rates

Attachment 3a
Pro-forma JCP&L Tariff Sheets

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

2) BGS Transmission Charge per KWH: As provided in the respective tariff for Service Classifications RS, RT, RGT, GS, GST, OL, SVL, MVL and ISL. Effective January 1, 2013, a RMR surcharge of **$0.000000** per KWH (includes Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage.

Effective September 1, 2016, a TRAILCO4-TEC surcharge of **$0.000468** per KWH (includes Sales and Use Tax as provided in Rider SUT), a PEPCO2-TEC surcharge of **$0.000015** per KWH (includes Sales and Use Tax as provided in Rider SUT), an ACE2-TEC surcharge of **$0.000086** per KWH (includes Sales and Use Tax as provided in Rider SUT), a Delmarva2-TEC surcharge of **$0.000001** per KWH (includes Sales and Use Tax as provided in Rider SUT), an AEP-East2-TEC surcharge of **$0.000105** per KWH (includes Sales and Use Tax as provided in Rider SUT), and a PPL2-TEC surcharge of **$0.000213** per KWH (includes Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage except lighting under Service Classifications OL, SVL, MVL and ISL.

Effective January 1, 2017, a PATH3-TEC surcharge of **$0.000044** per KWH (includes Sales and Use Tax as provided in Rider SUT), a VEPCO3-TEC surcharge of **$0.000335** per KWH (includes Sales and Use Tax as provided in Rider SUT), and a PSEG2-TEC surcharge of **$0.001719** per KWH (includes Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage except lighting under Service Classifications OL, SVL, MVL and ISL.

3) BGS Reconciliation Charge per KWH: $0.001476 (includes Sales and Use Tax as provided in Rider SUT)

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

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

3) BGS Transmission Charge per KWH: (Continued)

Effective September 1, 2016, the following TEC surcharges will be added to the BGS Transmission Charge applicable to all KWH usage, as follows (includes Sales and Use Tax as provided in Rider SUT):

	TRAILCO4-TEC	PEPCO2-TEC	ACE2-TEC
GT – High Tension Service	**$0.000105**	**$0.000003**	**$0.000019**
GT	**$0.000225**	**$0.000007**	**$0.000041**
GP	**$0.000311**	**$0.000010**	**$0.000057**
GS and GST	**$0.000468**	**$0.000015**	**$0.000086**

	Delmarva2-TEC	AEP-East2-TEC	PPL2-TEC
GT – High Tension Service	**$0.000000**	**$0.000024**	**$0.000048**
GT	**$0.000001**	**$0.000050**	**$0.000103**
GP	**$0.000001**	**$0.000070**	**$0.000142**
GS and GST	**$0.000001**	**$0.000105**	**$0.000213**

Effective January 1, 2017, the following TEC surcharges will be added to the BGS Transmission Charge applicable to all KWH usage, as follows (includes Sales and Use Tax as provided in Rider SUT):

	PATH3-TEC	VEPCO3-TEC	PSEG2-TEC
GT – High Tension Service	**$0.000005**	**$0.000043**	**$0.000220**
GT	**$0.000024**	**$0.000178**	**$0.000920**
GP	**$0.000027**	**$0.000208**	**$0.001071**
GS and GST	**$0.000044**	**$0.000335**	**$0.001719**

4) BGS Reconciliation Charge per KWH: $0.000384 (includes Sales and Use Tax as provided in Rider SUT)

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

Issued: **Effective: January 1, 2017**

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

Issued by James V. Fakult, President
300 Madison Avenue, Morristown, NJ 07962-1911

Attachment 3b
JCP&L Translation of PSE&G Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 3b

Jersey Central Power & Light Company
Proposed PSEG Project Transmission Enhancement Charge (PSEG-TEC Surcharge) effective January 1, 2017
To reflect FERC-approved PSEG Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 2017

2017 Average Monthly PSEG-TEC Costs Allocated to JCP&L Zone	$	2,514,587.28	(1)
2017 JCP&L Zone Transmission Peak Load (MW)		5954.8	
PSEG-Transmission Enhancement Rate ($/MW-month)	$	422.28	

				Effective January 1, 2017:	
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	PSEG-TEC Surcharge ($/kWh)	PSEG-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5168.8	26,192,111	16,283,741,070	$ 0.001608	$ 0.001719
Primary	351.1	1,779,146	1,776,180,338	$ 0.001002	$ 0.001071
Transmission @ 34.5 kV	287.0	1,454,329	1,689,295,440	$ 0.000861	$ 0.000920
Transmission @ 230 kV	14.0	70,943	345,159,760	$ 0.000206	$ 0.000220
Total	5820.9	29,496,529	20,094,376,608		

(1) Cost Allocation of PSEG Project Schedule 12 Charges to JCP&L Zone for 2017
(2) Based on 12 months PSEG Project costs from January through December 2017
(3) January through December 2017

BGS-RSCP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales January through December @ Customer		15,262,858	MWH
2	BGS-RSCP Eligible Sales January through December @ Transmission Node		16,937,499	MWH
3	BGS-RSCP Eligible Transmission Obligation		4,825	MW
4	PSEG-Transmission Enhancement Costs to RSCP Suppliers	$	24,449,957	= Line 3 x $422.28 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	1.44	= Line 4 / Line 2

Attachment 3c
JCP&L Translation of VEPCO Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 3c

Jersey Central Power & Light Company
Proposed VEPCO Project Transmission Enhancement Charge (VEPCO-TEC Surcharge) effective January 1, 2017
To reflect FERC-approved VEPCO Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 2017

2017 Average Monthly VEPCO-TEC Costs Allocated to JCP&L Zone	$ 489,119.74	(1)
2017 JCP&L Zone Transmission Peak Load (MW)	5954.8	
VEPCO-Transmission Enhancement Rate ($/MW-month)	$ 82.14	

				Effective January 1, 2017:	
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	VEPCO-TEC Surcharge ($/kWh)	VEPCO-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5168.8	5,094,704	16,283,741,070	$ 0.000313	$ 0.000335
Primary	351.1	346,067	1,776,180,338	$ 0.000195	$ 0.000208
Transmission @ 34.5 kV	287.0	282,886	1,689,295,440	$ 0.000167	$ 0.000178
Transmission @ 230 kV	14.0	13,799	345,159,760	$ 0.000040	$ 0.000043
Total	5820.9	5,737,456	20,094,376,608		

(1) Cost Allocation of VEPCO Project Schedule 12 Charges to JCP&L Zone for 2017
(2) Based on 12 months VEPCO Project costs from January through December 2017
(3) January through December 2017

BGS-RSCP Supplier Payment Adjustment

Line No.			
1	BGS-RSCP Eligible Sales January through December @ Customer	15,262,858	MWH
2	BGS-RSCP Eligible Sales January through December @ Transmission Node	16,937,499	MWH
3	BGS-RSCP Eligible Transmission Obligation	4,825	MW
4	VEPCO-Transmission Enhancement Costs to RSCP Suppliers	$ 4,755,833	= Line 3 x $82.14 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$ 0.28	= Line 4 / Line 2

Attachment 3d
JCP&L Translation of PATH Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Jersey Central Power & Light Company
Proposed PATH Project Transmission Enhancement Charge (PATH-TEC Surcharge) effective January 1, 2017
To reflect FERC-approved PATH Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 2017

2017 Average Monthly PATH-TEC Costs Allocated to JCP&L Zone	$	63,693.62	(1)
2017 JCP&L Zone Transmission Peak Load (MW)		5954.8	
PATH-Transmission Enhancement Rate ($/MW-month)	$	10.70	

				Effective January 1, 2017:	
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	PATH-TEC Surcharge ($/kWh)	PATH-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5168.8	663,437	16,283,741,070	$ 0.000041	$ 0.000044
Primary	351.1	45,065	1,776,180,338	$ 0.000025	$ 0.000027
Transmission @ 34.5 kV	287.0	36,838	1,689,295,440	$ 0.000022	$ 0.000024
Transmission @ 230 kV	14.0	1,797	345,159,760	$ 0.000005	$ 0.000005
Total	5820.9	747,137	20,094,376,608		

(1) Cost Allocation of PATH Project Schedule 12 Charges to JCP&L Zone for 2017
(2) Based on 12 months PATH Project costs from January through December 2017
(3) January through December 2017

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

Line No.				
1	BGS-RSCP Eligible Sales January through December @ Customer		15,262,858	MWH
2	BGS-RSCP Eligible Sales January through December @ Transmission Node		16,937,499	MWH
3	BGS-RSCP Eligible Transmission Obligation		4,825	MW
4	PATH-Transmission Enhancement Costs to RSCP Suppliers	$	619,309	= Line 3 x $10.70 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.04	= Line 4 / Line 2

Attachment 4 – ACE Tariffs and Rate Translation

Attachment 4a
Pro-forma ACE Tariff Sheets

Attachment 4b
ACE Translation of PSE&G Schedule 12 (Transmission Enhancement)
Charges into Customer Rates

Attachment 4c
ACE Translation of VEPCO Schedule 12 (Transmission Enhancement)
Charges into Customer Rates

Attachment 4d
ACE Translation of PATH Schedule 12 (Transmission Enhancement)
Charges into Customer Rates

Attachment 4a
Pro-forma ACE Tariff Sheets

RIDER (BGS) continued
Basic Generation Service (BGS)

CIEP Standby Fee $0.000161 per kWh

This charge recovers the costs associated with the winning BGS-CIEP bidders maintaining the availability of the hourly priced default electric supply service plus administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT. This charge is assessed on all kWhs delivered to all CIEP- eligible customers on Rate Schedules MGS Secondary, MGS Primary, AGS Secondary, AGS Primary or TGS.

Transmission Enhancement Charge

This charge reflects Transmission Enhancement Charges ("TECs"), implemented to compensate transmission owners for the annual transmission revenue requirements for "Required Transmission Enhancements" (as defined in Schedule 12 of the PJM OATT) that are requested by PJM for reliability or economic purposes and approved by the Federal Energy Regulatory Commission (FERC). The TEC charge (in $ per kWh by Rate Schedule), including administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT, is delineated in the following table.

	Rate Class							
	RS	MGS Secondary	MGS Primary	AGS Secondary	AGS Primary	TGS	SPL/CSL	DDC
VEPCo	0.000402	0.000317	0.000333	0.000221	0.000186	0.000142	-	0.000134
TrAILCo	0.000606	0.000461	0.000238	0.000277	0.000108	0.000208	-	0.000213
PSE&G	0.000642	0.000506	0.000531	0.000355	0.000298	0.000228	-	0.000214
PATH	0.000051	0.000041	0.000043	0.000029	0.000024	0.000018	-	0.000017
PPL	0.000244	0.000186	0.000096	0.000111	0.000044	0.000083	-	0.000086
Pepco	0.000024	0.000017	0.000010	0.000011	0.000004	0.000007	-	0.000009
Delmarva	0.000001	0.000001	0.000001	0.000001	-	0.000001	-	0.000001
AEP - East	0.000106	0.000080	0.000042	0.000048	0.000019	0.000036	-	0.000037
Total	0.002076	0.001609	0.001294	0.001053	0.000683	0.000723	-	0.000711

Date of Issue: **Effective Date:**

Issued by:

Attachment 4b
ACE Translation of PSE&G Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 4b

Atlantic City Electric Company

Proposed PSE&G Projects Transmission Enhancement Charge (PSE&G-TEC Surcharge) effective January 1, 2017

To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 1, 2017

Transmission Enhancement Costs Allocated to ACE Zone (2017)	$ 348,229
	$ 348,229
2017 ACE Zone Transmission Peak Load (MW)	2,673
Transmission Enhancement Rate ($/MW)	$ 130.26

Rate Class	Col. 1 Transmission Obligation (MW)	Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales Jan 2017 - Dec 2017 (kWh)	Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)	Col. 5 = Col. 4 x 1/(1-.005) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)	Col. 6 = Col. 5 x 1.06875 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,545	$ 2,415,634	4,028,660,063	$ 0.000600	$ 0.000601	$ 0.000642
MGS Secondary	353	$ 551,925	1,168,175,409	$ 0.000472	$ 0.000473	$ 0.000506
MGS Primary	6	$ 9,504	19,148,142	$ 0.000496	$ 0.000497	$ 0.000531
AGS Secondary	394	$ 615,080	1,858,223,848	$ 0.000331	$ 0.000332	$ 0.000355
AGS Primary	94	$ 147,194	528,913,165	$ 0.000278	$ 0.000279	$ 0.000298
TGS	146	$ 228,340	1,071,707,477	$ 0.000213	$ 0.000213	$ 0.000228
SPL/CSL	0	$ -	75,506,174	$ -	$ -	$ -
DDC	2	$ 2,472	12,386,246	$ 0.000200	$ 0.000200	$ 0.000214
	2,540	$ 3,970,149	8,762,720,526			

Attachment 4c
ACE Translation of VEPCO Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 4c

Atlantic City Electric Company

Proposed VEPCO Projects Transmission Enhancement Charge (VEPCO-TEC Surcharge) effective January 1, 2017

To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 1, 2017

Transmission Enhancement Costs Allocated to ACE Zone (2017)	$ 217,926
	$ 217,926
2017 ACE Zone Transmission Peak Load (MW)	2,673
Transmission Enhancement Rate ($/MW)	$ 81.52

Rate Class	Col. 1 Transmission Obligation (MW)	Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales Jan 2017 - Dec 2017 (kWh)	Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)	Col. 5 = Col. 4 x 1/(1-.005) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)	Col. 6 = Col. 5 x 1.06875 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,545	$ 1,511,734	4,028,660,063	$ 0.000375	$ 0.000376	$ 0.000402
MGS Secondary	353	$ 345,401	1,168,175,409	$ 0.000296	$ 0.000297	$ 0.000317
MGS Primary	6	$ 5,948	19,148,142	$ 0.000311	$ 0.000312	$ 0.000333
AGS Secondary	394	$ 384,925	1,858,223,848	$ 0.000207	$ 0.000207	$ 0.000221
AGS Primary	94	$ 92,116	528,913,165	$ 0.000174	$ 0.000174	$ 0.000186
TGS	146	$ 142,898	1,071,707,477	$ 0.000133	$ 0.000133	$ 0.000142
SPL/CSL	-	$ -	75,506,174	$ -	$ -	$ -
DDC	2	$ 1,547	12,386,246	$ 0.000125	$ 0.000125	$ 0.000134
	2,540	$ 2,484,568	8,762,720,526			

Attachment 4d
ACE Translation of PATH Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 4d

Atlantic City Electric Company

Proposed PATH Projects Transmission Enhancement Charge (PATH-TEC Surcharge) effective January 1, 2017

To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 1, 2017

Transmission Enhancement Costs Allocated to ACE Zone (2017)	$ 28,011
	$ 28,011
2017 ACE Zone Transmission Peak Load (MW)	2,673
Transmission Enhancement Rate ($/MW)	$ 10.48

Rate Class	Col. 1 Transmission Obligation (MW)	Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales Jan 2017 - Dec 2017 (kWh)	Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)	Col. 5 = Col. 4 x 1/(1-.005) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)	Col. 6 = Col. 5 x 1.06875 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,545	$ 194,309	4,028,660,063	$ 0.000048	$ 0.000048	$ 0.000051
MGS Secondary	353	$ 44,396	1,168,175,409	$ 0.000038	$ 0.000038	$ 0.000041
MGS Primary	6	$ 764	19,148,142	$ 0.000040	$ 0.000040	$ 0.000043
AGS Secondary	394	$ 49,476	1,858,223,848	$ 0.000027	$ 0.000027	$ 0.000029
AGS Primary	94	$ 11,840	528,913,165	$ 0.000022	$ 0.000022	$ 0.000024
TGS	146	$ 18,367	1,071,707,477	$ 0.000017	$ 0.000017	$ 0.000018
SPL/CSL	-	$ -	75,506,174	$ -	$ -	$ -
DDC	2	$ 199	12,386,246	$ 0.000016	$ 0.000016	$ 0.000017
	2,540	$ 319,351	8,762,720,526			

Attachment 5 – RECO Tariffs and Rate Translation

Attachment 5a
Pro-forma RECO Tariff Sheets

Attachment 5b
RECO Translation of PSE&G Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 5c
RECO Translation of VEPCO Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 5d
RECO Translation of PATH Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 5a
Pro-forma RECO Tariff Sheets

Rockland Electric Company
Calculation of Transmission Surcharges reflecting proposed changes effective January 1, 2017
To reflect: RMR Costs
FERC-approved ACE Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved AEP-East Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved Delmarva Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved PATH Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved PEPCO Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved PPL Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved PSE&G Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved TrailCo Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved VEPCo Project Schedule 12 Charges (Schedule 12 PJM OATT)

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

Transmission Project	Note	SC1	SC2 Sec	SC2 Pri	SC3	SC4	SC5	SC6	SC7
Reliability Must Run	(1)	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
ACE - TEC	(2)	0.00004	0.00002	0.00002	0.00002	0.00000	0.00002	0.00000	0.00001
AEP-East - TEC	(3)	0.00011	0.00006	0.00006	0.00005	0.00000	0.00007	0.00000	0.00004
Delmarva - TEC	(4)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
PATH - TEC	(5)	0.00004	0.00003	0.00002	0.00002	0.00000	0.00003	0.00000	0.00002
PEPCO - TEC	(6)	0.00001	0.00001	0.00000	0.00000	0.00000	0.00001	0.00000	0.00000
PPL - TEC	(7)	0.00022	0.00013	0.00012	0.00010	0.00000	0.00014	0.00000	0.00008
PSE&G - TEC	(8)	0.00623	0.00370	0.00334	0.00321	0.00000	0.00431	0.00000	0.00230
TrAILCo - TEC	(9)	0.00042	0.00024	0.00022	0.00021	0.00000	0.00028	0.00000	0.00016
VEPCo - TEC	(10)	0.00034	0.00020	0.00018	0.00018	0.00000	0.00024	0.00000	0.00013
Total ($/kWh and excl SUT)		$0.00741	$0.00439	$0.00396	$0.00379	$0.00000	$0.00510	$0.00000	$0.00274
Total (¢/kWh and excl SUT)		0.741 ¢	0.439 ¢	0.396 ¢	0.379 ¢	0.000 ¢	0.510 ¢	0.000 ¢	0.274 ¢

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

6.875%

Transmission Project	Note	SC1	SC2 Sec	SC2 Pri	SC3	SC4	SC5	SC6	SC7
Reliability Must Run	(1)	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
ACE - TEC	(2)	0.00004	0.00002	0.00002	0.00002	0.00000	0.00002	0.00000	0.00001
AEP-East - TEC	(3)	0.00012	0.00006	0.00006	0.00005	0.00000	0.00007	0.00000	0.00004
Delmarva - TEC	(4)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
PATH - TEC	(5)	0.00004	0.00003	0.00002	0.00002	0.00000	0.00003	0.00000	0.00002
PEPCO - TEC	(6)	0.00001	0.00001	0.00000	0.00000	0.00000	0.00001	0.00000	0.00000
PPL - TEC	(7)	0.00024	0.00014	0.00013	0.00011	0.00000	0.00015	0.00000	0.00009
PSE&G - TEC	(8)	0.00666	0.00395	0.00357	0.00343	0.00000	0.00461	0.00000	0.00246
TrAILCo - TEC	(9)	0.00045	0.00026	0.00024	0.00022	0.00000	0.00030	0.00000	0.00017
VEPCo - TEC	(10)	0.00036	0.00021	0.00019	0.00019	0.00000	0.00026	0.00000	0.00014
Total ($/kWh and incl SUT)		$0.00792	$0.00468	$0.00423	$0.00404	$0.00000	$0.00545	$0.00000	$0.00293
Total (¢/kWh and incl SUT)		0.792 ¢	0.468 ¢	0.423 ¢	0.404 ¢	0.000 ¢	0.545 ¢	0.000 ¢	0.293 ¢

Notes:

(1) RMR rates based on allocations by transmission zone. For RECO, the estimated allocation is zero percent for calendar year 2017.
(2) ACE-TEC rates pursuant to the Board’s Order dated July 29, 2016 in Docket No. ER16060527.
(3) AEP-East-TEC rates pursuant to the Board’s Order dated July 29, 2016 in Docket No. ER16060527.
(4) Delmarva-TEC rates pursuant to the Board’s Order dated July 29, 2016 in Docket No. ER16060527.
(5) PATH-TEC rates calculated in Attachment 5 of the joint filing.
(6) PEPCO-TEC rates pursuant to the Board’s Order dated July 29, 2016 in Docket No. ER16060527.
(7) PPL-TEC rates pursuant to the Board’s Order dated July 29, 2016 in Docket No. ER16060527.
(8) PSE&G-TEC rates calculated in Attachment 5 of the joint filing.
(9) TrAILCo-TEC rates pursuant to the Board’s Order dated July 29, 2016 in Docket No. ER16060527.
(10) VEPCo-TEC rates calculated in Attachment 5 of the joint filing.

SERVICE CLASSIFICATION NO. 1
RESIDENTIAL SERVICE (Continued)

RATE – MONTHLY (Continued)

(3) Transmission Charge

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

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

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

All kWh	0.792 ¢ per kWh	0.792 ¢ per kWh

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

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

* Definition of Summer Billing Months - June through September

(Continued)

SERVICE CLASSIFICATION NO. 2
GENERAL SERVICE (Continued)

RATE – MONTHLY (Continued)

(3) Transmission Charges (Continued)

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

	Summer Months*	Other Months
Secondary Voltage Service Only		
All kWh ....@	0.468 ¢ per kWh	0.468 ¢ per kWh
Primary Voltage Service Only		
All kWh ....@	0.423 ¢ per kWh	0.423 ¢ per kWh

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

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

* Definition of Summer Billing Months - June through September

(Continued)

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

RATE – MONTHLY (Continued)

(3) Transmission Charge

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

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

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

All kWh .....@	0.404 ¢ per kWh	0.404 ¢ per kWh

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

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

* Definition of Summer Billing Months - June through September

(Continued)

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

RATE - MONTHLY (Continued)

(3) Transmission Charge

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

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

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

All kWh ... @	0.545 ¢ per kWh	0.545 ¢ per kWh

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

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

* Definition of Summer Billing Months - June through September

(Continued)

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

RATE– MONTHLY (Continued)

(3) Transmission Charges (Continued)

(a) (Continued)

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

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

		Primary	High Voltage Distribution
All Periods	All kWh @	0.293 ¢ per kWh	0.293 ¢ per kWh

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

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

(Continued)

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

SPECIAL PROVISIONS

(A) Space Heating

Customers who take service under this classification for 10 kW or more of permanently installed space heating equipment may elect to have the electricity for this service billed separately. All monthly use shall be billed at a Distribution Charge of 3.159 ¢ per kWh during the billing months of October through May and 5.106 ¢ per kWh during the summer billing months and a Transmission Charge of 0.552 ¢ per kWh and a Transmission Surcharge of 0.293 ¢ per kWh during all billing months.

When this option is requested it shall apply for at least 12 months and shall be subject to a minimum charge of $26.96 per year per kW of space heating capacity. This provision applies for both heating and cooling where the two services are combined by the manufacturer in a single self-contained unit.

All usage under this Special Provision shall also be subject to Parts (4), (5), and (6) of RATE – MONTHLY. This Special Provision is not available to those customers taking high voltage distribution service.

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

(B) Budget Billing Plan

Any condominium association or cooperative housing corporation who takes service hereunder and any other customer taking service under Special Provision B of this Service Classification may, upon request, be billed monthly in accordance with the budget billing plan provided for in General Information Section 8 of this tariff.

(Continued)

Attachment 5b
RECO Translation of PSE&G Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 5b

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (PSE&G Project) effective January 1, 2017
To reflect FERC-approved PSE&G Project Schedule 12 Charges (Schedule 12 PJM OATT) for 2017

2017 Average Monthly PSE&G-TEC Costs Allocated to RECO	$ 598,514	(1)
2017 RECO Zone Transmission Peak Load (MW)	430.3	(2)
Transmission Enhancement Rate ($/MW-month)	$ 1,391.00	
SUT	6.875%	

Rate Class	Col. 1 BGS-Eligible Transmission Obligation (MW)	Col. 2 Transmission Obligation (Pct)	Col.3=Col.2 x $598,514 x 12 Allocated Cost Recovery (1)	Col. 4 BGS Eligible Sales Jan 2017 - Dec 2017 (kWh)	Col. 5 = Col. 3/Col. 4 Transmission Enhancement Charge ($/kWh)	Col. 6 = Col. 5 x 1.07 Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	260.0	60.43%	$ 4,340,067	696,339,000	$ 0.00623	$ 0.00666
SC2 Secondary	118.7	27.59%	$ 1,981,252	534,862,000	$ 0.00370	$ 0.00395
SC2 Primary	15.4	3.57%	$ 256,518	76,753,000	$ 0.00334	$ 0.00357
SC3	0.1	0.01%	$ 856	267,000	$ 0.00321	$ 0.00343
SC4	0.0	0.00%	$ -	6,455,000	$ -	$ -
SC5	3.9	0.90%	$ 64,431	14,964,000	$ 0.00431	$ 0.00461
SC6	0.0	0.00%	$ -	5,566,000	$ -	$ -
SC7	32.3	7.51%	$ 539,042	233,869,000	$ 0.00230	$ 0.00246
Total	430.3 (2)	100.00%	$ 7,182,166	1,569,075,000		

(1) Attachment 4 - Cost Allocation of PSE&G Project Schedule 12 Charges to RECO Zone for 2017
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.			
1	BGS-FP Eligible Sales Jan - Dec @ cust (RECO Eastern Division)	1,284,571	MWH
2	BGS-FP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)	1,195,103	MWH
3	BGS-FP Eligible Transmission Obligation	398	MW
4	Transmission Enhancement Costs to FP Suppliers	$ 6,643,141.58	= Line 3 x $1391 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$ 5.56	= Line 4/Line 2

Attachment 5c
RECO Translation of VEPCO Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 5c

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (VEPCo) effective January 1, 2017
To reflect FERC-approved VEPCo Project Schedule 12 Charges (Schedule 12 PJM OATT) for 2017

2017 Average Monthly VEPCo-TEC Costs Allocated to RECO	$	32,823	(1)
2017 RECO Zone Transmission Peak Load (MW)		430.3	(2)
Transmission Enhancement Rate ($/MW-month)	$	76.28	
SUT		6.875%	

Rate Class	Col. 1 BGS-Eligible Transmission Obligation (MW)	Col. 2 Transmission Obligation (Pct)	Col.3=Col.2 x $32,823 x 12 Allocated Cost Recovery (1)	Col. 4 BGS Eligible Sales Jan 2017 - Dec 2017(kWh)	Col. 5 = Col. 3/Col. 4 Transmission Enhancement Charge ($/kWh)	Col. 6 = Col. 5 x 1.07 Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	260.0	60.43%	$ 238,015	696,339,000	$ 0.00034	$ 0.00036
SC2 Secondary	118.7	27.59%	$ 108,655	534,862,000	$ 0.00020	$ 0.00021
SC2 Primary	15.4	3.57%	$ 14,068	76,753,000	$ 0.00018	$ 0.00019
SC3	0.1	0.01%	$ 47	267,000	$ 0.00018	$ 0.00019
SC4	0.0	0.00%	$ -	6,455,000	$ -	$ -
SC5	3.9	0.90%	$ 3,533	14,964,000	$ 0.00024	$ 0.00026
SC6	0.0	0.00%	$ -	5,566,000	$ -	$ -
SC7	32.3	7.51%	$ 29,562	233,869,000	$ 0.00013	$ 0.00014
Total	430.3 (2)	100.00%	$ 393,880	1,569,075,000		

(1) Attachment 4 - Cost Allocation of VEPCo Schedule 12 Charges to RECO Zone for 2017
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales Jan - Dec @ cust (RECO Eastern Division)		1,284,571	MWH
2	BGS-FP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)		1,195,103	MWH
3	BGS-FP Eligible Transmission Obligation		398	MW
4	Transmission Enhancement Costs to FP Suppliers	$	364,298.23	= Line 3 x $76.28 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.30	= Line 4/Line 2

Attachment 5d
RECO Translation of PATH Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (PATH) effective January 1, 2017
To reflect FERC-approved PATH Project Schedule 12 Charges (Schedule 12 PJM OATT) for 2017

2017 Average Monthly PATH-TEC Costs Allocated to RECO	$	4,282	(1)
2017 RECO Zone Transmission Peak Load (MW)		430.3	(2)
Transmission Enhancement Rate ($/MW-month)	$	9.95	
SUT		6.875%	

	Col. 1	Col. 2	Col.3=Col.2 x $4,282 x 12	Col. 4	Col. 5 = Col. 3/Col. 4	Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)	Allocated Cost Recovery (1)	BGS Eligible Sales Jan 2017 - Dec 2017 (kWh)	Transmission Enhancement Charge ($/kWh)	Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	260.0	60.43%	$ 31,050	696,339,000	$ 0.00004	$ 0.00004
SC2 Secondary	118.7	27.59%	$ 14,174	534,862,000	$ 0.00003	$ 0.00003
SC2 Primary	15.4	3.57%	$ 1,835	76,753,000	$ 0.00002	$ 0.00002
SC3	0.1	0.01%	$ 6	267,000	$ 0.00002	$ 0.00002
SC4	0.0	0.00%	$ -	6,455,000	$ -	$ -
SC5	3.9	0.90%	$ 461	14,964,000	$ 0.00003	$ 0.00003
SC6	0.0	0.00%	$ -	5,566,000	$ -	$ -
SC7	32.3	7.51%	$ 3,856	233,869,000	$ 0.00002	$ 0.00002
Total	430.3 (2)	100.00%	$ 51,382	1,569,075,000		

(1) Attachment 4 - Cost Allocation of PATH Project Schedule 12 Charges to RECO Zone for 2017
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales Jan - Dec @ cust (RECO Eastern Division)		1,284,571	MWH
2	BGS-FP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)		1,195,103	MWH
3	BGS-FP Eligible Transmission Obligation		398	MW
4	Transmission Enhancement Costs to FP Suppliers	$	47,519.24	= Line 3 x $9.95 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.04	= Line 4/Line 2

Attachment 6 – PJM Schedule 12 (Transmission Enhancement) Charges

Attachment 6a
PSE&G Project Charges

Attachment 6b
Potomac-Appalachian Transmission Highline Project Charges

Attachment 6c
Virginia Electric Power Company Project Charges

Attachment 6a
PSE&G Project Charges

Attachment 6a -PJM Schedule 12 - Transmission Enhancement Charges for January 2017 - December 2017
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 2017 Annual Revenue Requirement**	**ACE Zone Share**	**JCP&L Zone Share**	**PSE&G Zone Share1,2**	**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 kava transformers	b0130	$ 1,919,572.00	1.36%	47.63%	50.75%	0.00%	$26,106	$914,292	$974,183	$0	$1,914,581
Reconductor Kittatinny - Newtown 230 kV with 1590 ACSS	b0134	$ 893,162.00	0.00%	51.11%	45.96%	2.93%	$0	$456,495	$410,497	$26,170	$893,162
Build new Essex - Aldene 230 kV cable connected through phase angle regulator at Essex	b0145	$ 8,050,714.00	0.00%	73.45%	21.78%	4.77%	$0	$5,913,249	$1,753,446	$384,019	$8,050,714
Install 230-138kV transformer at Metuchen substation	b0161	$ 3,950,752.00	0.00%	0.00%	99.80%	0.20%	$0	$0	$3,942,850	$7,902	$3,950,752
Build a new 230 kV section from Branchburg - Flagtown and move the Flagtown - Somerville 230 kV circuit to the new section	b0169	$ 1,804,191.00	1.70%	25.66%	58.96%	0.00%	$30,671	$462,955	$1,063,751	$0	$1,557,378
Reconductor the Flagtown-Somerville-Bridgewater 230 kV circuit with 1590 ACSS	b0170	$ 590,969.00	0.00%	42.95%	38.36%	0.79%	$0	$253,821	$226,696	$4,669	$485,186
Replace wave trap at Branchburg 500kV substation	b0172.2	$ (9,800.00)	1.57%	3.57%	5.89%	0.24%	-$154	-$350	-$577	-$24	-$1,104
Replace both 230/138 kV transformers at Roseland	b0274	$ 2,871,418.00	0.00%	0.00%	88.56%	0.00%	$0	$0	$2,542,928	$0	$2,542,928
Branchburg 400 MVAR Capacitor	b0290	$ 9,916,964.00	1.57%	3.57%	5.89%	0.24%	$155,696	$354,036	$584,109	$23,801	$1,117,642
Install 4th 500/230 kV transformer at New Freedom	b0411	$ 2,115,192.00	47.01%	7.04%	22.31%	0.00%	$994,352	$148,910	$471,899	$0	$1,615,161
Saddle Brook - Athenia Upgrade Cable	b0472	$ 1,855,386.00	0.00%	0.00%	92.86%	3.47%	$0	$0	$1,722,911	$64,382	$1,787,293
Build new 500 kV transmission facilities from Pennsylvania - New Jersey border at Bushkill to Roseland (500kV and above elements of the project)	b0489	$ 87,011,502.00	1.57%	3.57%	5.89%	0.24%	$1,366,081	$3,106,311	$5,124,977	$208,828	$9,806,196
Build new 500 kV transmission facilities from Pennsylvania - New Jersey border at Bushkill to Roseland (Below 500 kV elements of the project) (In Service)	b0489.4	$ 8,150,258.00	5.07%	32.57%	40.51%	1.51%	$413,218	$2,654,539	$3,301,670	$123,069	$6,492,496
Susquehanna Roseland Breakers (In-Service)	b0489.5-.15	$ 217,407.00	1.57%	3.57%	5.89%	0.24%	$3,413	$7,761	$12,805	$522	$24,502
Loop the 5021 circuit into New Freedom 500 kV substation	b0498	$ 2,630,700.00	1.57%	3.57%	5.89%	0.24%	$41,302	$93,916	$154,948	$6,314	$296,480
Branchburg-Somerville-Flagtown Reconductor	b0664-b0665	$ 2,687,154.00	0.00%	36.35%	43.24%	1.61%	$0	$976,780	$1,161,925	$43,263	$2,181,969
Somerville -Bridgewater Reconductor	b0668	$ 648,940.00	0.00%	39.41%	38.76%	1.45%	$0	$255,747	$251,529	$9,410	$516,686
Reconductor Hudson - South Waterfront 230kV circuit	b0813	$ 731,433.00	0.00%	9.92%	83.73%	3.12%	$0	$72,558	$612,429	$22,821	$707,808
New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie	b0814	$ 5,250,301.00	0.00%	23.49%	67.03%	2.50%	$0	$1,233,296	$3,519,277	$131,258	$4,883,830
Reconductor South Mahwah 345 kV J-3410 Circuit	b1017	$ 2,992,247.00	0.00%	14.69%	32.84%	1.28%	$0	$439,561	$982,654	$38,301	$1,460,516
Reconductor South Mahwah 345 kV K-3411 Circuit	b1018	$ 2,615,692.00	0.00%	14.77%	32.74%	1.28%	$0	$386,338	$856,378	$33,481	$1,276,196

Attachment 6a -PJM Schedule 12 - Transmission Enhancement Charges for January 2017 - December 2017
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 2017 Annual Revenue Requirement**	**ACE Zone Share**	**JCP&L Zone Share**	**PSE&G Zone Share1,2**	**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*								
Bergen Substation Transformer	b1082	$ -	0.00%	0.00%	80.29%	3.19%	$0	$0	$0	$0	$0
West Orange Conversion (North Central Reliability)	b1154	$ 14,007,445.00	0.00%	0.00%	96.18%	3.82%	$0	$0	$13,472,361	$535,084	$14,007,445
Branchburg-Middlesex Sw Rack	b1155	$ 11,318,767.00	0.00%	4.61%	91.75%	3.64%	$0	$521,795	$10,384,969	$412,003	$11,318,767

Attachment 6a -PJM Schedule 12 - Transmission Enhancement Charges for January 2017 - December 2017
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 2017 Annual Revenue Requirement**	**ACE Zone Share**	**JCP&L Zone Share**	**PSE&G Zone Share1,2**	**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*								
Conversion	b1156	$ 37,706,462.00	0.00%	0.00%	96.18%	3.82%	$0	$0	$36,266,075	$1,440,387	$37,706,462
230kV Lawrence Switching Station Upgrade	b1228	$ 937,673.00	0.00%	0.00%	95.83%	3.81%	$0	$0	$898,572	$35,725	$934,297
Ridge Rd 69kV Breaker Station	b1255	$ (1,023,113.00)	0.00%	0.00%	96.18%	3.82%	$0	$0	-$984,030	-$39,083	-$1,023,113
Northeast Grid Reliability Project	b1304.1-b1304.4	$ 84,277,037.00	0.21%	1.06%	63.81%	2.53%	$176,982	$893,337	$53,777,177	$2,132,209	$56,979,705
Mickleton-Gloucester-Camden	b1398-b1398.7	$ 53,399,686.00	0.00%	12.82%	31.46%	1.25%	$0	$6,845,840	$16,799,541	$667,496	$24,312,877
Aldene-Springfield Rd. Conv	b1399	$ 14,879,831.00	0.00%	0.00%	96.18%	3.82%	$0	$0	$14,311,421	$568,410	$14,879,831
Replace Salem 500 kV breakers	b1410-b1415	$ 1,904,937.00	1.57%	3.57%	5.89%	0.24%	$29,908	$68,006	$112,201	$4,572	$214,686
Uprate Eagle Point-Gloucester 230 kV Circuit	b1588	$ 2,126,917.00	0.00%	10.31%	54.17%	2.16%	$0	$219,285	$1,152,151	$45,941	$1,417,377
Upgrade Camden Richmon 230kV	b1590	$ 3,128,164.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
New Cox's Corner-Lumberton 230kV Circuit	b1787	$ 5,329,019.00	4.96%	44.20%	48.08%	1.92%	$264,319	$2,355,426	$2,562,192	$102,317	$5,284,255
Build Mickleton-Gloucester Corridor Ultimate Design	b2139	$ 2,796,331.00	0.00%	0.00%	61.11%	2.44%	$0	$0	$1,708,838	$68,230	$1,777,068
Sewaren Switch 230kV Convers.	b2276	$ -	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Convert Bergen Marion 138 kV to double circuit 345kV and Sub	b2436.10	$ 25,825,267.00	1.57%	3.57%	3.43%	0.15%	$405,457	$921,962	$884,515	$38,738	$2,250,672
Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.21	$ 5,929,235.00	0.79%	1.79%	2.95%	0.12%	$46,544	$105,837	$174,616	$7,115	$334,112
Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.22	$ 4,703,680.00	0.79%	1.79%	2.95%	0.12%	$36,924	$83,961	$138,523	$5,644	$265,052
Construct New Bayway-Bayonne 345kV Circuit	b2436.33	$ 9,562,390.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Construct New North Ave-Bayonne 345kV Circuit	b2436.34	$ 6,958,816.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Construct North Ave-Airport 345kV Circuit and Substation Upgrades	b2436.50	$ 4,491,168.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (CWIP)	b2436.60	$ 3,635,129.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (CWIP)	b2436.70	$ 6,726,495.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation	b2436.81	$ 2,892,542.00	1.57%	3.57%	41.71%	0.13%	$45,413	$103,264	$1,206,479	$3,616	$1,358,772
Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.83	$ 2,892,542.00	1.57%	3.57%	41.71%	0.13%	$45,413	$103,264	$1,206,479	$3,616	$1,358,772
Convert Bayway-Linden "W" to 138kV circuit to 345kV	b2436.84	$ 3,996,678.00	0.79%	1.79%	2.95%	0.12%	$31,374	$71,341	$117,702	$4,796	$225,213
Convert Bayway-Linden "M" to 138kV circuit to 345kV	b2436.85	$ 3,996,678.00	0.79%	1.79%	2.95%	0.12%	$31,374	$71,341	$117,702	$4,796	$225,213

Attachment 6a -PJM Schedule 12 - Transmission Enhancement Charges for January 2017 - December 2017
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 *per PJM website*	**PJM Upgrade ID** *per PJM spreadsheet*	**Jan - Dec 2017 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share**	**JCP&L Zone Share** *per PJM Open Access Transmission Tariff*	**PSE&G Zone Share1,2**	**RE Zone Share**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades	b2436.90	$ 4,491,521.00	0.77%	1.79%	3.33%	0.14%	$34,360	$80,174	$149,343	$6,064	$269,940
New Bergen 345/230 kV transformer and any associated substation upgrades	b2437.10	$ 4,204,465.00	0.00%	0.00%	3.86%	0.15%	$0	$0	$162,292	$6,307	$168,599
New Bergen 345/138 kV transformer #1 and any associated substation upgrades	b2437.11	$ 4,233,079.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
New Bayway 345/138 kV transformer #1 and any associated substation upgrades	b2437.20	$ 1,729,664.00	0.00%	0.00%	92.72%	0.00%	$0	$0	$1,603,744	$0	$1,603,744
New Bayway 345/138 kV transformer #2 and any associated substation upgrades	b2437.21	$ 1,729,765.00	0.00%	0.00%	93.24%	0.00%	$0	$0	$1,612,833	$0	$1,612,833
New Linden 345/230 kV transformer and any associated substation upgrades	b2437.30	$ 6,508,436.00	0.00%	0.00%	68.93%	0.00%	$0	$0	$4,486,265	$0	$4,486,265
New Bayonne 245/69 kV Transformer & Sub Upgrades	b2437.33	$ 942,989.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Totals		**$ 483,133,849.00**					**$4,178,753**	**$30,175,047**	**$191,993,249**	**$7,182,166**	**$233,529,216**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) +

	(k)	(l)	(m)	(n)	(o)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 2017**	**2017 Trans. Peak Load [2]**	**Rate in $/MW-mo. [1]**	**2017 Impact (12 months)**	
PSE&G	$ 15,999,437.42	9,800.3	$ 1,632.55	$ 191,993,249	
JCP&L	$ 2,514,587.28	5,954.8	$ 422.28	$ 30,175,047	
ACE	$ 348,229.43	2,673.4	$ 130.26	$ 4,178,753	
RE	$ 598,513.83	402.0	$ 1,488.84	$ 7,182,166	
Total Impact on NJ Zones	**$ 19,460,767.96**	**18,830.5**		**$ 233,529,216**	
Notes on calculations >>>			= (k) / (l)	= (k) *12	

Notes:

1) Uncompressed rate - assumes implementation on January 1, 2017

2) Data on PJM website

Attachment 6b
Potomac-Appalachian Transmission Highline Project Charges

Attachment 6b Potomac-Allegheny Transmission Highline (PATH)
PJM Schedule 12 - Transmission Enhancement Charges for January 2017 - December 2017
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 2017 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	$	10,911,443.68	1.57%	3.57%	5.89%	0.24%	$171,310	$389,539	$642,684	$26,187	$1,229,720
Amos-Bedington 765 kV Circuit (APS)	b0491	Included above		1.57%	3.57%	5.89%	0.24%	$0	$0	$0	$0	$0
Bedington-Kemptown 500 kV Circuit	b0492 & b560	$	10,498,177.93	1.57%	3.57%	5.89%	0.24%	$164,821	$374,785	$618,343	$25,196	$1,183,145
Totals		**$**	**21,409,621.61**					**$336,131**	**$764,323**	**$1,261,027**	**$51,383**	**$2,412,864**
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 2017**	**2017 Trans. Peak Load [2]**	**Rate in $/MW-mo. [1]**	**2017 Impact (12 months)**
PSE&G	$	105,085.56	9,800.3	$10.72	$ 1,261,027
JCP&L	$	63,693.62	5,954.8	$10.70	$ 764,323
ACE	$	28,010.92	2,673.4	$10.48	$ 336,131
RE	$	4,281.92	402.0	$10.65	$ 51,383
Total Impact on NJ Zones	**$**	**201,072.03**	**18,830.5**		**$ 2,412,864**
Notes on calculations >>>				= (k) / (l)	= (k) *12

Notes:
1) Uncompressed rate - assumes implementation on January 1, 2017
2) Data on PJM website

Attachment 6c
Virginia Electric Power Company Project Charges

Attachment 6c - PJM Schedule 12 - Transmission Enhancement Charges for January 2017 - December 2017
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 2017 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share**	**JCP&L Zone Share**	**PSE&G Zone Share1**	**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	$257,519.00	1.57%	3.57%	5.89%	0.24%	$4,043	$9,193	$15,168	$618	$29,022
Loudoun 150 MVA capacitor @ 500 kV	b0222	$193,396.00	1.57%	3.57%	5.89%	0.24%	$3,036	$6,904	$11,391	$464	$21,796
500 kV breakers and bus work at Suffolk	b0231	$2,565,149.00	1.57%	3.57%	5.89%	0.24%	$40,273	$91,576	$151,087	$6,156	$289,092
Meadowbrook-Loudon 500kV circuit	b0328.1	$29,345,839.00	1.57%	3.57%	5.89%	0.24%	$460,730	$1,047,646	$1,728,470	$70,430	$3,307,276
Upgrade Mt. Storm 500 KV Substation	b0328.3	$1,767,292.00	1.57%	3.57%	5.89%	0.24%	$27,746	$63,092	$104,093	$4,242	$199,174
Upgrade Loudoun 500 KV Substation	b0328.4	$402,197.00	1.57%	3.57%	5.89%	0.24%	$6,314	$14,358	$23,689	$965	$45,328
Carson – Suffolk 500 kV, Suffolk 500/230 kV transformer & build Suffolk – Trascher 230 kV circuit	B0329.2B	$21,040,416.00	1.57%	3.57%	5.89%	0.24%	$330,335	$751,143	$1,239,281	$50,497	$2,371,255
500/230 KV transformer at Bristers, new 230 Bristers - Gainsville circuit	b0227	$2,408,761.00	0.71%	0.00%	0.00%	0.00%	$17,102	$0	$0	$0	$17,102
Rebuild Mt Storm-Doubs 500 KV circuit	b1507	$45,815,697.00	1.57%	3.57%	5.89%	0.24%	$719,306	$1,635,620	$2,698,545	$109,958	$5,163,429
Replace wave traps on Dooms-Lexington 500KV circuit	b0457	$13,233.00	1.57%	3.57%	5.89%	0.24%	$208	$472	$779	$32	$1,491
Morrisville H1T573	b1647	$2,020.00	1.57%	3.57%	5.89%	0.24%	$32	$72	$119	$5	$228
Morrisville H2T545	b1648	$2,020.00	1.57%	3.57%	5.89%	0.24%	$32	$72	$119	$5	$228
Morrisville H1T580	b1649	$106,559.00	1.57%	3.57%	5.89%	0.24%	$1,673	$3,804	$6,276	$256	$12,009
Morrisville H2T569	b1650	$106,559.00	1.57%	3.57%	5.89%	0.24%	$1,673	$3,804	$6,276	$256	$12,009
Replace wave traps on North Anna-Ladysmith 500KV circuit	b0784	$9,182.00	1.57%	3.57%	5.89%	0.24%	$144	$328	$541	$22	$1,035
Reconductor the Dickerson-Pleasant View 230 KV circuit	b0467.2	$670,004.00	1.75%	0.71%	0.00%	0.00%	$11,725	$4,757	$0	$0	$16,482
Install 500/230 kV transformer and two 230 kV breakers at Brambleton	b1188.6	$2,141,910.00	0.22%	0.00%	0.00%	0.00%	$4,712	$0	$0	$0	$4,712
New Brambleton 500 kV line, 3 ring bus, to Loudon to Pleasant View 500 kV	b1188	($1,246,719.00)	1.57%	3.57%	5.89%	0.24%	-$19,573	-$44,508	-$73,432	-$2,992	-$140,505
500 kV breaker at Brambleton	b1698.1	($41,629.00)	1.57%	3.57%	5.89%	0.24%	-$654	-$1,486	-$2,452	-$100	-$4,692
Install 2 500kV breakers at Chancellor 500 kV	b0756.1	$546,099.00	1.57%	3.57%	5.89%	0.24%	$8,574	$19,496	$32,165	$1,311	$61,545
Wreck and Rebuild 7 miles of Cloverdale - Lexington 500 kV Line	b1797	$2,481,373.00	1.57%	3.57%	5.89%	0.24%	$38,958	$88,585	$146,153	$5,955	$279,651
Build 450 MVAR SVC and 300 MVAR switched shunt at Loudoun 500 kV	b1798	$16,783,438.00	1.57%	3.57%	5.89%	0.24%	$263,500	$599,169	$988,544	$40,280	$1,891,493
Build 150 MVAR Switched Shunt at Pleasant View 500 kV Line	b1799	$5,021,607.00	1.57%	3.57%	5.89%	0.24%	$78,839	$179,271	$295,773	$12,052	$565,935
Install 250 MVAR SVC at Mt. Storm 500 kV Substation	b1805	$4,794,401.00	1.57%	3.57%	5.89%	0.24%	$75,272	$171,160	$282,390	$11,507	$540,329
At Yadkin 500 kV, install six 500 kV Breakers	b1906.1	$808,926.00	1.57%	3.57%	5.89%	0.24%	$12,700	$28,879	$47,646	$1,941	$91,166
Rebuild Lexington-Dooms 500 kV Line	b1908	$18,940,114.00	1.57%	3.57%	5.89%	0.24%	$297,360	$676,162	$1,115,573	$45,456	$2,134,551

Attachment 6c - PJM Schedule 12 - Transmission Enhancement Charges for January 2017 - December 2017
Calculation of costs and monthly PJM charges for VEPCO Projects

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				**Estimated New Jersey EDC Zone Charges by Project**				
Required Transmission Enhancement	**PJM Upgrade ID**	**Jan - Dec 2017 Annual Revenue Requirement**	**ACE Zone Share**	**JCP&L Zone Share**	**PSE&G Zone Share1**	**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*								
Surry 500 kV Station Work	b1905.2	$251,298.00	1.57%	3.57%	5.89%	0.24%	$3,945	$8,971	$14,801	$603	$28,321
Mt Storm - Replace MOD with breaker on 500kV side of Transformer	b0837	$90,489.00	1.57%	3.57%	5.89%	0.24%	$1,421	$3,230	$5,330	$217	$10,198
Uprate Section between Possum and Dumfries Substation	b1328	$126,715.00	0.66%	0.00%	0.00%	0.00%	$836	$0	$0	$0	$836
Rebuild Loudoun - Brambleto 500kV	b1694	$5,790,175.00	1.57%	3.57%	5.89%	0.24%	$90,906	$206,709	$341,041	$13,896	$652,553
R/P Midlothian 500kV 3 breaker Ring Bus	b2471	$1,265,889.00	0.79%	1.79%	2.95%	0.12%	$9,937	$22,596	$37,280	$1,519	$71,333
Surry to Skiffes Creek 500kV Line	b1905.1	$2,649,662.00	1.57%	3.57%	5.89%	0.24%	$41,600	$94,593	$156,065	$6,359	$298,617
Install Breaker and half scheme with minimum of eight 230kV Breakers	b1696	$893,287.00	0.46%	0.64%	0.00%	0.00%	$4,109	$5,717	$0	$0	$9,826
Build a second Loudon - Brambleton 500kV line	b2373	$6,361,180.00	0.79%	1.79%	2.95%	0.12%	$49,935	$113,547	$187,337	$7,633	$358,452
Rebuild Elmont-Cunningham 500kV Line	b2582	$3,613,520.00	0.79%	1.79%	2.95%	0.12%	$28,366	$64,501	$106,418	$4,336	$203,622
Totals		**$175,977,578.00**					**$2,615,116**	**$5,869,437**	**$9,666,468**	**$393,880**	**$18,544,901**
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 2017**	**2017 Trans. Peak Load** [2]	**Rate in $/MW-mo.** [1]	**2017 Impact (12 months)**
PSE&G	$ 805,539.01	9,800.3	$ 82.20	$ 9,666,468
JCP&L	$ 489,119.74	5,954.8	$ 82.14	$ 5,869,437
ACE	$ 217,926.30	2,673.4	$ 81.52	$ 2,615,116
RE	$ 32,823.32	402.0	$ 81.65	$ 393,880
Total Impact on NJ Zones	**$ 1,545,408.38**	**18,830.5**		**$18,544,901**
Notes on calculations >>>			= (k) / (l)	= (k) *12

Attachment 7 – Cost Allocations

Attachment 7a – Responsible Customer Shares for PSE&G Schedule 12 Projects
Source – PJM OATT
Attachment 7b – Responsible Customer Shares for VEPCO Schedule 12 Projects
Source – PJM OATT
Attachment 7c – Responsible Customer Shares for PATH Schedule 12 Projects
Source – PJM OATT

NOTE: The “Responsible Share” percentages (annual cost allocation) for regional facilities were amended by PJM after the issues of the PJM OATT tariff pages. PJM has not yet issued an updated tariff to reflect its modifications of the Responsible Share percentages. For these regional projects, PJM’s modifications allocate the new updated responsible percentages to New Jersey’s EDCs as follow: 1.57% for ACE; 3.57% for JCP&L; 0.24% for RE; and 5.89% for PSE&G

Attachment 7a – Responsible Customer Shares for PSE&G Schedule 12 Projects

Source – PJM OATT

SCHEDULE 12 – APPENDIX

(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%) / ConEd (0.26%) / JCPL (47.63%) / PSEG (50.75%)
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 (1.70%) / ConEd (1.06%) / JCPL (25.66%) / Neptune* (10.51%) / PSEG (58.96%) / ECP** (2.11%)
b0170	Reconductor the Flagtown-Somerville-Bridgewater 230 kV circuit with 1590 ACSS		JCLP (42.95%) / Neptune* (17.90%) / PSEG (38.36%) RE (0.79%)

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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 (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
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%)

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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		ConEd (8.48%) / PSEG (88.56%) / ECP** (2.96%)
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 (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0358	Reconductor the PSEG portion of Buckingham – Pleasant Valley 230 kV, replace wave trap and metering transformer		PSEG (100%)

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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%)
b0472	Increase the emergency rating of Saddle Brook – Athenia 230 kV by 25% by adding forced cooling		ConEd (1.64%) / ECP (2.03%) / PSEG (92.86%) / RE (3.47%)
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 (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)†
b489.1	Replace Athenia 230 kV breaker 31H		PSEG (100%)

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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)
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 (5.07%) / ComEd (0.29%) / ConEd (0.48%) / Dayton (0.03%) / DPL (1.75%) / JCPL (32.57%) / Neptune* (6.29%) / PECO (9.99%) / PENELEC (0.56%) / ECP** (0.95%) / PSEG (40.51%) / RE (1.51%) ††
b0489.5	Replace Roseland 230 kV breaker '42H' with 80 kA		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0489.6	Replace Roseland 230 kV breaker '51H' with 80 kA		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0489.7	Replace Roseland 230 kV breaker '71H' with 80 kA		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0489.8	Replace Roseland 230 kV breaker '31H' with 80 kA		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)

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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 (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0489.10	Replace Roseland 230 kV breaker '21H'		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0489.11	Replace Roseland 230 kV breaker '32H'		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0489.12	Replace Roseland 230 kV breaker '12H'		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0489.13	Replace Roseland 230 kV breaker '52H'		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0489.14	Replace Roseland 230 kV breaker '41H'		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0489.15	Replace Roseland 230 kV breaker '72H'		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0498	Loop the 5021 circuit into New Freedom 500 kV substation		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
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%)
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 (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
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 (36.35%) / NEPTUNE* (18.80%) / PSEG (43.24%) / RE (1.61%)
b0665	Reconductor with 2x1033 ACSS conductor		JCPL (36.35%) / NEPTUNE* (18.80%) / PSEG (43.24%) / RE (1.61%)
b0668	Reconductor with 2x1033 ACSS conductor		JCPL (39.41%) / NEPTUNE* (20.38%) / PSEG (38.76%) / RE (1.45%)
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 (9.92%) / NEPTUNE* (0.87%) / PEPCO (1.11%) / PSEG (83.73%) / RE (3.12%)

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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 (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.1	Replace Kearny 138 kV breaker '1-SHT' with 80 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.2	Replace Kearny 138 kV breaker '15HF' with 80 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.3	Replace Kearny 138 kV breaker '14HF' with 80 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.4	Replace Kearny 138 kV breaker '10HF' with 80 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.5	Replace Kearny 138 kV breaker '2HT' with 80 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.6	Replace Kearny 138 kV breaker '22HF' with 80 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.7	Replace Kearny 138 kV breaker '4HT' with 80 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.8	Replace Kearny 138 kV breaker '25HF' with 80 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)

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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 (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.10	Replace Essex 138 kV breaker '1BT' with 63 kA breaker and 2.5 cycle contact parting time		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.11	Replace Essex 138 kV breaker '2PM' with 63 kA breaker and 2.5 cycle contact parting time		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.12	Replace Marion 138 kV breaker '2HM' with 63 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.13	Replace Marion 138 kV breaker '2LM' with 63 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.14	Replace Marion 138 kV breaker '1LM' with 63 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.15	Replace Marion 138 kV breaker '6PM' with 63 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.16	Replace Marion 138 kV breaker '3PM' with 63 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.17	Replace Marion 138 kV breaker '4LM' with 63 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)

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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 (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.19	Replace Marion 138 kV breaker '1HM' with 63 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.20	Replace Marion 138 kV breaker '2PM3' with 63 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.21	Replace Marion 138 kV breaker '2PM1' with 63 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.22	Replace ECRR 138 kV breaker '903'		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.23	Replace Foundry 138 kV breaker '21P'		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.24	Change the contact parting time on Essex 138 kV breaker '3LM' to 2.5 cycles		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.25	Change the contact parting time on Essex 138 kV breaker '2BM' to 2.5 cycles		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)

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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 (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.27	Change the contact parting time on Essex 138 kV breaker '3PM' to 2.5 cycles		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.28	Change the contact parting time on Essex 138 kV breaker '4LM' to 2.5 cycles		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.29	Change the contact parting time on Essex 138 kV breaker '1PM' to 2.5 cycles		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.30	Change the contact parting time on Essex 138 kV breaker '1LM' to 2.5 cycles		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)

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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 (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0829.6	Replace Branchburg 500 kV breaker 91X		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0829.9	Replace Branchburg 230 kV breaker 102H		PSEG (100%)

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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		PSEG (100%)
b0829.12	Replace Branchburg 230 kV breaker 52H		PSEG (100%)
b0830	Build Roseland - Hudson 500 kV circuit as part of Branchburg – Hudson 500 kV project		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0830.1	Replace Roseland 230 kV breaker '82H' with 80 kA		PSEG (100%
b0830.2	Replace Roseland 230 kV breaker '91H' with 80 kA		PSEG (100%)

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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		PSEG (100%)
b0831	Replace 138/13 kV transformers with 230/13 kV units as part of Branchburg – Hudson 500 kV project		ComEd (2.51%) / Dayton (0.09%) / PENELEC (2.75%) / ECP** (2.45%) / PSEG (88.74%) / RE (3.46%)
b0832	Build Hudson 500 kV switching station as part of Branchburg – Hudson 500 kV project		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0833	Build Roseland 500 kV switching station as part of Branchburg – Hudson 500 kV project		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)

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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 (2.51%) / Dayton (0.09%) / PENELEC (2.75%) / ECP** (2.45%) / PSEG (88.74%) / RE (3.46%)
b0835	Build Hudson 230 kV transmission lines as part of Roseland – Hudson 500 kV project as part of Branchburg – Hudson 500 kV project		ComEd (2.51%) / Dayton (0.09%) / PENELEC (2.75%) / ECP** (2.45%) / PSEG (88.74%) / RE (3.46%)
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 (2.51%) / Dayton (0.09%) / PENELEC (2.75%) / ECP** (2.45%) / PSEG (88.74%) / RE (3.46%)
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%)

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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		ConEd (49.36%) / JCPL (14.69%) / NEPTUNE* (1.39%) / PSEG (32.84%) / RE (1.28%) / ECP** (0.44%)
b1018	Reconductor South Mahwah - Waldwick 345 kV K-3411 circuit		ConEd (49.38%) / JCPL (14.77%) / NEPTUNE* (1.39%) / PSEG (32.74%) / RE (1.28%) / 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%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1019.9	Replace line, ground, 230 kV main bus disconnects at Athenia on the B-2258 circuit		PSEG (100%)
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%)
b1082.1	Replace Bergen 138 kV breaker '30P' with 80 kA		PSEG (100%)
b1082.2	Replace Bergen 138 kV breaker '80P' with 80 kA		PSEG (100%)
b1082.3	Replace Bergen 138 kV breaker '70P' with 80 kA		PSEG (100%)
b1082.4	Replace Bergen 138 kV breaker '90P' with 63 kA		PSEG (100%)
b1082.5	Replace Bergen 138 kV breaker '50P' with 63 kA		PSEG (100%)
b1082.6	Replace Bergen 230 kV breaker '12H' with 80 kA		PSEG (100%)
b1082.7	Replace Bergen 230 kV breaker '21H' with 80 kA		PSEG (100%)
b1082.8	Replace Bergen 230 kV breaker '11H' with 80 kA		PSEG (100%)
b1082.9	Replace Bergen 230 kV breaker '20H' with 80 kA		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%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
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%)
b1155.3	Replace Branchburg 230 kV breaker '81H' with 63 kA		PSEG (100%)
b1155.4	Replace Branchburg 230 kV breaker '72H' with 63 kA		PSEG (100%)
b1155.5	Replace Branchburg 230 kV breaker '61H' with 63 kA		PSEG (100%)
b1155.6	Replace Branchburg 230 kV breaker '41H' with 63 kA		PSEG (100%)
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%)
b1156.13	Replace Camden 230 kV breaker '22H' with 80 kA		PSEG (100%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1156.14	Replace Camden 230 kV breaker '32H' with 80 kA		PSEG (100%)
b1156.15	Replace Camden 230 kV breaker '21H' with 80 kA		PSEG (100%)
b1156.16	Replace New Freedom 230 kV breaker '50H' with 63 kA		PSEG (100%)
b1156.17	Replace New Freedom 230 kV breaker '41H' with 63 kA		PSEG (100%)
b1156.18	Replace New Freedom 230 kV breaker '51H' with 63 kA		PSEG (100%)
b1156.19	Rebuild Camden 230 kV to 80 kA		PSEG (100%)
b1156.20	Rebuild Burlington 230 kV to 80 kA		PSEG (100%)
b1197.1	Reconductor the PSEG portion of the Burlington – Croydon circuit with 1590 ACSS		PSEG (100%)
b1228	Re-configure the Lawrence 230 kV substation to breaker and half		HTP (0.14%) / ECP (0.22%) / PSEG (95.83%) / RE (3.81%)
b1255	Build a new 69 kV substation (Ridge Road) and build new 69 kV circuits from Montgomery – Ridge Road – Penns Neck/Dow Jones		PSEG (96.18%) / RE (3.82%)
b1304.1	Convert the existing ‘D1304’ and ‘G1307’ 138 kV circuits between Roseland – Kearny – Hudson to 230 kV operation		AEC (0.21%) / BGE (0.88%) / ComEd (2.11%) / ConEd (9.05%) / Dayton (0.12%) / JCPL (1.06%) / Neptune (0.06%) / HTP (14.60%) / PENELEC (2.70%) / PEPCO (0.95%) / ECP (1.92%) / PSEG (63.81%) / RE (2.53%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1304.2	Expand existing Bergen 230 kV substation and reconfigure the Athenia 230 kV substation to breaker and a half scheme		AEC (0.21%) / BGE (0.88%) / ComEd (2.11%) / ConEd (9.05%) / Dayton (0.12%) / JCPL (1.06%) / Neptune (0.06%) / HTP (14.60%) / PENELEC (2.70%) / PEPCO (0.95%) / ECP (1.92%) / PSEG (63.81%) / RE (2.53%)
b1304.3	Build second 230 kV underground cable from Bergen to Athenia		AEC (0.21%) / BGE (0.88%) / ComEd (2.11%) / ConEd (9.05%) / Dayton (0.12%) / JCPL (1.06%) / Neptune (0.06%) / HTP (14.60%) / PENELEC (2.70%) / PEPCO (0.95%) / ECP (1.92%) / PSEG (63.81%) / RE (2.53%)
b1304.4	Build second 230 kV underground cable from Hudson to South Waterfront		AEC (0.21%) / BGE (0.88%) / ComEd (2.11%) / ConEd (9.05%) / Dayton (0.12%) / JCPL (1.06%) / Neptune (0.06%) / HTP (14.60%) / PENELEC (2.70%) / PEPCO (0.95%) / ECP (1.92%) / PSEG (63.81%) / RE (2.53%)
b1304.5	Replace Athenia 230 kV breaker '21H' with 80 kA		PSEG (100%)
b1304.6	Replace Athenia 230 kV breaker '41H' with 80 kA		PSEG (100%)
b1304.7	Replace South Waterfront 230 kV breaker '12H' with 80 kA		PSEG (100%)
b1304.8	Replace South Waterfront 230 kV breaker '22H' with 80 kA		PSEG (100%)
b1304.9	Replace South Waterfront 230 kV breaker '32H' with 80 kA		PSEG (100%)
b1304.10	Replace South Waterfront 230 kV breaker '52H' with 80 kA		PSEG (100%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1304.11	Replace South Waterfront 230 kV breaker '62H' with 80 kA		PSEG (100%)
b1304.12	Replace South Waterfront 230 kV breaker '72H' with 80 kA		PSEG (100%)
b1304.13	Replace South Waterfront 230 kV breaker '82H' with 80 kA		PSEG (100%)
b1304.14	Replace Essex 230 kV breaker '20H' with 80 kA		PSEG (100%)
b1304.15	Replace Essex 230 kV breaker '21H' with 80 kA		PSEG (100%)
b1304.16	Replace Essex 230 kV breaker '10H' with 80 kA		PSEG (100%)
b1304.17	Replace Essex 230 kV breaker '11H' with 80 kA		PSEG (100%)
b1304.18	Replace Essex 230 kV breaker '11HL' with 80 kA		PSEG (100%)
b1304.19	Replace Newport R 230 kV breaker '23H' with 63 kA		PSEG (100%)
b1304.20	Rebuild Athenia 230 kV substation to 80 kA		PSEG (100%)
b1304.21	Rebuild Bergen 230 kV substation to 80 kA		PSEG (100%)
b1398	Build two new parallel underground circuits from Gloucester to Camden		JCPL (12.82%) / NEPTUNE (1.18%) / HTP (0.79%) / PECO (51.08%) / PEPCO (0.57%) / ECP** (0.85%) / PSEG (31.46%) / RE (1.25%)
b1398.1	Install shunt reactor at Gloucester to offset cable charging		JCPL (12.82%) / NEPTUNE (1.18%) / HTP (0.79%) / PECO (51.08%) / PEPCO (0.57%) / ECP** (0.85%) / PSEG (31.46%) / RE (1.25%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1398.2	Reconfigure the Cuthbert station to breaker and a half scheme		JCPL (12.82%) / NEPTUNE (1.18%) / HTP (0.79%) / PECO (51.08%) / PEPCO (0.57%) / ECP** (0.85%) / PSEG (31.46%) / RE (1.25%)
b1398.3	Build a second 230 kV parallel overhead circuit from Mickelton – Gloucester		JCPL (12.82%) / NEPTUNE (1.18%) / HTP (0.79%) / PECO (51.08%) / PEPCO (0.57%) / ECP** (0.85%) / PSEG (31.46%) / RE (1.25%)
b1398.4	Reconductor the existing Mickleton – Gloucester 230 kV circuit (PSEG portion)		JCPL (12.82%) / NEPTUNE (1.18%) / HTP (0.79%) / PECO (51.08%) / PEPCO (0.57%) / ECP** (0.85%) / PSEG (31.46%) / RE (1.25%)
b1398.7	Reconductor the Camden – Richmond 230 kV circuit (PSEG portion) and upgrade terminal equipments at Camden substations		JCPL (12.82%) / NEPTUNE (1.18%) / HTP (0.79%) / PECO (51.08%) / PEPCO (0.57%) / ECP** (0.85%) / PSEG (31.46%) / RE (1.25%)
b1398.15	Replace Gloucester 230 kV breaker '21H' with 63 kA		PSEG (100%)
b1398.16	Replace Gloucester 230 kV breaker '51H' with 63 kA		PSEG (100%)
b1398.17	Replace Gloucester 230 kV breaker '56H' with 63 kA		PSEG (100%)
b1398.18	Replace Gloucester 230 kV breaker '26H' with 63 kA		PSEG (100%)
b1398.19	Replace Gloucester 230 kV breaker '71H' with 63 kA		PSEG (100%)
b1399	Convert the 138 kV path from Aldene – Springfield Rd. – West Orange to 230 kV		PSEG (96.18%) / RE (3.82%)
b1400	Install 230 kV circuit breakers at Bennetts Ln. “F” and “X” buses		PSEG (100%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1410	Replace Salem 500 kV breaker ‘11X’		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b1411	Replace Salem 500 kV breaker ‘12X’		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b1412	Replace Salem 500 kV breaker ‘20X’		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1413	Replace Salem 500 kV breaker ‘21X’		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b1414	Replace Salem 500 kV breaker ‘31X’		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b1415	Replace Salem 500 kV breaker ‘32X’		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1539	Replace Tosco 230 kV breaker 'CB1' with 63 kA		PSEG (100%)
b1540	Replace Tosco 230 kV breaker 'CB2' with 63 kA		PSEG (100%)
b1541	Open the Hudson 230 kV bus tie		PSEG (100%)
b1588	Reconductor the Eagle Point - Gloucester 230 kV circuit #1 and #2 with higher conductor rating		JCPL (10.31%) / Neptune* (0.98%) / HTP (0.75%) / PECO (30.81%) / ECP** (0.82%) / PSEG (54.17%) / RE (2.16%)
b1589	Re-configure the Kearny 230 kV substation and loop the P-2216-1 (Essex - NJT Meadows) 230 kV circuit		ATSI (8.00%) / HTP (20.18%) / PENELEC (7.77%) / PSEG (61.59%) / RE (2.46%)
b1590	Upgrade the PSEG portion of the Camden Richmond 230 kV circuit to six wire conductor and replace terminal equipment at Camden		BGE (3.05%) / ME (0.83%) / HTP (0.21%) / PECO (91.36%) / PEPCO (1.93%) / PPL (2.46%) / ECP** (0.16%)
b1749	Advance n1237 (Replace Essex 230 kV breaker '22H' with 80kA)		PSEG (100%)
b1750	Advance n0666.5 (Replace Hudson 230 kV breaker '1HB' with 80 kA (without TRV cap, so actually 63 kA))		PSEG (100%)
b1751	Advance n0666.3 (Replace Hudson 230 kV breaker '2HA' with 80 kA (without TRV cap, so actually 63 kA))		PSEG (100%)
b1752	Advance n0666.10 (Replace Hudson 230 kV breaker '2HB' with 80 kA (without TRV cap, so actually 63 kA))		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)

b1753	Marion 138 kV breaker '7PM' - delay the relay time to increase the contact parting time to 2.5 cycles		PSEG (100%)
b1754	Marion 138 kV breaker '3PM' - delay the relay time to increase the contact parting time to 2.5 cycles		PSEG (100%)
b1755	Marion 138 kV breaker '6PM' - delay the relay time to increase the contact parting time to 2.5 cycles		PSEG (100%)
b1787	Build a second 230 kV circuit from Cox’s Corner - Lumberton		AEC (4.96%) / JCPL (44.20%) / NEPTUNE* (0.53%) / HTP (0.15%) / ECP** (0.16%) / PSEG (48.08%) / RE (1.92%)
b2034	Install a reactor along the Kearny - Essex 138 kV line		PSEG (100%)
b2035	Replace Sewaren 138 kV breaker ‘11P’		PSEG (100%)
b2036	Replace Sewaren 138 kV breaker ‘21P’		PSEG (100%)
b2037	Replace PVSC 138 kV breaker ‘452’		PSEG (100%)
b2038	Replace PVSC 138 kV breaker ‘552’		PSEG (100%)
b2039	Replace Bayonne 138 kV breaker ‘11P’		PSEG (100%)
b2139	Reconductor the Mickleton - Gloucester 230 kV parallel circuits with double bundle conductor		PSEG (61.11%) / PECO (36.45%) / RE (2.44%)
b2146	Re-configure the Brunswick 230 kV and 69 kV substations		PSEG (96.16%) / RE (3.84%)

*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)

b2151	Construct Jackson Rd. 69 kV substation and loop the Cedar Grove - Hinchmans Ave into Jackson Rd. and construct Hawthorne 69 kV substation and build 69 kV circuit from Hinchmans Ave - Hawthorne - Fair Lawn		PSEG (100%)
b2159	Reconfigure the Linden, Bayway, North Ave, and Passaic Valley S.C. 138 kV substations. Construct and loop new 138 kV circuit to new airport station		PSEG (72.61%) / HTP (24.49%) / RE (2.90%)

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

SCHEDULE 12 – APPENDIX A

(12) Public Service Electric and Gas Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2218	Rebuild 4 miles of overhead line from Edison - Meadow Rd - Metuchen (Q 1317)		HTP (36.49%) / ECP** (63.51%)
b2239	50 MVAR reactor at Saddlebrook 230 kV		PSEG (100%)
b2240	50 MVAR reactor at Athenia 230 kV		PSEG (100%)
b2241	50 MVAR reactor at Bergen 230 kV		PSEG (100%)
b2242	50 MVAR reactor at Hudson 230 kV		PSEG (100%)
b2243	Two 50 MVAR reactors at Stanley Terrace 230 kV		PSEG (100%)
b2244	50 MVAR reactor at West Orange 230 kV		PSEG (100%)
b2245	50 MVAR reactor at Aldene 230 kV		PSEG (100%)
b2246	150 MVAR reactor at Camden 230 kV		PSEG (100%)
b2247	150 MVAR reactor at Gloucester 230 kV		PSEG (100%)
b2248	50 MVAR reactor at Clarksville 230 kV		PSEG (100%)
b2249	50 MVAR reactor at Hinchmans 230 kV		PSEG (100%)
b2250	50 MVAR reactor at Beaverbrook 230 kV		PSEG (100%)
b2251	50 MVAR reactor at Cox's Corner 230 kV		PSEG (100%)

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

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)
b2276	Eliminate the Sewaren 138 kV bus by installing a new 230 kV bay at Sewaren 230 kV		ConEd (*50.82*%) / ECP** (*49.18*%)
b2276.1	Convert the two 138 kV circuits from Sewaren – Metuchen to 230 kV circuits including Lafayette and Woodbridge substation		ConEd (*50.82*%) / ECP** (*49.18*%)
b2276.2	Reconfigure the Metuchen 230 kV station to accommodate the two converted circuits		ConEd (*50.82*%) / ECP** (*49.18*%)
b2290	Replace disconnect switches at Kilmer, Lake Nilson and Greenbrook 230 kV substations on the Raritian River - Middlesex (I-1023) circuit		PSEG (100%)
b2291	Replace circuit switcher at Lake Nelson 230 kV substation on the Raritian River - Middlesex (W-1037) circuit		PSEG (100%)
b2295	Replace the Salem 500 kV breaker 10X with 63kA breaker		PSEG (100%)
b2421	Install all 69kV lines to interconnect Plainfield, Greenbrook, and Bridgewater stations and establish the 69kV network		PSEG (100%)
b2421.1	Install two 18MVAR capacitors at Plainfield and S. Second St substation		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)
b2421.2	Install a second four (4) breaker 69kV ring bus at Bridgewater Switching Station		PSEG (100%)
b2436.10	Convert the Bergen – Marion 138 kV path to double circuit 345 kV and associated substation upgrades		**Load-Ration Share Allocation:** AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / Dominion (12.42%) / DPL (2.43%) / ECP** (0.20%) / EKPC (2.15%) / HTP*** (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%)
			DFAX Allocation: ConEd (93.00%) / ECP (5.76%) / HTP (0.24%) / PSEG (0.96%) / RE (0.04%)

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)

*Neptune Regional Transmission System, LLC
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***Hudson Transmission Partners, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2436.21	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades		**Load-Ratio Share Allocation:** AEC (1.53%) / AEP (15.32%) / APS (5.87 %) / ATSI (7.76%) / BGE (4.18 %) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69 %) / DPL (2.43 %) / Dominion (12.42%) / EKPC (2.15%) / HTP*** (0.20 %) / JCPL (3.54 %) / ME (1.77 %) / NEPTUNE* (0.42%) / PECO (5.18 %) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
			DFAX Allocation: ConEd (87.68%) / HTP*** (11.72%) / ECP** (0.60 %)

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2436.22	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades		**Load-Ratio Share Allocation:** AEC (1.53%) / AEP (15.32%) / APS (5.87 %) / ATSI (7.76%) / BGE (4.18 %) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01 %) / DEOK (3.21%) / DL (1.69 %) / DPL (2.43 %) / Dominion (12.42%) / EKPC (2.15%) / HTP*** (0.20 %) / JCPL (3.54 %) / ME (1.77 %) / NEPTUNE* (0.42%) / PECO (5.18 %) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
			DFAX Allocation: ConEd (87.69%) / HTP*** (11.71%) / ECP** (0.60 %)

*Neptune Regional Transmission System, LLC

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

***Hudson Transmission Partners, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2436.33	Construct a new Bayway – Bayonne 345 kV circuit and any associated substation upgrades		ConEd (86.07%) / ECP (0.30%) / HTP (13.63%)
b2436.34	Construct a new North Ave – Bayonne 345 kV circuit and any associated substation upgrades		ConEd (86.05%) / ECP (0.33%) / HTP (13.62%)

*Neptune Regional Transmission System, LLC
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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2436.50	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades		ConEd (85.84%) / HTP*** (13.60%) / ECP** (0.56%)
b2436.60	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades		ConEd (86.19%) / HTP*** (13.65%) / ECP** (0.16 %)
b2436.70	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades		ConEd (86.26%) / HTP*** (13.66%) / ECP** (0.08 %)

*Neptune Regional Transmission System, LLC

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

***Hudson Transmission Partners, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2436.81	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades		**Load-Ratio Share Allocation:** AEC (1.53%) / AEP (15.32%) / APS (5.87 %) / ATSI (7.76%) / BGE (4.18 %) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01 %) / DEOK (3.21%) / DL (1.69%) / DPL (2.43 %) / Dominion (12.42%) / EKPC (2.15%) / HTP*** (0.20 %) / JCPL (3.54 %) / ME (1.77 %) / NEPTUNE* (0.42%) / PECO (5.18 %) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
			DFAX Allocation: ConEd (12.79%) / HTP*** (6.60%) / ECP** (0.02%) / PSEG (77.53%) / RE (3.06%)

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2436.83	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades		**Load-Ratio Share Allocation:** AEC (1.53%) / AEP (15.32%) / APS (5.87 %) / ATSI (7.76%) / BGE (4.18 %) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01 %) / DEOK (3.21%) / DL (1.69%) / DPL (2.43 %) / Dominion (12.42%) / EKPC (2.15%) / HTP*** (0.20 %) / JCPL (3.54 %) / ME (1.77 %) / NEPTUNE* (0.42%) / PECO (5.18 %) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
			DFAX Allocation: ConEd (12.80%) / HTP*** (6.60%) / ECP** (0.02%) / PSEG (77.52%) / RE (3.06%)
b2436.84	Convert the Bayway – Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades		**Load-Ration Share Allocation:** AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / Dominion (12.42%) / DPL (2.43%) / ECP** (0.20%) / EKPC (2.15%) / HTP*** (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%)
			DFAX Allocation: ConEd (65.97%) / ECP (0.02%) / HTP (34.01%)

*Neptune Regional Transmission System, LLC
**East Coast Power, L.L.C.
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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2436.85	Convert the Bayway – Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades		**Load-Ration Share Allocation:** AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / Dominion (12.42%) / DPL (2.43%) / ECP** (0.20%) / EKPC (2.15%) / HTP*** (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%)
			DFAX Allocation: ConEd (65.97%) / ECP (0.02%) / HTP (34.01%)
b2436.90	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades		**Load-Ratio Share Allocation:** AEC (1.53%) / AEP (15.32%) / APS (5.87 %) / ATSI (7.76%) / BGE (4.18 %) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01 %) / DEOK (3.21%) / DL (1.69%) / DPL (2.43 %) / Dominion (12.42%) / EKPC (2.15%) / HTP*** (0.20 %) / JCPL (3.54 %) / ME (1.77 %) / NEPTUNE* (0.42%) / PECO (5.18 %) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
			DFAX Allocation: ConEd (99.16%) / HTP (0.05%) / PSEG (0.76%) / RE (0.03%)

*Neptune Regional Transmission System, LLC

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

***Hudson Transmission Partners, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2436.91	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades		PSEG (100%)
b2437.10	New Bergen 345/230 kV transformer and any associated substation upgrades		ConEd (89.34%) / HTP*** (1.07 %) / ECP** (5.58%) / PSEG (3.86 %) / RE (0.15%)
b2437.11	New Bergen 345/138 kV transformer #1 and any associated substation upgrades		ConEd (95.12%) / ECP (4.88%)
b2437.20	New Bayway 345/138 kV transformer #1 and any associated substation upgrades		ConEd (0.32%) / ECP (0.03%) / HTP (3.27%) / PSEG (92.72%) / RE (3.66%)
b2437.21	New Bayway 345/138 kV transformer #2 and any associated substation upgrades		ConEd (0.15%) / ECP (0.02%) / HTP (2.91%) / PSEG (93.24%) / RE (3.68%)
b2437.30	New Linden 345/230 kV transformer and any associated substation upgrades		ConEd (19.62%) / HTP*** (8.43%) / ECP** (0.25%) / Neptune (0.05%) / PSEG (68.93%) / RE (2.72%)
b2437.33	New Bayonne 345/69 kV transformer and any associated substation upgrades		ConEd (100%)
b2438	*Install two reactors at Tosco 230 kV*		*PSEG (100.00%)*

*Neptune Regional Transmission System, LLC

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

***Hudson Transmission Partners, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2439	*Replace the Tosco 138kV breaker 'CB1/2 (CBT)' with 63kA*		*PSEG (100.00%)*
b2474	Rebuild Athenia 138 kV to 80kA		PSEG (100%)
b2589	*Install a 100 MVAR 230 kV shunt reactor at Mercer station*		*PSEG (100%)*
b2590	*Install two 75 MVAR 230 kV capacitors at Sewaren station*		*PSEG (100%)*

*Neptune Regional Transmission System, LLC

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

***Hudson Transmission Partners, LLC

Attachment 7b – Responsible Customer Shares for VEPCO Schedule 12 Projects
Source – PJM OATT

SCHEDULE 12 – APPENDIX

(20) Virginia Electric and Power Company

Required Transmission Enhancements		Annual Revenue Requirement***	Responsible Customer(s)
b0217	Upgrade Mt. Storm - Doubs 500kV		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0222	Install 150 MVAR capacitor at Loudoun 500 kV		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)

* Neptune Regional Transmission System, LLC

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

*** Hudson Transmission Partners, LLC

*** The Annual Revenue Requirement for all Virginia Electric and Power Company projects in this Section 20 shall be as specified in Attachment 7 to Appendix A of Attachment H-16A and under the procedures detailed in Attachment H-16B.

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0223	Install 150 MVAR capacitor at Asburn 230 kV		Dominion (100%)
b0224	Install 150 MVAR capacitor at Dranesville 230 kV		Dominion (100%)
b0225	Install 33 MVAR capacitor at Possum Pt. 115 kV		Dominion (100%)
b0226	Install 500/230 kV transformer at Clifton and Clifton 500 kV 150 MVAR capacitor	As specified in Attachment 7 to Appendix A of Attachment H-16A and under the procedures detailed in Attachment H-16B	APS (3.69%) / BGE (3.54%) / Dominion (85.73%) / PEPCO (7.04%)
b0227	Install 500/230 kV transformer at Bristers; build new 230 kV Bristers-Gainsville circuit, upgrade two Loudoun-Brambleton circuits		AEC (0.71%) / APS (3.35%) / BGE (10.92%) / ConEd (0.10%) / DPL (1.66%) / Dominion (67.31%) / ME (0.89%) / PECO (2.33%) / PEPCO (12.19%) / PPL (0.54%)
b0227.1	Loudoun Sub – upgrade 6-230 kV breakers		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0231	Install 500 kV breakers & 500 kV bus work at Suffolk		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
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.

*** Hudson Transmission Partners, LLC

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0307	Reconductor Endless Caverns – Mt. Jackson 115 kV		Dominion (100%)
b0308	Replace L breaker and switches at Endless Caverns 115 kV		Dominion (100%)
b0309	Install SPS at Earleys 115 kV		Dominion (100%)
b0310	Reconductor Club House – South Hill and Chase City – South Hill 115 kV		Dominion (100%)
b0311	Reconductor Idylwood to Arlington 230 kV		Dominion (100%)
b0312	Reconductor Gallows to Ox 230 kV		Dominion (100%)
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 (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)

* Neptune Regional Transmission System, LLC

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0328.3	Upgrade Mt. Storm 500 kV substation		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0328.4	Upgrade Loudoun 500 kV substation		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0329	Build Carson – Suffolk 500 kV, install 2nd Suffolk 500/230 kV transformer & build Suffolk – Fentress 230 kV circuit		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0329	Build Carson – Suffolk 500 kV, install 2nd Suffolk 500/230 kV transformer & build Suffolk – Fentress 230 kV circuit		Dominion (100%)††
b0329.1	Replace Thole Street 115 kV breaker '48T196'		Dominion (100%)
b0329.2	Replace Chesapeake 115 kV breaker 'T242'		Dominion (100%)
b0329.3	Replace Chesapeake 115 kV breaker '8722'		Dominion (100%)
b0329.4	Replace Chesapeake 115 kV breaker '16422'		Dominion (100%)
b0330	Install Crewe 115 kV breaker and shift load from line 158 to 98		Dominion (100%)
b0331	Upgrade/resag Shell Bank – Whealton 115 kV (Line 165)		Dominion (100%)

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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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0332	Uprate/resag Chesapeake – Cradock 115 kV		Dominion (100%)
b0333	Replace wave trap on Elmont – Replace (Line #231)		Dominion (100%)
b0334	Uprate/resag Iron Bridge-Walmsley-Southwest 230 kV		Dominion (100%)
b0335	Build Chase City – Clarksville 115 kV		Dominion (100%)
b0336	Reconductor one span of Chesapeake – Dozier 115 kV close to Dozier substation		Dominion (100%)
b0337	Build Lexington 230 kV ring bus		Dominion (100%)
b0338	Replace Gordonsville 230/115 kV transformer for larger one		Dominion (100%)
b0339	Install Breaker at Dooms 230 kV Sub		Dominion (100%)
b0340	Reconductor one span Peninsula – Magruder 115 kV close to Magruder substation		Dominion (100%)
b0341	Install a breaker at Northern Neck 115 kV		Dominion (100%)
b0342	Replace Trowbridge 230/115 kV transformer		Dominion (100%)
b0403	2nd Dooms 500/230 kV transformer addition		APS (3.35%) / BGE (4.22%) / DPL (1.10%) / Dominion (83.94%) / PEPCO (7.39%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0412	Retension Pruntytown – Mt. Storm 500 kV to a 3502 MVA rating		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0450	Install 150 MVAR Capacitor at Fredricksburg 230 kV		Dominion (100%)
b0451	Install 25 MVAR Capacitor at Somerset 115 kV		Dominion (100%)
b0452	Install 150 MVAR Capacitor at Northwest 230 kV		Dominion (100%)
b0453.1	Convert Remingtion – Sowego 115 kV to 230 kV		APS (0.31%) / BGE (3.01%) / DPL (0.04%) / Dominion (92.75%) / ME (0.03%) / PEPCO (3.86%)
b0453.2	Add Sowego – Gainsville 230 kV		APS (0.31%) / BGE (3.01%) / DPL (0.04%) / Dominion (92.75%) / ME (0.03%) / PEPCO (3.86%)
b0453.3	Add Sowego 230/115 kV transformer		APS (0.31%) / BGE (3.01%) / DPL (0.04%) / Dominion (92.75%) / ME (0.03%) / PEPCO (3.86%)
b0454	Reconductor 2.4 miles of Newport News – Chuckatuck 230 kV		Dominion (100%)
b0455	Add 2nd Endless Caverns 230/115 kV transformer		APS (32.70%) / BGE (7.01%) / DPL (1.80%) / Dominion (50.82%) / PEPCO (7.67%)
b0456	Reconductor 9.4 miles of Edinburg – Mt. Jackson 115 kV		APS (33.69%) / BGE (12.18%) / Dominion (40.08%) / PEPCO (14.05%)
b0457	Replace both wave traps on Dooms – Lexington 500 kV		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0467.2	Reconductor the Dickerson – Pleasant View 230 kV circuit		AEC (1.75%) / APS (19.66%) / BGE (22.09%) / ConEd (0.18%) / DPL (3.69%) / JCPL (0.71%) / ME (2.48%) / Neptune* (0.06%) / PECO (5.53%) / PEPCO (41.78%) / PPL (2.07%)
b0492.6	Replace Mount Storm 500 kV breaker 55072		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0492.7	Replace Mount Storm 500 kV breaker 55172		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0492.8	Replace Mount Storm 500 kV breaker H1172-2		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0492.9	Replace Mount Storm 500 kV breaker G2T550		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0492.10	Replace Mount Storm 500 kV breaker G2T554		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0492.11	Replace Mount Storm 500 kV breaker G1T551		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0492.12	Upgrade nameplate rating of Mount Storm 500 kV breakers 55472, 57272, SX172, G3TSX1, G1TH11, G3T572, and SX22		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
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 (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0512.5	Advance n0716 (Ox - Replace 230kV breaker L242)		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.6	Advance n0717 (Possum Point - Replace 230kV breaker SC192)		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0583	Install dual primary protection schemes on Gosport lines 62 and 51 at the remote terminals (Chesapeake on the 62 line and Reeves Ave on the 51 line)		Dominion (100%)
b0756	Install a second 500/115 kV autotransformer at Chancellor 500 kV		Dominion (100%)
b0756.1	Install two 500 kV breakers at Chancellor 500 kV		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0757	Reconductor one mile of Chesapeake – Reeves Avenue 115 kV line		Dominion (100%)
b0758	Install a second Fredericksburg 230/115 kV autotransformer		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0759	Build a second Dooms – Dupont – Waynesboro 115 kV line		Dominion (100%)
b0760	Build 115 kV line from Kitty Hawk to Colington 115 kV (Colington on the existing line and Nag's Head and Light House DP on new line)		Dominion (100%)
b0761	Install a second 230/115 kV transformer at Possum Point		Dominion (100%)
b0762	Build a new Elko station and transfer load from Turner and Providence Forge stations		Dominion (100%)
b0763	Rebuild 17.5 miles of the line for a new summer rating of 262 MVA		Dominion (100%)
b0764	Increase the rating on 2.56 miles of the line between Greenwich and Thompson Corner; new rating to be 257 MVA		Dominion (100%)
b0765	Add a second Bull Run 230/115 kV autotransformer		Dominion (100%)
b0766	Increase the rating of the line between Loudoun and Cedar Grove to at least 150 MVA		Dominion (100%)
b0767	Extend the line from Old Church – Chickahominy 230 kV		Dominion (100%)
b0768	Loop line #251 Idylwood – Arlington into the GIS sub		Dominion (100%)
b0769	Re-tension 15 miles of the line for a new summer rating of 216 MVA		Dominion (100%)
b0770	Add a second 230/115 kV autotransformer at Lanexa		Dominion (100%)
b0770.1	Replace Lanexa 115 kV breaker '8532'		Dominion (100%)
b0770.2	Replace Lanexa 115 kV breaker '9232'		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0771	Build a parallel Chickahominy – Lanexa 230 kV line		Dominion (100%)
b0772	Install a second Elmont 230/115 kV autotransformer		Dominion (100%)
b0772.1	Replace Elmont 115 kV breaker '7392'		Dominion (100%)
b0774	Install a 33 MVAR capacitor at Bremo 115 kV		Dominion (100%)
b0775	Reconductor the Greenwich – Virginia Beach line to bring it up to a summer rating of 261 MVA; Reconductor the Greenwich – Amphibious Base line to bring it up to 291 MVA		Dominion (100%)
b0776	Re-build Trowbridge – Winfall 115 kV		Dominion (100%)
b0777	Terminate the Thelma – Carolina 230 kV circuit into Lakeview 230 kV		Dominion (100%)
b0778	Install 29.7 MVAR capacitor at Lebanon 115 kV		Dominion (100%)
b0779	Build a new 230 kV line from Yorktown to Hayes but operate at 115 kV initially		Dominion (100%)
b0780	Reconductor Chesapeake – Yadkin 115 kV line		Dominion (100%)
b0781	Reconductor and replace terminal equipment on line 17 and replace the wave trap on line 88		Dominion (100%)
b0782	Install a new 115 kV capacitor at Dupont Waynesboro substation		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0784	Replace wave traps on North Anna to Ladysmith 500 kV		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
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%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0837	At Mt. Storm, replace the existing MOD on the 500 kV side of the transformer with a circuit breaker		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0888	Replace Loudoun 230 kV Cap breaker 'SC352'		Dominion (100%)
b0892	Replace Chesapeake 115 kV breaker SX522		Dominion (100%)
b0893	Replace Chesapeake 115 kV breaker T202		Dominion (100%)
b0894	Replace Possum Point 115 kV breaker SX-32		Dominion (100%)
b0895	Replace Possum Point 115 kV breaker L92-1		Dominion (100%)
b0896	Replace Possum Point 115 kV breaker L92-2		Dominion (100%)
b0897	Replace Suffolk 115 kV breaker T202		Dominion (100%)
b0898	Replace Peninsula 115 kV breaker SC202		Dominion (100%)
b0921	Reconductor Brambleton - Cochran Mill 230 kV line with 201 Yukon conductor		Dominion (100%)
b0923	Install 50-100 MVAR variable reactor banks at Carson 230 kV		Dominion (100%)
b0924	Install 50-100 MVAR variable reactor banks at Dooms 230 kV		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0925	Install 50-100 MVAR variable reactor banks at Garrisonville 230 kV		Dominion (100%)
b0926	Install 50-100 MVAR variable reactor banks at Hamilton 230 kV		Dominion (100%)
b0927	Install 50-100 MVAR variable reactor banks at Yadkin 230 kV		Dominion (100%)
b0928	Install 50-100 MVAR variable reactor banks at Carolina, Dooms, Everetts, Idylwood, N. Alexandria, N. Anna, Suffolk and Valley 230 kV substations		Dominion (100%)
b1056	Build a 2nd Shawboro – Elizabeth City 230kV line		Dominion (100%)
b1058	Add a third 230/115 kV transformer at Suffolk substation		Dominion (100%)
b1058.1	Replace Suffolk 115 kV breaker ‘T122’ with a 40 kA breaker		Dominion (100%)
b1058.2	Convert Suffolk 115 kV straight bus to a ring bus for the three 230/115 kV transformers and three 115 kV lines		Dominion (100%)
b1071	Rebuild the existing 115 kV corridor between Landstown - Va Beach Substation for a double circuit arrangement (230 kV & 115 kV)		Dominion (100%)
b1076	Replace existing North Anna 500-230kV transformer with larger unit		Dominion (100%)
b1087	Replace Cannon Branch 230-115 kV with larger transformer		Dominion (100%)

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1088	Build new Radnor Heights Sub, add new underground circuit from Ballston - Radnor Heights, Tap the Glebe - Davis line and create circuits from Davis - Radnor Heights and Glebe - Radnor Heights		Dominion (100%)
b1089	Install 2nd Burke to Sideburn 230 kV underground cable		Dominion (100%)
b1090	Install a 150 MVAR 230 kV capacitor and one 230 kV breaker at Northwest		Dominion (100%)
b1095	Reconductor Chase City 115 kV bus and add a new tie breaker		Dominion (100%)
b1096	Construct 10 mile double ckt. 230kV tower line from Loudoun to Middleburg		Dominion (100%)
b1102	Replace Bremo 115 kV breaker '9122'		Dominion (100%)
b1103	Replace Bremo 115 kV breaker '822'		Dominion (100%)
b1172	Build a 4-6 mile long 230 kV line from Hopewell to Bull Hill (Ft Lee) and install a 230-115 kV Tx		Dominion (100%)

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1188	Build new Brambleton 500 kV three breaker ring bus connected to the Loudoun to Pleasant View 500 kV line		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b1188.1	Replace Loudoun 230 kV breaker ‘200852’ with a 63 kA breaker		Dominion (100%)
b1188.2	Replace Loudoun 230 kV breaker ‘2008T2094’ with a 63 kA breaker		Dominion (100%)
b1188.3	Replace Loudoun 230 kV breaker ‘204552’ with a 63 kA breaker		Dominion (100%)
b1188.4	Replace Loudoun 230 kV breaker ‘209452’ with a 63 kA breaker		Dominion (100%)
b1188.5	Replace Loudoun 230 kV breaker ‘WT2045’ with a 63 kA breaker		Dominion (100%)
b1188.6	Install one 500/230 kV transformer and two 230 kV breakers at Brambleton		AEC (0.22%) / BGE (7.90%) / DPL (0.59%) / Dominion (75.58%) / ME (0.22%) / PECO (0.73%) / PEPCO (14.76%)
b1224	Install 2nd Clover 500/230 kV transformer and a 150 MVAr capacitor		BGE (7.56%) / DPL (1.03%) / Dominion (78.21%) / ME (0.77%) / PECO (1.39%) / PEPCO (11.04%)
b1225	Replace Yorktown 115 kV breaker ‘L982-1’		Dominion (100%)

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

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1226	Replace Yorktown 115 kV breaker ‘L982-2’		Dominion (100%)
b1279	Line #69 Uprate – Increase rating on Locks – Purdy 115 kV to serve additional load at the Reams delivery point		Dominion (100%)
b1306	Reconfigure 115 kV bus at Endless Caverns substation such that the existing two 230/115 kV transformers at Endless Caverns operate in		Dominion (100%)
b1307	Install a 2nd 230/115 kV transformer at Northern Neck Substation		Dominion (100%)
b1308	Improve LSE’s power factor factor in zone to .973 PF, adjust LTC’s at Gordonsville and Remington, move existing shunt capacitor banks		Dominion (100%)
b1309	Install a 230 kV line from Lakeside to Northwest utilizing the idle line and 60 line ROW’s and reconductor the existing 221 line between Elmont and Northwest		Dominion (100%)
b1310	Install a 115 kV breaker at Broadnax substation on the South Hill side of Broadnax		Dominion (100%)
b1311	Install a 230 kV 3000 amp breaker at Cranes Corner substation to sectionalize the 2104 line into two lines		Dominion (100%)
b1312	Loop the 2054 line in and out of Hollymeade and place a 230 kV breaker at Hollymeade. This creates two lines: Charlottesville - Hollymeade		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1313	Resag wire to 125C from Chesterfield – Shockoe and replace line switch 1799 with 1200 amp switch. The new rating would be 231 MVA.		Dominion (100%)
b1314	Rebuild the 6.8 mile line #100 from Chesterfield to Harrowgate 115 kV for a minimum 300 MBA rating		Dominion (100%)
b1315	Convert line #64 Trowbridge to Winfall to 230 kV and install a 230 kV capacitor bank at Winfall		Dominion (100%)
b1316	Rebuild 10.7 miles of 115 kV line #80, Battleboro – Heartsease DP		Dominion (100%)
b1317	LSE load power factor on the #47 line will need to meet MOA requirements of .973 in 2015 to further resolve this issue through at least 2019		Dominion (100%)
b1318	Install a 115 kV bus tie breaker at Acca substation between the Line #60 and Line #95 breakers		Dominion (100%)
b1319	Resag line #222 to 150 C and upgrade any associated equipment to a 2000A rating to achieve a 706 MVA summer line rating		Dominion (100%)
b1320	Install a 230 kV, 150 MVAR capacitor bank at Southwest substation		Dominion (100%)
b1321	Build a new 230 kV line North Anna – Oak Green and install a 224 MVA 230/115 kV transformer at Oak Green		BGE (0.85%) / Dominion (97.96%) / PEPCO (1.19%)
b1322	Rebuild the 39 Line (Dooms – Sherwood) and the 91 Line (Sherwood – Bremo)		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1323	Install a 224 MVA 230/115 kV transformer at Staunton. Rebuild the 115 kV line #43 section Staunton - Verona		Dominion (100%)
b1324	Install a 115 kV capacitor bank at Oak Ridge. Install a capacitor bank at New Bohemia. Upgrade 230/34.5 kV transformer #3 at Kings Fork		Dominion (100%)
b1325	Rebuild 15 miles of line #2020 Winfall – Elizabeth City with a minimum 900 MVA rating		Dominion (100%)
b1326	Install a third 168 MVA 230/115 kV transformer at Kitty Hawk with a normally open 230 kV breaker and a low side 115 kV breaker		Dominion (100%)
b1327	Rebuild the 20 mile section of line #22 between Kerr Dam – Eatons Ferry substations		Dominion (100%)
b1328	Uprate the 3.63 mile line section between Possum and Dumfries substations, replace the 1600 amp wave trap at Possum Point		AEC (0.66%) / APS (3.59%) / DPL (0.91%) / Dominion (92.94%) / PECO (1.90%)
b1329	Install line-tie breakers at Sterling Park substation and BECO substation		Dominion (100%)
b1330	Install a five breaker ring bus at the expanded Dulles substation to accommodate the existing Dulles Arrangement and support the Metrorail		Dominion (100%)
b1331	Build a 230 kV line from Shawboro to Aydlett tap and connect Aydlett to the new line		Dominion (100%)
b1332	Build Cannon Branch to Nokesville 230 kV line		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1333	Advance n1728 (Replace Possum Point 230 kV breaker H9T237 with an 80 kA breaker)		Dominion (100%)
b1334	Advance n1748 (Replace Ox 230 kV breaker 22042 with a 63 kA breaker)		Dominion (100%)
b1335	Advance n1749 (Replace Ox 230 kV breaker 220T2603 with a 63 kA breaker)		Dominion (100%)
b1336	Advance n1750 (Replace Ox 230 kV breaker 24842 with a 63 kA breaker)		Dominion (100%)
b1337	Advance n1751 (Replace Ox 230 kV breaker 248T2013 with a 63 kA breaker)		Dominion (100%)
b1503.1	Loop Line #2095 in and out of Waxpool approximately 1.5 miles		Dominion (100%)
b1503.2	Construct a new 230kV line from Brambleton to BECO Substation of approximately 11 miles with approximately 10 miles utilizing the vacant side of existing Line #2095 structures		Dominion (100%)
b1503.3	Install a one 230 kV breaker, Future 230 kV ring-bus at Waxpool Substation		Dominion (100%)
b1503.4	The new Brambleton - BECO line will feed Shellhorn Substation load and Greenway TX's #2&3 load		Dominion (100%)
b1506.1	At Gainesville Substation, create two 115 kV straight-buses with a normally open tie-breaker		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1506.2	Upgrade Line 124 (radial from Loudoun) to a minimum continuous rating of 500 MVA and network it into the 115 kV bus feeding NOVEC's DP at Gainesville		Dominion (100%)
b1506.3	Install two additional 230 kV breakers in the ring at Gainesville (may require substation expansion) to accommodate conversion of NOVEC's Gainesville to Wheeler line		Dominion (100%)
b1506.4	Convert NOVEC's Gainesville-Wheeler line from 115 kV to 230 kV (will require Gainsville DP Upgrade replacement of three transformers total at Atlantic and Wheeler Substations)		Dominion (100%)
b1507	Rebuild Mt Storm – Doubs 500 kV		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b1508.1	Build a 2nd 230 kV Line Harrisonburg to Endless Caverns		APS (37.05%) / Dominion (62.95%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1508.2	Install a 3rd 230-115 kV Tx at Endless Caverns		APS (37.05%) / Dominion (62.95%)
b1508.3	Upgrade a 115 kV shunt capacitor banks at Merck and Edinburg		APS (37.05%) / Dominion (62.95%)
b1536	Advance n1752 (Replace OX 230 breaker 24342 with an (63kA breaker)		Dominion (100%)
b1537	Advance n1753 (Replace OX 230 breaker 243T2097 with an 63kA breaker)		Dominion (100%)
b1538	Replace Loudoun 230 kV breaker ‘29552’		Dominion (100%)
b1571	Replace Acca 115 kV breaker ‘6072’ with 40 kA		Dominion (100%)
b1647	Upgrade the name plate rating at Morrisville 500kV breaker ‘H1T573’ with 50kA breaker		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b1648	Upgrade name plate rating at Morrisville 500kV breaker ‘H2T545’ with 50kA breaker		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1649	Replace Morrisville 500kV breaker 'H1T580' with 50kA breaker		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b1650	Replace Morrisville 500kV breaker 'H2T569' with 50kA breaker		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b1651	Replace Loudoun 230kV breaker '295T2030' with 63kA breaker		Dominion (100%)
b1652	Replace Ox 230kV breaker '209742' with 63kA breaker		Dominion (100%)
b1653	Replace Clifton 230kV breaker '26582' with 63kA breaker		Dominion (100%)
b1654	Replace Clifton 230kV breaker '26682' with 63kA breaker		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1655	Replace Clifton 230kV breaker ‘205182’ with 63kA breaker		Dominion (100%)
b1656	Replace Clifton 230kV breaker ‘265T266’ with 63kA breaker		Dominion (100%)
b1657	Replace Clifton 230kV breaker ‘2051T2063’ with 63kA breaker		Dominion (100%)
b1694	Rebuild Loudoun - Brambleton 500 kV Rebuild Loudoun - Brambleton 500 kV		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b1696	Install a breaker and a half scheme with a minimum of eight 230 kV breakers for five existing lines at Idylwood 230 kV		AEC (0.46%) / APS (4.18%) / BGE (2.02%) / DPL (0.80%) / Dominion (88.45%) / JCPL (0.64%) / ME (0.50%) / NEPTUNE* (0.06%) / PECO (1.55%) / PEPCO (1.34%)
b1697	Build a 2nd Clark - Idylwood 230 kV line and install 230 kV gas-hybrid breakers at Clark		AEC (1.35%) / APS (15.65%) / BGE (10.53%) / DPL (2.59%) / Dominion (46.97%) / JCPL (2.36%) / ME (1.91%) / NEPTUNE* (0.23%) / PECO (4.48%) / PEPCO (11.23%) / PSEG (2.59%) / RE (0.11%)
b1698	Install a 2nd 500/230 kV transformer at Brambleton		APS (4.21%) / BGE (13.28%) / DPL (1.09%) / Dominion (59.38%) / PEPCO (22.04%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1698.1	Install a 500 kV breaker at Brambleton		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b1698.6	Replace Brambleton 230 kV breaker '2094T2095'		Dominion (100%)
b1699	Reconfigure Line #203 to feed Edwards Ferry sub radial from Pleasant View 230 kV and install new breaker bay at Pleasant View Sub		Dominion (100%)
b1700	Install a 230/115 kV transformer at the new Liberty substation to relieve Gainesville Transformer #3		Dominion (100%)
b1701	Reconductor line #2104 (Fredericksburg - Cranes Corner 230 kV)		APS (8.66%) / BGE (10.95%) / Dominion (63.30%) / PEPCO (17.09%)
b1724	Install a 2nd 138/115 kV transformer at Edinburg		Dominion (100%)
b1728	Replace the 115/34.5 kV transformer #1 at Hickory with a 230/34.5 kV transformer		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1729	Add 4 breaker ring bus at Burton 115 kV substation and construct a 115 kV line approximately 3.5 miles from Oakwood 115 kV substation to Burton 115 kV substation		Dominion (100%)
b1730	Install a 230/115 kV transformer at a new Liberty substation		Dominion (100%)
b1731	Uprate or rebuild Four Rivers – Kings Dominion 115 kV line or Install capacitors or convert load from 115 kV system to 230 kV system		Dominion (100%)
b1790	Split Wharton 115 kV capacitor bank into two smaller units and add additional reactive support in area by correcting power factor at Pantego 115 kV DP and FivePoints 115 kV DP to minimum of 0.973		Dominion (100%)
b1791	Wreck and rebuild 2.1 mile section of Line #11 section between Gordonsville and Somerset		APS (5.83%) / BGE (6.25%) / Dominion (78.38%) / PEPCO (9.54%)
b1792	Rebuild line #33 Halifax to Chase City, 26 miles. Install 230 kV 4 breaker ring bus		Dominion (100%)
b1793	Wreck and rebuild remaining section of Line #22, 19.5 miles and replace two pole H frame construction built in 1930		Dominion (100%)
b1794	Split 230 kV Line #2056 (Hornertown - Rocky Mount) and double tap line to Battleboro Substation. Expand station, install a 230 kV 3 breaker ring bus and install a 230/115 kV transformer		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1795	Reconductor segment of Line #54 (Carolina to Woodland 115 kV) to a minimum of 300 MVA		Dominion (100%)
b1796	Install 115 kV 25 MVAR capacitor bank at Kitty Hawk Substation		Dominion (100%)
b1797	Wreck and rebuild 7 miles of the Dominion owned section of Cloverdale - Lexington 500 kV		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b1798	Build a 450 MVAR SVC and 300 MVAR switched shunt at Loudoun 500 kV		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1799	Build 150 MVAR Switched Shunt at Pleasant View 500 kV		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b1805	Install a 250 MVAR SVC at the existing Mt. Storm 500kV substation		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b1809	Replace Brambleton 230 kV Breaker ‘22702’		Dominion (100%)
b1810	Replace Brambleton 230 kV Breaker ‘227T2094’		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1905.1	Surry to Skiffes Creek 500 kV Line (7 miles overhead)		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b1905.2	Surry 500 kV Station Work		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b1905.3	Skiffes Creek 500-230 kV Tx and Switching Station		Dominion (99.84%) / PEPCO (0.16%)
b1905.4	New Skiffes Creek - Whealton 230 kV line		Dominion (99.84%) / PEPCO (0.16%)
b1905.5	Whealton 230 kV breakers		Dominion (99.84%) / PEPCO (0.16%)
b1905.6	Yorktown 230 kV work		Dominion (99.84%) / PEPCO (0.16%)
b1905.7	Lanexa 115 kV work		Dominion (99.84%) / PEPCO (0.16%)

* Neptune Regional Transmission System, LLC

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

*** Hudson Transmission Partners, LLC

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1905.8	Surry 230 kV work		Dominion (99.84%) / PEPCO (0.16%)
b1905.9	Kings Mill, Peninmen, Toano, Waller, Warwick		Dominion (99.84%) / PEPCO (0.16%)
b1906.1	At Yadkin 500 kV, install six 500 kV breakers		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b1906.2	Install a 2nd 230/115 kV TX at Yadkin		Dominion (100%)
b1906.3	Install a 2nd 230/115 kV TX at Chesapeake		Dominion (100%)
b1906.4	Uprate Yadkin – Chesapeake 115 kV		Dominion (100%)
b1906.5	Install a third 500/230 kV TX at Yadkin		Dominion (100%)
b1907	Install a 3rd 500/230 kV TX at Clover		APS (5.83%) / BGE (4.74%) / Dominion (81.79%) / PEPCO (7.64%)

* Neptune Regional Transmission System, LLC

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

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1908	Rebuild Lexington – Dooms 500 kV		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b1909	Uprate Bremo – Midlothian 230 kV to its maximum operating temperature		APS (6.31%) / BGE (3.81%) / Dominion (81. 90%) / PEPCO (7.98%)
b1910	Build a Suffolk – Yadkin 230 kV line (14 miles) and install 4 breakers		Dominion (100%)
b1911	Add a second Valley 500/230 kV TX		APS (14.85%) / BGE (3.10%) / Dominion (74.12%) / PEPCO (7.93%)
b1912	Install a 500 MVAR SVC at Landstown 230 kV		DEOK (0.46%) / Dominion (99.54%)
b2053	Rebuild 28 mile line		AEP (100%)
b2125	Install four additional 230 kV 100 MVAR variable shunt reactor banks at Clifton, Gallows Road, Garrisonville, and Virginia Hills substations		Dominion (100%)
b2126	Install two additional 230 kV 100 MVAR variable shunt reactor banks at Churchland and Shawboro substations		Dominion (100%)

* Neptune Regional Transmission System, LLC

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

*** Hudson Transmission Partners, LLC

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2181	Add a motor to an existing switch at Prince George to allow for Sectionalizing scheme for line #2124 and allow for Brickhouse DP to be re-energized from the 115 kV source		Dominion (100%)
b2182	Install 230kV 4-breaker ring at Enterprise 230 kV to isolate load from transmission system when substation initially built		Dominion (100%)
b2183	Add a motor to an existing switch at Keene Mill to allow for a sectionalizing scheme		Dominion (100%)
b2184	Install a 230 kV breaker at Tarboro to split line #229. Each will feed an autotransformer at Tarboro. Install switches on each autotransformer		Dominion (100%)
b2185	Uprate Line #69 segment Reams DP to Purdy (19 miles) from 41 MVA to 162 MVA by replacing 5 structures and re-sagging the line from 50C to 75C		Dominion (100%)
b2186	Install a 2nd 230-115kV transformer at Earleys connected to the existing 115kV and 230kV ring busses. Add a 115 kV breaker and 230kV breaker to the ring busses		Dominion (100%)
b2187	Install 4 - 230kV breakers at Shellhorn 230 kV to isolate load		Dominion (100%)

* Neptune Regional Transmission System, LLC

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

SCHEDULE 12 – APPENDIX A

(20) Virginia Electric and Power Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1698.7	Replace Loudoun 230 kV breaker '203052' with 63kA rating		Dominion (100%)
b1793.1	Remove the Carolina 22 SPS to include relay logic changes, minor control wiring, relay resets and SCADA programming upon completion of project		Dominion (100%)
b2281	Additional Temporary SPS at Bath County		Dominion (100%)
b2350	Reconductor 211 feet of 545.5 ACAR conductor on 59 Line Elmont - Greenwood DP 115 kV to *achieve* a summer emergency rating of 906 amps or greater		Dominion (100%)
b2358	Install a 230 kV 54 MVAR capacitor bank on the 2016 line at Harmony Village Substation		Dominion (100%)
b2359	Wreck and rebuild approximately 1.3 miles of existing 230 kV line between Cochran Mill - X4-039 Switching Station		Dominion (100%)
b2360	Build a new 39 mile 230 kV transmission line from Dooms - Lexington on existing right-of-way		Dominion (100%)
b2361	Construct 230 kV OH line along existing Line #2035 corridor, approx. 2.4 miles from Idylwood - Dulles Toll Road (DTR) and 2.1 miles on new right-of-way along DTR to new Scott's Run Substation		Dominion (100%)
b2368	Replace the Brambleton 230 kV breaker '209502' with 63kA breaker		Dominion (100%)
b2369	Replace the Brambleton 230 kV breaker '213702' with 63kA breaker		Dominion (100%)
b2370	Replace the Brambleton 230 kV breaker 'H302' with 63kA breaker		Dominion (100%)

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)
b2373	Build a 2nd Loudoun - Brambleton 500 kV line within the existing ROW. The Loudoun - Brambleton 230 kV line will be relocated as an underbuild on the new 500 kV line		**Load-Ratio Share Allocation:** AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / ECP** (0.20%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%)
			DFAX Allocation: APS (35.59%) / BGE (17.80%) / Dominion (46.61%)
b2397	Replace the Beaumeade 230 kV breaker '2079T2116' with 63kA		Dominion (100%)
b2398	Replace the Beaumeade 230 kV breaker '2079T2130' with 63kA		Dominion (100%)
b2399	Replace the Beaumeade 230 kV breaker '208192' with 63kA		Dominion (100%)
b2400	Replace the Beaumeade 230 kV breaker '209592' with 63kA		Dominion (100%)
b2401	Replace the Beaumeade 230 kV breaker '211692' with 63kA		Dominion (100%)
b2402	Replace the Beaumeade 230 kV breaker '227T2130' with 63kA		Dominion (100%)
b2403	Replace the Beaumeade 230 kV breaker '274T2130' with 63kA		Dominion (100%)

*Neptune Regional Transmission System, LLC

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

***Hudson Transmission Partners, LLC

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2404	Replace the Beaumeade 230 kV breaker '227T2095' with 63kA		Dominion (100%)
b2405	Replace the Pleasant view 230 kV breaker '203T274' with 63kA		Dominion (100%)
b2443	Construct new underground 230 kV line from Glebe to Station C, rebuild Glebe Substation, construct 230 kV high side bus at Station C with option to install 800 MVA PAR		Dominion (97.11%) / ME (0.18%) / PEPCO (2.71%)
b2443.1	Replace the Idylwood 230 kV breaker ‘203512’ with 50kA		Dominion (100%)
b2443.2	Replace the Ox 230 kV breaker ‘206342’ with 63kA breaker		Dominion (100%)
b2443.3	Glebe – Station C PAR		**DFAX Allocation:** Dominion (22.57%) / PEPCO (77.43%)
b2457	Replace 24 115 kV wood h-frames with 230 kV Dominion pole H-frame structures on the Clubhouse – Purdy 115 kV line		Dominion (100%)
b2458.1	Replace 12 wood H-frame structures with steel H-frame structures and install shunts on all conductor splices on Carolina – Woodland 115 kV		Dominion (100%)
b2458.2	Upgrade all line switches and substation components at Carolina 115 kV to meet or exceed new conductor rating of 174 MVA		Dominion (100%)
b2458.3	Replace 14 wood H-frame structures on Carolina – Woodland 115 kV		Dominion (100%)
b2458.4	Replace 2.5 miles of static wire on Carolina – Woodland 115 kV		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2458.5	Replace 4.5 miles of conductor between Carolina 115 kV and Jackson DP 115 kV with min. 300 MVA summer STE rating; Replace 8 wood H-frame structures located between Carolina and Jackson DP with steel H-frames		Dominion (100%)
b2460.1	Replace Hanover 230 kV substation line switches with 3000A switches		Dominion (100%)
b2460.2	Replace wave traps at Four River 230 kV and Elmont 230 kV substations with 3000A wave traps		Dominion (100%)
b2461	Wreck and rebuild existing Remington CT – Warrenton 230 kV (approx. 12 miles) as a double-circuit 230 kV line		Dominion (100%)
b2461.1	Construct a new 230 kV line approximately 6 miles from NOVEC's Wheeler Substation a new 230 kV switching station in Vint Hill area		Dominion (100%)
b2461.2	Convert NOVEC's Gainesville – Wheeler line (approximately 6 miles) to 230 kV		Dominion (100%)
b2461.3	Complete a Vint Hill – Wheeler – Loudoun 230 kV networked line		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2471	Replace Midlothian 500 kV breaker 563T576 and motor operated switches with 3 breaker 500 kV ring bus. Terminate Lines # 563 Carson – Midlothian, #576 Midlothian –North Anna, Transformer #2 in new ring		**Load-Ratio Share Allocation:** AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / ECP** (0.20%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%)
			DFAX Allocation: Dominion (100%)
b2504	Rebuild 115 kV Line #32 from Halifax-South Boston (6 miles) for min. of 240 MVA and transfer Welco tap to Line #32. Moving Welco to Line #32 requires disabling auto-sectionalizing scheme		Dominion (100%)
b2505	Install structures in river to remove the 115 kV #65 line (Whitestone-Harmony Village 115 kV) from bridge and improve reliability of the line		Dominion (100%)
b2542	Replace the Loudoun 500 kV 'H2T502' breaker with a 50kA breaker		Dominion (100%)
b2543	Replace the Loudoun 500 kV 'H2T584' breaker with a 50kA breaker		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2582	Rebuild the Elmont – Cunningham 500 kV line		**Load-Ratio Share Allocation:** AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / ECP** (0.20%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%)
			DFAX Allocation: Dominion (81.64%)/ PEPCO (11.97%)/ BGE (6.40%)
b2583	Install 500 kV breaker at Ox Substation to remove Ox Tx#1 from H1T561 breaker failure outage.		Dominion (100%)
b2584	Relocate the Bremo load (transformer #5) to #2028 (Bremo-Charlottesville 230 kV) line and Cartersville distribution station to #2027 (Bremo-Midlothian 230 kV) line		Dominion (100%)
b2585	Reconductor 7.63 miles of existing line between Cranes and Stafford, upgrade associated line switches at Stafford		**DFAX Allocation:** PEPCO (100%)
b2620	*Wreck and rebuild the Chesapeake – Deep Creek – Bowers Hill – Hodges Ferry 115 kV line; minimum rating 239 MVA normal/emergency, 275 MVA load dump rating*		*Dominion (100%)*

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2622	*Rebuild Line #47 between Kings Dominion 115 kV and Fredericksburg 115 kV to current standards with summer emergency rating of 353 MVA at 115 kV*		*Dominion (100%)*
b2623	*Rebuild Line #4 between Bremo and Structure 8474 (4.5 miles) to current standards with a summer emergency rating of 261 MVA at 115 kV*		*Dominion (100%)*
b2624	*Rebuild 115 kV Lines #18 and #145 between Possum Point Generating Station and NOVEC's Smoketown DP (approx. 8.35 miles) to current 230 kV standards with a normal continuous summer rating of 524 MVA at 115 kV*		*Dominion (100%)*
b2625	*Rebuild 115 kV Line #48 between Thole Street and Structure 48/71 to current standard. The remaining line to Sewells Point is 2007 vintage. Rebuild 115 kV Line #107 line, Sewells Point to Oakwood, between structure 107/17 and 107/56 to current standard.*		*Dominion (100%)*
b2626	*Rebuild 115 kV Line #34 between Skiffes Creek and Yorktown and the double circuit portion of 115 kV Line #61 to current standards with a summer emergency rating of 353 MVA at 115 kV*		*Dominion (100%)*
b2627	*Rebuild 115 kV Line #1 between Crewe 115 kV and Fort Pickett DP 115 kV (12.2 miles) to current standards with summer emergency rating of 261 MVA at 115 kV*		*Dominion (100%)*

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		*Annual Revenue Requirement*	*Responsible Customer(s)*
b2628	*Rebuild 115 kV Line #82 Everetts – Voice of America (20.8 miles) to current standards with a summer emergency rating of 261 MVA at 115 kV*		*Dominion (100%)*
b2629	*Rebuild the 115 kV Lines #27 and #67 lines from Greenwich 115 kV to Burton 115 kV Structure 27/280 to current standard with a summer emergency rating of 262 MVA at 115 kV*		*Dominion (100%)*
b2630	*Install circuit switchers on Gravel Neck Power Station GSU units #4 and #5. Install two 230 kV CCVT's on Lines #2407 and #2408 for loss of source sensing*		*Dominion (100%)*
b2636	Install three 230 kV bus breakers and 230 kV, 100 MVAR Variable Shunt Reactor at Dahlgren to provide line protection during maintenance, remove the operational hazard and provide voltage reduction during light load conditions		Dominion (100%)
b2647	Rebuild Boydton Plank Rd – Kerr Dam 115 kV Line #38 (8.3 miles) to current standards with summer emergency rating of 353 MVA at 115 kV.		Dominion (100%)
b2648	Rebuild Carolina – Kerr Dam 115 kV Line #90 (38.7 miles) to current standards with summer emergency rating of 353 MVA 115 kV.		Dominion (100%)
b2649	Rebuild Clubhouse – Carolina 115 kV Line #130 (17.8 miles) to current standards with summer emergency rating of 353 MVA at 115 kV.		Dominion (100%)
b2650	Rebuild Twittys Creek – Pamplin 115 kV Line #154 (17.8 miles) to current standards with summer emergency rating of 353 MVA at 115 kV.		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		*Annual Revenue Requirement*	*Responsible Customer(s)*
b2651	Rebuild Buggs Island – Plywood 115 kV Line #127 (25.8 miles) to current standards with summer emergency rating of 353 MVA at 115 kV. The line should be rebuilt for 230 kV and operated at 115 kV.		Dominion (100%)
b2652	Rebuild Greatbridge – Hickory 115 kV Line #16 and Greatbridge – Chesapeake E.C. to current standard with summer emergency rating of 353 MVA at 115 kV.		Dominion (100%)
b2653.1	Build 20 mile 115 kV line from Pantego to Trowbridge with summer emergency rating of 353 MVA.		Dominion (100%)
b2653.2	Install 115 kV four-breaker ring bus at Pantego		Dominion (100%)
b2653.3	Install 115 kV breaker at Trowbridge		Dominion (100%)
b2654.1	Build 15 mile 115 kV line from Scotland Neck to S Justice Branch with summer emergency rating of 353 MVA. New line will be routed to allow HEMC to convert Dawson's Crossroads RP from 34.5 kV to 115 kV.		Dominion (100%)
b2654.2	Install 115 kV three-breaker ring bus at S Justice Branch		Dominion (100%)
b2654.3	Install 115 kV breaker at Scotland Neck		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		*Annual Revenue Requirement*	*Responsible Customer(s)*
b2665	*Rebuild the Cunningham – Dooms 500 kV line*		***Load-Ratio Share Allocation:*** *AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / ECP** (0.20%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%)*
			DFAX Allocation: *Dominion (71.81%) / PEPCO (28.19%)*
b2686	Pratts Area Improvement		Dominion (100%)
b2686.1	Build a 230 kV line from Remington Substation to Gordonsville Substation utilizing existing ROW		Dominion (100%)
b2686.11	Upgrading sections of the Gordonsville – Somerset 115 kV circuit		Dominion (100%)
b2686.12	Upgrading sections of the Somerset – Doubleday 115 kV circuit		Dominion (100%)
b2686.13	Upgrading sections of the Orange – Somerset 115 kV circuit		Dominion (100%)
b2686.14	Upgrading sections of the Mitchell – Mt. Run 115 kV circuit		Dominion (100%)
b2686.2	Install a 3rd 230/115 kV transformer at Gordonsville Substation		Dominion (100%)

**Neptune Regional Transmission System, LLC*
*** East Coast Power, LLC*
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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		*Annual Revenue Requirement*	*Responsible Customer(s)*
b2686.3	Upgrade Line 2088 between Gordonsville Substation and Louisa CT Station		Dominion (100%)
b2729	Optimal Capacitors Configuration: New 175 MVAR capacitor at Brambleton, new 175 MVAR capacitor at Ashburn, new 300 MVAR capacitor at Shelhorm, new 150 MVAR capacitor at Liberty		AEC (1.96%) / BGE (14.37%) / Dominion (35.11%) / DPL (3.76%) / ECP (0.29%) / HTP (0.34%) / JCPL (3.31%) / ME (2.52%) / Neptune (0.63%) / PECO (6.26%) / PEPCO (20.23%) / PPL (3.94%) /PSEG (7.29%)

Attachment 7c – Responsible Customer Shares for PATH Schedule 12 Projects
Source – PJM OATT

SCHEDULE 12 – APPENDIX

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0216	Install -100/+525 MVAR dynamic reactive device at Black Oak	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0218	Install third Wylie Ridge 500/345kV transformer	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (11.62%) / ConEd (1.79%) / DPL (19.05%) / Dominion (13.56%) / JCPL (15.28%) / PECO (38.70%)
b0220	Upgrade coolers on Wylie Ridge 500/345 kV #7		AEC (11.62%) / ConEd (1.79%) / DPL (19.05%) / Dominion (13.56%) / JCPL (15.28%) / PECO (38.70%)
b0229	Install fourth Bedington 500/138 kV		APS (50.98%) / BGE (13.42%) / DPL (2.03%) / Dominion (14.50%) / ME (1.43%) / PEPCO (17.64%)
b0230	Install fourth Meadowbrook 500/138 kV	As specified under the procedures detailed in Attachment H-18B, Section 1.b	APS (79.16%) / BGE (3.61%) / DPL (0.86%) / Dominion (11.75%) / ME (0.67%) / PEPCO (3.95%)

* Neptune Regional Transmission System, LLC

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0238	Reconductor Doubs – Dickerson and Doubs – Aqueduct 1200 MVA	As specified under the procedures detailed in Attachment H-18B, Section 1.b	BGE (16.66%) / Dominion (33.66%) / PEPCO (49.68%)
b0240	Open the Black Oak #3 500/138 kV transformer for the loss of Hatfield – Back Oak 500 kV line		APS (100%)
b0245	Replacement of the existing 954 ACSR conductor on the Bedington – Nipetown 138 kV line with high temperature/low sag conductor		APS (100%)
b0246	Rebuild of the Double Tollgate – Old Chapel 138 kV line with 954 ACSR conductor	As specified under the procedures detailed in Attachment H-18B, Section 1.b	APS (100%)
b0273	Open both North Shenandoah #3 transformer and Strasburg – Edinburgh 138 kV line for the loss of Mount Storm – Meadowbrook 572 500 kV		APS (100%)
b0322	Convert Lime Kiln substation to 230 kV operation		APS (100%)
b0323	Replace the North Shenandoah 138/115 kV transformer	As specified under the procedures detailed in Attachment H-18B, Section 1.b	APS (100%)

* Neptune Regional Transmission System, LLC

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

†Cost allocations associated with Regional Facilities and Necessary Lower Voltage Facilities associated with the project

††Cost allocations associated with below 500 kV elements of the project

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0328.2	Build new Meadow Brook – Loudoun 500 kV circuit (20 of 50 miles)	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0343	Replace Doubs 500/230 kV transformer #2	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.85%) / BGE (21.49%) / DPL (3.91%) / Dominion (28.86%) / ME (2.97%) / PECO (5.73%) / PEPCO (35.19%)
b0344	Replace Doubs 500/230 kV transformer #3	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.86%) / BGE (21.50%) / DPL (3.91%) / Dominion (28.82%) / ME (2.97%) / PECO (5.74%) / PEPCO (35.20%)
b0345	Replace Doubs 500/230 kV transformer #4	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.85%) / BGE (21.49%) / DPL (3.90%) / Dominion (28.83%) / ME (2.98%) / PECO (5.75%) / PEPCO (35.20%)
b0347.1	Build new Mt. Storm – 502 Junction 500 kV circuit	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)

* Neptune Regional Transmission System, LLC

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.2	Build new Mt. Storm – Meadow Brook 500 kV circuit	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0347.3	Build new 502 Junction 500 kV substation	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0347.4	Upgrade Meadow Brook 500 kV substation	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.5	Replace Harrison 500 kV breaker HL-3		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0347.6	Upgrade (per ABB inspection) breaker HL-6		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0347.7	Upgrade (per ABB inspection) breaker HL-7		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.8	Upgrade (per ABB inspection) breaker HL-8		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0347.9	Upgrade (per ABB inspection) breaker HL-10		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0347.10	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-1		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.11	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-3		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0347.12	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-4		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0347.13	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-6		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)

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**East Coast Power, L.L.C

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.14	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-7		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0347.15	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-9		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0347.16	Upgrade (per ABB inspection) Harrison 500 kV breaker 'HL-3'		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.17	Replace Meadow Brook 138 kV breaker 'MD-10'		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0347.18	Replace Meadow Brook 138 kV breaker 'MD-11'		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0347.19	Replace Meadow Brook 138 kV breaker 'MD-12'		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.20	Replace Meadow Brook 138 kV breaker 'MD-13'		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0347.21	Replace Meadow Brook 138 kV breaker 'MD-14'		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0347.22	Replace Meadow Brook 138 kV breaker 'MD-15'		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.23	Replace Meadow Brook 138 kV breaker 'MD-16'		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0347.24	Replace Meadow Brook 138 kV breaker 'MD-17'		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0347.25	Replace Meadow Brook 138 kV breaker 'MD-18'		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.26	Replace Meadow Brook 138 kV breaker 'MD-22#1 CAP'		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0347.27	Replace Meadow Brook 138 kV breaker 'MD-4'		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0347.28	Replace Meadow Brook 138 kV breaker 'MD-5'		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.29	Replace Meadowbrook 138 kV breaker ‘MD-6’		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0347.30	Replace Meadowbrook 138 kV breaker ‘MD-7’		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0347.31	Replace Meadowbrook 138 kV breaker ‘MD-8’		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.32	Replace Meadowbrook 138 kV breaker 'MD-9'		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0347.33	Replace Meadow Brook 138kV breaker 'MD-1'		APS (100%)
b0347.34	Replace Meadow Brook 138kV breaker 'MD-2'		APS (100%)
b0348	Upgrade Stonewall – Inwood 138 kV with 954 ACSR conductor		APS (100%)
b0373	Convert Doubs – Monocacy 138 kV facilities to 230 kV operation		AEC (1.82%) / APS (76.84%) / DPL (2.64%) / JCPL (4.53%) / ME (9.15%) / Neptune* (0.42%) / PPL (4.60%)
b0393	Replace terminal equipment at Harrison 500 kV and Belmont 500 kV		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0406.1	Replace Mitchell 138 kV breaker "#4 bank"		APS (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0406.2	Replace Mitchell 138 kV breaker "#5 bank"		APS (100%)
b0406.3	Replace Mitchell 138 kV breaker "#2 transf"		APS (100%)
b0406.4	Replace Mitchell 138 kV breaker "#3 bank"		APS (100%)
b0406.5	Replace Mitchell 138 kV breaker "Charlerio #2"		APS (100%)
b0406.6	Replace Mitchell 138 kV breaker "Charlerio #1"		APS (100%)
b0406.7	Replace Mitchell 138 kV breaker "Shepler Hill Jct"		APS (100%)
b0406.8	Replace Mitchell 138 kV breaker "Union Jct"		APS (100%)
b0406.9	Replace Mitchell 138 kV breaker "#1-2 138 kV bus tie"		APS (100%)
b0407.1	Replace Marlowe 138 kV breaker "#1 transf"		APS (100%)
b0407.2	Replace Marlowe 138 kV breaker "MBO"		APS (100%)
b0407.3	Replace Marlowe 138 kV breaker "BMA"		APS (100%)
b0407.4	Replace Marlowe 138 kV breaker "BMR"		APS (100%)
b0407.5	Replace Marlowe 138 kV breaker "WC-1"		APS (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0407.6	Replace Marlowe 138 kV breaker “R11”		APS (100%)
b0407.7	Replace Marlowe 138 kV breaker “W”		APS (100%)
b0407.8	Replace Marlowe 138 kV breaker “138 kV bus tie”		APS (100%)
b0408.1	Replace Trissler 138 kV breaker “Belmont 604”		APS (100%)
b0408.2	Replace Trissler 138 kV breaker “Edgelawn 90”		APS (100%)
b0409.1	Replace Weirton 138 kV breaker “Wylie Ridge 210”		APS (100%)
b0409.2	Replace Weirton 138 kV breaker “Wylie Ridge 216”		APS (100%)
b0410	Replace Glen Falls 138 kV breaker “McAlpin 30”		APS (100%)
b0417	Reconductor Mitchell – Shepler Hill Junction 138kV with 954 ACSR		APS (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0418	Install a breaker failure auto-restoration scheme at Cabot 500 kV for the failure of the #6 breaker		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0419	Install a breaker failure auto-restoration scheme at Bedington 500 kV for the failure of the #1 and #2 breakers		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0420	Operating Procedure to open the Black Oak 500/138 kV transformer #3 for the loss of Hatfield – Ronco 500 kV and the Hatfield #3 Generation		APS (100%)
b0445	Upgrade substation equipment and reconductor the Tidd – Mahans Lane – Weirton 138kV circuit with 954 ACSR		APS (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0460	Raise limiting structures on Albright – Bethelboro 138 kV to raise the rating to 175 MVA normal 214 MVA emergency		APS (100%)
b0491	Construct an Amos to Welton Spring to WV state line 765 kV circuit (APS equipment)	As specified under the procedures detailed in Attachment H-19B	AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0492	Construct a Welton Spring to Kemptown 765 kV line (APS equipment)	As specified under the procedures detailed in Attachment H-19B	AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0492.3	Replace Eastalco 230 kV breaker D-26		APS (100%)
b0492.4	Replace Eastalco 230 kV breaker D-28		APS (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0492.5	Replace Eastalco 230 kV breaker D-31		APS (100%)
b0495	Replace existing Kammer 765/500 kV transformer with a new larger transformer		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0533	Reconductor the Powell Mountain – Sutton 138 kV line		APS (100%)
b0534	Install a 28.61 MVAR capacitor on Sutton 138 kV		APS (100%)
b0535	Install a 44 MVAR capacitor on Dutch Fork 138 kV		APS (100%)
b0536	Replace Doubs circuit breaker DJ1		APS (100%)
b0537	Replace Doubs circuit breaker DJ7		APS (100%)
b0538	Replace Doubs circuit breaker DJ10		APS (100%)
b0572.1	Reconductor Albright – Mettiki – Williams – Parsons – Loughs Lane 138 kV with 954 ACSR		APS (100%)
b0572.2	Reconductor Albright – Mettiki – Williams – Parsons – Loughs Lane 138 kV with 954 ACSR		APS (100%)
b0573	Reconfigure circuits in Butler – Cabot 138 kV area		APS (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0577	Replace Fort Martin 500 kV breaker FL-1		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0584	Install 33 MVAR 138 kV capacitor at Necessity 138 kV		APS (100%)
b0585	Increase Cecil 138 kV capacitor size to 44 MVAR, replace five 138 kV breakers at Cecil due to increased short circuit fault duty as a result of the addition of the Prexy substation		APS (100%)
b0586	Increase Whiteley 138 kV capacitor size to 44 MVAR		APS (100%)
b0587	Reconductor AP portion of Tidd – Carnegie 138 kV and Carnegie – Weirton 138 kV with 954 ACSR		APS (100%)
b0588	Install a 40.8 MVAR 138 kV capacitor at Grassy Falls		APS (100%)
b0589	Replace five 138 kV breakers at Cecil		APS (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0590	Replace #1 and #2 breakers at Charleroi 138 kV		APS (100%)
b0591	Install a 25.2 MVAR capacitor at Seneca Caverns 138 kV		APS (100%)
b0673	Rebuild Elko – Carbon Center Junction using 230 kV construction		APS (100%)
b0674	Construct new Osage – Whiteley 138 kV circuit		APS (97.68%) / DL (0.96%) / PENELEC (1.09%) / ECP** (0.01%) / PSEG (0.25%) / RE (0.01%)
b0674.1	Replace the Osage 138 kV breaker 'CollinsF126'		APS (100%)
b0675.1	Convert Monocacy - Walkersville 138 kV to 230 kV		AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)
b0675.2	Convert Walkersville - Catoctin 138 kV to 230 kV		AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)
b0675.3	Convert Ringgold - Catoctin 138 kV to 230 kV		AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0675.4	Convert Catoctin - Carroll 138 kV to 230 kV		AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)
b0675.5	Convert portion of Ringgold Substation from 138 kV to 230 kV		AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)
b0675.6	Convert Catoctin Substation from 138 kV to 230 kV		AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)
b0675.7	Convert portion of Carroll Substation from 138 kV to 230 kV		AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)
b0675.8	Convert Monocacy Substation from 138 kV to 230 kV		AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)
b0675.9	Convert Walkersville Substation from 138 kV to 230 kV		AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0676.1	Reconductor Doubs - Lime Kiln (#207) 230kV		AEC (0.64%) / APS (86.70%) / DPL (0.53%) / JCPL (1.93%) / ME (4.04%) / NEPTUNE* (0.18%) / PECO (1.93%) / PENELEC (0.93%) / PSEG (2.92%) / RE (0.12%) / ECP** (0.08%)
b0676.2	Reconductor Doubs - Lime Kiln (#231) 230kV		AEC (0.64%) / APS (86.70%) / DPL (0.53%) / JCPL (1.93%) / ME (4.04%) / NEPTUNE* (0.18%) / PECO (1.93%) / PENELEC (0.93%) / PSEG (2.92%) / RE (0.12%) / ECP** (0.08%)
b0677	Reconductor Double Toll Gate – Riverton with 954 ACSR		APS (100%)
b0678	Reconductor Glen Falls - Oak Mound 138kV with 954 ACSR		APS (100%)
b0679	Reconductor Grand Point – Letterkenny with 954 ACSR		APS (100%)
b0680	Reconductor Greene – Letterkenny with 954 ACSR		APS (100%)
b0681	Replace 600/5 CT's at Franklin 138 kV		APS (100%)
b0682	Replace 600/5 CT's at Whiteley 138 kV		APS (100%)
b0684	Reconductor Guilford – South Chambersburg with 954 ACSR		APS (100%)
b0685	Replace Ringgold 230/138 kV #3 with larger transformer		APS (71.93%) / JCPL (4.17%) / ME (6.79%) / NEPTUNE* (0.38%) / PECO (4.05%) / PENELEC (5.88%) / ECP** (0.18%) / PSEG (6.37%) / RE (0.25%)

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0704	Install a third Cabot 500/138 kV transformer		APS (74.36%) / DL (2.73%) PENELEC (22.91%)
b0797	Advance n0321 (Replace Doubs Circuit Breaker DJ2)		APS(100%)
b0798	Advance n0322 (Replace Doubs Circuit Breaker DJ3)		APS(100%)
b0799	Advance n0323 (Replace Doubs Circuit Breaker DJ6)		APS(100%)
b0800	Advance n0327 (Replace Doubs Circuit Breaker DJ16)		APS(100%)
b0941	Replace Opequon 138 kV breaker 'BUSTIE'		APS(100%)
b0942	Replace Butler 138 kV breaker '#1 BANK'		APS(100%)
b0943	Replace Butler 138 kV breaker '#2 BANK'		APS(100%)
b0944	Replace Yukon 138 kV breaker 'Y-8'		APS(100%)
b0945	Replace Yukon 138 kV breaker 'Y-3'		APS(100%)
b0946	Replace Yukon 138 kV breaker 'Y-1'		APS(100%)
b0947	Replace Yukon 138 kV breaker 'Y-5'		APS(100%)
b0948	Replace Yukon 138 kV breaker 'Y-2'		APS(100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0949	Replace Yukon 138 kV breaker 'Y-19'		APS(100%)
b0950	Replace Yukon 138 kV breaker 'Y-4'		APS(100%)
b0951	Replace Yukon 138 kV breaker 'Y-9'		APS(100%)
b0952	Replace Yukon 138 kV breaker 'Y-11'		APS(100%)
b0953	Replace Yukon 138 kV breaker 'Y-13'		APS(100%)
b0954	Replace Charleroi 138 kV breaker '#1 XFMR BANK'		APS(100%)
b0955	Replace Yukon 138 kV breaker 'Y-7'		APS(100%)
b0956	Replace Pruntytown 138 kV breaker 'P-9'		APS(100%)
b0957	Replace Pruntytown 138 kV breaker 'P-12'		APS(100%)
b0958	Replace Pruntytown 138 kV breaker 'P-15'		APS(100%)
b0959	Replace Charleroi 138 kV breaker '#2 XFMR BANK'		APS(100%)
b0960	Replace Pruntytown 138 kV breaker 'P-2'		APS(100%)
b0961	Replace Pruntytown 138 kV breaker 'P-5'		APS(100%)
b0962	Replace Yukon 138 kV breaker 'Y-18'		APS(100%)

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

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

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

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0989	Replace Edgelawn 138 kV breaker 'GOFF RUN #632'		APS(100%)
b0990	Change reclosing on Cabot 138 kV breaker 'C-9'		APS(100%)
b0991	Change reclosing on Belmont 138 kV breaker 'B-7'		APS(100%)
b0992	Change reclosing on Belmont 138 kV breaker 'B-12'		APS(100%)
b0993	Change reclosing on Belmont 138 kV breaker 'B-9'		APS(100%)
b0994	Change reclosing on Belmont 138 kV breaker 'B-19'		APS(100%)
b0995	Change reclosing on Belmont 138 kV breaker 'B-21'		APS(100%)
b0996	Change reclosing on Willow Island 138 kV breaker 'FAIRVIEW #84'		APS(100%)
b0997	Change reclosing on Cabot 138 kV breaker 'C-4'		APS(100%)
b0998	Change reclosing on Cabot 138 kV breaker 'C-1'		APS(100%)
b0999	Replace Redbud 138 kV breaker 'BUS TIE'		APS(100%)
b1022.1	Reconfigure the Peters to Bethel Park 138 kV line and Elrama to Woodville 138 kV line to create a 138 kV path from Woodville to Peters and a 138 kV path from Elrama to Bethel Park		APS (96.98%) / DL (3.02%)
b1022.3	Add static capacitors at Smith 138 kV		APS (96.98%) / DL (3.02%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1022.4	Add static capacitors at North Fayette 138 kV		APS (96.98%) / DL (3.02%)
b1022.5	Add static capacitors at South Fayette 138 kV		APS (96.98%) / DL (3.02%)
b1022.6	Add static capacitors at Manifold 138 kV		APS (96.98%) / DL (3.02%)
b1022.7	Add static capacitors at Houston 138 kV		APS (96.98%) / DL (3.02%)
b1023.1	Install a 500/138 kV transformer at 502 Junction		APS (100%)
b1023.2	Construct a new Franklin - 502 Junction 138 kV line including a rebuild of the Whiteley - Franklin 138 kV line to double circuit		APS (100%)
b1023.3	Construct a new 502 Junction - Osage 138 kV line		APS (100%)
b1023.4	Construct Braddock 138 kV breaker station that connects the Charleroi - Gordon 138 kV line, Washington - Franklin 138 kV line and the Washington - Vanceville 138 kV line including a 66 MVAR capacitor		APS (100%)
b1027	Increase the size of the shunt capacitors at Enon 138 kV		APS (100%)
b1028	Raise three structures on the Osage - Collins Ferry 138 kV line to increase the line rating		APS (100%)
b1128	Reconductor the Edgewater – Vasco Tap; Edgewater – Loyalhanna 138 kV lines with 954 ACSR		APS (100%)
b1129	Reconductor the East Waynesboro – Ringgold 138 kV line with 954 ACSR		APS (100%)

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)
b1131	Upgrade Double Tollgate – Meadowbrook MDT Terminal Equipment		APS (100%)
b1132	Upgrade Double Tollgate-Meadowbrook MBG terminal equipment		APS (100%)
b1133	Upgrade terminal equipment at Springdale		APS (100%)
b1135	Reconductor the Bartonville – Meadowbrook 138 kV line with high temperature conductor		APS (100%)
b1137	Reconductor the Eastgate – Luxor 138 kV; Eastgate – Sony 138 kV line with 954 ACSR		APS (78.59%) / PENELEC (14.08%) / ECP ** (0.23%) / PSEG (6.83%) / RE (0.27%)
b1138	Reconductor the King Farm – Sony 138 kV line with 954 ACSR		APS (100%)
b1139	Reconductor the Yukon – Waltz Mills 138 kV line with high temperature conductor		APS (100%)
b1140	Reconductor the Bracken Junction – Luxor 138 kV line with 954 ACSR		APS (100%)
b1141	Reconductor the Sewickley – Waltz Mills Tap 138 kV line with high temperature conductor		APS (100%)
b1142	Reconductor the Bartonsville – Stephenson 138 kV; Stonewall – Stephenson 138 kV line with 954 ACSR		APS (100%)
b1143	Reconductor the Youngwood – Yukon 138 kV line with high temperature conductor		APS (89.92%) / PENELEC (10.08%)
b1144	Reconductor the Bull Creek Junction – Cabot 138 kV line with high temperature conductor		APS (100%)

** 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)
b1145	Reconductor the Lawson Junction – Cabot 138 kV line with high temperature conductor		APS (100%)
b1146	Replace Layton - Smithton #61 138 kV line structures to increase line rating		APS (100%)
b1147	Replace Smith – Yukon 138 kV line structures to increase line rating		APS (100%)
b1148	Reconductor the Loyalhanna – Luxor 138 kV line with 954 ACSR		APS (100%)
b1149	Reconductor the Luxor – Stony Springs Junction 138 kV line with 954 ACSR		APS (100%)
b1150	Upgrade terminal equipment at Social Hall		APS (100%)
b1151	Reconductor the Greenwood – Redbud 138 kV line with 954 ACSR		APS (100%)
b1152	Reconductor Grand Point – South Chambersburg		APS (100%)
b1159	Replace Peters 138 kV breaker ‘Bethel P OCB’		APS (100%)
b1160	Replace Peters 138 kV breaker ‘Cecil OCB’		APS (100%)
b1161	Replace Peters 138 kV breaker ‘Union JctOCB’		APS (100%)
b1162	Replace Double Toll Gate 138 kV breaker ‘DRB-2’		APS (100%)
b1163	Replace Double Toll Gate 138 kV breaker ‘DT 138 kV OCB’		APS (100%)
b1164	Replace Cecil 138 kV breaker ‘Enlow OCB’		APS (100%)
b1165	Replace Cecil 138 kV breaker ‘South Fayette’		APS (100%)
b1166	Replace Wylie Ridge 138 kV breaker ‘W-9’		APS (100%)
b1167	Replace Reid 138 kV breaker ‘RI-2’		APS (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1171.1	Install the second Black Oak 500/138 kV transformer, two 138 kV breaker, and related substation work		BGE (20.76%) / DPL (3.14%) / Dominion (39.55%) / ME (2.71%) / PECO (3.36%) / PEPCO (30.48%)
b1171.3	Install six 500 kV breakers and remove BOL1 500 kV breaker at Black Oak		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b1200	Reconductor Double Toll Gate – Greenwood 138 kV with 954 ACSR conductor		APS (100%)
b1221.1	Convert Carbon Center from 138 kV to a 230 kV ring bus		APS (100%)
b1221.2	Construct Bear Run 230 kV substation with 230/138 kV transformer		APS (100%)
b1221.3	Loop Carbon Center Junction – Williamette line into Bear Run		APS (100%)
b1221.4	Carbon Center – Carbon Center Junction & Carbon Center Junction – Bear Run conversion from 138 kV to 230 kV		APS (100%)
b1230	Reconductor Willow-Eureka & Eurkea-St Mary 138 kV lines		APS (100%)
b1232	Reconductor Nipetown – Reid 138 kV with 1033 ACCR		AEC (1.40%) / APS (75.74%) / DPL (1.92%) / JCPL (2.92%) / ME (6.10%) / Neptune (0.27%) / PECO (4.40%) / PENELEC (3.26%) / PPL (3.99%)

** 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)
b1233.1	Upgrade terminal equipment at Washington		APS (100%)
b1234	Replace structures between Ridgeway and Paper city		APS (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1235	Reconductor the Albright – Black Oak AFA 138 kV line with 795 ACSS/TW		APS (30.25%) / BGE (16.10%) / Dominion (30.51%) / PEPCO (23.14%)
b1237	Upgrade terminal equipment at Albright, replace bus and line side breaker disconnects and leads, replace breaker risers, upgrade RTU and line		APS (100%)
b1238	Install a 138 kV 44 MVAR capacitor at Edgelawn substation		APS (100%)
b1239	Install a 138 kV 44 MVAR capacitor at Ridgeway substation		APS (100%)
b1240	Install a 138 kV 44 MVAR capacitor at Elko Substation		APS (100%)
b1241	Upgrade terminal equipment at Washington substation on the GE Plastics/DuPont terminal		APS (100%)
b1242	Replace structures between Collins Ferry and West Run		APS (100%)
b1243	Install a 138 kV capacitor at Potter Substation		APS (100%)
b1261	Replace Butler 138 kV breaker '1-2 BUS 138'		APS (100%)
b1383	Install 2nd 500/138 kV transformer at 502 Junction		APS (93.27%) / DL (5.39%) / PENELEC (1.34%)
b1384	Reconductor approximately 2.17 miles of Bedington – Shepherdstown 138 kV with 954 ACSR		APS (100%)
b1385	Reconductor Halfway – Paramount 138 kV with 1033 ACCR		APS (100%)
b1386	Reconductor Double Tollgate – Meadow Brook 138 kV ckt 2 with 1033 ACCR		APS (93.33%) / BGE (3.39%) / PEPCO (3.28%)
b1387	Reconductor Double Tollgate – Meadow Brook 138 kV		APS (93.33%) / BGE (3.39%) / PEPCO (3.28%)

b1388	Reconductor Feagans Mill – Millville 138 kV with 954 ACSR		APS (100%)

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1389	Reconductor Bens Run – St. Mary's 138 kV with 954 ACSR		AEP (12.40%) / APS (17.80%) / DL (69.80%)
b1390	Replace Bus Tie Breaker at Opequon		APS (100%)
b1391	Replace Line Trap at Gore		APS (100%)
b1392	Replace structure on Belmont – Trissler 138 kV line		APS (100%)
b1393	Replace structures Kingwood – Pruntytown 138 kV line		APS (100%)
b1395	Upgrade Terminal Equipment at Kittanning		APS (100%)
b1401	Change reclosing on Pruntytown 138 kV breaker 'P-16' to 1 shot at 15 seconds		APS (100%)
b1402	Change reclosing on Rivesville 138 kV breaker 'Pruntytown #34' to 1 shot at 15 seconds		APS (100%)
b1403	Change reclosing on Yukon 138 kV breaker 'Y21 Shepler' to 1 shot at 15 seconds		APS (100%)
b1404	Replace the Kiski Valley 138 kV breaker 'Vandergrift' with a 40 kA breaker		APS (100%)
b1405	Change reclosing on Armstrong 138 kV breaker 'GARETTRJCT' at 1 shot at 15 seconds		APS (100%)
b1406	Change reclosing on Armstrong 138 kV breaker 'KITTANNING' to 1 shot at 15 seconds		APS (100%)
b1407	Change reclosing on Armstrong 138 kV breaker 'BURMA' to 1 shot at 15 seconds		APS (100%)

b1408	Replace the Weirton 138 kV breaker ‘Tidd 224’ with a 40 kA breaker		APS (100%)
b1409	Replace the Cabot 138 kV breaker ‘C9 Kiski Valley’ with a 40 kA breaker		APS (100%)

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1507.2	Terminal Equipment upgrade at Doubs substation		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b1507.3	Mt. Storm – Doubs transmission line rebuild in Maryland – Total line mileage for APS is 2.71 miles		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b1510	Install 59.4 MVAR capacitor at Waverly		APS (100%)
b1672	Install a 230 kV breaker at Carbon Center		APS (100%)

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** 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 (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0560	Install 250 MVAR capacitor at Kemptown 500 kV substation		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)

* Neptune Regional Transmission System, LLC

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1803	Build a 300 MVAR Switched Shunt at Doubs 500 kV and increase (~50 MVAR) in size the existing Switched Shunt at Doubs 500 kV		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b1804	Install a new 600 MVAR SVC at Meadowbrook 500kV		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b1816.1	Replace relaying at the Mt. Airy substation on the Carroll - Mt. Airy 230 kV line		APS (100%)
b1816.2	Adjust the control settings of all existing capacitors at Mt Airy 34.5kV, Monocacy 138kV, Ringgold 138kV served by Potomac Edison's Eastern 230 kV network to ensure that all units will be on during the identified N-1-1 contingencies		APS (100%)

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1816.3	Replace existing unidirectional LTC controller on the No. 4, 230/138 kV transformer at Carroll substation with a bidirectional unit		APS (100%)
b1816.4	Isolate and bypass the 138 kV reactor at Germantown Substation		APS (100%)
b1816.6	Replace 336.4 ACSR conductor on the Catoctin - Carroll 138 kV line using 556.5 ACSR (26/7) or equivalent on existing structures (12.7 miles), 800 A wave traps at Carroll and Catoctin with 1200 A units, and 556.5 ACSR SCCIR (Sub-conductor) line risers and bus traps with 795 ACSR or equivalent		APS (100%)
b1822	Replace the 1200 A wave trap, line risers, breaker risers with 1600 A capacity terminal equipment at Reid 138 kV SS		APS (100%)
b1823	Replace the 800 A wave trap with a 1200 A wave trap at Millville 138 kV substation		APS (100%)
b1824	Reconductor Grant Point - Guilford 138kV line approximately 8 miles of 556 ACSR with 795 ACSR		APS (100%)
b1825	Replace the 800 Amp line trap at Butler 138 kV Sub on the Cabot East 138 kV line		APS (100%)
b1826	Change the CT ratio at Double Toll Gate 138 kV SS on MDT line		APS (100%)
b1827	Change the CT ratio at Double Toll Gate 138 kV SS on MBG line		APS (100%)
b1828.1	Reconductor the Bartonville – Stephenson 3.03 mile 138 kV line of		APS (100%)

	556 ACSR with 795 ACSR		

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1828.2	Reconductor the Stonewall – Stephenson 2.08 mile 138 kV line of 556 ACSR with 795 ACSR		APS (100%)
b1829	Replace the existing 138 kV 556.5 ACSR substation conductor risers with 954 ACSR at the Redbud 138 kV substation, including but not limited to the line side disconnect leads		APS (100%)
b1830	Replace 1200 A wave trap and 1024 ACAR breaker risers at Halfway 138 kV substation, and replace 1024 ACAR breaker risers at Paramount 138 kV substation		APS (100%)
b1832	Replace the 1200 A line side and bus side disconnect switches with 1600 A switches, replace bus side, line side, and disconnect leads at Lime Kiln SS on the Doubs - Lime Kiln 1 (207) 230 kV line terminal		APS (100%)
b1833	Replace the 1200 A line side and bus side disconnect switches with 1600 A switches, replace bus side, line side, and disconnect leads at Lime Kiln SS on the Doubs - Lime Kiln 2 (231) 230 kV line terminal		APS (100%)
b1835	Reconductor 14.3 miles of 556 ACSR with 795 ACSR from Old Chapel to Millville 138 kV and upgrade line risers at Old Chapel 138 kV and Millville 138 kV and replace 1200 A wave trap at Millville 138 kV		APS (37.68%) / Dominion (34.46%) / PEPCO (13.69%) / BGE (11.45%) / ME (2.01%) / PENELEC (0.53%) / DL (0.18%)
b1836	Replace 1200 A wave trap with 1600 A wave trap at		APS (100%)

	Reid 138 kV SS		

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1837	Replace 750 CU breaker risers with 795 ACSR at Marlowe 138 kV and replace 1200 A wave traps with 1600 A wave traps at Marlowe 138 kV and Bedington 138 kV		APS (100%)
b1838	Replace the 1200 A Bedington 138 kV line air switch and the 1200 A 138 kV bus tie air switch at Nipetown 138 kV with 1600 A switches		APS (100%)
b1839	Install additional 33 MVAR capacitors at Grand Point 138 kV SS and Guildford 138 kV SS		APS (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1840	Construct a 138 kV line between Buckhannon and Weston 138 kV substations		APS (100%)
b1902	Replace line trap at Stonewall on the Stephenson 138 kV line terminal		APS (100%)
b1941	Loop the Homer City-Handsome Lake 345 kV line into the Armstrong substation and install a 345/138 kV transformer at Armstrong		APS (67.86%) / PENELEC (32.14%)
b1942	Change the CT ratio at Millville to improve the Millville – Old Chapel 138 kV line ratings		APS (100%)
b1964	Convert Moshannon substation to a 4 breaker 230 kV ring bus		APS (41.06%) / DPL (6.68%) / JCPL (5.48%) / ME (10.70%) / Neptune* (0.53%) / PECO (15.53%) / PPL (20.02%)
b1965	Install a 44 MVAR 138 kV capacitor at Luxor substation		APS (100%)
b1986	Upgrade the AP portion of the Elrama – Mitchell 138 kV line by replace breaker risers on the Mitchell 138 kV bus on the Elrama terminal		APS (100%)
b1987	Reconductor the Osage-Collins Ferry 138 kV line with 795 ACSS. Upgrade terminal equipment at Osage and Collins Ferry		APS (100%)
b1988	Raise structures between Lake Lynn and West Run to eliminate the clearance de-rates on the West Run – Lake Lynn 138 kV line		APS (100%)
b1989	Raise structures between Collins Ferry and West Run to eliminate the clearance de-rates on the Collins Ferry - West Run 138 kV line		APS (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2095	Replace Weirt 138 kV breaker 'S-TORONTO226' with 63kA rated breaker		APS (100%)
b2096	Revise the reclosing of Weirt 138 kV breaker '2&5 XFMR'		APS (100%)
b2097	Replace Ridgeley 138 kV breaker '#2 XFMR OCB'		APS (100%)
b2098	Revise the reclosing of Ridgeley 138 kV breaker 'AR3' with 40kA rated breaker		APS (100%)
b2099	Revise the reclosing of Ridgeley 138 kV breaker 'RC1'		APS (100%)
b2100	Replace Ridgeley 138 kV breaker 'WC4' with 40kA rated breaker		APS (100%)
b2101	Replace Ridgeley 138 kV breaker '1 XFMR OCB' with 40kA rated breaker		APS (100%)
b2102	Replace Armstrong 138 kV breaker 'GARETTRJCT' with 40kA rated breaker		APS (100%)
b2103	Replace Armstrong 138 kV breaker 'BURMA' with 40kA rated breaker		APS (100%)
b2104	Replace Armstrong 138 kV breaker 'KITTANNING' with 40kA rated breaker		APS (100%)
b2105	Replace Armstrong 138 kV breaker 'KISSINGERJCT' with 40kA rated breaker		APS (100%)
b2106	Replace Wylie Ridge 345 kV breaker 'WK-1' with 63kA rated breaker		APS (100%)
b2107	Replace Wylie Ridge 345 kV breaker 'WK-2' with 63kA rated breaker		APS (100%)
b2108	Replace Wylie Ridge 345 kV breaker 'WK-3' with 63kA rated breaker		APS (100%)
b2109	Replace Wylie Ridge 345 kV breaker 'WK-4' with 63kA rated breaker		APS (100%)

b2110	Replace Wylie Ridge 345 kV breaker 'WK-6' with 63kA rated breaker		APS (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2111	Replace Wylie Ridge 138 kV breaker 'WK-7' with 63kA rated breaker		APS (100%)
b2112	Replace Wylie Ridge 345 kV breaker 'WK-5'		APS (100%)
b2113	Replace Weirton 138 kV breaker 'NO 6 XFMR' with 63kA rated breaker		APS (100%)
b2114	Replace Armstrong 138 kV breaker 'Bus-Tie' (Status On-Hold pending retirement)		APS (100%)
b2124.1	Add a new 138 kV line exit		APS (100%)
b2124.2	Construct a 138 kV ring bus and install a 138/69 kV autotransformer		APS (100%)
b2124.3	Add new 138 kV line exit and install a 138/25 kV transformer		APS (100%)
b2124.4	Construct approximately 5.5 miles of 138 kV line		APS (100%)
b2124.5	Convert approximately 7.5 miles of 69 kV to 138 kV		APS (100%)
b2156	Install a 75 MVAR 230 kV capacitor at Shingletown Substation		APS (100%)
b2165	Replace 800A wave trap at Stonewall with a 1200 A wave trap		APS (100%)
b2166	Reconductor the Millville – Sleepy Hollow 138kV 4.25 miles of 556 ACSR with 795 ACSR, upgrade line risers at Sleepy Hollow, and change 1200 A CT tap at Millville to 800		APS (100%)
b2168	For Grassy Falls 138kV Capacitor bank adjust turn-on voltage to 1.0pu with a high limit of 1.04pu, For Crupperneck and Powell Mountain 138kV Capacitor Banks adjust turn-on voltage to 1.01pu with a high limit of 1.035pu		APS (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2169	Replace/Raise structures on the Yukon-Smithton 138 kV line section to eliminate clearance de-rate		APS (100%)
b2170	Replace/Raise structures on the Smithton-Shepler Hill Jct 138 kV line section to eliminate clearance de-rate		APS (100%)
b2171	Replace/Raise structures on the Parsons-William 138 kV line section to eliminate clearance de-rate		APS (100%)
b2172	Replace/Raise structures on the Parsons - Loughs Lane 138 kV line section to eliminate clearance de-rate		APS (100%)

SCHEDULE 12 – APPENDIX

(17) AEP Service Corporation on behalf of its Affiliate Companies (AEP Indiana Michigan Transmission Company, AEP Kentucky Transmission Company, AEP Ohio Transmission Company, AEP West Virginia Transmission Company, Appalachian 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 (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)

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

AEP Service Corporation on behalf of its Affiliate Companies (AEP Indiana Michigan Transmission Company, AEP Kentucky Transmission Company, AEP Ohio Transmission Company, AEP West Virginia Transmission Company, Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0490.2	Replace Amos 138 kV breaker ‘B’		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0490.3	Replace Amos 138 kV breaker ‘B1’		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)

AEP Service Corporation on behalf of its Affiliate Companies (AEP Indiana Michigan Transmission Company, AEP Kentucky Transmission Company, AEP Ohio Transmission Company, AEP West Virginia Transmission Company, Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0490.4	Replace Amos 138 kV breaker ‘C’		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0490.5	Replace Amos 138 kV breaker ‘C1’		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)

* Neptune Regional Transmission System, LLC

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

AEP Service Corporation on behalf of its Affiliate Companies (AEP Indiana Michigan Transmission Company, AEP Kentucky Transmission Company, AEP Ohio Transmission Company, AEP West Virginia Transmission Company, Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0490.6	Replace Amos 138 kV breaker ‘D’		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0490.7	Replace Amos 138 kV breaker ‘D2’		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)

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

AEP Service Corporation on behalf of its Affiliate Companies (AEP Indiana Michigan Transmission Company, AEP Kentucky Transmission Company, AEP Ohio Transmission Company, AEP West Virginia Transmission Company, Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company and Wheeling Power Company) (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0490.8	Replace Amos 138 kV breaker ‘E’		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)
b0490.9	Replace Amos 138 kV breaker ‘E2’		AEC (1.57%) / AEP (15.18%) / APS (5.89%) / ATSI (7.59%) / BGE (4.12%) / ComEd (12.38%) / ConEd (0.55%) / Dayton (2.02%) / DEOK (3.15%) / DL (1.72%) / DPL (2.53%) / Dominion (13.30%) / EKPC (2.14%) / HTP*** (0.20%) / JCPL (3.57%) / ME (1.72%) / NEPTUNE* (0.41%) / PECO (4.97%) / PENELEC (1.86%) / PEPCO (3.85%) / PPL (4.95%) / PSEG (5.89%) / RE (0.24%) / ECP** (0.20%)

* Neptune Regional Transmission System, LLC

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

Attachment 8

PATH Formula Rate for January 1, 2017 to December 31, 2017

ALSTON&BIRD LLP

The Atlantic Building
950 F Street, NW
Washington, DC 20004-1404

202-239-3300
Fax: 202-239-3333
www.alston.com

September 1, 2016

To: Parties to FERC Docket No. ER08-386-000

Re: Potomac-Appalachian Transmission Highline, LLC
PJM Open Access Transmission Tariff, Attachment H-19
Projected Transmission Revenue Requirement for Rate Year 2017

Pursuant to section IV of the Formula Rate Implementation Protocols ("Protocols") set forth in Attachment H-19B of the PJM Open Access Transmission Tariff ("PJM OATT"),[1] Potomac-Appalachian Transmission Highline, LLC ("PATH"), on behalf of its operating companies PATH West Virginia Transmission Company, LLC and PATH Allegheny Transmission Company, LLC, is submitting a Projected Transmission Revenue Requirement for Rate Year 2017 ("2017 PTRR") to PJM for posting.

The 2017 PTRR was developed pursuant to the PATH formula rate as set forth in Attachment H-19 of the PJM OATT. PATH has asked PJM to post a copy of the 2017 PTRR to the formula rates section of its internet site, located at:

> http://www.pjm.com/markets-and-operations/billing-settlements-and-credit/formula-rates.aspx

A copy of the 2017 PTRR is attached. Pursuant to section IV.C of the Protocols, within two business days of this submission to PJM, PATH will provide notice on PJM's website of the time, date and location of an open meeting among Interested Parties.

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

For the 12 months ended 12/31/2017

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	$10,911,444	(A)	$10,498,178	(B)	$21,409,622
2	PJM Project No.					
3	b0490 & b0491	$10,911,444	(C)			$10,911,444
4	b0492 & b0560			$10,498,178	(D)	$10,498,178
5						
6	Total (Sum lines 3 to 5)	$10,911,444		$10,498,178		$21,409,622

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., (7)
	(D)	Rate Formula Template - Attachment 5, page 31 col., (6)

Formula Rate - Non-Levelized

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2017

PATH West Virginia Transmission Company, LLC

Line No.			(1)		(2)	(3) Allocated Amount
1	GROSS REVENUE REQUIREMENT	(line 86)			12 months	$ 9,524,155
	REVENUE CREDITS		Total	Allocator		
2	Total Revenue Credits	Attachment 1, line 12	0	TP	1.00000	$ -
3	True-up Adjustment with Interest	Protocols	1,387,289	DA	1.00000	$ 1,387,289
4a	Accelerated True-up Adjustment with Interest		0	DA	1.00000	$ -
4b	Interest on Gains or Recoveries in Account 254	Company Records	0	DA	1.00000	-
5	NET REVENUE REQUIREMENT	(Lines 1 minus line 2 plus line 3 plus line 4a and 4b)				$ 10,911,444

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

For the 12 months ended 12/31/2017

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)	(1,020)	NP	1.00000	(1,020)
29	Account No. 283 (enter negative)	(Attachment 4)	3,138,021	NP	1.00000	3,138,021
30	Account No. 190	(Attachment 4)	3,405,804	NP	1.00000	3,405,804
31	Account No. 255 (enter negative)	(Attachment 4)	-	NP	1.00000	-
32	CWIP	(Attachment 4)	-	DA	1.00000	-
33	Unamortized Regulatory Asset	(Attachment 4)	-	DA	1.00000	-
34	Unamortized Abandoned Plant	(Attachment 4)	2,638,076	DA	1.00000	2,638,076
35	TOTAL ADJUSTMENTS (sum lines 27-34)		9,180,880			9,180,880
36	LAND HELD FOR FUTURE USE	(Attachment 4)	-	TP	1.00000	-
37	WORKING CAPITAL (Note C)					
38	CWC	calculated	99,035			99,035
39	Materials & Supplies (Note B)	(Attachment 4)	-	TE	1.00000	-
40	Prepayments (Account 165 - Note C)	(Attachment 4)	-	GP	1.00000	-
41	TOTAL WORKING CAPITAL (sum lines 38-40)		99,035			99,035
42	RATE BASE (sum lines 25, 35, 36, & 41)		9,279,915			9,279,915

Formula Rate - Non-Levelized

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2017

PATH West Virginia Transmission Company, LLC

	(1)	(2) **Form No. 1 Page, Line, Col.**	(3) **Company Total**	(4) **Allocator**		(5) **Transmission** (Col 3 times Col 4)
43	O&M					
44	Transmission	321.112.b	-	TE	1.00000	-
45	Less Account 565	321.96.b	-	TE	1.00000	-
46	Less Account 566 (Misc Trans Expense)	Line 56	-	DA	1.00000	-
47	A&G	323.197.b	763,194	W/S	1.00000	763,194
48	Less EPRI & Reg. Comm. Exp. & Other Ad	(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)	29,083			29,083
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	-	DA	1.00000	-
55	Miscellaneous Transmission Expense	Attachment 4	-	DA	1.00000	-
56	Total Account 566		-			-
57	TOTAL O&M (sum lines 44, 47, 49, 50, 51, 52, 56 less lines 45, 46 & 48)		792,277			792,277
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)	7,621,109	DA	1.00000	7,621,109
63	TOTAL DEPRECIATION (Sum lines 59-62)		7,621,109			7,621,109
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	8,454	GP	1.00000	8,454
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)		8,454			8,454
74	INCOME TAXES	(Note F)				
75	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		39.23%			
76	CIT=(T/1-T) * (1-(WCLTD/R)) =		39.38%			
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)		1.6454			
80	Amortized Investment Tax Credit (266.8f) (enter negative)		0			
81	Income Tax Calculation = line 76 * line 85		311,448	NA		311,448
82	ITC adjustment (line 79 * line 80)		0	NP	1.00000	-
83	Total Income Taxes	(line 81 plus line 82)	311,448			311,448
84	RETURN					
85	[Rate Base (line 42) * Rate of Return (line 121)]		790,867	NA		790,867
86	REV. REQUIREMENT (sum lines 57, 63, 73, 83, 85)		9,524,155			9,524,155

Attachment A

Formula Rate - Non-Levelized

Rate Formula Template

Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2017

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)						0		
96	Less transmission expenses included in OATT Ancillary Services (Note G)						0		
97	Included transmission expenses (line 95 less line 96)						0		
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%	10.40%		0.0520		
121	Total (sum lines 118-120)		0				0.0852	=R	

SUPPORTING CALCULATIONS AND NOTES

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2017

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=	6.50%	(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 The ROE consists of a base ROE of 10.40%, a 50 basis point adder for participation in PJM and a 150 basis point Incentive ROE adder.
No change in ROE may be made absent a Section 205 or 206 filing with FERC and no filing to change the ROE may be made by a Settling Party or Non-Opposing Party (as defined in the Settlement Agreement filed on October 7, 2011 in Docket No. ER08-386-000, et al.) except in accordance with the provisions of Section 3.2 of the Settlement Agreement.
Subject to rehearing of the November 30, 2012 Hearing Order in Docket No. ER12-2708-000, the post abandonment ROE will be 10.9% beginning September 1, 2012 and 10.4% beginning December 1, 2012. The 2012 true-up will be computed using an ROE that is a time-weighted average of the pre-abandonment ROE (i.e., 12.4%) and the allowed post abandonment ROE.
Example Calculation: For the first 244 days the authorized ROE will be 12.4%, for the next 91 days the ROE will be 10.9%, and for the remaining 31 days the ROE will be 10.4%. Therefore, the weighted ROE = (12.4% * 244 + 10.9% * 91+10.4% * 31)/366=11.858%.
Beginning with 2013 and through the remainder of the amortization period the ROE will be 10.4%.

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 12/31/2017

PATH Allegheny Transmission Company, LLC

Line No.			(1)	(2)		(3) Allocated Amount
1	GROSS REVENUE REQUIREMENT	(line 86)		12 months		$ 9,187,747
	REVENUE CREDITS		Total	Allocator		
2	Total Revenue Credits	Attachment 1, line 12	0	TP	1.00000	-
3	True-up Adjustment with Interest	Protocols	1,310,431	DA	1.00000	$ 1,310,431
4a	Accelerated True-up Adjustment with Interest		0	DA	1.00000	-
4b	Interest on Gains or Recoveries in Account 254	Company Records	0	DA	1.00000	-
5	NET REVENUE REQUIREMENT	(Lines 1 minus line 2 plus line 3 plus line 4a and 4b)				$ 10,498,178

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2017

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)	-	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)	-	NP	1.00000	-
29	Account No. 283 (enter negative)	(Attachment 4)	-	NP	1.00000	-
30	Account No. 190	(Attachment 4)	6,096,187	NP	1.00000	6,096,187
31	Account No. 255 (enter negative)	(Attachment 4)	-	NP	1.00000	-
32	CWIP	(Attachment 4)	-	DA	1.00000	-
33	Unamortized Regulatory Asset	(Attachment 4)	-	DA	1.00000	-
34	Unamortized Abandoned Plant	(Attachment 4)	2,711,986	DA	1.00000	2,711,986
35	TOTAL ADJUSTMENTS (sum lines 27-34)		8,808,172			8,808,172
36	LAND HELD FOR FUTURE USE	(Attachment 4)	-	TP	1.00000	-
37	WORKING CAPITAL (Note C)					
38	CWC	calculated	39,528			39,528
39	Materials & Supplies (Note B)	(Attachment 4)	-	TE	1.00000	-
40	Prepayments (Account 165 - Note C)	(Attachment 4)	-	GP	1.00000	-
41	TOTAL WORKING CAPITAL (sum lines 38-40)		39,528			39,528
42	RATE BASE (sum lines 25, 35, 36, & 41)		8,847,700			8,847,700

Attachment A

Formula Rate - Non-Levelized

Rate Formula Template

Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2017

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	125,982	TE	1.00000	125,982
45	Less Account 565	321.96.b	-	TE	1.00000	-
46	Less Account 566	Line 56	125,982	DA	1.00000	125,982
47	A&G	323.197.b	190,240	W/S	1.00000	190,240
48	Less EPRI & Reg. Comm. Exp. & Other Ad.	(Note D & Attach 4)	-	DA	1.00000	-
49	Plus Transmission Related Reg. Comm. Exp.	(Note D & Attach 4)	-	TE	1.00000	-
50	PBOP Expense adjustment	(Attachment 4)	-			-
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	-	DA	1.00000	-
55	Miscellaneous Transmission Expense	Attachment 4	125,982	DA	1.00000	125,982
56	Total Account 566		125,982			125,982
57	TOTAL O&M (sum lines 44, 47, 49, 50, 51, 52, 56 less lines 45,46, 48)		316,222			316,222
58	DEPRECIATION EXPENSE					
59	Transmission	336.7.b & c	-	TP	1.00000	-
60	General and Intangible	336.1.d&e + 336.10.b.c.d&e	-	W/S	1.00000	-
61	Common	336.11.b & c	-	CE	1.00000	-
62	Amortization of Abandoned Plant	(Attachment 4)	7,834,626	DA	1.00000	7,834,626
63	TOTAL DEPRECIATION (Sum lines 59-62)		7,834,626			7,834,626
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	14,670	GP	1.00000	14,670
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)		14,670			14,670
74	INCOME TAXES	(Note F)				
75	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		36.39%			
76	CIT=(T/1-T) * (1-(WCLTD/R)) =		34.68%			
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)		1.5722			
80	Amortized Investment Tax Credit	(266.8f) (enter negative)	0			
81	Income Tax Calculation = line 76 * line 85		263,236	NA		263,236
82	ITC adjustment (line 79 * line 80)		0	NP	1.00000	-
83	Total Income Taxes	(line 81 plus line 82)	263,236			263,236
84	RETURN					
85	[Rate Base (line 42) * Rate of Return (line 121)]		758,992	NA		758,992
86	REV. REQUIREMENT (sum lines 57, 63, 73, 83, 85)		9,187,747			9,187,747

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

For the 12 months ended 12/31/2017

PATH Allegheny 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)						125,982		
96	Less transmission expenses included in OATT Ancillary Services (Note G)						0		
97	Included transmission expenses (line 95 less line 96)						125,982		
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	1.00	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%	6.76%		0.0338	=WCLTD	
119	Preferred Stock	(Attachment 4)	0	0%	0.00%		0.0000		
120	Common Stock (Note J)	(Attachment 4)	0	50%	10.40%		0.0520		
121	Total (sum lines 118-120)		0				0.0858	=R	

SUPPORTING CALCULATIONS AND NOTES

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2017

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=	2.14%	(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	The ROE consists of a base ROE of 10.40%, a 50 basis point adder for participation in PJM and a 150 basis point Incentive ROE adder. No change in ROE may be made absent a Section 205 or 206 filing with FERC and no filing to change the ROE may be made by a Settling Party or Non-Opposing Party (as defined in the Settlement Agreement filed on October 7, 2011 in Docket No. ER08-386-000, et al.) except in accordance with the provisions of Section 3.2 of the Settlement Agreement. Subject to rehearing of the November 30, 2012 Hearing Order in Docket No. ER12-2708-000, the post abandonment ROE will be 10.9% beginning September 1, 2012 and 10.4% beginning December 1, 2012. The 2012 true-up will be computed using an ROE that is a time-weighted average of the pre-abandonment ROE (i.e., 12.4%) and the allowed post abandonment ROE. Example Calculation: For the first 244 days the authorized ROE will be 12.4%, for the next 91 days the ROE will be 10.9%, and for the remaining 31 days the ROE will be 10.4%. Therefore, the weighted ROE = (12.4% * 244 + 10.9% * 91+10.4% * 31)/366=11.858%. Beginning with 2013 and through the remander of the amortization period the ROE will be 10.4%.
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)	-
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 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	2016	-
3	January	company records	2017	-
4	February	company records	2017	-
5	March	company records	2017	-
6	April	company records	2017	-
7	May	company records	2017	-
8	June	company records	2017	-
9	July	company records	2017	-
10	August	company records	2017	-
11	September	company records	2017	-
12	October	company records	2017	-
13	November	company records	2017	-
14	December	p207.58.g	2017	-
15	**Transmission Plant In Service**	(sum lines 2-14) /13		-
16	**Calculation of Distribution Plant In Service**	Source		
17	December	p206.75.b	2016	-
18	January	company records	2017	-
19	February	company records	2017	-
20	March	company records	2017	-
21	April	company records	2017	-
22	May	company records	2017	-
23	June	company records	2017	-
24	July	company records	2017	-
25	August	company records	2017	-
26	September	company records	2017	-
27	October	company records	2017	-
28	November	company records	2017	-
29	December	p207.75.g	2017	-
30	**Distribution Plant In Service**	(sum lines 17-29) /13		-
31	**Calculation of Intangible Plant In Service**	Source		
32	December	p204.5.b	2016	-
33	December	p205.5.g	2017	-
34	**Intangible Plant In Service**	(sum lines 32 & 33) /2		-
35	**Calculation of General Plant In Service**	Source		
36	December	p206.99.b	2016	-
37	December	p207.99.g	2017	-
38	**General Plant In Service**	(sum lines 36 & 37) /2		-
39	**Calculation of Production Plant In Service**	Source		
40	December	p204.46b	2016	-
41	January	company records	2017	-
42	February	company records	2017	-
43	March	company records	2017	-
44	April	company records	2017	-
45	May	company records	2017	-
46	March	Attachment 6	2017	-
47	April	company records	2017	-
48	August	company records	2017	-
49	September	company records	2017	-
50	October	company records	2017	-
51	November	company records	2017	-
52	December	p205.46.g	2017	-
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	2016	-
56	December (Electric Portion)	p356	2017	-
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	2016	-	
61	January	company records	2017	-	
62	February	company records	2017	-	
63	March	company records	2017	-	
64	April	company records	2017	-	
65	May	company records	2017	-	
66	June	company records	2017	-	
67	July	company records	2017	-	
68	August	company records	2017	-	
69	September	company records	2017	-	
70	October	company records	2017	-	
71	November	company records	2017	-	
72	December	p219.25	2017	-	
73	**Transmission Accumulated Depreciation**	(sum lines 60-72) /13		-	
74	**Calculation of Distribution Accumulated Depreciation**	Source			
75	December	Prior year p219.26	2016	-	
76	January	company records	2017	-	
77	February	company records	2017	-	
78	March	company records	2017	-	
79	April	company records	2017	-	
80	May	company records	2017	-	
81	June	company records	2017	-	
82	July	company records	2017	-	
83	August	company records	2017	-	
84	September	company records	2017	-	
85	October	company records	2017	-	
86	November	company records	2017	-	
87	December	p219.26	2017	-	
88	**Distribution Accumulated Depreciation**	(sum lines 75-87) /13		-	
89	**Calculation of Intangible Accumulated Depreciation**	Source			
90	December	Prior year p200.21.c	2016	-	
91	December	p200.21c	2017	-	
92	**Accumulated Intangible Depreciation**	(sum lines 90 & 91) /2		-	
93	**Calculation of General Accumulated Depreciation**	Source			
94	December	Prior year p219.28	2016	-	
95	December	p219.28	2017	-	
96	**Accumulated General Depreciation**	(sum lines 94 & 95) /2		-	

97	**Calculation of Production Accumulated Depreciation**	Source	Year	Balance
98	December	Prior year p219	2016	-
99	January	company records	2017	-
100	February	company records	2017	-
101	March	company records	2017	-
102	April	company records	2017	-
103	May	company records	2017	-
104	June	company records	2017	-
105	July	company records	2017	-
106	August	company records	2017	-
107	September	company records	2017	-
108	October	company records	2017	-
109	November	company records	2017	-
110	December	p219.20 thru 219.24	2017	-
111	**Production Accumulated Depreciation**	(sum lines 98-110) /13		-
112	**Calculation of Common Accumulated Depreciation**	Source		
113	December (Electric Portion)	p356	2016	-
114	December (Electric Portion)	p356	2017	-
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	(1,020)	(1,020)	-1,020
119	Account No. 283 (enter negative)	277.9.k	1,383,321	4,892,720	3,138,021
120	Account No. 190	234.8.c	3,439,056	3,372,551	3,405,804
121	Account No. 255 (enter negative)	267.8.h	-	-	0

122	**Unamortized Abandoned Plant**	Per FERC Order					
123	**Monthly Balance**	Source	Months Remaining In Amortization Period	Beginning Balance	Amortization Expense (p114.10.c)	Additions (Deductions)	Ending Balance
124	December	p111.71.d (and Notes)	9				7,621,108.93
125	January	company records	8	7,621,109	952,638.62	-	6,668,470.31
126	February	company records	7	6,668,470	952,638.62	-	5,715,831.69
127	March	company records	6	5,715,832	952,638.62	-	4,763,193.08
128	April	company records	5	4,763,193	952,638.62	-	3,810,554.46
129	May	company records	4	3,810,554	952,638.62	-	2,857,915.85
130	June	company records	3	2,857,916	952,638.62	-	1,905,277.23
131	July	company records	2	1,905,277	952,638.62	-	952,638.62
132	August	company records	1	952,639	952,638.62	-	-
133	September	company records		-		-	-
134	October	company records		-		-	-
135	November	company records		-		-	-
136	December	p111.71.c (and Notes) Detail on p230b		-		-	-
137	**Ending Balance is a 13-Month Average**	(sum lines 124-136) /13			$7,621,108.93	-	$2,638,076.17
					Appendix A Line 62		Appendix A Line 34

Note: Deductions resulting from gains or recoveries that exceed the unamortized balance are recorded in FERC Account 254, Other Regulatory Liabilities.

138	Prepayments (Account 165)	111.57.c	-	-	0

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

					Amos Substation Upgrade	Amos to Welton Spring Line	Welton Spring Substation and SVC	Welton Spring to Interconnection with PATH Allegheny	Total
139	**Calculation of Transmission CWIP**	Source							
140	December	216.b	2016	$ -	-	-	-	-	-
141	January	company records	2017	-	-	-	-	-	-
142	February	company records	2017	-	-	-	-	-	-
143	March	company records	2017	-	-	-	-	-	-
144	April	company records	2017	-	-	-	-	-	-
145	May	company records	2017	-	-	-	-	-	-
146	June	company records	2017	-	-	-	-	-	-
147	July	company records	2017	-	-	-	-	-	-
148	August	company records	2017	-	-	-	-	-	-
149	September	company records	2017	-	-	-	-	-	-
150	October	company records	2017	-	-	-	-	-	-
151	November	company records	2017	-	-	-	-	-	-
152	December	216.b	2017	-	-	-	-	-	-
153	**Transmission CWIP**	(sum lines 140-152) /13		-	-	-	-	-	-

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
154	**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	
155	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					
156	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					
157	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						
			WV				
158	SIT=State Income Tax Rate or Composite		6.500%				6.50%

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			
159	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
160	Assigned to O&M	p227.6	-	-	-
161	Stores Expense Undistributed	p227.16	-	-	-
162	Undistributed Stores Exp		-	-	-
163	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.
164	Beginning Balance of Regulatory Asset	p111.72.d (and notes)	-	Uncapitalized costs as of date the rates become effective
165	Months Remaining in Amortization Period		-	As approved by FERC
166	Monthly Amortization	(line 164 - line 168) / 167	-	
167	Months in Year to be amortized		-	Number of months rates are in effect during the calendar year
168	Ending Balance of Regulatory Asset	p111.72.c	-	
169	Average Balance of Regulatory Asset	(line 164 + line 168)/2	-	

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
170	Monthly Balances for Capital Structure				
171		Year	Debt	Preferred Stock	Common Stock
172	January	2017	0	-	0
173	February	2017	-	-	-
174	March	2017	-	-	-
175	April	2017	-	-	-
176	May	2017	-	-	-
177	June	2017	-	-	-
178	July	2017	-	-	-
179	August	2017	-	-	-
180	September	2017	-	-	-
181	October	2017	-	-	-
182	November	2017	-	-	-
183	December	2017	-	-	-
184	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
185	Amortization Expense on Regulatory Asset		-
186	Miscellaneous Transmission Expense		-
187	Total Account 566	Footnote Data: Schedule Page 320 b. 97	-

PBOPs

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Details
188	**Calculation of PBOP Expenses**			
189	**PATH-WV - AEP Employees**			
190	Total PBOP expenses		$117,254,159	
191	Amount relating to retired personnel		$0	
192	Amount allocated on Labor		$117,254,159	
193	Labor dollars		1,151,954,661	
194	Cost per labor dollar		$0.102	
195	PATH WV labor (labor not capitalized) current year		114,018	
196	PATH WV PBOP Expense for current year		$11,606	
197	PATH WV PBOP Expense in Account 926 for current year		-$4,620	
198	PBOP Adjustment for Appendix A, Line 50		$16,226	
199	Lines 190-194 cannot change absent approval or acceptance by FERC in a separate proceeding.			
199	**PATH-WV - Allegheny Employees**			
200	Total PBOP expenses		$22,856,433	
201	Amount relating to retired personnel		$8,786,372	
202	Amount allocated on FTEs		$14,070,061	
203	Number of FTEs		4,474	
204	Cost per FTE		$3,145	
205	PATH WV FTEs (labor not capitalized) current year		-	
206	PATH WV PBOP Expense for current year		$0	
207	PATH WV PBOP Expense in Account 926 for current year		$0	
208	PBOP Adjustment for Appendix A, Line 50		$0	
209	Lines 200-204 cannot change absent approval or acceptance by FERC in a separate proceeding.			
210	PBOP Expense adjustment	(sum lines 198 & 208)	$16,226	

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	2016	-
3	January	company records	2017	-
4	February	company records	2017	-
5	March	company records	2017	-
6	April	company records	2017	-
7	May	company records	2017	-
8	June	company records	2017	-
9	July	company records	2017	-
10	August	company records	2017	-
11	September	company records	2017	-
12	October	company records	2017	-
13	November	company records	2017	-
14	December	p207.58.g	2017	-
15	**Transmission Plant In Service**	(sum lines 2-14) /13		-
16	**Calculation of Distribution Plant In Service**	Source		
17	December	p206.75.b	2016	-
18	January	company records	2017	-
19	February	company records	2017	-
20	March	company records	2017	-
21	April	company records	2017	-
22	May	company records	2017	-
23	June	company records	2017	-
24	July	company records	2017	-
25	August	company records	2017	-
26	September	company records	2017	-
27	October	company records	2017	-
28	November	company records	2017	-
29	December	p207.75.g	2017	-
30	**Distribution Plant In Service**	(sum lines 17-29) /13		-
31	**Calculation of Intangible Plant In Service**	Source		
32	December	p204.5b	2016	-
33	December	p205.5.g	2017	-
34	**Intangible Plant In Service**	(sum lines 32 & 33) /2		-
35	**Calculation of General Plant In Service**	Source		
36	December	p206.99.b	2016	-
37	December	p207.99.g	2017	-
38	**General Plant In Service**	(sum lines 36 & 37) /2		-
39	**Calculation of Production Plant In Service**	Source		
40	December	p204.46b	2016	-
41	January	company records	2017	-
42	February	company records	2017	-
43	March	company records	2017	-
44	April	company records	2017	-
45	May	company records	2017	-
46	March	Attachment 6	2017	-
47	April	company records	2017	-
48	August	company records	2017	-
49	September	company records	2017	-
50	October	company records	2017	-
51	November	company records	2017	-
52	December	p205.46.g	2017	-
53	**Production Plant In Service**	(sum lines 40-52) /13		-

Attachment 4 - Cost Support
PATH Allegheny Transmission Company, LLC

54	**Calculation of Common Plant In Service**	Source	Year	Balance	
55	December (Electric Portion)	p356	2016	-	
56	December (Electric Portion)	p356	2017	-	
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	2016	-	
61	January	company records	2017	-	
62	February	company records	2017	-	
63	March	company records	2017	-	
64	April	company records	2017	-	
65	May	company records	2017	-	
66	June	company records	2017	-	
67	July	company records	2017	-	
68	August	company records	2017	-	
69	September	company records	2017	-	
70	October	company records	2017	-	
71	November	company records	2017	-	
72	December	p219.25	2017	-	
73	**Transmission Accumulated Depreciation**	(sum lines 60-72) /13		-	
74	**Calculation of Distribution Accumulated Depreciation**	Source			
75	December	Prior year p219.26	2016	-	
76	January	company records	2017	-	
77	February	company records	2017	-	
78	March	company records	2017	-	
79	April	company records	2017	-	
80	May	company records	2017	-	
81	June	company records	2017	-	
82	July	company records	2017	-	
83	August	company records	2017	-	
84	September	company records	2017	-	
85	October	company records	2017	-	
86	November	company records	2017	-	
87	December	p219.26	2017	-	
88	**Distribution Accumulated Depreciation**	(sum lines 75-87) /13		-	
89	**Calculation of Intangible Accumulated Depreciation**	Source			
90	December	Prior year p200.21.c	2016	-	
91	December	p200.21c	2017	-	
92	**Accumulated Intangible Depreciation**	(sum lines 90 & 91) /2		-	
93	**Calculation of General Accumulated Depreciation**	Source			
94	December	Prior year p219.28	2016	-	
95	December	p219.28	2017	-	
96	**Accumulated General Depreciation**	(sum lines 94 & 95) /2		-	

Attachment 4 - Cost Support
PATH Allegheny Transmission Company, LLC

97	**Calculation of Production Accumulated Depreciation**	Source	Year	Balance
98	December	Prior year p219	2016	-
99	January	company records	2017	-
100	February	company records	2017	-
101	March	company records	2017	-
102	April	company records	2017	-
103	May	company records	2017	-
104	June	company records	2017	-
105	July	company records	2017	-
106	August	company records	2017	-
107	September	company records	2017	-
108	October	company records	2017	-
109	November	company records	2017	-
110	December	p219.20 thru 219.24	2017	-
111	**Production Accumulated Depreciation**	(sum lines 98-110) /13		-
112	**Calculation of Common Accumulated Depreciation**	Source		
113	December (Electric Portion)	p356	2016	-
114	December (Electric Portion)	p356	2017	-
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	-	-	-
119	Account No. 283 (enter negative)	277.9.k	-	-	-
120	Account No. 190	234.8.c	4,662,583	7,529,790	6,096,187
121	Account No. 255 (enter negative)	267.8.h	-	-	0

122	**Unamortized Abandoned Plant**	Per FERC Order					
123	**Monthly Balance**	Source	Months Remaining In Amortization Period	Beginning Balance	Amortization Expense (p114.10.c)	Additions (Deductions)	Ending Balance
124	December	p111.71.d (and Notes)	9				7,834,626
125	January	company records	8	7,834,626	979,328	-	6,855,298
126	February	company records	7	6,855,298	979,328	-	5,875,969
127	March	company records	6	5,875,969	979,328	-	4,896,641
128	April	company records	5	4,896,641	979,328	-	3,917,313
129	May	company records	4	3,917,313	979,328	-	2,937,985
130	June	company records	3	2,937,985	979,328	-	1,958,656
131	July	company records	2	1,958,656	979,328	-	979,328
132	August	company records	1	979,328	979,328	-	-
133	September	company records		-	-	-	-
134	October	company records		-	-	-	-
135	November	company records		-	-	-	-
136	December	p111.71.c (and Notes) Detail on p230b		-	-	-	-
137	**Ending Balance is a 13-Month Average**	(sum lines 124-136) /13			7,834,626 Appendix A Line 62	-	2,711,986 Appendix A Line 34

Note: Deductions resulting from gains or recoveries that exceed the unamortized balance are recorded in FERC Account 254, Other Regulatory Liabilities.

138	Prepayments (Account 165)	111.57.c	-	-	0

Attachment 4 - Cost Support
PATH Allegheny Transmission Company, LLC

139	**Calculation of Transmission CWIP**	Source				**Kemptown Substation**	**Kemptown to Interconnection with PATH West Virginia**	**Welton Spring Substation and SVC**	**Total**
140	December	216.b	2016	$	-				
141	January	company records	2017		-				
142	February	company records	2017		-				
143	March	company records	2017		-				
144	April	company records	2017		-				
145	May	company records	2017		-				
146	June	company records	2017		-				
147	July	company records	2017		-				
148	August	company records	2017		-				
149	September	company records	2017		-				
150	October	company records	2017		-				
151	November	company records	2017		-				
152	December	216.b	2017		-				
153	**Transmission CWIP**	(sum lines 140-152) /13			-	-	-	-	-

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
154	**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	
155	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					
156	Regulatory Commission Exp Account 928	p323.189.b	-	-	-	

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					
157	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			
158	SIT=State Income Tax Rate or Composite	8.250%	6.500%	6.000%			2.143%

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			
159	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
160	Assigned to O&M	p227.6	-	-	-
161	Stores Expense Undistributed	p227.16	-	-	-
162	Undistributed Stores Exp		-	-	-
163	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.
164	Beginning Balance of Regulatory Asset	p111.72.d (and notes)	-	Uncapitalized costs as of date the rates become effective
165	Months Remaining in Amortization Period		-	As approved by FERC
166	Monthly Amortization	(line 164 - line 168) / 167	-	
167	Months in Year to be Amortized		-	Number of months rates are in effect during the calendar year
168	Ending Balance of Regulatory Asset	p111.72.c	-	
169	Average Balance of Regulatory Asset	(line 164 + line 168)/2	-	

Attachment 4 - Cost Support
Ba

Capital Structure

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

170	Monthly Balances for Capital Structure				
171		Year	Debt	Preferred Stock	Common Stock
172	January	2017	0	-	0
173	February	2017	-	-	-
174	March	2017	-	-	-
175	April	2017	-	-	-
176	May	2017	-	-	-
177	June	2017	-	-	-
178	July	2017	-	-	-
179	August	2017	-	-	-
180	September	2017	-	-	-
181	October	2017	-	-	-
182	November	2017	-	-	-
183	December	2017	-	-	-
184	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
185	Amortization Expense on Regulatory Asset		-
186	Miscellaneous Transmission Expense		125,982
187	Total Account 566	Footnote Data: Schedule Page 320 b. 97	125,982

PBOPs

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Details
188	**Calculation of PBOP Expenses**		
189	**PATH - Allegheny - Allegheny Employees**		
190	Total PBOP expenses	$22,856,433	
191	Amount relating to retired personnel	$8,786,372	
192	Amount allocated on FTEs	$14,070,061	
193	Number of FTEs	4,475	
194	Cost per FTE	$3,144	
195	PATH Allegheny FTEs (labor not capitalized) current year	-	
196	PATH Allegheny PBOP Expense for current year	$0	
197	PATH Allegheny PBOP Expense in Account 926 for current year	$0	
198	PBOP Adjustment for Appendix A, Line 50	-	
199	Lines 190-194 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	10,911,444
4	21	NET TRANSMISSION PLANT IN SERVICE	-
5	32	CWIP	-
6	34	Unamortized Abandoned Plant	2,638,076
7		**Carrying charge (line 3/sum of lines 4, 5 and 6)**	**4.13614**

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**

				(1)	(2)	(3)	(4)	(5)	(6)	(7)
				PJM Upgrade ID: b0490 & b0491						
10		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**	**Unamortized Abandoned Plant**	**Totals**
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes		Yes	Yes	
12		FCR for This Project		413.6%	413.6%	413.6%	413.6%	413.6%	413.6%	
13	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		0	-	-	-	-	2,638,076.17	**2,638,076.17**
		Revenue Requirement		-	-	-	-	-	10,911,443.68	**10,911,443.68**

Attachment 5 - Transmission Enhancement Charge Worksheet
PATH Allegheny Transmission Company, LLC

1 New Plant Carrying Charge

2	Formula Line	Item	
3	5	NET REVENUE REQUIREMENT	10,498,178
4	21	NET TRANSMISSION PLANT IN SERVICE	-
5	32	CWIP	-
6	34	Unamortized Abandoned Plant	2,711,986
7		**Carrying charge (line 3/sum of lines 4, 5and 6)**	**3.87103**

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**

				(1)	(2)	(3)	(4)	(5)	(6)
				PJM Upgrade ID: b0492 & b0560					
10		Details		**Kemptown Substation - CWIP**	**Kemptown to Interconnection with PATH West Virginia - CWIP**	**Welton Spring Substation and SVC - CWIP**	**Transmission Plant In Service**	**Unamortized Abandoned Plant**	**Totals**
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes	Yes	
12		FCR for This Project		387.1%	387.1%	387.1%	387.1%	387.1%	
13	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		-	-	-	-	2,711,985.88	**2,711,985.88**
		Revenue Requirement		-	-	-	-	10,498,177.93	**10,498,177.93**

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

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]**:**

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

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]**:**	

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

Potomac-Appalachian Transmission Highline, LLC
PATH West Virginia Transmission Company, LLC

CALCULATION OF COST OF DEBT AFTER CONSTRUCTION PHASE

YEAR ENDED 12/31/2014

(HYPOTHETICAL EXAMPLE)

	Amount Outstanding	Unamortized Debt Issue Expense	Unamortized Debt Premium/ (Discount)	Unamortized Losses on Reacquired Debt	Net Amount Outstanding	Effective Cost Rate[1]	Annualized Cost
Debt:							
First Mortgage Bonds:	$ 300,000,000	$2,900,000	($2,320,000)	$0	$294,780,000	#N/A	#N/A
Other Long Term Debt:							
6.600% Series Medium Term Notes Due 2021	$ 200,000,000	$1,800,000		-	$198,200,000	#N/A	#N/A
					-		
Total Debt	$ 500,000,000	$ 4,700,000	$ (2,320,000)	$ -	$ 492,980,000	#N/A	#N/A
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	#N/A	$ 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	#N/A	13,200,000
			$ 500,000,000	(2,400,000)	$ 5,000,000	-	$ 492,600,000				$ 34,470,000

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

Attachment 7

PATH Allegheny Transmission Company, LLC

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

(HYPOTHETICAL EXAMPLE)

	Amount Outstanding	Unamortized Debt Issue Expense	Unamortized Debt Premium/ (Discount)	Unamortized Losses on Reacquired Debt	Net Amount Outstanding	Effective Cost Rate[1]	Annualized Cost
Debt:							
First Mortgage Bonds:							
	$ 300,000,000	$2,900,000	($2,320,000)	$0	$294,780,000	#N/A	#N/A
Other Long Term Debt:							
6.600% Series Medium Term Notes Due 2021	$ 200,000,000	$1,800,000		-	$198,200,000	#N/A	#N/A
					-		
Total Debt	$ 500,000,000	$ 4,700,000	$ (2,320,000)	$ -	$ 492,980,000	**#N/A**	#N/A
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	#N/A	$ 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	#N/A	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 2015 Available June 1, 2016		2015 Revenue Requirement Forecast by Sept 2, 2014		True-up Adjustment - Over (Under) Recovery
$16,511,590	-	$15,216,438	=	($1,295,152)

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			0.2780%				
An over or under collection will be recovered prorata over 2015, held for 2016 and returned prorate over 2017							
Calculation of Interest					**Monthly**		
January	Year 2015	(107,929)	0.2780%	12	3,601		111,530
February	Year 2015	(107,929)	0.2780%	11	3,300		111,230
March	Year 2015	(107,929)	0.2780%	10	3,000		110,930
April	Year 2015	(107,929)	0.2780%	9	2,700		110,630
May	Year 2015	(107,929)	0.2780%	8	2,400		110,330
June	Year 2015	(107,929)	0.2780%	7	2,100		110,030
July	Year 2015	(107,929)	0.2780%	6	1,800		109,730
August	Year 2015	(107,929)	0.2780%	5	1,500		109,430
September	Year 2015	(107,929)	0.2780%	4	1,200		109,130
October	Year 2015	(107,929)	0.2780%	3	900		108,829
November	Year 2015	(107,929)	0.2780%	2	600		108,529
December	Year 2015	(107,929)	0.2780%	1	300		108,229
					23,403		**1,318,555**
					Annual		
January through December	Year 2016	1,318,555	0.2780%	12	43,987		**1,362,542**
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
January	Year 2017	**(1,362,542)**	0.2780%		3,788	(115,607)	1,250,723
February	Year 2017	(1,250,723)	0.2780%		3,477	(115,607)	1,138,592
March	Year 2017	(1,138,592)	0.2780%		3,165	(115,607)	1,026,150
April	Year 2017	(1,026,150)	0.2780%		2,853	(115,607)	913,396
May	Year 2017	(913,396)	0.2780%		2,539	(115,607)	800,327
June	Year 2017	(800,327)	0.2780%		2,225	(115,607)	686,945
July	Year 2017	(686,945)	0.2780%		1,910	(115,607)	573,247
August	Year 2017	(573,247)	0.2780%		1,594	(115,607)	459,234
September	Year 2017	(459,234)	0.2780%		1,277	(115,607)	344,903
October	Year 2017	(344,903)	0.2780%		959	(115,607)	230,254
November	Year 2017	(230,254)	0.2780%		640	(115,607)	115,287
December	Year 2017	(115,287)	0.2780%		320	(115,607)	0
					24,746		
True-Up Adjustment with Interest						1,387,289	
Less Over (Under) Recovery						(1,295,152)	
Total Interest						92,137	

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

Reconciliation Revenue Requirement For Year 2015 Available June 1, 2016		2015 Revenue Requirement Forecast by Sept 2, 2014		True-up Adjustment - Over (Under) Recovery
$15,516,112	-	$14,292,713	=	($1,223,399)

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			0.2780%				
An over or under collection will be recovered prorata over 2015, held for 2016 and returned prorate over 2017							
Calculation of Interest					**Monthly**		
January	Year 2015	(101,950)	0.2780%	12	3,401		105,351
February	Year 2015	(101,950)	0.2780%	11	3,118		105,068
March	Year 2015	(101,950)	0.2780%	10	2,834		104,784
April	Year 2015	(101,950)	0.2780%	9	2,551		104,501
May	Year 2015	(101,950)	0.2780%	8	2,267		104,217
June	Year 2015	(101,950)	0.2780%	7	1,984		103,934
July	Year 2015	(101,950)	0.2780%	6	1,701		103,650
August	Year 2015	(101,950)	0.2780%	5	1,417		103,367
September	Year 2015	(101,950)	0.2780%	4	1,134		103,084
October	Year 2015	(101,950)	0.2780%	3	850		102,800
November	Year 2015	(101,950)	0.2780%	2	567		102,517
December	Year 2015	(101,950)	0.2780%	1	283		102,233
					22,107		**1,245,506**
					Annual		
January through December	Year 2016	1,245,506	0.2780%	12	41,550		**1,287,056**
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
January	Year 2017	**(1,287,056)**	0.2780%		3,578	(109,203)	1,181,431
February	Year 2017	(1,181,431)	0.2780%		3,284	(109,203)	1,075,513
March	Year 2017	(1,075,513)	0.2780%		2,990	(109,203)	969,300
April	Year 2017	(969,300)	0.2780%		2,695	(109,203)	862,792
May	Year 2017	(862,792)	0.2780%		2,399	(109,203)	755,988
June	Year 2017	(755,988)	0.2780%		2,102	(109,203)	648,887
July	Year 2017	(648,887)	0.2780%		1,804	(109,203)	541,489
August	Year 2017	(541,489)	0.2780%		1,505	(109,203)	433,791
September	Year 2017	(433,791)	0.2780%		1,206	(109,203)	325,795
October	Year 2017	(325,795)	0.2780%		906	(109,203)	217,498
November	Year 2017	(217,498)	0.2780%		605	(109,203)	108,900
December	Year 2017	(108,900)	0.2780%		303	(109,203)	0
					23,375		

True-Up Adjustment with Interest	$	1,310,431
Less Over (Under) Recovery	$	(1,223,399)
Total Interest	$	87,032

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**
Calculation of Interest for 2008 True-Up Period							
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)**
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**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

		Accrual Rate (Annual) Percent	Annual Depreciation Expense
TRANSMISSION PLANT			
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)	-		

		Accrual Rate (Annual) Percent	Annual Depreciation Expense
GENERAL PLANT			
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.d&e)	-		

		Accrual Rate (Annual) Percent	Annual Depreciation Expense
INTANGIBLE PLANT			
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 9

VEPCO Formula Rate for January 1, 2017 to December 31, 2017

Virginia Electric and Power Company
ATTACHMENT H-16A

Formula Rate -- Appendix A

Shaded cells are input cells

		Notes	FERC Form 1 Page # or Instruction (Note H)		2017 Projection (000's)
	Allocators				
	Wages & Salary Allocation Factor				
1	Transmission Wages Expense		p354.21b/ Attachment 5	$	35,851
2	Less Generator Step-ups		Attachment 5		95
3	Net Transmission Wage Expenses		(Line 1 - 2)		35,756
4	Total Wages Expense		p354.28b/Attachment 5		611,620
5	Less A&G Wages Expense		p354.27b/Attachment 5		82,202
6	Total		(Line 4 - 5)	$	529,419
7	**Wages & Salary Allocator**	(Note B)	(Line 3 / 6)		**6.7538%**
	Plant Allocation Factors				
8	Electric Plant in Service	(Notes A& Q)	p207.104.g/Attachment 5	$	37,371,929
9	Common Plant In Service - Electric		(Line 26)		0
10	Total Plant In Service		(Sum Lines 8 & 9)		37,371,929
11	Accumulated Depreciation (Total Electric Plant)	(Notes A & Q)	(Line 15 - 14 - 13 -12)		13,086,392
12	Accumulated Intangible Amortization	(Notes A & Q)	p200.21c/Attachment 5		117,350
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		13,203,741
16	Net Plant		(Line 10 - 15)		24,168,187
17	Transmission Gross Plant		(Line 31 - 30)		7,568,775
18	**Gross Plant Allocator**	(Note B)	(Line 17 / 10)		**20.2526%**
19	Transmission Net Plant		(Line 44 - 30)	$	6,289,960
20	**Net Plant Allocator**	(Note B)	(Line 19 / 16)		**26.0258%**
	Plant Calculations				
	Plant In Service				
21	Transmission Plant In Service	(Notes A & Q)	p207.58.g/Attachment 5	$	8,000,820
22	Less: Generator Step-ups	(Notes A & Q)	Attachment 5		331,484
23	Less: Interconnect Facilities Installed After March 15, 2000	(Notes A & Q)	Attachment 5		169,491
24	**Total Transmission Plant In Service**		(Lines 21 - 22 - 23)		**7,499,845**
25	General & Intangible	(Notes A & Q)	p205.5.g + p207.99.g/Attachment 5		1,020,603
26	Common Plant (Electric Only)		p356/Attachment 5		0
27	Total General & Common		(Line 25 + 26)		1,020,603
28	Wage & Salary Allocation Factor		(Line 7)		6.7538%
29	**General & Common Plant Allocated to Transmission**		(Line 27 * 28)	**$**	**68,930**
30	**Plant Held for Future Use (Including Land)**	(Notes C & Q)	p214.47.d/Attachment 5	**$**	**6,937**
31	**TOTAL Plant In Service**		**(Line 24 + 29 + 30)**	**$**	**7,575,712**
	Accumulated Depreciation				
32	Transmission Accumulated Depreciation	(Notes A & Q)	p219.25.c/Attachment 5	$	1,344,213
33	Less Accumulated Depreciation for Generator Step-ups	(Notes A & Q)	Attachment 5		82,214
34	Less Accumulated Depreciation for Interconnect Facilities Installed After March 15, 2000	(Notes A & Q)	Attachment 5		14,610
35	Total Accumulated Depreciation for Transmission		(Line 32 - 33 - 34)		1,247,389
36	Accumulated General Depreciation	(Notes A & Q)	p219.28.b/Attachment 5		347,962
37	Accumulated Intangible Amortization	(Notes A & Q)	(Line 12)		117,350
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)		465,311
41	Wage & Salary Allocation Factor		(Line 7)		6.7538%
42	**General & Common Allocated to Transmission**		(Line 40 * 41)		**31,426**
43	**TOTAL Accumulated Depreciation**		**(Line 35 + 42)**	**$**	**1,278,815**
44	**TOTAL Net Property, Plant & Equipment**		**(Line 31 - 43)**	**$**	**6,296,897**

Virginia Electric and Power Company
ATTACHMENT H-16A

Formula Rate -- Appendix A

		Notes	FERC Form 1 Page # or Instruction (Note H)		2017 Projection
	Adjustment To Rate Base				
	Accumulated Deferred Income Taxes				
45	ADIT net of FASB 106 and 109		Attachment 1	$	(1,262,661)
46	**Accumulated Deferred Income Taxes Allocated To Transmission**		(Line 45)	**$**	**(1,262,661)**
	Transmission O&M Reserves				
47	**Total Balance Transmission Related Account 242 Reserves**	Enter Negative	Attachment 5	**$**	**(8,937)**
	Unamortized Excess/Deficient Deferred Income Taxes				
47A	**Unamortized Exc/Def Deferral**		Attachment 5	**$**	**(2,457)**
	Prepayments				
48	Prepayments	(Notes A & R)	Attachment 5	$	1,822
49	**Total Prepayments Allocated to Transmission**		(Line 48)	**$**	**1,822**
	Materials and Supplies				
50	Undistributed Stores Exp	(Notes A & R)	p227.6c & 16.c	$	-
51	Wage & Salary Allocation Factor		(Line 7)		6.7538%
52	Total Transmission Allocated Materials and Supplies		(Line 50 * 51)		0
53	Transmission Materials & Supplies		p227.8c/2		45,088
54	**Total Materials & Supplies Allocated to Transmission**		(Line 52 + 53)	**$**	**45,088**
	Cash Working Capital				
55	Transmission Operation & Maintenance Expense		(Line 85)	$	111,569
56	1/8th Rule		x 1/8		12.5%
57	**Total Cash Working Capital Allocated to Transmission**		(Line 55 * 56)	**$**	**13,946**
	Network Credits				
58	Outstanding Network Credits	(Note N)	Attachment 5 / From PJM		0
59	Less Accumulated Depreciation Associated with Facilities with Outstanding Network Credits	(Note N)	Attachment 5 / From PJM		0
60	Net Outstanding Credits		(Line 58 - 59)		**0**
61	**TOTAL Adjustment to Rate Base**		(Line 46 + 47 + 47A + 49 + 54 + 57 - 60)	**$**	**(1,213,198)**
62	**Rate Base**		(Line 44 + 61)	**$**	**5,083,699**
	O&M				
	Transmission O&M				
63	Transmission O&M		p321.112.b/Attachment 5	$	23,684
64	Less GSU Maintenance		Attachment 5		126
65	Less Account 565 - Transmission by Others		p321.96.b/Attachment 5		(63,930)
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)	**$**	**87,489**
	Allocated General & Common Expenses				
68	Common Plant O&M	(Note A)	p356		0
69	Total A&G		Attachment 5		363,728
70	Less Property Insurance Account 924		p323.185b		10,240
71	Less Regulatory Commission Exp Account 928	(Note E)	p323.189b/Attachment 5		29,322
72	Less General Advertising Exp Account 930.1		p323.911b/Attachment 5		3,649
73	Less EPRI Dues	(Note D)	p352-353/Attachment 5		3,441
74	**General & Common Expenses**		(Lines 68 + 69) - Sum (70 to 73)	$	317,076
75	Wage & Salary Allocation Factor		(Line 7)		6.7538%
76	**General & Common Expenses Allocated to Transmission**		(Line 74 * 75)	**$**	**21,415**
	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		10,240
81	General Advertising Exp Account 930.1	(Note F)	Attachment 5		0
82	Total		(Line 80 + 81)		10,240
83	Net Plant Allocation Factor		(Line 20)		26.0258%
84	**A&G Directly Assigned to Transmission**		(Line 82 * 83)	**$**	**2,665**
85	**Total Transmission O&M**		**(Line 67 + 76 + 79 + 84)**	**$**	**111,569**

Virginia Electric and Power Company
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Formula Rate -- Appendix A

			Notes	FERC Form 1 Page # or Instruction (Note H)		2017 Projection
	Depreciation & Amortization Expense					
	Depreciation Expense					
86	Transmission Depreciation Expense		(Notes A and S)	p336.7b&c/Attachment 5	**$**	**184,954**
87	Less: GSU Depreciation			Attachment 5		**9,586**
88	Less Interconnect Facilities Depreciation			Attachment 5		**4,901**
89	Extraordinary Property Loss			Attachment 5		**0**
90	Total Transmission Depreciation			(Line 86 - 87 - 88 + 89)		**170,466**
91	General Depreciation		(Note A)	p336.10b&c&d/Attachment 5		26,458
92	Intangible Amortization		(Note A)	p336.1d&e/Attachment 5		29,636
93	Total			(Line 91 + 92)		**56,095**
94	Wage & Salary Allocation Factor			(Line 7)		6.7538%
95	**General and Intangible Depreciation Allocated to Transmission**			(Line 93 * 94)		**3,789**
96	Common Depreciation - Electric Only		(Note A)	p336.11.b		0
97	Common Amortization - Electric Only		(Note A)	p356 or p336.11d		0
98	Total			(Line 96 + 97)		0
99	Wage & Salary Allocation Factor			(Line 7)		6.7538%
100	**Common Depreciation - Electric Only Allocated to Transmission**			(Line 98 * 99)		**0**
101	**Total Transmission Depreciation & Amortization**			**(Line 90 + 95 + 100)**	**$**	**174,255**
	Taxes Other than Income					
102	**Taxes Other than Income**			Attachment 2	**$**	**49,942**
103	**Total Taxes Other than Income**			**(Line 102)**	**$**	**49,942**
	Return / Capitalization Calculations					
	Long Term Interest					
104	Long Term Interest		(Note T)	p117.62c through 67c/Attachment 5	$	453,202
105	Less LTD Interest on Securitization Bonds		(Note P)	Attachment 8		0
106	**Long Term Interest**			(Line 104 - 105)	$	453,202
107	**Preferred Dividends**		(Note T), enter positive	p118.29c	$	-
	Common Stock					
108	Proprietary Capital			p112.16c,d/2	$	10,346,898
109	Less Preferred Stock		(Note T), enter negative	(Line 117)		0
110	Less Account 219 - Accumulated Other Comprehensive Income		(Note T), enter negative	p112.15c,d/2		(45,001)
111	**Common Stock**			(Sum Lines 108 to 110)	$	10,301,897
	Capitalization					
112	Long Term Debt			p112.24c,d/2	$	9,180,968
113	Less Loss on Reacquired Debt		(Note T), enter negative	p111.81c,d/2		(4,846)
114	Plus Gain on Reacquired Debt		(Note T), enter positive	p113.61c,d/2		3,729
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)		9,179,851
117	Preferred Stock		(Note T), enter positive	p112.3c,d/2		0
118	Common Stock			(Line 111)		10,301,897
119	**Total Capitalization**			(Sum Lines 116 to 118)	$	19,481,748
120	Debt %	Total Long Term Debt		(Line 116 / 119)		47.1%
121	Preferred %	Preferred Stock		(Line 117 / 119)		0.0%
122	Common %	Common Stock		(Line 118 / 119)		52.9%
123	Debt Cost	Total Long Term Debt		(Line 106 / 116)		0.0494
124	Preferred Cost	Preferred Stock		(Line 107 / 117)		0.0000
125	Common Cost	Common Stock	(Note J)	Fixed		0.1140
126	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Line 120 * 123)		0.0233
127	Weighted Cost of Preferred	Preferred Stock		(Line 121 * 124)		0.0000
128	Weighted Cost of Common	Common Stock		(Line 122 * 125)		0.0603
129	**Total Return (R)**			(Sum Lines 126 to 128)		**0.0835**
130	**Investment Return = Rate Base * Rate of Return**			**(Line 62 * 129)**		**424,722**

Virginia Electric and Power Company
ATTACHMENT H-16A

Formula Rate -- Appendix A

		Notes	FERC Form 1 Page # or Instruction (Note H)		2017 Projection
	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		6.03%
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)} =			38.92%
135	T/ (1-T)				63.72%
	Transmission Related Income Tax Adjustments				
136	Amortized Investment Tax Credit (ITC)	(Note I) enter negative	Attachment 1	$	(137)
136A	Other Income Tax Adjustments		Attachment 5	$	1,443
137	T/(1-T)		(Line 135)		63.72%
138	**Transmission Income Taxes - Income Tax Adjustments**		((Line 136 + 136A) * (1 + Line 137))	**$**	**2,138**
139	**Transmission Income Taxes - Equity Return =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =	[Line 135 * 130 * (1-(126 / 129))]		**195,285**
140	**Total Transmission Income Taxes**		**(Line 138 + 139)**		**197,422**
	REVENUE REQUIREMENT				
	Summary				
141	Net Property, Plant & Equipment		(Line 44)	$	6,296,897
142	Adjustment to Rate Base		(Line 61)		(1,213,198)
143	**Rate Base**		(Line 62)	**$**	**5,083,699**
144	O&M		(Line 85)		111,569
145	Depreciation & Amortization		(Line 101)		174,255
146	Taxes Other than Income		(Line 103)		49,942
147	Investment Return		(Line 130)		424,722
148	Income Taxes		(Line 140)		197,422
149	One-time Credit to Reflect Application to 2014 of Final Rates from FERC Docket No. ER14-1831.				(3,207)
150	**Revenue Requirement**		**(Sum Lines 144 to 149)**	**$**	**954,702**
	Net Plant Carrying Charge				
151	Revenue Requirement		(Line 150)	**$**	**954,702**
152	Net Transmission Plant		(Line 24 - 35)		**6,252,457**
153	Net Plant Carrying Charge		(Line 151 / 152)		**15.2692%**
154	Net Plant Carrying Charge without Depreciation		(Line 151 - 86) / 152		**12.3111%**
155	Net Plant Carrying Charge without Depreciation, Return or Income Taxes		(Line 151 - 86 - 130 - 140) / 152		**2.3607%**
	Net Plant Carrying Charge Calculation with 100 Basis Point increase in ROE				
156	Gross Revenue Requirement Less Return and Taxes		(Line 150 - 147 - 148)	**$**	**332,558**
157	Increased Return and Taxes		Attachment 4		**666,157**
158	Net Revenue Requirement with 100 Basis Point increase in ROE		(Line 156 + 157)		**998,715**
159	Net Transmission Plant		(Line 152)		**6,252,457**
160	Net Plant Carrying Charge with 100 Basis Point increase in ROE		(Line 158 / 159)		**15.9732%**
161	Net Plant Carrying Charge with 100 Basis Point increase in ROE without Depreciation		(Line 158 - 86) / 159		**13.0151%**
162	**Revenue Requirement**		(Line 150)	**$**	**954,702**
163	True-up Adjustment		Attachment 6		**(24,426)**
164	Plus any increased ROE calculated on Attachment 7 other than PJM Schedule 12 projects.		Attachment 7		**2,839**
165	Facility Credits under Section 30.9 of the PJM OATT.		Attachment 5		**2,742**
166	Revenue Credits		Attachment 3		**(9,293)**
167	Interest on Network Credits		PJM data		0
168	**Annual Transmission Revenue Requirement (ATRR)**		(Line 162 + 163 +164 + 165 + 166 + 167)	**$**	**926,564**
	Rate for Network Integration Transmission Service				
169	1 CP Peak	(Note L)	PJM Data		**19,538.1**
170	Rate ($/MW-Year)		(Line 168 / 169)		**47,423.44**
171	**Rate for Network Integration Transmission Service ($/MW/Year)**		**(Line 170)**		**47,423.44**

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, 2017 Projection

	Only Transmission Related	*Plant Related*	*Labor Related*	*Total ADIT*
ADIT- 282	(1,333,986)	(61,507)	(76,191)	
ADIT-283	0	(3,635)	(1,346)	
ADIT-190	5,312	205,352	125,843	
Subtotal	(1,328,674)	140,210	48,306	
Wages & Salary Allocator			6.7538%	
Gross Plant Allocator		20.2526%		
End of Year ADIT	(1,328,674)	28,396	3,263	(1,297,015)
End of Previous Year ADIT (from Sheet	(1,258,520)	26,907	3,307	(1,228,306)
Average Beginning and End of Year ADI	(1,293,597)	27,652	3,285	(1,262,661)

End of Year ADIT	(1,297,015)
End of Previous Year ADIT	(1,228,306)
Average Beginning and End of Year ADIT	(1,262,661)

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

End of Year Balances :

A	B	C	D	E	F	G
ADIT-190	*Total*	*Production Or Other Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
BAD DEBTS VEPCO	28,232	28,232				Not applicable to Transmission Cost of Service calculation.
BOOK AMORT-CAPITAL LEASES (207)	(1,059)	(1,059)				Not applicable to Transmission Cost of Service calculation.
BOOK OP- GAIN(LOSS) SALE PROPR	62	62				Not applicable to Transmission Cost of Service calculation.
CAPITALIZED INTEREST - 481A ADJUST	3,765			3,765		Representive of the IRS settlement related to the 263A costs associated with the Generation capital repairs settlement.
CAPITALIZED INTEREST - DEPREC 481A	(902)			(902)		Represents the recovery of tax capitalized interest reported as taxable income.
CAPITALIZED INTEREST OPERATING CWIP	86,169	86,169				Not applicable to Transmission Cost of Service calculation.
CAPITALIZED O&M EXP-DISTRIBUTION	8,945	8,945				Not applicable to Transmission Cost of Service calculation.
CHAR CONTRIB CFWD CURRENT VEPCO	4,595	4,595				Not applicable to Transmission Cost of Service calculation.
CIAC DC-NONOP IN SERVICE	1,687	1,687				Not applicable to Transmission Cost of Service calculation.
CIAC NC-NONOP CWIP VEPCO	2,850	2,850				Not applicable to Transmission Cost of Service calculation.
CIAC NC-NONOP IN SERVICE	829	829				Not applicable to Transmission Cost of Service calculation.
CIAC VA-NONOP CWIP VEPCO	15,780	15,780				Not applicable to Transmission Cost of Service calculation.
CIAC VA-NONOP IN SERVICE	54,992	54,992				Not applicable to Transmission Cost of Service calculation.
CONTINGENT CLAIMS CURRENT VEPCO	(1,054)	(1,054)				Not applicable to Transmission Cost of Service calculation.
CONTINGENT CLAIMS NONCURRENT VEPCO	82,077	82,077				Not applicable to Transmission Cost of Service calculation.
CURR CAPIT RESTORATION COSTS 481A-DISTR VEPCO	757	757				Not applicable to Transmission Cost of Service calculation.
CUSTOMER ACCOUNTS- RES & REFUND VEPCO	(219)	(219)				Not applicable to Transmission Cost of Service calculation.
CUSTOMER ACCTS. INTEREST-RES & REFUND VEPCO	223	223				Not applicable to Transmission Cost of Service calculation.
CWIP ABANDONMENT NON CURRENT	-	-				Not applicable to Transmission Cost of Service calculation.
CWIP ABANDONMENT NON CURRENT-NA3	87,634	87,634				Not applicable to Transmission Cost of Service calculation.
CWIP ABANDONMENT NON CURRENT-WIND	1,186	1,186				Not applicable to Transmission Cost of Service calculation.
DC - BONUS DEPRECIATION DEF CUR	0	0				Not applicable to Transmission Cost of Service calculation.
DC - BONUS DEPRECIATION DEF NC	0	0				Not applicable to Transmission Cost of Service calculation.
DC BONUS DEPRECIATION	(36)	(36)				Not applicable to Transmission Cost of Service calculation.
DC BONUS DEPRECIATION 481A - GEN REPAIR	0	0				Not applicable to Transmission Cost of Service calculation.
DC BONUS DEPRECIATION CASUALTY 481A	(1)	(1)				Not applicable to Transmission Cost of Service calculation.
DC BONUS DEPRECIATION CIAC	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
DC BONUS DEPRECIATION GEN 481A - CAP INTEREST	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
DECOMM POUROVER VEPCO	2,955	2,955				Not applicable to Transmission Cost of Service calculation.
DECOMM TRUST BOOK INCOME NON OP VEPCO	9,109	9,109				Not applicable to Transmission Cost of Service calculation.
DECOMM TRUST BOOK INCOME OP VEPCO	16,728	16,728				Not applicable to Transmission Cost of Service calculation.
DECOMM TRUST-UNREALIZED G/L-NC VEPCO	10,150	10,150				Not applicable to Transmission Cost of Service calculation.
DEDESIGNATED DEBT NOT ISSUED VEPCO	(490)	(490)				Not applicable to Transmission Cost of Service calculation.
DEF G/L NONOPERATING VEPCO	(53)	(53)				Not applicable to Transmission Cost of Service calculation.
DEF G/L-FUTURE USE NONOP VEPCO	1,180	1,180				Not applicable to Transmission Cost of Service calculation.
DEF ITC- NCP	132	132				Not applicable to Transmission Cost of Service calculation.
DEFERRED FUEL EXPENSE CURRENT VEPCO	106	106				Not applicable to Transmission Cost of Service calculation.
DEFERRED FUEL EXPENSE VEPCO	-	-				Not applicable to Transmission Cost of Service calculation.
DEFERRED FUEL EXP-OTHER CURRENT VEPCO	39	39				Not applicable to Transmission Cost of Service calculation.
DEFERRED REVENUE CURRENT VEPCO	3,040	3,040				Not applicable to Transmission Cost of Service calculation.
DIRECTOR CHARITABLE DONATION VEPCO	143	143				Not applicable to Transmission Cost of Service calculation.
DOE SETTLEMENT VEPCO	513	513				Not applicable to Transmission Cost of Service calculation.
DOE SETTLEMENT-INVENT BASIS REDUCTION VEPCO	1,719	1,719				Not applicable to Transmission Cost of Service calculation.
DT-CAP INTEREST OPER IN SERVICE-FED	201,291			201,291		Represents tax "In Service" capitalized Interest placed in service net of tax amortization.
DT-COST OF REMOVAL-DIST DFIT ONLY	20,673	20,673				Represents the actual cost of removal allowable for tax over the accrued amount.
DT-COST OF REMOVAL-GENERAL DFIT ONLY	(2,022)				(2,022)	Represents the actual cost of removal allowable for tax over the accrued amount.
DT-COST OF REMOVAL-PROD DFIT ONLY	50,320	50,320				Represents the actual cost of removal allowable for tax over the accrued amount.
DT-COST OF REMOVAL-PROD NA DFIT ONLY	(12,385)	(12,385)				Represents the actual cost of removal allowable for tax over the accrued amount.
DT-COST OF REMOVAL-TRANS DFIT ONLY	5,582	350	5,233			Represents the actual cost of removal allowable for tax over the accrued amount.
FAS 133 CURRENT VEPCO	1,033	1,033				Not applicable to Transmission Cost of Service calculation.
FAS 133 NC VEPCO	(1,033)	(1,033)				Not applicable to Transmission Cost of Service calculation.
FAS 133-DEBT HEDGE CURRENT ASSET VEPCO	5,665	5,665				Not applicable to Transmission Cost of Service calculation.
FAS 133-DEBT VAL-MTM HEDGE NON CURR AS VEPCO	140,694	140,694				Not applicable to Transmission Cost of Service calculation.
FAS 133-DEFERRED G/L CAPACITY HEDGE CURR LIAB	-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133-DEFERRED G/L POWER HEDGE-CURR LIAB	-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133-FTR CURRENT LIAB VEPCO	-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133-FTR HEDGE CURRENT ASSET VEPCO	316	316				Not applicable to Transmission Cost of Service calculation.
FAS 143 ASSET OBLIGATION-DISTRIBUTION	2,779	2,779				Represents ARO accruals not deductible for tax.
FAS 143 ASSET OBLIGATION-GENERAL	50	50				Represents ARO accruals not deductible for tax.
FAS 143 ASSET OBLIGATION-NA	443	443				Represents ARO accruals not deductible for tax.
FAS 143 ASSET OBLIGATION-OTHER	109,709	109,709				Represents ARO accruals not deductible for tax.
FAS 143 ASSET OBLIGATION-TRANSMISSION	85	5	80			Represents ARO accruals not deductible for tax.
FAS 143 DECOMMISSIONING-NA	143,884	143,884				Not applicable to Transmission Cost of Service calculation.
FAS 143 DECOMMISSIONING-OTHER	203,986	203,986				Not applicable to Transmission Cost of Service calculation.
FAS109 on Unamortized ITC	8,248	8,248				Not applicable to Transmission Cost of Service calculation.
FEDERAL TAX INTEREST EXPENSE NON CURR VEPCO	(4)	(4)				Not applicable to Transmission Cost of Service calculation.
FEDERAL TAX INTEREST EXPENSE VEPCO	42	42				Not applicable to Transmission Cost of Service calculation.
FIN 18 - DC	0	0				Not applicable to Transmission Cost of Service calculation.
FIN 18 - FED	(148)	(148)				Not applicable to Transmission Cost of Service calculation.
FIN 18 - NC	5	5				Not applicable to Transmission Cost of Service calculation.
FIN 18 - VA	187	187				Not applicable to Transmission Cost of Service calculation.
FIN 18 - WV	6	6				Not applicable to Transmission Cost of Service calculation.
FUEL DEF CURRENT LIAB VEPCO	36,252	36,252				Not applicable to Transmission Cost of Service calculation.
FUEL DEF NON CUR LIAB VEPCO	3,502	3,502				Not applicable to Transmission Cost of Service calculation.
FUEL DEF OTHER CURRENT LIAB VEPCO	14,822	14,822				Not applicable to Transmission Cost of Service calculation.
FUEL DEF OTHER NON CUR LIAB	255	255				Not applicable to Transmission Cost of Service calculation.
FUEL HANDLING COSTS VEPCO	9	9				Not applicable to Transmission Cost of Service calculation.
General Business Credit - Def Current	3,206	3,206				Not applicable to Transmission Cost of Service calculation.
General Business Credit - Def NC	15,029	15,029				Not applicable to Transmission Cost of Service calculation.
HEADWATER BENEFITS VEPCO	1,345	1,345				Not applicable to Transmission Cost of Service calculation.
LONG TERM DISABILITY RESERVE VEPCO	8,973	1,293			7,680	Book estimate accrued and expensed; tax deduction when paid.
METERS	319	319				Not applicable to Transmission Cost of Service calculation.
NC - BONUS DEPRECIATION DEF CUR	6	6				Not applicable to Transmission Cost of Service calculation.
NC - BONUS DEPRECIATION DEF NC	10	10				Not applicable to Transmission Cost of Service calculation.
NC BONUS DEPRECIATION	(1,423)	(1,423)				Not applicable to Transmission Cost of Service calculation.
NC BONUS DEPRECIATION 481A - GEN REPAIR	14	14				Not applicable to Transmission Cost of Service calculation.
NC BONUS DEPRECIATION CASUALTY 481A	(29)	(29)				Not applicable to Transmission Cost of Service calculation.
NC BONUS DEPRECIATION CIAC	7	7				Not applicable to Transmission Cost of Service calculation.
NC BONUS DEPRECIATION GEN 481A - CAP INTEREST	(2)	(2)				Not applicable to Transmission Cost of Service calculation.
NC Deferred Current Adj - SOLAR ITC	35	35				Not applicable to Transmission Cost of Service calculation.
NC Deferred NonCurrent Adj - SOLAR ITC	8,915	8,915				Not applicable to Transmission Cost of Service calculation.
NOL CURRENT VEPCO	28,448	28,448				Not applicable to Transmission Cost of Service calculation.
NOL NC VEPCO	(28,448)	(28,448)				Not applicable to Transmission Cost of Service calculation.
NON CURR CAPIT RESTORATION COSTS 481A-D VEPCO	226	226				Not applicable to Transmission Cost of Service calculation.
NON CURRENT REC A4 ELEC TRAN VEPCO	241	241				Not applicable to Transmission Cost of Service calculation.
NUCLEAR FUEL-PERM DISPOSAL NORTH ANNA	(2)	(2)				Not applicable to Transmission Cost of Service calculation.
NUCLEAR FUEL-PERM DISPOSAL SURRY	(2)	(2)				Not applicable to Transmission Cost of Service calculation.
OBSOLETE INVENTORY RESERVE VEPCO	2,222	2,222				Not applicable to Transmission Cost of Service calculation.
OCI CF HEDGES OTHER PURCH/SALE NC Fed 100%	-	-				Not applicable to Transmission Cost of Service calculation.
OCI CF HEDGES OTHER PURCH/SALE NC State 100%	-	-				Not applicable to Transmission Cost of Service calculation.
OCI CF HEDGES-OTHER PURCH/SALE CURR Fed 100%	0	0				Not applicable to Transmission Cost of Service calculation.
OCI CF HEDGES-OTHER PURCH/SALE CURR State 100%	0	0				Not applicable to Transmission Cost of Service calculation.

OCI CF HEDGING DEBT CURR Fed 100%		364	364				Not applicable to Transmission Cost of Service calculation.
OCI CF HEDGING DEBT CURR State 100%		65	65				Not applicable to Transmission Cost of Service calculation.
OCI CF HEDGING DEBT NC Fed 100%		11,010	11,010				Not applicable to Transmission Cost of Service calculation.
OCI CF HEDGING DEBT NC State 100%		1,969	1,969				Not applicable to Transmission Cost of Service calculation.
OCI NUCLEAR DECOMM NC Fed 100%		(27,751)	(27,751)				Not applicable to Transmission Cost of Service calculation.
OCI NUCLEAR DECOMM NC State 100%		(4,962)	(4,962)				Not applicable to Transmission Cost of Service calculation.
OPEB VEPCO		(43,747)	(6,306)			(37,442)	Represents the difference between the book accrual expense and the actual funded amount.
POWERTREE CARBON CO, LLC. VEPCO		2	2				Not applicable to Transmission Cost of Service calculation.
PREMIUM, DEBT, DISCOUNT&EXP VEPCO		1,400	202		1,198		Books record the yield to maturity method; taxes amortize staight line.
Production Tax Credit - Def Current Fed		10,031	10,031				Not applicable to Transmission Cost of Service calculation.
Production Tax Credit - Def NC Fed		15,062	15,062				Not applicable to Transmission Cost of Service calculation.
P'SHIP INCOME - VIRGINIA CAPITAL VEPCO		215	215				Not applicable to Transmission Cost of Service calculation.
RA.CUR AFUDC DEBT AMORT RIDER		(5)	(5)				Not applicable to Transmission Cost of Service calculation.
RA.CUR AFUDC DEBT RIDER		35	35				Not applicable to Transmission Cost of Service calculation.
RA.CUR OTHER COSTS NONOPER RIDER		(164)	(164)				Not applicable to Transmission Cost of Service calculation.
RA.CUR OTHER COSTS OPER RIDER		1,008	1,008				Not applicable to Transmission Cost of Service calculation.
RA.NON CUR AFUDC DEBT AMORT RIDER		(16)	(16)				Not applicable to Transmission Cost of Service calculation.
RA.NON CUR AFUDC DEBT RIDER		409	409				Not applicable to Transmission Cost of Service calculation.
RA.NON CUR OTHER COSTS NON OPER RIDER		(10)	(10)				Not applicable to Transmission Cost of Service calculation.
RA.NON CUR OTHER COSTS OPER RIDER		2,309	2,309				Not applicable to Transmission Cost of Service calculation.
REACQUIRED DEBT GAIN(LOSS) VEPCO		(19)	(19)				Not applicable to Transmission Cost of Service calculation.
REC.CUR AFUDC DEBT AMORT RIDER		0	0				Not applicable to Transmission Cost of Service calculation.
REC.CUR AFUDC DEBT RIDER		2	2				Not applicable to Transmission Cost of Service calculation.
REC.CUR OTHER COST OPER RIDER		64	64				Not applicable to Transmission Cost of Service calculation.
REC.CUR OTHER COSTS NON OPER RIDER		37	37				Not applicable to Transmission Cost of Service calculation.
REC.NON CUR AFUDC DEBT AMORT RIDER		(1)	(1)				Not applicable to Transmission Cost of Service calculation.
REC.NON CUR AFUDC DEBT RIDER		3	3				Not applicable to Transmission Cost of Service calculation.
REC.NON CUR OTHER COST NON OPER RIDER		(23)	(23)				Not applicable to Transmission Cost of Service calculation.
REC.NON CUR OTHER COST OPER RIDER		175	175				Not applicable to Transmission Cost of Service calculation.
RECS VEPCO		6	6				Not applicable to Transmission Cost of Service calculation.
REG ASSET - A4 RAC COSTS CURRENT VEPCO		304	304				Not applicable to Transmission Cost of Service calculation.
REG ASSET - A4 RAC COSTS NONCURRENT VEPCO		1,203	1,203				Not applicable to Transmission Cost of Service calculation.
REG ASSET - ATRR CURRENT VEPCO		179	179				Not applicable to Transmission Cost of Service calculation.
REG ASSET - CUR - NUG		22	22				Not applicable to Transmission Cost of Service calculation.
REG ASSET - FTR - CURRENT VEPCO		16	16				Not applicable to Transmission Cost of Service calculation.
REG ASSET - NRC REQUIREMENT - NORTH ANNA VEPCO		436	436				Not applicable to Transmission Cost of Service calculation.
REG ASSET - NRC REQUIREMENT - SURRY VEPCO		201	201				Not applicable to Transmission Cost of Service calculation.
REG ASSET ABANDONED PLANT NCUC CURR VEPCO		24	24				Not applicable to Transmission Cost of Service calculation.
REG ASSET ABANDONED PLANT NCUC NON CURR VEPCO		113	113				Not applicable to Transmission Cost of Service calculation.
REG ASSET ASSET IMPAIRMENT NCUC CURR VEPCO		5	5				Not applicable to Transmission Cost of Service calculation.
REG ASSET ASSET IMPAIRMENT NCUC NONCURR VEPCO		16	16				Not applicable to Transmission Cost of Service calculation.
REG ASSET CCR DEF NCUC ORDER NONCURR VEPCO		272	272				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURR RIDER A4 NON VA OTHER VEPCO		44	44				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A5 DSM VEPCO		94	94				Not applicable to Transmission Cost of Service calculation.
REG ASSET DEF NC RECPS REC COST CURR VEPCO		15	15				Not applicable to Transmission Cost of Service calculation.
REG ASSET FUEL HEDGE NONOP VEPCO		5,449	5,449				Not applicable to Transmission Cost of Service calculation.
REG ASSET NATURAL DISASTER NCUC CURRENT VEPCO		5	5				Not applicable to Transmission Cost of Service calculation.
REG ASSET NUCLEAR OUTAGE DEFER-CURRENT		1,248	1,248				Not applicable to Transmission Cost of Service calculation.
REG ASSET RETIREMENT NCUC CURRENT VEPCO		2	2				Not applicable to Transmission Cost of Service calculation.
REG ASSET RETIREMENT NCUC NONCURR VEPCO		16	16				Not applicable to Transmission Cost of Service calculation.
REG ASSET RIDER PLANTS NCUC CURRENT VEPCO		12	12				Not applicable to Transmission Cost of Service calculation.
REG ASSET RIDER PLANTS NCUC NONCURR VEPCO		4	4				Not applicable to Transmission Cost of Service calculation.
REG ASSET-DEBT VAL-MTM NON CURR VEPCO		7,098	7,098				Not applicable to Transmission Cost of Service calculation.
REG ASSET-DEBT VALUATION - MTM - CUR VEPCO		286	286				Not applicable to Transmission Cost of Service calculation.
REG ASSET-HEDGE DEBT DEDESIGNATED DEBT NOT ISSUE VEPCO		(52)	(52)				Not applicable to Transmission Cost of Service calculation.
REG ATTR NON CURRENT VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
REG FUEL HEDGE VEPCO		(5,449)	(5,449)				Not applicable to Transmission Cost of Service calculation.
REG LIAB - DEF NC REPS REC COST - NC		846	846				Not applicable to Transmission Cost of Service calculation.
REG LIAB - DEFERRED G/L CAPACITY HEDGE - CURRENT		-	-				Not applicable to Transmission Cost of Service calculation.
REG LIAB - FTR CURRENT VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
REG LIAB A5 REC COSTS - VA NON CURRENT VEPCO		2,815	2,815				Not applicable to Transmission Cost of Service calculation.
REG LIAB ATRR NON CURRENT		11,526	11,526				Not applicable to Transmission Cost of Service calculation.
REG LIAB CURRENT DSM A5		-	-				Not applicable to Transmission Cost of Service calculation.
Reg Liab NC Excess Def Tax-GU for Exp Item		5,253	5,253				Not applicable to Transmission Cost of Service calculation.
REG LIAB OTHER NCUC CURRENT VEPCO		347	347				Not applicable to Transmission Cost of Service calculation.
REG LIAB OTHER NCUC NON CURR VEPCO		7,110	7,110				Not applicable to Transmission Cost of Service calculation.
REG LIAB PLANT CONTRA VASLSTX VEPCO		26,237	26,237				Not applicable to Transmission Cost of Service calculation.
REG LIAB VA OTHER CURRENT VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
REG LIAB-DEF G/L CAPACITY HEDGE NON CUR VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
REG LIAB-DEF G/L POWER HEDGE-CUR VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
REG LIABILITY DECOMM TRUST NC OP VEPCO		(348,567)	(348,567)				Not applicable to Transmission Cost of Service calculation.
REG LIABILITY DECOMM VEPCO		697,065	697,065				Not applicable to Transmission Cost of Service calculation.
REG NON CURRENT DSM A5 RIDER VEPCO		221	221				Not applicable to Transmission Cost of Service calculation.
REG RATE REFUND - CURRENT VEPCO		558	558				Not applicable to Transmission Cost of Service calculation.
REGULATORY ASSET - FAS 112 VEPCO		68	68				Not applicable to Transmission Cost of Service calculation.
REGULATORY ASSET - NUG VEPCO		47	47				Not applicable to Transmission Cost of Service calculation.
REGULATORY ASSET - PJM		3,969	3,969				Not applicable to Transmission Cost of Service calculation.
REGULATORY ASSET - VA SLS TAX CURRENT VEPCO		722	722				Not applicable to Transmission Cost of Service calculation.
REGULATORY ASSET - VA SLS TAX VEPCO		42	42				Not applicable to Transmission Cost of Service calculation.
RESTRICTED STOCK AWARD VEPCO		(56)	(56)				Not applicable to Transmission Cost of Service calculation.
RETENTION BONUS		28	4			24	Books accrues the costs of the bonus; tax takes the deduction when actually paid.
RETIRE-EXEC SUPP RET (ESRP)-NONOP (1261010) VEPCO		55	55				Not applicable to Transmission Cost of Service calculation.
RETIRE-EXEC SUPP RET (ESRP)-NONOP (2210020) VEPCO		32	32				Not applicable to Transmission Cost of Service calculation.
RETIREMENT - (FASB 87) VEPCO		126,413	18,221			108,192	Book estimate accrued and expensed; tax deduction when paid.
SALES TAX RECOVERY CWIP		8,151	8,151				Not applicable to Transmission Cost of Service calculation.
SALES TAX RECOVERY IN SERVICE (537)		12,759	12,759				Not applicable to Transmission Cost of Service calculation.
SEPARATION/ERT VEPCO		5,198	749			4,449	Book amount accrued and expensed; tax deduction when paid. These amounts will be paid in the next 12 months.
ST AFC DEF TAX-FUEL CWIP		3	3				Not applicable to Transmission Cost of Service calculation.
ST AFC DEF TAX-PLANT CWIP		596	596				Not applicable to Transmission Cost of Service calculation.
ST AFC DEF TAX-PLANT IN SERVICE		1,865	1,865				Not applicable to Transmission Cost of Service calculation.
ST AFUDC-NUCLEAR FUEL		(12)	(12)				Not applicable to Transmission Cost of Service calculation.
ST BOOK AMORT-CAPITAL LEASES (207)		(178)	(178)				Not applicable to Transmission Cost of Service calculation.
ST BOOK CAPITALIZED INTEREST CWIP		35	35				Not applicable to Transmission Cost of Service calculation.
ST BOOK DEP.- AMORT DESIGN DOC		(8)	(8)				Not applicable to Transmission Cost of Service calculation.
ST BOOK DEP.- AMORT LEASE IMPROV		(259)	(259)				Not applicable to Transmission Cost of Service calculation.
ST BOOK DEP.-AMORT PLANT ACO ADJ.		(857)	(857)				Not applicable to Transmission Cost of Service calculation.
ST BOOK DEPR (008)		(251,452)	(251,452)				Not applicable to Transmission Cost of Service calculation.
ST BOOK DEPREC-NA MERIT PROGRAM		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
ST BOOK DEPR-NON OPERATING VEPCO		(10)	(10)				Not applicable to Transmission Cost of Service calculation.
ST BOOK DEPR-UNRECOVERED PLT NORTH ANNA		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
ST BOOK DEPR-UNRECOVERED PLT SURRY		(1)	(1)				Not applicable to Transmission Cost of Service calculation.
ST BOOK OP- GAIN(LOSS) SALE PROPR		10	10				Not applicable to Transmission Cost of Service calculation.
ST CAP EXPENSE 481A - PROD OTHER (750)		(4,290)	(4,290)				Not applicable to Transmission Cost of Service calculation.
ST CAP EXPENSE 481A (570)		339	339				Not applicable to Transmission Cost of Service calculation.
ST CAPITAL EXPENSE		758	758				Not applicable to Transmission Cost of Service calculation.
ST CAPITALIZED INTEREST - 481A ADJUST		634	634				Not applicable to Transmission Cost of Service calculation.
ST CAPITALIZED INTEREST - DEPREC 481A		(152)	(152)				Not applicable to Transmission Cost of Service calculation.
ST CAPITALIZED INTEREST OPER IN SERVICE		33,902	33,902				Not applicable to Transmission Cost of Service calculation.
ST CAPITALIZED INTEREST OPERATING CWIP		14,512	14,512				Not applicable to Transmission Cost of Service calculation.
ST CAPITALIZED O&M EXP-DISTRIBUTION		1,506	1,506				Not applicable to Transmission Cost of Service calculation.
ST CAPITALIZED RESTORATION 481A		(2,482)	(2,482)				Not applicable to Transmission Cost of Service calculation.
ST CASUALTY LOSS AMORT		(2,027)	(2,027)				Not applicable to Transmission Cost of Service calculation.
ST CASUALTY LOSSES (132)		5,377	5,377				Not applicable to Transmission Cost of Service calculation.
ST CIAC DC-NONOP IN SERVICE		284	284				Not applicable to Transmission Cost of Service calculation.
ST CIAC NC-NONOP CWIP VEPCO		480	480				Not applicable to Transmission Cost of Service calculation.
ST CIAC NC-NONOP IN SERVICE		140	140				Not applicable to Transmission Cost of Service calculation.
ST CIAC VA-NONOP CWIP VEPCO		2,657	2,657				Not applicable to Transmission Cost of Service calculation.
ST CIAC VA-NONOP IN SERVICE		9,261	9,261				Not applicable to Transmission Cost of Service calculation.
ST COMPUTER SOFTWARE-BOOK AMORT		(2,159)	(2,159)				Not applicable to Transmission Cost of Service calculation.
ST COMPUTER SOFTWARE-CWIP		840	840				Not applicable to Transmission Cost of Service calculation.
ST COMPUTER SOFTWARE-TAX AMORT		2,432	2,432				Not applicable to Transmission Cost of Service calculation.
ST COST OF REMOVAL		1,140	1,140				Not applicable to Transmission Cost of Service calculation.
ST CWIP ABANDONMENT NON CURRENT-NA3		14,758	14,758				Not applicable to Transmission Cost of Service calculation.
ST CWIP ABANDONMENT NON CURRENT-WIND		200	200				Not applicable to Transmission Cost of Service calculation.
ST DEF G/L NONOPERATING VEPCO		(9)	(9)				Not applicable to Transmission Cost of Service calculation.
ST DEF G/L-FUTURE USE NONOP VEPCO		199	199				Not applicable to Transmission Cost of Service calculation.
ST DEPR LATERAL PIPELINE RECORDED TO FUEL EXP		(33)	(33)				Not applicable to Transmission Cost of Service calculation.
ST DOE SETTLEMENT-ASSET BASIS REDUCTION		-	-				Not applicable to Transmission Cost of Service calculation.
ST FAS 143 ASSET OBLIGATION		19,042	19,042				Not applicable to Transmission Cost of Service calculation.
ST FAS 143 DECOMMISSIONING-NA		24,232	24,232				Not applicable to Transmission Cost of Service calculation.
ST FAS 143 DECOMMISSIONING-OTHER		34,353	34,353				Not applicable to Transmission Cost of Service calculation.
ST FIXED ASSETS		240	240				Not applicable to Transmission Cost of Service calculation.
ST G/L INTERCO SALES -BOOK/TAX		90	90				Not applicable to Transmission Cost of Service calculation.
ST LIBERALIZED DEPR: PLANT FUTURE USE VEPCO		(10)	(10)				Not applicable to Transmission Cost of Service calculation.
ST LIBERALIZED DEPR: PLANT NON UTILITY VEPCO		37	37				Not applicable to Transmission Cost of Service calculation.

ST METERS	54	54				Not applicable to Transmission Cost of Service calculation.
ST NUCLEAR FUEL TAX G/L-NA	350	350				Not applicable to Transmission Cost of Service calculation.
ST NUCLEAR FUEL TAX G/L-SURRY	476	476				Not applicable to Transmission Cost of Service calculation.
ST NUCLEAR FUEL-COMMERCIAL BURN	(12,848)	(12,848)				Not applicable to Transmission Cost of Service calculation.
ST NUCLEAR FUEL-PERM DISPOSAL NORTH ANNA	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
ST NUCLEAR FUEL-PERM DISPOSAL SURRY	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
ST SALES TAX RECOVERY CWIP	1,373	1,373				Not applicable to Transmission Cost of Service calculation.
ST SALES TAX RECOVERY IN SERVICE (537)	2,149	2,149				Not applicable to Transmission Cost of Service calculation.
ST TAX AMORT	16,054	16,054				Not applicable to Transmission Cost of Service calculation.
ST TAX DEPR-BONUS DEPR	176,418	176,418				Not applicable to Transmission Cost of Service calculation.
ST TAX DEPR	379,945	379,945				Not applicable to Transmission Cost of Service calculation.
ST TAX OP G/L SALE PROP	289	289				Not applicable to Transmission Cost of Service calculation.
STATE INCOME TAX - CURRENT N/C	668	668				Not applicable to Transmission Cost of Service calculation.
STATE INCOME TAX - CURRENT VEPCO	654	654				Not applicable to Transmission Cost of Service calculation.
SUCCESS SHARE PLAN VEPCO	6,012	867			5,146	Book amount accrued as its earned; tax deduction is actual payout.
SUPPLEMENTAL-SUPPLEMENTAL RETIRE VEPCO	81	81				Not applicable to Transmission Cost of Service calculation.
VA - BONUS DEPRECIATION DEF CUR	535	535				Not applicable to Transmission Cost of Service calculation.
VA - BONUS DEPRECIATION DEF NC	802	802				Not applicable to Transmission Cost of Service calculation.
VA 282 DIFFERENCE ADJUSTMENT	1,555	1,555				Not applicable to Transmission Cost of Service calculation.
VA BASIS DIFFERENCES	(42,712)	(42,712)				Not applicable to Transmission Cost of Service calculation.
VA BONUS DEPRECIATION	(112,866)	(112,866)				Not applicable to Transmission Cost of Service calculation.
VA BONUS DEPRECIATION 481A - GEN REPAIR	1,360	1,360				Not applicable to Transmission Cost of Service calculation.
VA BONUS DEPRECIATION CASUALTY 481A	(2,342)	(2,342)				Not applicable to Transmission Cost of Service calculation.
VA BONUS DEPRECIATION CIAC	(194)	(194)				Not applicable to Transmission Cost of Service calculation.
VA BONUS DEPRECIATION GEN 481A - CAP INTEREST	(158)	(158)				Not applicable to Transmission Cost of Service calculation.
VA MINIMUM TAX CREDIT	299	299				Not applicable to Transmission Cost of Service calculation.
VACATION ACCRUAL VEPCO	7,323	7,323				Not applicable to Transmission Cost of Service calculation.
WEST VA POLLUTION CONTROL	1,272	1,272				Federal effect of state deductions.
WEST VA PROPERTY TAX VEPCO	3,820	3,820				Not applicable to Transmission Cost of Service calculation.
WORKERS COMPENSATION - FAS 112	2,775	400			2,375	Books accrues the costs of the bonus; tax takes the deduction when actually paid.
OCI	32,713	32,713				Not applicable to Transmission Cost of Service calculation.
BAD DEBTS VEPCO	-	-				Not applicable to Transmission Cost of Service calculation.
CONTINGENT CLAIMS CURRENT VEPCO	-	-				Not applicable to Transmission Cost of Service calculation.
CUSTOMER ACCOUNTS- RES & REFUND VEPCO	-	-				Not applicable to Transmission Cost of Service calculation.
DEDESIGNATED DEBT NOT ISSUED VEPCO	419	419				Not applicable to Transmission Cost of Service calculation.
Retention Bonus	-				-	Books accrues the costs of the bonus; tax takes the deduction when actually paid.
OPEB VEPCO	37,442				37,442	Represents the difference between the book accrual expense and the actual funded amount.
FIN 18 - FED	148	148				Not applicable to Transmission Cost of Service calculation.
RESTRICTED STOCK AWARD VEPCO	48	48				Not applicable to Transmission Cost of Service calculation.
RETIRE-EXEC SUPP RET (ESRP)-NONOP (1261010) VEPCO	-	-				Not applicable to Transmission Cost of Service calculation.
BOOK AMORT-CAPITAL LEASES (207)	1,059	1,059				Not applicable to Transmission Cost of Service calculation.
NUCLEAR FUEL-PERM DISPOSAL NORTH ANNA	2	2				Not applicable to Transmission Cost of Service calculation.
NUCLEAR FUEL-PERM DISPOSAL SURRY	2	2				Not applicable to Transmission Cost of Service calculation.
FAS 133 CURRENT VEPCO	-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133 NC VEPCO	-	-				Not applicable to Transmission Cost of Service calculation.
FEDERAL TAX INTEREST EXPENSE NON CURR VEPCO	-	-				Not applicable to Transmission Cost of Service calculation.
REACQUIRED DEBT GAIN(LOSS) VEPCO	321	321				Not applicable to Transmission Cost of Service calculation.
REG ASSET-HEDGE DEBT DEDESIGNATED DEBT NOT ISSUE VEPCO	889	889				Not applicable to Transmission Cost of Service calculation.
CAP EXPENSE 481A - PROD OTHER (750)	-	-				Not applicable to Transmission Cost of Service calculation.
CAPITALIZED RESTORATION 481A	-	-				Not applicable to Transmission Cost of Service calculation.
G/L INTERCO SALES -BOOK/TAX	-	-				Not applicable to Transmission Cost of Service calculation.
ROUND	0	0				Not applicable to Transmission Cost of Service calculation.
Subtotal - p234	2,347,158	2,010,651	5,312	205,352	125,843	
Less FASB 109 Above if not separately removed	13,501	13,501	0	0	0	
Less FASB 106 Above if not separately removed	0	0	0	0	0	
Total	2,333,657	1,997,150	5,312	205,352	125,843	

Instructions for Account 190:

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

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

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

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

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

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

A	B	C	D	E	F	G
	Total	*Production*	*Only*			
ADIT- 282		*Or Other*	*Transmission*	*Plant*	*Labor*	
		Related	*Related*	*Related*	*Related*	*Justification*
AFC DEF TAX-FUEL CWIP	(55)	(55)				Not applicable to Transmission Cost of Service calculation.
AFC DEF TAX-PLANT CWIP	(10,114)	(10,114)				Not applicable to Transmission Cost of Service calculation.
AFC DEF TAX-PLANT IN SERVICE	(31,646)	(31,646)				Not applicable to Transmission Cost of Service calculation.
AFUDC EQUITY (FAC045) - FLOW THRU	(25,042)	(25,042)				Not applicable to Transmission Cost of Service calculation.
AFUDC-NUCLEAR FUEL	208	208				Not applicable to Transmission Cost of Service calculation.
BOOK CAPITALIZED INTEREST CWIP	(599)	-		(599)		Represents the unallowable amount of book interest.
BOOK DEP.- AMORT DESIGN DOC	129	129				Not applicable to Transmission Cost of Service calculation.
BOOK DEP.- AMORT LEASE IMPROV	4,392	4,392				Not applicable to Transmission Cost of Service calculation.
BOOK DEP.-AMORT PLANT ACO ADJ.	14,543	14,543				Not applicable to Transmission Cost of Service calculation.
BOOK DEPR (008)	4,265,961	4,265,961				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.
BOOK DEPREC-NA MERIT PROGRAM	1	1				Represents a decrease to tax depreciation (Sec 162) as a result of casualty loss (Sec 165) reduction to tax basis.
BOOK DEPR-NON OPERATING VEPCO	171	171				Not applicable to Transmission Cost of Service calculation.
BOOK DEPR-UNRECOVERED PLT NORTH ANNA	4	4				Not applicable to Transmission Cost of Service calculation.
BOOK DEPR-UNRECOVERED PLT SURRY	16	16				Not applicable to Transmission Cost of Service calculation.
CAP EXPENSE 481A - PROD OTHER (750)	72,789	72,789				Not applicable to Transmission Cost of Service calculation.
CAP EXPENSE 481A (570)	(5,755)	(5,755)				Not applicable to Transmission Cost of Service calculation.
CAPITAL EXPENSE-DISTRIBUTION	(7,000)	(7,000)				Not applicable to Transmission Cost of Service calculation.
CAPITAL EXPENSE-PRODUCTION	(5,421)	(5,421)				Not applicable to Transmission Cost of Service calculation.
CAPITAL EXPENSE-PRODUCTION-NORTH ANNA	(446)	(446)				Not applicable to Transmission Cost of Service calculation.
CAPITALIZED INTEREST - DEPREC 481A	-	-				Not applicable to Transmission Cost of Service calculation.
CAPITALIZED INTEREST OPER IN SERVICE	201,306	201,306				Not applicable to Transmission Cost of Service calculation.
CAPITALIZED O&M EXP-DISTRIBUTION	-	-				Not applicable to Transmission Cost of Service calculation.
CAPITALIZED RESTORATION 481A	42,101	42,101				Not applicable to Transmission Cost of Service calculation.
CASUALTY LOSS AMORT	34,393			34,393		Represents a decrease to tax depreciation (Sec 162) as a result of casualty loss (Sec 165) reduction to tax basis.
CASUALTY LOSSES (132)	(91,222)			(91,222)		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.
DT-COMPUTER SOFTWARE-BOOK AMORT-FED	40,946	(19,199)			60,145	Represents total Book Computer Software Amortization Schedule M addition.
DT-COMPUTER SOFTWARE-CWIP-FED	(14,248)	(14,248)				Represents the allowable "In house" deduction for tax.
DT-COMPUTER SOFTWARE-TAX AMORT	(40,016)	39,463			(79,479)	Total tax amortization shown as a schedule M deduction and add back total book amortization.
COST OF REMOVAL	6,771	6,771				Not applicable to Transmission Cost of Service calculation.
CWIP ABANDONMENT NON CURRENT	-	-				Not applicable to Transmission Cost of Service calculation.
DC BONUS DEPRECIATION	111	111				Not applicable to Transmission Cost of Service calculation.
DC BONUS DEPRECIATION 481A - GEN REPAIR	(1)	(1)				Not applicable to Transmission Cost of Service calculation.
DC BONUS DEPRECIATION CASUALTY 481A	2	2				Not applicable to Transmission Cost of Service calculation.
DC BONUS DEPRECIATION CIAC	0	0				Not applicable to Transmission Cost of Service calculation.
DC BONUS DEPRECIATION GEN 481A - CAP INTEREST	0	0				Not applicable to Transmission Cost of Service calculation.
DEPR LATERAL PIPELINE RECORDED TO FUEL EXP	557	557				Not applicable to Transmission Cost of Service calculation.
DT-AFC DEF TAX-FUEL IN SERVICE NA	-	-				Represents the amount of amortization of AFC in service not allowable for tax.
DT-AFC DEF TAX-FUEL IN SERVICE-FED	-	-				Represents the amount of amortization of AFC in service not allowable for tax.
DT-AFC DEF TAX-PLANT IN SERVICE-DISTRIBUTION	-	-				Represents the amount of amortization of AFC in service not allowable for tax.
DT-AFC DEF TAX-PLANT IN SERVICE-GENERAL	-	75			(75)	Represents the amount of amortization of AFC in service not allowable for tax.
DT-AFC DEF TAX-PLANT IN SERVICE-INTANGIBLE	-	-				Represents the amount of amortization of AFC in service not allowable for tax.
DT-AFC DEF TAX-PLANT IN SERVICE-PRODUCTION	-	-				Represents the amount of amortization of AFC in service not allowable for tax.
DT-AFC DEF TAX-PLANT IN SERVICE-PRODUCTION N	-	-				Represents the amount of amortization of AFC in service not allowable for tax.
DT-AFC DEF TAX-PLANT IN SERVICE-TRANSMISSION	(0)	19,349	(19,349)			Represents the amount of amortization of AFC in service not allowable for tax.
DT-CAP INTEREST OPER IN SERVICE-FED	(201,291)	(201,291)				Not applicable to Transmission Cost of Service calculation.
DT-COST OF REMOVAL	(70,674)	(70,674)				Not applicable to Transmission Cost of Service calculation.
DT-LIBERALIZED DEPR-DISTRIBUTION	-	-				Difference between book and tax depreciation taking in consideration flow-through and ARAM.
DT-LIBERALIZED DEPR-FUEL-NA	-	-				Difference between book and tax depreciation taking in consideration flow-through and ARAM.
DT-LIBERALIZED DEPR-FUEL-SURRY	-	-				Difference between book and tax depreciation taking in consideration flow-through and ARAM.
DT-LIBERALIZED DEPR-GENERAL	1,195	57,976			(56,782)	Difference between book and tax depreciation taking in consideration flow-through and ARAM.
DT-LIBERALIZED DEPR-ODEC PLANT	-	-				Difference between book and tax depreciation taking in consideration flow-through and ARAM.
DT-LIBERALIZED DEPR-PEPCO ACQ ADJ	-	-				Difference between book and tax depreciation taking in consideration flow-through and ARAM.
DT-LIBERALIZED DEPR-PLANT OPER LAND	-	-				Difference between book and tax depreciation taking in consideration flow-through and ARAM.
DT-LIBERALIZED DEPR-PLANT OTHER	-	-				Difference between book and tax depreciation taking in consideration flow-through and ARAM.
DT-LIBERALIZED DEPR-PRODUCTION	-	-				Difference between book and tax depreciation taking in consideration flow-through and ARAM.
DT-LIBERALIZED DEPR-PRODUCTION BATH	-	-				Difference between book and tax depreciation taking in consideration flow-through and ARAM.

DT-LIBERALIZED DEPR-PRODUCTION NA		-	-				Difference between book and tax depreciation taking in consideration flow-through and ARAM.

DTLIBERALIZED DEPR-TRANSMISSION		(212,881)	1,101,756	(1,314,637)			Difference between book and tax depreciation taking in consideration flow-through and ARAM.
FAS 143 ASSET OBLIGATION-OTHER		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 143 DECOMMISSIONING-NA		-	-				Not applicable to Transmission Cost of Service calculation.
FIXED ASSETS		(4,079)			(4,079)		Represents IRS audit adjustments to plant-related differences.
G/L INTERCO SALES -BOOK/TAX		(1,530)	(1,530)				Not applicable to Transmission Cost of Service calculation.
LIBERALIZED DEPR: PLANT FUTURE USE VEPCO		163	163				Not applicable to Transmission Cost of Service calculation.
LIBERALIZED DEPR: PLANT NON UTILITY VEPCO		(633)	(633)				Not applicable to Transmission Cost of Service calculation.
NC BONUS DEPRECIATION		4,363	4,363				Not applicable to Transmission Cost of Service calculation.
NC BONUS DEPRECIATION 481A - GEN REPAIR		(40)	(40)				Not applicable to Transmission Cost of Service calculation.
NC BONUS DEPRECIATION CASUALTY 481A		83	83				Not applicable to Transmission Cost of Service calculation.
NC BONUS DEPRECIATION CIAC		(20)	(20)				Not applicable to Transmission Cost of Service calculation.
NC BONUS DEPRECIATION GEN 481A - CAP INTEREST		1	1				Not applicable to Transmission Cost of Service calculation.
NUCLEAR FUEL TAX G/L-NA		(5,942)	(5,942)				Not applicable to Transmission Cost of Service calculation.
NUCLEAR FUEL TAX G/L-SURRY		(8,075)	(8,075)				Not applicable to Transmission Cost of Service calculation.
NUCLEAR FUEL-COMMERCIAL BURN		217,972	217,972				Not applicable to Transmission Cost of Service calculation.
RA.CUR AFUDC EQUITY AMORT RIDER		(120)	(120)				Not applicable to Transmission Cost of Service calculation.
RA.CUR AFUDC EQUITY RIDER		(604)	(604)				Not applicable to Transmission Cost of Service calculation.
RA.NON CUR AFUDC EQUITY AMORT RIDER		776	776				Not applicable to Transmission Cost of Service calculation.
RA.NON CUR AFUDC EQUITY RIDER		(22,129)	(22,129)				Not applicable to Transmission Cost of Service calculation.
REC.CUR AFUDC EQUITY AMORT RIDER		13	13				Not applicable to Transmission Cost of Service calculation.
REC.CUR AFUDC EQUITY RIDER		(103)	(103)				Not applicable to Transmission Cost of Service calculation.
REC.NON CUR AFUDC EQUITY AMORT RIDER		50	50				Not applicable to Transmission Cost of Service calculation.
REC.NON CUR AFUDC EQUITY RIDER		(110)	(110)				Not applicable to Transmission Cost of Service calculation.
RESEARCH AND DEVELOPMENT (FED)		-	-				Not applicable to Transmission Cost of Service calculation.
SALES TAX RECOVERY IN SERVICE (537)		-	-				Not applicable to Transmission Cost of Service calculation.
ST AFC DEF TAX-FUEL CWIP		(9)	(9)				Not applicable to Transmission Cost of Service calculation.
ST AFC DEF TAX-PLANT CWIP		(1,703)	(1,703)				Not applicable to Transmission Cost of Service calculation.
ST AFC DEF TAX-PLANT IN SERVICE		(5,329)	(5,329)				Not applicable to Transmission Cost of Service calculation.
ST AFUDC-NUCLEAR FUEL		35	35				Not applicable to Transmission Cost of Service calculation.
ST BOOK AMORT-CAPITAL LEASES (207)		62	62				Not applicable to Transmission Cost of Service calculation.
ST BOOK CAPITALIZED INTEREST CWIP		(101)	(101)				Not applicable to Transmission Cost of Service calculation.
ST BOOK DEP.- AMORT DESIGN DOC		22	22				Not applicable to Transmission Cost of Service calculation.
ST BOOK DEP.- AMORT LEASE IMPROV		740	740				Not applicable to Transmission Cost of Service calculation.
ST BOOK DEP.-AMORT PLANT ACO ADJ.		2,449	2,449				Not applicable to Transmission Cost of Service calculation.
ST BOOK DEPR (008)		718,433	718,433				Not applicable to Transmission Cost of Service calculation.
ST BOOK DEPREC-NA MERIT PROGRAM		0	0				Not applicable to Transmission Cost of Service calculation.
ST BOOK DEPR-NON OPERATING VEPCO		29	29				Not applicable to Transmission Cost of Service calculation.
ST BOOK DEPR-UNRECOVERED PLT NORTH ANNA		1	1				Not applicable to Transmission Cost of Service calculation.
ST BOOK DEPR-UNRECOVERED PLT SURRY		3	3				Not applicable to Transmission Cost of Service calculation.
ST BOOK OP- GAIN(LOSS) SALE PROPR		(4)	(4)				Not applicable to Transmission Cost of Service calculation.
ST CAP EXPENSE 481A - PROD OTHER (750)		12,258	12,258				Not applicable to Transmission Cost of Service calculation.
ST CAP EXPENSE 481A (570)		(969)	(969)				Not applicable to Transmission Cost of Service calculation.
ST CAPITAL EXPENSE		(2,167)	(2,167)				Not applicable to Transmission Cost of Service calculation.
ST CAPITALIZED INTEREST - 481A ADJUST		(222)	(222)				Not applicable to Transmission Cost of Service calculation.
ST CAPITALIZED INTEREST - DEPREC 481A		53	53				Not applicable to Transmission Cost of Service calculation.
ST CAPITALIZED INTEREST OPER IN SERVICE		(11,866)	(11,866)				Not applicable to Transmission Cost of Service calculation.
ST CAPITALIZED INTEREST OPERATING CWIP		(5,079)	(5,079)				Not applicable to Transmission Cost of Service calculation.
ST CAPITALIZED O&M EXP-DISTRIBUTION		(527)	(527)				Not applicable to Transmission Cost of Service calculation.
ST CAPITALIZED RESTORATION 481A		7,090	7,090				Not applicable to Transmission Cost of Service calculation.
ST CASUALTY LOSS AMORT		5,792	5,792				Not applicable to Transmission Cost of Service calculation.
ST CASUALTY LOSSES (132)		(15,363)	(15,363)				Not applicable to Transmission Cost of Service calculation.
ST CIAC DC-NONOP IN SERVICE		(99)	(99)				Not applicable to Transmission Cost of Service calculation.
ST CIAC NC-NONOP CWIP VEPCO		(168)	(168)				Not applicable to Transmission Cost of Service calculation.
ST CIAC NC-NONOP IN SERVICE		(49)	(49)				Not applicable to Transmission Cost of Service calculation.
ST CIAC VA-NONOP CWIP VEPCO		(930)	(930)				Not applicable to Transmission Cost of Service calculation.
ST CIAC VA-NONOP IN SERVICE		(3,241)	(3,241)				Not applicable to Transmission Cost of Service calculation.
ST COMPUTER SOFTWARE-BOOK AMORT		6,168	6,168				Not applicable to Transmission Cost of Service calculation.
ST COMPUTER SOFTWARE-CWIP		(2,400)	(2,400)				Not applicable to Transmission Cost of Service calculation.
ST COMPUTER SOFTWARE-TAX AMORT		(6,949)	(6,949)				Not applicable to Transmission Cost of Service calculation.
ST COST OF REMOVAL		(399)	(399)				Not applicable to Transmission Cost of Service calculation.
ST CWIP ABANDONMENT NON CURRENT-NA3		(5,165)	(5,165)				Not applicable to Transmission Cost of Service calculation.
ST CWIP ABANDONMENT NON CURRENT-WIND		(70)	(70)				Not applicable to Transmission Cost of Service calculation.
ST DEF G/L NONOPERATING VEPCO		3	3				Not applicable to Transmission Cost of Service calculation.
ST DEF G/L-FUTURE USE NONOP VEPCO		(70)	(70)				Not applicable to Transmission Cost of Service calculation.
ST DEPR LATERAL PIPELINE RECORDED TO FUEL EXP		94	94				Not applicable to Transmission Cost of Service calculation.
ST DOE SETTLEMENT-ASSET BASIS REDUCTION		-	-				Not applicable to Transmission Cost of Service calculation.
ST FAS 143 ASSET OBLIGATION		(6,665)	(6,665)				Not applicable to Transmission Cost of Service calculation.
ST FAS 143 DECOMMISSIONING-NA		(8,481)	(8,481)				Not applicable to Transmission Cost of Service calculation.
ST FAS 143 DECOMMISSIONING-OTHER		(12,024)	(12,024)				Not applicable to Transmission Cost of Service calculation.
ST FIXED ASSETS		(687)	(687)				Not applicable to Transmission Cost of Service calculation.
ST G/L INTERCO SALES -BOOK/TAX		(258)	(258)				Not applicable to Transmission Cost of Service calculation.
ST LIBERALIZED DEPR: PLANT FUTURE USE VEPCO		27	27				Not applicable to Transmission Cost of Service calculation.
ST LIBERALIZED DEPR: PLANT NON UTILITY VEPCO		(107)	(107)				Not applicable to Transmission Cost of Service calculation.
ST METERS		(19)	(19)				Not applicable to Transmission Cost of Service calculation.
ST NUCLEAR FUEL TAX G/L-NA		(1,001)	(1,001)				Not applicable to Transmission Cost of Service calculation.
ST NUCLEAR FUEL TAX G/L-SURRY		(1,360)	(1,360)				Not applicable to Transmission Cost of Service calculation.
ST NUCLEAR FUEL-COMMERCIAL BURN		36,709	36,709				Not applicable to Transmission Cost of Service calculation.
ST NUCLEAR FUEL-PERM DISPOSAL NORTH ANNA		0	0				Not applicable to Transmission Cost of Service calculation.
ST NUCLEAR FUEL-PERM DISPOSAL SURRY		0	0				Not applicable to Transmission Cost of Service calculation.
ST SALES TAX RECOVERY CWIP		(480)	(480)				Not applicable to Transmission Cost of Service calculation.
ST SALES TAX RECOVERY IN SERVICE (537)		(752)	(752)				Not applicable to Transmission Cost of Service calculation.
ST TAX AMORT		(45,869)	(45,869)				Not applicable to Transmission Cost of Service calculation.
ST TAX DEPR-BONUS DEPR		(504,051)	(504,051)				Not applicable to Transmission Cost of Service calculation.
ST TAX DEPR		(1,085,558)	(1,085,558)				Not applicable to Transmission Cost of Service calculation.
ST TAX OP G/L SALE PROP		(825)	(825)				Not applicable to Transmission Cost of Service calculation.
TAX AMORT		(272,365)	(272,365)				Not applicable to Transmission Cost of Service calculation.
TAX DEPR-BONUS DEPR		(2,992,987)	(2,992,987)				Not applicable to Transmission Cost of Service calculation.
TAX DEPR		(6,449,063)	(6,449,063)				Not applicable to Transmission Cost of Service calculation.
TAX OP G/L SALE PROP		(4,897)	(4,897)				Not applicable to Transmission Cost of Service calculation.
VA 282 DIFFERENCE ADJUSTMENT		(4,442)	(4,442)				Not applicable to Transmission Cost of Service calculation.
VA BASIS DIFFERENCES		122,033	122,033				Not applicable to Transmission Cost of Service calculation.
VA BONUS DEPRECIATION		(3,310)	(3,310)				Not applicable to Transmission Cost of Service calculation.
VA BONUS DEPRECIATION		349,498	349,498				Not applicable to Transmission Cost of Service calculation.
VA BONUS DEPRECIATION 481A - GEN REPAIR		(3,886)	(3,886)				Not applicable to Transmission Cost of Service calculation.
VA BONUS DEPRECIATION CASUALTY 481A		6,690	6,690				Not applicable to Transmission Cost of Service calculation.
VA BONUS DEPRECIATION CIAC		555	555				Not applicable to Transmission Cost of Service calculation.
VA BONUS DEPRECIATION GEN 481A - CAP INTEREST		55	55				Not applicable to Transmission Cost of Service calculation.
Pollution Control		177,202	177,202				Not applicable to Transmission Cost of Service calculation.
BAD DEBTS VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
CONTINGENT CLAIMS CURRENT VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
CUSTOMER ACCOUNTS- RES & REFUND VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
DEDESIGNATED DEBT NOT ISSUED VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
Retention Bonus		-				-	Books accrues the costs of the bonus; tax takes the deduction when actually paid.
OPEB VEPCO		-				-	Represents the difference between the book accrual expense and the actual funded amount.
FIN 18 - FED		-	-				Not applicable to Transmission Cost of Service calculation.
RESTRICTED STOCK AWARD VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
RETIRE-EXEC SUPP RET (ESRP)-NONOP (1261010) VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
BOOK AMORT-CAPITAL LEASES (207)		(1,059)	(1,059)				Not applicable to Transmission Cost of Service calculation.
NUCLEAR FUEL-PERM DISPOSAL NORTH ANNA		(2)	(2)				Not applicable to Transmission Cost of Service calculation.
NUCLEAR FUEL-PERM DISPOSAL SURRY		(2)	(2)				Not applicable to Transmission Cost of Service calculation.
FAS 133 CURRENT VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133 NC VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
FEDERAL TAX INTEREST EXPENSE NON CURR VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
REACQUIRED DEBT GAIN(LOSS) VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
REG ASSET-HEDGE DEBT DEDESIGNATED DEBT NOT ISSUE VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
CAP EXPENSE 481A - PROD OTHER (750)		-	-				Not applicable to Transmission Cost of Service calculation.
CAPITALIZED RESTORATION 481A		-	-				Not applicable to Transmission Cost of Service calculation.
G/L INTERCO SALES -BOOK/TAX		-	-				Not applicable to Transmission Cost of Service calculation.
ROUND		0	0				Not applicable to Transmission Cost of Service calculation.
Subtotal - p275 (Form 1-F filer: see note 6 below)		(5,867,801)	(4,396,118)	(1,333,986)	(61,507)	(76,191)	
Less FASB 109 Above if not separately removed		(70,017)	(70,017)	0	0	0	
Less FASB 106 Above if not separately removed		0					
Total		(5,797,784)	(4,326,100)	(1,333,986)	(61,507)	(76,191)	

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
AFC DEF TAX-PLANT IN SERVICE	(20,089)	(20,089)				Not applicable to Transmission Cost of Service calculation.
AFUDC EQUITY (FAC045) - FLOW THRU	(15,897)	(15,897)				Not applicable to Transmission Cost of Service calculation.
AFUDC-NUCLEAR FUEL	132	132				Not applicable to Transmission Cost of Service calculation.
BAD DEBTS VEPCO	(1,424)	(1,424)				Not applicable to Transmission Cost of Service calculation.
BOOK DEP.- AMORT DESIGN DOC	82	82				Not applicable to Transmission Cost of Service calculation.
BOOK DEP.- AMORT LEASE IMPROV	2,788	2,788				Not applicable to Transmission Cost of Service calculation.
BOOK DEP.-AMORT PLANT ACO ADJ.	9,232	9,232				Not applicable to Transmission Cost of Service calculation.
BOOK DEPR (008)	2,708,135	2,708,135				Not applicable to Transmission Cost of Service calculation.
BOOK DEPREC-NA MERIT PROGRAM	1	1				Not applicable to Transmission Cost of Service calculation.
BOOK DEPR-UNRECOVERED PLT NORTH ANNA	2	2				Not applicable to Transmission Cost of Service calculation.
BOOK DEPR-UNRECOVERED PLT SURRY	10	10				Not applicable to Transmission Cost of Service calculation.
CAPITALIZED INTEREST OPER IN SERVICE	127,794	127,794				Not applicable to Transmission Cost of Service calculation.
COMPUTER SOFTWARE-BOOK AMORT	23,250	23,250				Not applicable to Transmission Cost of Service calculation.
COMPUTER SOFTWARE-CWIP	(9,045)	(9,045)				Not applicable to Transmission Cost of Service calculation.
COMPUTER SOFTWARE-TAX AMORT	(24,180)	(24,180)				Not applicable to Transmission Cost of Service calculation.
CONTINGENT CLAIMS CURRENT VEPCO	53	53				Not applicable to Transmission Cost of Service calculation.
CONTINGENT CLAIMS NONCURRENT VEPCO	(4,141)	(4,141)				Not applicable to Transmission Cost of Service calculation.
COST OF REMOVAL	4,298	4,298				Not applicable to Transmission Cost of Service calculation.
CURR CAPIT RESTORATION COSTS 481A-DISTR VEPCO	(15,005)	(15,005)				Not applicable to Transmission Cost of Service calculation.
CUSTOMER ACCOUNTS- RES & REFUND VEPCO	11	11				Not applicable to Transmission Cost of Service calculation.
CUSTOMER ACCTS. INTEREST-RES & REFUND VEPCO	(11)	(11)				Not applicable to Transmission Cost of Service calculation.
CWIP ABANDONMENT NON CURRENT	-	-				Not applicable to Transmission Cost of Service calculation.
DC - BONUS DEPRECIATION DEF CUR	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
DC - BONUS DEPRECIATION DEF NC	(1)	(1)				Not applicable to Transmission Cost of Service calculation.
DECOMM POUROVER VEPCO	(58,567)	(58,567)				Not applicable to Transmission Cost of Service calculation.
DECOMM TRUST BOOK INCOME NON OP VEPCO	(180,569)	(180,569)				Not applicable to Transmission Cost of Service calculation.
DECOMM TRUST BOOK INCOME OP VEPCO	(331,596)	(331,596)				Not applicable to Transmission Cost of Service calculation.
DECOMM TRUST-UNREALIZED G/L-NC VEPCO	(201,193)	(201,193)				Not applicable to Transmission Cost of Service calculation.
DEDESIGNATED DEBT NOT ISSUED VEPCO	25	25				Not applicable to Transmission Cost of Service calculation.
DEF ITC- NCP	(2,615)	(2,615)				Not applicable to Transmission Cost of Service calculation.
DEFERRED FUEL EXPENSE CURRENT VEPCO	(2,103)	(2,103)				Not applicable to Transmission Cost of Service calculation.
DEFERRED FUEL EXPENSE VEPCO	0	0				Not applicable to Transmission Cost of Service calculation.
DEFERRED FUEL EXP-OTHER CURRENT VEPCO	(779)	(779)				Not applicable to Transmission Cost of Service calculation.
DEFERRED REVENUE CURRENT VEPCO	(153)	(153)				Not applicable to Transmission Cost of Service calculation.
DEPR LATERAL PIPELINE RECORDED TO FUEL EXP	354	354				Not applicable to Transmission Cost of Service calculation.
DIRECTOR CHARITABLE DONATION VEPCO	(7)	(7)				Not applicable to Transmission Cost of Service calculation.
DOE SETTLEMENT VEPCO	(10,169)	(10,169)				Not applicable to Transmission Cost of Service calculation.
DOE SETTLEMENT-INVENT BASIS REDUCTION VEPCO	(87)	(87)				Not applicable to Transmission Cost of Service calculation.
DT-AFC DEF TAX-FUEL IN SERVICE NA	(9)	(9)				Not applicable to Transmission Cost of Service calculation.
DT-AFC DEF TAX-FUEL IN SERVICE-FED	0	0				Not applicable to Transmission Cost of Service calculation.
DT-AFC DEF TAX-PLANT IN SERVICE	19,004	19,004				Not applicable to Transmission Cost of Service calculation.
DT-CAP INTEREST OPER IN SERVICE-FED	(127,784)	(127,784)				Not applicable to Transmission Cost of Service calculation.
DT-COMPUTER SOFTWARE-BOOK AMORT-FED	(35,437)	(35,437)				Not applicable to Transmission Cost of Service calculation.
DT-COMPUTER SOFTWARE-CWIP-FED	9,444	9,444				Not applicable to Transmission Cost of Service calculation.
DT-COMPUTER SOFTWARE-TAX AMORT	49,233	49,233				Not applicable to Transmission Cost of Service calculation.
DT-COST OF REMOVAL	(44,866)	(44,866)				Not applicable to Transmission Cost of Service calculation.
DT-LIBERALIZED DEPR	3,333,790	3,333,790				Not applicable to Transmission Cost of Service calculation.
FAS 133 CURRENT VEPCO	(20,473)	(20,473)				Not applicable to Transmission Cost of Service calculation.
FAS 133 NC VEPCO	20,473	20,473				Not applicable to Transmission Cost of Service calculation.
FAS 133-DEBT HEDGE CURRENT ASSET VEPCO	(286)	(286)				Not applicable to Transmission Cost of Service calculation.
FAS 133-DEBT VAL-MTM HEDGE NON CURR AS VEPCO	(7,098)	(7,098)				Not applicable to Transmission Cost of Service calculation.
FAS 133-DEF G/L CAPACITY HEDGE-NON CURR VEPCO	-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133-DEFERRED G/L CAPACITY HEDGE CURR LIAB	-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133-DEFERRED G/L POWER HEDGE-CURR LIAB	-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133-FTR CURRENT LIAB VEPCO	-	-				Not applicable to Transmission Cost of Service calculation.
FEDERAL TAX INTEREST EXPENSE NON CURR VEPCO	52	52				Not applicable to Transmission Cost of Service calculation.
FEDERAL TAX INTEREST EXPENSE VEPCO	(701)	(701)				Not applicable to Transmission Cost of Service calculation.
FIXED ASSETS (2210010)	(120)	(120)				Not applicable to Transmission Cost of Service calculation.
FUEL DEF CURRENT LIAB VEPCO	(1,829)	(1,829)				Not applicable to Transmission Cost of Service calculation.
FUEL DEF NON CUR LIAB VEPCO	(177)	(177)				Not applicable to Transmission Cost of Service calculation.
FUEL DEF OTHER CURRENT LIAB VEPCO	(748)	(748)				Not applicable to Transmission Cost of Service calculation.
FUEL DEF OTHER NON CUR LIAB	(13)	(13)				Not applicable to Transmission Cost of Service calculation.
FUEL HANDLING COSTS VEPCO	(176)	(176)				Not applicable to Transmission Cost of Service calculation.
HEADWATER BENEFITS VEPCO	(68)	(68)				Not applicable to Transmission Cost of Service calculation.
LONG TERM DISABILITY RESERVE VEPCO	(453)	(453)				Not applicable to Transmission Cost of Service calculation.
NC - BONUS DEPRECIATION DEF NC	(45)	(45)				Not applicable to Transmission Cost of Service calculation.
NC Deferred Current Adj - SOLAR ITC	(12)	(12)				Not applicable to Transmission Cost of Service calculation.
NC Deferred NonCurrent Adj - SOLAR ITC	(3,120)	(3,120)				Not applicable to Transmission Cost of Service calculation.
NON CURR CAPIT RESTORATION COSTS 481A-D VEPCO	(4,477)	(4,477)				Not applicable to Transmission Cost of Service calculation.
NON CURRENT REC A4 ELEC TRAN VEPCO	(4,775)	(4,775)				Not applicable to Transmission Cost of Service calculation.
NUCLEAR FUEL TAX G/L-NA	(3,772)	(3,772)				Not applicable to Transmission Cost of Service calculation.
NUCLEAR FUEL TAX G/L-SURRY	(5,126)	(5,126)				Not applicable to Transmission Cost of Service calculation.
NUCLEAR FUEL-COMMERCIAL BURN	138,374	138,374				Not applicable to Transmission Cost of Service calculation.
OBSOLETE INVENTORY RESERVE VEPCO	(112)	(112)				Not applicable to Transmission Cost of Service calculation.
OPEB VEPCO	2,207	2,207				Not applicable to Transmission Cost of Service calculation.
POWERTREE CARBON CO, LLC. VEPCO	(40)	(40)				Not applicable to Transmission Cost of Service calculation.
PREMIUM, DEBT, DISCOUNT&EXP VEPCO	(71)	(71)				Not applicable to Transmission Cost of Service calculation.
P'SHIP INCOME - VIRGINIA CAPITAL VEPCO	(11)	(11)				Not applicable to Transmission Cost of Service calculation.
RA.CUR AFUDC DEBT AMORT RIDER	103	103				Not applicable to Transmission Cost of Service calculation.
RA.CUR AFUDC DEBT RIDER	(685)	(685)				Not applicable to Transmission Cost of Service calculation.
RA.CUR AFUDC EQUITY AMORT RIDER	(76)	(76)				Not applicable to Transmission Cost of Service calculation.
RA.CUR AFUDC EQUITY RIDER	(383)	(383)				Not applicable to Transmission Cost of Service calculation.
RA.CUR OTHER COSTS NONOPER RIDER	3,250	3,250				Not applicable to Transmission Cost of Service calculation.
RA.CUR OTHER COSTS OPER RIDER	(19,976)	(19,976)				Not applicable to Transmission Cost of Service calculation.
RA.NON CUR AFUDC DEBT AMORT RIDER	311	311				Not applicable to Transmission Cost of Service calculation.
RA.NON CUR AFUDC DEBT RIDER	(8,107)	(8,107)				Not applicable to Transmission Cost of Service calculation.
RA.NON CUR AFUDC EQUITY AMORT RIDER	493	493				Not applicable to Transmission Cost of Service calculation.
RA.NON CUR AFUDC EQUITY RIDER	(14,048)	(14,048)				Not applicable to Transmission Cost of Service calculation.
RA.NON CUR OTHER COSTS NON OPER RIDER	205	205				Not applicable to Transmission Cost of Service calculation.
RA.NON CUR OTHER COSTS OPER RIDER	(45,767)	(45,767)				Not applicable to Transmission Cost of Service calculation.
REACQUIRED DEBT GAIN(LOSS) VEPCO	374	374				Not applicable to Transmission Cost of Service calculation.
REC.CUR AFUDC DEBT AMORT RIDER	(5)	(5)				Not applicable to Transmission Cost of Service calculation.
REC.CUR AFUDC DEBT RIDER	(43)	(43)				Not applicable to Transmission Cost of Service calculation.
REC.CUR AFUDC EQUITY AMORT RIDER	8	8				Not applicable to Transmission Cost of Service calculation.
REC.CUR AFUDC EQUITY RIDER	(65)	(65)				Not applicable to Transmission Cost of Service calculation.
REC.CUR OTHER COST OPER RIDER	(1,269)	(1,269)				Not applicable to Transmission Cost of Service calculation.
REC.CUR OTHER COSTS NON OPER RIDER	(727)	(727)				Not applicable to Transmission Cost of Service calculation.
REC.NON CUR AFUDC DEBT AMORT RIDER	29	29				Not applicable to Transmission Cost of Service calculation.
REC.NON CUR AFUDC DEBT RIDER	(56)	(56)				Not applicable to Transmission Cost of Service calculation.
REC.NON CUR AFUDC EQUITY AMORT RIDER	32	32				Not applicable to Transmission Cost of Service calculation.
REC.NON CUR AFUDC EQUITY RIDER	(70)	(70)				Not applicable to Transmission Cost of Service calculation.
REC.NON CUR OTHER COST NON OPER RIDER	462	462				Not applicable to Transmission Cost of Service calculation.
REC.NON CUR OTHER COST OPER RIDER	(3,477)	(3,477)				Not applicable to Transmission Cost of Service calculation.
RECS VEPCO	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
REG ASSET - A4 RAC COSTS CURRENT VEPCO	(6,029)	(6,029)				Not applicable to Transmission Cost of Service calculation.
REG ASSET - A4 RAC COSTS NONCURRENT VEPCO	(23,844)	(23,844)				Not applicable to Transmission Cost of Service calculation.
REG ASSET - ATRR CURRENT VEPCO	(3,540)	(3,540)				Not applicable to Transmission Cost of Service calculation.
REG ASSET - CUR - NUG	(436)	(436)				Not applicable to Transmission Cost of Service calculation.
REG ASSET - FTR - CURRENT VEPCO	(316)	(316)				Not applicable to Transmission Cost of Service calculation.
REG ASSET - NRC REQUIREMENT - NORTH ANNA VEPCO	(8,639)	(8,639)				Not applicable to Transmission Cost of Service calculation.
REG ASSET - NRC REQUIREMENT - SURRY VEPCO	(3,989)	(3,989)				Not applicable to Transmission Cost of Service calculation.
REG ASSET ABANDONED PLANT NCUC CURR VEPCO	(474)	(474)				Not applicable to Transmission Cost of Service calculation.
REG ASSET ABANDONED PLANT NCUC NON CURR VEPCO	(2,235)	(2,235)				Not applicable to Transmission Cost of Service calculation.
REG ASSET ASSET IMPAIRMENT NCUC CURR VEPCO	(100)	(100)				Not applicable to Transmission Cost of Service calculation.
REG ASSET ASSET IMPAIRMENT NCUC NONCURR VEPCO	(314)	(314)				Not applicable to Transmission Cost of Service calculation.
REG ASSET CCR DEF NCUC ORDER NONCURR VEPCO	(5,382)	(5,382)				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURR RIDER A4 NON VA OTHER VEPCO	(879)	(879)				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A5 DSM VEPCO	(1,871)	(1,871)				Not applicable to Transmission Cost of Service calculation.
REG ASSET DEF NC RECPS REC COST CURR VEPCO	(292)	(292)				Not applicable to Transmission Cost of Service calculation.
REG ASSET FUEL HEDGE NONOP VEPCO	(275)	(275)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NATURAL DISASTER NCUC CURRENT VEPCO	(93)	(93)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NATURAL DISASTER NCUC NONCURR VEPCO	-	-				Not applicable to Transmission Cost of Service calculation.
REG ASSET NUCLEAR OUTAGE DEFER-CURRENT	(24,737)	(24,737)				Not applicable to Transmission Cost of Service calculation.
REG ASSET RETIREMENT NCUC CURRENT VEPCO	(49)	(49)				Not applicable to Transmission Cost of Service calculation.
REG ASSET RETIREMENT NCUC NONCURR VEPCO	(310)	(310)				Not applicable to Transmission Cost of Service calculation.
REG ASSET RIDER PLANTS NCUC CURRENT VEPCO	(243)	(243)				Not applicable to Transmission Cost of Service calculation.
REG ASSET RIDER PLANTS NCUC NONCURR VEPCO	(81)	(81)				Not applicable to Transmission Cost of Service calculation.
REG ASSET-DEBT VAL-MTM NON CURR VEPCO	(140,694)	(140,694)				Not applicable to Transmission Cost of Service calculation.
REG ASSET-DEBT VALUATION - MTM - CUR VEPCO	(5,665)	(5,665)				Not applicable to Transmission Cost of Service calculation.
REG ASSET-HEDGE DEBT DEDESIGNATED DEBT NOT ISSUE VEPCO	1,039	1,039				Not applicable to Transmission Cost of Service calculation.

REG ATTR NON CURRENT VEPCO	-	-				Not applicable to Transmission Cost of Service calculation.
REG FUEL HEDGE VEPCO	275	275				Not applicable to Transmission Cost of Service calculation.
REG LIAB - DEF NC REPS REC COST - NC	(43)	(43)				Not applicable to Transmission Cost of Service calculation.
REG LIAB - DEFERRED G/L CAPACITY HEDGE - CURRENT	-	-				Not applicable to Transmission Cost of Service calculation.
REG LIAB - FTR CURRENT VEPCO	-	-				Not applicable to Transmission Cost of Service calculation.
REG LIAB A5 REC COSTS - VA NON CURRENT VEPCO	(142)	(142)				Not applicable to Transmission Cost of Service calculation.
REG LIAB ATRR NON CURRENT	(581)	(581)				Not applicable to Transmission Cost of Service calculation.
REG LIAB CURRENT DSM A5	-	-				Not applicable to Transmission Cost of Service calculation.
Reg Liab NC Excess Def Tax-GU for Exp Item	940	940				Not applicable to Transmission Cost of Service calculation.
REG LIAB OTHER NCUC CURRENT VEPCO	(17)	(17)				Not applicable to Transmission Cost of Service calculation.
REG LIAB OTHER NCUC NON CURR VEPCO	(359)	(359)				Not applicable to Transmission Cost of Service calculation.
REG LIAB PLANT CONTRA VASLSTX VEPCO	(1,324)	(1,324)				Not applicable to Transmission Cost of Service calculation.
REG LIAB-DEF G/L POWER HEDGE-CUR VEPCO	-	-				Not applicable to Transmission Cost of Service calculation.
REG LIABILITY DECOMM TRUST NC OP VEPCO	17,584	17,584				Not applicable to Transmission Cost of Service calculation.
REG LIABILITY DECOMM VEPCO	(35,165)	(35,165)				Not applicable to Transmission Cost of Service calculation.
REG NON CURRENT DSM A5 RIDER VEPCO	(4,390)	(4,390)				Not applicable to Transmission Cost of Service calculation.
REG RATE REFUND - CURRENT VEPCO	(28)	(28)				Not applicable to Transmission Cost of Service calculation.
REGULATORY ASSET - FAS 112 VEPCO	(1,346)				(1,346)	Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
REGULATORY ASSET - NUG VEPCO	(928)	(928)				Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
REGULATORY ASSET - PJM	(78,681)	(78,681)				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 VEPCO	(14,306)	(14,306)				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 VEPCO	(842)	(842)				Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
RESEARCH AND DEVELOPMENT (FED)	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
RESTRICTED STOCK AWARD VEPCO	3	3				Not applicable to Transmission Cost of Service calculation.
RETENTION BONUS	(1)	(1)				Not applicable to Transmission Cost of Service calculation.
RETIRE-EXEC SUPP RET (ESRP)-NONOP (1261010) VEPCO	(3)	(3)				Not applicable to Transmission Cost of Service calculation.
RETIRE-EXEC SUPP RET (ESRP)-NONOP (2210020) VEPCO	(628)	(628)				Not applicable to Transmission Cost of Service calculation.
RETIREMENT - (FASB 87) VEPCO	(6,377)	(6,377)				Not applicable to Transmission Cost of Service calculation.
SEPARATION/ERT VEPCO	(262)	(262)				Not applicable to Transmission Cost of Service calculation.
SUCCESS SHARE PLAN VEPCO	(303)	(303)				Not applicable to Transmission Cost of Service calculation.
SUPPLEMENTAL-SUPPLEMENTAL RETIRE VEPCO	(4)	(4)				Not applicable to Transmission Cost of Service calculation.
TAX AMORT	(172,904)	(172,904)				Not applicable to Transmission Cost of Service calculation.
TAX DEPR-BONUS DEPR	(1,900,020)	(1,900,020)				Not applicable to Transmission Cost of Service calculation.
TAX DEPR	(4,094,022)	(4,094,022)				Not applicable to Transmission Cost of Service calculation.
TAX OP G/L SALE PROP	(3,109)	(3,109)				Not applicable to Transmission Cost of Service calculation.
VA - BONUS DEPRECIATION DEF CUR	(1,528)	(1,528)				Not applicable to Transmission Cost of Service calculation.
VA - BONUS DEPRECIATION DEF NC	(2,293)	(2,293)				Not applicable to Transmission Cost of Service calculation.
VA MINIMUM TAX CREDIT	(105)	(105)				Not applicable to Transmission Cost of Service calculation.
VACATION ACCRUAL VEPCO	(369)	(369)				Not applicable to Transmission Cost of Service calculation.
WEST VA POLLUTION CONTROL	(3,635)			(3,635)		Represents the deferred state tax impact related to WV Pollution control projects. This deferral will turn around once placed in service.
WEST VA PROPERTY TAX VEPCO	(193)	(193)				Not applicable to Transmission Cost of Service calculation.
WORKERS COMPENSATION - FAS 112	(140)	(140)				Not applicable to Transmission Cost of Service calculation.
OCI	(32,713)	(32,713)				Not applicable to Transmission Cost of Service calculation.
BAD DEBTS VEPCO	-	-				Not applicable to Transmission Cost of Service calculation.
CONTINGENT CLAIMS CURRENT VEPCO	-	-				Not applicable to Transmission Cost of Service calculation.
CUSTOMER ACCOUNTS- RES & REFUND VEPCO	-	-				Not applicable to Transmission Cost of Service calculation.
DEDESIGNATED DEBT NOT ISSUED VEPCO	(419)	(419)				Not applicable to Transmission Cost of Service calculation.
Retention Bonus	-				-	Books accrues the costs of the bonus; tax takes the deduction when actually paid.
OPEB VEPCO	(37,442)				(37,442)	Represents the difference between the book accrual expense and the actual funded amount.
FIN 18 - FED	(148)	(148)				Not applicable to Transmission Cost of Service calculation.
RESTRICTED STOCK AWARD VEPCO	(48)	(48)				Not applicable to Transmission Cost of Service calculation.
RETIRE-EXEC SUPP RET (ESRP)-NONOP (1261010) VEPCO	-	-				Not applicable to Transmission Cost of Service calculation.
BOOK AMORT-CAPITAL LEASES (207)	-	-				Not applicable to Transmission Cost of Service calculation.
NUCLEAR FUEL-PERM DISPOSAL NORTH ANNA	-	-				Not applicable to Transmission Cost of Service calculation.
NUCLEAR FUEL-PERM DISPOSAL SURRY	-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133 CURRENT VEPCO	-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133 NC VEPCO	-	-				Not applicable to Transmission Cost of Service calculation.
FEDERAL TAX INTEREST EXPENSE NON CURR VEPCO	-	-				Not applicable to Transmission Cost of Service calculation.
REACQUIRED DEBT GAIN(LOSS) VEPCO	(321)	(321)				Not applicable to Transmission Cost of Service calculation.
REG ASSET-HEDGE DEBT DEDESIGNATED DEBT NOT ISSUE VEPCO	(889)	(889)				Not applicable to Transmission Cost of Service calculation.
CAP EXPENSE 481A - PROD OTHER (750)	-	-				Not applicable to Transmission Cost of Service calculation.
CAPITALIZED RESTORATION 481A	-	-				Not applicable to Transmission Cost of Service calculation.
G/L INTERCO SALES -BOOK/TAX	-	-				Not applicable to Transmission Cost of Service calculation.
ROUND	1	1				Not applicable to Transmission Cost of Service calculation.
Subtotal - p277 (Form 1-F filer: see note 6, below)	(1,386,850)	(1,344,427)	-	(3,635)	(38,788)	
Less FASB 109 Above if not separately removed	(43,509)	(43,509)	-	-	-	
Less FASB 106 Above if not separately removed	(37,442)	-	-	-	(37,442)	
Total	(1,305,900)	(1,300,919)	-	(3,635)	(1,346)	

Instructions for Account 283:

1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly

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			749
2	Amortization to l	Total		137
3	Total		-	886
4	Total Form No.	Form No. 1 balance (p.266)	for amortization	886
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 of the Previous Year
(000's)

	Only Transmission Related	Plant Related	Labor Related	Total ADIT
ADIT- 282	(1,271,805)	(61,507)	(76,191)	
ADIT-283	0	(3,635)	(1,346)	
ADIT-190	13,285	205,352	125,843	
Subtotal	(1,258,520)	140,210	48,306	
Wages & Salary Allocator			6.8458%	
Gross Plant Allocator		19.1904%		
End of Year ADIT	(1,258,520)	26,907	3,307	(1,228,306)

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 VEPCO	28,232	28,232				Not applicable to Transmission Cost of Service calculation.
BOOK AMORT-CAPITAL LEASES (207)	(1,059)	(1,059)				Not applicable to Transmission Cost of Service calculation.
BOOK OP- GAIN(LOSS) SALE PROPR	62	62				Not applicable to Transmission Cost of Service calculation.
CAPITALIZED INTEREST - 481A ADJUST	3,765			3,765		Representive of the IRS settlement related to the 263A costs associated with the Generation capital repairs settlement.
CAPITALIZED INTEREST - DEPREC 481A	(902)			(902)		Represents the recovery of tax capitalized interest reported as taxable income.
CAPITALIZED INTEREST OPERATING CWIP	86,169	86,169				Not applicable to Transmission Cost of Service calculation.
CAPITALIZED O&M EXP-DISTRIBUTION	8,945	8,945				Not applicable to Transmission Cost of Service calculation.
CHAR CONTRIB CFWD CURRENT VEPCO	4,595	4,595				Not applicable to Transmission Cost of Service calculation.
CIAC DC-NONOP IN SERVICE	1,687	1,687				Not applicable to Transmission Cost of Service calculation.
CIAC NC-NONOP CWIP VEPCO	2,850	2,850				Not applicable to Transmission Cost of Service calculation.
CIAC NC-NONOP IN SERVICE	829	829				Not applicable to Transmission Cost of Service calculation.
CIAC VA-NONOP CWIP VEPCO	15,780	15,780				Not applicable to Transmission Cost of Service calculation.
CIAC VA-NONOP IN SERVICE	54,992	54,992				Not applicable to Transmission Cost of Service calculation.
CONTINGENT CLAIMS CURRENT VEPCO	(1,054)	(1,054)				Not applicable to Transmission Cost of Service calculation.
CONTINGENT CLAIMS NONCURRENT VEPCO	82,077	82,077				Not applicable to Transmission Cost of Service calculation.
CURR CAPIT RESTORATION COSTS 481A-DISTR VEPCO	757	757				Not applicable to Transmission Cost of Service calculation.
CUSTOMER ACCOUNTS- RES & REFUND VEPCO	(219)	(219)				Not applicable to Transmission Cost of Service calculation.
CUSTOMER ACCTS. INTEREST-RES & REFUND VEPCO	223	223				Not applicable to Transmission Cost of Service calculation.
CWIP ABANDONMENT NON CURRENT	-	-				Not applicable to Transmission Cost of Service calculation.
CWIP ABANDONMENT NON CURRENT-NA3	87,634	87,634				Not applicable to Transmission Cost of Service calculation.
CWIP ABANDONMENT NON CURRENT-WIND	1,186	1,186				Not applicable to Transmission Cost of Service calculation.
DC - BONUS DEPRECIATION DEF CUR	0	0				Not applicable to Transmission Cost of Service calculation.
DC - BONUS DEPRECIATION DEF NC	0	0				Not applicable to Transmission Cost of Service calculation.
DC BONUS DEPRECIATION	(36)	(36)				Not applicable to Transmission Cost of Service calculation.
DC BONUS DEPRECIATION 481A - GEN REPAIR	0	0				Not applicable to Transmission Cost of Service calculation.
DC BONUS DEPRECIATION CASUALTY 481A	(1)	(1)				Not applicable to Transmission Cost of Service calculation.
DC BONUS DEPRECIATION CIAC	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
DC BONUS DEPRECIATION GEN 481A - CAP INTEREST	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
DECOMM POUROVER VEPCO	2,955	2,955				Not applicable to Transmission Cost of Service calculation.
DECOMM TRUST BOOK INCOME NON OP VEPCO	9,109	9,109				Not applicable to Transmission Cost of Service calculation.
DECOMM TRUST BOOK INCOME OP VEPCO	16,728	16,728				Not applicable to Transmission Cost of Service calculation.
DECOMM TRUST-UNREALIZED G/L-NC VEPCO	10,150	10,150				Not applicable to Transmission Cost of Service calculation.
DEDESIGNATED DEBT NOT ISSUED VEPCO	(490)	(490)				Not applicable to Transmission Cost of Service calculation.
DEF G/L NONOPERATING VEPCO	(53)	(53)				Not applicable to Transmission Cost of Service calculation.
DEF G/L-FUTURE USE NONOP VEPCO	1,180	1,180				Not applicable to Transmission Cost of Service calculation.
DEF ITC- NCP	132	132				Not applicable to Transmission Cost of Service calculation.
DEFERRED FUEL EXPENSE CURRENT VEPCO	106	106				Not applicable to Transmission Cost of Service calculation.
DEFERRED FUEL EXPENSE VEPCO	-	-				Not applicable to Transmission Cost of Service calculation.
DEFERRED FUEL EXP-OTHER CURRENT VEPCO	39	39				Not applicable to Transmission Cost of Service calculation.
DEFERRED REVENUE CURRENT VEPCO	3,040	3,040				Not applicable to Transmission Cost of Service calculation.
DIRECTOR CHARITABLE DONATION VEPCO	143	143				Not applicable to Transmission Cost of Service calculation.
DOE SETTLEMENT VEPCO	513	513				Not applicable to Transmission Cost of Service calculation.
DOE SETTLEMENT-INVENT BASIS REDUCTION VEPCO	1,719	1,719				Not applicable to Transmission Cost of Service calculation.
DT-CAP INTEREST OPER IN SERVICE-FED	201,291			201,291		Represents tax "In Service" capitalized Interest placed in service net of tax amortization.
DT-COST OF REMOVAL-DIST DFIT ONLY	20,673	20,673				Represents the actual cost of removal allowable for tax over the accrued amount.
DT-COST OF REMOVAL-GENERAL DFIT ONLY	(2,022)				(2,022)	Represents the actual cost of removal allowable for tax over the accrued amount.
DT-COST OF REMOVAL-PROD DFIT ONLY	50,320	50,320				Represents the actual cost of removal allowable for tax over the accrued amount.
DT-COST OF REMOVAL-PROD NA DFIT ONLY	(12,385)	(12,385)				Represents the actual cost of removal allowable for tax over the accrued amount.
DT-COST OF REMOVAL-TRANS DFIT ONLY	14,087	882	13,205			Represents the actual cost of removal allowable for tax over the accrued amount.
FAS 133 CURRENT VEPCO	1,033	1,033				Not applicable to Transmission Cost of Service calculation.
FAS 133 NC VEPCO	(1,033)	(1,033)				Not applicable to Transmission Cost of Service calculation.
FAS 133-DEBT HEDGE CURRENT ASSET VEPCO	5,665	5,665				Not applicable to Transmission Cost of Service calculation.
FAS 133-DEBT VAL-MTM HEDGE NON CURR AS VEPCO	140,694	140,694				Not applicable to Transmission Cost of Service calculation.
FAS 133-DEFERRED G/L CAPACITY HEDGE CURR LIAB	-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133-DEFERRED G/L POWER HEDGE-CURR LIAB	-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133-FTR CURRENT LIAB VEPCO	-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133-FTR HEDGE CURRENT ASSET VEPCO	316	316				Not applicable to Transmission Cost of Service calculation.
FAS 143 ASSET OBLIGATION-DISTRIBUTION	2,779	2,779				Represents ARO accruals not deductible for tax.
FAS 143 ASSET OBLIGATION-GENERAL	50	50				Represents ARO accruals not deductible for tax.
FAS 143 ASSET OBLIGATION-NA	443	443				Represents ARO accruals not deductible for tax.
FAS 143 ASSET OBLIGATION-OTHER	109,709	109,709				Represents ARO accruals not deductible for tax.
FAS 143 ASSET OBLIGATION-TRANSMISSION	85	5	80			Represents ARO accruals not deductible for tax.
FAS 143 DECOMMISSIONING-NA	143,884	143,884				Not applicable to Transmission Cost of Service calculation.
FAS 143 DECOMMISSIONING-OTHER	203,986	203,986				Not applicable to Transmission Cost of Service calculation.
FAS109 on Unamortized ITC	8,248	8,248				Not applicable to Transmission Cost of Service calculation.
FEDERAL TAX INTEREST EXPENSE NON CURR VEPCO	(4)	(4)				Not applicable to Transmission Cost of Service calculation.
FEDERAL TAX INTEREST EXPENSE VEPCO	42	42				Not applicable to Transmission Cost of Service calculation.
FIN 18 - DC	0	0				Not applicable to Transmission Cost of Service calculation.
FIN 18 - FED	(148)	(148)				Not applicable to Transmission Cost of Service calculation.
FIN 18 - NC	5	5				Not applicable to Transmission Cost of Service calculation.
FIN 18 - VA	187	187				Not applicable to Transmission Cost of Service calculation.
FIN 18 - WV	6	6				Not applicable to Transmission Cost of Service calculation.
FUEL DEF CURRENT LIAB VEPCO	36,252	36,252				Not applicable to Transmission Cost of Service calculation.
FUEL DEF NON CUR LIAB VEPCO	3,502	3,502				Not applicable to Transmission Cost of Service calculation.
FUEL DEF OTHER CURRENT LIAB VEPCO	14,822	14,822				Not applicable to Transmission Cost of Service calculation.
FUEL DEF OTHER NON CUR LIAB	255	255				Not applicable to Transmission Cost of Service calculation.
FUEL HANDLING COSTS VEPCO	9	9				Not applicable to Transmission Cost of Service calculation.
General Business Credit - Def Current	3,206	3,206				Not applicable to Transmission Cost of Service calculation.
General Business Credit - Def NC	15,029	15,029				Not applicable to Transmission Cost of Service calculation.
HEADWATER BENEFITS VEPCO	1,345	1,345				Not applicable to Transmission Cost of Service calculation.
LONG TERM DISABILITY RESERVE VEPCO	8,973	1,293			7,680	Book estimate accrued and expensed; tax deduction when paid.
METERS	319	319				Not applicable to Transmission Cost of Service calculation.
NC - BONUS DEPRECIATION DEF CUR	6	6				Not applicable to Transmission Cost of Service calculation.
NC - BONUS DEPRECIATION DEF NC	10	10				Not applicable to Transmission Cost of Service calculation.
NC BONUS DEPRECIATION	(1,423)	(1,423)				Not applicable to Transmission Cost of Service calculation.
NC BONUS DEPRECIATION 481A - GEN REPAIR	14	14				Not applicable to Transmission Cost of Service calculation.
NC BONUS DEPRECIATION CASUALTY 481A	(29)	(29)				Not applicable to Transmission Cost of Service calculation.
NC BONUS DEPRECIATION CIAC	7	7				Not applicable to Transmission Cost of Service calculation.
NC BONUS DEPRECIATION GEN 481A - CAP INTEREST	(2)	(2)				Not applicable to Transmission Cost of Service calculation.
NC Deferred Current Adj - SOLAR ITC	35	35				Not applicable to Transmission Cost of Service calculation.
NC Deferred NonCurrent Adj - SOLAR ITC	8,915	8,915				Not applicable to Transmission Cost of Service calculation.
NOL CURRENT VEPCO	28,448	28,448				Not applicable to Transmission Cost of Service calculation.
NOL NC VEPCO	(28,448)	(28,448)				Not applicable to Transmission Cost of Service calculation.
NON CURR CAPIT RESTORATION COSTS 481A-D VEPCO	226	226				Not applicable to Transmission Cost of Service calculation.
NON CURRENT REC A4 ELEC TRAN VEPCO	241	241				Not applicable to Transmission Cost of Service calculation.
NUCLEAR FUEL-PERM DISPOSAL NORTH ANNA	(2)	(2)				Not applicable to Transmission Cost of Service calculation.
NUCLEAR FUEL-PERM DISPOSAL SURRY	(2)	(2)				Not applicable to Transmission Cost of Service calculation.
OBSOLETE INVENTORY RESERVE VEPCO	2,222	2,222				Not applicable to Transmission Cost of Service calculation.
OCI CF HEDGES OTHER PURCH/SALE NC Fed 100%	-	-				Not applicable to Transmission Cost of Service calculation.

OCI CF HEDGES OTHER PURCH/SALE NC State 100%		-	-				Not applicable to Transmission Cost of Service calculation.
OCI CF HEDGES-OTHER PURCH/SALE CURR Fed 100%		0	0				Not applicable to Transmission Cost of Service calculation.
OCI CF HEDGES-OTHER PURCH/SALE CURR State 100%		0	0				Not applicable to Transmission Cost of Service calculation.
OCI CF HEDGING DEBT CURR Fed 100%		364	364				Not applicable to Transmission Cost of Service calculation.
OCI CF HEDGING DEBT CURR State 100%		65	65				Not applicable to Transmission Cost of Service calculation.
OCI CF HEDGING DEBT NC Fed 100%		11,010	11,010				Not applicable to Transmission Cost of Service calculation.
OCI CF HEDGING DEBT NC State 100%		1,969	1,969				Not applicable to Transmission Cost of Service calculation.
OCI NUCLEAR DECOMM NC Fed 100%		(27,751)	(27,751)				Not applicable to Transmission Cost of Service calculation.
OCI NUCLEAR DECOMM NC State 100%		(4,962)	(4,962)				Not applicable to Transmission Cost of Service calculation.
OPEB VEPCO		(43,747)	(6,306)			(37,442)	Represents the difference between the book accrual expense and the actual funded amount.
POWERTREE CARBON CO, LLC. VEPCO		2	2				Not applicable to Transmission Cost of Service calculation.
PREMIUM, DEBT, DISCOUNT&EXP VEPCO		1,400	202		1,198		Books record the yield to maturity method; taxes amortize staight line.
Production Tax Credit - Def Current Fed		10,031	10,031				Not applicable to Transmission Cost of Service calculation.
Production Tax Credit - Def NC Fed		15,062	15,062				Not applicable to Transmission Cost of Service calculation.
P'SHIP INCOME - VIRGINIA CAPITAL VEPCO		215	215				Not applicable to Transmission Cost of Service calculation.
RA.CUR AFUDC DEBT AMORT RIDER		(5)	(5)				Not applicable to Transmission Cost of Service calculation.
RA.CUR AFUDC DEBT RIDER		35	35				Not applicable to Transmission Cost of Service calculation.
RA.CUR OTHER COSTS NONOPER RIDER		(164)	(164)				Not applicable to Transmission Cost of Service calculation.
RA.CUR OTHER COSTS OPER RIDER		1,008	1,008				Not applicable to Transmission Cost of Service calculation.
RA.NON CUR AFUDC DEBT AMORT RIDER		(16)	(16)				Not applicable to Transmission Cost of Service calculation.
RA.NON CUR AFUDC DEBT RIDER		409	409				Not applicable to Transmission Cost of Service calculation.
RA.NON CUR OTHER COSTS NON OPER RIDER		(10)	(10)				Not applicable to Transmission Cost of Service calculation.
RA.NON CUR OTHER COSTS OPER RIDER		2,309	2,309				Not applicable to Transmission Cost of Service calculation.
REACQUIRED DEBT GAIN(LOSS) VEPCO		(19)	(19)				Not applicable to Transmission Cost of Service calculation.
REC.CUR AFUDC DEBT AMORT RIDER		0	0				Not applicable to Transmission Cost of Service calculation.
REC.CUR AFUDC DEBT RIDER		2	2				Not applicable to Transmission Cost of Service calculation.
REC.CUR OTHER COST OPER RIDER		64	64				Not applicable to Transmission Cost of Service calculation.
REC.CUR OTHER COSTS NON OPER RIDER		37	37				Not applicable to Transmission Cost of Service calculation.
REC.NON CUR AFUDC DEBT AMORT RIDER		(1)	(1)				Not applicable to Transmission Cost of Service calculation.
REC.NON CUR AFUDC DEBT RIDER		3	3				Not applicable to Transmission Cost of Service calculation.
REC.NON CUR OTHER COST NON OPER RIDER		(23)	(23)				Not applicable to Transmission Cost of Service calculation.
REC.NON CUR OTHER COST OPER RIDER		175	175				Not applicable to Transmission Cost of Service calculation.
RECS VEPCO		6	6				Not applicable to Transmission Cost of Service calculation.
REG ASSET - A4 RAC COSTS CURRENT VEPCO		304	304				Not applicable to Transmission Cost of Service calculation.
REG ASSET - A4 RAC COSTS NONCURRENT VEPCO		1,203	1,203				Not applicable to Transmission Cost of Service calculation.
REG ASSET - ATRR CURRENT VEPCO		179	179				Not applicable to Transmission Cost of Service calculation.
REG ASSET - CUR - NUG		22	22				Not applicable to Transmission Cost of Service calculation.
REG ASSET - FTR - CURRENT VEPCO		16	16				Not applicable to Transmission Cost of Service calculation.
REG ASSET - NRC REQUIREMENT - NORTH ANNA VEPCO		436	436				Not applicable to Transmission Cost of Service calculation.
REG ASSET - NRC REQUIREMENT - SURRY VEPCO		201	201				Not applicable to Transmission Cost of Service calculation.
REG ASSET ABANDONED PLANT NCUC CURR VEPCO		24	24				Not applicable to Transmission Cost of Service calculation.
REG ASSET ABANDONED PLANT NCUC NON CURR VEPCO		113	113				Not applicable to Transmission Cost of Service calculation.
REG ASSET ASSET IMPAIRMENT NCUC CURR VEPCO		5	5				Not applicable to Transmission Cost of Service calculation.
REG ASSET ASSET IMPAIRMENT NCUC NONCURR VEPCO		16	16				Not applicable to Transmission Cost of Service calculation.
REG ASSET CCR DEF NCUC ORDER NONCURR VEPCO		272	272				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURR RIDER A4 NON VA OTHER VEPCO		44	44				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A5 DSM VEPCO		94	94				Not applicable to Transmission Cost of Service calculation.
REG ASSET DEF NC RECPS REC COST CURR VEPCO		15	15				Not applicable to Transmission Cost of Service calculation.
REG ASSET FUEL HEDGE NONOP VEPCO		5,449	5,449				Not applicable to Transmission Cost of Service calculation.
REG ASSET NATURAL DISASTER NCUC CURRENT VEPCO		5	5				Not applicable to Transmission Cost of Service calculation.
REG ASSET NUCLEAR OUTAGE DEFER-CURRENT		1,248	1,248				Not applicable to Transmission Cost of Service calculation.
REG ASSET RETIREMENT NCUC CURRENT VEPCO		2	2				Not applicable to Transmission Cost of Service calculation.
REG ASSET RETIREMENT NCUC NONCURR VEPCO		16	16				Not applicable to Transmission Cost of Service calculation.
REG ASSET RIDER PLANTS NCUC CURRENT VEPCO		12	12				Not applicable to Transmission Cost of Service calculation.
REG ASSET RIDER PLANTS NCUC NONCURR VEPCO		4	4				Not applicable to Transmission Cost of Service calculation.
REG ASSET-DEBT VAL-MTM NON CURR VEPCO		7,098	7,098				Not applicable to Transmission Cost of Service calculation.
REG ASSET-DEBT VALUATION - MTM - CUR VEPCO		286	286				Not applicable to Transmission Cost of Service calculation.
REG ASSET-HEDGE DEBT DEDESIGNATED DEBT NOT ISSUE VEPCO		(52)	(52)				Not applicable to Transmission Cost of Service calculation.
REG ATTR NON CURRENT VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
REG FUEL HEDGE VEPCO		(5,449)	(5,449)				Not applicable to Transmission Cost of Service calculation.
REG LIAB - DEF NC REPS REC COST - NC		846	846				Not applicable to Transmission Cost of Service calculation.
REG LIAB - DEFERRED G/L CAPACITY HEDGE - CURRENT		-	-				Not applicable to Transmission Cost of Service calculation.
REG LIAB - FTR CURRENT VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
REG LIAB A5 REC COSTS - VA NON CURRENT VEPCO		2,815	2,815				Not applicable to Transmission Cost of Service calculation.
REG LIAB ATRR NON CURRENT		11,526	11,526				Not applicable to Transmission Cost of Service calculation.
REG LIAB CURRENT DSM A5		-	-				Not applicable to Transmission Cost of Service calculation.
Reg Liab NC Excess Def Tax-GU for Exp Item		5,253	5,253				Not applicable to Transmission Cost of Service calculation.
REG LIAB OTHER NCUC CURRENT VEPCO		347	347				Not applicable to Transmission Cost of Service calculation.
REG LIAB OTHER NCUC NON CURR VEPCO		7,110	7,110				Not applicable to Transmission Cost of Service calculation.
REG LIAB PLANT CONTRA VASLSTX VEPCO		26,237	26,237				Not applicable to Transmission Cost of Service calculation.
REG LIAB VA OTHER CURRENT VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
REG LIAB-DEF G/L CAPACITY HEDGE NON CUR VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
REG LIAB-DEF G/L POWER HEDGE-CUR VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
REG LIABILITY DECOMM TRUST NC OP VEPCO		(348,567)	(348,567)				Not applicable to Transmission Cost of Service calculation.
REG LIABILITY DECOMM VEPCO		697,065	697,065				Not applicable to Transmission Cost of Service calculation.
REG NON CURRENT DSM A5 RIDER VEPCO		221	221				Not applicable to Transmission Cost of Service calculation.
REG RATE REFUND - CURRENT VEPCO		558	558				Not applicable to Transmission Cost of Service calculation.
REGULATORY ASSET - FAS 112 VEPCO		68	68				Not applicable to Transmission Cost of Service calculation.
REGULATORY ASSET - NUG VEPCO		47	47				Not applicable to Transmission Cost of Service calculation.
REGULATORY ASSET - PJM		3,969	3,969				Not applicable to Transmission Cost of Service calculation.
REGULATORY ASSET - VA SLS TAX CURRENT VEPCO		722	722				Not applicable to Transmission Cost of Service calculation.
REGULATORY ASSET - VA SLS TAX VEPCO		42	42				Not applicable to Transmission Cost of Service calculation.
RESTRICTED STOCK AWARD VEPCO		(56)	(56)				Not applicable to Transmission Cost of Service calculation.
RETENTION BONUS		28	4			24	Books accrues the costs of the bonus; tax takes the deduction when actually paid.
RETIRE-EXEC SUPP RET (ESRP)-NONOP (1261010) VEPCO		55	55				Not applicable to Transmission Cost of Service calculation.
RETIRE-EXEC SUPP RET (ESRP)-NONOP (2210020) VEPCO		32	32				Not applicable to Transmission Cost of Service calculation.
RETIREMENT - (FASB 87) VEPCO		126,413	18,221			108,192	Book estimate accrued and expensed; tax deduction when paid.
SALES TAX RECOVERY CWIP		8,151	8,151				Not applicable to Transmission Cost of Service calculation.
SALES TAX RECOVERY IN SERVICE (537)		12,759	12,759				Not applicable to Transmission Cost of Service calculation.
SEPARATION/ERT VEPCO		5,198	749			4,449	Book amount accrued and expensed; tax deduction when paid. These amounts will be paid in the next 12 months.
ST AFC DEF TAX-FUEL CWIP		3	3				Not applicable to Transmission Cost of Service calculation.
ST AFC DEF TAX-PLANT CWIP		596	596				Not applicable to Transmission Cost of Service calculation.
ST AFC DEF TAX-PLANT IN SERVICE		1,865	1,865				Not applicable to Transmission Cost of Service calculation.
ST AFUDC-NUCLEAR FUEL		(12)	(12)				Not applicable to Transmission Cost of Service calculation.
ST BOOK AMORT-CAPITAL LEASES (207)		(178)	(178)				Not applicable to Transmission Cost of Service calculation.
ST BOOK CAPITALIZED INTEREST CWIP		35	35				Not applicable to Transmission Cost of Service calculation.
ST BOOK DEP.- AMORT DESIGN DOC		(8)	(8)				Not applicable to Transmission Cost of Service calculation.
ST BOOK DEP.- AMORT LEASE IMPROV		(259)	(259)				Not applicable to Transmission Cost of Service calculation.
ST BOOK DEP.-AMORT PLANT ACO ADJ.		(857)	(857)				Not applicable to Transmission Cost of Service calculation.
ST BOOK DEPR (008)		(251,452)	(251,452)				Not applicable to Transmission Cost of Service calculation.
ST BOOK DEPREC-NA MERIT PROGRAM		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
ST BOOK DEPR-NON OPERATING VEPCO		(10)	(10)				Not applicable to Transmission Cost of Service calculation.
ST BOOK DEPR-UNRECOVERED PLT NORTH ANNA		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
ST BOOK DEPR-UNRECOVERED PLT SURRY		(1)	(1)				Not applicable to Transmission Cost of Service calculation.
ST BOOK OP- GAIN(LOSS) SALE PROPR		10	10				Not applicable to Transmission Cost of Service calculation.
ST CAP EXPENSE 481A - PROD OTHER (750)		(4,290)	(4,290)				Not applicable to Transmission Cost of Service calculation.
ST CAP EXPENSE 481A (570)		339	339				Not applicable to Transmission Cost of Service calculation.
ST CAPITAL EXPENSE		758	758				Not applicable to Transmission Cost of Service calculation.
ST CAPITALIZED INTEREST - 481A ADJUST		634	634				Not applicable to Transmission Cost of Service calculation.
ST CAPITALIZED INTEREST - DEPREC 481A		(152)	(152)				Not applicable to Transmission Cost of Service calculation.
ST CAPITALIZED INTEREST OPER IN SERVICE		33,902	33,902				Not applicable to Transmission Cost of Service calculation.
ST CAPITALIZED INTEREST OPERATING CWIP		14,512	14,512				Not applicable to Transmission Cost of Service calculation.
ST CAPITALIZED O&M EXP-DISTRIBUTION		1,506	1,506				Not applicable to Transmission Cost of Service calculation.
ST CAPITALIZED RESTORATION 481A		(2,482)	(2,482)				Not applicable to Transmission Cost of Service calculation.
ST CASUALTY LOSS AMORT		(2,027)	(2,027)				Not applicable to Transmission Cost of Service calculation.
ST CASUALTY LOSSES (132)		5,377	5,377				Not applicable to Transmission Cost of Service calculation.
ST CIAC DC-NONOP IN SERVICE		284	284				Not applicable to Transmission Cost of Service calculation.
ST CIAC NC-NONOP CWIP VEPCO		480	480				Not applicable to Transmission Cost of Service calculation.
ST CIAC NC-NONOP IN SERVICE		140	140				Not applicable to Transmission Cost of Service calculation.
ST CIAC VA-NONOP CWIP VEPCO		2,657	2,657				Not applicable to Transmission Cost of Service calculation.
ST CIAC VA-NONOP IN SERVICE		9,261	9,261				Not applicable to Transmission Cost of Service calculation.
ST COMPUTER SOFTWARE-BOOK AMORT		(2,159)	(2,159)				Not applicable to Transmission Cost of Service calculation.
ST COMPUTER SOFTWARE-CWIP		840	840				Not applicable to Transmission Cost of Service calculation.
ST COMPUTER SOFTWARE-TAX AMORT		2,432	2,432				Not applicable to Transmission Cost of Service calculation.
ST COST OF REMOVAL		1,140	1,140				Not applicable to Transmission Cost of Service calculation.
ST CWIP ABANDONMENT NON CURRENT-NA3		14,758	14,758				Not applicable to Transmission Cost of Service calculation.
ST CWIP ABANDONMENT NON CURRENT-WIND		200	200				Not applicable to Transmission Cost of Service calculation.
ST DEF G/L NONOPERATING VEPCO		(9)	(9)				Not applicable to Transmission Cost of Service calculation.
ST DEF G/L-FUTURE USE NONOP VEPCO		199	199				Not applicable to Transmission Cost of Service calculation.

ST DEPR LATERAL PIPELINE RECORDED TO FUEL EXP	(33)	(33)				Not applicable to Transmission Cost of Service calculation.
ST DOE SETTLEMENT-ASSET BASIS REDUCTION	-	-				Not applicable to Transmission Cost of Service calculation.
ST FAS 143 ASSET OBLIGATION	19,042	19,042				Not applicable to Transmission Cost of Service calculation.
ST FAS 143 DECOMMISSIONING-NA	24,232	24,232				Not applicable to Transmission Cost of Service calculation.
ST FAS 143 DECOMMISSIONING-OTHER	34,353	34,353				Not applicable to Transmission Cost of Service calculation.
ST FIXED ASSETS	240	240				Not applicable to Transmission Cost of Service calculation.
ST G/L INTERCO SALES -BOOK/TAX	90	90				Not applicable to Transmission Cost of Service calculation.
ST LIBERALIZED DEPR: PLANT FUTURE USE VEPCO	(10)	(10)				Not applicable to Transmission Cost of Service calculation.
ST LIBERALIZED DEPR: PLANT NON UTILITY VEPCO	37	37				Not applicable to Transmission Cost of Service calculation.
ST METERS	54	54				Not applicable to Transmission Cost of Service calculation.
ST NUCLEAR FUEL TAX G/L-NA	350	350				Not applicable to Transmission Cost of Service calculation.
ST NUCLEAR FUEL TAX G/L-SURRY	476	476				Not applicable to Transmission Cost of Service calculation.
ST NUCLEAR FUEL-COMMERCIAL BURN	(12,848)	(12,848)				Not applicable to Transmission Cost of Service calculation.
ST NUCLEAR FUEL-PERM DISPOSAL NORTH ANNA	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
ST NUCLEAR FUEL-PERM DISPOSAL SURRY	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
ST SALES TAX RECOVERY CWIP	1,373	1,373				Not applicable to Transmission Cost of Service calculation.
ST SALES TAX RECOVERY IN SERVICE (537)	2,149	2,149				Not applicable to Transmission Cost of Service calculation.
ST TAX AMORT	16,054	16,054				Not applicable to Transmission Cost of Service calculation.
ST TAX DEPR-BONUS DEPR	176,418	176,418				Not applicable to Transmission Cost of Service calculation.
ST TAX DEPR	379,945	379,945				Not applicable to Transmission Cost of Service calculation.
ST TAX OP G/L SALE PROP	289	289				Not applicable to Transmission Cost of Service calculation.
STATE INCOME TAX - CURRENT N/C	668	668				Not applicable to Transmission Cost of Service calculation.
STATE INCOME TAX - CURRENT VEPCO	654	654				Not applicable to Transmission Cost of Service calculation.
SUCCESS SHARE PLAN VEPCO	6,012	867			5,146	Book amount accrued as its earned; tax deduction is actual payout.
SUPPLEMENTAL-SUPPLEMENTAL RETIRE VEPCO	81	81				Not applicable to Transmission Cost of Service calculation.
VA - BONUS DEPRECIATION DEF CUR	535	535				Not applicable to Transmission Cost of Service calculation.
VA - BONUS DEPRECIATION DEF NC	802	802				Not applicable to Transmission Cost of Service calculation.
VA 282 DIFFERENCE ADJUSTMENT	1,555	1,555				Not applicable to Transmission Cost of Service calculation.
VA BASIS DIFFERENCES	(42,712)	(42,712)				Not applicable to Transmission Cost of Service calculation.
VA BONUS DEPRECIATION	(112,866)	(112,866)				Not applicable to Transmission Cost of Service calculation.
VA BONUS DEPRECIATION 481A - GEN REPAIR	1,360	1,360				Not applicable to Transmission Cost of Service calculation.
VA BONUS DEPRECIATION CASUALTY 481A	(2,342)	(2,342)				Not applicable to Transmission Cost of Service calculation.
VA BONUS DEPRECIATION CIAC	(194)	(194)				Not applicable to Transmission Cost of Service calculation.
VA BONUS DEPRECIATION GEN 481A - CAP INTEREST	(158)	(158)				Not applicable to Transmission Cost of Service calculation.
VA MINIMUM TAX CREDIT	299	299				Not applicable to Transmission Cost of Service calculation.
VACATION ACCRUAL VEPCO	7,323	7,323				Not applicable to Transmission Cost of Service calculation.
WEST VA POLLUTION CONTROL	1,272	1,272				Federal effect of state deductions.
WEST VA PROPERTY TAX VEPCO	3,820	3,820				Not applicable to Transmission Cost of Service calculation.
WORKERS COMPENSATION - FAS 112	2,775	400			2,375	Books accrues the costs of the bonus; tax takes the deduction when actually paid.
OCI	32,713	32,713				Not applicable to Transmission Cost of Service calculation.
BAD DEBTS VEPCO	-	-				Not applicable to Transmission Cost of Service calculation.
CONTINGENT CLAIMS CURRENT VEPCO	-	-				Not applicable to Transmission Cost of Service calculation.
CUSTOMER ACCOUNTS- RES & REFUND VEPCO	-	-				Not applicable to Transmission Cost of Service calculation.
DEDESIGNATED DEBT NOT ISSUED VEPCO	419	419				Not applicable to Transmission Cost of Service calculation.
Retention Bonus	-				-	Books accrues the costs of the bonus; tax takes the deduction when actually paid.
OPEB VEPCO	37,442				37,442	Represents the difference between the book accrual expense and the actual funded amount.
FIN 18 - FED	148	148				Not applicable to Transmission Cost of Service calculation.
RESTRICTED STOCK AWARD VEPCO	48	48				Not applicable to Transmission Cost of Service calculation.
RETIRE-EXEC SUPP RET (ESRP)-NONOP (1261010) VEPCO	-	-				Not applicable to Transmission Cost of Service calculation.
BOOK AMORT-CAPITAL LEASES (207)	1,059	1,059				Not applicable to Transmission Cost of Service calculation.
NUCLEAR FUEL-PERM DISPOSAL NORTH ANNA	2	2				Not applicable to Transmission Cost of Service calculation.
NUCLEAR FUEL-PERM DISPOSAL SURRY	2	2				Not applicable to Transmission Cost of Service calculation.
FAS 133 CURRENT VEPCO	-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133 NC VEPCO	-	-				Not applicable to Transmission Cost of Service calculation.
FEDERAL TAX INTEREST EXPENSE NON CURR VEPCO	-	-				Not applicable to Transmission Cost of Service calculation.
REACQUIRED DEBT GAIN(LOSS) VEPCO	321	321				Not applicable to Transmission Cost of Service calculation.
REG ASSET-HEDGE DEBT DEDESIGNATED DEBT NOT ISSUE VEPCO	889	889				Not applicable to Transmission Cost of Service calculation.
CAP EXPENSE 481A - PROD OTHER (750)	-	-				Not applicable to Transmission Cost of Service calculation.
CAPITALIZED RESTORATION 481A	-	-				Not applicable to Transmission Cost of Service calculation.
G/L INTERCO SALES -BOOK/TAX	-	-				Not applicable to Transmission Cost of Service calculation.
ROUND	0	0				Not applicable to Transmission Cost of Service calculation.
Subtotal - p234	2,355,663	2,011,183	13,285	205,352	125,843	
Less FASB 109 Above if not separately removed	13,501	13,501	0	0	0	
Less FASB 106 Above if not separately removed	-	0	0	0	0	
Total	2,342,162	1,997,682	13,285	205,352	125,843	

Instructions for Account 190:

1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to

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

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

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

5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates,

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

A **ADIT- 282**	**B** **Total**	**C** **Production Or Other Related**	**D** **Only Transmission Related**	**E** **Plant Related**	**F** **Labor Related**	**G** **Justification**
AFC DEF TAX-FUEL CWIP	(55)	(55)				Not applicable to Transmission Cost of Service calculation.
AFC DEF TAX-PLANT CWIP	(10,114)	(10,114)				Not applicable to Transmission Cost of Service calculation.
AFC DEF TAX-PLANT IN SERVICE	(31,646)	(31,646)				Not applicable to Transmission Cost of Service calculation.
AFUDC EQUITY (FAC045) - FLOW THRU	(25,042)	(25,042)				Not applicable to Transmission Cost of Service calculation.
AFUDC-NUCLEAR FUEL	208	208				Not applicable to Transmission Cost of Service calculation.
BOOK CAPITALIZED INTEREST CWIP	(599)	-		(599)		Represents the unallowable amount of book interest.
BOOK DEP.- AMORT DESIGN DOC	129	129				Not applicable to Transmission Cost of Service calculation.
BOOK DEP.- AMORT LEASE IMPROV	4,392	4,392				Not applicable to Transmission Cost of Service calculation.
BOOK DEP.-AMORT PLANT ACO ADJ.	14,543	14,543				Not applicable to Transmission Cost of Service calculation.
BOOK DEPR (008)	4,265,961	4,265,961				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.
BOOK DEPREC-NA MERIT PROGRAM	1	1				Represents a decrease to tax depreciation (Sec 162) as a result of casualty loss (Sec 165) reduction to tax basis.
BOOK DEPR-NON OPERATING VEPCO	171	171				Not applicable to Transmission Cost of Service calculation.
BOOK DEPR-UNRECOVERED PLT NORTH ANNA	4	4				Not applicable to Transmission Cost of Service calculation.
BOOK DEPR-UNRECOVERED PLT SURRY	16	16				Not applicable to Transmission Cost of Service calculation.
CAP EXPENSE 481A - PROD OTHER (750)	72,789	72,789				Not applicable to Transmission Cost of Service calculation.
CAP EXPENSE 481A (570)	(5,755)	(5,755)				Not applicable to Transmission Cost of Service calculation.
CAPITAL EXPENSE-DISTRIBUTION	(7,000)	(7,000)				Not applicable to Transmission Cost of Service calculation.
CAPITAL EXPENSE-PRODUCTION	(5,421)	(5,421)				Not applicable to Transmission Cost of Service calculation.
CAPITAL EXPENSE-PRODUCTION-NORTH ANNA	(446)	(446)				Not applicable to Transmission Cost of Service calculation.
CAPITALIZED INTEREST - DEPREC 481A	-	-				Not applicable to Transmission Cost of Service calculation.
CAPITALIZED INTEREST OPER IN SERVICE	201,306	201,306				Not applicable to Transmission Cost of Service calculation.
CAPITALIZED O&M EXP-DISTRIBUTION	-	-				Not applicable to Transmission Cost of Service calculation.
CAPITALIZED RESTORATION 481A	42,101	42,101				Not applicable to Transmission Cost of Service calculation.
CASUALTY LOSS AMORT	34,393			34,393		Represents a decrease to tax depreciation (Sec 162) as a result of casualty loss (Sec 165) reduction to tax basis.
CASUALTY LOSSES (132)	(91,222)			(91,222)		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.
DT-COMPUTER SOFTWARE-BOOK AMORT-FED	36,624	(23,521)			60,145	Represents total Book Computer Software Amortization Schedule M addition.
DT-COMPUTER SOFTWARE-CWIP-FED	(14,248)	(14,248)				Represents the allowable "In house" deduction for tax.
DT-COMPUTER SOFTWARE-TAX AMORT	(38,090)	41,389			(79,479)	Total tax amortization shown as a schedule M deduction and add back total book amortization.
COST OF REMOVAL	6,771	6,771				Not applicable to Transmission Cost of Service calculation.
CWIP ABANDONMENT NON CURRENT	-	-				Not applicable to Transmission Cost of Service calculation.
DC BONUS DEPRECIATION	111	111				Not applicable to Transmission Cost of Service calculation.
DC BONUS DEPRECIATION 481A - GEN REPAIR	(1)	(1)				Not applicable to Transmission Cost of Service calculation.
DC BONUS DEPRECIATION CASUALTY 481A	2	2				Not applicable to Transmission Cost of Service calculation.
DC BONUS DEPRECIATION CIAC	0	0				Not applicable to Transmission Cost of Service calculation.
DC BONUS DEPRECIATION GEN 481A - CAP INTEREST	0	0				Not applicable to Transmission Cost of Service calculation.
DEPR LATERAL PIPELINE RECORDED TO FUEL EXP	557	557				Not applicable to Transmission Cost of Service calculation.
DT-AFC DEF TAX-FUEL IN SERVICE NA	-	-				Represents the amount of amortization of AFC in service not allowable for tax.
DT-AFC DEF TAX-FUEL IN SERVICE-FED	-	-				Represents the amount of amortization of AFC in service not allowable for tax.
DT-AFC DEF TAX-PLANT IN SERVICE-DISTRIBUTION	-	-				Represents the amount of amortization of AFC in service not allowable for tax.
DT-AFC DEF TAX-PLANT IN SERVICE-GENERAL	-	75			(75)	Represents the amount of amortization of AFC in service not allowable for tax.
DT-AFC DEF TAX-PLANT IN SERVICE-INTANGIBLE	-	-				Represents the amount of amortization of AFC in service not allowable for tax.
DT-AFC DEF TAX-PLANT IN SERVICE-PRODUCTION	-	-				Represents the amount of amortization of AFC in service not allowable for tax.

DT-AFC DEF TAX-PLANT IN SERVICE-PRODUCTION N		-	-				Represents the amount of amortization of AFC in service not allowable for tax.

DT-AFC DEF TAX-PLANT IN SERVICE-TRANSMISSION		(0)	19,349	(19,349)			Represents the amount of amortization of AFC in service not allowable for tax.
DT-CAP INTEREST OPER IN SERVICE-FED		(201,291)	(201,291)				Not applicable to Transmission Cost of Service calculation.
DT-COST OF REMOVAL		(70,674)	(70,674)				Not applicable to Transmission Cost of Service calculation.
DT-LIBERALIZED DEPR-DISTRIBUTION		-	-				Difference between book and tax depreciation taking in consideration flow-through and ARAM.
DT-LIBERALIZED DEPR-FUEL-NA		-	-				Difference between book and tax depreciation taking in consideration flow-through and ARAM.
DT-LIBERALIZED DEPR-FUEL-SURRY		-	-				Difference between book and tax depreciation taking in consideration flow-through and ARAM.
DT-LIBERALIZED DEPR-GENERAL		-	56,782			(56,782)	Difference between book and tax depreciation taking in consideration flow-through and ARAM.
DT-LIBERALIZED DEPR-ODEC PLANT		-	-				Difference between book and tax depreciation taking in consideration flow-through and ARAM.
DT-LIBERALIZED DEPR-PEPCO ACQ ADJ		-	-				Difference between book and tax depreciation taking in consideration flow-through and ARAM.
DT-LIBERALIZED DEPR-PLANT OPER LAND		-	-				Difference between book and tax depreciation taking in consideration flow-through and ARAM.
DT-LIBERALIZED DEPR-PLANT OTHER		-	-				Difference between book and tax depreciation taking in consideration flow-through and ARAM.
DT-LIBERALIZED DEPR-PRODUCTION		-	-				Difference between book and tax depreciation taking in consideration flow-through and ARAM.
DT-LIBERALIZED DEPR-PRODUCTION BATH		-	-				Difference between book and tax depreciation taking in consideration flow-through and ARAM.
DT-LIBERALIZED DEPR-PRODUCTION NA		-	-				Difference between book and tax depreciation taking in consideration flow-through and ARAM.
DTLIBERALIZED DEPR-TRANSMISSION		0	1,252,456	(1,252,456)			Difference between book and tax depreciation taking in consideration flow-through and ARAM.
FAS 143 ASSET OBLIGATION-OTHER		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 143 DECOMMISSIONING-NA		-	-				Not applicable to Transmission Cost of Service calculation.
FIXED ASSETS		(4,079)			(4,079)		Represents IRS audit adjustments to plant-related differences.
G/L INTERCO SALES -BOOK/TAX		(1,530)	(1,530)				Not applicable to Transmission Cost of Service calculation.
LIBERALIZED DEPR: PLANT FUTURE USE VEPCO		163	163				Not applicable to Transmission Cost of Service calculation.
LIBERALIZED DEPR: PLANT NON UTILITY VEPCO		(633)	(633)				Not applicable to Transmission Cost of Service calculation.
NC BONUS DEPRECIATION		4,363	4,363				Not applicable to Transmission Cost of Service calculation.
NC BONUS DEPRECIATION 481A - GEN REPAIR		(40)	(40)				Not applicable to Transmission Cost of Service calculation.
NC BONUS DEPRECIATION CASUALTY 481A		83	83				Not applicable to Transmission Cost of Service calculation.
NC BONUS DEPRECIATION CIAC		(20)	(20)				Not applicable to Transmission Cost of Service calculation.
NC BONUS DEPRECIATION GEN 481A - CAP INTEREST		1	1				Not applicable to Transmission Cost of Service calculation.
NUCLEAR FUEL TAX G/L-NA		(5,942)	(5,942)				Not applicable to Transmission Cost of Service calculation.
NUCLEAR FUEL TAX G/L-SURRY		(8,075)	(8,075)				Not applicable to Transmission Cost of Service calculation.
NUCLEAR FUEL-COMMERCIAL BURN		217,972	217,972				Not applicable to Transmission Cost of Service calculation.
RA.CUR AFUDC EQUITY AMORT RIDER		(120)	(120)				Not applicable to Transmission Cost of Service calculation.
RA.CUR AFUDC EQUITY RIDER		(604)	(604)				Not applicable to Transmission Cost of Service calculation.
RA.NON CUR AFUDC EQUITY AMORT RIDER		776	776				Not applicable to Transmission Cost of Service calculation.
RA.NON CUR AFUDC EQUITY RIDER		(22,129)	(22,129)				Not applicable to Transmission Cost of Service calculation.
REC.CUR AFUDC EQUITY AMORT RIDER		13	13				Not applicable to Transmission Cost of Service calculation.
REC.CUR AFUDC EQUITY RIDER		(103)	(103)				Not applicable to Transmission Cost of Service calculation.
REC.NON CUR AFUDC EQUITY AMORT RIDER		50	50				Not applicable to Transmission Cost of Service calculation.
REC.NON CUR AFUDC EQUITY RIDER		(110)	(110)				Not applicable to Transmission Cost of Service calculation.
RESEARCH AND DEVELOPMENT (FED)		-	-				Not applicable to Transmission Cost of Service calculation.
SALES TAX RECOVERY IN SERVICE (537)		-	-				Not applicable to Transmission Cost of Service calculation.
ST AFC DEF TAX-FUEL CWIP		(9)	(9)				Not applicable to Transmission Cost of Service calculation.
ST AFC DEF TAX-PLANT CWIP		(1,703)	(1,703)				Not applicable to Transmission Cost of Service calculation.
ST AFC DEF TAX-PLANT IN SERVICE		(5,329)	(5,329)				Not applicable to Transmission Cost of Service calculation.
ST AFUDC-NUCLEAR FUEL		35	35				Not applicable to Transmission Cost of Service calculation.
ST BOOK AMORT-CAPITAL LEASES (207)		62	62				Not applicable to Transmission Cost of Service calculation.
ST BOOK CAPITALIZED INTEREST CWIP		(101)	(101)				Not applicable to Transmission Cost of Service calculation.
ST BOOK DEP.- AMORT DESIGN DOC		22	22				Not applicable to Transmission Cost of Service calculation.
ST BOOK DEP.- AMORT LEASE IMPROV		740	740				Not applicable to Transmission Cost of Service calculation.
ST BOOK DEP.-AMORT PLANT ACO ADJ.		2,449	2,449				Not applicable to Transmission Cost of Service calculation.
ST BOOK DEPR (008)		718,433	718,433				Not applicable to Transmission Cost of Service calculation.
ST BOOK DEPREC-NA MERIT PROGRAM		0	0				Not applicable to Transmission Cost of Service calculation.
ST BOOK DEPR-NON OPERATING VEPCO		29	29				Not applicable to Transmission Cost of Service calculation.
ST BOOK DEPR-UNRECOVERED PLT NORTH ANNA		1	1				Not applicable to Transmission Cost of Service calculation.
ST BOOK DEPR-UNRECOVERED PLT SURRY		3	3				Not applicable to Transmission Cost of Service calculation.
ST BOOK OP- GAIN(LOSS) SALE PROPR		(4)	(4)				Not applicable to Transmission Cost of Service calculation.
ST CAP EXPENSE 481A - PROD OTHER (750)		12,258	12,258				Not applicable to Transmission Cost of Service calculation.
ST CAP EXPENSE 481A (570)		(969)	(969)				Not applicable to Transmission Cost of Service calculation.
ST CAPITAL EXPENSE		(2,167)	(2,167)				Not applicable to Transmission Cost of Service calculation.
ST CAPITALIZED INTEREST - 481A ADJUST		(222)	(222)				Not applicable to Transmission Cost of Service calculation.
ST CAPITALIZED INTEREST - DEPREC 481A		53	53				Not applicable to Transmission Cost of Service calculation.
ST CAPITALIZED INTEREST OPER IN SERVICE		(11,866)	(11,866)				Not applicable to Transmission Cost of Service calculation.
ST CAPITALIZED INTEREST OPERATING CWIP		(5,079)	(5,079)				Not applicable to Transmission Cost of Service calculation.
ST CAPITALIZED O&M EXP-DISTRIBUTION		(527)	(527)				Not applicable to Transmission Cost of Service calculation.
ST CAPITALIZED RESTORATION 481A		7,090	7,090				Not applicable to Transmission Cost of Service calculation.
ST CASUALTY LOSS AMORT		5,792	5,792				Not applicable to Transmission Cost of Service calculation.
ST CASUALTY LOSSES (132)		(15,363)	(15,363)				Not applicable to Transmission Cost of Service calculation.
ST CIAC DC-NONOP IN SERVICE		(99)	(99)				Not applicable to Transmission Cost of Service calculation.
ST CIAC NC-NONOP CWIP VEPCO		(168)	(168)				Not applicable to Transmission Cost of Service calculation.
ST CIAC NC-NONOP IN SERVICE		(49)	(49)				Not applicable to Transmission Cost of Service calculation.
ST CIAC VA-NONOP CWIP VEPCO		(930)	(930)				Not applicable to Transmission Cost of Service calculation.
ST CIAC VA-NONOP IN SERVICE		(3,241)	(3,241)				Not applicable to Transmission Cost of Service calculation.
ST COMPUTER SOFTWARE-BOOK AMORT		6,168	6,168				Not applicable to Transmission Cost of Service calculation.
ST COMPUTER SOFTWARE-CWIP		(2,400)	(2,400)				Not applicable to Transmission Cost of Service calculation.
ST COMPUTER SOFTWARE-TAX AMORT		(6,949)	(6,949)				Not applicable to Transmission Cost of Service calculation.
ST COST OF REMOVAL		(399)	(399)				Not applicable to Transmission Cost of Service calculation.
ST CWIP ABANDONMENT NON CURRENT-NA3		(5,165)	(5,165)				Not applicable to Transmission Cost of Service calculation.
ST CWIP ABANDONMENT NON CURRENT-WIND		(70)	(70)				Not applicable to Transmission Cost of Service calculation.
ST DEF G/L NONOPERATING VEPCO		3	3				Not applicable to Transmission Cost of Service calculation.
ST DEF G/L-FUTURE USE NONOP VEPCO		(70)	(70)				Not applicable to Transmission Cost of Service calculation.
ST DEPR LATERAL PIPELINE RECORDED TO FUEL EXP		94	94				Not applicable to Transmission Cost of Service calculation.
ST DOE SETTLEMENT-ASSET BASIS REDUCTION		-	-				Not applicable to Transmission Cost of Service calculation.
ST FAS 143 ASSET OBLIGATION		(6,665)	(6,665)				Not applicable to Transmission Cost of Service calculation.
ST FAS 143 DECOMMISSIONING-NA		(8,481)	(8,481)				Not applicable to Transmission Cost of Service calculation.
ST FAS 143 DECOMMISSIONING-OTHER		(12,024)	(12,024)				Not applicable to Transmission Cost of Service calculation.
ST FIXED ASSETS		(687)	(687)				Not applicable to Transmission Cost of Service calculation.
ST G/L INTERCO SALES -BOOK/TAX		(258)	(258)				Not applicable to Transmission Cost of Service calculation.
ST LIBERALIZED DEPR: PLANT FUTURE USE VEPCO		27	27				Not applicable to Transmission Cost of Service calculation.
ST LIBERALIZED DEPR: PLANT NON UTILITY VEPCO		(107)	(107)				Not applicable to Transmission Cost of Service calculation.
ST METERS		(19)	(19)				Not applicable to Transmission Cost of Service calculation.
ST NUCLEAR FUEL TAX G/L-NA		(1,001)	(1,001)				Not applicable to Transmission Cost of Service calculation.
ST NUCLEAR FUEL TAX G/L-SURRY		(1,360)	(1,360)				Not applicable to Transmission Cost of Service calculation.
ST NUCLEAR FUEL-COMMERCIAL BURN		36,709	36,709				Not applicable to Transmission Cost of Service calculation.
ST NUCLEAR FUEL-PERM DISPOSAL NORTH ANNA		0	0				Not applicable to Transmission Cost of Service calculation.
ST NUCLEAR FUEL-PERM DISPOSAL SURRY		0	0				Not applicable to Transmission Cost of Service calculation.
ST SALES TAX RECOVERY CWIP		(480)	(480)				Not applicable to Transmission Cost of Service calculation.
ST SALES TAX RECOVERY IN SERVICE (537)		(752)	(752)				Not applicable to Transmission Cost of Service calculation.
ST TAX AMORT		(45,869)	(45,869)				Not applicable to Transmission Cost of Service calculation.
ST TAX DEPR-BONUS DEPR		(504,051)	(504,051)				Not applicable to Transmission Cost of Service calculation.
ST TAX DEPR		(1,085,558)	(1,085,558)				Not applicable to Transmission Cost of Service calculation.
ST TAX OP G/L SALE PROP		(825)	(825)				Not applicable to Transmission Cost of Service calculation.
TAX AMORT		(272,365)	(272,365)				Not applicable to Transmission Cost of Service calculation.
TAX DEPR-BONUS DEPR		(2,992,987)	(2,992,987)				Not applicable to Transmission Cost of Service calculation.
TAX DEPR		(6,449,063)	(6,449,063)				Not applicable to Transmission Cost of Service calculation.
TAX OP G/L SALE PROP		(4,897)	(4,897)				Not applicable to Transmission Cost of Service calculation.
VA 282 DIFFERENCE ADJUSTMENT		(4,442)	(4,442)				Not applicable to Transmission Cost of Service calculation.
VA BASIS DIFFERENCES		122,033	122,033				Not applicable to Transmission Cost of Service calculation.
VA BONUS DEPRECIATION		(3,310)	(3,310)				Not applicable to Transmission Cost of Service calculation.
VA BONUS DEPRECIATION		349,498	349,498				Not applicable to Transmission Cost of Service calculation.
VA BONUS DEPRECIATION 481A - GEN REPAIR		(3,886)	(3,886)				Not applicable to Transmission Cost of Service calculation.
VA BONUS DEPRECIATION CASUALTY 481A		6,690	6,690				Not applicable to Transmission Cost of Service calculation.
VA BONUS DEPRECIATION CIAC		555	555				Not applicable to Transmission Cost of Service calculation.
VA BONUS DEPRECIATION GEN 481A - CAP INTEREST		55	55				Not applicable to Transmission Cost of Service calculation.
Pollution Control		177,202	177,202				Not applicable to Transmission Cost of Service calculation.
BAD DEBTS VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
CONTINGENT CLAIMS CURRENT VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
CUSTOMER ACCOUNTS- RES & REFUND VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
DEDESIGNATED DEBT NOT ISSUED VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
Retention Bonus		-				-	Books accrues the costs of the bonus; tax takes the deduction when actually paid.
OPEB VEPCO		-				-	Represents the difference between the book accrual expense and the actual funded amount.
FIN 18 - FED		-	-				Not applicable to Transmission Cost of Service calculation.
RESTRICTED STOCK AWARD VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
RETIRE-EXEC SUPP RET (ESRP)-NONOP (1261010) VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
BOOK AMORT-CAPITAL LEASES (207)		(1,059)	(1,059)				Not applicable to Transmission Cost of Service calculation.
NUCLEAR FUEL-PERM DISPOSAL NORTH ANNA		(2)	(2)				Not applicable to Transmission Cost of Service calculation.
NUCLEAR FUEL-PERM DISPOSAL SURRY		(2)	(2)				Not applicable to Transmission Cost of Service calculation.
FAS 133 CURRENT VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133 NC VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
FEDERAL TAX INTEREST EXPENSE NON CURR VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
REACQUIRED DEBT GAIN(LOSS) VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
REG ASSET-HEDGE DEBT DEDESIGNATED DEBT NOT ISSUE VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.

CAP EXPENSE 481A - PROD OTHER (750)	-	-				Not applicable to Transmission Cost of Service calculation.
CAPITALIZED RESTORATION 481A	-	-				Not applicable to Transmission Cost of Service calculation.
G/L INTERCO SALES -BOOK/TAX	-	-				Not applicable to Transmission Cost of Service calculation.
ROUND	0	0				Not applicable to Transmission Cost of Service calculation.
Subtotal - p275 (Form 1-F filer: see	(5,658,511)	(4,249,008)	(1,271,805)	(61,507)	(76,191)	
Less FASB 109 Above if not separately	(70,017)	(70,017)	0	0	0	
Less FASB 106 Above if not separately	0					
Total	(5,588,494)	(4,178,991)	(1,271,805)	(61,507)	(76,191)	

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

A ADIT-283	B Total	C Production Or Other Related	D Only Transmission Related	E Plant Related	F Labor Related	G Justification
AFC DEF TAX-PLANT IN SERVICE	(20,089)	(20,089)				Not applicable to Transmission Cost of Service calculation.
AFUDC EQUITY (FAC045) - FLOW THRU	(15,897)	(15,897)				Not applicable to Transmission Cost of Service calculation.
AFUDC-NUCLEAR FUEL	132	132				Not applicable to Transmission Cost of Service calculation.
BAD DEBTS VEPCO	(1,424)	(1,424)				Not applicable to Transmission Cost of Service calculation.
BOOK DEP.- AMORT DESIGN DOC	82	82				Not applicable to Transmission Cost of Service calculation.
BOOK DEP.- AMORT LEASE IMPROV	2,788	2,788				Not applicable to Transmission Cost of Service calculation.
BOOK DEP.-AMORT PLANT ACO ADJ.	9,232	9,232				Not applicable to Transmission Cost of Service calculation.
BOOK DEPR (008)	2,708,135	2,708,135				Not applicable to Transmission Cost of Service calculation.
BOOK DEPREC-NA MERIT PROGRAM	1	1				Not applicable to Transmission Cost of Service calculation.
BOOK DEPR-UNRECOVERED PLT NORTH ANNA	2	2				Not applicable to Transmission Cost of Service calculation.
BOOK DEPR-UNRECOVERED PLT SURRY	10	10				Not applicable to Transmission Cost of Service calculation.
CAPITALIZED INTEREST OPER IN SERVICE	127,794	127,794				Not applicable to Transmission Cost of Service calculation.
COMPUTER SOFTWARE-BOOK AMORT	23,250	23,250				Not applicable to Transmission Cost of Service calculation.
COMPUTER SOFTWARE-CWIP	(9,045)	(9,045)				Not applicable to Transmission Cost of Service calculation.
COMPUTER SOFTWARE-TAX AMORT	(24,180)	(24,180)				Not applicable to Transmission Cost of Service calculation.
CONTINGENT CLAIMS CURRENT VEPCO	53	53				Not applicable to Transmission Cost of Service calculation.
CONTINGENT CLAIMS NONCURRENT VEPCO	(4,141)	(4,141)				Not applicable to Transmission Cost of Service calculation.
COST OF REMOVAL	4,298	4,298				Not applicable to Transmission Cost of Service calculation.
CURR CAPIT RESTORATION COSTS 481A-DISTR VEPCO	(15,005)	(15,005)				Not applicable to Transmission Cost of Service calculation.
CUSTOMER ACCOUNTS- RES & REFUND VEPCO	11	11				Not applicable to Transmission Cost of Service calculation.
CUSTOMER ACCTS. INTEREST-RES & REFUND VEPCO	(11)	(11)				Not applicable to Transmission Cost of Service calculation.
CWIP ABANDONMENT NON CURRENT	-	-				Not applicable to Transmission Cost of Service calculation.
DC - BONUS DEPRECIATION DEF CUR	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
DC - BONUS DEPRECIATION DEF NC	(1)	(1)				Not applicable to Transmission Cost of Service calculation.
DECOMM POUROVER VEPCO	(58,567)	(58,567)				Not applicable to Transmission Cost of Service calculation.
DECOMM TRUST BOOK INCOME NON OP VEPCO	(180,569)	(180,569)				Not applicable to Transmission Cost of Service calculation.
DECOMM TRUST BOOK INCOME OP VEPCO	(331,596)	(331,596)				Not applicable to Transmission Cost of Service calculation.
DECOMM TRUST-UNREALIZED G/L-NC VEPCO	(201,193)	(201,193)				Not applicable to Transmission Cost of Service calculation.
DEDESIGNATED DEBT NOT ISSUED VEPCO	25	25				Not applicable to Transmission Cost of Service calculation.
DEF ITC- NCP	(2,615)	(2,615)				Not applicable to Transmission Cost of Service calculation.
DEFERRED FUEL EXPENSE CURRENT VEPCO	(2,103)	(2,103)				Not applicable to Transmission Cost of Service calculation.
DEFERRED FUEL EXPENSE VEPCO	0	0				Not applicable to Transmission Cost of Service calculation.
DEFERRED FUEL EXP-OTHER CURRENT VEPCO	(779)	(779)				Not applicable to Transmission Cost of Service calculation.
DEFERRED REVENUE CURRENT VEPCO	(153)	(153)				Not applicable to Transmission Cost of Service calculation.
DEPR LATERAL PIPELINE RECORDED TO FUEL EXP	354	354				Not applicable to Transmission Cost of Service calculation.
DIRECTOR CHARITABLE DONATION VEPCO	(7)	(7)				Not applicable to Transmission Cost of Service calculation.
DOE SETTLEMENT VEPCO	(10,169)	(10,169)				Not applicable to Transmission Cost of Service calculation.
DOE SETTLEMENT-INVENT BASIS REDUCTION VEPCO	(87)	(87)				Not applicable to Transmission Cost of Service calculation.
DT-AFC DEF TAX-FUEL IN SERVICE NA	(9)	(9)				Not applicable to Transmission Cost of Service calculation.
DT-AFC DEF TAX-FUEL IN SERVICE-FED	0	0				Not applicable to Transmission Cost of Service calculation.
DT-AFC DEF TAX-PLANT IN SERVICE	19,004	19,004				Not applicable to Transmission Cost of Service calculation.
DT-CAP INTEREST OPER IN SERVICE-FED	(127,784)	(127,784)				Not applicable to Transmission Cost of Service calculation.
DT-COMPUTER SOFTWARE-BOOK AMORT-FED	(35,437)	(35,437)				Not applicable to Transmission Cost of Service calculation.
DT-COMPUTER SOFTWARE-CWIP-FED	9,444	9,444				Not applicable to Transmission Cost of Service calculation.
DT-COMPUTER SOFTWARE-TAX AMORT	49,233	49,233				Not applicable to Transmission Cost of Service calculation.
DT-COST OF REMOVAL	(44,866)	(44,866)				Not applicable to Transmission Cost of Service calculation.
DT-LIBERALIZED DEPR	3,333,790	3,333,790				Not applicable to Transmission Cost of Service calculation.
FAS 133 CURRENT VEPCO	(20,473)	(20,473)				Not applicable to Transmission Cost of Service calculation.
FAS 133 NC VEPCO	20,473	20,473				Not applicable to Transmission Cost of Service calculation.
FAS 133-DEBT HEDGE CURRENT ASSET VEPCO	(286)	(286)				Not applicable to Transmission Cost of Service calculation.
FAS 133-DEBT VAL-MTM HEDGE NON CURR AS VEPCO	(7,098)	(7,098)				Not applicable to Transmission Cost of Service calculation.
FAS 133-DEF G/L CAPACITY HEDGE-NON CURR VEPCO	-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133-DEFERRED G/L CAPACITY HEDGE CURR LIAB	-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133-DEFERRED G/L POWER HEDGE-CURR LIAB	-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133-FTR CURRENT LIAB VEPCO	-	-				Not applicable to Transmission Cost of Service calculation.
FEDERAL TAX INTEREST EXPENSE NON CURR VEPCO	52	52				Not applicable to Transmission Cost of Service calculation.
FEDERAL TAX INTEREST EXPENSE VEPCO	(701)	(701)				Not applicable to Transmission Cost of Service calculation.
FIXED ASSETS (2210010)	(120)	(120)				Not applicable to Transmission Cost of Service calculation.
FUEL DEF CURRENT LIAB VEPCO	(1,829)	(1,829)				Not applicable to Transmission Cost of Service calculation.
FUEL DEF NON CUR LIAB VEPCO	(177)	(177)				Not applicable to Transmission Cost of Service calculation.
FUEL DEF OTHER CURRENT LIAB VEPCO	(748)	(748)				Not applicable to Transmission Cost of Service calculation.
FUEL DEF OTHER NON CUR LIAB	(13)	(13)				Not applicable to Transmission Cost of Service calculation.
FUEL HANDLING COSTS VEPCO	(176)	(176)				Not applicable to Transmission Cost of Service calculation.
HEADWATER BENEFITS VEPCO	(68)	(68)				Not applicable to Transmission Cost of Service calculation.
LONG TERM DISABILITY RESERVE VEPCO	(453)	(453)				Not applicable to Transmission Cost of Service calculation.
NC - BONUS DEPRECIATION DEF NC	(45)	(45)				Not applicable to Transmission Cost of Service calculation.
NC Deferred Current Adj - SOLAR ITC	(12)	(12)				Not applicable to Transmission Cost of Service calculation.
NC Deferred NonCurrent Adj - SOLAR ITC	(3,120)	(3,120)				Not applicable to Transmission Cost of Service calculation.
NON CURR CAPIT RESTORATION COSTS 481A-D VEPCO	(4,477)	(4,477)				Not applicable to Transmission Cost of Service calculation.
NON CURRENT REC A4 ELEC TRAN VEPCO	(4,775)	(4,775)				Not applicable to Transmission Cost of Service calculation.
NUCLEAR FUEL TAX G/L-NA	(3,772)	(3,772)				Not applicable to Transmission Cost of Service calculation.
NUCLEAR FUEL TAX G/L-SURRY	(5,126)	(5,126)				Not applicable to Transmission Cost of Service calculation.
NUCLEAR FUEL-COMMERCIAL BURN	138,374	138,374				Not applicable to Transmission Cost of Service calculation.
OBSOLETE INVENTORY RESERVE VEPCO	(112)	(112)				Not applicable to Transmission Cost of Service calculation.
OPEB VEPCO	2,207	2,207				Not applicable to Transmission Cost of Service calculation.
POWERTREE CARBON CO, LLC. VEPCO	(40)	(40)				Not applicable to Transmission Cost of Service calculation.
PREMIUM, DEBT, DISCOUNT&EXP VEPCO	(71)	(71)				Not applicable to Transmission Cost of Service calculation.
P'SHIP INCOME - VIRGINIA CAPITAL VEPCO	(11)	(11)				Not applicable to Transmission Cost of Service calculation.
RA.CUR AFUDC DEBT AMORT RIDER	103	103				Not applicable to Transmission Cost of Service calculation.
RA.CUR AFUDC DEBT RIDER	(685)	(685)				Not applicable to Transmission Cost of Service calculation.
RA.CUR AFUDC EQUITY AMORT RIDER	(76)	(76)				Not applicable to Transmission Cost of Service calculation.
RA.CUR AFUDC EQUITY RIDER	(383)	(383)				Not applicable to Transmission Cost of Service calculation.
RA.CUR OTHER COSTS NONOPER RIDER	3,250	3,250				Not applicable to Transmission Cost of Service calculation.
RA.CUR OTHER COSTS OPER RIDER	(19,976)	(19,976)				Not applicable to Transmission Cost of Service calculation.
RA.NON CUR AFUDC DEBT AMORT RIDER	311	311				Not applicable to Transmission Cost of Service calculation.
RA.NON CUR AFUDC DEBT RIDER	(8,107)	(8,107)				Not applicable to Transmission Cost of Service calculation.
RA.NON CUR AFUDC EQUITY AMORT RIDER	493	493				Not applicable to Transmission Cost of Service calculation.
RA.NON CUR AFUDC EQUITY RIDER	(14,048)	(14,048)				Not applicable to Transmission Cost of Service calculation.
RA.NON CUR OTHER COSTS NON OPER RIDER	205	205				Not applicable to Transmission Cost of Service calculation.
RA.NON CUR OTHER COSTS OPER RIDER	(45,767)	(45,767)				Not applicable to Transmission Cost of Service calculation.
REACQUIRED DEBT GAIN(LOSS) VEPCO	374	374				Not applicable to Transmission Cost of Service calculation.
REC.CUR AFUDC DEBT AMORT RIDER	(5)	(5)				Not applicable to Transmission Cost of Service calculation.
REC.CUR AFUDC DEBT RIDER	(43)	(43)				Not applicable to Transmission Cost of Service calculation.
REC.CUR AFUDC EQUITY AMORT RIDER	8	8				Not applicable to Transmission Cost of Service calculation.
REC.CUR AFUDC EQUITY RIDER	(65)	(65)				Not applicable to Transmission Cost of Service calculation.
REC.CUR OTHER COST OPER RIDER	(1,269)	(1,269)				Not applicable to Transmission Cost of Service calculation.
REC.CUR OTHER COSTS NON OPER RIDER	(727)	(727)				Not applicable to Transmission Cost of Service calculation.
REC.NON CUR AFUDC DEBT AMORT RIDER	29	29				Not applicable to Transmission Cost of Service calculation.
REC.NON CUR AFUDC DEBT RIDER	(56)	(56)				Not applicable to Transmission Cost of Service calculation.
REC.NON CUR AFUDC EQUITY AMORT RIDER	32	32				Not applicable to Transmission Cost of Service calculation.
REC.NON CUR AFUDC EQUITY RIDER	(70)	(70)				Not applicable to Transmission Cost of Service calculation.
REC.NON CUR OTHER COST NON OPER RIDER	462	462				Not applicable to Transmission Cost of Service calculation.
REC.NON CUR OTHER COST OPER RIDER	(3,477)	(3,477)				Not applicable to Transmission Cost of Service calculation.
RECS VEPCO	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
REG ASSET - A4 RAC COSTS CURRENT VEPCO	(6,029)	(6,029)				Not applicable to Transmission Cost of Service calculation.

REG ASSET - A4 RAC COSTS NONCURRENT VEPCO		(23,844)	(23,844)				Not applicable to Transmission Cost of Service calculation.
REG ASSET - ATRR CURRENT VEPCO		(3,540)	(3,540)				Not applicable to Transmission Cost of Service calculation.
REG ASSET - CUR - NUG		(436)	(436)				Not applicable to Transmission Cost of Service calculation.
REG ASSET - FTR - CURRENT VEPCO		(316)	(316)				Not applicable to Transmission Cost of Service calculation.
REG ASSET - NRC REQUIREMENT - NORTH ANNA VEPCO		(8,639)	(8,639)				Not applicable to Transmission Cost of Service calculation.
REG ASSET - NRC REQUIREMENT - SURRY VEPCO		(3,989)	(3,989)				Not applicable to Transmission Cost of Service calculation.
REG ASSET ABANDONED PLANT NCUC CURR VEPCO		(474)	(474)				Not applicable to Transmission Cost of Service calculation.
REG ASSET ABANDONED PLANT NCUC NON CURR VEPCO		(2,235)	(2,235)				Not applicable to Transmission Cost of Service calculation.
REG ASSET ASSET IMPAIRMENT NCUC CURR VEPCO		(100)	(100)				Not applicable to Transmission Cost of Service calculation.
REG ASSET ASSET IMPAIRMENT NCUC NONCURR VEPCO		(314)	(314)				Not applicable to Transmission Cost of Service calculation.
REG ASSET CCR DEF NCUC ORDER NONCURR VEPCO		(5,382)	(5,382)				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURR RIDER A4 NON VA OTHER VEPCO		(879)	(879)				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A5 DSM VEPCO		(1,871)	(1,871)				Not applicable to Transmission Cost of Service calculation.
REG ASSET DEF NC RECPS REC COST CURR VEPCO		(292)	(292)				Not applicable to Transmission Cost of Service calculation.
REG ASSET FUEL HEDGE NONOP VEPCO		(275)	(275)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NATURAL DISASTER NCUC CURRENT VEPCO		(93)	(93)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NATURAL DISASTER NCUC NONCURR VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
REG ASSET NUCLEAR OUTAGE DEFER-CURRENT		(24,737)	(24,737)				Not applicable to Transmission Cost of Service calculation.
REG ASSET RETIREMENT NCUC CURRENT VEPCO		(49)	(49)				Not applicable to Transmission Cost of Service calculation.
REG ASSET RETIREMENT NCUC NONCURR VEPCO		(310)	(310)				Not applicable to Transmission Cost of Service calculation.
REG ASSET RIDER PLANTS NCUC CURRENT VEPCO		(243)	(243)				Not applicable to Transmission Cost of Service calculation.
REG ASSET RIDER PLANTS NCUC NONCURR VEPCO		(81)	(81)				Not applicable to Transmission Cost of Service calculation.
REG ASSET-DEBT VAL-MTM NON CURR VEPCO		(140,694)	(140,694)				Not applicable to Transmission Cost of Service calculation.
REG ASSET-DEBT VALUATION - MTM - CUR VEPCO		(5,665)	(5,665)				Not applicable to Transmission Cost of Service calculation.
REG ASSET-HEDGE DEBT DEDESIGNATED DEBT NOT ISSUE VEPCO		1,039	1,039				Not applicable to Transmission Cost of Service calculation.
REG ATTR NON CURRENT VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
REG FUEL HEDGE VEPCO		275	275				Not applicable to Transmission Cost of Service calculation.
REG LIAB - DEF NC REPS REC COST - NC		(43)	(43)				Not applicable to Transmission Cost of Service calculation.
REG LIAB - DEFERRED G/L CAPACITY HEDGE - CURRENT		-	-				Not applicable to Transmission Cost of Service calculation.
REG LIAB - FTR CURRENT VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
REG LIAB A5 REC COSTS - VA NON CURRENT VEPCO		(142)	(142)				Not applicable to Transmission Cost of Service calculation.
REG LIAB ATRR NON CURRENT		(581)	(581)				Not applicable to Transmission Cost of Service calculation.
REG LIAB CURRENT DSM A5		-	-				Not applicable to Transmission Cost of Service calculation.
Reg Liab NC Excess Def Tax-GU for Exp Item		940	940				Not applicable to Transmission Cost of Service calculation.
REG LIAB OTHER NCUC CURRENT VEPCO		(17)	(17)				Not applicable to Transmission Cost of Service calculation.
REG LIAB OTHER NCUC NON CURR VEPCO		(359)	(359)				Not applicable to Transmission Cost of Service calculation.
REG LIAB PLANT CONTRA VASLSTX VEPCO		(1,324)	(1,324)				Not applicable to Transmission Cost of Service calculation.
REG LIAB-DEF G/L POWER HEDGE-CUR VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
REG LIABILITY DECOMM TRUST NC OP VEPCO		17,584	17,584				Not applicable to Transmission Cost of Service calculation.
REG LIABILITY DECOMM VEPCO		(35,165)	(35,165)				Not applicable to Transmission Cost of Service calculation.
REG NON CURRENT DSM A5 RIDER VEPCO		(4,390)	(4,390)				Not applicable to Transmission Cost of Service calculation.
REG RATE REFUND - CURRENT VEPCO		(28)	(28)				Not applicable to Transmission Cost of Service calculation.
REGULATORY ASSET - FAS 112 VEPCO		(1,346)				(1,346)	Not applicable to Transmission Cost of Service calculation.
REGULATORY ASSET - NUG VEPCO		(928)	(928)				Not applicable to Transmission Cost of Service calculation.
REGULATORY ASSET - PJM		(78,681)	(78,681)				Not applicable to Transmission Cost of Service calculation.
REGULATORY ASSET - VA SLS TAX CURRENT VEPCO		(14,306)	(14,306)				Not applicable to Transmission Cost of Service calculation.
REGULATORY ASSET - VA SLS TAX VEPCO		(842)	(842)				Not applicable to Transmission Cost of Service calculation.
RESEARCH AND DEVELOPMENT (FED)		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
RESTRICTED STOCK AWARD VEPCO		3	3				Not applicable to Transmission Cost of Service calculation.
RETENTION BONUS		(1)	(1)				Not applicable to Transmission Cost of Service calculation.
RETIRE-EXEC SUPP RET (ESRP)-NONOP (1261010) VEPCO		(3)	(3)				Not applicable to Transmission Cost of Service calculation.
RETIRE-EXEC SUPP RET (ESRP)-NONOP (2210020) VEPCO		(628)	(628)				Not applicable to Transmission Cost of Service calculation.
RETIREMENT - (FASB 87) VEPCO		(6,377)	(6,377)				Not applicable to Transmission Cost of Service calculation.
SEPARATION/ERT VEPCO		(262)	(262)				Not applicable to Transmission Cost of Service calculation.
SUCCESS SHARE PLAN VEPCO		(303)	(303)				Not applicable to Transmission Cost of Service calculation.
SUPPLEMENTAL-SUPPLEMENTAL RETIRE VEPCO		(4)	(4)				Not applicable to Transmission Cost of Service calculation.
TAX AMORT		(172,904)	(172,904)				Not applicable to Transmission Cost of Service calculation.
TAX DEPR-BONUS DEPR		(1,900,020)	(1,900,020)				Not applicable to Transmission Cost of Service calculation.
TAX DEPR		(4,094,022)	(4,094,022)				Not applicable to Transmission Cost of Service calculation.
TAX OP G/L SALE PROP		(3,109)	(3,109)				Not applicable to Transmission Cost of Service calculation.
VA - BONUS DEPRECIATION DEF CUR		(1,528)	(1,528)				Not applicable to Transmission Cost of Service calculation.
VA - BONUS DEPRECIATION DEF NC		(2,293)	(2,293)				Not applicable to Transmission Cost of Service calculation.
VA MINIMUM TAX CREDIT		(105)	(105)				Not applicable to Transmission Cost of Service calculation.
VACATION ACCRUAL VEPCO		(369)	(369)				Not applicable to Transmission Cost of Service calculation.
WEST VA POLLUTION CONTROL		(3,635)			(3,635)		Not applicable to Transmission Cost of Service calculation.
WEST VA PROPERTY TAX VEPCO		(193)	(193)				Not applicable to Transmission Cost of Service calculation.
WORKERS COMPENSATION - FAS 112		(140)	(140)				Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
OCI		(32,713)	(32,713)				Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
BAD DEBTS VEPCO		-	-				Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
CONTINGENT CLAIMS CURRENT VEPCO		-	-				Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
CUSTOMER ACCOUNTS- RES & REFUND VEPCO		-	-				Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
DEDESIGNATED DEBT NOT ISSUED VEPCO		(419)	(419)				Not applicable to Transmission Cost of Service calculation.
Retention Bonus		-				-	Not applicable to Transmission Cost of Service calculation.
OPEB VEPCO		(37,442)				(37,442)	Not applicable to Transmission Cost of Service calculation.
FIN 18 - FED		(148)	(148)				Not applicable to Transmission Cost of Service calculation.
RESTRICTED STOCK AWARD VEPCO		(48)	(48)				Not applicable to Transmission Cost of Service calculation.
RETIRE-EXEC SUPP RET (ESRP)-NONOP (1261010) VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
BOOK AMORT-CAPITAL LEASES (207)		-	-				Not applicable to Transmission Cost of Service calculation.
NUCLEAR FUEL-PERM DISPOSAL NORTH ANNA		-	-				Not applicable to Transmission Cost of Service calculation.
NUCLEAR FUEL-PERM DISPOSAL SURRY		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133 CURRENT VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133 NC VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
FEDERAL TAX INTEREST EXPENSE NON CURR VEPCO		-	-				Not applicable to Transmission Cost of Service calculation.
REACQUIRED DEBT GAIN(LOSS) VEPCO		(321)	(321)				Not applicable to Transmission Cost of Service calculation.
REG ASSET-HEDGE DEBT DEDESIGNATED DEBT NOT ISSUE VEPCO		(889)	(889)				Not applicable to Transmission Cost of Service calculation.
CAP EXPENSE 481A - PROD OTHER (750)		-	-				Not applicable to Transmission Cost of Service calculation.
CAPITALIZED RESTORATION 481A		-	-				Not applicable to Transmission Cost of Service calculation.
G/L INTERCO SALES -BOOK/TAX		-	-				Not applicable to Transmission Cost of Service calculation.
ROUND		1	1				Not applicable to Transmission Cost of Service calculation.
Subtotal - p277 (Form 1-F filer: see		(1,386,850)	(1,344,427)	0	(3,635)	(38,788)	
Less FASB 109 Above if not separately		(43,509)	(43,509)	-	-	-	
Less FASB 106 Above if not separately		(37,442)	-	-	-	(37,442)	
Total		(1,305,900)	(1,300,919)	-	(3,635)	(1,346)	

Instructions for Account 283:

1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to

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

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

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

5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates,

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

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 1B
Projected Accumulated Deferred Federal Income Taxes Associated with Pro-rata Liberalized Depreciation

Applicable to the Projections of 2016 and Later and True-ups of 2014 and Later

If the formula rate population is for determining a projected ATRR, enter the year for which the projection is being made on line 1 and populate the remainder of this Attachment 1B with the projected data associated with that year. If the formula rate population is for determining a true-up ATRR for use on Line A of Attachment 6, enter the year for which the true-up is being calculated on line 1 and populate the remainder of this Attachment 1B with the data that was included in Attachment 1B of the projection associated with that year.

Sheet 1 of 3

Line 1 Projection for Year: 2017

Line 2 Number of Days in Year: 365 (Enter 365, or for Leap Year enter 366)

Part 1: Account 282, Transmission Plant In Service

Columns 3, 4, 7, and 8 are in dollars (except line 16).

Line	(1) Year	(2) Month	(3) Projected Transmission Plant in Service ADIT	(4) Activity	(5) Remaining Days	(6) Ratio	(7) Activity with Proration	(8) ADIT with Proration
3	2016	Dec	(1,336,117,378)					(1,336,117,378)
4	2017	Jan	(1,348,050,421)	(11,933,043)	335	0.917808	(10,952,245)	(1,347,069,623)
5	2017	Feb	(1,359,983,464)	(11,933,043)	307	0.841096	(10,036,833)	(1,357,106,456)
6	2017	Mar	(1,371,916,507)	(11,933,043)	276	0.756164	(9,023,342)	(1,366,129,798)
7	2017	Apr	(1,383,849,550)	(11,933,043)	246	0.673973	(8,042,544)	(1,374,172,342)
8	2017	May	(1,395,782,592)	(11,933,043)	215	0.589041	(7,029,053)	(1,381,201,395)
9	2017	Jun	(1,407,715,635)	(11,933,043)	185	0.506849	(6,048,255)	(1,387,249,650)
10	2017	Jul	(1,419,648,678)	(11,933,043)	154	0.421918	(5,034,763)	(1,392,284,413)
11	2017	Aug	(1,431,581,721)	(11,933,043)	123	0.336986	(4,021,272)	(1,396,305,685)
12	2017	Sep	(1,443,514,764)	(11,933,043)	93	0.254795	(3,040,474)	(1,399,346,159)
13	2017	Oct	(1,455,447,807)	(11,933,043)	62	0.169863	(2,026,983)	(1,401,373,142)
14	2017	Nov	(1,467,380,850)	(11,933,043)	32	0.087671	(1,046,185)	(1,402,419,327)
15	2017	Dec	(1,479,313,892)	(11,933,043)	1	0.002740	(32,693)	(1,402,452,020)

16 Total Transmission Plant In Service Net of GSU and GI Plant as a Percentage of Total Transmission Plant In Service: 93.74%

17 Amount to be Entered (in thousands) in Column D of the Account 282 Section of Attachment 1A Only When the Formula Rate Population is to Calculate a Projected ATRR: (1,252,455,842)

18 Amount to be Entered (in thousands) in Column D of the Account 282 Section of Attachment 1 Only When the Formula Rate Population is to Calculate a Projected ATRR: (1,314,636,914)

Explanations:

Col. 3	Projected Account 282 month-end ADIT (excludes cost of removal).
Col. 4	Monthly change in ADIT balance.
Col. 5	Number of days remaining in the year as of and including the last day of the month.
Col. 6	Col. 5 divided by the number of days in the year.
Col. 7	Col. 4 multiplied by col. 6.
Col. 8, Line 3	Amount from col. 3, line 3.
Col. 8, Lines 4-15	Col. 8 of previous month plus col. 7 of current month.
Col. 8, Line 16	Appendix A Line 24 ÷ Appendix A, Line 21 (from the projection population of the formula)
Col. 8, Line 17	Col. 8, Line 3 multiplied by line 16.
Col. 8, Line 18	Col. 8, Line 15 multiplied by line 16.

Attachment 1B (Continued)
2017
Sheet 2 of 3

Part 2: Account 282, General Plant

Columns 3, 4, 7, and 8 are in dollars.

Line	(1) Year	(2) Month	(3) Projected General Plant ADIT	(4) Activity	(5) Remaining Days	(6) Ratio	(7) Activity with Proration	(8) ADIT with Proration
1	2016	Dec	(56,781,575)					(56,781,575)
2	2017	Jan	(56,781,575)	0	335	0.917808	0	(56,781,575)
3	2017	Feb	(56,781,575)	0	307	0.841096	0	(56,781,575)
4	2017	Mar	(56,781,575)	0	276	0.756164	0	(56,781,575)
5	2017	Apr	(56,781,575)	0	246	0.673973	0	(56,781,575)
6	2017	May	(56,781,575)	0	215	0.589041	0	(56,781,575)
7	2017	Jun	(56,781,575)	0	185	0.506849	0	(56,781,575)
8	2017	Jul	(56,781,575)	0	154	0.421918	0	(56,781,575)
9	2017	Aug	(56,781,575)	0	123	0.336986	0	(56,781,575)
10	2017	Sep	(56,781,575)	0	93	0.254795	0	(56,781,575)
11	2017	Oct	(56,781,575)	0	62	0.169863	0	(56,781,575)
12	2017	Nov	(56,781,575)	0	32	0.087671	0	(56,781,575)
13	2017	Dec	(56,781,575)	0	1	0.002740	0	(56,781,575)
14	Amount to be Entered (in thousands) in Column F of the Account 282 Section of Attachment 1A Only When the Formula Rate Population is to Calculate a Projected ATRR:							(56,781,575)
15	Amount to be Entered (in thousands) in Column F of the Account 282 Section of Attachment 1 Only When the Formula Rate Population is to Calculate a Projected ATRR:							(56,781,575)

Explanations:

Col. 3	Projected Account 282 month-end ADIT (excludes cost of removal).
Col. 4	Current month change in ADIT balance.
Col. 5	Number of days remaining in the year as of and including the last day of the month.
Col. 6	Col. 5 divided by the number of days in the year.
Col. 7	Col. 4 multiplied by Col. 6.
Col. 8, Line 1	Amount from col. 3, line 1.
Col. 8, Lines 2-13	Col. 8 of previous month plus Col. 7 of current month.
Col. 8, Line 14	Col. 8, Line 1.
Col. 8, Line 15	Col. 8, Line 13.

Attachment 1B (Continued)
2017
Sheet 3 of 3

Part 3: Account 282, Computer Software - Book Amortization

Columns 3, 4, 7, and 8 are in dollars.
The column and line explanations are as described for Part 2.

Line	(1) Year	(2) Month	(3) Projected Computer Software Book Amount ADIT	(4) Activity	(5) Remaining Days	(6) Ratio	(7) Activity with Proration	(8) ADIT with Proration
1	2016	Dec	60,144,587					60,144,587
2	2017	Jan	60,144,587	0	335	0.917808	0	60,144,587
3	2017	Feb	60,144,587	0	307	0.841096	0	60,144,587
4	2017	Mar	60,144,587	0	276	0.756164	0	60,144,587
5	2017	Apr	60,144,587	0	246	0.673973	0	60,144,587
6	2017	May	60,144,587	0	215	0.589041	0	60,144,587
7	2017	Jun	60,144,587	0	185	0.506849	0	60,144,587
8	2017	Jul	60,144,587	0	154	0.421918	0	60,144,587
9	2017	Aug	60,144,587	0	123	0.336986	0	60,144,587
10	2017	Sep	60,144,587	0	93	0.254795	0	60,144,587
11	2017	Oct	60,144,587	0	62	0.169863	0	60,144,587
12	2017	Nov	60,144,587	0	32	0.087671	0	60,144,587
13	2017	Dec	60,144,587	0	1	0.002740	0	60,144,587

14 Amount to be Entered (in thousands) in Column F of the Account 282 Section of Attachment 1A Only When the Formula Rate Population is to Calculate a Projected ATRR: 60,144,587

15 Amount to be Entered (in thousands) in Column F of the Account 282 Section of Attachment 1 Only When the Formula Rate Population is to Calculate a Projected ATRR: 60,144,587

Part 4: Account 282, Computer Software - Tax Amortization

Columns 3, 4, 7, and 8 are in dollars.
The column and line explanations are as described for Part 2.

Line	(1) Year	(2) Month	(3) Projected Computer Software Tax Amount ADIT	(4) Activity	(5) Remaining Days	(6) Ratio	(7) Activity with Proration	(8) ADIT with Proration
1	2016	Dec	(79,478,955)					(79,478,955)
2	2017	Jan	(79,478,955)	0	335	0.917808	0	(79,478,955)
3	2017	Feb	(79,478,955)	0	307	0.841096	0	(79,478,955)
4	2017	Mar	(79,478,955)	0	276	0.756164	0	(79,478,955)
5	2017	Apr	(79,478,955)	0	246	0.673973	0	(79,478,955)
6	2017	May	(79,478,955)	0	215	0.589041	0	(79,478,955)
7	2017	Jun	(79,478,955)	0	185	0.506849	0	(79,478,955)
8	2017	Jul	(79,478,955)	0	154	0.421918	0	(79,478,955)
9	2017	Aug	(79,478,955)	0	123	0.336986	0	(79,478,955)
10	2017	Sep	(79,478,955)	0	93	0.254795	0	(79,478,955)
11	2017	Oct	(79,478,955)	0	62	0.169863	0	(79,478,955)
12	2017	Nov	(79,478,955)	0	32	0.087671	0	(79,478,955)
13	2017	Dec	(79,478,955)	0	1	0.002740	0	(79,478,955)

14 Amount to be Entered (in thousands) in Column F of the Account 282 Section of Attachment 1A Only When the Formula Rate Population is to Calculate a Projected ATRR: (79,478,955)

15 Amount to be Entered (in thousands) in Column F of the Account 282 Section of Attachment 1 Only When the Formula Rate Population is to Calculate a Projected ATRR: (79,478,955)

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 1C
True-up of Accumulated Deferred Federal Income Taxes Associated with Pro-rata Liberalized Depreciation

Applicable to the True-ups of 2015 and Later

If the formula rate population is for determining a projected ATRR, do not populate this Attachment 1C. If the formula rate population is for determining a true-up ATRR for use on Line A of Attachment 6, enter the year for which the true-up is being calculated on line 1 and populate the remainder of this Attachment 1C with the actual data associated with that year. Use the amounts from lines 17 and 18 of Part 1, and lines 14 and 15 of Parts 2, 3, and 4, in populating Attachment 1 and Attachment 1A as instructed in this Attachment 1C.

Sheet 1 of 3

Line 1	True-up Year:		(If Populated, Must Match Attachment 1B, Part 1, Line 1)
Line 2	Number of Days in Year:	365	(From Attachment 1B, Part 1, Line 2)

Part 1: Account 282, Transmission Plant In Service

Columns 3 through 12 are in dollars (except line 16).

Line	(1) Year	(2) Month	(3) Actual Transmission Plant In Service ADIT	(4) Actual Activity	(5) Projected Activity from Column (4) of Attachment 1B	(6) Activity Difference	(7) Reversal of Projected Activity Not Realized	(8) Activity Not in Projection	(9) Reversal of Projected Activity Not Realized With Proration	(10) Projected Activity With Proration from Column (7) of Attachment 1B	(11) ADIT Activity for True-up	(12) ADIT Balances for True-up
3	-	Dec										-
4	-	Jan		-		-	-	-	-		-	-
5	-	Feb		-		-	-	-	-		-	-
6	-	Mar		-		-	-	-	-		-	-
7	-	Apr		-		-	-	-	-		-	-
8	-	May		-		-	-	-	-		-	-
9	-	Jun		-		-	-	-	-		-	-
10	-	Jul		-		-	-	-	-		-	-
11	-	Aug		-		-	-	-	-		-	-
12	-	Sep		-		-	-	-	-		-	-
13	-	Oct		-		-	-	-	-		-	-
14	-	Nov		-		-	-	-	-		-	-
15	-	Dec		-		-	-	-	-		-	-

16	Total Transmission Plant In Service Net of GSU and GI Plant as a Percentage of Total Transmission Plant In Service:	
17	Amount to be Entered (in thousands) in Column D of the Account 282 Section of Attachment 1A Only When the Formula Rate Population is to Calculate a True-up ATRR:	-
18	Amount to be Entered (in thousands) in Column D of the Account 282 Section of Attachment 1 Only When the Formula Rate Population is to Calculate a True-up ATRR:	-

<u>Explanations</u>:

Col. 3	Actual Account 282 month-end ADIT (excludes cost of removal).
Col. 4	Monthly change in ADIT balance.
Col. 6	Col. 4 minus col. 5
Col. 7	The portion of the amount in col. 6 included in original projection but not realized.
Col. 8	The portion of the amount in col. 6 not included in original projection.
Col. 9	The amount in col. 7 multiplied by the ratio from col. 6 of Attachment 1B, Part 1.
Col. 11	The sum of col. 8, col. 9, and col. 10.
Col. 12, Line 3	Amount from col. 3, line 3.
Col. 12, Lines 4-15	Col. 12 of previous month plus col. 11 of current month.
Col. 12, Line 16	Appendix A, Line 24 ÷ Appendix A, Line 21 (from the true-up population of the formula)
Col. 12, Line 17	Col. 12, Line 3 multiplied by line 16.
Col. 12, Line 18	Col. 12, Line 15 multiplied by line 16.

Attachment 1C (Continued)

-

Sheet 2 of 3

Part 2: Account 282, General Plant

Columns 3 through 12 are in dollars.

Line	(1) Year	(2) Month	(3) Actual General Plant ADIT	(4) Actual Activity	(5) Projected Activity from Column (4) of Attachment 1B	(6) Activity Difference	(7) Reversal of Projected Activity Not Realized	(8) Activity Not in Projection	(9) Reversal of Projected Activity Not Realized With Proration	(10) Projected Activity With Proration from Column (7) of Attachment 1B	(11) ADIT Activity for True-up	(12) ADIT Balances for True-up
1	-	Dec										-
2	-	Jan		-		-	-	-	-		-	-
3	-	Feb		-		-	-	-	-		-	-
4	-	Mar		-		-	-	-	-		-	-
5	-	Apr		-		-	-	-	-		-	-
6	-	May		-		-	-	-	-		-	-
7	-	Jun		-		-	-	-	-		-	-
8	-	Jul		-		-	-	-	-		-	-
9	-	Aug		-		-	-	-	-		-	-
10	-	Sep		-		-	-	-	-		-	-
11	-	Oct		-		-	-	-	-		-	-
12	-	Nov		-		-	-	-	-		-	-
13	-	Dec		-		-	-	-	-		-	-

14 Amount to be Entered (in thousands) in Column F of the Account 282 Section of Attachment 1A Only When the Formula Rate Population is to Calculate a True-up ATRR: -

15 Amount to be Entered (in thousands) in Column F of the Account 282 Section of Attachment 1 Only When the Formula Rate Population is to Calculate a True-up ATRR: -

Explanations:

Col. 3	Actual Account 282 month-end ADIT (excludes cost of removal).
Col. 4	Monthly change in ADIT balance.
Col. 6	Col. 4 minus col. 5
Col. 7	The portion of the amount in col. 6 included in original projection but not realized.
Col. 8	The portion of the amount in col. 6 not included in original projection.
Col. 9	The amount in col. 7 multiplied by the ratio from col. 6 of Attachment 1B, Part 2, 3 or 4 (as appropriate).
Col. 11	The sum of col. 8, col. 9, and col. 10.
Col. 12, Line 1	Amount from col. 3, line 1.
Col. 12, Lines 2-13	Col. 12 of previous month plus col. 11 of current month.
Col. 12, Line 14	Amount from col. 12, line 1.
Col. 12, Line 15	Amount from col. 12, line 13.

Attachment 1C (Continued)

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Sheet 3 of 3

Part 3: Account 282, Computer Software - Book Amortization

Columns 3 through 12 are in dollars.
The column and line explanations are as described for Part 2.

Line	(1) Year	(2) Month	(3) Actual Computer Software Book Amount ADIT	(4) Actual Activity	(5) Projected Activity from Column (4) of Attachment 1B	(6) Activity Difference	(7) Reversal of Projected Activity Not Realized	(8) Activity Not in Projection	(9) Reversal of Projected Activity Not Realized With Proration	(10) Projected Activity With Proration from Column (7) of Attachment 1B	(11) ADIT Activity for True-up	(12) ADIT Balances for True-up
1	-	Dec										-
2	-	Jan		-		-	-	-	-		-	-
3	-	Feb		-		-	-	-	-		-	-
4	-	Mar		-		-	-	-	-		-	-
5	-	Apr		-		-	-	-	-		-	-
6	-	May		-		-	-	-	-		-	-
7	-	Jun		-		-	-	-	-		-	-
8	-	Jul		-		-	-	-	-		-	-
9	-	Aug		-		-	-	-	-		-	-
10	-	Sep		-		-	-	-	-		-	-
11	-	Oct		-		-	-	-	-		-	-
12	-	Nov		-		-	-	-	-		-	-
13	-	Dec		-		-	-	-	-		-	-

14 Amount to be Entered (in thousands) in Column F of the Account 282 Section of Attachment 1A Only When the Formula Rate Population is to Calculate a True-up ATRR: -

15 Amount to be Entered (in thousands) in Column F of the Account 282 Section of Attachment 1 Only When the Formula Rate Population is to Calculate a True-up ATRR: -

Part 4: Account 282, Computer Software - Tax Amortization

Columns 3 through 12 are in dollars.
The column and line explanations are as described for Part 2.

Line	(1) Year	(2) Month	(3) Actual Computer Software Tax Amount ADIT	(4) Actual Activity	(5) Projected Activity from Column (4) of Attachment 1B	(6) Activity Difference	(7) Reversal of Projected Activity Not Realized	(8) Activity Not in Projection	(9) Reversal of Projected Activity Not Realized With Proration	(10) Projected Activity With Proration from Column (7) of Attachment 1B	(11) ADIT Activity for True-up	(12) ADIT Balances for True-up
1	-	Dec										-
2	-	Jan		-		-	-	-	-		-	-
3	-	Feb		-		-	-	-	-		-	-
4	-	Mar		-		-	-	-	-		-	-
5	-	Apr		-		-	-	-	-		-	-
6	-	May		-		-	-	-	-		-	-
7	-	Jun		-		-	-	-	-		-	-
8	-	Jul		-		-	-	-	-		-	-
9	-	Aug		-		-	-	-	-		-	-
10	-	Sep		-		-	-	-	-		-	-
11	-	Oct		-		-	-	-	-		-	-
12	-	Nov		-		-	-	-	-		-	-
13	-	Dec		-		-	-	-	-		-	-

14 Amount to be Entered (in thousands) in Column F of the Account 282 Section of Attachment 1A Only When the Formula Rate Population is to Calculate a True-up ATRR: -

15 Amount to be Entered (in thousands) in Column F of the Account 282 Section of Attachment 1 Only When the Formula Rate Population is to Calculate a True-up ATRR: -

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 1C - 2014
True-up of Accumulated Deferred Federal Income Taxes Associated with Pro-rata Liberalized Depreciation

Applicable Only to the True-up of 2014

If the formula rate population is for determining the 2014 true-up ATRR for use on Line A of Attachment 6, populate this Attachment 1C - 2014 with the actual data associated with that year. Use the amounts from lines 17 and 18 of Part 1, and lines 14 and 15 of Parts 2, 3, and 4, in populating Attachment 1 and Attachment 1A as instructed in this Attachment 1C - 2014.

Sheet 1 of 4

Line 1 True-up Year: 2014
Line 2 Number of Days in Year: 365

Part 1: Account 282, Transmission Plant In Service

Columns 3 through 12 are in dollars (except lines 15b, 15e, and 16).

Line	(1) Year	(2) Month	(3) Actual Transmission Plant In Service ADIT	(4) Actual Activity	(5) Projected Activity from Column (4) of Attachment 1B	(6) Activity Difference	(7) Reversal of Projected Activity Not Realized	(8) Activity Not in Projection	(9) Reversal of Projected Activity Not Realized With Proration	(10) Projected Activity With Proration from Column (7) of Attachment 1B	(11) ADIT Activity for True-up	(12) ADIT Balances for True-up
3	2013	Dec										-
4	2014	Jan		-		-	-	-	-		-	-
5	2014	Feb		-		-	-	-	-		-	-
6	2014	Mar		-		-	-	-	-		-	-
7	2014	Apr		-		-	-	-	-		-	-
8	2014	May		-		-	-	-	-		-	-
9	2014	Jun		-		-	-	-	-		-	-
10	2014	Jul		-		-	-	-	-		-	-
11	2014	Aug		-		-	-	-	-		-	-
12	2014	Sep		-		-	-	-	-		-	-
13	2014	Oct		-		-	-	-	-		-	-
14	2014	Nov		-		-	-	-	-		-	-
15	2014	Dec		-		-	-	-	-		-	-

15a	Pre-change -- Average of Actual ADIT Balance from Col. 3, December 2013 and April 2014	-
15b	4 Months Divided by 12 Months	33.33%
15c	Component of Average ADIT Balance Attributable to January Through April (15a X 15b)	-
15d	Post-change -- Average of ADIT Balances for True-up from Col. 12, April 2014 and December 2014	-
15e	8 Months Divided by 12 Months	66.67%
15f	Component of Average ADIT Balance Attributable to May Through December (15d X 15e)	-
15g	Pre-change Component plus Post-change Component (15c + 15f)	-
16	Total Transmission Plant In Service Net of GSU and GI Plant as a Percentage of Total Transmission Plant In Service:	
17	Amount to be Entered (in thousands) in Column D of the Account 282 Section of Attachment 1A Only When the Formula Rate Population is to Calculate the 2014 True-up ATRR:	-
18	Amount to be Entered (in thousands) in Column D of the Account 282 Section of Attachment 1 Only When the Formula Rate Population is to Calculate the 2014 True-up ATRR:	-

Explanations:

Col. 3	Actual Account 282 month-end ADIT (excludes cost of removal).
Col. 4	Monthly change in ADIT balance.
Col. 6	Col. 4 minus col. 5
Col. 7	The portion of the amount in col. 6 included in original projection but not realized.
Col. 8	The portion of the amount in col. 6 not included in original projection.
Col. 9	The amount in col. 7 multiplied by the ratio from col. 6 of Attachment 1B, Part 1.
Col. 11	The sum of col. 8, col. 9, and col. 10.
Col. 12, Line 3	Amount from col. 3, line 3.
Col. 12, Lines 4-15	Col. 12 of previous month plus col. 11 of current month.
Col. 12, Line 16	Appendix A, Line 24 ÷ Appendix A, Line 21 (from the true-up population of the formula)
Col. 12, Line 17	Col. 12, Line 15g multiplied by line 16.
Col. 12, Line 18	Col. 12, Line 15g multiplied by line 16.

Attachment 1C - 2014 (Continued)
2014
Sheet 2 of 4

Part 2: Account 282, General Plant

Columns 3 through 12 are in dollars (except lines 13b and 13e).

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Line	Year	Month	Actual General Plant ADIT	Actual Activity	Projected Activity from Column (4) of Attachment 1B	Activity Difference	Reversal of Projected Activity Not Realized	Activity Not in Projection	Reversal of Projected Activity Not Realized With Proration	Projected Activity With Proration from Column (7) of Attachment 1B	ADIT Activity for True-up	ADIT Balances for True-up
1	2013	Dec										-
2	2014	Jan		-		-	-	-	-		-	-
3	2014	Feb		-		-	-	-	-		-	-
4	2014	Mar		-		-	-	-	-		-	-
5	2014	Apr		-		-	-	-	-		-	-
6	2014	May		-		-	-	-	-		-	-
7	2014	Jun		-		-	-	-	-		-	-
8	2014	Jul		-		-	-	-	-		-	-
9	2014	Aug		-		-	-	-	-		-	-
10	2014	Sep		-		-	-	-	-		-	-
11	2014	Oct		-		-	-	-	-		-	-
12	2014	Nov		-		-	-	-	-		-	-
13	2014	Dec		-		-	-	-	-		-	-

13a	Pre-change -- Average of Actual ADIT Balance from Col. 3, December 2013 and April 2014	-
13b	4 Months Divided by 12 Months	33.33%
13c	Component of Average ADIT Balance Attributable to January Through April (13a X 13b)	-
13d	Post-change -- Average of ADIT Balances for True-up from Col. 12, April 2014 and December 2014	-
13e	8 Months Divided by 12 Months	66.67%
13f	Component of Average ADIT Balance Attributable to May Through December (13d X 13e)	-
13g	Pre-change Component plus Post-change Component (13c + 13f)	-
14	Amount to be Entered (in thousands) in Column F of the Account 282 Section of Attachment 1A Only When the Formula Rate Population is to Calculate the 2014 True-up ATRR:	-
15	Amount to be Entered (in thousands) in Column F of the Account 282 Section of Attachment 1 Only When the Formula Rate Population is to Calculate the 2014 True-up ATRR:	-

Explanations:

Col. 3	Actual Account 282 month-end ADIT (excludes cost of removal).
Col. 4	Monthly change in ADIT balance.
Col. 6	Col. 4 minus col. 5
Col. 7	The portion of the amount in col. 6 included in original projection but not realized.
Col. 8	The portion of the amount in col. 6 not included in original projection.
Col. 9	The amount in col. 7 multiplied by the ratio from col. 6 of Attachment 1B, Part 2, 3 or 4 (as appropriate).
Col. 11	The sum of col. 8, col. 9, and col. 10.
Col. 12, Line 1	Amount from col. 3, line 1.
Col. 12, Lines 2-13	Col. 12 of previous month plus col. 11 of current month.
Col. 12, Line 14	Amount from col. 12, line 13g.
Col. 12, Line 15	Amount from col. 12, line 13g.

Attachment 1C - 2014 (Continued)
2014
Sheet 3 of 4

Part 3: Account 282, Computer Software - Book Amortization

Columns 3 through 12 are in dollars (except lines 13b and 13e).
The column and line explanations are as described for Part 2.

Line	(1) Year	(2) Month	(3) Actual Computer Software Book Amount ADIT	(4) Actual Activity	(5) Projected Activity from Column (4) of Attachment 1B	(6) Activity Difference	(7) Reversal of Projected Activity Not Realized	(8) Activity Not in Projection	(9) Reversal of Projected Activity Not Realized With Proration	(10) Projected Activity With Proration from Column (7) of Attachment 1B	(11) ADIT Activity for True-up	(12) ADIT Balances for True-up
1	2013	Dec										-
2	2014	Jan		-		-	-	-	-		-	-
3	2014	Feb		-		-	-	-	-		-	-
4	2014	Mar		-		-	-	-	-		-	-
5	2014	Apr		-		-	-	-	-		-	-
6	2014	May		-		-	-	-	-		-	-
7	2014	Jun		-		-	-	-	-		-	-
8	2014	Jul		-		-	-	-	-		-	-
9	2014	Aug		-		-	-	-	-		-	-
10	2014	Sep		-		-	-	-	-		-	-
11	2014	Oct		-		-	-	-	-		-	-
12	2014	Nov		-		-	-	-	-		-	-
13	2014	Dec		-		-	-	-	-		-	-

13a	Pre-change -- Average of Actual ADIT Balance from Col. 3, December 2013 and April 2014	-
13b	4 Months Divided by 12 Months	33.33%
13c	Component of Average ADIT Balance Attributable to January Through April (13a X 13b)	-
13d	Post-change -- Average of ADIT Balances for True-up from Col. 12, April 2014 and December 2014	-
13e	8 Months Divided by 12 Months	66.67%
13f	Component of Average ADIT Balance Attributable to May Through December (13d X 13e)	-
13g	Pre-change Component plus Post-change Component (13c + 13f)	-
14	Amount to be Entered (in thousands) in Column F of the Account 282 Section of Attachment 1A Only When the Formula Rate Population is to Calculate the 2014 True-up ATRR:	-
15	Amount to be Entered (in thousands) in Column F of the Account 282 Section of Attachment 1 Only When the Formula Rate Population is to Calculate the 2014 True-up ATRR:	-

Attachment 1C - 2014 (Continued)
2014
Sheet 4 of 4

Part 4: Account 282, Computer Software - Tax Amortization

Columns 3 through 12 are in dollars (except lines 13b and 13e).
The column and line explanations are as described for Part 2.

Line	(1) Year	(2) Month	(3) Actual Computer Software Tax Amount ADIT	(4) Actual Activity	(5) Projected Activity from Column (4) of Attachment 1B	(6) Activity Difference	(7) Reversal of Projected Activity Not Realized	(8) Activity Not in Projection	(9) Reversal of Projected Activity Not Realized With Proration	(10) Projected Activity With Proration from Column (7) of Attachment 1B	(11) ADIT Activity for True-up	(12) ADIT Balances for True-up
1	2013	Dec										-
2	2014	Jan		-		-	-	-	-		-	-
3	2014	Feb		-		-	-	-	-		-	-
4	2014	Mar		-		-	-	-	-		-	-
5	2014	Apr		-		-	-	-	-		-	-
6	2014	May		-		-	-	-	-		-	-
7	2014	Jun		-		-	-	-	-		-	-
8	2014	Jul		-		-	-	-	-		-	-
9	2014	Aug		-		-	-	-	-		-	-
10	2014	Sep		-		-	-	-	-		-	-
11	2014	Oct		-		-	-	-	-		-	-
12	2014	Nov		-		-	-	-	-		-	-
13	2014	Dec		-		-	-	-	-		-	-

13a	Pre-change -- Average of Actual ADIT Balance from Col. 3, December 2013 and April 2014	-
13b	4 Months Divided by 12 Months	33.33%
13c	Component of Average ADIT Balance Attributable to January Through April (13a X 13b)	-
13d	Post-change -- Average of ADIT Balances for True-up from Col. 12, April 2014 and December 2014	-
13e	8 Months Divided by 12 Months	66.67%
13f	Component of Average ADIT Balance Attributable to May Through December (13d X 13e)	-
13g	Pre-change Component plus Post-change Component (13c + 13f)	-
14	Amount to be Entered (in thousands) in Column F of the Account 282 Section of Attachment 1A Only When the Formula Rate Population is to Calculate the 2014 True-up ATRR:	-
15	Amount to be Entered (in thousands) in Column F of the Account 282 Section of Attachment 1 Only When the Formula Rate Population is to Calculate the 2014 True-up ATRR:	-

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 2 - Taxes Other Than Income Worksheet
2017 (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)	$ 47,010	100.0000%	$ 47,010
1a	Other Plant Related Taxes	0	20.2526%	-
2				-
3				-
4				-
5				-
				-
	Total Plant Related	$ 47,010		$ 47,010
	Labor Related		***Wages & Salary Allocator***	
6	Federal FICA & Unemployment & State Unemployment	$ 43,419		
	Total Labor Related	$ 43,419	6.7538%	$ 2,932
	Other Included		***Gross Plant Allocator***	
7	Sales and Use Tax	$ -		
	Total Other Included	$ -	20.2526%	$ -
	Total Included	$ 90,429		$ 49,942
	Currently Excluded			
8	Business and Occupation Tax - West Virginia	$ 20,106		
9	Gross Receipts Tax	0		
10	IFTA Fuel Tax	16		
11	Property Taxes - Other	178,111		
12	Property Taxes - Generator Step-Ups and Interconnects	1,501		
13	Sales and Use Tax - not allocated to Transmission	5,356		
14	Sales and Use Tax - Retail	0		
15	Other	23,374		
16		0		
17		0		
18		0		
19		0		
20		0		
21	Total "Other" Taxes (included on p. 263)	$ 228,464		
22	Total "Taxes Other Than Income Taxes" - acct 408.10 (p. 114.14)	$ 318,893		
23	Difference	$ (90,429)		

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
2017

Directly Assigned Property Taxes	$	226,622
Production Property Tax		93,529
Transmission Property Tax		46,889
GSU/Interconnect Facilities		1,501
Distribution Property tax		82,919
General Property Tax		1,784
Total check		226,622

Allocation of General Property Tax to Transmission

General Property Tax	$	1,784
Wages & Salary Allocator		6.7538%
Trans General		120

Total Transmission Property Taxes

Transmission	$	46,889
General		120
Total Transmission Property Taxes	$	47,010

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 3 - Revenue Credit Workpaper
2017 (000's)

			Transmission Related	Production/Other Related	Total
	Account 454 - Rent from Electric Property				
1	Rent from Electric Property - Transmission Related (Note 3)		8,376		8,376
2	Total Rent Revenues	(Sum Lines 1)	8,376	-	8,376
	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)		1,940		1,940
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)		4,455		4,455
9	Revenues from Directly Assigned Transmission Facility Charges (Note 2)		2,890		2,890
10	Rent or Attachment Fees associated with Transmission Facilities (Note 3)				-
11	Gross Revenue Credits (Accounts 454 and 456)	(Sum Lines 2-10)	17,660	-	17,660
12	Less line 14g		(8,367)	-	(8,367)
13	Total Revenue Credits		9,293	-	9,293
	Revenue Adjustment to Determine Revenue Credit				
14a	Revenues included in lines 1-11 which are subject to 50/50 sharing. (Lines 1 + 8 + 10)		12,831	-	12,831
14b	Costs associated with revenues in line 14a		3,904	-	3,904
14c	Net Revenues (14a - 14b)		8,927	-	8,927
14d	50% Share of Net Revenues (14c / 2)		4,463	-	4,463
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)		4,463	-	4,463
14g	Line 14f less line 14a		(8,367)	-	(8,367)

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
2017 (000's)

	Return and Taxes with Basis Point increase in ROE				
A		Basis Point increase in ROE and Income Taxes		(Line 130 + 140)	666,157
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)	5,083,699
	Long Term Interest				
104		**Long Term Interest**		p117.62c through 67c	453,202
105		Less LTD Interest on Securitization (Note P)		Attachment 8	0
106		Long Term Interest		(Line 104 - 105)	453,202
107	Preferred Dividends		enter positive	p118.29c	0
	Common Stock				
108		Proprietary Capital		p112.16c,d/2	10,346,898
109		Less Preferred Stock	enter negative	(Line 117)	0
110		Less Account 219 - Accumulated Other Comprehensive Income	enter negative	p112.15c,d/2	-45,001
111		Common Stock		(Sum Lines 108 to 110)	10,301,897
	Capitalization				
112		Long Term Debt		p112.24c,d/2	9,180,968
113		Less Loss on Reacquired Debt	enter negative	p111.81c,d/2	-4,846
114		Plus Gain on Reacquired Debt	enter positive	p113.61c,d/2	3,729
115		Less LTD on Securitization Bonds	enter negative	Attachment 8	0
116		Total Long Term Debt		(Sum Lines 112 to 115)	9,179,851
117		Preferred Stock		p112.3c,d/2	0
118		Common Stock		(Line 111)	10,301,897
119		Total Capitalization		(Sum Lines 116 to 118)	19,481,748
120		Debt %	Total Long Term Debt	(Line 116 / 119)	47.1%
121		Preferred %	Preferred Stock	(Line 117 / 119)	0.0%
122		Common %	Common Stock	(Line 118 / 119)	52.9%
123		Debt Cost	Total Long Term Debt	(Line 106 / 116)	0.0494
124		Preferred Cost	Preferred Stock	(Line 107 / 117)	0.0000
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)	0.0233
127		Weighted Cost of Preferred	Preferred Stock	(Line 121 * 124)	0.0000
128		Weighted Cost of Common	Common Stock	(Line 122 * 125)	0.0656
129	Total Return (R)			**(Sum Lines 126 to 128)**	**0.0888**
130	Investment Return = Rate Base * Rate of Return			**(Line 62 * 129)**	**451,604**

Composite Income Taxes

	Income Tax Rates				
131		FIT=Federal Income Tax Rate			0.3500
132		SIT=State Income Tax Rate or Composite			0.0603
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)} =		0.3892
135		T/ (1-T)			0.6372
	Transmission Related Income Tax Adjustments				
136	Amortized Investment Tax Credit (ITC)	(Note I) enter negative	Attachment 1	$	(137)
136A	Other Income Tax Adjustments		Attachment 5	$	1,443
137	T/(1-T)		(Line 135)		63.72%
138	**Transmission Income Taxes - Income Tax Adjustments**		((Line 136 + 136A) * (1 + Line 137))	**$**	**2,138**
139	**Transmission Income Taxes - Equity Return =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =	[Line 135 * 130 * (1-(126 / 129))]		**212,415**
140	**Total Transmission Income Taxes**		**(Line 138 + 139)**		**214,553**

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 5 - Cost Support
2017 - 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	36,519,092	36,834,861	36,903,851	36,982,646	37,055,251	37,152,466	37,258,567	37,488,582	37,580,473	37,640,275	37,884,291	38,078,930	38,455,786	37,371,929	0	
15	Accumulated Depreciation (Total Electric Plant)	(Notes A & Q)	p219.29c	12,675,433	12,759,923	12,846,220	12,934,326	13,023,300	13,112,459	13,201,321	13,289,111	13,378,339	13,470,228	13,562,249	13,653,234	13,742,494	13,203,741	0	
12	Accumulated Intangible Amortization	(Notes A & Q)	p200.21c	102,728	105,100	107,489	109,896	112,321	114,764	117,224	119,703	122,200	124,714	127,246	129,797	132,365	117,350	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	7,728,423	7,824,134	7,842,056	7,842,256	7,852,360	7,898,152	7,934,020	8,080,373	8,119,972	8,123,259	8,126,466	8,273,837	8,365,348	8,000,820	0	
15	Generator Step-Ups		Trans. Input Sht	331,484	331,484	331,484	331,484	331,484	331,484	331,484	331,484	331,484	331,484	331,484	331,484	331,484	331,484	0	
23	Generator Interconnect Facilities		Input Sht	169,491	169,491	169,491	169,491	169,491	169,491	169,491	169,491	169,491	169,491	169,491	169,491	169,491	169,491		
25	General & Intangible		p205.5.g & p207.99.g/G&I Wksht	995,868	999,991	1,004,113	1,008,236	1,012,358	1,016,480	1,020,603	1,024,725	1,028,848	1,032,970	1,037,093	1,041,215	1,045,337	1,020,603	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	1,272,274	1,284,002	1,295,841	1,307,697	1,319,563	1,331,483	1,343,482	1,355,658	1,368,015	1,380,413	1,392,817	1,405,368	1,418,150	1,344,213	0	
33	Transmission Accumulated Depreciation - Generator Step-Ups		GSU Input Sht	77,421	78,220	79,019	79,817	80,616	81,415	82,214	83,013	83,812	84,610	85,409	86,208	87,007	82,214	0	
34	Transmission Accumulated Depreciation - Interconnection Facilities		Input Sht	12,159	12,568	12,976	13,385	13,793	14,202	14,610	15,018	15,427	15,835	16,244	16,652	17,061	14,610		
36	Accumulated General Depreciation	(Notes A & Q)	p219.28.b	334,891	337,069	339,248	341,426	343,605	345,783	347,962	350,140	352,319	354,497	356,676	358,854	361,033	347,962	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														184,954	0	
91	Depreciation-General	(Note A)															26,458	0	
92	Depreciation-Intangible	(Note A)	p336.1d&e/Attachment 5														29,636	0	Respondent is Electric Utility only.
87	Depreciation - Generator Step-Ups																9,586	0	
88	Depreciation - Interconnection Facilities																4,901	0	
96	Common Depreciation - Electric Only	(Note A)	p336.11.b														-	0	
97	Common Amortization - Electric Only	(Note A)	p356 or p336.11d														-	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	-	800	1,707	1,978	1,507	1,030	1,924	2,307	1,788	2,513	4,101	1,214	2,816	23,684	19,619	Excludes PJM admin & ODEC ancillary revenue
64	Generator Step-Ups		Input Sheet		-	-	-	-	-	-	-	-	-	-	-	-	126	0	reimbursements, VA Sales & Use Tax, trans. deferrals,
65	Transmission by Others		p321.96.b	-	(5,328)	(5,328)	(5,328)	(5,328)	(5,328)	(5,328)	(5,328)	(5,328)	(5,328)	(5,328)	(5,328)	(5,328)	(63,930)	0	and charges for generation-related ancillary services.

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														611,620	0	
5	Total A&G Wages Expense	(Note A)	p354.27b/Trans. Wksht														82,202	0	
1	Transmission Wages	(Note A)	p354.21b/Trans. Wksht														35,851	0	
2	Generator Step-Ups		Trans. Wksht														95	0	

Specific identification

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	15,883	15,883	15,593	15,593	15,593	15,593	15,593	15,593	15,593	15,593	15,869	15,869	15,869	15,701	8,764	Specific identification based on plant records. The following plant investments are included:
																Form 1 Amount	Transmission Related	Non-transmission Related	
																15,701	6,937	8,764	Enter Details
																			Chickahominy-Skiffes Creek; Ox-Occoquan-Pohick-Van Dorn; Trans Substation Skiffes Creek; Transmission Easements Pender Oakton, Yorktown; Loudon Sub

EPRI Dues Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1 Amount	EPRI Dues	Details
	Allocated General & Common Expenses					
73	Less EPRI Dues	(Note D)	p352-353/Attachment 5	$3,441	3,441	See Form 1

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 5 - Cost Support
2017 - Projection

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	$ 29,322		29,322	See FERC Form 1 pages 350-351.
	Directly Assigned A&G						
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b/Attachment 5		0		

Safety Related Advertising Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1 Amount	Safety Related	Non-safety Related	Details
	Directly Assigned A&G						
81	General Advertising Exp Account 930.1	(Note F)	Attachment 5	3,649	-	3,649	

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)		5.59%	0.28%	0.17%			6.03%

Education and Out Reach Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1 Amount	Education & Outreach	Other	Details
	Directly Assigned A&G						
78	General Advertising Exp Account 930.1	(Note K)	p323.191b	3,649	-	3,649	- Informing public about transmission operations including service quality.

Excluded Plant Cost Support

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

Instructions:

		Example
1	Remove all investment below 69 kV or generator step up transformers included in transmission plant in service that are not a result of the RTEP Process	
2	If unable to determine the investment below 69kV in a substation with investment of 69 kV and higher as well as below 69 kV, the following formula will be used:	Example
A	Total investment in substation	1,000,000
B	Identifiable investment in Transmission (provide workpapers)	500,000
C	Identifiable investment in Distribution (provide workpapers)	400,000
D	Amount to be excluded (A x (C / (B + C)))	444,444

Transmission Related Account 242 Reserves

Line #s	Descriptions	Notes	Page #'s & Instructions	Beginning Year Balance	End of Year Balance	Average Balance	Allocation	Transmission Related		Details
47	Transmission Related Account 242 Reserves (exclude current year environmental site related reserves)			Enter $	Enter $			Amount		
	Directly Assignable to Transmission			$ 7,700	$ 7,551	$ 7,626	100%	7,626		
	Labor Related, General plant related or Common Plant related			$ 469	$ 749	$ 609	6.754%	41		
	Plant Related			$ 6,073	$ 6,467	$ 6,270	20.25%	1,270		
	Other			$ 131,186	$ 148,983	$ 140,084	0.00%	-		
	Total Transmission Related Reserves			$ -	$ -	$ -		8,937	To line 47	

Prepayments

Line #s	Descriptions	Notes	Page #'s & Instructions	Beginning Year Balance	End of Year Balance	Average Balance Before Exclusion	Fixed Prepayments Exclusion Amount [1]			To Line 48	Description of the Prepayments
48	Prepayments										
	Wages & Salary Allocator								6.754%		
	Pension Liabilities, if any, in Account 242			$ 35	$ 18			$ 26	6.754%	2	
				$ -	$ -			$ -			Instruction: If the Prepayments Account 165 Beginning or End of Year Balance does not agree with the Form 1 Reference, enter below a note explaining the difference.
	Prepayments Account 165		p111.57d&c	$ 33,822	$ 28,051	$ 30,937	$ 3,980	$ 26,957	6.754%	1,821	Projections.
	Prepaid Pensions if not included in Prepayments							$ -	6.754%	-	

[1] The Fixed Prepayments Exclusion Amount may be changed only pursuant to a Section 205 or Section 206 proceeding.

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.			2,742	ODEC/NCEMC Transmission Charges from PJM Invoices

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	19,538.1	

A&G Expenses - Other Post Employment Benefits

Line #s	Descriptions	Notes	Page #'s & Instructions	Amount
	Total A&G Expenses		p323.197b	358,302
	Less OPEB Current Year			19,422
	Plus: Stated OPEB		Fixed (from FERC accepted § 205 Filing)	(13,996)
69	Current Year Total A&G Expenses			363,728

Interest on Long-Term Debt

Line #s	Descriptions	Notes	Page #'s & Instructions	Amount
	Interest on Long-Term Debt		p117.62c through 67c	454,796
	Less Interest on Short-Term Debt Included in Account 430			(1,594)
104	Total Interest on Long-Term Debt			453,202

Income Tax Adjustments

Line #s	Descriptions	Notes	Page #s & Instructions	Transmission Depreciation Expense Amount		Tax Rate		Amount to Line 136A	Beginning Year Balance	End of Year Balance	Average
	Tax Adj. for the AFUDC Equity Component of Transmission Depr. Expense	(Notes B, C)	Inst. 1, 2, below	$ 3,830	X	38.92%	=	$ 1,491			
	Amortization of Excess/Deficient Deferred Taxes -- Transmission Component										
	Amortized Excess Deferred Taxes	(Note C)	Inst. 1, 3, 4, below (Enter Negative)					$ (48)	$ (2,481)	$ (2,433)	$ (2,457)
	Amortized Deficient Deferred Taxes	(Note C)	Inst. 1, 3, 4, below (Enter Positive)								$ -
136A	Total Other Income Tax Adjustments to Line 136A							$ 1,443			
47A	Unamortized Exc/Def Deferral to Line 47A										$ (2,457)

Inst. 1 The Capital Recovery Rate is the depreciation rate excluding salvage and cost of removal applicable to the included assets.

Inst. 2 Transmission Depreciation Expense Amount is (1) the gross cumulative amount based upon tax records of capitalized AFUDC equity embedded in the gross plant attributable to the transmission function multiplied by (2) the Capital Recovery Rate (described in Instruction 1). For 2016, determine tax expense amounts for each of September through December and include only the sum of those four monthly amounts. The amount entered will be supported by work papers. Tax Rate is from Appendix A, Line 134.

Inst. 3 Upon enactment of changes in tax law, deferred taxes are re-measured and adjusted in the Company's books of account, resulting in excess or deficient accumulated deferred taxes. Such excess or deficient deferred taxes attributed to the transmission function (separately referred to as "Exc/Def Deferral") will be based upon tax records and calculated in the calendar year in which the excess or deficient amount was measured and recorded for financial reporting purposes. Each Exc/Def Deferral will be reduced by any offsetting balance of a previous Exc/Def Deferral attributable to the same taxing authority before being multiplied by the Capital Recovery Rate in effect at the inception of the Exc/Def Deferral to determine the annual amortization amount. Amortization in the first and last years will include only the appropriate number of months. For each re-measurement of deferred taxes, the amount entered will be supported by work papers providing the Exc/Def Deferral, the amount amortized during the applicable year, and the unamortized balance at the end of the applicable year. Do not include amounts amortized prior to September 1, 2016.

Inst. 4 The Beginning Balance is the sum of the Exc/Def Deferrals less any associated amortization recognized in prior years.

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.

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

<u>Summary of Formula Rate Process including True-Up Adjustment</u>

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

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.	775,672.73
B	ATRR based on projected costs included for the previous calendar year but excludes the true-up adjustment.	798,513.48
C	Difference (A-B)	(22,841)
D	Future Value Factor (1+i)^24	1.06941
E	True-up Adjustment (C*D)	(24,426)

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

---

[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.

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
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(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	12.3111%
4	B	161	Net Plant Carrying Charge with 100 Basis Point increase in ROE without Depreciation	13.0151%
5	C		Line B less Line A	0.7039%
6	**FCR if a CIAC**			
7	D	155	Net Plant Carrying Charge without Depreciation, Return, or Income Taxes	2.3607%

These Three Columns are Repeated to Provide Line Number References on All Pages

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. Depreciation will be calculated for each project using the applicable Life input in effect during the months of each calendar year the project was in service.**

10			10	Details		**Project A**				**Project A-1**			
11	Schedule 12	(Yes or No)	11	Schedule 12	(Yes or No)	Yes	b0217			Yes	b0217		
12	Life		12	Life		43	Upgrade Mt.Storm - Doubs 500 kV			43	Upgrade Mt.Storm - Doubs 500 kV		
13	FCR W/O incentive	Line 3	13	FCR W/O incentive	Line 3	12.3111%				12.3111%	Replace Capacitors		
14	Incentive Factor (Basis Points /100)		14	Incentive Factor (Basis Points /100)		0				0			
15	FCR W incentive L.13 +(L.14*L.5)		15	FCR W incentive L.13 +(L.14*L.5)		12.3111%				12.3111%			
16	Investment		16	Investment		1,039,321				911,807			
17	Annual Depreciation Exp		17	Annual Depreciation Exp		24,170				21,205			
18	In Service Month (1-12)		18	In Service Month (1-12)		12				7			
19			19		**Invest Yr**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006	20	W / O incentive	2006								
21	W incentive	2006	21	W incentive	2006								
22	W / O incentive	2007	22	W / O incentive	2007	1,039,321	849	1,038,472					
23	W incentive	2007	23	W incentive	2007	1,039,321	849	1,038,472					
24	W / O incentive	2008	24	W / O incentive	2008	1,038,472	20,379	1,018,093					
25	W incentive	2008	25	W incentive	2008	1,038,472	20,379	1,018,093					
26	W / O incentive	2009	26	W / O incentive	2009	1,018,093	20,379	997,714					
27	W incentive	2009	27	W incentive	2009	1,018,093	20,379	997,714					
28	W / O incentive	2010	28	W / O incentive	2010	997,714	20,379	977,335					
29	W incentive	2010	29	W incentive	2010	997,714	20,379	977,335					
30	W / O incentive	2011	30	W / O incentive	2011	977,335	20,379	956,957					
31	W incentive	2011	31	W incentive	2011	977,335	20,379	956,957					
32	W / O incentive	2012	32	W / O incentive	2012	956,957	20,379	936,578					
33	W incentive	2012	33	W incentive	2012	956,957	20,379	936,578					
34	W / O incentive	2013	34	W / O incentive	2013	936,578	23,222	913,355					
35	W incentive	2013	35	W incentive	2013	936,578	23,222	913,355					
36	W / O incentive	2014	36	W / O incentive	2014	913,355	24,170	889,185		911,807	9,719	902,088	
37	W incentive	2014	37	W incentive	2014	913,355	24,170	889,185		911,807	9,719	902,088	
38	W / O incentive	2015	38	W / O incentive	2015	889,185	24,170	865,015		902,088	21,205	880,883	
39	W incentive	2015	39	W incentive	2015	889,185	24,170	865,015		902,088	21,205	880,883	
40	W / O incentive	2016	40	W / O incentive	2016	865,015	24,170	840,844		880,883	21,205	859,678	
41	W incentive	2016	41	W incentive	2016	865,015	24,170	840,844		880,883	21,205	859,678	
42	W / O incentive	2017	42	W / O incentive	2017	840,844	24,170	816,674	126,200	859,678	21,205	838,474	125,736
43	W incentive	2017	43	W incentive	2017	840,844	24,170	816,674	126,200	859,678	21,205	838,474	125,736

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	A	Projected Revenue Requirement without Incentive for Previous Calendar Year*	264,875	-
B	B	Projected Revenue Requirement with Incentive for Previous Calendar Year*	264,875	-
C	C	Actual Revenue Requirement without Incentive for Previous Calendar Year *	135,617	134,479
D	D	Actual Revenue Requirement with Incentive for Previous Calendar Year *	135,617	134,479
E	E	True-Up Adjustment Before Interest without Incentive for Previous Calendar Year (C-A)	(129,258)	134,479
F	F	True-Up Adjustment Before Interest with Incentive for Previous Calendar Year (B-D)	(129,258)	134,479
G	G	Future Value Factor (1+i)^24 months from Attachment 6	1.06941	1.06941
H	H	True-Up Adjustment without Incentive (E*G)	(138,230)	143,813
I	I	True-Up Adjustment with Incentive (F*G)	(138,230)	143,813

* 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	W / O incentive	(12,030)	269,549
W incentive	W incentive	(12,030)	269,549

Virginia Electric and Power Company
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(dollars)

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10			Project B				Project B-1				Project E		
11	Schedule 12	(Yes or No)	Yes	b0222			Yes	b0222			Yes	B0226	
12	Life		43	Install 150 MVAR capacitor			43	Install 150 MVAR capacitor			43	Install 500/230 kV transformer at	
13	FCR W/O incentive	Line 3	12.3111%	at Loudoun			12.3111%	at Loudoun - Replacement of			12.3111%	Clifton and Clifton 500 KV 150 M	
14	Incentive Factor (Basis Points /100)		0				0	Circuit Breaker			0	capacitor	
15	FCR W incentive L.13 +(L.14*L.5)		12.3111%				12.3111%				12.3111%		
16	Investment		1,081,176				591,996				8,085,443		
17	Annual Depreciation Exp		25,144				13,767				188,034		
18	In Service Month (1-12)		9				4				8		
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006	1,081,176	6,183	1,074,993								
21	W incentive	2006	1,081,176	6,183	1,074,993								
22	W / O incentive	2007	1,074,993	21,200	1,053,793						8,085,443	59,452	8,025,991
23	W incentive	2007	1,074,993	21,200	1,053,793						8,085,443	59,452	8,025,991
24	W / O incentive	2008	1,053,793	21,200	1,032,594						8,025,991	158,538	7,867,453
25	W incentive	2008	1,053,793	21,200	1,032,594						8,025,991	158,538	7,867,453
26	W / O incentive	2009	1,032,594	21,200	1,011,394						7,867,453	158,538	7,708,915
27	W incentive	2009	1,032,594	21,200	1,011,394						7,867,453	158,538	7,708,915
28	W / O incentive	2010	1,011,394	21,200	990,195						7,708,915	158,538	7,550,377
29	W incentive	2010	1,011,394	21,200	990,195						7,708,915	158,538	7,550,377
30	W / O incentive	2011	990,195	21,200	968,995						7,550,377	158,538	7,391,839
31	W incentive	2011	990,195	21,200	968,995						7,550,377	158,538	7,391,839
32	W / O incentive	2012	968,995	21,200	947,796						7,391,839	158,538	7,233,301
33	W incentive	2012	968,995	21,200	947,796						7,391,839	158,538	7,233,301
34	W / O incentive	2013	947,796	24,158	923,638		591,996	9,752	582,244		7,233,301	180,660	7,052,641
35	W incentive	2013	947,796	24,158	923,638		591,996	9,752	582,244		7,233,301	180,660	7,052,641
36	W / O incentive	2014	923,638	25,144	898,494		582,244	13,767	568,477		7,052,641	188,034	6,864,607
37	W incentive	2014	923,638	25,144	898,494		582,244	13,767	568,477		7,052,641	188,034	6,864,607
38	W / O incentive	2015	898,494	25,144	873,351		568,477	13,767	554,709		6,864,607	188,034	6,676,574
39	W incentive	2015	898,494	25,144	873,351		568,477	13,767	554,709		6,864,607	188,034	6,676,574
40	W / O incentive	2016	873,351	25,144	848,207		554,709	13,767	540,942		6,676,574	188,034	6,488,540
41	W incentive	2016	873,351	25,144	848,207		554,709	13,767	540,942		6,676,574	188,034	6,488,540
42	W / O incentive	2017	848,207	25,144	823,064	128,020	540,942	13,767	527,175	79,516	6,488,540	188,034	6,300,507
43	W incentive	2017	848,207	25,144	823,064	128,020	540,942	13,767	527,175	79,516	6,488,540	188,034	6,300,507
A						145,575				90,483			
B						145,575				90,483			
C						137,711				85,125			
D						137,711				85,125			
E						(7,864)				(5,359)			
F						(7,864)				(5,359)			
G						1.06941				1.06941			
H						(8,410)				(5,730)			
I						(8,410)				(5,730)			
	W / O incentive					119,610				73,786			
	W incentive					119,610				73,786			

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

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10			
11	Schedule 12	(Yes or No)	
12	Life		
13	FCR W/O incentive	Line 3	VAR
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	975,272
43	W incentive	2017	975,272

A	1,131,756
B	1,131,756
C	1,048,323
D	1,048,323
E	(83,433)
F	(83,433)
G	1.06941
H	(89,224)
I	(89,224)

W / O incentive	886,048
W incentive	886,048

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(dollars)

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

10			Project G-1				Project G-2				Project H-1		
11	Schedule 12	(Yes or No)	Yes	B0403			Yes	B0403			Yes	b0328.1	
12	Life		43	2nd Dooms 500/230 kV transformer			43	2nd Dooms 500/230 kV transformer			43	Build new Meadowbrook-Loudon	
13	FCR W/O incentive	Line 3	12.3111%	addition			12.3111%	addition			12.3111%	(30 of 50 miles)	
14	Incentive Factor (Basis Points /100)		0				0				1.5		
15	FCR W incentive L.13 +(L.14*L.5)		12.3111%				12.3111%	Spare Transformer Addition			13.3670%	line 2101 v11	
16	Investment		7,174,215				2,414,294				21,850,320		
17	Annual Depreciation Exp		166,842				56,146				508,147		
18	In Service Month (1-12)		11				4				6		
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007	7,174,215	17,584	7,156,631								
23	W incentive	2007	7,174,215	17,584	7,156,631								
24	W / O incentive	2008	7,156,631	140,671	7,015,960								
25	W incentive	2008	7,156,631	140,671	7,015,960								
26	W / O incentive	2009	7,015,960	140,671	6,875,289		2,414,294	33,532	2,380,762		21,850,320	232,070	21,618,250
27	W incentive	2009	7,015,960	140,671	6,875,289		2,414,294	33,532	2,380,762		21,850,320	232,070	21,618,250
28	W / O incentive	2010	6,875,289	140,671	6,734,618		2,380,762	47,339	2,333,423		21,618,250	428,438	21,189,812
29	W incentive	2010	6,875,289	140,671	6,734,618		2,380,762	47,339	2,333,423		21,618,250	428,438	21,189,812
30	W / O incentive	2011	6,734,618	140,671	6,593,948		2,333,423	47,339	2,286,084		21,189,812	428,438	20,761,374
31	W incentive	2011	6,734,618	140,671	6,593,948		2,333,423	47,339	2,286,084		21,189,812	428,438	20,761,374
32	W / O incentive	2012	6,593,948	140,671	6,453,277		2,286,084	47,339	2,238,745		20,761,374	428,438	20,332,937
33	W incentive	2012	6,593,948	140,671	6,453,277		2,286,084	47,339	2,238,745		20,761,374	428,438	20,332,937
34	W / O incentive	2013	6,453,277	160,299	6,292,977		2,238,745	53,945	2,184,800		20,332,937	488,220	19,844,717
35	W incentive	2013	6,453,277	160,299	6,292,977		2,238,745	53,945	2,184,800		20,332,937	488,220	19,844,717
36	W / O incentive	2014	6,292,977	166,842	6,126,135		2,184,800	56,146	2,128,654		19,844,717	508,147	19,336,570
37	W incentive	2014	6,292,977	166,842	6,126,135		2,184,800	56,146	2,128,654		19,844,717	508,147	19,336,570
38	W / O incentive	2015	6,126,135	166,842	5,959,293		2,128,654	56,146	2,072,508		19,336,570	508,147	18,828,423
39	W incentive	2015	6,126,135	166,842	5,959,293		2,128,654	56,146	2,072,508		19,336,570	508,147	18,828,423
40	W / O incentive	2016	5,959,293	166,842	5,792,451		2,072,508	56,146	2,016,361		18,828,423	508,147	18,320,276
41	W incentive	2016	5,959,293	166,842	5,792,451		2,072,508	56,146	2,016,361		18,828,423	508,147	18,320,276
42	W / O incentive	2017	5,792,451	166,842	5,625,609	869,689	2,016,361	56,146	1,960,215	300,927	18,320,276	508,147	17,812,129
43	W incentive	2017	5,792,451	166,842	5,625,609	869,689	2,016,361	56,146	1,960,215	300,927	18,320,276	508,147	17,812,129
A						993,760				343,095			
B						993,760				343,095			
C						934,646				323,052			
D						934,646				323,052			
E						(59,114)				(20,043)			
F						(59,114)				(20,043)			
G						1.06941				1.06941			
H						(63,217)				(21,434)			
I						(63,217)				(21,434)			
	W / O incentive					806,472				279,493			
	W incentive					806,472				279,493			

Virginia Electric and Power Company
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10			
11	Schedule 12	(Yes or No)	
12	Life		500kV circuit
13	FCR W/O incentive	Line 3	
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	2,732,302
43	W incentive	2017	2,923,062

A	3,114,900
B	3,333,466
C	2,932,821
D	3,136,539
E	(182,079)
F	(196,927)
G	1.06941
H	(194,717)
I	(210,596)

W / O incentive	2,537,585
W incentive	2,712,466

Virginia Electric and Power Company
ATTACHMENT H-16A
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10			Project H-2				Project H-3				Project H-4		
11	Schedule 12	(Yes or No)	Yes	b0328.1			Yes	b0328.1			Yes	b0328.1	
12	Life		43	Build new Meadowbrook-Loudon 500kV circuit			43	Build new Meadowbrook-Loudon 500kV circuit			43	Build new Meadowbrook-Loudon	
13	FCR W/O incentive	Line 3	12.3111%	(30 of 50 miles)			12.3111%	(30 of 50 miles)			12.3111%	(30 of 50 miles)	
14	Incentive Factor (Basis Points /100)		1.5				1.5				1.5		
15	FCR W incentive L.13 +(L.14*L.5)		13.3670%	Line 2030 & 559 v12 & v13			13.3670%	Line 580 - Phase 1			13.3670%	Line 124	
16	Investment		45,089,209				13,581,000				11,224,282		
17	Annual Depreciation Exp		1,048,586				315,837				261,030		
18	In Service Month (1-12)		12				7				4		
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009	45,089,209	36,838	45,052,371								
27	W incentive	2009	45,089,209	36,838	45,052,371								
28	W / O incentive	2010	45,052,371	884,102	44,168,269		13,581,000	122,051	13,458,949		11,224,282	155,893	11,068,389
29	W incentive	2010	45,052,371	884,102	44,168,269		13,581,000	122,051	13,458,949		11,224,282	155,893	11,068,389
30	W / O incentive	2011	44,168,269	884,102	43,284,167		13,458,949	266,294	13,192,654		11,068,389	220,084	10,848,305
31	W incentive	2011	44,168,269	884,102	43,284,167		13,458,949	266,294	13,192,654		11,068,389	220,084	10,848,305
32	W / O incentive	2012	43,284,167	884,102	42,400,065		13,192,654	266,294	12,926,360		10,848,305	220,084	10,628,221
33	W incentive	2012	43,284,167	884,102	42,400,065		13,192,654	266,294	12,926,360		10,848,305	220,084	10,628,221
34	W / O incentive	2013	42,400,065	1,007,465	41,392,600		12,926,360	303,451	12,622,909		10,628,221	250,793	10,377,428
35	W incentive	2013	42,400,065	1,007,465	41,392,600		12,926,360	303,451	12,622,909		10,628,221	250,793	10,377,428
36	W / O incentive	2014	41,392,600	1,048,586	40,344,014		12,622,909	315,837	12,307,072		10,377,428	261,030	10,116,398
37	W incentive	2014	41,392,600	1,048,586	40,344,014		12,622,909	315,837	12,307,072		10,377,428	261,030	10,116,398
38	W / O incentive	2015	40,344,014	1,048,586	39,295,427		12,307,072	315,837	11,991,234		10,116,398	261,030	9,855,368
39	W incentive	2015	40,344,014	1,048,586	39,295,427		12,307,072	315,837	11,991,234		10,116,398	261,030	9,855,368
40	W / O incentive	2016	39,295,427	1,048,586	38,246,841		11,991,234	315,837	11,675,397		9,855,368	261,030	9,594,338
41	W incentive	2016	39,295,427	1,048,586	38,246,841		11,991,234	315,837	11,675,397		9,855,368	261,030	9,594,338
42	W / O incentive	2017	38,246,841	1,048,586	37,198,255	5,692,662	11,675,397	315,837	11,359,560	1,733,770	9,594,338	261,030	9,333,309
43	W incentive	2017	38,246,841	1,048,586	37,198,255	6,090,970	11,675,397	315,837	11,359,560	1,855,382	9,594,338	261,030	9,333,309
A						6,488,135				1,975,465			
B						6,944,220				2,114,618			
C						6,108,188				1,859,541			
D						6,533,289				1,989,242			
E						(379,948)				(115,923)			
F						(410,931)				(125,377)			
G						1.06941				1.06941			
H						(406,319)				(123,970)			
I						(439,453)				(134,079)			
	W / O incentive					5,286,343				1,609,800			
	W incentive					5,651,518				1,721,303			

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

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References on All Pages

10			
11	Schedule 12	(Yes or No)	
12	Life		500kV circuit
13	FCR W/O incentive	Line 3	
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	1,426,134
43	W incentive	2017	1,526,062

A	1,625,145
B	1,739,521
C	1,529,863
D	1,636,469
E	(95,282)
F	(103,052)
G	1.06941
H	(101,896)
I	(110,205)

W / O incentive	1,324,239
W incentive	1,415,857

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

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10				Project H-5				Project H-6				Project H-7	
11	Schedule 12	(Yes or No)	Yes	b0328.1			Yes	b0328.1			Yes	b0328.1	
12	Life		43	Build new Meadowbrook-Loudon 500kV circuit			43	Build new Meadowbrook-Loudon 500kV circuit			43	Build new Meadowbrook-Loudon	
13	FCR W/O incentive	Line 3	12.3111%	(30 of 50 miles)			12.3111%	(30 of 50 miles)			12.3111%	(30 of 50 miles)	
14	Incentive Factor (Basis Points /100)		1.5				1.5				1.5		
15	FCR W incentive L.13 +(L.14*L.5)		13.3670%	Line 114			13.3670%	Clevenger DP/580			13.3670%	Line 580 - Phase 2	
16	Investment		14,655,559				16,900,800				11,362,770		
17	Annual Depreciation Exp		340,827				393,042				264,250		
18	In Service Month (1-12)		6				9				12		
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009											
27	W incentive	2009											
28	W / O incentive	2010	14,655,559	155,655	14,499,904		16,900,800	96,655	16,804,145		11,362,770	9,283	11,353,487
29	W incentive	2010	14,655,559	155,655	14,499,904		16,900,800	96,655	16,804,145		11,362,770	9,283	11,353,487
30	W / O incentive	2011	14,499,904	287,364	14,212,540		16,804,145	331,388	16,472,757		11,353,487	222,799	11,130,687
31	W incentive	2011	14,499,904	287,364	14,212,540		16,804,145	331,388	16,472,757		11,353,487	222,799	11,130,687
32	W / O incentive	2012	14,212,540	287,364	13,925,176		16,472,757	331,388	16,141,369		11,130,687	222,799	10,907,888
33	W incentive	2012	14,212,540	287,364	13,925,176		16,472,757	331,388	16,141,369		11,130,687	222,799	10,907,888
34	W / O incentive	2013	13,925,176	327,461	13,597,715		16,141,369	377,628	15,763,740		10,907,888	253,888	10,654,000
35	W incentive	2013	13,925,176	327,461	13,597,715		16,141,369	377,628	15,763,740		10,907,888	253,888	10,654,000
36	W / O incentive	2014	13,597,715	340,827	13,256,888		15,763,740	393,042	15,370,698		10,654,000	264,250	10,389,750
37	W incentive	2014	13,597,715	340,827	13,256,888		15,763,740	393,042	15,370,698		10,654,000	264,250	10,389,750
38	W / O incentive	2015	13,256,888	340,827	12,916,061		15,370,698	393,042	14,977,656		10,389,750	264,250	10,125,499
39	W incentive	2015	13,256,888	340,827	12,916,061		15,370,698	393,042	14,977,656		10,389,750	264,250	10,125,499
40	W / O incentive	2016	12,916,061	340,827	12,575,234		14,977,656	393,042	14,584,615		10,125,499	264,250	9,861,249
41	W incentive	2016	12,916,061	340,827	12,575,234		14,977,656	393,042	14,584,615		10,125,499	264,250	9,861,249
42	W / O incentive	2017	12,575,234	340,827	12,234,407	1,868,002	14,584,615	393,042	14,191,573	2,164,380	9,861,249	264,250	9,596,998
43	W incentive	2017	12,575,234	340,827	12,234,407	1,998,983	14,584,615	393,042	14,191,573	2,316,303	9,861,249	264,250	9,596,998

A						2,128,497				2,465,901			
B						2,278,386				2,639,702			
C						2,003,630				2,321,114			
D						2,143,336				2,483,108			
E						(124,867)				(144,787)			
F						(135,049)				(156,594)			
G						1.06941				1.06941			
H						(133,534)				(154,837)			
I						(144,423)				(167,463)			
	W / O incentive					1,734,468				2,009,543			
	W incentive					1,854,560				2,148,839			

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

These Three Columns are Repeated to Provide Line Number References on All Pages			
10			
11	Schedule 12	(Yes or No)	
12	Life		500kV circuit
13	FCR W/O incentive	Line 3	
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	1,462,016
43	W incentive	2017	1,564,745
A			1,665,487
B			1,782,975
C			1,567,612
D			1,677,119
E			(97,875)
F			(105,856)
G			1.06941
H			(104,669)
I			(113,204)
	W / O incentive		1,357,348
	W incentive		1,451,542

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

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are Repeated to Provide
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10				Project H-8				Project H-9				Project H-10	
11	Schedule 12	(Yes or No)	Yes	b0328.1			Yes	b0328.3			Yes	b0328.4	
12	Life		43	Build new Meadowbrook-Loudon 500kV circuit			43	Upgrade Mt Storm 500 kV Substation			43	Upgrade Loudoun 500 kV Substa	
13	FCR W/O incentive	Line 3	12.3111%	(30 of 50 miles)			12.3111%				12.3111%		
14	Incentive Factor (Basis Points /100)		1.5				1.5				1.5		
15	FCR W incentive L.13 +(L.14*L.5)		13.3670%	Line 535			13.3670%				13.3670%		
16	Investment		95,296,209				13,726,825				3,123,926		
17	Annual Depreciation Exp		2,216,191				319,228				72,649		
18	In Service Month (1-12)		4				5				5		
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009											
27	W incentive	2009											
28	W / O incentive	2010											
29	W incentive	2010											
30	W / O incentive	2011	95,296,209	1,323,558	93,972,651		13,726,825	168,221	13,558,604		3,123,926	38,283	3,085,643
31	W incentive	2011	95,296,209	1,323,558	93,972,651		13,726,825	168,221	13,558,604		3,123,926	38,283	3,085,643
32	W / O incentive	2012	93,972,651	1,868,553	92,104,097		13,558,604	269,153	13,289,451		3,085,643	61,253	3,024,389
33	W incentive	2012	93,972,651	1,868,553	92,104,097		13,558,604	269,153	13,289,451		3,085,643	61,253	3,024,389
34	W / O incentive	2013	92,104,097	2,129,281	89,974,816		13,289,451	306,710	12,982,741		3,024,389	69,800	2,954,589
35	W incentive	2013	92,104,097	2,129,281	89,974,816		13,289,451	306,710	12,982,741		3,024,389	69,800	2,954,589
36	W / O incentive	2014	89,974,816	2,216,191	87,758,625		12,982,741	319,228	12,663,512		2,954,589	72,649	2,881,939
37	W incentive	2014	89,974,816	2,216,191	87,758,625		12,982,741	319,228	12,663,512		2,954,589	72,649	2,881,939
38	W / O incentive	2015	87,758,625	2,216,191	85,542,434		12,663,512	319,228	12,344,284		2,881,939	72,649	2,809,290
39	W incentive	2015	87,758,625	2,216,191	85,542,434		12,663,512	319,228	12,344,284		2,881,939	72,649	2,809,290
40	W / O incentive	2016	85,542,434	2,216,191	83,326,243		12,344,284	319,228	12,025,055		2,809,290	72,649	2,736,640
41	W incentive	2016	85,542,434	2,216,191	83,326,243		12,344,284	319,228	12,025,055		2,809,290	72,649	2,736,640
42	W / O incentive	2017	83,326,243	2,216,191	81,110,052	12,338,182	12,025,055	319,228	11,705,827	1,780,000	2,736,640	72,649	2,663,991
43	W incentive	2017	83,326,243	2,216,191	81,110,052	13,206,315	12,025,055	319,228	11,705,827	1,905,286	2,736,640	72,649	2,663,991
A						13,530,523				2,027,316			
B						14,486,093				2,170,532			
C						12,825,507				1,908,008			
D						13,722,530				2,041,495			
E						(705,016)				(119,308)			
F						(763,563)				(129,037)			
G						1.06941				1.06941			
H						(753,950)				(127,589)			
I						(816,561)				(137,994)			
	W / O incentive					11,584,232				1,652,410			
	W incentive					12,389,754				1,767,292			

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

These Three Columns
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Line Number
References on All Pages

10				
11	Schedule 12	(Yes or No)		
12	Life			tion
13	FCR W/O incentive	Line 3		
14	Incentive Factor (Basis Points /100)			
15	FCR W incentive L.13 +(L.14*L.5)			
16	Investment			
17	Annual Depreciation Exp			
18	In Service Month (1-12)			
19				**Rev Req**
20	W / O incentive		2006	
21	W incentive		2006	
22	W / O incentive		2007	
23	W incentive		2007	
24	W / O incentive		2008	
25	W incentive		2008	
26	W / O incentive		2009	
27	W incentive		2009	
28	W / O incentive		2010	
29	W incentive		2010	
30	W / O incentive		2011	
31	W incentive		2011	
32	W / O incentive		2012	
33	W incentive		2012	
34	W / O incentive		2013	
35	W incentive		2013	
36	W / O incentive		2014	
37	W incentive		2014	
38	W / O incentive		2015	
39	W incentive		2015	
40	W / O incentive		2016	
41	W incentive		2016	
42	W / O incentive		2017	405,089
43	W incentive		2017	433,601

A	461,373
B	493,966
C	434,221
D	464,600
E	(27,152)
F	(29,366)
G	1.06941
H	(29,037)
I	(31,404)

W / O incentive	376,053
W incentive	402,197

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

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10			**Project I-1**				**Project I-2A**				**Project I-2B**		
11	Schedule 12	(Yes or No)	Yes	b0329			Yes	b0329			Yes	b0329	
12	Life		43	Carson-Suffolk 500 kV line +			43	Carson-Suffolk 500 kV line +			43	Carson-Suffolk 500 kV line +	
13	FCR W/O incentive	Line 3	12.3111%	Suffolk 500/230 # 2 transformer +			12.3111%	Suffolk 500/230 # 2 transformer +			12.3111%	Suffolk 500/230 # 2 transformer	
14	Incentive Factor (Basis Points /100)		1.5	Suffolk - Thrasher 230kV line			1.5	Suffolk - Thrasher 230kV line			1.5	Suffolk - Thrasher 230kV line	
15	FCR W incentive L.13 +(L.14*L.5)		13.3670%				13.3670%				13.3670%		
16	Investment		2,434,850	Cost associated with below 500 kV elements.			38,926,257	Cost associated with below 500 kV elements.			163,412,321	Cost associated with Regional F	
17	Annual Depreciation Exp		56,624				905,262				3,800,287	Necessary Lower Voltage Facilit	
18	In Service Month (1-12)		12				6				5		
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009	2,434,850	1,989	2,432,861								
27	W incentive	2009	2,434,850	1,989	2,432,861								
28	W / O incentive	2010	2,432,861	47,742	2,385,119								
29	W incentive	2010	2,432,861	47,742	2,385,119								
30	W / O incentive	2011	2,385,119	47,742	2,337,376		38,926,257	413,432	38,512,825		163,412,321	2,002,602	161,409,719
31	W incentive	2011	2,385,119	47,742	2,337,376		38,926,257	413,432	38,512,825		163,412,321	2,002,602	161,409,719
32	W / O incentive	2012	2,337,376	47,742	2,289,634		38,512,825	763,260	37,749,565		161,409,719	3,204,163	158,205,556
33	W incentive	2012	2,337,376	47,742	2,289,634		38,512,825	763,260	37,749,565		161,409,719	3,204,163	158,205,556
34	W / O incentive	2013	2,289,634	54,404	2,235,230		37,749,565	869,761	36,879,803		158,205,556	3,651,256	154,554,300
35	W incentive	2013	2,289,634	54,404	2,235,230		37,749,565	869,761	36,879,803		158,205,556	3,651,256	154,554,300
36	W / O incentive	2014	2,235,230	56,624	2,178,606		36,879,803	905,262	35,974,541		154,554,300	3,800,287	150,754,014
37	W incentive	2014	2,235,230	56,624	2,178,606		36,879,803	905,262	35,974,541		154,554,300	3,800,287	150,754,014
38	W / O incentive	2015	2,178,606	56,624	2,121,982		35,974,541	905,262	35,069,280		150,754,014	3,800,287	146,953,727
39	W incentive	2015	2,178,606	56,624	2,121,982		35,974,541	905,262	35,069,280		150,754,014	3,800,287	146,953,727
40	W / O incentive	2016	2,121,982	56,624	2,065,357		35,069,280	905,262	34,164,018		146,953,727	3,800,287	143,153,441
41	W incentive	2016	2,121,982	56,624	2,065,357		35,069,280	905,262	34,164,018		146,953,727	3,800,287	143,153,441
42	W / O incentive	2017	2,065,357	56,624	2,008,733	307,408	34,164,018	905,262	33,258,756	5,055,518	143,153,441	3,800,287	139,353,154
43	W incentive	2017	2,065,357	56,624	2,008,733	328,917	34,164,018	905,262	33,258,756	5,411,473	143,153,441	3,800,287	139,353,154

A	350,364	5,766,062
B	374,993	6,173,510
C	329,847	5,418,772
D	352,802	5,797,991
E	(20,517)	(347,290)
F	(22,191)	(375,519)
G	1.06941	1.06941
H	(21,942)	(371,395)
I	(23,731)	(401,583)

W / O incentive	285,466	4,684,123
W incentive	305,186	5,009,890

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

These Three Columns
are Repeated to Provide
Line Number
References on All Pages

10			
11	Schedule 12	(Yes or No)	
12	Life		
13	FCR W/O incentive	Line 3	-
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		acilities and
17	Annual Depreciation Exp		es.
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	21,190,177
43	W incentive	2017	22,681,657

A	24,133,052
B	25,837,891
C	22,714,062
D	24,303,173
E	(1,418,990)
F	(1,534,717)
G	1.06941
H	(1,517,481)
I	(1,641,240)

W / O incentive	19,672,696
W incentive	21,040,416

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

These Three Columns are Repeated to Provide Line Number References on All Pages														
10			**Project J**				**Project K-1**				**Project K-2**		
11	Schedule 12	(Yes or No)	Yes	b0512			No				No		
12	Life		43	MAPP Project -- Dominion Portion			43	Loudoun Bank # 1 transformer			43	Loudoun Bank # 2 transformer	
13	FCR W/O incentive	Line 3	12.3111%				12.3111%	replacement			12.3111%	replacement	
14	Incentive Factor (Basis Points /100)		1.5				1.5				1.5		
15	FCR W incentive L.13 +(L.14*L.5)		13.3670%				13.3670%				13.3670%		
16	Investment						13,672,006				14,621,030		
17	Annual Depreciation Exp		-				317,954				340,024		
18	In Service Month (1-12)						12				5		
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009					13,672,006	11,170	13,660,836				
27	W incentive	2009					13,672,006	11,170	13,660,836				
28	W / O incentive	2010					13,660,836	268,079	13,392,758		14,621,030	179,179	14,441,851
29	W incentive	2010					13,660,836	268,079	13,392,758		14,621,030	179,179	14,441,851
30	W / O incentive	2011					13,392,758	268,079	13,124,679		14,441,851	286,687	14,155,164
31	W incentive	2011					13,392,758	268,079	13,124,679		14,441,851	286,687	14,155,164
32	W / O incentive	2012	-	-	-		13,124,679	268,079	12,856,600		14,155,164	286,687	13,868,477
33	W incentive	2012	-	-	-		13,124,679	268,079	12,856,600		14,155,164	286,687	13,868,477
34	W / O incentive	2013	-	-	-		12,856,600	305,485	12,551,116		13,868,477	326,690	13,541,787
35	W incentive	2013	-	-	-		12,856,600	305,485	12,551,116		13,868,477	326,690	13,541,787
36	W / O incentive	2014	-	-	-		12,551,116	317,954	12,233,162		13,541,787	340,024	13,201,763
37	W incentive	2014	-	-	-		12,551,116	317,954	12,233,162		13,541,787	340,024	13,201,763
38	W / O incentive	2015	-	-	-		12,233,162	317,954	11,915,208		13,201,763	340,024	12,861,739
39	W incentive	2015	-	-	-		12,233,162	317,954	11,915,208		13,201,763	340,024	12,861,739
40	W / O incentive	2016	-	-	-		11,915,208	317,954	11,597,255		12,861,739	340,024	12,521,715
41	W incentive	2016	-	-	-		11,915,208	317,954	11,597,255		12,861,739	340,024	12,521,715
42	W / O incentive	2017	-	-	-	-	11,597,255	317,954	11,279,301	1,726,136	12,521,715	340,024	12,181,691
43	W incentive	2017	-	-	-	-	11,597,255	317,954	11,279,301	1,846,912	12,521,715	340,024	12,181,691
A						-				1,967,340			
B						-				2,105,635			
C						-				1,852,132			
D						-				1,981,032			
E						-				(115,208)			
F						-				(124,603)			
G						1.06941				1.06941			
H						-				(123,205)			
I						-				(133,251)			
	W / O incentive					-				1,602,931			
	W incentive					-				1,713,660			

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

These Three Columns are Repeated to Provide Line Number References on All Pages			
10			
11	Schedule 12	(Yes or No)	
12	Life		
13	FCR W/O incentive	Line 3	
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	1,860,659
43	W incentive	2017	1,991,080

A	2,121,237
B	2,270,570
C	1,995,874
D	2,134,996
E	(125,363)
F	(135,575)
G	1.06941
H	(134,064)
I	(144,985)

W / O incentive	1,726,595
W incentive	1,846,095

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

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10			Project L-1a				Project L-1b				Project L-2		
11	Schedule 12	(Yes or No)	No				No				No		
12	Life		43	Ox Bank # 1 transformer replacement			43	Ox Bank # 1 transformer spare			43	Ox Bank # 2 transformer replacement	
13	FCR W/O incentive	Line 3	12.3111%				12.3111%				12.3111%		
14	Incentive Factor (Basis Points /100)		1.5				1.5				1.5		
15	FCR W incentive L.13 +(L.14*L.5)		13.3670%				13.3670%				13.3670%		
16	Investment		10,714,404				2,857,132				11,501,538		
17	Annual Depreciation Exp		249,172				66,445				267,478		
18	In Service Month (1-12)		7				12				3		
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009	10,714,404	96,290	10,618,114		2,857,132	2,334	2,854,798		11,501,538	178,537	11,323,001
27	W incentive	2009	10,714,404	96,290	10,618,114		2,857,132	2,334	2,854,798		11,501,538	178,537	11,323,001
28	W / O incentive	2010	10,618,114	210,086	10,408,028		2,854,798	56,022	2,798,776		11,323,001	225,520	11,097,481
29	W incentive	2010	10,618,114	210,086	10,408,028		2,854,798	56,022	2,798,776		11,323,001	225,520	11,097,481
30	W / O incentive	2011	10,408,028	210,086	10,197,942		2,798,776	56,022	2,742,753		11,097,481	225,520	10,871,960
31	W incentive	2011	10,408,028	210,086	10,197,942		2,798,776	56,022	2,742,753		11,097,481	225,520	10,871,960
32	W / O incentive	2012	10,197,942	210,086	9,987,855		2,742,753	56,022	2,686,731		10,871,960	225,520	10,646,440
33	W incentive	2012	10,197,942	210,086	9,987,855		2,742,753	56,022	2,686,731		10,871,960	225,520	10,646,440
34	W / O incentive	2013	9,987,855	239,401	9,748,455		2,686,731	63,839	2,622,892		10,646,440	256,988	10,389,452
35	W incentive	2013	9,987,855	239,401	9,748,455		2,686,731	63,839	2,622,892		10,646,440	256,988	10,389,452
36	W / O incentive	2014	9,748,455	249,172	9,499,282		2,622,892	66,445	2,556,447		10,389,452	267,478	10,121,974
37	W incentive	2014	9,748,455	249,172	9,499,282		2,622,892	66,445	2,556,447		10,389,452	267,478	10,121,974
38	W / O incentive	2015	9,499,282	249,172	9,250,110		2,556,447	66,445	2,490,002		10,121,974	267,478	9,854,496
39	W incentive	2015	9,499,282	249,172	9,250,110		2,556,447	66,445	2,490,002		10,121,974	267,478	9,854,496
40	W / O incentive	2016	9,250,110	249,172	9,000,938		2,490,002	66,445	2,423,557		9,854,496	267,478	9,587,019
41	W incentive	2016	9,250,110	249,172	9,000,938		2,490,002	66,445	2,423,557		9,854,496	267,478	9,587,019
42	W / O incentive	2017	9,000,938	249,172	8,751,766	1,341,952	2,423,557	66,445	2,357,112	360,722	9,587,019	267,478	9,319,541
43	W incentive	2017	9,000,938	249,172	8,751,766	1,435,677	2,423,557	66,445	2,357,112	385,962	9,587,019	267,478	9,319,541

A		1,529,797	442,074
B		1,637,172	473,149
C		1,440,346	387,053
D		1,540,427	413,990
E		(89,450)	(55,021)
F		(96,745)	(59,160)
G		1.06941	1.06941
H		(95,659)	(58,840)
I		(103,460)	(63,266)
	W / O incentive	1,246,293	301,882
	W incentive	1,332,217	322,696

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

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Line Number
References on All Pages

10			
11	Schedule 12 (Yes or No)		
12	Life		
13	FCR W/O incentive Line 3		
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	1,431,284
43	W incentive	2017	1,531,100

A	1,631,914
B	1,746,317
C	1,536,610
D	1,643,241
E	(95,305)
F	(103,076)
G	1.06941
H	(101,920)
I	(110,231)

W / O incentive	1,329,364
W incentive	1,420,870

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

These Three Columns are Repeated to Provide Line Number References on All Pages													
10				Project M				Project N				Project O	
11	Schedule 12	(Yes or No)	No				No				No		
12	Life		43	Yadkin Bank # 2 transformer			43	Carson Bank # 1 transformer			43	Lexington Bank # 1 transformer	
13	FCR W/O incentive	Line 3	12.3111%	replacement			12.3111%	replacement			12.3111%	replacement	
14	Incentive Factor (Basis Points /100)		1.5				1.5				1.5		
15	FCR W incentive L.13 +(L.14*L.5)		13.3670%				13.3670%				13.3670%		
16	Investment		16,589,691				19,292,307				10,377,062		
17	Annual Depreciation Exp		385,807				448,658				241,327		
18	In Service Month (1-12)		6				5				12		
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009											
27	W incentive	2009											
28	W / O incentive	2010	16,589,691	176,198	16,413,493		19,292,307	236,425	19,055,882				
29	W incentive	2010	16,589,691	176,198	16,413,493		19,292,307	236,425	19,055,882				
30	W / O incentive	2011	16,413,493	325,288	16,088,205		19,055,882	378,281	18,677,601		10,377,062	8,478	10,368,584
31	W incentive	2011	16,413,493	325,288	16,088,205		19,055,882	378,281	18,677,601		10,377,062	8,478	10,368,584
32	W / O incentive	2012	16,088,205	325,288	15,762,917		18,677,601	378,281	18,299,321		10,368,584	203,472	10,165,112
33	W incentive	2012	16,088,205	325,288	15,762,917		18,677,601	378,281	18,299,321		10,368,584	203,472	10,165,112
34	W / O incentive	2013	15,762,917	370,677	15,392,240		18,299,321	431,064	17,868,257		10,165,112	231,863	9,933,249
35	W incentive	2013	15,762,917	370,677	15,392,240		18,299,321	431,064	17,868,257		10,165,112	231,863	9,933,249
36	W / O incentive	2014	15,392,240	385,807	15,006,433		17,868,257	448,658	17,419,598		9,933,249	241,327	9,691,922
37	W incentive	2014	15,392,240	385,807	15,006,433		17,868,257	448,658	17,419,598		9,933,249	241,327	9,691,922
38	W / O incentive	2015	15,006,433	385,807	14,620,627		17,419,598	448,658	16,970,940		9,691,922	241,327	9,450,595
39	W incentive	2015	15,006,433	385,807	14,620,627		17,419,598	448,658	16,970,940		9,691,922	241,327	9,450,595
40	W / O incentive	2016	14,620,627	385,807	14,234,820		16,970,940	448,658	16,522,282		9,450,595	241,327	9,209,268
41	W incentive	2016	14,620,627	385,807	14,234,820		16,970,940	448,658	16,522,282		9,450,595	241,327	9,209,268
42	W / O incentive	2017	14,234,820	385,807	13,849,013	2,114,527	16,522,282	448,658	16,073,624	2,455,122	9,209,268	241,327	8,967,941
43	W incentive	2017	14,234,820	385,807	13,849,013	2,262,794	16,522,282	448,658	16,073,624	2,627,210	9,209,268	241,327	8,967,941
A						2,405,011				2,738,860			
B						2,574,372				2,931,674			
C						2,268,054				2,633,536			
D						2,426,198				2,817,106			
E						(136,957)				(105,324)			
F						(148,174)				(114,567)			
G						1.06941				1.06941			
H						(146,463)				(112,634)			
I						(158,459)				(122,519)			
	W / O incentive					1,968,063				2,342,488			
	W incentive					2,104,335				2,504,691			

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

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10			
11	Schedule 12 (Yes or No)		
12	Life		
13	FCR W/O incentive Line 3		
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	1,360,238
43	W incentive	2017	1,456,203
A			1,562,869
B			1,673,491
C			1,457,477
D			1,559,656
E			(105,392)
F			(113,835)
G			1.06941
H			(112,707)
I			(121,736)
	W / O incentive		1,247,531
	W incentive		1,334,468

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

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10			**Project P**				**Project Q**				**Project R-1**		
11	Schedule 12	(Yes or No)	No				No				No	s0124	
12	Life		43	Dooms Bank # 7 transformer			43	Valley Bank # 1 transformer			43	Garrisonville 230 kV UG line	
13	FCR W/O incentive	Line 3	12.3111%	replacement			12.3111%	replacement			12.3111%	Phase 1	
14	Incentive Factor (Basis Points /100)		1.5				1.5				1.25		
15	FCR W incentive L.13 +(L.14*L.5)		13.3670%				13.3670%				13.1910%		
16	Investment		18,897,652				12,056,414				91,286,696		
17	Annual Depreciation Exp		439,480				280,382				2,122,946		
18	In Service Month (1-12)		8				12				6		
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009											
27	W incentive	2009											
28	W / O incentive	2010					12,056,414	9,850	12,046,564		91,286,696	969,548	90,317,148
29	W incentive	2010					12,056,414	9,850	12,046,564		91,286,696	969,548	90,317,148
30	W / O incentive	2011	18,897,652	138,953	18,758,699		12,046,564	236,400	11,810,164		90,317,148	1,789,935	88,527,213
31	W incentive	2011	18,897,652	138,953	18,758,699		12,046,564	236,400	11,810,164		90,317,148	1,789,935	88,527,213
32	W / O incentive	2012	18,758,699	370,542	18,388,156		11,810,164	236,400	11,573,763		88,527,213	1,789,935	86,737,277
33	W incentive	2012	18,758,699	370,542	18,388,156		11,810,164	236,400	11,573,763		88,527,213	1,789,935	86,737,277
34	W / O incentive	2013	18,388,156	422,246	17,965,911		11,573,763	269,386	11,304,377		86,737,277	2,039,694	84,697,584
35	W incentive	2013	18,388,156	422,246	17,965,911		11,573,763	269,386	11,304,377		86,737,277	2,039,694	84,697,584
36	W / O incentive	2014	17,965,911	439,480	17,526,430		11,304,377	280,382	11,023,995		84,697,584	2,122,946	82,574,637
37	W incentive	2014	17,965,911	439,480	17,526,430		11,304,377	280,382	11,023,995		84,697,584	2,122,946	82,574,637
38	W / O incentive	2015	17,526,430	439,480	17,086,950		11,023,995	280,382	10,743,614		82,574,637	2,122,946	80,451,691
39	W incentive	2015	17,526,430	439,480	17,086,950		11,023,995	280,382	10,743,614		82,574,637	2,122,946	80,451,691
40	W / O incentive	2016	17,086,950	439,480	16,647,470		10,743,614	280,382	10,463,232		80,451,691	2,122,946	78,328,744
41	W incentive	2016	17,086,950	439,480	16,647,470		10,743,614	280,382	10,463,232		80,451,691	2,122,946	78,328,744
42	W / O incentive	2017	16,647,470	439,480	16,207,990	2,461,921	10,463,232	280,382	10,182,850	1,551,266	78,328,744	2,122,946	76,205,798
43	W incentive	2017	16,647,470	439,480	16,207,990	2,635,380	10,463,232	280,382	10,182,850	1,660,266	78,328,744	2,122,946	76,205,798
A						2,803,650				1,767,157			
B						3,001,876				1,891,817			
C						2,638,515				1,663,307			
D						2,823,275				1,779,499			
E						(165,135)				(103,850)			
F						(178,601)				(112,318)			
G						1.06941				1.06941			
H						(176,597)				(111,058)			
I						(190,998)				(120,114)			
	W / O incentive					2,285,324				1,440,208			
	W incentive					2,444,382				1,540,151			

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

These Three Columns are Repeated to Provide Line Number References on All Pages

10			
11	Schedule 12	(Yes or No)	
12	Life		
13	FCR W/O incentive	Line 3	
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	11,635,428
43	W incentive	2017	12,315,309

A	13,257,947
B	14,035,969
C	12,480,230
D	13,205,401
E	(777,718)
F	(830,568)
G	1.06941
H	(831,698)
I	(888,217)

W / O incentive	10,803,730
W incentive	11,427,093

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

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References on All Pages

10			Project R-2				Project R-3				Project S-1		
11	Schedule 12	(Yes or No)	No	s0124			No	s0124			No	s0133	
12	Life		43	Garrisonville 230 kV UG line			43	Garrisonville 230 kV UG line			43	Pleasant View Hamilton 230kV	
13	FCR W/O incentive	Line 3	12.3111%	Phase 2			12.3111%	Phase 3			12.3111%	transmission line	
14	Incentive Factor (Basis Points /100)		1.25				1.25				1.25		
15	FCR W incentive L.13 +(L.14*L.5)		13.1910%				13.1910%				13.1910%		
16	Investment		32,204,664				13,426,813				84,118,070		
17	Annual Depreciation Exp		748,946				312,251				1,956,234		
18	In Service Month (1-12)		6				2				10		
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009											
27	W incentive	2009											
28	W / O incentive	2010									84,118,070	343,620	83,774,450
29	W incentive	2010									84,118,070	343,620	83,774,450
30	W / O incentive	2011	32,204,664	342,043	31,862,621						83,774,450	1,649,374	82,125,077
31	W incentive	2011	32,204,664	342,043	31,862,621						83,774,450	1,649,374	82,125,077
32	W / O incentive	2012	31,862,621	631,464	31,231,157		13,426,813	230,362	13,196,451		82,125,077	1,649,374	80,475,703
33	W incentive	2012	31,862,621	631,464	31,231,157		13,426,813	230,362	13,196,451		82,125,077	1,649,374	80,475,703
34	W / O incentive	2013	31,231,157	719,575	30,511,582		13,196,451	300,006	12,896,445		80,475,703	1,879,519	78,596,183
35	W incentive	2013	31,231,157	719,575	30,511,582		13,196,451	300,006	12,896,445		80,475,703	1,879,519	78,596,183
36	W / O incentive	2014	30,511,582	748,946	29,762,636		12,896,445	312,251	12,584,193		78,596,183	1,956,234	76,639,949
37	W incentive	2014	30,511,582	748,946	29,762,636		12,896,445	312,251	12,584,193		78,596,183	1,956,234	76,639,949
38	W / O incentive	2015	29,762,636	748,946	29,013,690		12,584,193	312,251	12,271,942		76,639,949	1,956,234	74,683,715
39	W incentive	2015	29,762,636	748,946	29,013,690		12,584,193	312,251	12,271,942		76,639,949	1,956,234	74,683,715
40	W / O incentive	2016	29,013,690	748,946	28,264,745		12,271,942	312,251	11,959,690		74,683,715	1,956,234	72,727,481
41	W incentive	2016	29,013,690	748,946	28,264,745		12,271,942	312,251	11,959,690		74,683,715	1,956,234	72,727,481
42	W / O incentive	2017	28,264,745	748,946	27,515,799	4,182,556	11,959,690	312,251	11,647,439	1,765,405	72,727,481	1,956,234	70,771,247
43	W incentive	2017	28,264,745	748,946	27,515,799	4,427,965	11,959,690	312,251	11,647,439	1,869,265	72,727,481	1,956,234	70,771,247
A						4,763,498				2,009,980			
B						5,044,001				2,128,603			
C						4,483,085				1,891,395			
D						4,744,533				2,001,960			
E						(280,413)				(118,585)			
F						(299,468)				(126,643)			
G						1.06941				1.06941			
H						(299,876)				(126,816)			
I						(320,254)				(135,433)			
	W / O incentive					3,882,680				1,638,589			
	W incentive					4,107,711				1,733,832			

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

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Line Number
References on All Pages

10			
11	Schedule 12 (Yes or No)		
12	Life		
13	FCR W/O incentive Line 3		
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	10,789,399
43	W incentive	2017	11,420,727

A	12,375,574
B	13,102,661
C	11,570,031
D	12,243,147
E	(805,543)
F	(859,514)
G	1.06941
H	(861,455)
I	(919,172)

W / O incentive	9,927,944
W incentive	10,501,555

Virginia Electric and Power Company
ATTACHMENT H-16A
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10			Project S-2				Project T-1				Project T-2		
11	Schedule 12	(Yes or No)	No	s0133			Yes	b0768			Yes	b0768	
12	Life		43	Pleasant View Hamilton 230kV			43	Glen Carlyn Line 251 GIB substation project			43	Glen Carlyn Line 251 GIB substa	
13	FCR W/O incentive	Line 3	12.3111%	transmission line			12.3111%				12.3111%		
14	Incentive Factor (Basis Points /100)		1.25				1.25	Loop Line 251 Idylwood -- Arlington into			1.25	Loop Line 251 Idylwood -- Arlingt	
15	FCR W incentive L.13 +(L.14*L.5)		13.1910%				13.1910%	the GIS sub			13.1910%	the GIS sub	
16	Investment		1,301,988				205,578				23,483,583		
17	Annual Depreciation Exp		30,279				4,781				546,130		
18	In Service Month (1-12)		2				6				6		
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009											
27	W incentive	2009											
28	W / O incentive	2010					205,578	2,183	203,395				
29	W incentive	2010					205,578	2,183	203,395				
30	W / O incentive	2011	1,301,988	22,338	1,279,650		203,395	4,031	199,364		23,483,583	249,417	23,234,166
31	W incentive	2011	1,301,988	22,338	1,279,650		203,395	4,031	199,364		23,483,583	249,417	23,234,166
32	W / O incentive	2012	1,279,650	25,529	1,254,121		199,364	4,031	195,333		23,234,166	460,462	22,773,703
33	W incentive	2012	1,279,650	25,529	1,254,121		199,364	4,031	195,333		23,234,166	460,462	22,773,703
34	W / O incentive	2013	1,254,121	29,091	1,225,029		195,333	4,593	190,739		22,773,703	524,713	22,248,990
35	W incentive	2013	1,254,121	29,091	1,225,029		195,333	4,593	190,739		22,773,703	524,713	22,248,990
36	W / O incentive	2014	1,225,029	30,279	1,194,751		190,739	4,781	185,958		22,248,990	546,130	21,702,861
37	W incentive	2014	1,225,029	30,279	1,194,751		190,739	4,781	185,958		22,248,990	546,130	21,702,861
38	W / O incentive	2015	1,194,751	30,279	1,164,472		185,958	4,781	181,178		21,702,861	546,130	21,156,731
39	W incentive	2015	1,194,751	30,279	1,164,472		185,958	4,781	181,178		21,702,861	546,130	21,156,731
40	W / O incentive	2016	1,164,472	30,279	1,134,193		181,178	4,781	176,397		21,156,731	546,130	20,610,601
41	W incentive	2016	1,164,472	30,279	1,134,193		181,178	4,781	176,397		21,156,731	546,130	20,610,601
42	W / O incentive	2017	1,134,193	30,279	1,103,914	168,047	176,397	4,781	171,616	26,203	20,610,601	546,130	20,064,471
43	W incentive	2017	1,134,193	30,279	1,103,914	177,894	176,397	4,781	171,616	27,734	20,610,601	546,130	20,064,471
A						191,419				29,857			
B						202,678				31,609			
C						180,163				28,106			
D						190,658				29,739			
E						(11,255)				(1,752)			
F						(12,020)				(1,871)			
G						1.06941				1.06941			
H						(12,037)				(1,873)			
I						(12,855)				(2,000)			
	W / O incentive					156,010				24,330			
	W incentive					165,039				25,734			

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

These Three Columns
are Repeated to Provide
Line Number
References on All Pages

10			
11	Schedule 12	(Yes or No)	
12	Life		tion project
13	FCR W/O incentive	Line 3	
14	Incentive Factor (Basis Points /100)		on into
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	3,049,912
43	W incentive	2017	3,228,864

A		3,473,534
B		3,678,077
C		3,269,058
D		3,459,705
E		(204,477)
F		(218,372)
G		1.06941
H		(218,669)
I		(233,529)
	W / O incentive	2,831,243
	W incentive	2,995,335

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 7 - Transmission Enhancement Annual Revenue Requirement Worksheet
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10			Project U-1				Project U-2				Project V		
11	Schedule 12	(Yes or No)	Yes	b0453.1			Yes	b0453.2			Yes	b0337	
12	Life		43	Convert Remington - Sowego			43	Add Sowego - Gainsville 230 kV			43	Build Lexington 230kV ring bus	
13	FCR W/O incentive	Line 3	12.3111%	115kV to 230kV			12.3111%				12.3111%		
14	Incentive Factor (Basis Points /100)		1.25				1.25				1.25		
15	FCR W incentive L.13 +(L.14*L.5)		13.1910%				13.1910%				13.1910%		
16	Investment		1,472,605				12,889,633				6,389,531		
17	Annual Depreciation Exp		34,247				299,759				148,594		
18	In Service Month (1-12)		9				5				3		
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009									6,389,531	99,184	6,290,347
27	W incentive	2009									6,389,531	99,184	6,290,347
28	W / O incentive	2010	1,472,605	8,422	1,464,183						6,290,347	125,285	6,165,062
29	W incentive	2010	1,472,605	8,422	1,464,183						6,290,347	125,285	6,165,062
30	W / O incentive	2011	1,464,183	28,875	1,435,309						6,165,062	125,285	6,039,777
31	W incentive	2011	1,464,183	28,875	1,435,309						6,165,062	125,285	6,039,777
32	W / O incentive	2012	1,435,309	28,875	1,406,434		12,889,633	157,961	12,731,672		6,039,777	125,285	5,914,492
33	W incentive	2012	1,435,309	28,875	1,406,434		12,889,633	157,961	12,731,672		6,039,777	125,285	5,914,492
34	W / O incentive	2013	1,406,434	32,904	1,373,530		12,731,672	288,004	12,443,668		5,914,492	142,767	5,771,726
35	W incentive	2013	1,406,434	32,904	1,373,530		12,731,672	288,004	12,443,668		5,914,492	142,767	5,771,726
36	W / O incentive	2014	1,373,530	34,247	1,339,284		12,443,668	299,759	12,143,909		5,771,726	148,594	5,623,132
37	W incentive	2014	1,373,530	34,247	1,339,284		12,443,668	299,759	12,143,909		5,771,726	148,594	5,623,132
38	W / O incentive	2015	1,339,284	34,247	1,305,037		12,143,909	299,759	11,844,150		5,623,132	148,594	5,474,538
39	W incentive	2015	1,339,284	34,247	1,305,037		12,143,909	299,759	11,844,150		5,623,132	148,594	5,474,538
40	W / O incentive	2016	1,305,037	34,247	1,270,791		11,844,150	299,759	11,544,391		5,474,538	148,594	5,325,945
41	W incentive	2016	1,305,037	34,247	1,270,791		11,844,150	299,759	11,544,391		5,474,538	148,594	5,325,945
42	W / O incentive	2017	1,270,791	34,247	1,236,544	188,587	11,544,391	299,759	11,244,633	1,702,553	5,325,945	148,594	5,177,351
43	W incentive	2017	1,270,791	34,247	1,236,544	199,618	11,544,391	299,759	11,244,633	1,802,814	5,325,945	148,594	5,177,351
A						214,860				2,026,316			
B						227,479				2,146,001			
C						202,244				1,823,753			
D						214,006				1,930,456			
E						(12,616)				(202,563)			
F						(13,473)				(215,545)			
G						1.06941				1.06941			
H						(13,491)				(216,622)			
I						(14,408)				(230,505)			
	W / O incentive					175,096				1,485,931			
	W incentive					185,210				1,572,309			

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

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10			
11	Schedule 12 (Yes or No)		
12	Life		
13	FCR W/O incentive Line 3		
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	795,131
43	W incentive	2017	841,341

A	909,104
B	962,214
C	853,644
D	903,008
E	(55,461)
F	(59,205)
G	1.06941
H	(59,310)
I	(63,315)

W / O incentive	735,821
W incentive	778,026

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 7 - Transmission Enhancement Annual Revenue Requirement Worksheet
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10			**Project W**				**Project X**				**Project AA - 1**		
11	Schedule 12	(Yes or No)	Yes	b0467.2			Yes	b0311			Yes	b0231	
12	Life		43	Reconductor the Dickerson - Pleasant			43	Reconductor Idylwood to Arlington			43	Install 500 kV breakers and	
13	FCR W/O incentive	Line 3	12.3111%	View 230 kV circuit			12.3111%	230 kV			12.3111%	500 kV bus work at Suffolk	
14	Incentive Factor (Basis Points /100)		1.25				1.25				0		
15	FCR W incentive L.13 +(L.14*L.5)		13.1910%				13.1910%				12.3111%		
16	Investment		5,249,379				3,196,608				21,912,291		
17	Annual Depreciation Exp		122,079				74,340				509,588		
18	In Service Month (1-12)		6				8				11		
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009					3,196,608	23,504	3,173,104		21,912,291	53,707	21,858,584
27	W incentive	2009					3,196,608	23,504	3,173,104		21,912,291	53,707	21,858,584
28	W / O incentive	2010					3,173,104	62,679	3,110,425		21,858,584	429,653	21,428,932
29	W incentive	2010					3,173,104	62,679	3,110,425		21,858,584	429,653	21,428,932
30	W / O incentive	2011	5,249,379	55,753	5,193,626		3,110,425	62,679	3,047,746		21,428,932	429,653	20,999,279
31	W incentive	2011	5,249,379	55,753	5,193,626		3,110,425	62,679	3,047,746		21,428,932	429,653	20,999,279
32	W / O incentive	2012	5,193,626	102,929	5,090,697		3,047,746	62,679	2,985,068		20,999,279	429,653	20,569,626
33	W incentive	2012	5,193,626	102,929	5,090,697		3,047,746	62,679	2,985,068		20,999,279	429,653	20,569,626
34	W / O incentive	2013	5,090,697	117,291	4,973,406		2,985,068	71,424	2,913,643		20,569,626	489,604	20,080,022
35	W incentive	2013	5,090,697	117,291	4,973,406		2,985,068	71,424	2,913,643		20,569,626	489,604	20,080,022
36	W / O incentive	2014	4,973,406	122,079	4,851,327		2,913,643	74,340	2,839,304		20,080,022	509,588	19,570,434
37	W incentive	2014	4,973,406	122,079	4,851,327		2,913,643	74,340	2,839,304		20,080,022	509,588	19,570,434
38	W / O incentive	2015	4,851,327	122,079	4,729,248		2,839,304	74,340	2,764,964		19,570,434	509,588	19,060,845
39	W incentive	2015	4,851,327	122,079	4,729,248		2,839,304	74,340	2,764,964		19,570,434	509,588	19,060,845
40	W / O incentive	2016	4,729,248	122,079	4,607,170		2,764,964	74,340	2,690,624		19,060,845	509,588	18,551,257
41	W incentive	2016	4,729,248	122,079	4,607,170		2,764,964	74,340	2,690,624		19,060,845	509,588	18,551,257
42	W / O incentive	2017	4,607,170	122,079	4,485,091	681,759	2,690,624	74,340	2,616,284	401,010	18,551,257	509,588	18,041,669
43	W incentive	2017	4,607,170	122,079	4,485,091	721,761	2,690,624	74,340	2,616,284	424,358	18,551,257	509,588	18,041,669
A						776,060				457,124			
B						821,759				483,869			
C						730,745				430,386			
D						773,362				455,315			
E						(45,315)				(26,737)			
F						(48,398)				(28,554)			
G						1.06941				1.06941			
H						(48,460)				(28,593)			
I						(51,757)				(30,536)			
	W / O incentive					633,299				372,417			
	W incentive					670,004				393,822			

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

These Three Columns are Repeated to Provide Line Number References on All Pages			
10			
11	Schedule 12 (Yes or No)		
12	Life		
13	FCR W/O incentive Line 3		
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	2,762,091
43	W incentive	2017	2,762,091
A			3,148,046
B			3,148,046
C			2,963,886
D			2,963,886
E			(184,160)
F			(184,160)
G			1.06941
H			(196,943)
I			(196,943)
	W / O incentive		2,565,149
	W incentive		2,565,149

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

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References on All Pages

10			**Project AB-2**				**Project AC**				**Project AG**		
11	Schedule 12	(Yes or No)	Yes	b0456			Yes	b0227			Yes	b0455	
12	Life		43	Re-Conductor 9.4 miles of Edinburg - Mt. Jackson			43	Install 500/230 kV transformer at Bristers;			43	Add 2nd Endless Caverns 230/11	
13	FCR W/O incentive	Line 3	12.3111%	115 kV			12.3111%	build new 230 kV Bristers- Gainesville circuit,			12.3111%	transformer	
14	Incentive Factor (Basis Points /100)		0				0	upgrade two Loudoun - Brambleton circuits			0		
15	FCR W incentive L.13 +(L.14*L.5)		12.3111%				12.3111%				12.3111%		
16	Investment		4,839,985				21,117,166				3,424,618		
17	Annual Depreciation Exp		112,558				491,097				79,642		
18	In Service Month (1-12)		11				6				5		
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009	4,839,985	11,863	4,828,122		21,117,166	224,284	20,892,882		3,424,618	41,968	3,382,650
27	W incentive	2009	4,839,985	11,863	4,828,122		21,117,166	224,284	20,892,882		3,424,618	41,968	3,382,650
28	W / O incentive	2010	4,828,122	94,902	4,733,221		20,892,882	414,062	20,478,820		3,382,650	67,149	3,315,500
29	W incentive	2010	4,828,122	94,902	4,733,221		20,892,882	414,062	20,478,820		3,382,650	67,149	3,315,500
30	W / O incentive	2011	4,733,221	94,902	4,638,319		20,478,820	414,062	20,064,758		3,315,500	67,149	3,248,351
31	W incentive	2011	4,733,221	94,902	4,638,319		20,478,820	414,062	20,064,758		3,315,500	67,149	3,248,351
32	W / O incentive	2012	4,638,319	94,902	4,543,417		20,064,758	414,062	19,650,696		3,248,351	67,149	3,181,202
33	W incentive	2012	4,638,319	94,902	4,543,417		20,064,758	414,062	19,650,696		3,248,351	67,149	3,181,202
34	W / O incentive	2013	4,543,417	108,144	4,435,274		19,650,696	471,838	19,178,858		3,181,202	76,519	3,104,682
35	W incentive	2013	4,543,417	108,144	4,435,274		19,650,696	471,838	19,178,858		3,181,202	76,519	3,104,682
36	W / O incentive	2014	4,435,274	112,558	4,322,716		19,178,858	491,097	18,687,761		3,104,682	79,642	3,025,040
37	W incentive	2014	4,435,274	112,558	4,322,716		19,178,858	491,097	18,687,761		3,104,682	79,642	3,025,040
38	W / O incentive	2015	4,322,716	112,558	4,210,158		18,687,761	491,097	18,196,664		3,025,040	79,642	2,945,398
39	W incentive	2015	4,322,716	112,558	4,210,158		18,687,761	491,097	18,196,664		3,025,040	79,642	2,945,398
40	W / O incentive	2016	4,210,158	112,558	4,097,600		18,196,664	491,097	17,705,567		2,945,398	79,642	2,865,756
41	W incentive	2016	4,210,158	112,558	4,097,600		18,196,664	491,097	17,705,567		2,945,398	79,642	2,865,756
42	W / O incentive	2017	4,097,600	112,558	3,985,042	610,090	17,705,567	491,097	17,214,470	2,640,624	2,865,756	79,642	2,786,113
43	W incentive	2017	4,097,600	112,558	3,985,042	610,090	17,705,567	491,097	17,214,470	2,640,624	2,865,756	79,642	2,786,113
A						695,372				3,051,228			
B						695,372				3,051,228			
C						654,663				2,834,414			
D						654,663				2,834,414			
E						(40,709)				(216,814)			
F						(40,709)				(216,814)			
G						1.06941				1.06941			
H						(43,535)				(231,863)			
I						(43,535)				(231,863)			
	W / O incentive					566,556				2,408,761			
	W incentive					566,556				2,408,761			

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

These Three Columns
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Line Number
References on All Pages

10			
11	Schedule 12	(Yes or No)	
12	Life		5kV
13	FCR W/O incentive	Line 3	
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	427,547
43	W incentive	2017	427,547

A	505,947
B	505,947
C	458,952
D	458,952
E	(46,995)
F	(46,995)
G	1.06941
H	(50,257)
I	(50,257)

W / O incentive	377,290
W incentive	377,290

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

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10			**2009 Add-1**				**2009 Add-6**				**Project AJ**		
11	Schedule 12	(Yes or No)	Yes	B0453.3			Yes	B0837			Yes	B0327	
12	Life		43	Add Sowego 230/115/ kV transformer			43	At Mt. Storm, replace the existing MOD on			43	Build 2nd Harrisonburg - Valley 2	
13	FCR W/O incentive	Line 3	12.3111%				12.3111%	the 500 kV side of the transformer with a			12.3111%		
14	Incentive Factor (Basis Points /100)		1.25				0	circuit breaker			0		
15	FCR W incentive L.13 +(L.14*L.5)		13.1910%				12.3111%				12.3111%		
16	Investment		3,355,513				779,172				6,211,387		
17	Annual Depreciation Exp		78,035				18,120				144,451		
18	In Service Month (1-12)		9				6				7		
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009	3,355,513	19,190	3,336,323		779,172	8,276	770,896				
27	W incentive	2009	3,355,513	19,190	3,336,323		779,172	8,276	770,896				
28	W / O incentive	2010	3,336,323	65,794	3,270,529		770,896	15,278	755,619		6,211,387	55,821	6,155,566
29	W incentive	2010	3,336,323	65,794	3,270,529		770,896	15,278	755,619		6,211,387	55,821	6,155,566
30	W / O incentive	2011	3,270,529	65,794	3,204,734		755,619	15,278	740,341		6,155,566	121,792	6,033,774
31	W incentive	2011	3,270,529	65,794	3,204,734		755,619	15,278	740,341		6,155,566	121,792	6,033,774
32	W / O incentive	2012	3,204,734	65,794	3,138,940		740,341	15,278	725,063		6,033,774	121,792	5,911,982
33	W incentive	2012	3,204,734	65,794	3,138,940		740,341	15,278	725,063		6,033,774	121,792	5,911,982
34	W / O incentive	2013	3,138,940	74,975	3,063,965		725,063	17,410	707,653		5,911,982	138,786	5,773,196
35	W incentive	2013	3,138,940	74,975	3,063,965		725,063	17,410	707,653		5,911,982	138,786	5,773,196
36	W / O incentive	2014	3,063,965	78,035	2,985,930		707,653	18,120	689,533		5,773,196	144,451	5,628,745
37	W incentive	2014	3,063,965	78,035	2,985,930		707,653	18,120	689,533		5,773,196	144,451	5,628,745
38	W / O incentive	2015	2,985,930	78,035	2,907,895		689,533	18,120	671,413		5,628,745	144,451	5,484,294
39	W incentive	2015	2,985,930	78,035	2,907,895		689,533	18,120	671,413		5,628,745	144,451	5,484,294
40	W / O incentive	2016	2,907,895	78,035	2,829,859		671,413	18,120	653,292		5,484,294	144,451	5,339,843
41	W incentive	2016	2,907,895	78,035	2,829,859		671,413	18,120	653,292		5,484,294	144,451	5,339,843
42	W / O incentive	2017	2,829,859	78,035	2,751,824	421,620	653,292	18,120	635,172	97,433	5,339,843	144,451	5,195,392
43	W incentive	2017	2,829,859	78,035	2,751,824	446,176	653,292	18,120	635,172	97,433	5,339,843	144,451	5,195,392
A						480,596				111,076			
B						508,724				111,076			
C						452,478				104,583			
D						478,695				104,583			
E						(28,119)				(6,493)			
F						(30,029)				(6,493)			
G						1.06941				1.06941			
H						(30,070)				(6,944)			
I						(32,114)				(6,944)			
	W / O incentive					391,549				90,489			
	W incentive					414,063				90,489			

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

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10			
11	Schedule 12	(Yes or No)	
12	Life		30 kV
13	FCR W/O incentive	Line 3	
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	792,955
43	W incentive	2017	792,955
A			903,496
B			903,496
C			850,477
D			850,477
E			(53,019)
F			(53,019)
G			1.06941
H			(56,699)
I			(56,699)
	W / O incentive		736,256
	W incentive		736,256

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 7 - Transmission Enhancement Annual Revenue Requirement Worksheet
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10			Project AK-1				Project AK-2				Project AK-3		
11	Schedule 12	(Yes or No)	Yes	B1507			Yes	B1507			Yes	B1507	
12	Life		43	Rebuild Mt Storm - Doubs 500 kV			43	Rebuild Mt Storm - Doubs 500 kV			43	Rebuild Mt. Storm-Doubs 500 kV	
13	FCR W/O incentive	Line 3	12.3111%				12.3111%				12.3111%		
14	Incentive Factor (Basis Points /100)		0				0				0		
15	FCR W incentive L.13 +(L.14*L.5)		12.3111%				12.3111%				12.3111%		
16	Investment		23,947,642				21,791,010				120,381,556		
17	Annual Depreciation Exp		556,922				506,768				2,799,571		
18	In Service Month (1-12)		12				5				5		
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009											
27	W incentive	2009											
28	W / O incentive	2010											
29	W incentive	2010											
30	W / O incentive	2011	23,947,642	19,565	23,928,077								
31	W incentive	2011	23,947,642	19,565	23,928,077								
32	W / O incentive	2012	23,928,077	469,562	23,458,515		21,791,010	267,047	21,523,963				
33	W incentive	2012	23,928,077	469,562	23,458,515		21,791,010	267,047	21,523,963				
34	W / O incentive	2013	23,458,515	535,082	22,923,433		21,523,963	486,894	21,037,069		120,381,556	1,749,732	118,631,824
35	W incentive	2013	23,458,515	535,082	22,923,433		21,523,963	486,894	21,037,069		120,381,556	1,749,732	118,631,824
36	W / O incentive	2014	22,923,433	556,922	22,366,512		21,037,069	506,768	20,530,301		118,631,824	2,799,571	115,832,253
37	W incentive	2014	22,923,433	556,922	22,366,512		21,037,069	506,768	20,530,301		118,631,824	2,799,571	115,832,253
38	W / O incentive	2015	22,366,512	556,922	21,809,590		20,530,301	506,768	20,023,534		115,832,253	2,799,571	113,032,682
39	W incentive	2015	22,366,512	556,922	21,809,590		20,530,301	506,768	20,023,534		115,832,253	2,799,571	113,032,682
40	W / O incentive	2016	21,809,590	556,922	21,252,668		20,023,534	506,768	19,516,766		113,032,682	2,799,571	110,233,111
41	W incentive	2016	21,809,590	556,922	21,252,668		20,023,534	506,768	19,516,766		113,032,682	2,799,571	110,233,111
42	W / O incentive	2017	21,252,668	556,922	20,695,746	3,139,086	19,516,766	506,768	19,009,998	2,878,310	110,233,111	2,799,571	107,433,540
43	W incentive	2017	21,252,668	556,922	20,695,746	3,139,086	19,516,766	506,768	19,009,998	2,878,310	110,233,111	2,799,571	107,433,540
A						3,574,247				3,276,684			
B						3,574,247				3,276,684			
C						3,363,489				3,083,208			
D						3,363,489				3,083,208			
E						(210,757)				(193,476)			
F						(210,757)				(193,476)			
G						1.06941				1.06941			
H						(225,386)				(206,905)			
I						(225,386)				(206,905)			
	W / O incentive					2,913,700				2,671,404			
	W incentive					2,913,700				2,671,404			

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

These Three Columns
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Line Number
References on All Pages

10			
11	Schedule 12 (Yes or No)		
12	Life		
13	FCR W/O incentive Line 3		
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	16,198,194
43	W incentive	2017	16,198,194
A			18,431,484
B			18,431,484
C			17,339,670
D			17,339,670
E			(1,091,814)
F			(1,091,814)
G			1.06941
H			(1,167,596)
I			(1,167,596)
	W / O incentive		15,030,598
	W incentive		15,030,598

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

These Three Columns
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10			Project AK-4				Project AK-5				Project AK-6		
11	Schedule 12	(Yes or No)	Yes	B1507			Yes	B1507			Yes	B1507	
12	Life		43	Rebuild Mt. Storm-Doubs 500 kV			43	Rebuild Mt. Storm-Doubs 500 kV			43	Rebuild Mt. Storm-Doubs 500 kV	
13	FCR W/O incentive	Line 3	12.3111%				12.3111%				12.3111%		
14	Incentive Factor (Basis Points /100)		0				0				0		
15	FCR W incentive L.13 +(L.14*L.5)		12.3111%				12.3111%				12.3111%		
16	Investment		149,952,489				15,394,401				615,875		
17	Annual Depreciation Exp		3,487,267				358,009				14,323		
18	In Service Month (1-12)		5				5				12		
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009											
27	W incentive	2009											
28	W / O incentive	2010											
29	W incentive	2010											
30	W / O incentive	2011											
31	W incentive	2011											
32	W / O incentive	2012											
33	W incentive	2012											
34	W / O incentive	2013											
35	W incentive	2013											
36	W / O incentive	2014	149,952,489	2,179,542	147,772,947								
37	W incentive	2014	149,952,489	2,179,542	147,772,947								
38	W / O incentive	2015	147,772,947	3,487,267	144,285,680		15,394,401	223,756	15,170,645				
39	W incentive	2015	147,772,947	3,487,267	144,285,680		15,394,401	223,756	15,170,645				
40	W / O incentive	2016	144,285,680	3,487,267	140,798,413		15,170,645	223,756	14,946,889		615,875	597	615,278
41	W incentive	2016	144,285,680	3,487,267	140,798,413		15,170,645	223,756	14,946,889		615,875	597	615,278
42	W / O incentive	2017	140,798,413	3,487,267	137,311,145	20,606,495	14,946,889	223,756	14,723,134	2,050,115	615,278	14,323	600,956
43	W incentive	2017	140,798,413	3,487,267	137,311,145	20,606,495	14,946,889	223,756	14,723,134	2,050,115	615,278	14,323	600,956
A						19,700,681				332,093			
B						19,700,681				332,093			
C						22,042,147				1,437,405			
D						22,042,147				1,437,405			
E						2,341,466				1,105,312			
F						2,341,466				1,105,312			
G						1.06941				1.06941			
H						2,503,985				1,182,031			
I						2,503,985				1,182,031			
	W / O incentive					23,110,480				3,232,146			
	W incentive					23,110,480				3,232,146			

Virginia Electric and Power Company
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10			
11	Schedule 12	(Yes or No)	
12	Life		
13	FCR W/O incentive	Line 3	
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	89,189
43	W incentive	2017	89,189

A	1,042,111
B	1,042,111
C	-
D	-
E	(1,042,111)
F	(1,042,111)
G	1.06941
H	(1,114,443)
I	(1,114,443)

W / O incentive	(1,025,254)
W incentive	(1,025,254)

Virginia Electric and Power Company
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10			Project AK-7				Project AL				Project AM		
11	Schedule 12	(Yes or No)	Yes	B1507			Yes	B0457			Yes	B0784	
12	Life		43	Rebuild Mt. Storm-Doubs 500 kV			43	Replace both wave traps on			43	Replace wave traps on North Anr	
13	FCR W/O incentive	Line 3	12.3111%				12.3111%	Dooms - Lexington 500 kV			12.3111%	Ladysmith 500 kV	
14	Incentive Factor (Basis Points /100)		0				0				0		
15	FCR W incentive L.13 +(L.14*L.5)		12.3111%				12.3111%				12.3111%		
16	Investment		-				108,763				75,695		
17	Annual Depreciation Exp		-				2,529				1,760		
18	In Service Month (1-12)						12				10		
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009											
27	W incentive	2009											
28	W / O incentive	2010											
29	W incentive	2010											
30	W / O incentive	2011					108,763	89	108,674		75,695	309	75,386
31	W incentive	2011					108,763	89	108,674		75,695	309	75,386
32	W / O incentive	2012					108,674	2,133	106,542		75,386	1,484	73,902
33	W incentive	2012					108,674	2,133	106,542		75,386	1,484	73,902
34	W / O incentive	2013					106,542	2,430	104,111		73,902	1,691	72,210
35	W incentive	2013					106,542	2,430	104,111		73,902	1,691	72,210
36	W / O incentive	2014					104,111	2,529	101,582		72,210	1,760	70,450
37	W incentive	2014					104,111	2,529	101,582		72,210	1,760	70,450
38	W / O incentive	2015					101,582	2,529	99,053		70,450	1,760	68,690
39	W incentive	2015					101,582	2,529	99,053		70,450	1,760	68,690
40	W / O incentive	2016					99,053	2,529	96,523		68,690	1,760	66,929
41	W incentive	2016					99,053	2,529	96,523		68,690	1,760	66,929
42	W / O incentive	2017	-	-	-	0	96,523	2,529	93,994	14,257	66,929	1,760	65,169
43	W incentive	2017	-	-	-	0	96,523	2,529	93,994	14,257	66,929	1,760	65,169

A			109,758		16,233
B			109,758		16,233
C			-		15,276
D			-		15,276
E			(109,758)		(957)
F			(109,758)		(957)
G			1.06941		1.06941
H			(117,377)		(1,024)
I			(117,377)		(1,024)
	W / O incentive		(117,377)		13,233
	W incentive		(117,377)		13,233

Virginia Electric and Power Company
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(dollars)

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10			
11	Schedule 12	(Yes or No)	
12	Life		a to
13	FCR W/O incentive	Line 3	
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	9,892
43	W incentive	2017	9,892

A	11,264
B	11,264
C	10,600
D	10,600
E	(664)
F	(664)
G	1.06941
H	(710)
I	(710)

W / O incentive	9,182
W incentive	9,182

Virginia Electric and Power Company
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10			**Project AO**				**Project AP-1**				**Project AP-2**		
11	Schedule 12	(Yes or No)	Yes	B1224			Yes	B1508.3			Yes	B1508.3	
12	Life		43	Install 2nd Clover 500/230			43	Upgrade a 115 kV shunt capacitor banks			43	Upgrade a 115 kV shunt capacitc	
13	FCR W/O incentive	Line 3	12.3111%	kV transformer and a 150			12.3111%	at Merck and Edinburg			12.3111%	at Merck and Edinburg	
14	Incentive Factor (Basis Points /100)		0	MVAr capacitor			0				0		
15	FCR W incentive L.13 +(L.14*L.5)		12.3111%				12.3111%	Merck			12.3111%	Edinburg	
16	Investment		14,160,502				511,009				755,038		
17	Annual Depreciation Exp		329,314				11,884				17,559		
18	In Service Month (1-12)		4				7				2		
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009											
27	W incentive	2009											
28	W / O incentive	2010											
29	W incentive	2010											
30	W / O incentive	2011											
31	W incentive	2011											
32	W / O incentive	2012					511,009	4,592	506,417		755,038	12,954	742,084
33	W incentive	2012					511,009	4,592	506,417		755,038	12,954	742,084
34	W / O incentive	2013	14,160,502	233,264	13,927,238		506,417	11,418	494,999		742,084	16,870	725,213
35	W incentive	2013	14,160,502	233,264	13,927,238		506,417	11,418	494,999		742,084	16,870	725,213
36	W / O incentive	2014	13,927,238	329,314	13,597,924		494,999	11,884	483,115		725,213	17,559	707,654
37	W incentive	2014	13,927,238	329,314	13,597,924		494,999	11,884	483,115		725,213	17,559	707,654
38	W / O incentive	2015	13,597,924	329,314	13,268,610		483,115	11,884	471,231		707,654	17,559	690,095
39	W incentive	2015	13,597,924	329,314	13,268,610		483,115	11,884	471,231		707,654	17,559	690,095
40	W / O incentive	2016	13,268,610	329,314	12,939,296		471,231	11,884	459,347		690,095	17,559	672,536
41	W incentive	2016	13,268,610	329,314	12,939,296		471,231	11,884	459,347		690,095	17,559	672,536
42	W / O incentive	2017	12,939,296	329,314	12,609,982	1,902,018	459,347	11,884	447,463	67,703	672,536	17,559	654,977
43	W incentive	2017	12,939,296	329,314	12,609,982	1,902,018	459,347	11,884	447,463	67,703	672,536	17,559	654,977

A	2,162,429	77,068
B	2,162,429	77,068
C	2,036,181	72,515
D	2,036,181	72,515
E	(126,247)	(4,553)
F	(126,247)	(4,553)
G	1.06941	1.06941
H	(135,010)	(4,869)
I	(135,010)	(4,869)

W / O incentive	1,767,008	62,834
W incentive	1,767,008	62,834

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

These Three Columns are Repeated to Provide Line Number References on All Pages

10			
11	Schedule 12 (Yes or No)		
12	Life		r banks
13	FCR W/O incentive Line 3		
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	99,275
43	W incentive	2017	99,275

A	113,028
B	113,028
C	106,360
D	106,360
E	(6,668)
F	(6,668)
G	1.06941
H	(7,131)
I	(7,131)

W / O incentive	92,144
W incentive	92,144

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10				**Project AQ**				**Project AR**				**Project AS**	
11	Schedule 12	(Yes or No)	Yes	B1647			Yes	B1648			Yes	B1649	
12	Life		43	Upgrade the name plate			43	Upgrade the name plate rating			43	Replace Morrisville 500 kV	
13	FCR W/O incentive	Line 3	12.3111%	rating at Morrisville 500 kV			12.3111%	at Morrisville 500 kV			12.3111%	breaker 'H1T580' with	
14	Incentive Factor (Basis Points /100)		0	breaker 'H1T573' with			0	breaker 'H2T545' with			0	50kA breaker	
15	FCR W incentive L.13 +(L.14*L.5)		12.3111%	50kA breaker			12.3111%	50kA breaker			12.3111%		
16	Investment		16,278				16,278				858,877		
17	Annual Depreciation Exp		379				379				19,974		
18	In Service Month (1-12)		1				1				1		
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009											
27	W incentive	2009											
28	W / O incentive	2010											
29	W incentive	2010											
30	W / O incentive	2011											
31	W incentive	2011											
32	W / O incentive	2012											
33	W incentive	2012											
34	W / O incentive	2013	16,278	350	15,928		16,278	350	15,928		858,877	18,489	840,388
35	W incentive	2013	16,278	350	15,928		16,278	350	15,928		858,877	18,489	840,388
36	W / O incentive	2014	15,928	379	15,549		15,928	379	15,549		840,388	19,974	820,414
37	W incentive	2014	15,928	379	15,549		15,928	379	15,549		840,388	19,974	820,414
38	W / O incentive	2015	15,549	379	15,170		15,549	379	15,170		820,414	19,974	800,440
39	W incentive	2015	15,549	379	15,170		15,549	379	15,170		820,414	19,974	800,440
40	W / O incentive	2016	15,170	379	14,792		15,170	379	14,792		800,440	19,974	780,466
41	W incentive	2016	15,170	379	14,792		15,170	379	14,792		800,440	19,974	780,466
42	W / O incentive	2017	14,792	379	14,413	2,176	14,792	379	14,413	2,176	780,466	19,974	760,493
43	W incentive	2017	14,792	379	14,413	2,176	14,792	379	14,413	2,176	780,466	19,974	760,493

A						2,477				2,477			
B						2,477				2,477			
C						2,330				2,330			
D						2,330				2,330			
E						(147)				(147)			
F						(147)				(147)			
G						1.06941				1.06941			
H						(157)				(157)			
I						(157)				(157)			
	W / O incentive					2,020				2,020			
	W incentive					2,020				2,020			

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10			
11	Schedule 12	(Yes or No)	
12	Life		
13	FCR W/O incentive	Line 3	
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	114,829
43	W incentive	2017	114,829

A	130,682
B	130,682
C	122,949
D	122,949
E	(7,733)
F	(7,733)
G	1.06941
H	(8,270)
I	(8,270)

W / O incentive	106,559
W incentive	106,559

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10				**Project AT**				**Project AU-1**				**Project AU-2**	
11	Schedule 12	(Yes or No)	Yes	B1650			Yes	B1188.6			Yes	B1188.6	
12	Life		43	Replace Morrisville 500 kV			43	Install one 500/230 kV			43	Install one 500/230 kV	
13	FCR W/O incentive	Line 3	12.3111%	breaker 'H2T569' with			12.3111%	transformer and two 230 kV breakers			12.3111%	transformer and two 230 kV brea	
14	Incentive Factor (Basis Points /100)		0	50kA breaker			0	at Brambleton			0	at Brambleton	
15	FCR W incentive L.13 +(L.14*L.5)		12.3111%				12.3111%				12.3111%		
16	Investment		858,877				235,892				16,717,801		
17	Annual Depreciation Exp		19,974				5,486				388,786		
18	In Service Month (1-12)		1				6				12		
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009											
27	W incentive	2009											
28	W / O incentive	2010											
29	W incentive	2010											
30	W / O incentive	2011											
31	W incentive	2011											
32	W / O incentive	2012					235,892	2,505	233,387				
33	W incentive	2012					235,892	2,505	233,387				
34	W / O incentive	2013	858,877	18,489	840,388		233,387	5,271	228,116		16,717,801	16,199	16,701,602
35	W incentive	2013	858,877	18,489	840,388		233,387	5,271	228,116		16,717,801	16,199	16,701,602
36	W / O incentive	2014	840,388	19,974	820,414		228,116	5,486	222,630		16,701,602	388,786	16,312,816
37	W incentive	2014	840,388	19,974	820,414		228,116	5,486	222,630		16,701,602	388,786	16,312,816
38	W / O incentive	2015	820,414	19,974	800,440		222,630	5,486	217,144		16,312,816	388,786	15,924,029
39	W incentive	2015	820,414	19,974	800,440		222,630	5,486	217,144		16,312,816	388,786	15,924,029
40	W / O incentive	2016	800,440	19,974	780,466		217,144	5,486	211,658		15,924,029	388,786	15,535,243
41	W incentive	2016	800,440	19,974	780,466		217,144	5,486	211,658		15,924,029	388,786	15,535,243
42	W / O incentive	2017	780,466	19,974	760,493	114,829	211,658	5,486	206,172	31,206	15,535,243	388,786	15,146,457
43	W incentive	2017	780,466	19,974	760,493	114,829	211,658	5,486	206,172	31,206	15,535,243	388,786	15,146,457
A						130,682				35,523			
B						130,682				35,523			
C						122,949				33,425			
D						122,949				33,425			
E						(7,733)				(2,098)			
F						(7,733)				(2,098)			
G						1.06941				1.06941			
H						(8,270)				(2,244)			
I						(8,270)				(2,244)			
	W / O incentive					106,559				28,962			
	W incentive					106,559				28,962			

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

These Three Columns
are Repeated to Provide
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10			
11	Schedule 12	(Yes or No)	
12	Life		
13	FCR W/O incentive	Line 3	ers
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	2,277,420
43	W incentive	2017	2,277,420

A	2,590,633
B	2,590,633
C	2,436,836
D	2,436,836
E	(153,797)
F	(153,797)
G	1.06941
H	(164,472)
I	(164,472)

W / O incentive	2,112,948
W incentive	2,112,948

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

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10			Project AV-1				Project AV-2				Project AW		
11	Schedule 12	(Yes or No)	Yes	B1188			Yes	B1188			Yes	B1698.1	
12	Life		43	Build new Brambleton 500 kV three			43	Build new Brambleton 500 kV three ring bus			43	Install a 500 kV breaker at	
13	FCR W/O incentive	Line 3	12.3111%	ring bus connected to the Loudoun			12.3111%	connected to the Loudoun to Pleasant View			12.3111%	Brambleton	
14	Incentive Factor (Basis Points /100)		0	to Pleasant View 500 kV line			0	500 kV line			0		
15	FCR W incentive L.13 +(L.14*L.5)		12.3111%				12.3111%				12.3111%		
16	Investment		-				1,617,569				-		
17	Annual Depreciation Exp		-				37,618				-		
18	In Service Month (1-12)						1						
19			Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009											
27	W incentive	2009											
28	W / O incentive	2010											
29	W incentive	2010											
30	W / O incentive	2011											
31	W incentive	2011											
32	W / O incentive	2012											
33	W incentive	2012											
34	W / O incentive	2013	-	-	-								
35	W incentive	2013	-	-	-								
36	W / O incentive	2014	-	-	-		1,617,569	36,050	1,581,519				
37	W incentive	2014	-	-	-		1,617,569	36,050	1,581,519				
38	W / O incentive	2015	-	-	-		1,581,519	37,618	1,543,901		-	-	-
39	W incentive	2015	-	-	-		1,581,519	37,618	1,543,901		-	-	-
40	W / O incentive	2016	-	-	-		1,543,901	37,618	1,506,283		-	-	-
41	W incentive	2016	-	-	-		1,543,901	37,618	1,506,283		-	-	-
42	W / O incentive	2017	-	-	-	0	1,506,283	37,618	1,468,665	220,743	-	-	-
43	W incentive	2017	-	-	-	0	1,506,283	37,618	1,468,665	220,743	-	-	-
A						1,357,306				251,091			
B						1,357,306				251,091			
C						-				236,180			
D						-				236,180			
E						(1,357,306)				(14,911)			
F						(1,357,306)				(14,911)			
G						1.06941				1.06941			
H						(1,451,516)				(15,946)			
I						(1,451,516)				(15,946)			
	W / O incentive					(1,451,516)				204,797			
	W incentive					(1,451,516)				204,797			

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

These Three Columns are Repeated to Provide Line Number References on All Pages			
10			
11	Schedule 12 (Yes or No)		
12	Life		
13	FCR W/O incentive Line 3		
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	0
43	W incentive	2017	0

A	38,927
B	38,927
C	-
D	-
E	(38,927)
F	(38,927)
G	1.06941
H	(41,629)
I	(41,629)

W / O incentive	(41,629)
W incentive	(41,629)

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

These Three Columns
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Line Number
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10				**Project AX-1**				**Project AX-2**				**Project AY-1**	
11	Schedule 12	(Yes or No)	Yes	B1321			Yes	B1321			Yes	B0756.1	
12	Life		43	Build a new 230 kV line North Anna -- Oak			43	Build a new 230 kV line North Anna -- Oak			43	Install two 500 kV breakers at	
13	FCR W/O incentive	Line 3	12.3111%	Green and install a 224 MVA 230/115			12.3111%	Green and install a 224 MVA 230/115			12.3111%	Chancellor 500 kV	
14	Incentive Factor (Basis Points /100)		0	kV transformer at Oak Green			0	kV transformer at Oak Green			0		
15	FCR W incentive L.13 +(L.14*L.5)		12.3111%				12.3111%				12.3111%		
16	Investment		31,865,589				6,369,934				4,076,165		
17	Annual Depreciation Exp		741,060				148,138				94,795		
18	In Service Month (1-12)		3				6				5		
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009											
27	W incentive	2009											
28	W / O incentive	2010											
29	W incentive	2010											
30	W / O incentive	2011											
31	W incentive	2011											
32	W / O incentive	2012											
33	W incentive	2012											
34	W / O incentive	2013									4,076,165	59,247	4,016,918
35	W incentive	2013									4,076,165	59,247	4,016,918
36	W / O incentive	2014									4,016,918	94,795	3,922,124
37	W incentive	2014									4,016,918	94,795	3,922,124
38	W / O incentive	2015	31,865,589	586,673	31,278,916		6,369,934	80,241	6,289,693		3,922,124	94,795	3,827,329
39	W incentive	2015	31,865,589	586,673	31,278,916		6,369,934	80,241	6,289,693		3,922,124	94,795	3,827,329
40	W / O incentive	2016	31,278,916	741,060	30,537,856		6,289,693	148,138	6,141,555		3,827,329	94,795	3,732,535
41	W incentive	2016	31,278,916	741,060	30,537,856		6,289,693	148,138	6,141,555		3,827,329	94,795	3,732,535
42	W / O incentive	2017	30,537,856	741,060	29,796,796	4,455,002	6,141,555	148,138	5,993,417	895,115	3,732,535	94,795	3,637,740
43	W incentive	2017	30,537,856	741,060	29,796,796	4,455,002	6,141,555	148,138	5,993,417	895,115	3,732,535	94,795	3,637,740
A						3,127,139				583,801			
B						3,127,139				583,801			
C						3,666,346				515,895			
D						3,666,346				515,895			
E						539,206				(67,907)			
F						539,206				(67,907)			
G						1.06941				1.06941			
H						576,632				(72,620)			
I						576,632				(72,620)			
	W / O incentive					5,031,634				822,495			
	W incentive					5,031,634				822,495			

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

These Three Columns are Repeated to Provide Line Number References on All Pages			
10			
11	Schedule 12	(Yes or No)	
12	Life		
13	FCR W/O incentive	Line 3	
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	548,477
43	W incentive	2017	548,477
A			621,836
B			621,836
C			587,128
D			587,128
E			(34,708)
F			(34,708)
G			1.06941
H			(37,117)
I			(37,117)
	W / O incentive		511,360
	W incentive		511,360

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

These Three Columns are Repeated to Provide Line Number References on All Pages													
10				Project AY-2				Project AZ				Project BA	
11	Schedule 12	(Yes or No)	Yes	B0756.1			Yes	B1797			Yes	B1799	
12	Life		43	Install two 500 kV breakers at			43	Wreck and rebuild 7 miles of the			43	Build 150 MVAR Switched Shunt	
13	FCR W/O incentive	Line 3	12.3111%	Chancellor 500 kV			12.3111%	Dominion owned section of Cloverdale -			12.3111%	View 500 kV	
14	Incentive Factor (Basis Points /100)		0				0	Lexington 500 kV			0		
15	FCR W incentive L.13 +(L.14*L.5)		12.3111%				12.3111%				12.3111%		
16	Investment		116,523				18,459,911				25,985,144		
17	Annual Depreciation Exp		2,710				429,300				604,306		
18	In Service Month (1-12)		12				10				11		
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009											
27	W incentive	2009											
28	W / O incentive	2010											
29	W incentive	2010											
30	W / O incentive	2011											
31	W incentive	2011											
32	W / O incentive	2012											
33	W incentive	2012											
34	W / O incentive	2013					18,459,911	89,438	18,370,473				
35	W incentive	2013					18,459,911	89,438	18,370,473				
36	W / O incentive	2014	116,523	113	116,410		18,370,473	429,300	17,941,173		25,985,144	75,538	25,909,606
37	W incentive	2014	116,523	113	116,410		18,370,473	429,300	17,941,173		25,985,144	75,538	25,909,606
38	W / O incentive	2015	116,410	2,710	113,700		17,941,173	429,300	17,511,873		25,909,606	604,306	25,305,300
39	W incentive	2015	116,410	2,710	113,700		17,941,173	429,300	17,511,873		25,909,606	604,306	25,305,300
40	W / O incentive	2016	113,700	2,710	110,990		17,511,873	429,300	17,082,573		25,305,300	604,306	24,700,994
41	W incentive	2016	113,700	2,710	110,990		17,511,873	429,300	17,082,573		25,305,300	604,306	24,700,994
42	W / O incentive	2017	110,990	2,710	108,281	16,207	17,082,573	429,300	16,653,272	2,505,934	24,700,994	604,306	24,096,689
43	W incentive	2017	110,990	2,710	108,281	16,207	17,082,573	429,300	16,653,272	2,505,934	24,700,994	604,306	24,096,689

A		-	2,704,647
B		-	2,704,647
C		17,329	2,681,680
D		17,329	2,681,680
E		17,329	(22,967)
F		17,329	(22,967)
G		1.06941	1.06941
H		18,532	(24,561)
I		18,532	(24,561)
	W / O incentive	34,739	2,481,373
	W incentive	34,739	2,481,373

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

These Three Columns
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10			
11	Schedule 12	(Yes or No)	
12	Life		at Pleasant
13	FCR W/O incentive	Line 3	
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	3,608,081
43	W incentive	2017	3,608,081

A	2,536,276
B	2,536,276
C	3,858,058
D	3,858,058
E	1,321,782
F	1,321,782
G	1.06941
H	1,413,526
I	1,413,526

W / O incentive	5,021,607
W incentive	5,021,607

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

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10				**Project BB-1**				**Project BB-2**				**Project BB-3**	
11	Schedule 12	(Yes or No)	Yes	B1798			Yes	B1798			Yes	B1798	
12	Life		43	Build a 450 MVAR SVC and 300 MVAR			43	Build a 450 MVAR SVC and 300 MVAR			43	Build a 450 MVAR SVC and 300	
13	FCR W/O incentive	Line 3	12.3111%	switched shunt at Loudoun 500 kV			12.3111%	switched shunt at Loudoun 500 kV			12.3111%	switched shunt at Loudoun 500 k	
14	Incentive Factor (Basis Points /100)		0				0				0		
15	FCR W incentive L.13 +(L.14*L.5)		12.3111%				12.3111%				12.3111%		
16	Investment		3,131,641				39,174,512				18,443,400		
17	Annual Depreciation Exp		72,829				911,035				428,916		
18	In Service Month (1-12)		12				5				6		
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009											
27	W incentive	2009											
28	W / O incentive	2010											
29	W incentive	2010											
30	W / O incentive	2011											
31	W incentive	2011											
32	W / O incentive	2012											
33	W incentive	2012											
34	W / O incentive	2013	3,131,641	3,035	3,128,606								
35	W incentive	2013	3,131,641	3,035	3,128,606								
36	W / O incentive	2014	3,128,606	72,829	3,055,778		39,174,512	569,397	38,605,115		18,443,400	232,330	18,211,070
37	W incentive	2014	3,128,606	72,829	3,055,778		39,174,512	569,397	38,605,115		18,443,400	232,330	18,211,070
38	W / O incentive	2015	3,055,778	72,829	2,982,949		38,605,115	911,035	37,694,080		18,211,070	428,916	17,782,154
39	W incentive	2015	3,055,778	72,829	2,982,949		38,605,115	911,035	37,694,080		18,211,070	428,916	17,782,154
40	W / O incentive	2016	2,982,949	72,829	2,910,120		37,694,080	911,035	36,783,045		17,782,154	428,916	17,353,238
41	W incentive	2016	2,982,949	72,829	2,910,120		37,694,080	911,035	36,783,045		17,782,154	428,916	17,353,238
42	W / O incentive	2017	2,910,120	72,829	2,837,291	426,615	36,783,045	911,035	35,872,010	5,383,368	17,353,238	428,916	16,924,322
43	W incentive	2017	2,910,120	72,829	2,837,291	426,615	36,783,045	911,035	35,872,010	5,383,368	17,353,238	428,916	16,924,322

A						485,287				6,129,290			
B						485,287				6,129,290			
C						456,477				5,758,426			
D						456,477				5,758,426			
E						(28,810)				(370,863)			
F						(28,810)				(370,863)			
G						1.06941				1.06941			
H						(30,809)				(396,605)			
I						(30,809)				(396,605)			
	W / O incentive					395,805				4,986,763			
	W incentive					395,805				4,986,763			

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

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10			
11	Schedule 12	(Yes or No)	
12	Life		MVAR
13	FCR W/O incentive	Line 3	V
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	2,538,895
43	W incentive	2017	2,538,895
A			2,887,333
B			2,887,333
C			2,715,615
D			2,715,615
E			(171,718)
F			(171,718)
G			1.06941
H			(183,637)
I			(183,637)
	W / O incentive		2,355,258
	W incentive		2,355,258

Virginia Electric and Power Company
ATTACHMENT H-16A
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10				**Project BB-4**				**Project BB-5**				**Project BB-6**	
11	Schedule 12 (Yes or No)		Yes	B1798			Yes	B1798			Yes	B1798	
12	Life		43	Build a 450 MVAR SVC and 300 MVAR			43	Build a 450 MVAR SVC and 300 MVAR			43	Build a 450 MVAR SVC and 300	
13	FCR W/O incentive Line 3		12.3111%	switched shunt at Loudoun 500 kV			12.3111%	switched shunt at Loudoun 500 kV			12.3111%	switched shunt at Loudoun 500 k	
14	Incentive Factor (Basis Points /100)		0				0				0		
15	FCR W incentive L.13 +(L.14*L.5)		12.3111%				12.3111%				12.3111%		
16	Investment		37,531,444				8,352,171				4,584,027		
17	Annual Depreciation Exp		872,824				194,237				106,605		
18	In Service Month (1-12)		8				12				1		
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009											
27	W incentive	2009											
28	W / O incentive	2010											
29	W incentive	2010											
30	W / O incentive	2011											
31	W incentive	2011											
32	W / O incentive	2012											
33	W incentive	2012											
34	W / O incentive	2013											
35	W incentive	2013											
36	W / O incentive	2014	37,531,444	327,309	37,204,135		8,352,171	8,093	8,344,078				
37	W incentive	2014	37,531,444	327,309	37,204,135		8,352,171	8,093	8,344,078				
38	W / O incentive	2015	37,204,135	872,824	36,331,311		8,344,078	194,237	8,149,841		4,584,027	102,163	4,481,864
39	W incentive	2015	37,204,135	872,824	36,331,311		8,344,078	194,237	8,149,841		4,584,027	102,163	4,481,864
40	W / O incentive	2016	36,331,311	872,824	35,458,486		8,149,841	194,237	7,955,605		4,481,864	106,605	4,375,258
41	W incentive	2016	36,331,311	872,824	35,458,486		8,149,841	194,237	7,955,605		4,481,864	106,605	4,375,258
42	W / O incentive	2017	35,458,486	872,824	34,585,662	5,184,441	7,955,605	194,237	7,761,368	1,161,706	4,375,258	106,605	4,268,653
43	W incentive	2017	35,458,486	872,824	34,585,662	5,184,441	7,955,605	194,237	7,761,368	1,161,706	4,375,258	106,605	4,268,653
A						4,265,969				1,247,886			
B						4,265,969				1,247,886			
C						5,544,631				1,242,118			
D						5,544,631				1,242,118			
E						1,278,661				(5,769)			
F						1,278,661				(5,769)			
G						1.06941				1.06941			
H						1,367,412				(6,169)			
I						1,367,412				(6,169)			
	W / O incentive					6,551,852				1,155,537			
	W incentive					6,551,852				1,155,537			

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10			
11	Schedule 12	(Yes or No)	
12	Life		MVAR
13	FCR W/O incentive	Line 3	v
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	638,687
43	W incentive	2017	638,687
A			-
B			-
C			654,133
D			654,133
E			654,133
F			654,133
G			1.06941
H			699,536
I			699,536
	W / O incentive		1,338,223
	W incentive		1,338,223

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10			**Project BC**				**Project BD-1**				**Project BD-2**		
11	Schedule 12	(Yes or No)	Yes	B1805			Yes	B1508.1			Yes	B1508.1	
12	Life		43	Install a 250 MVAR SVC at the existing Mt.			43	Build a 2nd 230kV line Harrisonburg to			43	Build a 2nd 230kV line Harrisonb	
13	FCR W/O incentive	Line 3	12.3111%	Storm 500 kV substation			12.3111%	Endless Caverns			12.3111%	Endless Caverns	
14	Incentive Factor (Basis Points /100)		0				0				0		
15	FCR W incentive L.13 +(L.14*L.5)		12.3111%				12.3111%				12.3111%		
16	Investment		37,153,276				4,829,987				50,892,286		
17	Annual Depreciation Exp		864,030				112,325				1,183,542		
18	In Service Month (1-12)		6				10				9		
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009											
27	W incentive	2009											
28	W / O incentive	2010											
29	W incentive	2010											
30	W / O incentive	2011											
31	W incentive	2011											
32	W / O incentive	2012											
33	W incentive	2012											
34	W / O incentive	2013					4,829,987	23,401	4,806,586				
35	W incentive	2013					4,829,987	23,401	4,806,586				
36	W / O incentive	2014	37,153,276	468,016	36,685,260		4,806,586	112,325	4,694,261		50,892,286	345,200	50,547,086
37	W incentive	2014	37,153,276	468,016	36,685,260		4,806,586	112,325	4,694,261		50,892,286	345,200	50,547,086
38	W / O incentive	2015	36,685,260	864,030	35,821,230		4,694,261	112,325	4,581,935		50,547,086	1,183,542	49,363,545
39	W incentive	2015	36,685,260	864,030	35,821,230		4,694,261	112,325	4,581,935		50,547,086	1,183,542	49,363,545
40	W / O incentive	2016	35,821,230	864,030	34,957,201		4,581,935	112,325	4,469,610		49,363,545	1,183,542	48,180,003
41	W incentive	2016	35,821,230	864,030	34,957,201		4,581,935	112,325	4,469,610		49,363,545	1,183,542	48,180,003
42	W / O incentive	2017	34,957,201	864,030	34,093,171	5,114,473	4,469,610	112,325	4,357,285	655,671	48,180,003	1,183,542	46,996,462
43	W incentive	2017	34,957,201	864,030	34,093,171	5,114,473	4,469,610	112,325	4,357,285	655,671	48,180,003	1,183,542	46,996,462
A						5,769,763				651,204			
B						5,769,763				651,204			
C						5,470,465				701,655			
D						5,470,465				701,655			
E						(299,298)				50,450			
F						(299,298)				50,450			
G						1.06941				1.06941			
H						(320,072)				53,952			
I						(320,072)				53,952			
	W / O incentive					4,794,401				709,623			
	W incentive					4,794,401				709,623			

Virginia Electric and Power Company
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10			
11	Schedule 12	(Yes or No)	
12	Life		urg to
13	FCR W/O incentive	Line 3	
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	7,042,195
43	W incentive	2017	7,042,195

A	7,788,588
B	7,788,588
C	7,530,999
D	7,530,999
E	(257,589)
F	(257,589)
G	1.06941
H	(275,468)
I	(275,468)

W / O incentive	6,766,728
W incentive	6,766,728

Virginia Electric and Power Company
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10				Project BD-3				Project BD-4				Project BD-5	
11	Schedule 12	(Yes or No)	Yes	B1508.1			Yes	B1508.1			Yes	B1508.1	
12	Life		43	Build a 2nd 230kV line Harrisonburg to			43	Build a 2nd 230kV line Harrisonburg to			43	Build a 2nd 230kV line Harrisonb	
13	FCR W/O incentive	Line 3	12.3111%	Endless Caverns			12.3111%	Endless Caverns			12.3111%	Endless Caverns	
14	Incentive Factor (Basis Points /100)		0				0				0		
15	FCR W incentive L.13 +(L.14*L.5)		12.3111%				12.3111%				12.3111%		
16	Investment		2,000,000				5,640,543				-		
17	Annual Depreciation Exp		46,512				131,175				-		
18	In Service Month (1-12)		12				6						
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009											
27	W incentive	2009											
28	W / O incentive	2010											
29	W incentive	2010											
30	W / O incentive	2011											
31	W incentive	2011											
32	W / O incentive	2012											
33	W incentive	2012											
34	W / O incentive	2013											
35	W incentive	2013											
36	W / O incentive	2014	2,000,000	1,938	1,998,062								
37	W incentive	2014	2,000,000	1,938	1,998,062								
38	W / O incentive	2015	1,998,062	46,512	1,951,550		5,640,543	71,053	5,569,490		-	-	-
39	W incentive	2015	1,998,062	46,512	1,951,550		5,640,543	71,053	5,569,490		-	-	-
40	W / O incentive	2016	1,951,550	46,512	1,905,039		5,569,490	131,175	5,438,314		-	-	-
41	W incentive	2016	1,951,550	46,512	1,905,039		5,569,490	131,175	5,438,314		-	-	-
42	W / O incentive	2017	1,905,039	46,512	1,858,527	278,181	5,438,314	131,175	5,307,139	792,619	-	-	-
43	W incentive	2017	1,905,039	46,512	1,858,527	278,181	5,438,314	131,175	5,307,139	792,619	-	-	-
A						-				-			
B						-				-			
C						297,436				456,822			
D						297,436				456,822			
E						297,436				456,822			
F						297,436				456,822			
G						1.06941				1.06941			
H						318,081				488,530			
I						318,081				488,530			
	W / O incentive					596,261				1,281,149			
	W incentive					596,261				1,281,149			

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10			
11	Schedule 12	(Yes or No)	
12	Life		urg to
13	FCR W/O incentive	Line 3	
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	0
43	W incentive	2017	0
A			-
B			-
C			-
D			-
E			-
F			-
G			1.06941
H			-
I			-
	W / O incentive		-
	W incentive		-

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10				**Project BE**				**Project BF-1**				**Project BF-2**	
11	Schedule 12	(Yes or No)	Yes	B1508.2			Yes	B2053			Yes	B2053	
12	Life		43	Install a 3rd 230 - 115 kV Tx at			43	Rebuild 28 mile line			43	Rebuild 28 mile line	
13	FCR W/O incentive	Line 3	12.3111%	Endless Caverns			12.3111%	(Altavista - Skimmer, 115kV)			12.3111%	(Altavista - Skimmer, 115kV)	
14	Incentive Factor (Basis Points /100)		0				0				0		
15	FCR W incentive L.13 +(L.14*L.5)		12.3111%				12.3111%				12.3111%		
16	Investment		11,994,009				6,782,738				23,121,045		
17	Annual Depreciation Exp		278,930				157,738				537,699		
18	In Service Month (1-12)		9				11				3		
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009											
27	W incentive	2009											
28	W / O incentive	2010											
29	W incentive	2010											
30	W / O incentive	2011											
31	W incentive	2011											
32	W / O incentive	2012											
33	W incentive	2012											
34	W / O incentive	2013											
35	W incentive	2013											
36	W / O incentive	2014	11,994,009	81,355	11,912,654		6,782,738	19,717	6,763,021				
37	W incentive	2014	11,994,009	81,355	11,912,654		6,782,738	19,717	6,763,021				
38	W / O incentive	2015	11,912,654	278,930	11,633,724		6,763,021	157,738	6,605,283		23,121,045	425,678	22,695,367
39	W incentive	2015	11,912,654	278,930	11,633,724		6,763,021	157,738	6,605,283		23,121,045	425,678	22,695,367
40	W / O incentive	2016	11,633,724	278,930	11,354,793		6,605,283	157,738	6,447,545		22,695,367	537,699	22,157,668
41	W incentive	2016	11,633,724	278,930	11,354,793		6,605,283	157,738	6,447,545		22,695,367	537,699	22,157,668
42	W / O incentive	2017	11,354,793	278,930	11,075,863	1,659,665	6,447,545	157,738	6,289,806	941,795	22,157,668	537,699	21,619,969
43	W incentive	2017	11,354,793	278,930	11,075,863	1,659,665	6,447,545	157,738	6,289,806	941,795	22,157,668	537,699	21,619,969
A						1,119,624				1,983,445			
B						1,119,624				1,983,445			
C						1,774,864				1,007,044			
D						1,774,864				1,007,044			
E						655,240				(976,401)			
F						655,240				(976,401)			
G						1.06941				1.06941			
H						700,719				(1,044,172)			
I						700,719				(1,044,172)			
	W / O incentive					2,360,385				(102,377)			
	W incentive					2,360,385				(102,377)			

Virginia Electric and Power Company
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10			
11	Schedule 12	(Yes or No)	
12	Life		
13	FCR W/O incentive	Line 3	
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	3,232,462
43	W incentive	2017	3,232,462

A	1,163,355
B	1,163,355
C	2,730,045
D	2,730,045
E	1,566,689
F	1,566,689
G	1.06941
H	1,675,431
I	1,675,431

W / O incentive	4,907,893
W incentive	4,907,893

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10			**Project BF-3**				**Project BF-4**				**Project BG-1**		
11	Schedule 12 (Yes or No)		Yes	B2053			Yes	B2053			Yes	B1906.1	
12	Life		43	Rebuild 28 mile line			43	Rebuild 28 mile line			43	At Yadkin 500 kV, install six 500	
13	FCR W/O incentive Line 3		12.3111%	(Altavista - Skimmer, 115kV)			12.3111%	(Altavista - Skimmer, 115kV)			12.3111%		
14	Incentive Factor (Basis Points /100)		0				0				0		
15	FCR W incentive L.13 +(L.14*L.5)		12.3111%				12.3111%				12.3111%		
16	Investment		12,060,669				944,125				4,398,307		
17	Annual Depreciation Exp		280,481				21,956				102,286		
18	In Service Month (1-12)		6				12				5		
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009											
27	W incentive	2009											
28	W / O incentive	2010											
29	W incentive	2010											
30	W / O incentive	2011											
31	W incentive	2011											
32	W / O incentive	2012											
33	W incentive	2012											
34	W / O incentive	2013											
35	W incentive	2013											
36	W / O incentive	2014											
37	W incentive	2014											
38	W / O incentive	2015	12,060,669	151,927	11,908,742		944,125	915	943,210		4,398,307	63,929	4,334,378
39	W incentive	2015	12,060,669	151,927	11,908,742		944,125	915	943,210		4,398,307	63,929	4,334,378
40	W / O incentive	2016	11,908,742	280,481	11,628,261		943,210	21,956	921,254		4,334,378	102,286	4,232,092
41	W incentive	2016	11,908,742	280,481	11,628,261		943,210	21,956	921,254		4,334,378	102,286	4,232,092
42	W / O incentive	2017	11,628,261	280,481	11,347,781	1,694,787	921,254	21,956	899,297	134,022	4,232,092	102,286	4,129,806
43	W incentive	2017	11,628,261	280,481	11,347,781	1,694,787	921,254	21,956	899,297	134,022	4,232,092	102,286	4,129,806
A						-				-			
B						-				-			
C						976,782				5,911			
D						976,782				5,911			
E						976,782				5,911			
F						976,782				5,911			
G						1.06941				1.06941			
H						1,044,579				6,321			
I						1,044,579				6,321			
	W / O incentive					2,739,366				140,343			
	W incentive					2,739,366				140,343			

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

These Three Columns
are Repeated to Provide
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10			
11	Schedule 12	(Yes or No)	
12	Life		V breakers
13	FCR W/O incentive	Line 3	
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	617,009
43	W incentive	2017	617,009

A	1,085,174
B	1,085,174
C	410,678
D	410,678
E	(674,495)
F	(674,495)
G	1.06941
H	(721,311)
I	(721,311)

W / O incentive	(104,303)
W incentive	(104,303)

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

These Three Columns are Repeated to Provide Line Number References on All Pages													
10			**Project BG-2**				**Project BH-1**				**Project BH-2**		
11	Schedule 12	(Yes or No)	Yes	B1906.1			Yes	B1908			Yes	B1908	
12	Life		43	At Yadkin 500 kV, install six 500 kV breakers			43	Rebuild Lexington-Dooms 500 kV			43	Rebuild Lexington-Dooms 500 k	
13	FCR W/O incentive	Line 3	12.3111%				12.3111%				12.3111%		
14	Incentive Factor (Basis Points /100)		0				0				0		
15	FCR W incentive L.13 +(L.14*L.5)		12.3111%				12.3111%				12.3111%		
16	Investment		5,644,742				72,049,058				30,025,678		
17	Annual Depreciation Exp		131,273				1,675,559				698,272		
18	In Service Month (1-12)		11				5				12		
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009											
27	W incentive	2009											
28	W / O incentive	2010											
29	W incentive	2010											
30	W / O incentive	2011											
31	W incentive	2011											
32	W / O incentive	2012											
33	W incentive	2012											
34	W / O incentive	2013											
35	W incentive	2013											
36	W / O incentive	2014											
37	W incentive	2014											
38	W / O incentive	2015	5,644,742	16,409	5,628,333		72,049,058	1,047,225	71,001,833		30,025,678	29,095	29,996,583
39	W incentive	2015	5,644,742	16,409	5,628,333		72,049,058	1,047,225	71,001,833		30,025,678	29,095	29,996,583
40	W / O incentive	2016	5,628,333	131,273	5,497,060		71,001,833	1,675,559	69,326,274		29,996,583	698,272	29,298,312
41	W incentive	2016	5,628,333	131,273	5,497,060		71,001,833	1,675,559	69,326,274		29,996,583	698,272	29,298,312
42	W / O incentive	2017	5,497,060	131,273	5,365,787	799,943	69,326,274	1,675,559	67,650,714	10,107,274	29,298,312	698,272	28,600,040
43	W incentive	2017	5,497,060	131,273	5,365,787	799,943	69,326,274	1,675,559	67,650,714	10,107,274	29,298,312	698,272	28,600,040
A						-				423,111			
B						-				423,111			
C						105,933				6,727,360			
D						105,933				6,727,360			
E						105,933				6,304,249			
F						105,933				6,304,249			
G						1.06941				1.06941			
H						113,286				6,741,820			
I						113,286				6,741,820			
	W / O incentive					913,229				16,849,094			
	W incentive					913,229				16,849,094			

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

These Three Columns are Repeated to Provide Line Number References on All Pages

10			
11	Schedule 12	(Yes or No)	
12	Life		
13	FCR W/O incentive	Line 3	
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	4,262,245
43	W incentive	2017	4,262,245

A	3,701,203
B	3,701,203
C	187,982
D	187,982
E	(3,513,221)
F	(3,513,221)
G	1.06941
H	(3,757,070)
I	(3,757,070)

W / O incentive	505,175
W incentive	505,175

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

These Three Columns
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Line Number
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10			Project BH-3				Project BI				Project BJ		
11	Schedule 12	(Yes or No)	Yes	B1908			Yes	B1698			Yes	B1905.1	
12	Life		43	Rebuild Lexington-Dooms 500 kV			43	Install a 2nd 500/230 kV transformer			43	Surry to Skiffes Creek 500 kV Lin	
13	FCR W/O incentive	Line 3	12.3111%				12.3111%	at Brambleton			12.3111%	(7 miles overhead)	
14	Incentive Factor (Basis Points /100)		0				0				0		
15	FCR W incentive L.13 +(L.14*L.5)		12.3111%				12.3111%				12.3111%		
16	Investment		13,043,080				22,268,738				145,000,000		
17	Annual Depreciation Exp		303,327				517,878				3,372,093		
18	In Service Month (1-12)		12				6				11		
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009											
27	W incentive	2009											
28	W / O incentive	2010											
29	W incentive	2010											
30	W / O incentive	2011											
31	W incentive	2011											
32	W / O incentive	2012											
33	W incentive	2012											
34	W / O incentive	2013											
35	W incentive	2013											
36	W / O incentive	2014											
37	W incentive	2014											
38	W / O incentive	2015											
39	W incentive	2015											
40	W / O incentive	2016	13,043,080	12,639	13,030,441		22,268,738	280,517	21,988,221				
41	W incentive	2016	13,043,080	12,639	13,030,441		22,268,738	280,517	21,988,221				
42	W / O incentive	2017	13,030,441	303,327	12,727,114	1,888,852	22,268,738	517,878	21,750,860	3,227,535	145,000,000	421,512	144,578,488
43	W incentive	2017	13,030,441	303,327	12,727,114	1,888,852	22,268,738	517,878	21,750,860	3,227,535	145,000,000	421,512	144,578,488
A						283,340				-			
B						283,340				-			
C						-				-			
D						-				-			
E						(283,340)				-			
F						(283,340)				-			
G						1.06941				1.06941			
H						(303,007)				-			
I						(303,007)				-			
	W / O incentive					1,585,845				3,227,535			
	W incentive					1,585,845				3,227,535			

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

These Three Columns
are Repeated to Provide
Line Number
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10			
11	Schedule 12	(Yes or No)	
12	Life		e
13	FCR W/O incentive	Line 3	
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	2,649,662
43	W incentive	2017	2,649,662

A	-
B	-
C	-
D	-
E	-
F	-
G	1.06941
H	-
I	-

W / O incentive	2,649,662
W incentive	2,649,662

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

These Three Columns are Repeated to Provide Line Number References on All Pages													
10				**Project BK**				**Project BM**					**Project BN**
11	Schedule 12	(Yes or No)	Yes	B1905.2			Yes	B1905.4			Yes	B1905.5	
12	Life		43	Surry 500 kV Station Work			43	Skiffes Creek - Whealton 230 kV line			43	Whealton 230 kV breakers	
13	FCR W/O incentive	Line 3	12.3111%				12.3111%				12.3111%		
14	Incentive Factor (Basis Points /100)		0				0				0		
15	FCR W incentive L.13 +(L.14*L.5)		12.3111%				12.3111%				12.3111%		
16	Investment		1,834,471				-				4,500,000		
17	Annual Depreciation Exp		42,662				-				104,651		
18	In Service Month (1-12)		5								6		
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009											
27	W incentive	2009											
28	W / O incentive	2010											
29	W incentive	2010											
30	W / O incentive	2011											
31	W incentive	2011											
32	W / O incentive	2012											
33	W incentive	2012											
34	W / O incentive	2013											
35	W incentive	2013											
36	W / O incentive	2014	1,834,471	26,664	1,807,807								
37	W incentive	2014	1,834,471	26,664	1,807,807								
38	W / O incentive	2015	1,807,807	42,662	1,765,145								
39	W incentive	2015	1,807,807	42,662	1,765,145								
40	W / O incentive	2016	1,765,145	42,662	1,722,483		-	-	-		4,500,000	56,686	4,443,314
41	W incentive	2016	1,765,145	42,662	1,722,483		-	-	-		4,500,000	56,686	4,443,314
42	W / O incentive	2017	1,722,483	42,662	1,679,821	252,093	-	-	-	-	4,500,000	104,651	4,395,349
43	W incentive	2017	1,722,483	42,662	1,679,821	252,093	-	-	-	-	4,500,000	104,651	4,395,349
A						270,401				-			
B						270,401				-			
C						269,657				-			
D						269,657				-			
E						(744)				-			
F						(744)				-			
G						1.06941				1.06941			
H						(796)				-			
I						(796)				-			
	W / O incentive					251,298				-			
	W incentive					251,298				-			

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

These Three Columns are Repeated to Provide Line Number References on All Pages			
10			
11	Schedule 12 (Yes or No)		
12	Life		
13	FCR W/O incentive Line 3		
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	652,211
43	W incentive	2017	652,211

A	-
B	-
C	-
D	-
E	-
F	-
G	1.06941
H	-
I	-

W / O incentive	652,211
W incentive	652,211

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

These Three Columns are Repeated to Provide Line Number References on All Pages													
10				**Project BS**				**Project BT-1**				**Project BT-2**	
11	Schedule 12	(Yes or No)	Yes	B1907			Yes	B1909			Yes	B1909	
12	Life		43	Install a 3rd 500/230 kV TX at Clover			43	Uprate Bremo – Midlothian 230 kV to			43	Uprate Bremo – Midlothian 230 k	
13	FCR W/O incentive	Line 3	12.3111%				12.3111%	its maximum operating temperature			12.3111%	its maximum operating temperatu	
14	Incentive Factor (Basis Points /100)		0				0				0		
15	FCR W incentive L.13 +(L.14*L.5)		12.3111%				12.3111%				12.3111%		
16	Investment		18,752,755				755,603				2,748,141		
17	Annual Depreciation Exp		436,111				17,572				63,910		
18	In Service Month (1-12)		4				6				11		
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009											
27	W incentive	2009											
28	W / O incentive	2010											
29	W incentive	2010											
30	W / O incentive	2011											
31	W incentive	2011											
32	W / O incentive	2012											
33	W incentive	2012											
34	W / O incentive	2013											
35	W incentive	2013											
36	W / O incentive	2014											
37	W incentive	2014											
38	W / O incentive	2015					755,603	9,518	746,085				
39	W incentive	2015					755,603	9,518	746,085				
40	W / O incentive	2016	18,752,755	308,912	18,443,843		746,085	17,572	728,513		2,748,141	7,989	2,740,152
41	W incentive	2016	18,752,755	308,912	18,443,843		746,085	17,572	728,513		2,748,141	7,989	2,740,152
42	W / O incentive	2017	18,752,755	436,111	18,316,644	2,717,943	728,513	17,572	710,940	106,179	2,748,141	63,910	2,684,231
43	W incentive	2017	18,752,755	436,111	18,316,644	2,717,943	728,513	17,572	710,940	106,179	2,748,141	63,910	2,684,231
A						-				-			
B						-				-			
C						-				61,196			
D						-				61,196			
E						-				61,196			
F						-				61,196			
G						1.06941				1.06941			
H						-				65,443			
I						-				65,443			
	W / O incentive					2,717,943				171,622			
	W incentive					2,717,943				171,622			

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

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are Repeated to Provide
Line Number
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10			
11	Schedule 12	(Yes or No)	
12	Life		V to
13	FCR W/O incentive	Line 3	ure
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	398,304
43	W incentive	2017	398,304

A	-
B	-
C	-
D	-
E	-
F	-
G	1.06941
H	-
I	-

W / O incentive	398,304
W incentive	398,304

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

These Three Columns
are Repeated to Provide
Line Number
References on All Pages

10				**Project BU**				**Project BV-1A**				**Project BV-1B**	
11	Schedule 12	(Yes or No)	Yes	B1328			Yes	B1912			Yes	B1912	
12	Life		43	Uprate the 3.63 mile line section between			43	Install a 500 MVAR SVC at			43	Install a 500 MVAR SVC at	
13	FCR W/O incentive	Line 3	12.3111%	Possum and Dumfries substations,			12.3111%	Landstown 230 kV			12.3111%	Landstown 230 kV	
14	Incentive Factor (Basis Points /100)		0	Replace 1600 amp wave trap at Possum Point			0	(Includes project modifications.)			0	(Includes project modifications.)	
15	FCR W incentive L.13 +(L.14*L.5)		12.3111%				12.3111%				12.3111%		
16	Investment		3,699,668				17,562,450				24,000,000		
17	Annual Depreciation Exp		86,039				408,429				558,140		
18	In Service Month (1-12)		12				4				6		
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009											
27	W incentive	2009											
28	W / O incentive	2010											
29	W incentive	2010											
30	W / O incentive	2011											
31	W incentive	2011											
32	W / O incentive	2012											
33	W incentive	2012											
34	W / O incentive	2013											
35	W incentive	2013											
36	W / O incentive	2014											
37	W incentive	2014											
38	W / O incentive	2015	3,699,668	3,585	3,696,083								
39	W incentive	2015	3,699,668	3,585	3,696,083								
40	W / O incentive	2016	3,696,083	86,039	3,610,044		17,562,450	289,304	17,273,146		24,000,000	302,326	23,697,674
41	W incentive	2016	3,696,083	86,039	3,610,044		17,562,450	289,304	17,273,146		24,000,000	302,326	23,697,674
42	W / O incentive	2017	3,610,044	86,039	3,524,005	525,180	17,562,450	408,429	17,154,021	2,545,426	24,000,000	558,140	23,441,860
43	W incentive	2017	3,610,044	86,039	3,524,005	525,180	17,562,450	408,429	17,154,021	2,545,426	24,000,000	558,140	23,441,860
A						395,765				-			
B						395,765				-			
C						23,163				-			
D						23,163				-			
E						(372,603)				-			
F						(372,603)				-			
G						1.06941				1.06941			
H						(398,465)				-			
I						(398,465)				-			
	W / O incentive					126,715				2,545,426			
	W incentive					126,715				2,545,426			

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

These Three Columns are Repeated to Provide Line Number References on All Pages

10			
11	Schedule 12 (Yes or No)		
12	Life		
13	FCR W/O incentive Line 3		
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	3,478,456
43	W incentive	2017	3,478,456

A	-
B	-
C	-
D	-
E	-
F	-
G	1.06941
H	-
I	-

W / O incentive	3,478,456
W incentive	3,478,456

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

These Three Columns
are Repeated to Provide
Line Number
References on All Pages

10			Project BV-1C				Project BV-2				Project BW		
11	Schedule 12	(Yes or No)	Yes	B1912			Yes	B1912			Yes	B1701	
12	Life		43	Install a 500 MVAR SVC at			43	125 MVAr STATCOM at Lynnhaven			43	Reconductor line #2104	
13	FCR W/O incentive	Line 3	12.3111%	Landstown 230 kV			12.3111%				12.3111%	(Fredericksburg - Cranes Corner	
14	Incentive Factor (Basis Points /100)		0	(Includes project modifications.)			0				0		
15	FCR W incentive L.13 +(L.14*L.5)		12.3111%				12.3111%				12.3111%		
16	Investment		23,003,709				24,064,108				3,023,624		
17	Annual Depreciation Exp		534,970				559,630				70,317		
18	In Service Month (1-12)		11				1				7		
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009											
27	W incentive	2009											
28	W / O incentive	2010											
29	W incentive	2010											
30	W / O incentive	2011											
31	W incentive	2011											
32	W / O incentive	2012											
33	W incentive	2012											
34	W / O incentive	2013											
35	W incentive	2013											
36	W / O incentive	2014											
37	W incentive	2014											
38	W / O incentive	2015											
39	W incentive	2015											
40	W / O incentive	2016	23,003,709	66,871	22,936,838						3,023,624	32,229	2,991,395
41	W incentive	2016	23,003,709	66,871	22,936,838						3,023,624	32,229	2,991,395
42	W / O incentive	2017	23,003,709	534,970	22,468,739	3,334,058	24,064,108	536,312	23,527,796	3,343,801	3,023,624	70,317	2,953,307
43	W incentive	2017	23,003,709	534,970	22,468,739	3,334,058	24,064,108	536,312	23,527,796	3,343,801	3,023,624	70,317	2,953,307

A		-	-
B		-	-
C		-	-
D		-	-
E		-	-
F		-	-
G		1.06941	1.06941
H		-	-
I		-	-
	W / O incentive	3,334,058	3,343,801
	W incentive	3,334,058	3,343,801

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

These Three Columns are Repeated to Provide Line Number References on All Pages

10			
11	Schedule 12 (Yes or No)		
12	Life		
13	FCR W/O incentive Line 3		230 kV)
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	438,231
43	W incentive	2017	438,231

A	-
B	-
C	-
D	-
E	-
F	-
G	1.06941
H	-
I	-

W / O incentive	438,231
W incentive	438,231

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

These Three Columns
are Repeated to Provide
Line Number
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10			**Project BX**				**Project BY-1**				**Project BY-2**		
11	Schedule 12	(Yes or No)	Yes	B1791			Yes	B1694			Yes	B1694	
12	Life		43	Wreck and rebuild 2.1 mile section of			43	Rebuild Loudoun - Brambleton 500 kV			43	Rebuild Loudoun - Brambleton 5	
13	FCR W/O incentive	Line 3	12.3111%	Gordonsville and Somerset (Line #11)			12.3111%				12.3111%		
14	Incentive Factor (Basis Points /100)		0				0				0		
15	FCR W incentive L.13 +(L.14*L.5)		12.3111%				12.3111%				12.3111%		
16	Investment		3,441,963				22,068,195				20,197,670		
17	Annual Depreciation Exp		80,046				513,214				469,713		
18	In Service Month (1-12)		5				2				6		
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009											
27	W incentive	2009											
28	W / O incentive	2010											
29	W incentive	2010											
30	W / O incentive	2011											
31	W incentive	2011											
32	W / O incentive	2012											
33	W incentive	2012											
34	W / O incentive	2013											
35	W incentive	2013											
36	W / O incentive	2014											
37	W incentive	2014											
38	W / O incentive	2015	3,441,963	50,029	3,391,934								
39	W incentive	2015	3,441,963	50,029	3,391,934								
40	W / O incentive	2016	3,391,934	80,046	3,311,889		22,068,195	449,062	21,619,133		20,197,670	254,428	19,943,242
41	W incentive	2016	3,391,934	80,046	3,311,889		22,068,195	449,062	21,619,133		20,197,670	254,428	19,943,242
42	W / O incentive	2017	3,311,889	80,046	3,231,843	482,850	22,068,195	513,214	21,554,981	2,862,812	20,197,670	469,713	19,727,957
43	W incentive	2017	3,311,889	80,046	3,231,843	482,850	22,068,195	513,214	21,554,981	2,862,812	20,197,670	469,713	19,727,957
A						-				-			
B						-				-			
C						321,383				-			
D						321,383				-			
E						321,383				-			
F						321,383				-			
G						1.06941				1.06941			
H						343,690				-			
I						343,690				-			
	W / O incentive					826,539				2,862,812			
	W incentive					826,539				2,862,812			

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

These Three Columns
are Repeated to Provide
Line Number
References on All Pages

10			
11	Schedule 12	(Yes or No)	
12	Life		00 kV
13	FCR W/O incentive	Line 3	
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	2,927,363
43	W incentive	2017	2,927,363

A	-
B	-
C	-
D	-
E	-
F	-
G	1.06941
H	-
I	-

W / O incentive	2,927,363
W incentive	2,927,363

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

These Three Columns
are Repeated to Provide
Line Number
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10		**Project BZ**		**Project CA-1**		**Project CA-2**
11	Schedule 12 (Yes or No)	Yes	B1696	Yes	B2373	Yes	B2373
12	Life	43	Install a breaker and a half scheme with	43	Build 2nd Loudoun - Brambleton 500 kV within	43	Build 2nd Loudoun - Brambleton
13	FCR W/O incentive Line 3	12.3111%	a minimum of eight 230 kV breakers	12.3111%	existing ROW. The Loudoun - Brambleton	12.3111%	existing ROW. The Loudoun - Br
14	Incentive Factor (Basis Points /100)	0	for five existing lines at Idylwood 230 kV	0	230 kV line relocated as an underbuild on the	0	230 kV line relocated as an unde
15	FCR W incentive L.13 +(L.14*L.5)	12.3111%		12.3111%	new 500 kV line.	12.3111%	new 500 kV line.
16	Investment	6,163,333		27,896,771		24,551,607	
17	Annual Depreciation Exp	143,333		648,762		570,968	
18	In Service Month (1-12)	9		12		5	

19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009											
27	W incentive	2009											
28	W / O incentive	2010											
29	W incentive	2010											
30	W / O incentive	2011											
31	W incentive	2011											
32	W / O incentive	2012											
33	W incentive	2012											
34	W / O incentive	2013											
35	W incentive	2013											
36	W / O incentive	2014											
37	W incentive	2014											
38	W / O incentive	2015					27,896,771	27,032	27,869,739				
39	W incentive	2015					27,896,771	27,032	27,869,739				
40	W / O incentive	2016	6,163,333	41,806	6,121,527		27,869,739	648,762	27,220,977				
41	W incentive	2016	6,163,333	41,806	6,121,527		27,869,739	648,762	27,220,977				
42	W / O incentive	2017	6,163,333	143,333	6,020,000	893,287	27,220,977	648,762	26,572,215	3,960,040	24,551,607	356,855	24,194,752
43	W incentive	2017	6,163,333	143,333	6,020,000	893,287	27,220,977	648,762	26,572,215	3,960,040	24,551,607	356,855	24,194,752

A		-	-
B		-	-
C		-	157,938
D		-	157,938
E		-	157,938
F		-	157,938
G		1.06941	1.06941
H		-	168,900
I		-	168,900
	W / O incentive	893,287	4,128,940
	W incentive	893,287	4,128,940

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

These Three Columns
are Repeated to Provide
Line Number
References on All Pages

10			
11	Schedule 12	(Yes or No)	
12	Life		500 kV within
13	FCR W/O incentive	Line 3	ambleton
14	Incentive Factor (Basis Points /100)		build on the
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	2,232,240
43	W incentive	2017	2,232,240

A	-
B	-
C	-
D	-
E	-
F	-
G	1.06941
H	-
I	-

W / O incentive	2,232,240
W incentive	2,232,240

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

These Three Columns are Repeated to Provide Line Number References on All Pages													
10			Project CB-1				Project CB-2				Project CC		
11	Schedule 12	(Yes or No)	Yes	B2582			Yes	B2582			Yes	B1911	
12	Life		43	Rebuild the Elmont - Cunningham 500 kV line			43	Rebuild the Elmont - Cunningham 500 kV line			43	Add a second Valley 500/230 kV	
13	FCR W/O incentive	Line 3	12.3111%				12.3111%				12.3111%		
14	Incentive Factor (Basis Points /100)		0				0				0		
15	FCR W incentive L.13 +(L.14*L.5)		12.3111%				12.3111%				12.3111%		
16	Investment		50,000,000				44,996,707				22,662,771		
17	Annual Depreciation Exp		1,162,791				1,046,435				527,041		
18	In Service Month (1-12)		7				12				6		
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**
20	W / O incentive	2006											
21	W incentive	2006											
22	W / O incentive	2007											
23	W incentive	2007											
24	W / O incentive	2008											
25	W incentive	2008											
26	W / O incentive	2009											
27	W incentive	2009											
28	W / O incentive	2010											
29	W incentive	2010											
30	W / O incentive	2011											
31	W incentive	2011											
32	W / O incentive	2012											
33	W incentive	2012											
34	W / O incentive	2013											
35	W incentive	2013											
36	W / O incentive	2014											
37	W incentive	2014											
38	W / O incentive	2015											
39	W incentive	2015											
40	W / O incentive	2016									22,662,771	285,481	22,377,290
41	W incentive	2016									22,662,771	285,481	22,377,290
42	W / O incentive	2017	50,000,000	532,946	49,467,054	3,339,213	44,996,707	43,601	44,953,106	274,307	22,662,771	527,041	22,135,730
43	W incentive	2017	50,000,000	532,946	49,467,054	3,339,213	44,996,707	43,601	44,953,106	274,307	22,662,771	527,041	22,135,730
A						-				-			
B						-				-			
C						-				-			
D						-				-			
E						-				-			
F						-				-			
G						1.06941				1.06941			
H						-				-			
I						-				-			
	W / O incentive					3,339,213				274,307			
	W incentive					3,339,213				274,307			

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

These Three Columns
are Repeated to Provide
Line Number
References on All Pages

10			
11	Schedule 12	(Yes or No)	
12	Life		TX
13	FCR W/O incentive	Line 3	
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Rev Req**
20	W / O incentive	2006	
21	W incentive	2006	
22	W / O incentive	2007	
23	W incentive	2007	
24	W / O incentive	2008	
25	W incentive	2008	
26	W / O incentive	2009	
27	W incentive	2009	
28	W / O incentive	2010	
29	W incentive	2010	
30	W / O incentive	2011	
31	W incentive	2011	
32	W / O incentive	2012	
33	W incentive	2012	
34	W / O incentive	2013	
35	W incentive	2013	
36	W / O incentive	2014	
37	W incentive	2014	
38	W / O incentive	2015	
39	W incentive	2015	
40	W / O incentive	2016	
41	W incentive	2016	
42	W / O incentive	2017	3,284,644
43	W incentive	2017	3,284,644

A	-
B	-
C	-
D	-
E	-
F	-
G	1.06941
H	-
I	-

W / O incentive	3,284,644
W incentive	3,284,644

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

These Three Columns are Repeated to Provide Line Number References on All Pages

10			**Project CE**						
11	Schedule 12	(Yes or No)	Yes	B2471			If Yes for Schedule 12 Include in this Total.	If No for Schedule 12 include in this Sum.	
12	Life		43	R/P Midlothian 500 kV breaker and					
13	FCR W/O incentive	Line 3	12.3111%	M.O. switches with 3 breaker 500 kV ring bus.					
14	Incentive Factor (Basis Points /100)		0	Terminate Lines #563 Carson - Midlothian,					
15	FCR W incentive L.13 +(L.14*L.5)		12.3111%	#576 Midlothian - North Anna,					
16	Investment		7,824,557	Transformer #2 in new ring				Annual Revenue Requirement including Incentive if Applicable	Annual Revenue Requirement excluding Incentive
17	Annual Depreciation Exp		181,966						
18	In Service Month (1-12)		11						
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Total**	**Sum**	**Sum**
20	W / O incentive	2006							
21	W incentive	2006							
22	W / O incentive	2007							
23	W incentive	2007							
24	W / O incentive	2008							
25	W incentive	2008							
26	W / O incentive	2009							
27	W incentive	2009							
28	W / O incentive	2010							
29	W incentive	2010							
30	W / O incentive	2011							
31	W incentive	2011							
32	W / O incentive	2012							
33	W incentive	2012							
34	W / O incentive	2013							
35	W incentive	2013							
36	W / O incentive	2014							
37	W incentive	2014							
38	W / O incentive	2015	7,824,557	22,746	7,801,811				
39	W incentive	2015	7,824,557	22,746	7,801,811				
40	W / O incentive	2016	7,801,811	181,966	7,619,845				
41	W incentive	2016	7,801,811	181,966	7,619,845				
42	W / O incentive	2017	7,619,845	181,966	7,437,878	1,108,855	236,794,834		45,204,662
43	W incentive	2017	7,619,845	181,966	7,437,878	1,108,855	241,307,840	48,043,744	

A	-
B	-
C	146,841
D	146,841
E	146,841
F	146,841
G	1.06941
H	157,033
I	157,033

W / O incentive	1,265,889
W incentive	1,265,889

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]

Depreciation Rates Applicable Through March 31, 2013

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%
Miscellaneous Equipment	2.53%
Stores Equipment	5.08%
Power Operated Equipment	8.16%
Tools, Shop and Garage Equipment	4.76%
Electric Vehicle Recharge Equipment	13.23%

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

Virginia Electric and Power Company

ATTACHMENT H-16A

Attachment 9 - Depreciation Rates (Continued)[1]

Depreciation Rates Applicable on and After April 1, 2013

Plant Type	Applied Depreciation Rate
Transmission Plant	
Land	
Land Rights	1.17%
Structures and Improvements	1.53%
Station Equipment	2.89%
Station Equipment - Power Supply Computer Equipment	10.46%
Towers and Fixtures	2.08%
Poles and Fixtures	2.11%
Overhead conductors and Devices	1.92%
Underground Conduit	1.65%
Underground Conductors and Devices	1.92%
Roads and Trails	1.06%
General Plant	
Land	
Land Rights	1.71%
Structures and Improvements - Major	1.95%
Structures and Improvements - Other	2.82%
Office Furniture and Equipment	2.68%
Office Furniture and Equipment - EDP Hardware	15.26%
Office Furniture and Equipment - EDP Fixed Location	7.26%
Transportation Equipment	3.90%
Stores Equipment	2.52%
Tools, Shop and Garage Equipment	4.32%
Laboratory Equipment	3.69%
Power Operated Equipment	4.75%
Communication Equipment	3.14%
Communication Equipment - Massed	5.97%
Communication Equipment - 25 Years	2.48%
Miscellaneous Equipment	6.67%

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

Attachment 10

PSE&G Formula Rate for January 1, 2017 to December 31, 2017

Hesser G. McBride, Jr.
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PSEG
Services Corporation

October 17, 2016

VIA ELECTRONIC FILING

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

Re: Public Service Electric and Gas Company
Docket No. ER09-1257-000
Informational Filing of 2017 Formula Rate Annual Update

Dear Secretary Bose:

Pursuant to the Formula Rate Implementation Protocols ("Protocols") of Public Service Electric and Gas Company ("PSE&G") contained in Attachment H-10B of the PJM Interconnection , L.L.C. ("PJM") Open Access Transmission Tariff ("OATT"), PSE&G submits its Formula Rate Annual Update ("Annual Update") for 2017. This 2017 Annual Update sets forth PSE&G's annual transmission revenue requirement calculated in accordance with its Formula Rate for network transmission service under the PJM OATT for the period commencing January 1, 2017 to and including December 31, 2017. The 2017 Annual Update also includes a True-up Adjustment for the 2015 Rate Year (January 1, 2015 to and including December 31, 2015).

In accordance with the Protocols, this submission is provided to the Federal Energy Regulatory Commission for informational purposes only and requires no action by the Commission. As required by the Protocols, PSE&G is also providing a copy of this filing to PJM for posting on the PJM website. Exhibit 1 of this filing includes a copy of PSE&G's 2017 Annual Update. Consistent with the Commission Staff's Guidance on Formula Rate Updates, PSE&G is submitting the formula rate template and additional exhibits in Microsoft Excel format.

In addition to PSE&G's 2017 Annual Update formula rate template, PSE&G also submits Workpaper 1, which contains additional supporting information pursuant to Commission Staff's Guidance on Formula Rate Updates for the computation of accumulated deferred income taxes ("ADIT").

In 2015, the Internal Revenue Service ("IRS") issued several private letter rulings ("PLRs") regarding the computation of ADIT that is applied to reduce rate base. Based on the guidance in those PLRs, PSE&G determined that it must use the IRS proration rules, set forth in Internal Revenue Code ("IRC") regulation section 1.167(l)-1(h)(6), to calculate projected ADIT in the formula rate projection submitted herewith. Specifically, these rules require that the actual amount of the ADIT balance at the beginning of the year (i.e., January 1, 2017), and a pro rata portion of the amount of any projected increase to be credited or decrease to be charged during the future period shall be determined by multiplying any such increase or decrease by a fraction, the numerator of which is the number of days remaining in the period at the time that increase or decrease is to be accrued, and the denominator of which is the total number of days in the period. For PSE&G, the accrual period is monthly. Thus, in accordance with Example 2 of IRC regulation section 1.167(l)-1(h)(6), the monthly increases/(decreases) to the forecasted changes to PSE&G's ADIT balance are reflected on the last day of the month. Work Paper 1, provided herewith, details the calculation of PSE&G's prorated ADIT amount.

Thank you for your attention to this matter and please advise the undersigned of any questions.

Respectfully submitted,

Hesser G. McBride, Jr.

Hesser G. McBride, Jr.

Attachments

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 12/31/2017
	Allocators			
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense	(Note O)	Attachment 5	29,783,185
2	Total Wages Expense	(Note O)	Attachment 5	206,099,440
3	Less A&G Wages Expense	(Note O)	Attachment 5	7,544,875
4	Total Wages Less A&G Wages Expense		(Line 2 - Line 3)	198,554,565
5	**Wages & Salary Allocator**		(Line 1 / Line 4)	**15.0000%**
	Plant Allocation Factors			
6	Electric Plant in Service	(Note B)	Attachment 5	18,706,592,731
7	Common Plant in Service - Electric		(Line 22)	180,461,300
8	Total Plant in Service		(Line 6 + 7)	18,887,054,031
9	Accumulated Depreciation (Total Electric Plant)	(Note B & J)	Attachment 5	3,438,430,659
10	Accumulated Intangible Amortization - Electric	(Note B)	Attachment 5	4,531,392
11	Accumulated Common Plant Depreciation & Amortization - Electric	(Note B & J)	Attachment 5	28,812,089
12	Accumulated Common Amortization - Electric	(Note B)	Attachment 5	44,572,229
13	Total Accumulated Depreciation		(Line 9 + Line 10 + Line 11 + Line 12)	3,516,346,369
14	Net Plant		(Line 8 - Line 13)	15,370,707,662
15	Transmission Gross Plant		(Line 31)	9,671,727,259
16	**Gross Plant Allocator**		(Line 15 / Line 8)	**51.2082%**
17	Transmission Net Plant		(Line 43)	8,816,219,582
18	**Net Plant Allocator**		(Line 17 / Line 14)	**57.3573%**
	Plant Calculations			
	Plant In Service			
19	Transmission Plant In Service	(Note B)	Attachment 5	9,599,663,592
20	General	(Note B)	Attachment 5	224,065,400
21	Intangible - Electric	(Note B)	Attachment 5	11,733,759
22	Common Plant - Electric	(Note B)	Attachment 5	180,461,300
23	Total General, Intangible & Common Plant		(Line 20 + Line 21 + Line 22)	416,260,459
24	Less: General Plant Account 397 -- Communications	(Note B)	Attachment 5	26,500,088
25	Less: Common Plant Account 397 -- Communications	(Note B)	Attachment 5	19,892,821
26	General and Intangible Excluding Acct. 397		(Line 23 - Line 24 - Line 25)	369,867,550
27	Wage & Salary Allocator		(Line 5)	15.0000%
28	General and Intangible Plant Allocated to Transmission		(Line 26 * Line 27)	55,480,133
29	Account No. 397 Directly Assigned to Transmission	(Note B)	Attachment 5	16,583,534
30	Total General and Intangible Functionalized to Transmission		(Line 28 + Line 29)	72,063,667
31	**Total Plant In Rate Base**		(Line 19 + Line 30)	**9,671,727,259**
	Accumulated Depreciation			
32	Transmission Accumulated Depreciation	(Note B & J)	Attachment 5	815,358,651
33	Accumulated General Depreciation	(Note B & J)	Attachment 5	104,939,497
34	Accumulated Common Plant Depreciation - Electric	(Note B & J)	Attachment 5	73,384,318
35	Less: Amount of General Depreciation Associated with Acct. 397	(Note B & J)	Attachment 5	22,539,175
36	Balance of Accumulated General Depreciation		(Line 33 + Line 34 - Line 35)	155,784,640
37	Accumulated Intangible Amortization - Electric	(Note B)	(Line 10)	4,531,392
38	Accumulated General and Intangible Depreciation Ex. Acct. 397		(Line 36 + 37)	160,316,032
39	Wage & Salary Allocator		(Line 5)	15.0000%
40	Subtotal General and Intangible Accum. Depreciation Allocated to Transmission		(Line 38 * Line 39)	24,047,405
41	Accumulated General Depreciation Associated with Acct. 397 Directly Assigned to Transmission	(Note B & J)	Attachment 5	16,101,621
42	**Total Accumulated Depreciation**		(Lines 32 + 40 + 41)	**855,507,677**
43	**Total Net Property, Plant & Equipment**		(Line 31 - Line 42)	**8,816,219,582**

Public Service Electric and Gas Company

ATTACHMENT H-10A

	Formula Rate -- Appendix A	**Notes**	**FERC Form 1 Page # or Instruction**	**12 Months Ended 12/31/2017**
	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	-2,257,796,613
	CWIP for Incentive Transmission Projects			
45	CWIP Balances for Current Rate Year	(Note B & H)	Attachment 6	362,136,575
	Abandoned Transmission Projects			
45a	Unamortized Abandoned Transmission Projects	(Note R)	Attachment 5	0
46	**Plant Held for Future Use**	(Note C & Q)	Attachment 5	22,009,446
	Prepayments			
47	Prepayments	(Note A & Q)	Attachment 5	0
	Materials and Supplies			
48	Undistributed Stores Expense	(Note Q)	Attachment 5	0
49	Wage & Salary Allocator		(Line 5)	15.0000%
50	Total Undistributed Stores Expense Allocated to Transmission		(Line 48 * Line 49)	0
51	Transmission Materials & Supplies	(Note N & Q))	Attachment 5	16,840,790
52	Total Materials & Supplies Allocated to Transmission		(Line 50 + Line 51)	16,840,790
	Cash Working Capital			
53	Operation & Maintenance Expense		(Line 80)	130,300,299
54	1/8th Rule		1/8	12.5%
55	Total Cash Working Capital Allocated to Transmission		(Line 53 * Line 54)	16,287,537
	Network Credits			
56	Outstanding Network Credits	(Note N & Q))	Attachment 5	0
57	**Total Adjustment to Rate Base**		**(Lines 44 + 45 + 45a + 46 + 47 + 52 + 55 - 56)**	**(1,840,522,264)**
58	**Rate Base**		(Line 43 + Line 57)	**6,975,697,317**
	Operations & Maintenance Expense			
	Transmission O&M			
59	Transmission O&M	(Note O)	Attachment 5	99,724,192
60	Plus Transmission Lease Payments	(Note O)	Attachment 5	0
61	**Transmission O&M**		(Lines 59 + 60)	**99,724,192**
	Allocated Administrative & General Expenses			
62	Total A&G	(Note O)	Attachment 5	202,793,230
63	Plus: Actual PBOP expense	(Note J)	Attachment 5	33,048,517
64	Less: Actual PBOP expense	(Note O)	Attachment 5	33,328,250
65	Less Property Insurance Account 924	(Note O)	Attachment 5	4,022,046
66	Less Regulatory Commission Exp Account 928	(Note E & O)	Attachment 5	11,216,380
67	Less General Advertising Exp Account 930.1	(Note O)	Attachment 5	3,116,470
68	Less EPRI Dues	(Note D & O)	Attachment 5	0
69	**Administrative & General Expenses**		Sum (Lines 62 to 63) - Sum (Lines 64 to 68)	184,158,602
70	Wage & Salary Allocator		(Line 5)	15.0000%
71	**Administrative & General Expenses Allocated to Transmission**		(Line 69 * Line 70)	**27,623,790**
	Directly Assigned A&G			
72	Regulatory Commission Exp Account 928	(Note G & O)	Attachment 5	645,380
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)	645,380
75	Property Insurance Account 924		(Line 65)	4,022,046
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)	4,022,046
78	Net Plant Allocator		(Line 18)	57.3573%
79	**A&G Directly Assigned to Transmission**		(Line 77 * Line 78)	**2,306,936**
80	**Total Transmission O&M**		**(Lines 61 + 71 + 74 + 79)**	**130,300,299**

Public Service Electric and Gas Company

ATTACHMENT H-10A

Formula Rate -- Appendix A

Shaded cells are input cells

Line	Description		Notes	FERC Form 1 Page # or Instruction	12 Months Ended 12/31/2017
	Depreciation & Amortization Expense				
	Depreciation Expense				
81	Transmission Depreciation Expense Including Amortization of Limited Term Plant		(Note J & O)	Attachment 5	228,796,129
81a	Amortization of Abandoned Plant Projects		(Note R)	Attachment 5	0
82	General Depreciation Expense Including Amortization of Limited Term Plant		(Note J & O)	Attachment 5	21,659,659
83	Less: Amount of General Depreciation Expense Associated with Acct. 397		(Note J & O)	Attachment 5	4,729,585
84	Balance of General Depreciation Expense			(Line 82 - Line 83)	16,930,074
85	Intangible Amortization		(Note A & O)	Attachment 5	10,051,339
86	Total			(Line 84 + Line 85)	26,981,413
87	Wage & Salary Allocator			(Line 5)	15.00%
88	General Depreciation & Intangible Amortization Allocated to Transmission			(Line 86 * Line 87)	4,047,212
89	General Depreciation Expense for Acct. 397 Directly Assigned to Transmission		(Note J & O)	Attachment 5	1,658,353
90	**General Depreciation and Intangible Amortization Functionalized to Transmission**			(Line 88 + Line 89)	**5,705,565**
91	**Total Transmission Depreciation & Amortization**			**(Lines 81 + 81a + 90)**	**234,501,695**
	Taxes Other than Income Taxes				
92	Taxes Other than Income Taxes		(Note O)	Attachment 2	10,156,257
93	**Total Taxes Other than Income Taxes**			(Line 92)	**10,156,257**
	Return \ Capitalization Calculations				
94	**Long Term Interest**			p117.62.c through 67.c	273,028,458
95	**Preferred Dividends**		enter positive	p118.29.d	0
	Common Stock				
96	Proprietary Capital		(Note P)	Attachment 5	7,232,269,434
97	Less Accumulated Other Comprehensive Income Account 219		(Note P)	Attachment 5	1,479,925
98	Less Preferred Stock			(Line 106)	0
99	Less Account 216.1		(Note P)	Attachment 5	3,398,888
100	**Common Stock**			(Line 96 - 97 - 98 - 99)	7,227,390,621
	Capitalization				
101	Long Term Debt		(Note P)	Attachment 5	6,587,117,120
102	Less Loss on Reacquired Debt		(Note P)	Attachment 5	70,401,824
103	Plus Gain on Reacquired Debt		(Note P)	Attachment 5	0
104	Less ADIT associated with Gain or Loss		(Note P)	Attachment 5	16,982,115
105	Total Long Term Debt			(Line 101 - 102 + 103 - 104)	6,499,733,181
106	Preferred Stock		(Note P)	Attachment 5	0
107	Common Stock			(Line 100)	7,227,390,621
108	**Total Capitalization**			(Sum Lines 105 to 107)	13,727,123,802
109	Debt %	Total Long Term Debt		(Line 105 / Line 108)	47.35%
110	Preferred %	Preferred Stock		(Line 106 / Line 108)	0.00%
111	Common %	Common Stock		(Line 107 / Line 108)	52.65%
112	Debt Cost	Total Long Term Debt		(Line 94 / Line 105)	0.0420
113	Preferred Cost	Preferred Stock		(Line 95 / Line 106)	0.0000
114	Common Cost	Common Stock	(Note J)	Fixed	0.1168
115	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Line 109 * Line 112)	0.0199
116	Weighted Cost of Preferred	Preferred Stock		(Line 110 * Line 113)	0.0000
117	Weighted Cost of Common	Common Stock		(Line 111 * Line 114)	0.0615
118	**Rate of Return on Rate Base (ROR)**			(Sum Lines 115 to 117)	**0.0814**
119	**Investment Return = Rate Base * Rate of Return**			**(Line 58 * Line 118)**	**567,720,029**

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 12/31/2017**
	Composite Income Taxes				
	Income Tax Rates				
120	FIT=Federal Income Tax Rate		(Note I)		35.00%
121	SIT=State Income Tax Rate or Composite				9.00%
122	p	(percent of federal income tax deductible for state purposes)		Per State Tax Code	0.00%
123	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			40.85%
124	T / (1-T)				69.06%
	ITC Adjustment				
125	Amortized Investment Tax Credit	enter negative	(Note O)	Attachment 5	-868,656
126	1/(1-T)			1 / (1 - Line 123)	169.06%
127	Net Plant Allocation Factor			(Line 18)	57.36%
128	**ITC Adjustment Allocated to Transmission**			(Line 125 * Line 126 * Line 127)	**-842,329**
129	**Income Tax Component =**	(T/1-T) * Investment Return * (1-(WCLTD/ROR)) =		[Line 124 * Line 119 * (1- (Line 115 / Line 118))]	**296,257,777**
130	**Total Income Taxes**			**(Line 128 + Line 129)**	**295,415,448**
	Revenue Requirement				
	Summary				
131	Net Property, Plant & Equipment			(Line 43)	8,816,219,582
132	Total Adjustment to Rate Base			(Line 57)	-1,840,522,264
133	**Rate Base**			(Line 58)	**6,975,697,317**
134	Total Transmission O&M			(Line 80)	130,300,299
135	Total Transmission Depreciation & Amortization			(Line 91)	234,501,695
136	Taxes Other than Income			(Line 93)	10,156,257
137	Investment Return			(Line 119)	567,720,029
138	Income Taxes			(Line 130)	295,415,448
139	**Gross Revenue Requirement**			**(Sum Lines 134 to 138)**	**1,238,093,728**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
140	Transmission Plant In Service			(Line 19)	9,599,663,592
141	Excluded Transmission Facilities		(Note B & M)	Attachment 5	0
142	Included Transmission Facilities			(Line 140 - Line 141)	9,599,663,592
143	Inclusion Ratio			(Line 142 / Line 140)	100.00%
144	Gross Revenue Requirement			(Line 139)	1,238,093,728
145	**Adjusted Gross Revenue Requirement**			(Line 143 * Line 144)	**1,238,093,728**
	Revenue Credits & Interest on Network Credits				
146	**Revenue Credits**		(Note O)	Attachment 3	23,864,514
147	**Interest on Network Credits**		(Note N & O)	Attachment 5	0
148	**Net Revenue Requirement**			**(Line 145 - Line 146 + Line 147)**	**1,214,229,214**
	Net Plant Carrying Charge				
149	Gross Revenue Requirement			(Line 144)	**1,238,093,728**
150	Net Transmission Plant, CWIP and Abandoned Plant			(Line 19 - Line 32 + Line 45 + Line 45a)	**9,146,441,516**
151	Net Plant Carrying Charge			(Line 149 / Line 150)	**13.5363%**
152	Net Plant Carrying Charge without Depreciation			(Line 149 - Line 81) / Line 150	**11.0349%**
153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes			(Line 149 - Line 81 - Line 119 - Line 130) / Line 15	**1.5980%**
	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)	**374,958,250**
155	Increased Return and Taxes			Attachment 4	**925,227,364**
156	Net Revenue Requirement per 100 Basis Point increase in ROE			(Line 154 + Line 155)	**1,300,185,614**
157	Net Transmission Plant, CWIP and Abandoned Plant			(Line 19 - Line 32 + Line 45 + Line 45a)	**9,146,441,516**
158	Net Plant Carrying Charge per 100 Basis Point increase in ROE			(Line 156 / Line 157)	**14.2152%**
159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation			(Line 156 - Line 81) / Line 157	**11.7137%**
160	**Net Revenue Requirement**			(Line 148)	**1,214,229,214**
161	True-up amount			Attachment 6	**-36,791,241**
162	Plus any increased ROE calculated on Attachment 7 other than PJM Sch. 12 projects not paid by other PJM transmission zones			Attachment 7	**7,726,945**
163	Facility Credits under Section 30.9 of the PJM OATT			Attachment 5	**0**
164	**Net Zonal Revenue Requirement**			(Line 160 + 161 + 162 + 163)	**1,185,164,918**
	Network Zonal Service Rate				
165	1 CP Peak		(Note L)	Attachment 5	**9,800.3**
166	Rate ($/MW-Year)			(Line 164 / 165)	**120,931.26**
167	**Network Service Rate ($/MW/Year)**			**(Line 166)**	**120,931.26**

Public Service Electric and Gas Company

ATTACHMENT H-10A

Formula Rate -- Appendix A	**Notes**	**FERC Form 1 Page # or Instruction**	**12 Months Ended 12/31/2017**

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 shall be based upon the Company's Actual Annual PBOP Expense until changed by a filing at FERC The actual Annual PBOP Expense to be included in the Formula Rate Annual Update that is required to be filed on or before October 15 of each year shall be based upon the Actual Annual PBOP Expense as charged to FERC Account 926 on behalf of electric employees for PBOP and as included by the Company in its most recent True-up Adjustment filing. PSEG will provide, in connection with each annual True-Up Adjustment filing a confidential copy of relevant pages from annual actuarial valuation report supporting the derivation of the Actual Annual PBOP Expense as charged to FERC Account 926 on behalf of electric employees 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 Transmission Owner whole on Line "&A248&"."
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 R	Unamortized Abandoned Plant and Amortization of Abandoned Plant may only be included pursuant to a Commission Order authorizing such inclusion

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31,2017

	Only Transmission Related	*Plant Related*	*Labor Related*	*Total ADIT*	
ADIT- 282	0	(4,075,528,187)	0		From Acct. 282 total, below
ADIT-283	0	(16,982,115)	0		From Acct. 283 total, below
ADIT-190	0	427,991	2,299,557		From Acct. 190 total, below
Subtotal	0	(4,092,082,310)	2,299,557		
Wages & Salary Allocator			15.0000%		
Net Plant Allocator		57.3573%			
End of Year ADIT	0	(2,347,107,042)	344,934	**(2,346,762,109)**	
End of Previous Year ADIT (from Sheet 1A-ADIT (3))	0	(2,169,176,051)	344,934	**(2,168,831,118)**	
Average Beginning and End of Year ADIT	0	(2,258,141,547)	344,934	**(2,257,796,613)**	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

(16,982,115) < 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*
ADIT - Real Estate Taxes	427,991			427,991		Book estimate accrued and expensed, tax deduction when paid related to plant
Vacation Pay	2,294,581				2,294,581	Vacation pay earned and expensed for books, tax deduction when paid - employees in all functions
OPEB	121,713,902				121,713,902	FASB 106 - Post Retirement Obligation, labor related.
Deferred Dividend Equivalents	2,964,680				2,964,680	Book accrual of dividends on employee stock options affecting all functions
Deferred Compensation	387,627				387,627	Book estimate accrued and expensed, tax deduction when paid - employees in all functions
ADIT - Unallowable PIP Accrual	(218,285)				(218,285)	Book estimate accrued and expensed, tax deduction when paid - employees in all functions
Bankruptcies $ Acfc	147,040	147,040				Book estimate accrued and expensed, tax deduction when paid - Generation Related
Federal Taxes Deferred	14,753,517			14,753,517		FASB 109 - deferred tax asset primarily associated with items previously flowed through due to regulation
Miscellaneous	(331,516)	2,797,529			(3,129,045)	
Subtotal - p234	**142,139,537**	**2,944,569**		**15,181,508**	**124,013,459**	
Less FASB 109 Above if not separately removed	14,753,517			14,753,517		
Less FASB 106 Above if not separately removed	121,713,902				121,713,902	
Total	**5,672,118**	**2,944,569**		**427,991**	**2,299,557**	

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 31,2017

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 (Federal)	(3,675,898,492)	(9,144,703)		(3,666,753,789)		Basis difference resulting from accelerated tax depreciation versus depreciation used for ratemaking purposes - related to all functions
Depreciation - Liberalized Depreciation (State)	(320,565,175)	88,209,223		(408,774,398)		Basis difference resulting from accelerated tax depreciation versus depreciation used for ratemaking purposes - related to all functions
Accounting for Income Taxes	(211,560,168)	52,447,501		(264,007,669)		FASB 109 - deferred tax liability primarily associated with plant related items previously flowed through due to regulation
Subtotal - p275	**(4,208,023,835)**	**131,512,021**		**(4,339,535,856)**		
Less FASB 109 Above if not separately removed	(264,007,669)			(264,007,669)		
Less FASB 106 Above if not separately removed						
Total	**(3,944,016,166)**	**131,512,021**		**(4,075,528,187)**		

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

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Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31,2017

A	B	C	D	E	F	G
ADIT-283	*Total*	Gas, Prod or Other Related	Only Transmission Related	Plant	Labor	
Securitization Regulatory Asset	26,437,829	26,437,829				Generation Related (Securitization of Stranded Costs)
Environmental Cleanup Costs	88,629,131	88,629,131				Book estimate accrued and expensed, tax deduction when paid - Manufactured Gas Plants
New Jersey Corporation Business Tax	9,651,432	9,651,432				New Jersey Corporate Income Tax - Plant Related- Contra Account of 190 NJCBT
Accelerated Activity Plan	(102,386,095)	(102,386,095)				Demand Side management and Associated Programs - Retail Related
Loss on Reacquired Debt	(16,982,115)			(16,982,115)		Tax deduction when reacquired, booked amortizes to expense
Additional Pension Deduction	(134,787,630)	(134,787,630)				Associated with Pension Liability not in rates
Sales Tax Reserve	7,193,851	7,193,851				Sales tax audit reserve
Miscellaneous	(216,397,587)	(216,397,587)				Miscellaneous Tax Adjustments
Deferred Gain	49,546,499	49,546,499				Deferred gain resulted from 2000 deregulation step up basis
Accounting for Income Taxes (FAS109) - Federal	(219,093,956)			(219,093,956)		FASB 109 - deferred tax liability primarily non-plant related items previously flowed through due to regulation
Subtotal - p277	**(508,188,641)**	**(272,112,571)**		**(236,076,070)**		
Less FASB 109 Above if not separately removed	(219,093,956)			(219,093,956)		
Less FASB 106 Above if not separately removed						
Total	**(289,094,685)**	**(272,112,571)**		**(16,982,115)**		

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 31,2016

	Only Transmission Related	*Plant Related*	*Labor Related*	*Total ADIT*	
ADIT- 282	0	(3,765,312,995)	0		From Acct. 282 total, below
ADIT-283	0	(16,982,115)	0		From Acct. 283 total, below
ADIT-190	0	427,991	2,299,557		From Acct. 190 total, below
Subtotal	0	(3,781,867,119)	2,299,557		
Wages & Salary Allocator			15.0000%		
Net Plant Allocator		57.3573%			
End of Year ADIT	0	(2,169,176,051)	344,934	**(2,168,831,118)**	

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

(16,982,115) < 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 *ADIT-190*	B *Total*	C *Gas, Prod Or Other Related*	D *Only Transmission Related*	E *Plant Related*	F *Labor Related*	G *Justification*
ADIT - Real Estate Taxes	427,991			427,991		Book estimate accrued and expensed, tax deduction when paid related to plant
Vacation Pay	2,294,581				2,294,581	Vacation pay earned and expensed for books, tax deduction when paid - employees in all functions
OPEB	137,864,407				137,864,407	FASB 106 - Post Retirement Obligation, labor related.
Deferred Dividend Equivalents	2,964,680				2,964,680	Book accrual of dividends on employee stock options affecting all functions
Deferred Compensation	387,627				387,627	Book estimate accrued and expensed, tax deduction when paid - employees in all functions
ADIT - Unallowable PIP Accrual	(218,285)				(218,285)	Book estimate accrued and expensed, tax deduction when paid - employees in all functions
Bankruptcies $ Acfc	147,040	147,040				Book estimate accrued and expensed, tax deduction when paid - Generation Related
Federal Taxes Deferred	14,753,517			14,753,517		FASB 109 - deferred tax asset primarily associated with items previously flowed through due to regulation
Miscellaneous	(331,516)	2,797,529			(3,129,045)	
Subtotal - p234	**158,290,041**	**2,944,569**		**15,181,508**	**140,163,964**	
Less FASB 109 Above if not separately removed	14,753,517			14,753,517		
Less FASB 106 Above if not separately removed	137,864,407				137,864,407	
Total	**5,672,118**	**2,944,569**		**427,991**	**2,299,557**	

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 31,2016

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 (Federal)	(3,454,618,678)	(5,916,899)		(3,448,701,778.55)		Basis difference resulting from accelerated tax depreciation versus depreciation used for ratemaking purposes - related to all functions
Depreciation - Liberalized Depreciation (State)	(219,112,028)	97,499,189		(316,611,217)		Basis difference resulting from accelerated tax depreciation versus depreciation used for ratemaking purposes - related to all functions
Accounting for Income Taxes	(359,864,585)	(5,916,899)		(353,947,685)		FASB 109 - deferred tax liability primarily associated with plant related items previously flowed through due to regulation
Subtotal - p275	**(4,033,595,291)**	**85,665,390**		**(4,119,260,681)**		
Less FASB 109 Above if not separately removed	(353,947,685)			(353,947,685)		
Less FASB 106 Above if not separately removed						
Total	**(3,679,647,606)**	**85,665,390**		**(3,765,312,995)**		

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

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Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31,2016

A	B	C	D	E	F	G
ADIT-283	*Total*	Related	Only Transmission Related	Plant	Labor	
Securitization Regulatory Asset	26,437,829	26,437,829				Generation Related (Securitization of Stranded Costs)
Environmental Cleanup Costs	88,629,131	88,629,131				Book estimate accrued and expensed, tax deduction when paid - Manufactured Gas Plants
New Jersey Corporation Business Tax	9,651,432	9,651,432				New Jersey Corporate Income Tax - Plant Related- Contra Account of 190 NJCBT
Accelerated Activity Plan	(102,386,095)	(102,386,095)				Demand Side management and Associated Programs - Retail Related
Loss on Reacquired Debt	(16,982,115)			(16,982,115)		Tax deduction when reacquired, booked amortizes to expense
Additional Pension Deduction	(134,273,967)	(134,273,967)				Associated with Pension Liability not in rates
Sales Tax Reserve	7,193,851	7,193,851				Sales tax audit reserve
Miscellaneous	(216,397,587)	(216,397,587)				Miscellaneous Tax Adjustments
Deferred Gain	49,546,499	49,546,499				Deferred gain resulted from 2000 deregulation step up basis
Accounting for Income Taxes (FAS109) - Federal	(219,093,956)			(219,093,956)		FASB 109 - deferred tax liability primarily non-plant related items previously flowed through due to regulation
Subtotal - p277	**(507,674,977)**	**(271,598,907)**		**(236,076,070)**		
Less FASB 109 Above if not separately removed	(219,093,956)			(219,093,956)		
Less FASB 106 Above if not separately removed						
Total	**(288,581,022)**	**(271,598,907)**		**(16,982,115)**		

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, 2017

	Other Taxes	***Page 263 Col (i)***	***Allocator***	***Allocated Amount***	
	Plant Related				
1	Real Estate	20,804,000			Attachment #5
2	***Total Plant Related***	20,804,000	N/A	7,847,000	
	Labor Related		***Wages & Salary Allocator***		
3	FICA	14,296,575			
4	Federal Unemployment Tax	163,741			
5	New Jersey Unemployment Tax	603,135			
6	New Jersey Workforce Development	331,596			
7					
8	***Total Labor Related***	15,395,047	15.0000%	2,309,257	
	Other Included		***Net Plant Allocator***		
9					
10					
11					
12					
13	***Total Other Included***	0	57.3573%	0	
14	***Total Included (Lines 8 + 14 + 19)***	36,199,047		10,156,257	
	Currently Excluded				
15	Corporate Business Tax	0			
16	TEFA	0			
17	Use & Sales Tax	0			
18	Local Franchise Tax	0			
19	PA Corporate Income Tax	0			
20	Municipal Utility	0			
21	Public Utility Fund	0			
22	**Subtotal, Excluded**	0			
23	**Total, Included and Excluded (Line 20 + Line 28)**	36,199,047			
24	**Total Other Taxes from p114.14.g - Actual**	36,199,047			
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, 2017

	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)		600,000
	Account 456 - Other Electric Revenues		
3	Transmission for Others		0
4	Schedule 1A		4,800,000
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)		
6	Point to Point Service revenues for which the load is not included in the divisor received by Transmission Owner		8,200,000
7	Professional Services (Note 2)		45,000
8	Revenues from Directly Assigned Transmission Facility Charges (Note 1)		9,268,580
9	Rent or Attachment Fees associated with Transmission Facilities (Note 2)		4,751,227
10	Gross Revenue Credits	(Sum Lines 1-9)	27,664,806
11	Less line 18	- line 18	(3,800,293)
12	Total Revenue Credits	line 10 + line 11	23,864,514
13	Revenues associated with lines 2, 7, and 9 (Note 2)		5,396,227
14	Income Taxes associated with revenues in line 13		2,204,359
15	One half margin (line 13 - line 14)/2		1,595,934
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		1,595,934
18	Line 13 less line 17		3,800,293

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	925,227,364
B	100 Basis Point increase in ROE			1.00%

Return Calculation

			Appendix A Line or Source Reference	
1	**Rate Base**		(Line 43 + Line 57)	6,975,697,317
2	**Long Term Interest**		p117.62.c through 67.c	273,028,458
3	**Preferred Dividends**	enter positive	p118.29.d	0
	Common Stock			
4	Proprietary Capital		Attachment 5	7,232,269,434
5	Less Accumulated Other Comprehensive Income Account 219		p112.15.c	1,479,925
6	Less Preferred Stock		(Line 106)	0
7	Less Account 216.1		Attachment 5	3,398,888
8	Common Stock		(Line 96 - 97 - 98 - 99)	7,227,390,621
	Capitalization			
9	Long Term Debt		Attachment 5	6,587,117,120
10	Less Loss on Reacquired Debt		Attachment 5	70,401,824
11	Plus Gain on Reacquired Debt		Attachment 5	0
12	Less ADIT associated with Gain or Loss		Attachment 5	16,982,115
13	Total Long Term Debt		(Line 101 - 102 + 103 - 104)	6,499,733,181
14	Preferred Stock		Attachment 5	0
15	Common Stock		(Line 100)	7,227,390,621
16	Total Capitalization		(Sum Lines 105 to 107)	13,727,123,802
17	Debt %	Total Long Term Debt	(Line 105 / Line 108)	47.3%
18	Preferred %	Preferred Stock	(Line 106 / Line 108)	0.0%
19	Common %	Common Stock	(Line 107 / Line 108)	52.7%
20	Debt Cost	Total Long Term Debt	(Line 94 / Line 105)	0.0420
21	Preferred Cost	Preferred Stock	(Line 95 / Line 106)	0.0000
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)	0.0199
24	Weighted Cost of Preferred	Preferred Stock	(Line 110 * Line 113)	0.0000
25	Weighted Cost of Common	Common Stock	(Line 111 * Line 114)	0.0668
26	**Rate of Return on Rate Base (ROR)**		**(Sum Lines 115 to 117)**	**0.0867**
27	**Investment Return = Rate Base * Rate of Return**		**(Line 58 * Line 118)**	**604,447,380**

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	-868,656
38	1/(1-T)		1 / (1 - Line 123)	169%
39	Net Plant Allocation Factor		(Line 18)	57.3573%
40	**ITC Adjustment Allocated to Transmission**		(Line 125 * Line 126 * Line 127)	**-842,329**
41	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		321,622,313
42	**Total Income Taxes**			**320,779,984**

Public Service Electric and Gas Company

ATTACHMENT H-10A

Attachment 5 - Cost Support - December 31, 2017

Electric / Non-electric Cost Support

				Previous Year	Current Year - 2017														
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 (Excludes Asset Retirement Costs - ARC)	(Note B)	p207.104g	17,914,138,579	17,918,065,090	17,950,818,414	18,074,806,299	18,113,192,849	18,549,837,416	19,020,636,331	19,046,736,994	19,077,148,860	19,130,025,430	19,246,946,120	19,364,495,117	19,778,858,010	18,706,592,731	
7	Common Plant in Service - Electric	(Note B)	p356	168,948,526	169,491,918	169,598,732	171,248,083	173,646,184	174,844,724	177,283,590	178,855,176	179,405,096	179,829,179	195,027,122	198,973,897	208,844,671	180,461,300	
9	Accumulated Depreciation (Total Electric Plant)	(Note B & J)	p219.29c	3,329,983,732	3,325,097,502	3,347,773,785	3,370,716,318	3,393,692,290	3,414,828,514	3,434,708,685	3,457,873,607	3,480,822,303	3,501,977,932	3,523,996,466	3,547,839,383	3,570,288,050	3,438,430,659	
10	Accumulated Intangible Amortization	(Note B)	p200.21c	3,367,740	3,561,358	3,754,976	3,948,594	4,142,211	4,335,829	4,529,447	4,723,065	4,916,683	5,110,300	5,303,918	5,497,536	5,716,437	4,531,392	
11	Accumulated Common Plant Depreciation - Electric	(Note B & J)	p356	27,112,407	26,394,369	25,703,927	26,181,423	26,866,624	27,658,379	28,193,265	28,983,518	29,791,522	30,508,045	31,435,041	32,405,295	33,323,337	28,812,089	
12	Accumulated Common Amortization - Electric	(Note B)	p356	40,821,845	41,437,679	42,053,512	42,669,346	43,291,087	43,912,828	44,556,844	45,210,103	45,863,363	46,516,622	47,171,791	47,826,960	48,107,003	44,572,229	
	Plant In Service																	
19	Transmission Plant in Service (Excludes Asset Retirement Costs - ARC)	(Note B)	p207.58.g	9,092,953,440	9,100,171,773	9,101,181,106	9,175,876,439	9,187,830,772	9,418,266,105	9,845,882,438	9,850,760,771	9,854,874,104	9,882,815,437	9,946,373,770	10,003,596,103	10,335,044,436	9,599,663,592	
20	General (Excludes Asset Retirement Costs - ARC)	(Note B)	p207.99.g	239,054,942	212,544,301	213,487,773	215,689,440	218,046,121	219,438,210	220,899,002	222,795,333	226,576,752	228,325,907	229,460,168	230,031,551	236,500,704	224,065,400	
21	Intangible - Electric	(Note B)	p205.5.g	11,617,067	11,617,067	11,617,067	11,617,067	11,617,067	11,617,067	11,617,067	11,617,067	11,617,067	11,617,067	11,617,067	11,617,067	13,134,067	11,733,759	
22	Common Plant in Service - Electric	(Note B)	p356	168,948,526	169,491,918	169,598,732	171,248,083	173,646,184	174,844,724	177,283,590	178,855,176	179,405,096	179,829,179	195,027,122	198,973,897	208,844,671	180,461,300	
24	General Plant Account 397 -- Communications	(Note B)	p207.94g	23,660,284	23,925,764	24,191,244	24,523,104	24,987,704	25,535,145	26,198,855	26,862,565	27,526,275	28,189,985	28,894,695	29,633,405	30,372,115	26,500,088	
25	Common Plant Account 397 -- Communications	(Note B)	p356	11,897,337	12,997,337	14,097,337	15,197,337	15,857,337	16,517,337	17,177,337	17,342,337	17,342,337	17,342,337	31,662,087	35,067,891	36,108,331	19,892,821	
29	Account No. 397 Directly Assigned to Transmission	(Note B)	Company Records	16,583,534	16,583,534	16,583,534	16,583,534	16,583,534	16,583,534	16,583,534	16,583,534	16,583,534	16,583,534	16,583,534	16,583,534	16,583,534	16,583,534	
	Accumulated Depreciation																	
32	Transmission Accumulated Depreciation	(Note B & J)	p219.25.c	749,953,237	760,789,479	771,656,739	783,096,391	793,448,950	803,949,381	812,754,044	825,133,464	837,924,110	847,827,639	859,232,285	871,109,376	882,787,363	815,358,651	
33	Accumulated General Depreciation	(Note B & J)	p219.28.b	129,291,152	101,659,513	101,467,590	102,136,125	102,645,416	101,612,210	102,069,276	102,988,284	103,423,492	104,256,564	104,455,576	104,072,318	104,135,950	104,939,497	
34	Accumulated Common Plant Depreciation & Amortization - Electric	(Note B & J)	p356	67,934,253	67,832,048	67,757,440	68,850,768	70,157,711	71,571,207	72,750,109	74,193,621	75,654,884	77,024,667	78,606,832	80,232,255	81,430,340	73,384,318	
35	Accumulated General Depreciation Associated with Acct. 397	(Note B & J)	Company Records	20,431,087	20,771,446	21,123,184	21,479,485	21,830,407	22,052,991	22,402,876	22,759,667	23,121,989	23,489,842	23,982,898	24,510,492	25,052,913	22,539,175	
41	Acc. Deprec. Acct. 397 Directly Assigned to Transmission	(Note B & J)	Company Records	15,272,445	15,410,641	15,548,837	15,687,033	15,825,229	15,963,425	16,101,621	16,239,818	16,378,014	16,516,210	16,654,406	16,792,602	16,930,798	16,101,621	

Wages & Salary

Line #s	**Descriptions**	**Notes**	**Page #'s & Instructions**	**End of Year**
2	Total Wage Expense	(Note A)	p354.28b	206,099,440
3	Total A&G Wages Expense	(Note A)	p354.27b	7,544,875
1	Transmission Wages		p354.21b	29,783,185

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	20,440,107	27,940,107	24,190,107
46	Transmission Only			18,259,446	25,759,446	22,009,446

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	0	0	0	0	15.000%	-

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	0
51	Transmission Materials & Supplies	(Note N & Q))	p227.8.b,c	16,840,790	16,840,790	16,840,790

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	0

O&M Expenses

Line #s	**Descriptions**	**Notes**	**Page #'s & Instructions**	**End of Year**
59	Transmission O&M	(Note O)	p.321.112.b	99,724,192
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	4,022,046

Adjustments to A & G Expense

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
62	Total A&G Expenses		p323.197b	202,793,230
63	Actual PBOP expense	(Note J)	Company Records	33,048,517
64	Actual PBOP expense	(Note O)	Company Records	33,328,250

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	11,216,380	0
	Directly Assigned A&G				
72	Regulatory Commission Exp Account 928	(Note G & O)	p351.11-13h	645,380	645,380

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	3,116,470	0	3,116,470

Education and Out Reach Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year	Education & Outreach	Other
	Directly Assigned A&G					
76	General Advertising Exp Account 930.1	(Note K & O)	p323.191b	3,116,470	0	3,116,470

Depreciation Expense

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
	Depreciation Expense			
81	Depreciation-Transmission	(Note J & O)	p336.7.f	228,796,129
82	Depreciation-General & Common	(Note J & O)	p336.10&11.f	21,659,659
83	Depreciation-General Expense Associated with Acct. 397	(Note J & O)	Company Records	4,729,585
85	Depreciation-Intangible	(Note A & O)	p336.1.f	10,051,339
89	Transmission Depreciation Expense for Acct. 397	(Note J & O)	Company Records	1,658,353

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		p263.33i	20,804,000	7,847,000	12.957.000

PSE&G's real estate taxes detail is in an access database which contains a list of the towns PSE&G pays taxes to, which are billed on a quarterly basis for various parcels of property by major classification. Every parcel is associated with a Lot & Block number. These Lot & Blocks are identified to a particular type of property and are labeled. This is the breakout of transmission real estate taxes from total electric.

Attachment 5 - Cost Support - December 31, 2017

Return \ Capitalization

Line #s	Descriptions	Notes	Page #'s & Instructions	2014 End of Year	2015 End of Year	Average
96	Proprietary Capital	(Note P)	p112.16.c,d	6,835,533,489	7,629,005,378	7,232,269,434
97	Accumulated Other Comprehensive Income Account 219	(Note P)	p112.15.c,d	1,732,845	1,227,004	1,479,925
99	Account 216.1	(Note P)	p119.53.c&d	3,323,160	3,474,616	3,398,888
101	Long Term Debt	(Note P)	p112.18.c,d thru 23.c,d	6,312,375,094	6,861,859,145	6,587,117,120
102	Loss on Reacquired Debt	(Note P)	p111.81.c,d	74,029,072	66,774,576	70,401,824
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)	16,982,115	16,982,115	16,982,115
106	Preferred Stock	(Note P)	p112.3.c,d	0	0	0

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 Credit	(Note O)	p266.8.f	868,656

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			
165	1 CP Peak	(Note L)	PJM Data	9,800.3

Abandoned Transmission Projects

Line #s		Descriptions		BRH Project	Project X	Project Y
	a	Beginning Balance of Unamortized Transmission Projects	Per FERC Order	$ -	$ -	$ -
Attachment 7	b	Years remaining in Amortization Period	Per FERC Order	$ -	$ -	$ -
81	c	Transmission Depreciation Expense Including Amortization of Limited Term Plant	(line a / line b)	$ -	$ -	$ -
	d	Ending Balance of Unamortized Transmission Projects	(line a - line c)	$ -	$ -	$ -
	e	Average Balance of Unamortized Abandoned Transmission Projects	(line a + d)/2	$ -	$ -	$ -
	g	Non Incentive Return and Income Taxes	(Appendix A line 137+ line 138)	$ -	$ -	$ -
	h	Rate Base	(Appendix A line 58)	$ -	$ -	$ -
Attachment 7	i	Non Incentive Return and Income Taxes	(line g / line h)	-	-	-
		Docket No. ER12-2274-000 authorizing $3,500,000 amortization over one-year recovery of BRH Abandoned Transmission Project		ER12-2274		

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6 - True-up Adjustment for Network Integration Transmission Service - December 31, 2017

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	2011	TO populates the formula with Year 2010 actual data and calculates the 2010 True-Up Adjustment Before Interest
October	2011	TO calculates the Interest to include in the 2010 True-Up Adjustment
October	2011	TO populates the formula with Year 2012 estimated data and 2010 True-Up Adjustment
June	2012	TO populates the formula with Year 2011 actual data and calculates the 2011 True-Up Adjustment Before Interest
October	2012	TO calculates the Interest to include in the 2011 True-Up Adjustment
October	2012	TO populates the formula with Year 2013 estimated data and 2011 True-Up Adjustment
June	2013	TO populates the formula with Year 2012 actual data and calculates the 2012 True-Up Adjustment Before Interest
October	2013	TO calculates the Interest to include in the 2012 True-Up Adjustment
October	2013	TO populates the formula with Year 2014 estimated data and 2012 True-Up Adjustment
June	2014	TO populates the formula with Year 2013 actual data and calculates the 2013 True-Up Adjustment Before Interest
October	2014	TO calculates the Interest to include in the 2013 True-Up Adjustment
October	2014	TO populates the formula with Year 2015 estimated data and 2013 True-Up Adjustment
June	2015	TO populates the formula with Year 2014 actual data and calculates the 2014 True-Up Adjustment Before Interest
October	2015	TO calculates the Interest to include in the 2014 True-Up Adjustment
October	2015	TO populates the formula with Year 2016 estimated data and 2014 True-Up Adjustment
June	2016	TO populates the formula with Year 2015 actual data and calculates the 2015 True-Up Adjustment Before Interest
October	2016	TO calculates the Interest to include in the 2015 True-Up Adjustment
October	2016	TO populates the formula with Year 2017 estimated data and 2015 True-Up Adjustment

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.	884,004,745	
B	ATRR based on projected costs included for the previous calendar year but excludes the true-up adjustment.	918,419,851	
C	Difference (A-B)	-34,415,106	<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	1.06904	
E	True-up Adjustment (C*D)	-36,791,241	

Where:
i = average interest rate as calculated below

Interest on Amount of Refunds or Surcharges

Month	Yr	Month
January	Year 1	0.2800%
February	Year 1	0.2500%
March	Year 1	0.2800%
April	Year 1	0.2700%
May	Year 1	0.2800%
June	Year 1	0.2700%
July	Year 1	0.2800%
August	Year 1	0.2800%
September	Year 1	0.2700%
October	Year 1	0.2800%
November	Year 1	0.2700%
December	Year 1	0.2800%
January	Year 2	0.2800%
February	Year 2	0.2600%
March	Year 2	0.2800%
April	Year 2	0.2800%
May	Year 2	0.2900%
June	Year 2	0.2800%
July	Year 2	0.3000%
August	Year 2	0.3000%
September	Year 2	0.2900%
Average Interest Rate		0.2786%

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2017

	Estimated Additions - 2017												
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	Other Projects PIS (Monthly additions)	Ridge Road 69kV Breaker Station (B1255) (monthly additions)	Cox's Corner-Lumberton 230kV Circuit (B1787) (monthly additions)	Sewaren Switch 230kV Conversion (B2276) (monthly additions)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (monthly additions)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (monthly additions)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (monthly additions)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33) (monthly additions)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (monthly additions)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70) (monthly additions)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81) (monthly additions	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83) (monthly additions)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) (monthly addtions)
		(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)
Dec-16	8,630,725,699	3,894,089	31,718,020	117,787,484	174,934,554	23,542,140	23,542,140	379,627	379,627	379,627	746,033	746,033	746,033
Jan	7,018,333.00			200,000									
Feb	809,333.00			200,000									
Mar	74,545,333.00			150,000									
Apr	10,954,333.00										100,000	100,000	100,000
May	135,078,869.35				831,844	831,844	831,844				9,202,909	9,202,909	9,202,909
Jun	276,465,893.00							14,245,750	14,245,750	14,245,750	14,245,750	14,245,750	25,715,094
Jul	3,878,333.00							111,111	111,111	111,111	111,111	111,111	111,111
Aug	4,113,333.00												
Sep	27,941,333.00												
Oct	31,860,185.00	31,698,148											
Nov	54,119,492.00	50,000							3,052,841				
Dec	298,274,629.00	54,000						334,949	30,440,109	334,949	334,949	334,949	334,949
Total	**9,555,785,098**	**35,696,237**	**31,718,020**	**118,337,484**	**175,766,398**	**24,373,985**	**24,373,985**	**15,071,438**	**48,229,438**	**15,071,438**	**24,740,752**	**24,740,752**	**36,210,096**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2017

Estimated Transmission Enhancement Charges (Before True-Up) - 2017

Total Projects	Branchburg (B0130)	Kittatinny (B0134)	Essex Aldene (B0145)	New Freedom Trans.(B0411)	New Freedom Loop (B0498)	Metuchen Transformer (B0161)	Branchburg-Flagtown-Somerville (B0169)	Flagtown-Somerville-Bridgewater (B0170)	Roseland Transformers (B0274)	Wave Trap Branchburg (B0172.2)	Reconductor Hudson - South Waterfront (B0813)	Reconductor South Mahwah J-3410 Circuit (B1017)
583,935,997	**2,176,785**	**882,891**	**9,471,779**	**2,398,697**	**3,045,575**	**2,954,897**	**1,795,196**	**784,820**	**2,410,045**	**3,081**	**1,082,298**	**2,463,182**

Actual Transmission Enhancement Charges - 2015

Total Projects	Branchburg (B0130)	Kittatinny (B0134)	Essex Aldene (B0145)	New Freedom Trans.(B0411)	New Freedom Loop (B0498)	Metuchen Transformer (B0161)	Branchburg-Flagtown-Somerville (B0169)	Flagtown-Somerville-Bridgewater (B0170)	Roseland Transformers (B0274)	Wave Trap Branchburg (B0172.2)	Reconductor Hudson - South Waterfront (B0813)	Reconductor South Mahwah J-3410 Circuit (B1017)
441,614,467	**2,397,208**	**970,986**	**10,416,881**	**2,639,133**	**3,346,067**	**3,244,794**	**1,971,555**	**862,264**	**2,646,618**	**3,388**	**1,187,289**	**2,701,236**

Reconciliation by Project (without interest)

Total Projects	Branchburg (B0130)	Kittatinny (B0134)	Essex Aldene (B0145)	New Freedom Trans.(B0411)	New Freedom Loop (B0498)	Metuchen Transformer (B0161)	Branchburg-Flagtown-Somerville (B0169)	Flagtown-Somerville-Bridgewater (B0170)	Roseland Transformers (B0274)	Wave Trap Branchburg (B0172.2)	Reconductor Hudson - South Waterfront (B0813)	Reconductor South Mahwah J-3410 Circuit (B1017)
(37,470,926)	**(240,601)**	**9,608**	**(1,329,286)**	**(265,195)**	**(388,081)**	**931,538**	**8,414**	**(181,331)**	**431,576**	**(12,049)**	**(328,205)**	**494,896**

Interest	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904

True Up by Project (with interest) - 2015

Total Projects	Branchburg (B0130)	Kittatinny (B0134)	Essex Aldene (B0145)	New Freedom Trans.(B0411)	New Freedom Loop (B0498)	Metuchen Transformer (B0161)	Branchburg-Flagtown-Somerville (B0169)	Flagtown-Somerville-Bridgewater (B0170)	Roseland Transformers (B0274)	Wave Trap Branchburg (B0172.2)	Reconductor Hudson - South Waterfront (B0813)	Reconductor South Mahwah J-3410 Circuit (B1017)
(40,058,045)	**(257,213)**	**10,271**	**(1,421,064)**	**(283,505)**	**(414,875)**	**995,855**	**8,994**	**(193,851)**	**461,373**	**(12,881)**	**(350,866)**	**529,065**

Estimated Transmission Enhancement Charges (After True-Up) - 2017

Total Projects	Branchburg (B0130)	Kittatinny (B0134)	Essex Aldene (B0145)	New Freedom Trans.(B0411)	New Freedom Loop (B0498)	Metuchen Transformer (B0161)	Branchburg-Flagtown-Somerville (B0169)	Flagtown-Somerville-Bridgewater (B0170)	Roseland Transformers (B0274)	Wave Trap Branchburg (B0172.2)	Reconductor Hudson - South Waterfront (B0813)	Reconductor South Mahwah J-3410 Circuit (B1017)
543,877,952	**1,919,572**	**893,162**	**8,050,714**	**2,115,192**	**2,630,700**	**3,950,752**	**1,804,191**	**590,969**	**2,871,418**	**(9,800)**	**731,433**	**2,992,247**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2017

Estimated Additions - 2017													
(N)	(O)	(P)	(R)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)	(AB)
Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (monthly additions)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (monthly additions)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (monthly additions)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (monthly additions)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20) (monthly additions)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (monthly additions)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (monthly additions)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (monthly additions)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (monthly additions)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (monthly additions)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33) (monthly additions)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34) (monthly additions)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50) (monthly additions)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (monthly additions)
(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	CWIP	CWIP	CWIP	CWIP	CWIP	CWIP	CWIP
746,033	28,424,689	25,651,961	25,651,961	379,627	379,627	2,198,436	4,625,382	14,778,172	3,714,412	49,155,059	38,606,395	24,972,388	14,218,134
							200,891	1,514,456	1,514,456	4,471,494	2,983,818	2,445,601	1,492,800
							157,145	772,139	772,139	1,615,457	5,294,067	3,772,152	2,011,913
							84,346	2,665,294	2,665,294	10,402,961	3,908,591	2,726,808	1,464,903
100,000						600,000	70,466	1,139,869	1,139,869	5,544,882	8,324,360	3,755,273	1,697,247
9,202,909	831,844					55,217,452	(750,521)	278,546	278,546	2,766,124	693,122	668,620	4,604,903
25,715,094				14,245,750	14,245,750		240,780	1,006,698	1,007,433	(10,134,914)	(2,391,753)	3,673,331	(10,831,235)
111,111				111,111	111,111		165,541	514,043	548,243	14,398,552	10,969,971	3,344,325	1,364,867
							143,039	141,297	173,205	7,110,731	5,690,922	2,418,229	1,459,955
							143,996	71,435	104,310	9,564,096	3,942,417	1,019,996	1,505,400
							117,436	57,308	84,551	4,393,711	3,130,713	761,645	5,783,798
							99,697	837,601	837,601	3,619,909	7,113,736	496,425	(705,983)
334,949				334,949	334,949		(3,027,181)	150,811	423,870	231,110	11,738,046	206,651	(19,809,090)
36,210,096	**29,256,534**	**25,651,961**	**25,651,961**	**15,071,438**	**15,071,438**	**58,015,888**	**2,271,018**	**23,927,668**	**13,263,928**	**103,139,173**	**100,004,406**	**50,261,443**	**4,257,610**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2017

Estimated Transmission Enhancement Charges (Before True-Up) - 2017

Reconductor South Mahwah K-3411 Circuit (B1018)	Branchburg 400 MVAR Capacitor (B0290)	Saddle Brook - Athenia Upgrade Cable (B0472)	Branchburg-Sommerville-Flagtown Reconductor (B0664 & B0665)	Somerville-Bridgewater Reconductor (B0668)	New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie (B0814)	Salem 500 kV breakers (B1410-B1415)	230kV Lawrence Switching Station Upgrade (B1228)	Branchburg-Middlesex Switch Rack (B1155)	Aldene-Springfield Rd. Conversion (B1399)	Upgrade Camden-Richmond 230kV Circuit (B1590)	Susquehanna Roseland Breakers (b0489.5-B0489.15)	Susquehanna Roseland < 500KV (B0489.4)	Susquehanna Roseland > 500KV (B0489)
2,557,912	**9,808,871**	**1,757,923**	**2,272,904**	**783,889**	**5,685,123**	**1,979,240**	**2,755,781**	**8,650,024**	**9,280,898**	**1,449,606**	**737,976**	**5,413,780**	**97,799,286**

Actual Transmission Enhancement Charges - 2015

Reconductor South Mahwah K-3411 Circuit (B1018)	Branchburg 400 MVAR Capacitor (B0290)	Saddle Brook - Athenia Upgrade Cable (B0472)	Branchburg-Sommerville-Flagtown Reconductor (B0664 & B0665)	Somerville-Bridgewater Reconductor (B0668)	New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie (B0814)	Salem 500 kV breakers (B1410-B1415)	230kV Lawrence Switching Station Upgrade (B1228)	Branchburg-Middlesex Switch Rack (B1155)	Aldene-Springfield Rd. Conversion (B1399)	Upgrade Camden-Richmond 230kV Circuit (B1590)	Susquehanna Roseland Breakers (b0489.5-B0489.15)	Susquehanna Roseland < 500KV (B0489.4)	Susquehanna Roseland > 500KV (B0489)
2,804,096	**10,749,859**	**1,926,521**	**2,491,058**	**858,935**	**6,228,271**	**2,168,874**	**3,017,865**	**8,688,697**	**10,056,881**	**1,570,150**	**808,174**	**5,917,569**	**103,713,135**

Reconciliation by Project (without interest)

Reconductor South Mahwah K-3411 Circuit (B1018)	Branchburg 400 MVAR Capacitor (B0290)	Saddle Brook - Athenia Upgrade Cable (B0472)	Branchburg-Sommerville-Flagtown Reconductor (B0664 & B0665)	Somerville-Bridgewater Reconductor (B0668)	New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie (B0814)	Salem 500 kV breakers (B1410-B1415)	230kV Lawrence Switching Station Upgrade (B1228)	Branchburg-Middlesex Switch Rack (B1155)	Aldene-Springfield Rd. Conversion (B1399)	Upgrade Camden-Richmond 230kV Circuit (B1590)	Susquehanna Roseland Breakers (b0489.5-B0489.15)	Susquehanna Roseland < 500KV (B0489.4)	Susquehanna Roseland > 500KV (B0489)
54,049	**101,112**	**91,169**	**387,496**	**(126,234)**	**(406,739)**	**(69,504)**	**(1,700,687)**	**2,496,384**	**5,237,330**	**1,570,150**	**(486,948)**	**1,122,037**	**(8,317,198)**
1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904

True Up by Project (with interest) - 2015

Reconductor South Mahwah K-3411 Circuit (B1018)	Branchburg 400 MVAR Capacitor (B0290)	Saddle Brook - Athenia Upgrade Cable (B0472)	Branchburg-Sommerville-Flagtown Reconductor (B0664 & B0665)	Somerville-Bridgewater Reconductor (B0668)	New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie (B0814)	Salem 500 kV breakers (B1410-B1415)	230kV Lawrence Switching Station Upgrade (B1228)	Branchburg-Middlesex Switch Rack (B1155)	Aldene-Springfield Rd. Conversion (B1399)	Upgrade Camden-Richmond 230kV Circuit (B1590)	Susquehanna Roseland Breakers (b0489.5-B0489.15)	Susquehanna Roseland < 500KV (B0489.4)	Susquehanna Roseland > 500KV (B0489)
57,780	**108,093**	**97,464**	**414,250**	**(134,949)**	**(434,822)**	**(74,302)**	**(1,818,108)**	**2,668,743**	**5,598,933**	**1,678,558**	**(520,569)**	**1,199,506**	**(8,891,446)**

Estimated Transmission Enhancement Charges (After True-Up) - 2017

Reconductor South Mahwah K-3411 Circuit (B1018)	Branchburg 400 MVAR Capacitor (B0290)	Saddle Brook - Athenia Upgrade Cable (B0472)	Branchburg-Sommerville-Flagtown Reconductor (B0664 & B0665)	Somerville-Bridgewater Reconductor (B0668)	New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie (B0814)	Salem 500 kV breakers (B1410-B1415)	230kV Lawrence Switching Station Upgrade (B1228)	Branchburg-Middlesex Switch Rack (B1155)	Aldene-Springfield Rd. Conversion (B1399)	Upgrade Camden-Richmond 230kV Circuit (B1590)	Susquehanna Roseland Breakers (b0489.5-B0489.15)	Susquehanna Roseland < 500KV (B0489.4)	Susquehanna Roseland > 500KV (B0489)
2,615,692	**9,916,964**	**1,855,386**	**2,687,154**	**648,940**	**5,250,301**	**1,904,937**	**937,673**	**11,318,767**	**14,879,831**	**3,128,164**	**217,407**	**6,613,287**	**88,907,841**

Public Service Electric and Gas Company

ATTACHMENT H-10A

Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2017

Estimated Additions - 2017												
(AC)	(AD)	(AE)	(AF)	(AG)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)	(AN)	(AO)
Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70) (monthly additions)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81) (monthly additions	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83) (monthly additions)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) (monthly addtions)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (monthly additions)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (monthly additions)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91) (monthly additions)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (monthly additions)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (monthly additions)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20) (monthly additions)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (monthly additions)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (monthly additions)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33) (monthly additions)
CWIP	CWIP	CWIP	CWIP	CWIP	CWIP	CWIP	CWIP	CWIP	CWIP	CWIP	CWIP	CWIP
42,282,365	18,236,335	18,236,335	22,366,079	22,366,079	1,614,587	969,183	1,161,480	1,190,502	8,535,498	8,536,190	33,234,907	2,350,713
1,149,765	524,126	524,126	1,638,738	1,638,738	178,117	142,556	3,254	3,254	95,263	95,263	2,558,110	1,354,119
4,006,008	801,777	801,777	1,358,137	1,358,137	114,787	87,616	1,999	1,999	638,059	638,059	982,311	673,596
2,330,959	121,578	121,578	457,506	457,506	70,596	35,902	2,709	2,709	101,816	101,816	94,871	2,614,579
4,140,080	72,396	72,396	202,460	202,460	54,389	12,189	3,282	3,282	132,757	132,757	(362,165)	1,109,663
2,251,829	(8,761,866)	(8,761,866)	(8,738,200)	(8,738,200)	(766,599)	(753,083)	4,541	4,541	523,915	523,915	(36,136,389)	1,079,154
(10,744,291)	(10,983,937)	(10,983,937)	(17,222,953)	(17,222,953)	186,344	131,016	4,228	4,228	(9,697,733)	(9,698,467)	397,817	415,904
2,634,327	181,909	181,909	189,565	189,565	86,847	6,742	6,120	6,120	(56,647)	(56,647)	1,431,336	473,101
1,575,657	177,768	177,768	184,911	184,911	81,004	6,268	5,542	5,542	44,383	44,383	800,315	103,120
924,483	275,135	275,135	282,494	282,494	85,728	8,725	5,627	5,627	78,277	78,277	1,181,149	29,834
855,836	314,441	314,441	320,539	320,539	123,637	5,343	4,663	4,663	238,204	238,204	457,421	24,722
518,378	268,980	268,980	277,484	277,484	324,352	7,450	6,502	6,502	222,766	222,766	277,282	754,175
3,713,643	(1,175,507)	(1,175,507)	(1,316,761)	(1,316,761)	268,376	(659,909)	2,921	2,921	(856,557)	(856,514)	(4,916,965)	3,082,418
55,639,039	**53,134**	**53,134**	**0**	**0**	**2,422,164**	**(0)**	**1,212,870**	**1,241,892**	**0**	**0**	**(0)**	**14,065,098**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2017

Estimated Transmission Enhancement Charges (Before True-Up) - 2017

Burlington - Camden 230kV Conversion (B1156)	Mickleton-Gloucester-Camden(B1398-B1398.7)	North Central Reliability (West Orange Conversion) (B1154)	Northeast Grid Reliability Project (B1304.1-B1304.4)	Northeast Grid Reliability Project (B1304.5-B1304.21)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83)
44,933,061	**56,992,730**	**46,192,451**	**81,902,152**	**47,792,699**	**23,318,838**	**3,199,550**	**3,199,550**	**1,090,341**	**1,464,046**	**1,090,341**	**1,908,566**	**1,908,566**

Actual Transmission Enhancement Charges - 2015

Burlington - Camden 230kV Conversion (B1156)	Mickleton-Gloucester-Camden(B1398-B1398.7)	North Central Reliability (West Orange Conversion) (B1154)	Northeast Grid Reliability Project (B1304.1-B1304.4)	Northeast Grid Reliability Project (B1304.5-B1304.21)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83)
47,814,854	**39,857,912**	**50,370,637**	**46,859,053**	**-**	**-**	**-**	**-**	**2,441**	**2,441**	**2,441**	**2,441**	**2,441**

Reconciliation by Project (without interest)

Burlington - Camden 230kV Conversion (B1156)	Mickleton-Gloucester-Camden(B1398-B1398.7)	North Central Reliability (West Orange Conversion) (B1154)	Northeast Grid Reliability Project (B1304.1-B1304.4)	Northeast Grid Reliability Project (B1304.5-B1304.21)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83)
(15,649,808)	**(3,407,055)**	**(45,038,492)**	**(19,684,688)**	**-**	**(170,148)**	**-**	**-**	**2,441**	**2,441**	**2,441**	**2,441**	**2,441**

1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904

True Up by Project (with interest) - 2015

Burlington - Camden 230kV Conversion (B1156)	Mickleton-Gloucester-Camden(B1398-B1398.7)	North Central Reliability (West Orange Conversion) (B1154)	Northeast Grid Reliability Project (B1304.1-B1304.4)	Northeast Grid Reliability Project (B1304.5-B1304.21)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83)
(16,730,324)	**(3,642,290)**	**(48,148,101)**	**(21,043,785)**	**-**	**(181,895)**	**-**	**-**	**2,610**	**2,610**	**2,610**	**2,610**	**2,610**

Estimated Transmission Enhancement Charges (After True-Up) - 2017

Burlington - Camden 230kV Conversion (B1156)	Mickleton-Gloucester-Camden(B1398-B1398.7)	North Central Reliability (West Orange Conversion) (B1154)	Northeast Grid Reliability Project (B1304.1-B1304.4)	Northeast Grid Reliability Project (B1304.5-B1304.21)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83)
28,202,737	**53,350,440**	**(1,955,650)**	**60,858,367**	**47,792,699**	**23,136,943**	**3,199,550**	**3,199,550**	**1,092,951**	**1,466,656**	**1,092,951**	**1,911,176**	**1,911,176**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2017

Estimated Additions - 2017

	(AP)	(AQ)	(AR)	(AS)	(AT)	(AU)	(AV)	(AW)	(AX)	(AY)	(AZ)
	Other Projects PIS (monthly balances)	Ridge Road 69kV Breaker Station (B1255)	Cox's Corner-Lumberton 230kV Circuit (B1787)	Sewaren Switch 230kV Conversion (B2276)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81)
		(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)
Dec-14	8,630,725,699	3,894,089	31,718,020	117,787,484	174,934,554	23,542,140	23,542,140	379,627	379,627	379,627	746,033
Jan	7,018,333	3,894,089	31,718,020	117,987,484	174,934,554	23,542,140	23,542,140	379,627	379,627	379,627	746,033
Feb	809,333	3,894,089	31,718,020	118,187,484	174,934,554	23,542,140	23,542,140	379,627	379,627	379,627	746,033
Mar	74,545,333	3,894,089	31,718,020	118,337,484	174,934,554	23,542,140	23,542,140	379,627	379,627	379,627	746,033
Apr	10,954,333	3,894,089	31,718,020	118,337,484	174,934,554	23,542,140	23,542,140	379,627	379,627	379,627	846,033
May	135,078,869	3,894,089	31,718,020	118,337,484	175,766,398	24,373,985	24,373,985	379,627	379,627	379,627	10,048,942
Jun	276,465,893	3,894,089	31,718,020	118,337,484	175,766,398	24,373,985	24,373,985	14,625,377	14,625,377	14,625,377	24,294,692
Jul	3,878,333	3,894,089	31,718,020	118,337,484	175,766,398	24,373,985	24,373,985	14,736,488	14,736,488	14,736,488	24,405,803
Aug	4,113,333	3,894,089	31,718,020	118,337,484	175,766,398	24,373,985	24,373,985	14,736,488	14,736,488	14,736,488	24,405,803
Sep	27,941,333	3,894,089	31,718,020	118,337,484	175,766,398	24,373,985	24,373,985	14,736,488	14,736,488	14,736,488	24,405,803
Oct	31,860,185	35,592,237	31,718,020	118,337,484	175,766,398	24,373,985	24,373,985	14,736,488	14,736,488	14,736,488	24,405,803
Nov	54,119,492	35,642,237	31,718,020	118,337,484	175,766,398	24,373,985	24,373,985	14,736,488	17,789,329	14,736,488	24,405,803
Dec	298,274,629	35,696,237	31,718,020	118,337,484	175,766,398	24,373,985	24,373,985	15,071,438	48,229,438	15,071,438	24,740,752
Total	**9,555,785,098**	**145,871,602**	**412,334,261**	**1,537,337,290**	**2,280,803,953**	**312,702,578**	**312,702,578**	**105,657,016**	**141,867,858**	**105,657,016**	**184,943,564**
Average 13 Month Balance		**11,220,892**	**31,718,020**	**118,256,715**	**175,446,458**	**24,054,044**	**24,054,044**	**8,127,463**	**10,912,912**	**8,127,463**	**14,226,428**
Average 13 Month in service		**4.09**	**13.00**	**12.99**	**12.98**	**12.83**	**12.83**	**7.01**	**2.94**	**7.01**	**7.48**
13 Month Average CWIP to Appendix A, line 45											

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2017

Estimated Transmission Enhancement Charges (Before True-Up) - 2017

Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30)	Upgrade Eagle Point-Gloucester 230kV Circuit (B1588)	Mickleton-Gloucester 230kV Circuit (B2139)	Ridge Road 69kV Breaker Station (B1255)	Cox's Corner-Lumberton 230kV Circuit (B1787)	Sewaren Switch 230kV Conversion (B2276)	Susquehanna Roseland < 500KV (B0489.4) (CWIP)
2,737,100	**2,737,100**	**3,843,966**	**3,405,679**	**3,405,679**	**1,090,341**	**1,090,341**	**4,909,357**	**1,565,912**	**2,478,656**	**1,488,600**	**4,157,150**	**15,669,479**	**-**

Actual Transmission Enhancement Charges - 2015

Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30)	Upgrade Eagle Point-Gloucester 230kV Circuit (B1588)	Mickleton-Gloucester 230kV Circuit (B2139)	Ridge Road 69kV Breaker Station (B1255)	Cox's Corner-Lumberton 230kV Circuit (B1787)	Sewaren Switch 230kV Conversion (B2276)	Susquehanna Roseland < 500KV (B0489.4) (CWIP)
2,441	**2,441**	**-**	**-**	**-**	**2,441**	**2,441**	**-**	**1,282,387**	**1,375,013**	**-**	**1,096,185**	**928,580**	**-**

Reconciliation by Project (without interest)

Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30)	Upgrade Eagle Point-Gloucester 230kV Circuit (B1588)	Mickleton-Gloucester 230kV Circuit (B2139)	Ridge Road 69kV Breaker Station (B1255)	Cox's Corner-Lumberton 230kV Circuit (B1787)	Sewaren Switch 230kV Conversion (B2276)	Susquehanna Roseland < 500KV (B0489.4) (CWIP)
2,441	**2,441**	**-**	**-**	**-**	**2,441**	**2,441**	**-**	**524,773**	**297,158**	**(2,349,496)**	**1,096,185**	**928,580**	**1,437,708**

1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904

True Up by Project (with interest) - 2015

Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30)	Upgrade Eagle Point-Gloucester 230kV Circuit (B1588)	Mickleton-Gloucester 230kV Circuit (B2139)	Ridge Road 69kV Breaker Station (B1255)	Cox's Corner-Lumberton 230kV Circuit (B1787)	Sewaren Switch 230kV Conversion (B2276)	Susquehanna Roseland < 500KV (B0489.4) (CWIP)
2,610	**2,610**	**-**	**-**	**-**	**2,610**	**2,610**	**-**	**561,005**	**317,675**	**(2,511,713)**	**1,171,869**	**992,693**	**1,536,972**

Estimated Transmission Enhancement Charges (After True -Up) - 2017

Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30)	Upgrade Eagle Point-Gloucester 230kV Circuit (B1588)	Mickleton-Gloucester 230kV Circuit (B2139)	Ridge Road 69kV Breaker Station (B1255)	Cox's Corner-Lumberton 230kV Circuit (B1787)	Sewaren Switch 230kV Conversion (B2276)	Susquehanna Roseland < 500KV (B0489.4) (CWIP)
2,739,710	**2,739,710**	**3,843,966**	**3,405,679**	**3,405,679**	**1,092,951**	**1,092,951**	**4,909,357**	**2,126,917**	**2,796,331**	**(1,023,113)**	**5,329,019**	**16,662,171**	**1,536,972**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2017

Estimated Additions - 2017													
(BA)	(BB)	(BC)	(BD)	(BE)	(BF)	(BG)	(BH)	(BI)	(BJ)	(BK)	(BL)	(BM)	(BN)
Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34)
(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	CWIP	CWIP	CWIP	CWIP	CWIP
746,033	746,033	746,033	28,424,689	25,651,961	25,651,961	379,627	379,627	2,198,436	4,625,382	14,778,172	3,714,412	49,155,059	38,606,395
746,033	746,033	746,033	28,424,689	25,651,961	25,651,961	379,627	379,627	2,198,436	4,826,273	16,292,628	5,228,868	53,626,554	41,590,213
746,033	746,033	746,033	28,424,689	25,651,961	25,651,961	379,627	379,627	2,198,436	4,983,418	17,064,767	6,001,007	55,242,011	46,884,280
746,033	746,033	746,033	28,424,689	25,651,961	25,651,961	379,627	379,627	2,198,436	5,067,764	19,730,061	8,666,301	65,644,972	50,792,872
846,033	846,033	846,033	28,424,689	25,651,961	25,651,961	379,627	379,627	2,798,436	5,138,231	20,869,930	9,806,170	71,189,854	59,117,231
10,048,942	10,048,942	10,048,942	29,256,534	25,651,961	25,651,961	379,627	379,627	58,015,888	4,387,710	21,148,476	10,084,716	73,955,979	59,810,353
24,294,692	35,764,036	35,764,036	29,256,534	25,651,961	25,651,961	14,625,377	14,625,377	58,015,888	4,628,490	22,155,174	11,092,149	63,821,065	57,418,600
24,405,803	35,875,147	35,875,147	29,256,534	25,651,961	25,651,961	14,736,488	14,736,488	58,015,888	4,794,031	22,669,217	11,640,392	78,219,617	68,388,571
24,405,803	35,875,147	35,875,147	29,256,534	25,651,961	25,651,961	14,736,488	14,736,488	58,015,888	4,937,070	22,810,514	11,813,597	85,330,348	74,079,493
24,405,803	35,875,147	35,875,147	29,256,534	25,651,961	25,651,961	14,736,488	14,736,488	58,015,888	5,081,066	22,881,948	11,917,907	94,894,443	78,021,910
24,405,803	35,875,147	35,875,147	29,256,534	25,651,961	25,651,961	14,736,488	14,736,488	58,015,888	5,198,502	22,939,256	12,002,458	99,288,155	81,152,623
24,405,803	35,875,147	35,875,147	29,256,534	25,651,961	25,651,961	14,736,488	14,736,488	58,015,888	5,298,199	23,776,857	12,840,058	102,908,064	88,266,360
24,740,752	36,210,096	36,210,096	29,256,534	25,651,961	25,651,961	15,071,438	15,071,438	58,015,888	2,271,018	23,927,668	13,263,928	103,139,173	100,004,406
184,943,564	**265,228,974**	**265,228,974**	**376,175,716**	**333,475,494**	**333,475,494**	**105,657,016**	**105,657,016**	**475,719,285**	**61,237,152**	**271,044,669**	**128,071,965**	**996,415,294**	**844,133,308**
14,226,428	**20,402,229**	**20,402,229**	**28,936,594**	**25,651,961**	**25,651,961**	**8,127,463**	**8,127,463**	**36,593,791**	**4,710,550**	**20,849,590**	**9,851,690**	**76,647,330**	**64,933,331**
7.48	**7.32**	**7.32**	**12.86**	**13.00**	**13.00**	**7.01**	**7.01**	**8.20**	**26.96**	**11.33**	**9.66**	**9.66**	**8.44**
									4,710,550	**20,849,590**	**9,851,690**	**76,647,330**	**64,933,331**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2017

Estimated Transmission Enhancement Charges (Before True-Up) - 2017

Susquehanna Roseland >= 500kV (B0489) (CWIP)	North Central Reliability (West Orange Conversion) (B1154) (CWIP)	Mickleton-Gloucester-Camden(B1398-B1398.7) (CWIP)	Mickleton-Gloucester-Camden Breakers (B1398.15-B1398.19) (CWIP)	Burlington - Camden 230kV Conversion (B1156) (CWIP)	Burlington - Camden 230kV Conversion (B1156.13-B1156.20) (CWIP)	Northeast Grid Reliability Project (B1304.1-B1304.4) (CWIP)	Northeast Grid Reliability Project (B1304.5-B1304.21) (CWIP)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (CWIP)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (CWIP)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (CWIP)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33) (CWIP)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34) (CWIP)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50) (CWIP)
-	-	-	-	-	-	-	-	519,803	2,300,724	1,087,121	8,457,930	7,165,306	4,476,177

Actual Transmission Enhancement Charges - 2015

Susquehanna Roseland >= 500kV (B0489) (CWIP)	North Central Reliability (West Orange Conversion) (B1154) (CWIP)	Mickleton-Gloucester-Camden(B1398-B1398.7) (CWIP)	Mickleton-Gloucester-Camden Breakers (B1398.15-B1398.19) (CWIP)	Burlington - Camden 230kV Conversion (B1156) (CWIP)	Burlington - Camden 230kV Conversion (B1156.13-B1156.20) (CWIP)	Northeast Grid Reliability Project (B1304.1-B1304.4) (CWIP)	Northeast Grid Reliability Project (B1304.5-B1304.21) (CWIP)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (CWIP)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (CWIP)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (CWIP)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33) (CWIP)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34) (CWIP)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50) (CWIP)
1,955,563	-	9,560,846	24,003	-	-	31,772,294	2,336,445	3,818,309	836,684	819,896	530,656	105,699	178,025

Reconciliation by Project (without interest)

Susquehanna Roseland >= 500kV (B0489) (CWIP)	North Central Reliability (West Orange Conversion) (B1154) (CWIP)	Mickleton-Gloucester-Camden(B1398-B1398.7) (CWIP)	Mickleton-Gloucester-Camden Breakers (B1398.15-B1398.19) (CWIP)	Burlington - Camden 230kV Conversion (B1156) (CWIP)	Burlington - Camden 230kV Conversion (B1156.13-B1156.20) (CWIP)	Northeast Grid Reliability Project (B1304.1-B1304.4) (CWIP)	Northeast Grid Reliability Project (B1304.5-B1304.21) (CWIP)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (CWIP)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (CWIP)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (CWIP)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33) (CWIP)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34) (CWIP)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50) (CWIP)
(1,773,865)	14,932,131	46,065	(83,909)	8,889,934	(1,345,566)	21,906,193	(2,492,734)	2,028,469	401,257	390,077	10,765	(193,155)	14,023

1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904

True Up by Project (with interest) - 2015

Susquehanna Roseland >= 500kV (B0489) (CWIP)	North Central Reliability (West Orange Conversion) (B1154) (CWIP)	Mickleton-Gloucester-Camden(B1398-B1398.7) (CWIP)	Mickleton-Gloucester-Camden Breakers (B1398.15-B1398.19) (CWIP)	Burlington - Camden 230kV Conversion (B1156) (CWIP)	Burlington - Camden 230kV Conversion (B1156.13-B1156.20) (CWIP)	Northeast Grid Reliability Project (B1304.1-B1304.4) (CWIP)	Northeast Grid Reliability Project (B1304.5-B1304.21) (CWIP)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (CWIP)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (CWIP)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (CWIP)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33) (CWIP)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34) (CWIP)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50) (CWIP)
(1,896,338)	15,963,096	49,246	(89,702)	9,503,725	(1,438,469)	23,418,670	(2,664,841)	2,168,522	428,961	417,010	11,508	(206,491)	14,991

Estimated Transmission Enhancement Charges (After True-Up) - 2017

Susquehanna Roseland >= 500kV (B0489) (CWIP)	North Central Reliability (West Orange Conversion) (B1154) (CWIP)	Mickleton-Gloucester-Camden(B1398-B1398.7) (CWIP)	Mickleton-Gloucester-Camden Breakers (B1398.15-B1398.19) (CWIP)	Burlington - Camden 230kV Conversion (B1156) (CWIP)	Burlington - Camden 230kV Conversion (B1156.13-B1156.20) (CWIP)	Northeast Grid Reliability Project (B1304.1-B1304.4) (CWIP)	Northeast Grid Reliability Project (B1304.5-B1304.21) (CWIP)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (CWIP)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (CWIP)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (CWIP)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33) (CWIP)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34) (CWIP)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50) (CWIP)
(1,896,338)	15,963,096	49,246	(89,702)	9,503,725	(1,438,469)	23,418,670	(2,664,841)	2,688,325	2,729,685	1,504,131	8,469,439	6,958,816	4,491,168

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2017

Estimated Additions - 2017														
(BO)	(BP)	(BQ)	(BR)	(BS)	(BT)	(BU)	(BV)	(BW)	(BX)	(BY)	(BZ)	(CA)	(CB)	(CC)
Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33)
CWIP	CWIP	CWIP	CWIP	CWIP	CWIP	CWIP	CWIP	CWIP	CWIP	CWIP	CWIP	CWIP	CWIP	CWIP
24,972,388	14,218,134	42,282,365	18,236,335	18,236,335	22,366,079	22,366,079	1,614,587	969,183	1,161,480	1,190,502	8,535,498	8,536,190	33,234,907	2,350,713
27,417,988	15,710,934	43,432,130	18,760,460	18,760,460	24,004,817	24,004,817	1,792,704	1,111,740	1,164,734	1,193,755	8,630,761	8,631,453	35,793,017	3,704,832
31,190,140	17,722,847	47,438,137	19,562,238	19,562,238	25,362,954	25,362,954	1,907,491	1,199,355	1,166,733	1,195,755	9,268,820	9,269,511	36,775,328	4,378,428
33,916,948	19,187,749	49,769,096	19,683,815	19,683,815	25,820,461	25,820,461	1,978,087	1,235,257	1,169,442	1,198,463	9,370,635	9,371,327	36,870,200	6,993,007
37,672,221	20,884,997	53,909,176	19,756,211	19,756,211	26,022,921	26,022,921	2,032,476	1,247,447	1,172,724	1,201,745	9,503,392	9,504,084	36,508,035	8,102,670
38,340,841	25,489,899	56,161,005	10,994,345	10,994,345	17,284,721	17,284,721	1,265,877	494,364	1,177,265	1,206,287	10,027,307	10,027,999	371,646	9,181,824
42,014,172	14,658,664	45,416,715	10,408	10,408	61,767	61,767	1,452,221	625,380	1,181,493	1,210,515	329,575	329,532	769,462	9,597,728
45,358,497	16,023,531	48,051,042	192,317	192,317	251,333	251,333	1,539,068	632,122	1,187,613	1,216,635	272,928	272,885	2,200,799	10,070,829
47,776,726	17,483,486	49,626,699	370,086	370,086	436,244	436,244	1,620,072	638,390	1,193,156	1,222,178	317,310	317,267	3,001,113	10,173,949
48,796,723	18,988,886	50,551,182	645,220	645,220	718,738	718,738	1,705,799	647,116	1,198,783	1,227,805	395,587	395,544	4,182,262	10,203,783
49,558,367	24,772,684	51,407,018	959,661	959,661	1,039,277	1,039,277	1,829,437	652,459	1,203,446	1,232,468	633,791	633,748	4,639,683	10,228,505
50,054,792	24,066,700	51,925,395	1,228,641	1,228,641	1,316,761	1,316,761	2,153,788	659,909	1,209,949	1,238,971	856,557	856,514	4,916,965	10,982,680
50,261,443	4,257,610	55,639,039	53,134	53,134	0	0	2,422,164	(0)	1,212,870	1,241,892	0	0	(0)	14,065,098
527,331,247	**233,466,121**	**645,608,999**	**110,452,871**	**110,452,871**	**144,686,074**	**144,686,074**	**23,313,771**	**10,112,723**	**15,399,688**	**15,776,971**	**58,142,161**	**58,146,053**	**199,263,415**	**110,034,048**
40,563,942	**17,958,932**	**49,662,231**	**8,496,375**	**8,496,375**	**11,129,698**	**11,129,698**	**1,793,367**	**777,902**	**1,184,591**	**1,213,613**	**4,472,474**	**4,472,773**	**15,327,955**	**8,464,158**
10.49	**54.84**	**11.60**	**2,078.76**	**2,078.76**	**13.00**	**13.00**	**9.63**	**13.00**	**12.70**	**12.70**	**13.00**	**13.00**	**13.00**	**7.82**
40,563,942	**17,958,932**	**49,662,231**	**8,496,375**	**8,496,375**	**11,129,698**	**11,129,698**	**1,793,367**	**777,902**	**1,184,591**	**1,213,613**	**4,472,474**	**4,472,773**	**15,327,955**	**8,464,158**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2017

Estimated Transmission Enhancement Charges (Before True-Up) - 2017

Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (CWIP)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70) (CWIP)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81) (CWIP)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83) (CWIP)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) (CWIP)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (CWIP)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (CWIP)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91) (CWIP)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (CWIP)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (CWIP)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20) (CWIP)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (CWIP)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (CWIP)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33) (CWIP)
1,981,744	**5,480,161**	**937,564**	**937,564**	**1,228,147**	**1,228,147**	**197,896**	**85,840**	**130,718**	**133,921**	**493,532**	**493,565**	**1,691,419**	**934,008**

Actual Transmission Enhancement Charges - 2015

Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (CWIP)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70) (CWIP)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81) (CWIP)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83) (CWIP)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) (CWIP)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (CWIP)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (CWIP)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91) (CWIP)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (CWIP)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (CWIP)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20) (CWIP)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (CWIP)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (CWIP)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33) (CWIP)
209,207	**414,795**	**249,912**	**249,912**	**236,839**	**236,839**	**849,382**	**780,003**	**1,506,352**	**1,530,122**	**148,281**	**148,345**	**101,157**	**20,804**

Reconciliation by Project (without interest)

Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (CWIP)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70) (CWIP)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81) (CWIP)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83) (CWIP)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) (CWIP)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (CWIP)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (CWIP)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91) (CWIP)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (CWIP)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (CWIP)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20) (CWIP)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (CWIP)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (CWIP)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33) (CWIP)
174,669	**143,477**	**40,974**	**40,974**	**26,959**	**26,959**	**420,618**	**370,802**	**624,921**	**648,692**	**133,935**	**133,998**	**(86,377)**	**8,401**

1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904	1.06904

True Up by Project (with interest) - 2015

Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (CWIP)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70) (CWIP)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81) (CWIP)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83) (CWIP)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) (CWIP)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (CWIP)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (CWIP)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91) (CWIP)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (CWIP)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (CWIP)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20) (CWIP)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (CWIP)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (CWIP)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33) (CWIP)
186,728	**153,383**	**43,803**	**43,803**	**28,821**	**28,821**	**449,659**	**396,404**	**668,068**	**693,479**	**143,182**	**143,250**	**(92,340)**	**8,981**

Estimated Transmission Enhancement Charges (After True-Up) - 2017

Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (CWIP)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70) (CWIP)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81) (CWIP)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83) (CWIP)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) (CWIP)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (CWIP)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (CWIP)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91) (CWIP)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (CWIP)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (CWIP)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20) (CWIP)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (CWIP)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (CWIP)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33) (CWIP)
2,168,472	**5,633,543**	**981,366**	**981,366**	**1,256,968**	**1,256,968**	**647,554**	**482,244**	**798,786**	**827,400**	**636,713**	**636,814**	**1,599,079**	**942,989**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2017

1 New Plant Carrying Charge

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

		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	11.03%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.71%
5	C		Line B less Line A	0.68%

6 **FCR if a CIAC**

7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.60%

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

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

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 **For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the** 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

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			42			42			42		
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No			No			No			No		
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		11.03%			11.03%			11.03%			11.03%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.03%			11.03%			11.03%			11.03%		
17	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 or Amort Exp		492,395			192,120			2,061,086			528,306		
19	Months in service for depreciation expense from			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 or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**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	18,711,016	492,395	4,095,968	7,604,733	192,120	1,656,722	81,584,670	2,061,086	17,773,557	20,647,970	528,306	4,504,919
31		W Increased ROE	2010	18,711,016	492,395	4,095,968	7,604,733	192,120	1,656,722	81,584,670	2,061,086	17,773,557	20,647,970	528,306	4,504,919
32		W 11.68 % ROE	2011	18,218,621	492,395	3,746,858	7,412,613	192,120	1,516,263	79,523,584	2,061,086	16,266,692	20,119,663	528,306	4,122,360
33		W Increased ROE	2011	18,218,621	492,395	3,746,858	7,412,613	192,120	1,516,263	79,523,584	2,061,086	16,266,692	20,119,663	528,306	4,122,360
34		W 11.68 % ROE	2012	17,726,226	492,395	3,154,416	7,220,494	192,120	1,276,451	77,462,497	2,061,086	13,693,952	19,591,357	528,306	3,470,422
35		W Increased ROE	2012	17,726,226	492,395	3,154,416	7,220,494	192,120	1,276,451	77,462,497	2,061,086	13,693,952	19,591,357	528,306	3,470,422
36		W 11.68 % ROE	2013	17,233,831	492,395	2,886,756	7,028,374	192,120	1,168,598	75,401,411	2,061,086	12,536,886	19,063,051	528,306	3,176,807
37		W Increased ROE	2013	17,233,831	492,395	2,886,756	7,028,374	192,120	1,168,598	75,401,411	2,061,086	12,536,886	19,063,051	528,306	3,176,807
38		W 11.68 % ROE	2014	16,741,436	492,395	2,555,172	6,836,255	192,120	1,034,441	73,340,324	2,061,086	11,097,629	18,534,745	528,306	2,812,043
39		W Increased ROE	2014	16,741,436	492,395	2,555,172	6,836,255	192,120	1,034,441	73,340,324	2,061,086	11,097,629	18,534,745	528,306	2,812,043
40		W 11.68 % ROE	2015	16,249,041	492,395	2,397,208	6,644,135	192,120	970,986	71,279,238	2,061,086	10,416,881	18,006,439	528,306	2,639,133
41		W Increased ROE	2015	16,249,041	492,395	2,397,208	6,644,135	192,120	970,986	71,279,238	2,061,086	10,416,881	18,006,439	528,306	2,639,133
42		W 11.68 % ROE	2016	15,756,645	492,395	2,316,538	6,452,016	192,120	939,068	69,218,152	2,061,086	10,074,454	17,478,132	528,306	2,551,745
43		W Increased ROE	2016	15,756,645	492,395	2,316,538	6,452,016	192,120	939,068	69,218,152	2,061,086	10,074,454	17,478,132	528,306	2,551,745
44		W 11.68 % ROE	2017	15,264,250	492,395	2,176,785	6,259,896	192,120	882,891	67,157,065	2,061,086	9,471,779	16,949,826	528,306	2,398,697
45		W Increased ROE	2017	15,264,250	492,395	2,176,785	6,259,896	192,120	882,891	67,157,065	2,061,086	9,471,779	16,949,826	528,306	2,398,697

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2017

1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if if not a CIAC**			
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5	C		Line B less Line A	0.68%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.60%

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which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

10		Details		**New Freedom Loop (B0498)**			**Metuchen Transformer (B0161)**			**Branchburg-Flagtown-Somerville (B0169)**			**Flagtown-Somerville-Bridgewater (B0170)**		
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			42			42			42		
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No			No			No			No		
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		11.03%			11.03%			11.03%			11.03%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.03%			11.03%			11.03%			11.03%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		27,005,248			25,799,055			15,731,554			6,961,495		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		642,982			614,263			374,561			165,750		
19	Months in service for depreciation expense from			13.00			13.00			13.00			13.00		
20	Year placed in Service (0 if CWIP)			2008			2009			2009			2008		
21			**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**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	26,273,620	642,982	5,703,044	25,488,527	613,738	5,522,598	15,539,319	375,568	3,368,301	6,770,372	165,750	1,469,662
31		W Increased ROE	2010	26,273,620	642,982	5,703,044	25,488,527	613,738	5,522,598	15,539,319	375,568	3,368,301	6,770,372	165,750	1,469,662
32		W 11.68 % ROE	2011	25,630,832	642,987	5,221,521	24,896,838	614,263	5,061,682	15,121,425	374,561	3,075,759	6,604,623	165,750	1,345,559
33		W Increased ROE	2011	25,630,832	642,987	5,221,521	24,896,838	614,263	5,061,682	15,121,425	374,561	3,075,759	6,604,623	165,750	1,345,559
34		W 11.68 % ROE	2012	24,987,652	642,982	4,395,482	24,282,576	614,263	4,260,879	14,746,864	374,561	2,589,159	6,438,873	165,750	1,132,702
35		W Increased ROE	2012	24,987,652	642,982	4,395,482	24,282,576	614,263	4,260,879	14,746,864	374,561	2,589,159	6,438,873	165,750	1,132,702
36		W 11.68 % ROE	2013	24,344,669	642,982	4,025,278	23,668,312	614,263	3,902,590	14,372,303	374,561	2,371,359	6,273,123	165,750	1,037,298
37		W Increased ROE	2013	24,344,669	642,982	4,025,278	23,668,312	614,263	3,902,590	14,372,303	374,561	2,371,359	6,273,123	165,750	1,037,298
38		W 11.68 % ROE	2014	23,701,687	642,982	3,563,358	23,054,049	614,263	3,454,841	13,997,743	374,561	2,099,276	6,107,373	165,750	918,263
39		W Increased ROE	2014	23,701,687	642,982	3,563,358	23,054,049	614,263	3,454,841	13,997,743	374,561	2,099,276	6,107,373	165,750	918,263
40		W 11.68 % ROE	2015	23,058,705	642,982	3,346,067	22,439,786	614,263	3,244,794	13,623,182	374,561	1,971,555	5,941,623	165,750	862,264
41		W Increased ROE	2015	23,058,705	642,982	3,346,067	22,439,786	614,263	3,244,794	13,623,182	374,561	1,971,555	5,941,623	165,750	862,264
42		W 11.68 % ROE	2016	22,415,723	642,982	3,238,044	21,825,523	614,263	3,140,998	13,248,621	374,561	1,908,350	5,775,874	165,750	834,421
43		W Increased ROE	2016	22,415,723	642,982	3,238,044	21,825,523	614,263	3,140,998	13,248,621	374,561	1,908,350	5,775,874	165,750	834,421
44		W 11.68 % ROE	2017	21,772,741	642,982	3,045,575	21,211,259	614,263	2,954,897	12,874,060	374,561	1,795,196	5,610,124	165,750	784,820
45		W Increased ROE	2017	21,772,741	642,982	3,045,575	21,211,259	614,263	2,954,897	12,874,060	374,561	1,795,196	5,610,124	165,750	784,820

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2017

1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if if not a CIAC**			
		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	11.03%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.71%
5	C		Line B less Line A	0.68%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.60%

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

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

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

10		Details		**Roseland Transformers (B0274)**	**Wave Trap Branchburg (B0172.2)**	**Reconductor Hudson - South Waterfront (B0813)**	**Reconductor South Mahwah J-3410 Circuit (B1017)**
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	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
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		11.03%	11.03%	11.03%	11.03%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.03%	11.03%	11.03%	11.03%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		21,073,706	27,988	9,158,918	20,626,991
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		501,755	666	218,069	491,119
19	Months in service for depreciation expense from			13.00	13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)			2009	2008	2010	2011

21		Invest Yr	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**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						
27	W Increased ROE	2008				36,369	577	5,114						
28	W 11.68 % ROE	2009	21,092,458	268,347	2,634,066	35,792	866	8,379						
29	W Increased ROE	2009	21,092,458	268,347	2,634,066	35,792	866	8,379						
30	W 11.68 % ROE	2010	20,797,967	501,579	4,507,079	27,122	666	5,890	8,806,222	18,700	169,959			
31	W Increased ROE	2010	20,797,967	501,579	4,507,079	27,122	666	5,890	8,806,222	18,700	169,959			
32	W 11.68 % ROE	2011	20,302,520	501,725	4,128,443	25,878	666	5,289	9,140,218	218,069	1,850,822	20,623,951	300,198	2,435,793
33	W Increased ROE	2011	20,302,520	501,725	4,128,443	25,878	666	5,289	9,140,218	218,069	1,850,822	20,623,951	300,198	2,435,793
34	W 11.68 % ROE	2012	19,802,055	501,755	3,475,512	25,212	666	4,453	8,922,149	218,069	1,557,946	20,326,793	491,119	3,543,678
35	W Increased ROE	2012	19,802,055	501,755	3,475,512	25,212	666	4,453	8,922,149	218,069	1,557,946	20,326,793	491,119	3,543,678
36	W 11.68 % ROE	2013	19,300,300	501,755	3,183,218	24,546	666	4,077	8,704,079	218,069	1,427,360	19,835,674	491,119	3,246,963
37	W Increased ROE	2013	19,300,300	501,755	3,183,218	24,546	666	4,077	8,704,079	218,069	1,427,360	19,835,674	491,119	3,246,963
38	W 11.68 % ROE	2014	18,798,545	501,755	2,817,996	23,880	666	3,609	8,486,010	218,069	1,263,663	19,344,555	491,119	2,874,636
39	W Increased ROE	2014	18,798,545	501,755	2,817,996	23,880	666	3,609	8,486,010	218,069	1,263,663	19,344,555	491,119	2,874,636
40	W 11.68 % ROE	2015	18,296,790	501,755	2,646,618	23,213	666	3,388	8,267,940	218,069	1,187,289	18,853,437	491,119	2,701,236
41	W Increased ROE	2015	18,296,790	501,755	2,646,618	23,213	666	3,388	8,267,940	218,069	1,187,289	18,853,437	491,119	2,701,236
42	W 11.68 % ROE	2016	17,795,036	501,755	2,561,882	22,547	666	3,277	8,049,871	218,069	1,150,001	18,362,318	491,119	2,616,920
43	W Increased ROE	2016	17,795,036	501,755	2,561,882	22,547	666	3,277	8,049,871	218,069	1,150,001	18,362,318	491,119	2,616,920
44	W 11.68 % ROE	2017	17,293,281	501,755	2,410,045	21,880	666	3,081	7,831,801	218,069	1,082,298	17,871,199	491,119	2,463,182
45	W Increased ROE	2017	17,293,281	501,755	2,410,045	21,880	666	3,081	7,831,801	218,069	1,082,298	17,871,199	491,119	2,463,182

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2017

1 New Plant Carrying Charge

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

		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	11.03%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.71%
5	C		Line B less Line A	0.68%

6 **FCR if a CIAC**

7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.60%

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

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

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

10		Details		Reconductor South Mahwah K-3411 Circuit (B1018)	Branchburg 400 MVAR Capacitor (B0290)	Saddle Brook - Athenia Upgrade Cable (B0472)	Branchburg-Sommerville-Flagtown Reconductor (B0664 & B0665)
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	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
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		11.03%	11.03%	11.03%	11.03%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.03%	11.03%	11.03%	11.03%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		21,170,273	80,435,315	14,404,842	18,664,931
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		504,054	1,915,127	342,972	444,403
19	Months in service for depreciation expense from			13.00	13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)			2011	2012	2012	2012

21		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	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												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011	20,511,158	37,566	284,735									
33	W Increased ROE	2011	20,511,158	37,566	284,735									
34	W 11.68 % ROE	2012	21,132,707	504,054	3,677,641	79,937,194	1,240,233	9,062,770	14,401,477	210,412	1,537,549	19,820,557	318,342	2,326,229
35	W Increased ROE	2012	21,132,707	504,054	3,677,641	79,937,194	1,240,233	9,062,770	14,401,477	210,412	1,537,549	19,820,557	318,342	2,326,229
36	W 11.68 % ROE	2013	20,628,652	504,054	3,370,070	79,195,082	1,915,127	12,917,996	14,194,429	342,972	2,315,058	18,294,505	443,163	2,984,887
37	W Increased ROE	2013	20,628,652	504,054	3,370,070	79,195,082	1,915,127	12,917,996	14,194,429	342,972	2,315,058	18,294,505	443,163	2,984,887
38	W 11.68 % ROE	2014	20,124,598	504,054	2,983,683	77,279,955	1,915,127	11,437,086	13,851,457	342,972	2,049,664	17,903,425	444,403	2,650,353
39	W Increased ROE	2014	20,124,598	504,054	2,983,683	77,279,955	1,915,127	11,437,086	13,851,457	342,972	2,049,664	17,903,425	444,403	2,650,353
40	W 11.68 % ROE	2015	19,620,544	504,054	2,804,096	75,364,829	1,915,127	10,749,859	13,508,484	342,972	1,926,521	17,459,022	444,403	2,491,058
41	W Increased ROE	2015	19,620,544	504,054	2,804,096	75,364,829	1,915,127	10,749,859	13,508,484	342,972	1,926,521	17,459,022	444,403	2,491,058
42	W 11.68 % ROE	2016	19,116,490	504,054	2,717,165	73,449,702	1,915,127	10,418,379	13,165,512	342,972	1,867,140	17,014,619	444,403	2,414,181
43	W Increased ROE	2016	19,116,490	504,054	2,717,165	73,449,702	1,915,127	10,418,379	13,165,512	342,972	1,867,140	17,014,619	444,403	2,414,181
44	W 11.68 % ROE	2017	18,612,436	504,054	2,557,912	71,534,576	1,915,127	9,808,871	12,822,540	342,972	1,757,923	16,570,216	444,403	2,272,904
45	W Increased ROE	2017	18,612,436	504,054	2,557,912	71,534,576	1,915,127	9,808,871	12,822,540	342,972	1,757,923	16,570,216	444,403	2,272,904

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2017

1 New Plant Carrying Charge

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

		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	11.03%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.71%
5	C		Line B less Line A	0.68%

6 **FCR if a CIAC**

7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.60%

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

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

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

10		Details		**Somerville-Bridgewater Reconductor (B0668)**			**New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie (B0814)**			**Salem 500 kV breakers (B1410-B1415)**			**230kV Lawrence Switching Station Upgrade (B1228)**		
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			42			42			42		
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No			No			No			No		
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		11.03%			11.03%			11.03%			11.03%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.03%			11.03%			11.03%			11.03%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		6,390,403			46,073,245			15,876,913			22,040,646		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		152,152			1,096,982			378,022			524,777		
19	Months in service for depreciation expense from			13.00			13.00			13.00			13.00		
20	Year placed in Service (0 if CWIP)			2012			2012			2011			2013		
21			**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**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												
27		W Increased ROE	2008												
28		W 11.68 % ROE	2009												
29		W Increased ROE	2009												
30		W 11.68 % ROE	2010												
31		W Increased ROE	2010												
32		W 11.68 % ROE	2011							2,640,253	9,537	73,000			
33		W Increased ROE	2011							2,640,253	9,537	73,000			
34		W 11.68 % ROE	2012	4,404,012	57,853	422,751	22,800,866	123,008	898,857	7,275,941	108,279	790,336			
35		W Increased ROE	2012	4,404,012	57,853	422,751	22,800,866	123,008	898,857	7,275,941	108,279	790,336			
36		W 11.68 % ROE	2013	6,291,725	151,180	1,025,313	45,385,800	1,083,543	7,389,162	9,926,683	192,972	1,305,797	22,127,065	248,542	1,698,840
37		W Increased ROE	2013	6,291,725	151,180	1,025,313	45,385,800	1,083,543	7,389,162	9,926,683	192,972	1,305,797	22,127,065	248,542	1,698,840
38		W 11.68 % ROE	2014	6,181,332	152,152	913,777	44,747,660	1,094,148	6,607,679	15,445,872	289,093	1,755,636	21,792,104	524,777	3,209,866
39		W Increased ROE	2014	6,181,332	152,152	913,777	44,747,660	1,094,148	6,607,679	15,445,872	289,093	1,755,636	21,792,104	524,777	3,209,866
40		W 11.68 % ROE	2015	6,029,218	152,152	858,935	43,772,546	1,096,982	6,228,271	15,276,916	378,019	2,168,874	21,267,327	524,777	3,017,865
41		W Increased ROE	2015	6,029,218	152,152	858,935	43,772,546	1,096,982	6,228,271	15,276,916	378,019	2,168,874	21,267,327	524,777	3,017,865
42		W 11.68 % ROE	2016	5,878,038	152,152	832,651	42,680,131	1,096,983	6,038,051	15,330,967	388,479	2,163,341	20,742,550	524,777	2,926,137
43		W Increased ROE	2016	5,878,038	152,152	832,651	42,680,131	1,096,983	6,038,051	15,330,967	388,479	2,163,341	20,742,550	524,777	2,926,137
44		W 11.68 % ROE	2017	5,724,913	152,152	783,889	41,578,581	1,096,982	5,685,123	14,510,533	378,022	1,979,240	20,217,772	524,777	2,755,781
45		W Increased ROE	2017	5,724,913	152,152	783,889	41,578,581	1,096,982	5,685,123	14,510,533	378,022	1,979,240	20,217,772	524,777	2,755,781

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2017

1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if if not a CIAC**			
		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	11.03%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.71%
5	C		Line B less Line A	0.68%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.60%

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

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

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

10		Details		**Branchburg-Middlesex Switch Rack (B1155)**	**Aldene-Springfield Rd. Conversion (B1399)**	**Upgrade Camden-Richmond 230kV Circuit (B1590)**	**Susquehanna Roseland Breakers (b0489.5-B0489.15)**
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	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	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		11.03%	11.03%	11.03%	11.03%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.03%	11.03%	11.03%	11.88%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		68,312,808	72,443,911	11,268,594	5,857,687
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		1,626,495	1,724,855	268,300	139,469
19	Months in service for depreciation expense from			13.00	13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)			2013	2014	2014	2010

21		**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**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												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010										2,662,585	7,802	70,915
31	W Increased ROE	2010										2,662,585	7,802	70,915
32	W 11.68 % ROE	2011										5,849,885	116,061	966,188
33	W Increased ROE	2011										5,849,885	116,061	1,014,845
34	W 11.68 % ROE	2012										5,733,823	139,469	1,000,541
35	W Increased ROE	2012										5,733,823	139,469	1,051,531
36	W 11.68 % ROE	2013	20,876,286	101,812	695,908							5,594,354	139,469	916,713
37	W Increased ROE	2013	20,876,286	101,812	695,908							5,594,354	139,469	967,047
38	W 11.68 % ROE	2014	60,374,269	1,439,907	8,878,852	68,405,611	556,909	3,438,903	7,389,782	37,992	234,599	5,454,886	139,469	811,586
39	W Increased ROE	2014	60,374,269	1,439,907	8,878,852	68,405,611	556,909	3,438,903	7,389,782	37,992	234,599	5,454,886	139,469	859,361
40	W 11.68 % ROE	2015	61,346,085	1,497,329	8,688,697	71,213,315	1,708,815	10,056,881	11,126,578	265,823	1,570,150	5,315,417	139,469	762,575
41	W Increased ROE	2015	61,346,085	1,497,329	8,688,697	71,213,315	1,708,815	10,056,881	11,126,578	265,823	1,570,150	5,315,417	139,469	808,174
42	W 11.68 % ROE	2016	65,809,557	1,625,244	9,243,999	70,208,024	1,703,925	9,831,890	10,863,757	259,565	1,517,260	5,175,948	139,469	738,687
43	W Increased ROE	2016	65,809,557	1,625,244	9,243,999	70,208,024	1,703,925	9,831,890	10,863,757	259,565	1,517,260	5,175,948	139,469	783,397
44	W 11.68 % ROE	2017	63,648,517	1,626,495	8,650,024	68,474,262	1,724,855	9,280,898	10,705,213	268,300	1,449,606	5,036,479	139,469	695,238
45	W Increased ROE	2017	63,648,517	1,626,495	8,650,024	68,474,262	1,724,855	9,280,898	10,705,213	268,300	1,449,606	5,036,479	139,469	737,976

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2017

1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if if not a CIAC**			
		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	11.03%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.71%
5	C		Line B less Line A	0.68%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.60%

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

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

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

10		Details		**Susquehanna Roseland < 500KV (B0489.4)**			**Susquehanna Roseland > 500KV (B0489)**			**Burlington - Camden 230kV Conversion (B1156)**			**Mickleton-Gloucester-Camden(B1398-B1398.7)**		
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			42			42			42		
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No			No			No			No		
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		125			125			0			0		
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		11.03%			11.03%			11.03%			11.03%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.88%			11.88%			11.03%			11.03%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		40,538,248			722,869,825			356,525,651			439,443,096		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		965,196			17,211,186			8,488,706			10,462,931		
19	Months in service for depreciation expense from				13.00			13.00			13.00			13.00	
20	Year placed in Service (0 if CWIP)			2011			2012			2011			2013		
21			**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**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												
27		W Increased ROE	2008												
28		W 11.68 % ROE	2009												
29		W Increased ROE	2009												
30		W 11.68 % ROE	2010												
31		W Increased ROE	2010												
32		W 11.68 % ROE	2011	7,844,331	111,778	905,525				19,902,939	147,204	1,150,144			
33		W Increased ROE	2011	7,844,331	111,778	952,449				19,902,939	147,204	1,150,144			
34		W 11.68 % ROE	2012	7,628,074	184,491	1,331,330	4,694,511	8,598	62,828	19,848,511	475,501	3,452,558			
35		W Increased ROE	2012	7,628,074	184,491	1,399,243	4,694,511	8,598	66,040	19,848,511	475,501	3,452,558			
36		W 11.68 % ROE	2013	6,391,895	159,242	1,047,292	25,426,870	605,606	4,138,257	118,115,741	2,827,106	19,237,368	777,714	1,424	9,736
37		W Increased ROE	2013	6,391,895	159,242	1,104,801	25,426,870	605,606	4,367,027	118,115,741	2,827,106	19,237,368	777,714	1,424	9,736
38		W 11.68 % ROE	2014	40,082,737	717,210	4,387,056	666,963,000	10,160,548	62,692,814	333,325,376	6,107,990	37,392,933	83,696,796	854,944	5,279,191
39		W Increased ROE	2014	40,082,737	717,210	4,647,913	666,963,000	10,160,548	66,426,879	333,325,376	6,107,990	37,392,933	83,696,796	854,944	5,279,191
40		W 11.68 % ROE	2015	39,365,526	965,196	5,579,868	711,440,230	16,714,518	97,780,708	346,271,067	8,256,393	47,814,854	436,685,203	6,739,741	39,857,912
41		W Increased ROE	2015	39,365,526	965,196	5,917,569	711,440,230	16,714,518	103,713,135	346,271,067	8,256,393	47,814,854	436,685,203	6,739,741	39,857,912
42		W 11.68 % ROE	2016	38,400,330	965,196	5,410,793	696,007,937	17,226,265	97,802,922	337,124,933	8,445,973	47,474,838	420,023,804	10,185,340	58,791,720
43		W Increased ROE	2016	38,400,330	965,196	5,742,497	696,007,937	17,226,265	103,815,086	337,124,933	8,445,973	47,474,838	420,023,804	10,185,340	58,791,720
44		W 11.68 % ROE	2017	37,435,134	965,196	5,096,113	678,154,289	17,211,186	92,044,606	330,265,484	8,488,706	44,933,061	421,661,646	10,462,931	56,992,730
45		W Increased ROE	2017	37,435,134	965,196	5,413,780	678,154,289	17,211,186	97,799,286	330,265,484	8,488,706	44,933,061	421,661,646	10,462,931	56,992,730

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2017

1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if if not a CIAC**			
		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	11.03%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.71%
5	C		Line B less Line A	0.68%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.60%

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

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

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

10		Details		**North Central Reliability (West Orange Conversion (B1154)**	**Northeast Grid Reliability Project (B1304.1-B1304.4)**	**Northeast Grid Reliability Project (B1304.5-B1304.21)**	**Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)**
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	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	25	25	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		11.03%	11.03%	11.03%	11.03%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.03%	11.20%	11.20%	11.03%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		370,184,658	625,991,050	351,791,077	175,766,398
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		8,813,920	14,904,549	8,375,978	4,184,914
19	Months in service for depreciation expense from			13.00	13.00	13.00	12.98
20	Year placed in Service (0 if CWIP)			2012	2013	2016	2016

21			Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	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												
27		W Increased ROE	2008												
28		W 11.68 % ROE	2009												
29		W Increased ROE	2009												
30		W 11.68 % ROE	2010												
31		W Increased ROE	2010												
32		W 11.68 % ROE	2011												
33		W Increased ROE	2011												
34		W 11.68 % ROE	2012	16,441,748	30,113	220,046									
35		W Increased ROE	2012	16,441,748	30,113	220,046									
36		W 11.68 % ROE	2013	257,640,264	6,135,009	41,929,935	23,466,022	86,647	592,253						
37		W Increased ROE	2013	257,640,264	6,135,009	41,929,935	23,466,022	86,647	598,801						
38		W 11.68 % ROE	2014	360,673,484	7,742,354	47,135,528	274,113,325	2,382,627	14,708,781						
39		W Increased ROE	2014	360,673,484	7,742,354	47,135,528	274,113,325	2,382,627	14,884,013						
40		W 11.68 % ROE	2015	355,885,266	8,777,921	50,370,637	433,597,024	7,852,675	46,296,391				-	-	-
41		W Increased ROE	2015	355,885,266	8,777,921	50,370,637	433,597,024	7,852,675	46,859,053				-	-	-
42		W 11.68 % ROE	2016	345,570,065	8,768,102	48,774,658	828,555,066	17,720,856	102,541,677				153,948,340	1,985,885	11,640,166
43		W Increased ROE	2016	345,570,065	8,768,102	48,774,658	828,555,066	17,720,856	103,807,445				153,948,340	1,985,885	11,640,166
44		W 11.68 % ROE	2017	338,731,158	8,813,920	46,192,451	597,948,245	14,904,549	80,887,339	351,791,077	8,375,978	47,195,653	173,780,513	4,177,297	23,318,838
45		W Increased ROE	2017	338,731,158	8,813,920	46,192,451	597,948,245	14,904,549	81,902,152	351,791,077	8,375,978	47,792,699	173,780,513	4,177,297	23,318,838

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2017

1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if if not a CIAC**			
		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	11.03%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.71%
5	C		Line B less Line A	0.68%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.60%

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

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

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

10		Details		**Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21)**			**Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22)**			**Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33)**			**Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60)**		
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			42			42			42		
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No			No			No			No		
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		11.03%			11.03%			11.03%			11.03%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.03%			11.03%			11.03%			11.03%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		24,373,985			24,373,985			15,071,438			48,229,438		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		580,333			580,333			358,844			1,148,320		
19	Months in service for depreciation expense from			12.83			12.83			7.01			2.94		
20	Year placed in Service (0 if CWIP)			2016			2016			2015			2015		
21			**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**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												
27		W Increased ROE	2008												
28		W 11.68 % ROE	2009												
29		W Increased ROE	2009												
30		W 11.68 % ROE	2010												
31		W Increased ROE	2010												
32		W 11.68 % ROE	2011												
33		W Increased ROE	2011												
34		W 11.68 % ROE	2012												
35		W Increased ROE	2012												
36		W 11.68 % ROE	2013												
37		W Increased ROE	2013												
38		W 11.68 % ROE	2014												
39		W Increased ROE	2014												
40		W 11.68 % ROE	2015							225,037	412	2,441	225,037	412	2,441
41		W Increased ROE	2015							225,037	412	2,441	225,037	412	2,441
42		W 11.68 % ROE	2016	19,694,890	252,499	1,480,230	19,694,890	252,499	1,480,230						
43		W Increased ROE	2016	19,694,890	252,499	1,480,230	19,694,890	252,499	1,480,230						
44		W 11.68 % ROE	2017	24,121,486	572,715	3,199,550	24,121,486	572,715	3,199,550	15,071,025	193,511	1,090,341	48,229,026	259,831	1,464,046
45		W Increased ROE	2017	24,121,486	572,715	3,199,550	24,121,486	572,715	3,199,550	15,071,025	193,511	1,090,341	48,229,026	259,831	1,464,046

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2017

1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if if not a CIAC**			
		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	11.03%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.71%
5	C		Line B less Line A	0.68%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.60%

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

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

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

10		Details		**Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70)**	**Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81)**	**Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83)**	**Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84)**
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	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
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		11.03%	11.03%	11.03%	11.03%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.03%	11.03%	11.03%	11.03%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		15,071,438	24,740,752	24,740,752	36,210,096
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		358,844	589,066	589,066	862,145
19	Months in service for depreciation expense from			7.01	7.48	7.48	7.32
20	Year placed in Service (0 if CWIP)			2015	2015	2015	2015

21			Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	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												
27		W Increased ROE	2008												
28		W 11.68 % ROE	2009												
29		W Increased ROE	2009												
30		W 11.68 % ROE	2010												
31		W Increased ROE	2010												
32		W 11.68 % ROE	2011												
33		W Increased ROE	2011												
34		W 11.68 % ROE	2012												
35		W Increased ROE	2012												
36		W 11.68 % ROE	2013												
37		W Increased ROE	2013												
38		W 11.68 % ROE	2014												
39		W Increased ROE	2014												
40		W 11.68 % ROE	2015	225,037	412	2,441	225,037	412	2,441	225,037	412	2,441	225,037	412	2,441
41		W Increased ROE	2015	225,037	412	2,441	225,037	412	2,441	225,037	412	2,441	225,037	412	2,441
42		W 11.68 % ROE	2016												
43		W Increased ROE	2016												
44		W 11.68 % ROE	2017	15,071,025	193,511	1,090,341	24,740,340	338,724	1,908,566	24,740,340	338,724	1,908,566	36,209,684	485,767	2,737,100
45		W Increased ROE	2017	15,071,025	193,511	1,090,341	24,740,340	338,724	1,908,566	24,740,340	338,724	1,908,566	36,209,684	485,767	2,737,100

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2017

1	New Plant Carrying Charge				
2	**Fixed Charge Rate (FCR) if if not a CIAC**				
			Formula Line		
3		A	152	Net Plant Carrying Charge without Depreciation	11.03%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.71%
5		C		Line B less Line A	0.68%
6	**FCR if a CIAC**				
7		D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.60%
				The FCR resulting from Formula in a given year is used for that year only.	
				Therefore actual revenues collected in a year do not change based on cost data for subsequent years.	
8				Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.	
9				For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.	

10		Details		**Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85)**			**Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90)**			**Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91)**			**New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10)**		
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			42			42			42		
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No			No			No			No		
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		11.03%			11.03%			11.03%			11.03%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.03%			11.03%			11.03%			11.03%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		36,210,096			29,256,534			-			25,651,961		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		862,145			696,584			-			610,761		
19	Months in service for depreciation expense from			7.32			12.86			7.01			13.00		
20	Year placed in Service (0 if CWIP)			2015			2016			2016			2016		
21			**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**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												
27		W Increased ROE	2008												
28		W 11.68 % ROE	2009												
29		W Increased ROE	2009												
30		W 11.68 % ROE	2010												
31		W Increased ROE	2010												
32		W 11.68 % ROE	2011												
33		W Increased ROE	2011												
34		W 11.68 % ROE	2012												
35		W Increased ROE	2012												
36		W 11.68 % ROE	2013												
37		W Increased ROE	2013												
38		W 11.68 % ROE	2014												
39		W Increased ROE	2014												
40		W 11.68 % ROE	2015	225,037	412	2,441									
41		W Increased ROE	2015	225,037	412	2,441									
42		W 11.68 % ROE	2016				27,239,122	349,220	2,047,240	19,694,915	252,499	1,480,232	25,264,003	323,897	1,898,794
43		W Increased ROE	2016				27,239,122	349,220	2,047,240	19,694,915	252,499	1,480,232	25,264,003	323,897	1,898,794
44		W 11.68 % ROE	2017	36,209,684	485,767	2,737,100	28,907,314	688,967	3,843,966				25,328,064	610,761	3,405,679
45		W Increased ROE	2017	36,209,684	485,767	2,737,100	28,907,314	688,967	3,843,966				25,328,064	610,761	3,405,679

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2017

1 New Plant Carrying Charge

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

		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	11.03%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.71%
5	C		Line B less Line A	0.68%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.60%

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

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

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

10		Details		**New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11)**			**New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20)**			**New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21)**			**New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30)**		
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			42			42			42		
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No			No			No			No		
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		11.03%			11.03%			11.03%			11.03%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.03%			11.03%			11.03%			11.03%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		25,651,961			15,071,438			15,071,438			58,015,888		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		610,761			358,844			358,844			1,381,331		
19	Months in service for depreciation expense from			13.00			7.01			7.01			8.20		
20	Year placed in Service (0 if CWIP)			2016			2015			2015			2017		
21			**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**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												
27		W Increased ROE	2008												
28		W 11.68 % ROE	2009												
29		W Increased ROE	2009												
30		W 11.68 % ROE	2010												
31		W Increased ROE	2010												
32		W 11.68 % ROE	2011												
33		W Increased ROE	2011												
34		W 11.68 % ROE	2012												
35		W Increased ROE	2012												
36		W 11.68 % ROE	2013												
37		W Increased ROE	2013												
38		W 11.68 % ROE	2014												
39		W Increased ROE	2014												
40		W 11.68 % ROE	2015				225,037	412	2,441	225,037	412	2,441			
41		W Increased ROE	2015				225,037	412	2,441	225,037	412	2,441			
42		W 11.68 % ROE	2016	25,264,003	323,897	1,898,794									
43		W Increased ROE	2016	25,264,003	323,897	1,898,794									
44		W 11.68 % ROE	2017	25,328,064	610,761	3,405,679	15,071,025	193,511	1,090,341	15,071,025	193,511	1,090,341	58,015,888	871,281	4,909,357
45		W Increased ROE	2017	25,328,064	610,761	3,405,679	15,071,025	193,511	1,090,341	15,071,025	193,511	1,090,341	58,015,888	871,281	4,909,357

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2017

1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if if not a CIAC**			
		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	11.03%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.71%
5	C		Line B less Line A	0.68%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.60%

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

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

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

10		Details		**Upgrade Eagle Point-Gloucester 230kV Circuit (B1588)**			**Mickleton-Gloucester 230kV Circuit (B2139)**			**Ridge Road 69kV Breaker Station (B1255)**			**Cox's Corner-Lumberton 230kV Circuit (B1787)**		
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			42			42			42		
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No			No			No			No		
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		11.03%			11.03%			11.03%			11.03%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.03%			11.03%			11.03%			11.03%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		12,084,309			19,023,718			35,696,237			31,718,020		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		287,722			452,946			849,910			755,191		
19	Months in service for depreciation expense from			13.00			13.00			4.09			13.00		
20	Year placed in Service (0 if CWIP)			2015			2015			2016			2015		
21			**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**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												
27		W Increased ROE	2008												
28		W 11.68 % ROE	2009												
29		W Increased ROE	2009												
30		W 11.68 % ROE	2010												
31		W Increased ROE	2010												
32		W 11.68 % ROE	2011												
33		W Increased ROE	2011												
34		W 11.68 % ROE	2012												
35		W Increased ROE	2012												
36		W 11.68 % ROE	2013												
37		W Increased ROE	2013												
38		W 11.68 % ROE	2014												
39		W Increased ROE	2014												
40		W 11.68 % ROE	2015	11,980,348	216,491	1,282,387	18,260,361	232,128	1,375,013	-	-	-	17,370,246	185,057	1,096,185
41		W Increased ROE	2015	11,980,348	216,491	1,282,387	18,260,361	232,128	1,375,013	-	-	-	17,370,246	185,057	1,096,185
42		W 11.68 % ROE	2016	11,830,218	284,623	1,654,204	18,061,375	434,232	2,525,192	33,374,758	483,594	2,807,871	33,763,562	703,781	4,125,793
43		W Increased ROE	2016	11,830,218	284,623	1,654,204	18,061,375	434,232	2,525,192	33,374,758	483,594	2,807,871	33,763,562	703,781	4,125,793
44		W 11.68 % ROE	2017	11,583,195	287,722	1,565,912	18,357,357	452,946	2,478,656	35,212,643	267,164	1,488,600	30,829,183	755,191	4,157,150
45		W Increased ROE	2017	11,583,195	287,722	1,565,912	18,357,357	452,946	2,478,656	35,212,643	267,164	1,488,600	30,829,183	755,191	4,157,150

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2017

1 New Plant Carrying Charge

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

Line		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	11.03%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.71%
5	C		Line B less Line A	0.68%

6 **FCR if a CIAC**

Line				
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.60%

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

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

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

10		Details		**Sewaren Switch 230kV Conversion (B2276)**	**Susquehanna Roseland < 500KV (B0489.4) (CWIP)**	**Susquehanna Roseland >= 500kV (B0489) (CWIP)**	**North Central Reliability (West Orange Conversion) (B1154) (CWIP)**
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	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		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		11.03%	11.03%	11.03%	11.03%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.03%	11.88%	11.88%	11.03%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		118,337,484			
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		2,817,559	-	-	-
19	Months in service for depreciation expense from			12.99			
20	Year placed in Service (0 if CWIP)			2015			

21			Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	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							8,927,082		819,421			
27		W Increased ROE	2008							8,927,082		858,682			
28		W 11.68 % ROE	2009				8,601,534		794,647	33,993,795		3,927,226			
29		W Increased ROE	2009				8,601,534		833,737	33,993,795		4,120,411			
30		W 11.68 % ROE	2010				10,121,290		1,719,499	83,961,998		10,780,919			
31		W Increased ROE	2010				10,121,290		1,811,185	83,961,998		11,355,769			
32		W 11.68 % ROE	2011				30,831,150		3,376,923	133,618,838		19,674,374	19,588,655		1,299,846
33		W Increased ROE	2011				30,831,150		3,565,874	133,618,838		20,775,227	19,588,655		1,299,846
34		W 11.68 % ROE	2012				38,077,851		5,359,127	264,235,891		27,190,938	139,052,337		10,137,161
35		W Increased ROE	2012				38,077,851		5,676,479	264,235,891		28,801,108	139,052,337		10,137,161
36		W 11.68 % ROE	2013				40,538,248		5,381,625	567,928,477		56,420,758	79,292,223		21,408,869
37		W Increased ROE	2013				40,538,248		5,730,133	567,928,477		60,074,507	79,292,223		21,408,869
38		W 11.68 % ROE	2014				12,476,737		1,537,307	34,481,067		28,945,163	31,617,517		3,895,715
39		W Increased ROE	2014				12,476,737		1,646,580	34,481,067		31,002,624	31,617,517		3,895,715
40		W 11.68 % ROE	2015	13,591,177	156,762	928,580	-		-	15,544,417		1,822,213	-		-
41		W Increased ROE	2015	13,591,177	156,762	928,580	-		-	15,544,417		1,955,563	-		-
42		W 11.68 % ROE	2016	112,005,777	1,617,265	9,480,938	-		-				-		-
43		W Increased ROE	2016	112,005,777	1,617,265	9,480,938	-		-				-		-
44		W 11.68 % ROE	2017	116,563,457	2,815,636	15,669,479	-		-	-		-	-		-
45		W Increased ROE	2017	116,563,457	2,815,636	15,669,479	-		-	-		-	-		-

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2017

1 New Plant Carrying Charge

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

		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	11.03%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.71%
5	C		Line B less Line A	0.68%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.60%

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

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

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

10		Details		**Mickleton-Gloucester-Camden(B1398-B1398.7) (CWIP)**			**Mickleton-Gloucester-Camden Breakers (B1398.15-B1398.19) (CWIP)**			**Burlington - Camden 230kV Conversion (B1156) (CWIP)**			**Burlington - Camden 230kV Conversion (B1156.13-B1156.20) (CWIP)**		
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			42			42			42		
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No			No			No			No		
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		11.03%			11.03%			11.03%			11.03%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.03%			11.03%			11.03%			11.03%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment									-			-	
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp			-			-			-			-	
19	Months in service for depreciation expense from														
20	Year placed in Service (0 if CWIP)														
21			**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**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												
27		W Increased ROE	2008												
28		W 11.68 % ROE	2009												
29		W Increased ROE	2009												
30		W 11.68 % ROE	2010												
31		W Increased ROE	2010												
32		W 11.68 % ROE	2011	1,648,851		56,106				22,089,378		1,874,440			
33		W Increased ROE	2011	1,648,851		56,106				22,089,378		1,874,440			
34		W 11.68 % ROE	2012	22,706,717		1,587,335	532,375		24,600	128,653,138		10,501,318	9,231,712		791,084
35		W Increased ROE	2012	22,706,717		1,587,335	532,375		24,600	128,653,138		10,501,318	9,231,712		791,084
36		W 11.68 % ROE	2013	117,558,986		7,924,475	532,375		73,965	155,344,760		22,819,788	8,854,018		1,275,855
37		W Increased ROE	2013	117,558,986		7,924,475	532,375		73,965	155,344,760		22,819,788	8,854,018		1,275,855
38		W 11.68 % ROE	2014	160,260,925		16,099,944	532,375		65,596	56,976,438		7,020,285	3,745,932		461,551
39		W Increased ROE	2014	160,260,925		16,099,944	532,375		65,596	56,976,438		7,020,285	3,745,932		461,551
40		W 11.68 % ROE	2015	81,558,947		9,560,846	204,760		24,003	-		-	-		-
41		W Increased ROE	2015	81,558,947		9,560,846	204,760		24,003	-		-	-		-
42		W 11.68 % ROE	2016							-		-	-		-
43		W Increased ROE	2016							-		-	-		-
44		W 11.68 % ROE	2017	-		-	-		-	-		-	-		-
45		W Increased ROE	2017	-		-	-		-	-		-	-		-

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2017

1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if if not a CIAC**			
		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	11.03%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.71%
5	C		Line B less Line A	0.68%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.60%

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

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

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

10		Details		**Northeast Grid Reliability Project (B1304.1-B1304.4) (CWIP)**			**Northeast Grid Reliability Project (B1304.5-B1304.21) (CWIP)**			**Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (CWIP)**			**Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (CWIP)**		
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			42			42			42		
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No			No			No			No		
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		25			25			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		11.03%			11.03%			11.03%			11.03%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.20%			11.20%			11.03%			11.03%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment								2,271,018			23,927,668		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp			-			-		54,072			569,706		
19	Months in service for depreciation expense from									26.96			11.33		
20	Year placed in Service (0 if CWIP)														
21			**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**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												
27		W Increased ROE	2008												
28		W 11.68 % ROE	2009												
29		W Increased ROE	2009												
30		W 11.68 % ROE	2010												
31		W Increased ROE	2010												
32		W 11.68 % ROE	2011												
33		W Increased ROE	2011												
34		W 11.68 % ROE	2012	81,587,177		6,341,372	5,537,185		457,198						
35		W Increased ROE	2012	81,587,177		6,416,475	5,537,185		462,613						
36		W 11.68 % ROE	2013	184,611,449		18,512,179	18,052,410		1,627,531						
37		W Increased ROE	2013	184,611,449		18,751,945	18,052,410		1,648,610						
38		W 11.68 % ROE	2014	211,553,988		28,743,491	33,293,621		3,699,551	9,496,612		391,383	1,589,541		61,526
39		W Increased ROE	2014	211,553,988		29,152,116	33,293,621		3,752,145	9,496,612		391,383	1,589,541		61,526
40		W 11.68 % ROE	2015	232,789,181		31,313,982	31,157,349		2,302,742	79,833,944		3,818,309	14,281,935		836,684
41		W Increased ROE	2015	232,789,181		31,772,294	31,157,349		2,336,445	79,833,944		3,818,309	14,281,935		836,684
42		W 11.68 % ROE	2016	72,001,234		8,335,564	3,028,455		350,603	3,108,397		5,826,722	19,887,254		1,426,555
43		W Increased ROE	2016	72,001,234		8,459,954	3,028,455		355,835	3,108,397		5,826,722	19,887,254		1,426,555
44		W 11.68 % ROE	2017	-		-	-		-	2,271,018		519,803	23,927,668		2,300,724
45		W Increased ROE	2017	-		-	-		-	2,271,018		519,803	23,927,668		2,300,724

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2017

1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if if not a CIAC**			
		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	11.03%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.71%
5	C		Line B less Line A	0.68%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.60%

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

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

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

10		Details		**Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (CWIP)**			**Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33) (CWIP)**			**Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34) (CWIP)**			**Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50) (CWIP)**		
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			42			42			42		
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No			No			No			No		
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		11.03%			11.03%			11.03%			11.03%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.03%			11.03%			11.03%			11.03%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		13,263,928			103,139,173			100,004,406			50,261,443		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		315,808			2,455,695			2,381,057			1,196,701		
19	Months in service for depreciation expense from			9.66			9.66			8.44			10.49		
20	Year placed in Service (0 if CWIP)														
21			**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**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												
27		W Increased ROE	2008												
28		W 11.68 % ROE	2009												
29		W Increased ROE	2009												
30		W 11.68 % ROE	2010												
31		W Increased ROE	2010												
32		W 11.68 % ROE	2011												
33		W Increased ROE	2011												
34		W 11.68 % ROE	2012												
35		W Increased ROE	2012												
36		W 11.68 % ROE	2013												
37		W Increased ROE	2013												
38		W 11.68 % ROE	2014	1,531,032		58,653	2,114,342		74,197	1,476,460		58,912	838,906		41,991
39		W Increased ROE	2014	1,531,032		58,653	2,114,342		74,197	1,476,460		58,912	838,906		41,991
40		W 11.68 % ROE	2015	14,081,213		819,896	7,520,100		530,656	1,567,639		105,699	3,286,307		178,025
41		W Increased ROE	2015	14,081,213		819,896	7,520,100		530,656	1,567,639		105,699	3,286,307		178,025
42		W 11.68 % ROE	2016	5,133,133		1,064,877	46,154,190		2,887,183	31,456,933		1,636,015	29,153,435		1,549,513
43		W Increased ROE	2016	5,133,133		1,064,877	46,154,190		2,887,183	31,456,933		1,636,015	29,153,435		1,549,513
44		W 11.68 % ROE	2017	13,263,928		1,087,121	103,139,173		8,457,930	100,004,406		7,165,306	50,261,443		4,476,177
45		W Increased ROE	2017	13,263,928		1,087,121	103,139,173		8,457,930	100,004,406		7,165,306	50,261,443		4,476,177

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2017

1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if if not a CIAC**			
		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	11.03%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.71%
5	C		Line B less Line A	0.68%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.60%

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

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

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

10		Details		**Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (CWIP)**			**Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70) (CWIP)**			**Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81) (CWIP)**			**Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83) (CWIP)**		
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			42			42			42		
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No			No			No			No		
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		11.03%			11.03%			11.03%			11.03%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.03%			11.03%			11.03%			11.03%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		4,257,610			55,639,039			53,134			53,134		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		101,372			1,324,739			1,265			1,265		
19	Months in service for depreciation expense from			54.84			11.60			2,078.76			2,078.76		
20	Year placed in Service (0 if CWIP)														
21			**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**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												
27		W Increased ROE	2008												
28		W 11.68 % ROE	2009												
29		W Increased ROE	2009												
30		W 11.68 % ROE	2010												
31		W Increased ROE	2010												
32		W 11.68 % ROE	2011												
33		W Increased ROE	2011												
34		W 11.68 % ROE	2012												
35		W Increased ROE	2012												
36		W 11.68 % ROE	2013												
37		W Increased ROE	2013												
38		W 11.68 % ROE	2014	433,918		21,259	1,370,003		56,093	597,317		24,145	597,317		24,145
39		W Increased ROE	2014	433,918		21,259	1,370,003		56,093	597,317		24,145	597,317		24,145
40		W 11.68 % ROE	2015	3,386,828		209,207	7,110,556		414,795	4,018,145		249,912	4,018,145		249,912
41		W Increased ROE	2015	3,386,828		209,207	7,110,556		414,795	4,018,145		249,912	4,018,145		249,912
42		W 11.68 % ROE	2016	13,451,622		1,007,913	32,115,662		1,793,514	16,422,638		1,119,514	16,422,638		1,119,514
43		W Increased ROE	2016	13,451,622		1,007,913	32,115,662		1,793,514	16,422,638		1,119,514	16,422,638		1,119,514
44		W 11.68 % ROE	2017	4,257,610		1,981,744	55,639,039		5,480,161	53,134		937,564	53,134		937,564
45		W Increased ROE	2017	4,257,610		1,981,744	55,639,039		5,480,161	53,134		937,564	53,134		937,564

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2017

1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if if not a CIAC**			
		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	11.03%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.71%
5	C		Line B less Line A	0.68%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.60%

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

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

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,

which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

10		Details		**Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) (CWIP)**			**Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (CWIP)**			**Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (CWIP)**			**Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91) (CWIP)**		
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			42			42			42		
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No			No			No			No		
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		11.03%			11.03%			11.03%			11.03%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.03%			11.03%			11.03%			11.03%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		11,129,698			11,129,698			2,422,164			777,902		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		264,993			264,993			57,671			18,521		
19	Months in service for depreciation expense from			13.00			13.00			9.63			13.00		
20	Year placed in Service (0 if CWIP)														
21			Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	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												
27		W Increased ROE	2008												
28		W 11.68 % ROE	2009												
29		W Increased ROE	2009												
30		W 11.68 % ROE	2010												
31		W Increased ROE	2010												
32		W 11.68 % ROE	2011												
33		W Increased ROE	2011												
34		W 11.68 % ROE	2012												
35		W Increased ROE	2012												
36		W 11.68 % ROE	2013												
37		W Increased ROE	2013												
38		W 11.68 % ROE	2014	569,297		24,114	569,297		24,114	1,581,597		63,898	1,286,903		48,434
39		W Increased ROE	2014	569,297		24,114	569,297		24,114	1,581,597		63,898	1,286,903		48,434
40		W 11.68 % ROE	2015	3,852,871		236,839	3,852,871		236,839	14,750,089		849,382	13,603,685		780,003
41		W Increased ROE	2015	3,852,871		236,839	3,852,871		236,839	14,750,089		849,382	13,603,685		780,003
42		W 11.68 % ROE	2016	17,333,648		1,276,434	17,333,648		1,276,434	906,569		1,081,821	715,475		863,750
43		W Increased ROE	2016	17,333,648		1,276,434	17,333,648		1,276,434	906,569		1,081,821	715,475		863,750
44		W 11.68 % ROE	2017	11,129,698		1,228,147	11,129,698		1,228,147	2,422,164		197,896	777,902		85,840
45		W Increased ROE	2017	11,129,698		1,228,147	11,129,698		1,228,147	2,422,164		197,896	777,902		85,840

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2017

1	New Plant Carrying Charge	1			
2	**Fixed Charge Rate (FCR) if if not a CIAC**				
			Formula Line		
3		A	152	Net Plant Carrying Charge without Depreciation	11.03%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.71%
5		C		Line B less Line A	0.68%
6	**FCR if a CIAC**				
7		D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.60%

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

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

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

10		Details			**New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (CWIP)**			**New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (CWIP)**			**New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20) (CWIP)**			**New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (CWIP)**		
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			42			42			42		
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)		No			No			No			No		
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			11.03%			11.03%			11.03%			11.03%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project			11.03%			11.03%			11.03%			11.03%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment			1,212,870			1,241,892			4,472,474			4,472,773		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp			28,878			29,569			106,487			106,495		
19	Months in service for depreciation expense from				12.70			12.70			13.00			13.00		
20	Year placed in Service (0 if CWIP)															
21				**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**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												
27		W Increased ROE		2008												
28		W 11.68 % ROE		2009												
29		W Increased ROE		2009												
30		W 11.68 % ROE		2010												
31		W Increased ROE		2010												
32		W 11.68 % ROE		2011												
33		W Increased ROE		2011												
34		W 11.68 % ROE		2012												
35		W Increased ROE		2012												
36		W 11.68 % ROE		2013												
37		W Increased ROE		2013												
38		W 11.68 % ROE		2014	4,799,334		220,160	5,002,105		223,171	123,509		4,946	124,051		4,952
39		W Increased ROE		2014	4,799,334		220,160	5,002,105		223,171	123,509		4,946	124,051		4,952
40		W 11.68 % ROE		2015	20,855,739		1,506,352	21,058,511		1,530,122	2,601,853		148,281	2,602,395		148,345
41		W Increased ROE		2015	20,855,739		1,506,352	21,058,511		1,530,122	2,601,853		148,281	2,602,395		148,345
42		W 11.68 % ROE		2016	2,285,677		1,326,708	2,524,127		1,323,679	7,543,949		639,295	7,544,669		639,379
43		W Increased ROE		2016	2,285,677		1,326,708	2,524,127		1,323,679	7,543,949		639,295	7,544,669		639,379
44		W 11.68 % ROE		2017	1,212,870		130,718	1,241,892		133,921	4,472,474		493,532	4,472,773		493,565
45		W Increased ROE		2017	1,212,870		130,718	1,241,892		133,921	4,472,474		493,532	4,472,773		493,565

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2017

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2	**Fixed Charge Rate (FCR) if if not a CIAC**			
		Formula Line		
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5	C		Line B less Line A	0.68%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.60%

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

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

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

				New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (CWIP)			**New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33) (CWIP)**					
10		Details										
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes			Yes					
12	Useful life of the project	Life		42			42					
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No			No					
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		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		11.03%			11.03%					
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.03%			11.03%					
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		15,327,955			14,065,098					
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		364,951			334,883					
19	Months in service for depreciation expense from			13.00			7.82					
20	Year placed in Service (0 if CWIP)											
21			**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**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							$ 32,346,385		$ 32,346,385
27		W Increased ROE	2008							$ 32,385,646	$ 32,385,646	
28		W 11.68 % ROE	2009							$ 51,356,608		$ 51,356,608
29		W Increased ROE	2009							$ 51,588,883	$ 51,588,883	
30		W 11.68 % ROE	2010							$ 61,349,032		$ 61,349,032
31		W Increased ROE	2010							$ 62,015,568	$ 62,015,568	
32		W 11.68 % ROE	2011							$ 78,438,322		$ 78,438,322
33		W Increased ROE	2011							$ 79,823,709	$ 79,823,709	
34		W 11.68 % ROE	2012							$ 129,728,618		$ 129,728,618
35		W Increased ROE	2012							$ 131,858,773	$ 131,858,773	
36		W 11.68 % ROE	2013							$ 279,708,533		$ 279,708,533
37		W Increased ROE	2013							$ 284,314,797	$ 284,314,797	
38		W 11.68 % ROE	2014	337,481		13,854	133,460		5,677	$ 342,977,142		$ 342,977,142
39		W Increased ROE	2014	337,481		13,854	133,460		5,677	$ 349,823,024	$ 349,823,024	
40		W 11.68 % ROE	2015	2,972,226		101,157	258,129		20,804	$ 434,110,713		$ 434,110,713
41		W Increased ROE	2015	2,972,226		101,157	258,129		20,804	$ 441,614,467	$ 441,614,467	
42		W 11.68 % ROE	2016	16,168,432		851,765	3,913,246		145,981	$ 522,903,602		$ 522,903,602
43		W Increased ROE	2016	16,168,432		851,765	3,913,246		145,981	$ 530,687,571	$ 530,687,571	
44		W 11.68 % ROE	2017	15,327,955		1,691,419	14,065,098		934,008	$ 576,209,051		$ 576,209,051
45		W Increased ROE	2017	15,327,955		1,691,419	14,065,098		934,008	$ 583,935,997	$ 583,935,997	

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 Ending December 31, 2017

Required Transmission Enhancements

Upgrade ID	**RTEP Baseline Project Description**	**Estimated/Actual Project Cost (thru 2017) ***	**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	May-09
b0498	Loop the 5021 circuit into New Freedom 500 kV substation	$ 27,005,248	May-09
b0161	Install 230-138kV transformer at Metuchen substation	$ 25,799,055	Nov-08
b0169	Build a new 230 kV section from Branchburg - Flagtown and move the Flagtown - Somerville 230 kV circuit to the new section	$ 15,731,554	May-08
b0170	Reconductor the Flagtown-Somerville-Bridgewater 230 kV circuit with 1590 ACSS	$ 6,961,495	May-09
b0274	Replace both 230/138 kV transformers at Roseland	$ 21,073,706	Apr-12
b0172.2	Replace wave trap at Branchburg 500kV substation	$ 27,988	Feb-07
b0813	Reconductor Hudson - South Waterfront 230kV circuit	$ 9,158,918	May-12
b1017	Reconductor South Mahwah 345 kV J-3410 Circuit	$ 20,626,991	Dec-12
b1018	Reconductor South Mahwah 345 kV K-3411 Circuit	$ 21,170,273	May-11
b0290	Branchburg 400 MVAR Capacitor	$ 80,435,315	Nov-10
b0472	Saddle Brook - Athenia Upgrade Cable	$ 14,404,842	Nov-08
b0664-b0665	Branchburg-Somerville-Flagtown Reconductor	$ 18,664,931	Apr-12
b0668	Somerville -Bridgewater Reconductor	$ 6,390,403	Apr-12
b0814	New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie	$ 46,073,245	Dec-10
b1410-b1415	Replace Salem 500 kV breakers	$ 15,876,913	Oct-12
b1228	230kV Lawrence Switching Station Upgrade	$ 22,040,646	May-11
b1155	Branchburg-Middlesex Swich Rack	$ 68,312,808	Dec-11
b1399	Aldene-Springfield Rd. Conversion	$ 72,443,911	Dec-12
b1590	Upgrade Camden-Richmond 230kV Circuit (B1590)	$ 11,268,594	Apr-13
b1588	Uprate EaglePoint-Gloucester 230kV Circuit	$ 12,084,309	May-11
b2139	Build Mickleton-Gloucester Corridor Ultimate Design	$ 19,023,718	Dec-13
b1255	Ridge Road 69kV Breaker Station	$ 35,696,237	May-16
b1787	New Cox's Corner-Lumberton 230kV Circuit	$ 31,718,020	Nov-13
b2276	Sewaren Switch 230kV Conversion	$ 118,337,484	Dec-13
b0489.5-b0489.15	Susquehanna Roseland Breakers	$ 5,857,687	Jun-14
b0489.4	Build new 500 kV transmission facilities from Pennsylvania - New Jersey border at Bushkill to Roseland (500kV and above elements of the project)	$ 40,538,248	Nov-11
b0489	Build new 500 kV transmission facilities from Pennsylvania - New Jersey border at Bushkill to Roseland (Below 500 kV elements of the project)	$ 722,869,825	Mar-15
b1156	Burlington - Camden 230kV Conversion	$ 356,525,651	Oct-14
b1398 - b1398.7	Mickleton-Gloucester-Camden	$ 439,443,096	Jun-15
b1154	North Central Reliability (West Orange Conversion)	$ 370,184,658	Jun-15
b1304.1-b1304.4	Northeast Grid Reliability Project	$ 625,991,050	Jun-15
b1304.5-b1304.21	Northeast Grid Reliability Project	$ 351,791,077	Jul-16
b2436.10	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades	$ 175,766,398	Jan-16
b2436.21	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades	$ 24,373,985	May-16
b2436.22	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades	$ 24,373,985	May-16
b2436.33	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades	$ 15,071,438	Dec-15

Upgrade ID	RTEP Baseline Project Description	Estimated/Actual Project Cost (thru 2017) *	Anticipated/Actual In-Service Date *
b2436.60	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades	$ 48,229,438	Dec-15
b2436.70	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades	$ 15,071,438	Dec-15
b2436.81	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades	$ 24,740,752	Dec-15
b2436.83	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades	$ 24,740,752	Dec-15
b2436.84	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades	$ 36,210,096	Dec-15
b2436.85	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades	$ 36,210,096	Dec-15
b2436.90	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades	$ 29,256,534	May-16
b2437.10	New Bergen 345/230 kV transformer and any associated substation upgrades	$ 25,651,961	May-16
b2437.11	New Bergen 345/138 kV transformer #1 and any associated substation upgrades	$ 25,651,961	May-16
b2437.20	New Bayway 345/138 kV transformer #1 and any associated substation upgrades	$ 15,071,438	Dec-15
b2437.21	New Bayway 345/138 kV transformer #2 and any associated substation upgrades	$ 15,071,438	Dec-15
b2437.30	New Linden 345/230 kV transformer and any associated substation upgrades	$ 58,015,888	Jul-16
b2436.10-b2437.33	Bergen Linden Corridor (BLC) (CWIP)	$ 371,812,578	Various
	Total	**$ 4,736,352,180**	

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

Work Paper 1

Public Service Electric and Gas Company

Accumulated Deferred Income Taxes Using The Proration Methodology - Tax Basis

Amounts reflected in Annual Update Filing

2016 EOY Amount	(3,765,312,995)	A
2017 EOY Amount	(4,075,528,187)	B

Account 282, Plant-related Liberalized Depreciation, for 2017

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	
Line	Year	Month	Projected Monthly (Increase) In ADIT - Depreciable Tax Basis	Days Outstanding During the Year	Proration Percentage	Monthly Prorated Amount	Cumulative "prorated" ADIT	Beginning & Ending ADIT Balance	
1	2016	Dec						(3,765,312,995)	A
2	2017	Jan	(31,359,495)	335	91.78%	(28,782,002)	(3,794,094,997)		
3	2017	Feb	(31,293,390)	307	84.11%	(26,320,741)	(3,820,415,738)		
4	2017	Mar	(31,231,697)	276	75.62%	(23,616,297)	(3,844,032,035)		
5	2017	Apr	(31,645,456)	246	67.40%	(21,328,171)	(3,865,360,206)		
6	2017	May	(31,970,725)	215	58.90%	(18,832,071)	(3,884,192,277)		
7	2017	Jun	(33,434,748)	185	50.68%	(16,946,379)	(3,901,138,656)		
8	2017	Jul	(32,046,386)	154	42.19%	(13,520,941)	(3,914,659,597)		
9	2017	Aug	(31,838,854)	123	33.70%	(10,729,258)	(3,925,388,855)		
10	2017	Sep	(32,783,725)	93	25.48%	(8,353,114)	(3,933,741,969)		
11	2017	Oct	(32,427,917)	62	16.99%	(5,508,304)	(3,939,250,273)		
12	2017	Nov	(31,729,581)	32	8.77%	(2,781,771)	(3,942,032,044)		
13	2017	Dec	(32,877,380)	1	0.27%	(90,075)	(3,942,122,119)		
		Total	(384,639,354)			(176,809,124)			

14	Projected 2017 Liberalized Depreciation based on ADIT Proration Methodology:	(176,809,124)	
15	Plus: Projected 2017 ADIT associated with Liberalized Deprecation not subject to Proration Methodology:	(133,406,068)	
16	Projected 2017 EOY Federal and State Liberalized Depreciation ADIT included in the FERC Formula Filing:	(4,075,528,187)	B

Explanations:

Col. 8, Line 1	Represents the estimated beginning plant-related Liberalized Depreciation ADIT balance as of 1/1/2017.
Lines 2 - 13	Represents the Forecasted Rate period (e.g. 2017).
Col. 3	Represents the monthly (increase) additions to the ADIT balance associated with depreciatable tax basis before proration.
Col. 4	Number of days remaining in the year as of and including the last day of the month.
Col. 5	Col. 4 divided by the number of days in the year, 365.
Col. 6	Col. 3 multiplied by Col. 5.
Col. 7	Col. 6 of previous month plus Col. 7; represents the cumulative balance.
Col. 8, Line 14	Total projected plant-related Liberalized Depreciation ADIT related to depreciable tax basis.
Col. 8, Line 15	Projected plant-related Liberalized Depreciation ADIT that is not subjected to the proration rules.
Col. 8, Line 16	Projected Total EOY balance of plant-related Liberalized Depreciation ADIT that is included in the formula rate.