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PSEG
Services Corporation

VIA ELECTRONIC MAIL & OVERNIGHT MAIL

December 8, 2017

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, 2015
-and-
In the Matter of the Provision of
Basic Generation Service for the Period Beginning June 1, 2016
-and-
In the Matter of the Provision of
Basic Generation Service for the Period Beginning June 1, 2017

Docket Nos. EO03050394, ER14040370, ER15040482, ER16040337
++
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, AEP East Operating Companies and AEP East Transmission Companies (”AEP”) in FERC Docket No. ER17-405-000, 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 August 23, 2017 in BPU Docket No. ER17060671, 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, 2018, 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, VEPCo, AEP, and PSE&G, annual formula rate updates filed with FERC on or about September 9, 2017, September 9, 2017, November 8, 2017, and October 27, 2017, respectively. The specific additional PJM transmission charges related to the PATH, VEPCo, AEP, and PSE&G filings are found in Schedule 12 of the PJM OATT. On July 19, 2017, 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 2018, 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, 2018. 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, 2018, 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 2018 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, VEPCo, AEP, and PSE&G, projects posted on the PJM website. Attachment 7 provides excerpts of the Schedule 12 OATT indicating the responsible share of projects. Attachments 8, 9, 10, and 11 provide the formula rate updates for PATH, AEP, 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, 2018. 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, 2018 through December 31, 2018

Line #	Description	Rate			Source
(1)	Transmission Service Annual Revenue Requirement	$	1,397,054,471.91		Page 4 of Attachment 11 -Line 164
(2)	Total Schedule 12 TEC Included in above	$	(541,034,211.00)		Attachment 6a Column (a)
(3)	PSE&G Customer Share of Schedule 12 TEC	$	225,935,859.21		Attachment 6a Column (h)
(4)	Total Transmission Costs Borne by PSE&G customers	$	1,081,956,120.11		=(1) +(2) +(3)
(5)	2017 PSE&G Network Service Peak		9,566.9	MW	Page 4 of Attachment 11 - -Line 165
(6)	2017 Derived Network Integration Transmission Service Rate	$	113,093.70	per MW-year	
	Resulting 2018 BGS Firm Transmission Service Supplier Rate	$	309.85	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 2e
PSE&G Translation of AEP East Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 2a
Pro-forma PSE&G Tariff Sheets

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 75**
Superseding
B.P.U.N.J. No. 15 ELECTRIC **XXX Revised Sheet No. 75**

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	$0.117094	$0.125144	$0.117148	$0.125202
RS – in excess of 600 kWh	0.117094	0.125144	0.126266	0.134947
RHS – first 600 kWh	0.094463	0.100957	0.089567	0.095725
RHS – in excess of 600 kWh	0.094463	0.100957	0.101759	0.108755
RLM On-Peak	0.198125	0.211746	0.209563	0.223970
RLM Off-Peak	0.057109	0.061035	0.053345	0.057012
WH	0.054424	0.058166	0.051835	0.055399
WHS	0.054891	0.058665	0.051426	0.054962
HS	0.093989	0.100451	0.094868	0.101390
BPL	0.051712	0.055267	0.046936	0.050163
BPL-POF	0.051712	0.055267	0.046936	0.050163
PSAL	0.051712	0.055267	0.046936	0.050163

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.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 79**
Superseding
B.P.U.N.J. No. 15 ELECTRIC **XXX Revised Sheet No. 79**

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	$ 5.7899
Charge including New Jersey Sales and Use Tax (SUT)	$ 6.1880
Charge applicable in the months of October through May	$ 5.7899
Charge including New Jersey Sales and Use Tax (SUT)	$ 6.1880

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	$ 113,093.70 per MW per year
PJM Reallocation	$ 0.00 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	$102.26 per MW per month
Virginia Electric and Power Company	$ 88.04 per MW per month
Potomac-Appalachian Transmission Highline L.L.C.	($10.28) per MW per month
PPL Electric Utilities Corporation	$ 52.22 per MW per month
American Electric Power Service Corporation	$ 31.06 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.	$ 3.24 per MW per month
Baltimore Gas and Electric Company	$ 6.91 per MW per month

Above rates converted to a charge per kW of Transmission Obligation, applicable in all months	$ 9.7093
Charge including New Jersey Sales and Use Tax (SUT)	$ 10.3768

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

Date of Issue: Effective:

Issued by 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.

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	$ 113,093.70 per MW per year
PJM Reallocation	$ 0.00 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	$102.26 per MW per month
Virginia Electric and Power Company	$ 88.04 per MW per month
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Potomac Electric Power Company.	$ 3.24 per MW per month
Baltimore Gas and Electric Company	$ 6.91 per MW per month

Above rates converted to a charge per kW of Transmission Obligation, applicable in all months	$ 9.7093
Charge including New Jersey Sales and Use Tax (SUT)	$ 10.3768

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-RSC
NITS Charges for January 2018 - December 201

		Effective 1/1/18 - 12/31/1	
PSE&G Annual Transmission Service Revenue Requirement	$	1,397,054,471.91	
Total Schedule 12 TEC Included in above	$	(541,034,211.00)	
PSE&G Customer Share of Schedule 12 NITS	$	225,935,859.21	
NITS Charges for Jan 2018 - Dec 2018	$	1,081,956,120.11	
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,566.90	
Term (Months)		12	
OATT rate	$	9,424.48	/MW/month

all values show w/o NJ SUT

converted to $/MW/yr =	$	113,093.70	/MW/yr	**Jan 18 - Dec 18 NITS Charge**			
	$	82,031.68	/MW/yr	**2015 - 2017 Weighted Average of**	**$ 72,688.29**	**$ 82,516.44**	**$ 91,224.00**
	$	95,817.05	/MW/yr	**2016- 2018 Weighted Average of**	**$ 82,516.44**	**$ 91,224.00**	**$ 113,093.70**
	$	90,073.15	/MW/yr	**Jan 18 - Dec 18 Weighted Average**			
Resulting Increase in Transmission Rate	$	23,020.55	/MW/yr				
Resulting Increase in Transmission Rate	$	1,918.38	/MW/month				

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	3,892.6	25.5	73.1	0.0	0.0	2.8	0.0	0.0
Total Annual Energy - MWh	12,201,595.6	133,055.9	218,245.6	1,283.0	27.0	15,196.6	158,968.0	296,268.0
Change in energy charge								
in $/MWh	$ 7.3441	$ 4.4119	$ 7.7106	$ -	$ -	$ 4.2416	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.007344**	**$ 0.004412**	**$ 0.007711**	**$ -**	**$ -**	**$ 0.004242**	**$ -**	**$ -**

Line #						
1	Total BGS-RSCP Trans Obl		6,658.8	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust		23,949,599	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes		25,728,145	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	153,289,267		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl adjusted for migration
5	Change in Average Supplier Payment Rate	$	5.9580	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	5.96	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	153,339,741		unrounded	= (6) * (3)
8	Difference due to rounding	$	50,474		unrounded	= (7) - (4)

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

Attachment 2c
Page 1 of 1

Transmission Charge Adjustment - BGS-RSCP
Attachment 6c - PJM Schedule 12 - Transmission Enhancement Charges for January 2018 - December 2018
Calculation of costs and monthly PJM charges for VEPCO Projects

TEC Charges for Jan 2018 - Dec 2018	$	10,107,330.97	
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,566.9	
Term (Months)		12	
OATT rate	$	88.04	/MW/month
Resulting Increase in Transmission Rate	$	1,056.48	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	3,892.6	25.5	73.1	0.0	0.0	2.8	0.0	0.0
Total Annual Energy - MWh	12,201,595.6	133,055.9	218,245.6	1,283.0	27.0	15,196.6	158,968.0	296,268.0
Change in energy charge								
in $/MWh	$ 0.3370	$ 0.2025	$ 0.3539	$ -	$ -	$ 0.1947	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000337**	**$ 0.000202**	**$ 0.000354**	**$ -**	**$ -**	**$ 0.000195**	**$ -**	**$ -**
Current Energy Charge								
in $/MWh	$ 0.3219	$ 0.1934	$ 0.3379	$ -	$ -	$ 0.1859	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000322**	**$ 0.000193**	**$ 0.000338**	**$ -**	**$ -**	**$ 0.000186**	**$ -**	**$ -**
Variance Energy Charge								
in $/MWh	**$ 0.01516**	**$ 0.00911**	**$ 0.01592**	**$ -**	**$ -**	**$ 0.00876**	**$ -**	**$ -**
in $/kWh - rounded to 6 places	**0.000015**	**0.000009**	**0.000016**	**0**	**0**	**0.000009**	**0**	**0**
% difference	**4.66%**	**4.66%**	**4.73%**	**0.00%**	**0.00%**	**4.84%**	**0.00%**	**0.00%**

Line #						
1	Total BGS-RSCP Trans Obl		6,658.8	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust		23,949,599.4	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes		25,728,144.5	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	7,034,889		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.2734	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	0.27	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	6,946,599		unrounded	= (6) * (3)
8	Difference due to rounding	$	(88,290)		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 2018 - December 2018
Calculation of costs and monthly PJM charges for PATH Project

TEC Charges for Jan 2018 - Dec 2018	$	(1,180,707.59)		
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,566.9		
Term (Months)		12		
OATT rate	$	(10.28)	/MW/month	all values show w/o NJ SUT
Resulting Increase in Transmission Rate	$	(123.36)	/MW/yr	

	RS	**RHS**	**RLM**	**WH**	**WHS**	**HS**	**PSAL**	**BPL**
Trans Obl - MW	3,892.6	25.5	73.1	0.0	0.0	2.8	0.0	0.0
Total Annual Energy - MWh	12,201,595.6	133,055.9	218,245.6	1,283.0	27.0	15,196.6	158,968.0	296,268.0
Change in energy charge								
in $/MWh	$ (0.0394)	$ (0.0236)	$ (0.0413)	$ -	$ -	$ (0.0227)	$ -	$ -
in $/kWh - rounded to 6 places	**$ (0.000039)**	**$ (0.000024)**	**$ (0.000041)**	**$ -**	**$ -**	**$ (0.000023)**	**$ -**	**$ -**
Current Energy Charge								
in $/MWh	$ 0.0433	$ 0.0260	$ 0.0455	$ -	$ -	$ 0.0250	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000043**	**$ 0.000026**	**$ 0.000045**	**$ -**	**$ -**	**$ 0.000025**	**$ -**	**$ -**
Variance Energy Charge								
in $/MWh	**$ (0.08269)**	**$ (0.04968)**	**$ (0.08682)**	**$ -**	**$ -**	**$ (0.04776)**	**$ -**	**$ -**
in $/kWh - rounded to 6 places	**-0.000083**	**-0.00005**	**-0.000087**	**0**	**0**	**-0.000048**	**0**	**0**
% difference	**-193.02%**	**-192.31%**	**-193.33%**	**0.00%**	**0.00%**	**-192.00%**	**0.00%**	**0.00%**

Line #						
1	Total BGS-RSCP Trans Obl		6,658.8	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust		23,949,599	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes		25,728,145	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	(821,430)		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	(0.0319)	/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	$	(771,844)		unrounded	= (6) * (3)
8	Difference due to rounding	$	49,585		unrounded	= (7) - (4)

Attachment 2e

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

Attachment 2e

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges for January 2018 - December 2018
Calculation of costs and monthly PJM charges for AEP -East Projects

TEC Charges for January 2018 - December 2018	$	3,566,077	
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,566.9	
Term (Months)		12	
OATT rate	$	31.06	/MW/month
converted to $/MW/yr =	$	372.72	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	3,892.6	25.5	73.1	0.0	0.0	2.8	0.0	0.0
Total Annual Energy - MWh	12,201,595.6	133,055.9	218,245.6	1,283.0	27.0	15,196.6	158,968.0	296,268.0
Energy Charge								
in $/MWh	$ 0.118907	$ 0.071431	$ 0.124840	$ -	$ -	$ 0.068674	$ -	$ -
in $/kWh - rounded to 6 places	**0.000119**	**0.000071**	**0.000125**	**0**	**0**	**0.000069**	**0**	**0**
Current Energy Charge								
in $/MWh	$ 0.107881	$ 0.064808	$ 0.113264	$ -	$ -	$ 0.062305	$ -	$ -
in $/kWh - rounded to 6 places	**0.000108**	**0.000065**	**0.000113**	**0**	**0**	**0.000062**	**0**	**0**
Variance Energy Charge								
in $/MWh	**$ 0.01103**	**$ 0.00662**	**$ 0.01158**	**$ -**	**$ -**	**$ 0.00637**	**$ -**	**$ -**
in $/kWh - rounded to 6 places	**0.000011**	**0.000007**	**0.000012**	**0**	**0**	**0.000006**	**0**	**0**
% difference	**10.19%**	**10.77%**	**10.62%**	**0.00%**	**0.00%**	**9.68%**	**0.00%**	**0.00%**

Line #						
1	Total BGS-RSCP eligbile Trans Obl		6658.8	MW		= sum of BGS-RSCP eligible Trans Obl
2	Total BGS-RSCP eligbile energy @ cust		23,949,599	MWh		= sum of BGS-RSCP eligible kWh @ cust
3	Total BGS-RSCP eligbile energy @ trans nodes		25,728,145	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	2,481,868		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.0965	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	0.10	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	2,572,814		unrounded	= (6) * (3)
8	Difference due to rounding	$	90,947		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 3e
JCP&L Translation of AEP 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, ISL and LED)

2) BGS Transmission Charge per KWH: As provided in the respective tariff for Service Classifications RS, RT, RGT, GS, GST, OL, SVL, MVL, ISL and LED. Effective September 1, 2017, a RMR surcharge of **$0.000131** 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, 2017, the following TEC surcharges (include 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, ISL and LED:

TRAILCO-TEC surcharge of **$0.000461** per KWH
PEPCO-TEC surcharge of **$0.000015** per KWH
ACE-TEC surcharge of **$0.000084** per KWH
Delmarva-TEC surcharge of **$0.000001** per KWH
PPL-TEC surcharge of **$0.000211** per KWH
BG&E-TEC surcharge of **$0.000031** per KWH

Effective January 1, 2018, the following TEC surcharges (include 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, ISL and LED:

AEP-East-TEC surcharge of **$0.000115** per KWH
PATH-TEC surcharge of **($0.000039)** per KWH
VEPCO-TEC surcharge of **$0.000341** per KWH
PSEG-TEC surcharge of **$0.001691** per KWH

3) BGS Reconciliation Charge per KWH: ($0.000207) (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, 2017, the following TEC surcharges (include Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage:

	TRAILCO-TEC	PEPCO-TEC	ACE-TEC
GS and GST	**$0.000461**	**$0.000015**	**$0.000084**
GP	**$0.000283**	**$0.000009**	**$0.000052**
GT	**$0.000251**	**$0.000007**	**$0.000046**
GT – High Tension Service	**$0.000059**	**$0.000002**	**$0.000011**

	Delmarva-TEC	PPL-TEC	BG&E-TEC
GS and GST	**$0.000001**	**$0.000211**	**$0.000031**
GP	**$0.000001**	**$0.000129**	**$0.000019**
GT	**$0.000001**	**$0.000114**	**$0.000017**
GT – High Tension Service	**$0.000000**	**$0.000027**	**$0.000004**

Effective January 1, 2018, the following TEC surcharges (include Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage:

	AEP-East-TEC	PATH-TEC	VEPCO-TEC	PSEG-TEC
GS and GST	**$0.000115**	**($0.000039)**	**$0.000341**	**$0.001691**
GP	**$0.000078**	**($0.000027)**	**$0.000231**	**$0.001144**
GT	**$0.000073**	**($0.000025)**	**$0.000213**	**$0.001053**
GT – High Tension Service	**$0.000018**	**($0.000006)**	**$0.000052**	**$0.000258**

4) BGS Reconciliation Charge per KWH: $0.002032 (includes Sales and Use Tax as provided in Rider SUT)

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

Attachment 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, 2018
To reflect FERC-approved PSEG Project Transmission Enhancement Charge (Schedule 12 PJM OATT) for January - December 2018

2018 Average Monthly PSEG-TEC Costs Allocated to JCP&L Zone	$	2,538,643.18	(1)
2018 JCP&L Zone Transmission Peak Load (MW)		5,721.0	
PSEG-Transmission Enhancement Rate ($/MW-month)	$	443.74	

Effective January 1, 2018:

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)	4934.8	26,277,287	16,572,627,418	$	0.001586	$	0.001691
Primary	348.5	1,855,726	1,730,276,418	$	0.001073	$	0.001144
Transmission @ 34.5 kV	293.5	1,562,856	1,581,370,077	$	0.000988	$	0.001053
Transmission @ 230 kV	15.5	82,536	341,655,635	$	0.000242	$	0.000258
Total	5592.3	29,778,404	20,225,929,548				

(1) Cost Allocation of PSEG Project Schedule 12 Charges to JCP&L Zone for 2018
(2) Based on 12 months PSEG Project costs from January through December 2018
(3) January 2018 through December 2018

BGS-RSCP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales January through December @ Customer		15,159,224	MWH
2	BGS-RSCP Eligible Sales January through December @ Transmission Node		16,830,967	MWH
3	BGS-RSCP Eligible Transmission Obligation		4,688	MW
4	PSEG-Transmission Enhancement Costs to RSCP Suppliers	$	24,964,700	= Line 3 x $443.74 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	1.48	= 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, 2018
To reflect FERC-approved VEPCO Project Transmission Enhancement Charge (Schedule 12 PJM OATT) for January - December 2018

2018 Average Monthly VEPCO-TEC Costs Allocated to JCP&L Zone	$	512,593.41	(1)
2018 JCP&L Zone Transmission Peak Load (MW)		5,721.0	
VEPCO-Transmission Enhancement Rate ($/MW-month)	$	89.60	

				Effective January 1, 2018:	
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)	4934.8	5,305,812	16,572,627,418	$ 0.000320	$ 0.000341
Primary	348.5	374,701	1,730,276,418	$ 0.000217	$ 0.000231
Transmission @ 34.5 kV	293.5	315,566	1,581,370,077	$ 0.000200	$ 0.000213
Transmission @ 230 kV	15.5	16,665	341,655,635	$ 0.000049	$ 0.000052
Total	5592.3	6,012,745	20,225,929,548		

(1) Cost Allocation of VEPCO Project Schedule 12 Charges to JCP&L Zone for 2018
(2) Based on 12 months VEPCO Project costs from January through December 2018
(3) January 2018 through December 2018

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

Line No.				
1	BGS-RSCP Eligible Sales January through December @ Customer		15,159,224	MWH
2	BGS-RSCP Eligible Sales January through December @ Transmission Node		16,830,967	MWH
3	BGS-RSCP Eligible Transmission Obligation		4,688	MW
4	VEPCO-Transmission Enhancement Costs to RSCP Suppliers	$	5,040,780	= Line 3 x $89.60 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.30	= Line 4 / Line 2

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

Attachment 3d

Jersey Central Power & Light Company
Proposed PATH Project Transmission Enhancement Charge (PATH-TEC Surcharge) effective January 1, 2018
To reflect FERC-approved PATH Project Transmission Enhancement Charge (Schedule 12 PJM OATT) for January - December 2018

2018 Average Monthly PATH-TEC Costs Allocated to JCP&L Zone	$	(59,794.68)	(1)
2018 JCP&L Zone Transmission Peak Load (MW)		5,721.0	
PATH-Transmission Enhancement Rate ($/MW-month)	$	(10.45)	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	**Effective January 1, 2018:** PATH-TEC Surcharge ($/kWh)	PATH-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	4934.8	(618,930)	16,572,627,418	$ (0.000037)	$ (0.000039)
Primary	348.5	(43,709)	1,730,276,418	$ (0.000025)	$ (0.000027)
Transmission @ 34.5 kV	293.5	(36,811)	1,581,370,077	$ (0.000023)	$ (0.000025)
Transmission @ 230 kV	15.5	(1,944)	341,655,635	$ (0.000006)	$ (0.000006)
Total	5592.3	(701,394)	20,225,929,548		

(1) Cost Allocation of PATH Project Schedule 12 Charges to JCP&L Zone for 2018
(2) Based on 12 months PATH Project costs from January through December 2018
(3) January 2018 through December 2018

BGS-RSCP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales January through December @ Customer		15,159,224	MWH
2	BGS-RSCP Eligible Sales January through December @ Transmission Node		16,830,967	MWH
3	BGS-RSCP Eligible Transmission Obligation		4,688	MW
4	PATH-Transmission Enhancement Costs to RSCP Suppliers	$	(588,013)	= Line 3 x ($10.45) x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	(0.03)	= Line 4 / Line 2

Attachment 3e

JCP&L Translation of AEP Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 3e

Jersey Central Power & Light Company
Proposed AEP-East Project Transmission Enhancement Charge (AEP-East-TEC Surcharge) effective January 1, 2018
To reflect FERC-approved AEP-East Project Transmission Enhancement Charge (Schedule 12 PJM OATT) for January - December 2018

2018 Average Monthly AEP-East-TEC Costs Allocated to JCP&L Zone	$	173,603.09	(1)
2018 JCP&L Zone Transmission Peak Load (MW)		5,721.0	
AEP-East-Transmission Enhancement Rate ($/MW-month)	$	30.34	

				Effective January 1, 2018:			
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)		AEP-East-TEC Surcharge ($/kWh)		AEP-East-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	4934.8	1,796,951	16,572,627,418	$	0.000108	$	0.000115
Primary	348.5	126,902	1,730,276,418	$	0.000073	$	0.000078
Transmission @ 34.5 kV	293.5	106,875	1,581,370,077	$	0.000068	$	0.000073
Transmission @ 230 kV	15.5	5,644	341,655,635	$	0.000017	$	0.000018
Total	5592.3	2,036,372	20,225,929,548				

(1) Cost Allocation of AEP-East Project Schedule 12 Charges to JCP&L Zone for 2018
(2) Based on 12 months AEP-East Project costs from January through December 2018
(3) January 2018 through December 2018

BGS-RSCP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales January through December @ Customer		15,159,224	MWH
2	BGS-RSCP Eligible Sales January through December @ Transmission Node		16,830,967	MWH
3	BGS-RSCP Eligible Transmission Obligation		4,688	MW
4	AEP-East-Transmission Enhancement Costs to RSCP Suppliers	$	1,707,191	= Line 3 x $30.34 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.10	= 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 4e
ACE Translation of AEP East 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 $0.000160 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	0.000437	0.000361	0.000293	0.000242	0.000194	0.000187	-	0.000147
TrAILCo	0.000588	0.000492	0.000531	0.000325	0.000261	0.000250	-	0.000206
PSE&G	0.000654	0.000540	0.000438	0.000361	0.000291	0.000280	-	0.000222
PATH	(0.000050)	(0.000042)	(0.000034)	(0.000028)	(0.000022)	(0.000021)	-	(0.000017)
PPL	0.000238	0.000199	0.000215	0.000131	0.000105	0.000102	-	0.000083
Pepco	0.000021	0.000018	0.000019	0.000012	0.000010	0.000010	-	0.000007
JCP&L	0.000003	0.000003	0.000003	0.000002	0.000002	0.000001	-	0.000001
Delmarva	0.000001	0.000001	0.000001	0.000001	0.000001	0.000001	-	0.000001
BG&E	0.000073	0.000061	0.000066	0.000041	0.000032	0.000031	-	0.000026
AEP - East	0.000131	0.000108	0.000087	0.000073	0.000058	0.000055	-	0.000044
Total	0.002096	0.001741	0.001619	0.001160	0.000932	0.000896	-	0.000720

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 Jan 1, 2018
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective Jan 1, 2018

Transmission Enhancement Costs Allocated to ACE Zone (2018)	$ 349,222
	$ 349,222
2018 ACE Zone Transmission Peak Load (MW)	2,541
Transmission Enhancement Rate ($/MW)	$ 137.45

Rate Class	Col. 1 Transmission Obligation (MW)	Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales Jun 2017 - May 2018 (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 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,545	$ 2,548,946	4,171,964,933	$ 0.000611	$ 0.000613	$ 0.000654
MGS Secondary	353	$ 582,384	1,152,950,462	$ 0.000505	$ 0.000506	$ 0.000540
MGS Primary	6	$ 10,029	24,456,016	$ 0.000410	$ 0.000411	$ 0.000438
AGS Secondary	394	$ 649,025	1,917,585,029	$ 0.000338	$ 0.000339	$ 0.000361
AGS Primary	94	$ 155,317	571,955,641	$ 0.000272	$ 0.000273	$ 0.000291
TGS	146	$ 240,941	920,786,585	$ 0.000262	$ 0.000263	$ 0.000280
SPL/CSL	0	$ -	73,240,385	$ -	$ -	$ -
DDC	2	$ 2,609	12,621,752	$ 0.000207	$ 0.000208	$ 0.000222
	2,540	$ 4,189,250	8,845,560,805			

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 Jan 1, 2018
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective Jan 1, 2018

Transmission Enhancement Costs Allocated to ACE Zone (2018)	$ 233,537
	$ 233,537
2018 ACE Zone Transmission Peak Load (MW)	2,541
Transmission Enhancement Rate ($/MW)	$ 91.91

Rate Class	Col. 1 Transmission Obligation (MW)	Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales Jun 2017 - May 2018 (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 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,545	$ 1,704,572	4,171,964,933	$ 0.000409	$ 0.000410	$ 0.000437
MGS Secondary	353	$ 389,461	1,152,950,462	$ 0.000338	$ 0.000339	$ 0.000361
MGS Primary	6	$ 6,707	24,456,016	$ 0.000274	$ 0.000275	$ 0.000293
AGS Secondary	394	$ 434,026	1,917,585,029	$ 0.000226	$ 0.000227	$ 0.000242
AGS Primary	94	$ 103,866	571,955,641	$ 0.000182	$ 0.000182	$ 0.000194
TGS	146	$ 161,126	920,786,585	$ 0.000175	$ 0.000175	$ 0.000187
SPL/CSL	-	$ -	73,240,385	$ -	$ -	$ -
DDC	2	$ 1,745	12,621,752	$ 0.000138	$ 0.000138	$ 0.000147
	2,540	$ 2,801,503	8,845,560,805			

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 Jan 1, 2018

To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective Jan 1, 2018

Transmission Enhancement Costs Allocated to ACE Zone (2018)	$ (26,892)
	$ (26,892)
2018 ACE Zone Transmission Peak Load (MW)	2,541
Transmission Enhancement Rate ($/MW)	$ (10.58)

Rate Class	Col. 1 Transmission Obligation (MW)	Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales Jun 2017 - May 2018 (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 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,545	$ (196,281)	4,171,964,933	$ (0.000047)	$ (0.000047)	$ (0.000050)
MGS Secondary	353	$ (44,846)	1,152,950,462	$ (0.000039)	$ (0.000039)	$ (0.000042)
MGS Primary	6	$ (772)	24,456,016	$ (0.000032)	$ (0.000032)	$ (0.000034)
AGS Secondary	394	$ (49,978)	1,917,585,029	$ (0.000026)	$ (0.000026)	$ (0.000028)
AGS Primary	94	$ (11,960)	571,955,641	$ (0.000021)	$ (0.000021)	$ (0.000022)
TGS	146	$ (18,554)	920,786,585	$ (0.000020)	$ (0.000020)	$ (0.000021)
SPL/CSL	-	$ -	73,240,385	$ -	$ -	$ -
DDC	2	$ (201)	12,621,752	$ (0.000016)	$ (0.000016)	$ (0.000017)
	2,540	$ (322,593)	8,845,560,805			

Attachment 4e

ACE Translation of AEP East Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 4e

Atlantic City Electric Company
Proposed AEP Projects Transmission Enhancement Charge (AEP Project-TEC Surcharge) effective Jan 1, 2018
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective Jan 1, 2018

Transmission Enhancement Costs Allocated to ACE Zone (2018)	$ 70,064
	$ 70,064
2018 ACE Zone Transmission Peak Load (MW)	2,541
Transmission Enhancement Rate ($/MW-Month)	$ 27.58

Rate Class	Col. 1 Transmission Obligation (MW)	Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales Jun 2017 - May 2018 (kWh)	Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)	Col. 5 = Col. 4 x 1/(1-Effective Rate) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)	Col. 6 = Col. 5 x 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,545.4	$ 511,390.50	4,171,964,933	$ 0.000123	$ 0.000123	$ 0.000131
MGS Secondary	353.1	$ 116,843	1,152,950,462	$ 0.000101	$ 0.000101	$ 0.000108
MGS Primary	6.1	$ 2,012	24,456,016	$ 0.000082	$ 0.000082	$ 0.000087
AGS Secondary	393.5	$ 130,213	1,917,585,029	$ 0.000068	$ 0.000068	$ 0.000073
AGS Primary	94.2	$ 31,161	571,955,641	$ 0.000054	$ 0.000054	$ 0.000058
TGS	146.1	$ 48,340	920,786,585	$ 0.000052	$ 0.000052	$ 0.000055
SPL/CSL	0.0	$ -	73,240,385	$ -	$ -	$ -
DDC	1.6	$ 523	12,621,752	$ 0.000041	$ 0.000041	$ 0.000044
	2,540	$ 840,482	8,845,560,805			

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 5e
RECO Translation of AEP Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 5a
Pro-forma RECO Tariff Sheets

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 ...... @	1.208 ¢ per kWh	1.208 ¢ per kWh
Over 250 kWh ..... @	1.208 ¢ per kWh	1.208 ¢ 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	0.948 ¢ per kWh	0.948 ¢ 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)

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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 ....@	0.590 ¢ per kWh	0.590 ¢ per kWh
Primary Voltage Service Only		
All kWh ....@	0.527 ¢ per kWh	0.527 ¢ 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 ......@	0.810 ¢ per kWh	0.810 ¢ per kWh
Off-Peak All other kWh ......@	0.810 ¢ per kWh	0.810 ¢ 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 .....@	0.577 ¢ per kWh	0.577¢ 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. 4
PUBLIC STREET LIGHTING SERVICE (Continued)

RATE – MONTHLY (Continued)

(1) Luminaire Charges (Continued)

Nominal Lumens	Luminaire Type	Watts	Total Wattage	Distribution Charge	Transmission Charge
Post Top Luminaires					
16,000	Sodium Vapor-Offset	150	199	$23.00	$0.48
Off-Roadway Luminaires					
27,500	Sodium Vapor	250	311	$ 19.19	$ 0.75
46,000	Sodium Vapor	400	488	27.00	1.18
Post-Top Luminaires					
4,000	Mercury Vapor	100	130	$ 11.75	$ 0.31
7,900	Mercury Vapor	175	215	14.39	0.52
7,900	Merc. Vapor-Offset	175	215	16.90	0.52

The above Transmission Charges apply to all customers taking Basic Generation Service from the Company. Transmission charges are also applicable to customers located in the Company's Central and Western Divisions and obtaining Competitive Energy Supply. Transmission 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. A Transmission Surcharge, to recover Reliability Must Run Charges, of 0.001 ¢ per kWh will also apply to all customers taking Basic Generation Service from the Company.

(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 ... @	0.793 ¢ per kWh	0.793 ¢ per kWh
Next 450 kWh ... @	0.793 ¢ per kWh	0.793 ¢ per kWh
Over 700 kWh ... @	0.793 ¢ per kWh	0.793 ¢ 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 ... @	0.632 ¢ per kWh	0.632 ¢ 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. 6
PRIVATE OVERHEAD LIGHTING SERVICE (Continued)

RATE – MONTHLY (Continued)

(1) Distribution and Transmission Charges (Continued)

(b) Distribution and Transmission Charges for Service Type C

The above Transmission Charges apply to all customers taking Basic Generation Service from the Company. Transmission charges are also applicable to customers located in the Company's Central and Western Divisions and obtaining Competitive Energy Supply. Transmission 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. A Transmission Surcharge, to recover Reliability Must Run Charges, of 0.001 ¢ per kWh will also apply to all customers taking Basic Generation Service from the Company.

(2) 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. For service type A, B, or C if not metered, the charges shall be applied to the kWh estimated as follows:

kWh = (Total Wattage divided by 1,000) times Monthly Burn Hours*

* See Monthly Burn Hours Table.

(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 @	$1.91 per kW	$1.91 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 @	0.383 ¢ per kWh	0.383 ¢ 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 3.289 ¢ per kWh during the billing months of October through May and 5.316 ¢ per kWh during the summer billing months and a Transmission Charge of 0.551 ¢ per kWh and a Transmission Surcharge of 0.383 ¢ 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 $26.93 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, 2018
To reflect FERC-approved PSE&G Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period January 2018 to December 2018

2018 Average Monthly PSE&G-TEC Costs Allocated to RECO	$ 748,486	(1)
2018 RECO Zone Transmission Peak Load (MW)	439.8	(2)
Transmission Enhancement Rate ($/MW-month)	$ 1,701.84	
SUT	6.625%	

	Col. 1	Col. 2	Col.3=Col.2 x $748,486 x 12	Col. 4	Col. 5 = Col. 3/Col. 4	Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)	Allocated Cost Recovery (1)	BGS Eligible Sales January 2018 - December 2018 (kWh)	Transmission Enhancement Charge ($/kWh)	Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	262.5	59.69%	$ 5,361,237	692,439,000	$ 0.00774	$ 0.00825
SC2 Secondary	124.6	28.32%	$ 2,543,770	528,990,000	$ 0.00481	$ 0.00513
SC2 Primary	13.9	3.15%	$ 283,339	65,159,000	$ 0.00435	$ 0.00464
SC3	0.1	0.01%	$ 1,289	275,000	$ 0.00469	$ 0.00500
SC4	0.0	0.00%	$ -	6,441,000	$ -	$ -
SC5	3.7	0.85%	$ 76,205	14,763,000	$ 0.00516	$ 0.00550
SC6	0.0	0.00%	$ -	5,550,000	$ -	$ -
SC7	35.1	7.97%	$ 715,992	227,701,000	$ 0.00314	$ 0.00335
Total	439.8 (2)	100.00%	$ 8,981,832	1,541,318,000		

(1) Attachment 4 - Cost Allocation of PSE&G Project Schedule 12 Charges to RECO Zone for January 2018 through December 2018
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.			
1	BGS-RSCP Eligible Sales Jan - Dec @ cust (RECO Eastern Division)	1,263,798	MWH
2	BGS-RSCP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)	1,176,362	MWH
3	BGS-RSCP Eligible Transmission Obligation	405	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$ 8,265,859.34	= Line 3 x $1701.84 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$ 7.03	= 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, 2018
To reflect FERC-approved VEPCo Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period January 2018 through December 2018

2018 Average Monthly VEPCo-TEC Costs Allocated to RECO	$	33,924	(1)
2018 RECO Zone Transmission Peak Load (MW)		439.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	77.13	
SUT		6.625%	

	Col. 1	Col. 2	Col.3=Col.2 x $33,924 x 12	Col. 4	Col. 5 = Col. 3/Col. 4	Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)	Allocated Cost Recovery (1)	BGS Eligible Sales January 2018 - December 2018 (kWh)	Transmission Enhancement Charge ($/kWh)	Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	262.5	59.69%	$ 242,988	692,439,000	$ 0.00035	$ 0.00037
SC2 Secondary	124.6	28.32%	$ 115,292	528,990,000	$ 0.00022	$ 0.00023
SC2 Primary	13.9	3.15%	$ 12,842	65,159,000	$ 0.00020	$ 0.00021
SC3	0.1	0.01%	$ 58	275,000	$ 0.00021	$ 0.00022
SC4	0.0	0.00%	$ -	6,441,000	$ -	$ -
SC5	3.7	0.85%	$ 3,454	14,763,000	$ 0.00023	$ 0.00025
SC6	0.0	0.00%	$ -	5,550,000	$ -	$ -
SC7	35.1	7.97%	$ 32,451	227,701,000	$ 0.00014	$ 0.00015
Total	439.8 (2)	100.00%	$ 407,085	1,541,318,000		

(1) Attachment 4 - Cost Allocation of VEPCo Schedule 12 Charges to RECO Zone for January 2018 through December 2018
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales Jan - Dec @ cust (RECO Eastern Division)		1,263,798	MWH
2	BGS-RSCP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)		1,176,362	MWH
3	BGS-RSCP Eligible Transmission Obligation		405	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	374,621.43	= Line 3 x $77.13 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.32	= Line 4/Line 2

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

Attachment 5d

Rockland Electric Company

Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (PATH) effective January 1, 2018

To reflect FERC-approved PATH Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period January 2018 to December 2018

2018 Average Monthly PATH-TEC Costs Allocated to RECO	$	(3,955)	(1)
2018 RECO Zone Transmission Peak Load (MW)		439.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	(8.99)	
SUT		6.625%	

Rate Class	Col. 1 BGS-Eligible Transmission Obligation (MW)	Col. 2 Transmission Obligation (Pct)	Col.3=Col.2 x $-3,955 x 12 Allocated Cost Recovery (1)	Col. 4 BGS Eligible Sales January 2018 - December 2018 (kWh)	Col. 5 = Col. 3/Col. 4 Transmission Enhancement Charge ($/kWh)	Col. 6 = Col. 5 x 1.07 Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	262.5	59.69%	$ (28,326)	692,439,000	$ (0.00004)	$ (0.00004)
SC2 Secondary	124.6	28.32%	$ (13,440)	528,990,000	$ (0.00003)	$ (0.00003)
SC2 Primary	13.9	3.15%	$ (1,497)	65,159,000	$ (0.00002)	$ (0.00002)
SC3	0.1	0.01%	$ (7)	275,000	$ (0.00003)	$ (0.00003)
SC4	0.0	0.00%	$ -	6,441,000	$ -	$ -
SC5	3.7	0.85%	$ (403)	14,763,000	$ (0.00003)	$ (0.00003)
SC6	0.0	0.00%	$ -	5,550,000	$ -	$ -
SC7	35.1	7.97%	$ (3,783)	227,701,000	$ (0.00002)	$ (0.00002)
Total	439.8 (2)	100.00%	$ (47,456)	1,541,318,000		

(1) Attachment 4 - Cost Allocation of PATH Project Schedule 12 Charges to RECO Zone for January 2018 through December 2018

(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales Jan - Dec @ cust (RECO Eastern Division)		1,263,798	MWH
2	BGS-RSCP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)		1,176,362	MWH
3	BGS-RSCP Eligible Transmission Obligation		405	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	(43,664.55)	= Line 3 x $-8.99 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	(0.04)	= Line 4/Line 2

Attachment 5e
RECO Translation of AEP East Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 5e

Rockland Electric Company

Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (AEP East) effective January 1, 2018

To reflect FERC-approved AEP-East Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period January 2018 to December 2018

2018 Average Monthly AEP-East-TEC Costs Allocated to RECO	$	11,929	(1)
2018 RECO Zone Transmission Peak Load (MW)		439.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	27.12	
SUT		6.625%	

	Col. 1	Col. 2		Col.3=Col.2 x $11,929 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales January 2018 - December 2018 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	262.5	59.69%	$	85,443	692,439,000	$	0.00012	$	0.00013
SC2 Secondary	124.6	28.32%	$	40,541	528,990,000	$	0.00008	$	0.00009
SC2 Primary	13.9	3.15%	$	4,516	65,159,000	$	0.00007	$	0.00007
SC3	0.1	0.01%	$	21	275,000	$	0.00008	$	0.00009
SC4	0.0	0.00%	$	-	6,441,000	$	-	$	-
SC5	3.7	0.85%	$	1,214	14,763,000	$	0.00008	$	0.00009
SC6	0.0	0.00%	$	-	5,550,000	$	-	$	-
SC7	35.1	7.97%	$	11,411	227,701,000	$	0.00005	$	0.00005
Total	439.8 (2)	100.00%	$	143,146	1,541,318,000				

(1) Attachment 2 - Cost Allocation of AEP East Schedule 12 Charges to RECO Zone for January 2018 through December 2018.

(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales Jan - Dec @ cust (RECO Eastern Division)		1,263,798	MWH
2	BGS-RSCP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)		1,176,362	MWH
3	BGS-RSCP Eligible Transmission Obligation		405	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	131,722.20	= Line 3 x $27.12 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.11	= Line 4/Line 2

Attachment 5

Rockland Electric Company

Calculation of Transmission Surcharges reflecting proposed changes effective January 1, 2018

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)
FERC-approved BG&E 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)
FERC-approved MAIT Project Schedule 12 Charges (Schedule 12 PJM OATT) filed on October 24, 2017

(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)	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001
ACE - TEC	(2)	0.00004	0.00002	0.00002	0.00002	0.00000	0.00002	0.00000	0.00001
AEP-East - TEC	(3)	0.00012	0.00008	0.00007	0.00008	0.00000	0.00008	0.00000	0.00005
BG&E- TEC	(4)	0.00003	0.00002	0.00001	0.00002	0.00000	0.00002	0.00000	0.00001
Delmarva - TEC	(5)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
PATH - TEC	(6)	(0.00004)	(0.00003)	(0.00002)	(0.00003)	0.00000	(0.00003)	0.00000	(0.00002)
PEPCO - TEC	(7)	0.00001	0.00001	0.00000	0.00000	0.00000	0.00001	0.00000	0.00000
PPL - TEC	(8)	0.00021	0.00013	0.00010	0.00013	0.00000	0.00014	0.00000	0.00008
PSE&G - TEC	(9)	0.00774	0.00481	0.00435	0.00469	0.00000	0.00516	0.00000	0.00314
TrAILCo - TEC	(10)	0.00041	0.00025	0.00020	0.00026	0.00000	0.00027	0.00000	0.00016
VEPCo - TEC	(11)	0.00035	0.00022	0.00020	0.00021	0.00000	0.00023	0.00000	0.00014
MAIT -TEC	(12)	0.00002	0.00001	0.00001	0.00002	0.00000	0.00001	0.00000	0.00001
Total ($/kWh and excl SUT)		$0.00890	$0.00553	$0.00495	$0.00541	$0.00001	$0.00592	$0.00001	$0.00359
Total (¢/kWh and excl SUT)		0.890 ¢	0.553 ¢	0.495 ¢	0.541 ¢	0.001 ¢	0.592 ¢	0.001 ¢	0.359 ¢

(B) Transmission Surcharge rates by Transmission Project and Service Class (including SUT) 6.625%

Transmission Project	Note	SC1	SC2 Sec	SC2 Pri	SC3	SC4	SC5	SC6	SC7
Reliability Must Run	(1)	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001
ACE - TEC	(2)	0.00004	0.00002	0.00002	0.00002	0.00000	0.00002	0.00000	0.00001
AEP-East - TEC	(3)	0.00013	0.00009	0.00007	0.00009	0.00000	0.00009	0.00000	0.00005
BG&E- TEC	(4)	0.00003	0.00002	0.00001	0.00002	0.00000	0.00002	0.00000	0.00001
Delmarva - TEC	(5)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
PATH - TEC	(6)	(0.00004)	(0.00003)	(0.00002)	(0.00003)	0.00000	(0.00003)	0.00000	(0.00002)
PEPCO - TEC	(7)	0.00001	0.00001	0.00000	0.00000	0.00000	0.00001	0.00000	0.00000
PPL - TEC	(8)	0.00022	0.00014	0.00011	0.00014	0.00000	0.00015	0.00000	0.00009
PSE&G - TEC	(9)	0.00825	0.00513	0.00464	0.00500	0.00000	0.00550	0.00000	0.00335
TrAILCo - TEC	(10)	0.00044	0.00027	0.00021	0.00028	0.00000	0.00029	0.00000	0.00017
VEPCo - TEC	(11)	0.00037	0.00023	0.00021	0.00022	0.00000	0.00025	0.00000	0.00015
MAIT -TEC	(12)	0.00002	0.00001	0.00001	0.00002	0.00000	0.00001	0.00000	0.00001
Total ($/kWh and incl SUT)		$0.00948	$0.00590	$0.00527	$0.00577	$0.00001	$0.00632	$0.00001	$0.00383
Total (¢/kWh and incl SUT)		0.948 ¢	0.590 ¢	0.527 ¢	0.577 ¢	0.001 ¢	0.632 ¢	0.001 ¢	0.383 ¢

Notes:

(1) RMR rates based on allocations by transmission zone.
(2) ACE-TEC rates pursuant to the Board’s Order dated August 23, 2017 in Docket No. ER17060671.
(3) AEP-East-TEC rates calculated in Attachment 5 of the joint filing.
(4) BG&E-TEC rates pursuant to the Board’s Order dated August 23, 2017 in Docket No. ER17060671.
(5) Delmarva-TEC rates pursuant to the Board’s Order dated August 23, 2017 in Docket No. ER17060671.
(6) PATH-TEC rates calculated in Attachment 5 of the joint filing.
(7) PEPCO-TEC rates pursuant to the Board’s Order dated August 23, 2017 in Docket No. ER17060671.
(8) PPL-TEC rates pursuant to the Board’s Order dated August 23, 2017 in Docket No. ER17060671.
(9) PSE&G-TEC rates calculated in Attachment 5 of the joint filing.
(10) TrAILCo-TEC rates pursuant to the Board’s Order dated August 23, 2017 in Docket No. ER17060671.
(11) VEPCo-TEC rates calculated in Attachment 5 of the joint filing.
(12) MAIT-TEC rates calculated in Attachment 5 of the joint filing made on October 24, 2017.

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 6d
AEP Project Charges

Attachment 6a
PSE&G Project Charges

Attachment 6a -PJM Schedule 12 - Transmission Enhancement Charges for January 2018 - December 2018
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 2018 Annual Revenue Requirement** *per PJM website*	**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 Open Access Transmission Tariff								
Replace all derated Branchburg 500/230 kava transformers	b0130	$ 2,087,349.00	1.36%	47.76%	50.88%	0.00%	$28,388	$996,918	$1,062,043	$0	$2,087,349
Reconductor Kittatinny - Newtown 230 kV with 1590 ACSS	b0134	$ 850,003.00	0.00%	51.11%	45.96%	2.93%	$0	$434,437	$390,661	$24,905	$850,003
Build new Essex - Aldene 230 kV cable connected through phase angle regulator at Essex	b0145	$ 9,091,577.00	0.00%	73.45%	21.78%	4.77%	$0	$6,677,763	$1,980,145	$433,668	$9,091,577
Install 230-138kV transformer at Metuchen substation	b0161	$ 2,827,274.00	0.00%	0.00%	99.80%	0.20%	$0	$0	$2,821,619	$5,655	$2,827,274
Build a new 230 kV section from Branchburg - Flagtown and move the Flagtown - Somerville 230 kV circuit to the new section	b0169	$ 1,729,848.00	1.72%	25.94%	59.59%	0.00%	$29,753	$448,723	$1,030,816	$0	$1,509,292
Reconductor the Flagtown-Somerville-Bridgewater 230 kV circuit with 1590 ACSS	b0170	$ 756,061.00	0.00%	42.95%	38.36%	0.79%	$0	$324,728	$290,025	$5,973	$620,726
Replace wave trap at Branchburg 500kV substation	b0172.2	$ 2,966.00	1.70%	3.78%	6.22%	0.25%	$50	$112	$184	$7	$354
Replace both 230/138 kV transformers at Roseland	b0274	$ 2,305,846.00	0.00%	0.00%	96.77%	0.00%	$0	$0	$2,231,367	$0	$2,231,367
Branchburg 400 MVAR Capacitor	b0290	$ 8,609,965.00	1.70%	3.78%	6.22%	0.25%	$146,369	$325,457	$535,540	$21,525	$1,028,891
Inst Conemaugh 250 MVAR Cap	b0376	$ 309,816.00	1.70%	3.78%	6.22%	0.25%	$5,267	$11,711	$19,271	$775	$37,023
Install 4th 500/230 kV transformer at New Freedom	b0411	$ 2,308,744.00	47.01%	7.04%	22.31%	0.00%	$1,085,341	$162,536	$515,081	$0	$1,762,957
Saddle Brook - Athenia Upgrade Cable	b0472	$ 1,696,187.00	0.00%	0.00%	94.41%	3.53%	$0	$0	$1,601,370	$59,875	$1,661,246
Build new 500 kV transmission facilities from Pennsylvania - New Jersey border at Bushkill to Roseland (500kV and above elements of the project)	b0489	$ 94,112,611.00	1.70%	3.78%	6.22%	0.25%	$1,599,914	$3,557,457	$5,853,804	$235,282	$11,246,457
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	$ 5,230,927.00	5.09%	32.73%	40.71%	1.52%	$266,254	$1,712,082	$2,129,510	$79,510	$4,187,357
Susquehanna Roseland Breakers (In-Service)	b0489.5-.15	$ 712,221.00	1.70%	3.78%	6.22%	0.25%	$12,108	$26,922	$44,300	$1,781	$85,110
Loop the 5021 circuit into New Freedom 500 kV substation	b0498	$ 2,933,997.00	1.70%	3.78%	6.22%	0.25%	$49,878	$110,905	$182,495	$7,335	$350,613
Branchburg-Somerville-Flagtown Reconductor	b0664-b0665	$ 2,192,993.00	0.00%	36.35%	43.24%	1.61%	$0	$797,153	$948,250	$35,307	$1,780,710
Somerville -Bridgewater Reconductor	b0668	$ 756,314.00	0.00%	39.41%	38.76%	1.45%	$0	$298,063	$293,147	$10,967	$602,177
Reconductor Hudson - South Waterfront 230kV circuit	b0813	$ 1,043,635.00	0.00%	9.92%	83.73%	3.12%	$0	$103,529	$873,836	$32,561	$1,009,926
New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie	b0814	$ 5,479,087.00	0.00%	23.49%	67.03%	2.50%	$0	$1,287,038	$3,672,632	$136,977	$5,096,647
Reconductor South Mahwah 345 kV J-3410 Circuit	b1017	$ 2,375,680.00	0.00%	29.01%	64.85%	2.53%	$0	$689,185	$1,540,628	$60,105	$2,289,918

Attachment 6a -PJM Schedule 12 - Transmission Enhancement Charges for January 2018 - December 2018
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 2018 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*								
Reconductor South Mahwah 345 kV K-3411 Circuit	b1018	$ 2,467,608.00	0.00%	29.18%	64.68%	2.53%	$0	$720,048	$1,596,049	$62,430	$2,378,527
West Orange Conversion (North Central Reliability)	b1154	$ 44,797,073.00	0.00%	0.00%	96.18%	3.82%	$0	$0	$43,085,825	$1,711,248	$44,797,073
Branchburg-Middlesex Sw Rack	b1155	$ 7,567,834.00	0.00%	4.61%	91.75%	3.64%	$0	$348,877	$6,943,488	$275,469	$7,567,834

Attachment 6a -PJM Schedule 12 - Transmission Enhancement Charges for January 2018 - December 2018
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 2018 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share** *per PJM Open Access Transmission Tariff*	**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**
Conversion	b1156	$ 43,578,096.00	0.00%	0.00%	96.18%	3.82%	$0	$0	$41,913,413	$1,664,683	$43,578,096
Reconf Kearny Loop in P2216	b1589	$ 1,834,804.00	0.00%	0.00%	61.59%	2.46%	$0	$0	$1,130,056	$45,136	$1,175,192
230kV Lawrence Switching Station Upgrade	b1228	$ 2,575,300.00	0.00%	0.00%	95.83%	3.81%	$0	$0	$2,467,910	$98,119	$2,566,029
Ridge Rd 69kV Breaker Station	b1255	$ 2,187,531.00	0.00%	0.00%	96.18%	3.82%	$0	$0	$2,103,967	$83,564	$2,187,531
Northeast Grid Reliability Project	b1304.1-b1304.4	$ 52,506,121.00	0.23%	1.17%	70.16%	2.78%	$120,764	$614,322	$36,838,294	$1,459,670	$39,033,050
Mickleton-Gloucester-Camden	b1398-b1398.7	$ 56,957,204.00	0.00%	12.82%	31.46%	1.25%	$0	$7,301,914	$17,918,736	$711,965	$25,932,615
Aldene-Springfield Rd. Conv	b1399	$ 8,961,530.00	0.00%	0.00%	96.18%	3.82%	$0	$0	$8,619,200	$342,330	$8,961,530
Replace Salem 500 kV breakers	b1410-b1415	$ 1,845,236.00	1.70%	3.78%	6.22%	0.25%	$31,369	$69,750	$114,774	$4,613	$220,506
Uprate Eagle Point-Gloucester 230 kV Circuit	b1588	$ 1,521,168.00	0.00%	10.31%	54.17%	2.16%	$0	$156,832	$824,017	$32,857	$1,013,706
Upgrade Camden Richmon 230kV	b1590	$ 1,423,188.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
New Cox's Corner-Lumberton 230kV Circuit	b1787	$ 4,445,472.00	4.96%	44.20%	48.08%	1.92%	$220,495	$1,964,899	$2,137,383	$85,353	$4,408,130
Build Mickleton-Gloucester Corridor Ultimate Design	b2139	$ 2,572,761.00	0.00%	0.00%	61.11%	2.44%	$0	$0	$1,572,214	$62,775	$1,634,990
Reconfigure Brunswick New 69kV	b2146	$ 12,104,081.00	0.00%	0.00%	96.16%	3.84%	$0	$0	$11,639,284	$464,797	$12,104,081
Convert Bergen Marion 138 kV to double circuit 345kV and Sub	b2436.10	$ 24,635,732.00	0.85%	1.89%	6.94%	0.28%	$209,404	$465,615	$1,709,720	$68,980	$2,453,719
Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.21	$ 8,363,705.00	0.85%	1.89%	3.11%	0.13%	$71,091	$158,074	$260,111	$10,873	$500,150
Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.22	$ 6,288,553.00	0.85%	1.89%	3.11%	0.13%	$53,453	$118,854	$195,574	$8,175	$376,055
Construct New Bayway-Bayonne 345kV Circuit	b2436.33	$ 21,395,928.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Construct New North Ave-Bayonne 345kV Circuit	b2436.34	$ 14,828,378.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Construct North Ave-Airport 345kV Circuit and Substation Upgrades	b2436.50	$ 7,154,410.00	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	$ 5,909,755.00	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	$ 11,613,136.00	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	$ 6,167,683.00	0.85%	1.89%	47.56%	1.88%	$52,425	$116,569	$2,933,350	$115,952	$3,218,297
Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.83	$ 6,167,328.00	0.85%	1.89%	47.56%	1.88%	$52,422	$116,562	$2,933,181	$115,946	$3,218,112
Convert Bayway-Linden "W" to 138kV circuit to 345kV	b2436.84	$ 6,123,326.00	0.85%	1.89%	3.11%	0.13%	$52,048	$115,731	$190,435	$7,960	$366,175
Convert Bayway-Linden "M" to 138kV circuit to 345kV	b2436.85	$ 6,123,326.00	0.85%	1.89%	3.11%	0.13%	$52,048	$115,731	$190,435	$7,960	$366,175

Attachment 6a -PJM Schedule 12 - Transmission Enhancement Charges for January 2018 - December 2018
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 2018 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share** *per PJM Open Access Transmission Tariff*	**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**
Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades	b2436.90	$ 4,564,634.00	0.85%	1.89%	48.41%	1.91%	$38,799	$86,272	$2,209,739	$87,185	$2,421,995
New Bergen 345/230 kV transformer and any associated substation upgrades	b2437.10	$ 3,564,320.00	0.00%	0.00%	5.38%	0.22%	$0	$0	$191,760	$7,842	$199,602
New Bergen 345/138 kV transformer #1 and any associated substation upgrades	b2437.11	$ 3,574,488.00	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	$ 2,037,016.00	0.00%	0.00%	92.71%	3.66%	$0	$0	$1,888,518	$74,555	$1,963,072
New Bayway 345/138 kV transformer #2 and any associated substation upgrades	b2437.21	$ 2,038,355.00	0.00%	0.00%	93.23%	3.68%	$0	$0	$1,900,358	$75,011	$1,975,370
New Linden 345/230 kV transformer and any associated substation upgrades	b2437.30	$ 4,194,201.00	0.00%	0.00%	85.78%	3.39%	$0	$0	$3,597,786	$142,183	$3,739,969
Install two 175 MVAR Re at Hptcg	b2702	$ 1,531,829.00	0.85%	1.89%	53.11%	0.13%	$13,021	$28,952	$813,554	$1,991	$857,518
Totals		**$ 541,034,211.00**					**$4,190,663**	**$30,463,718**	**$225,935,859**	**$8,981,832**	**$269,572,073**
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 2018**	**2018 Trans. Peak Load [2]**	**Rate in $/MW-mo. [1]**	**2018 Impact (12 months)**	
PSE&G	$ 18,827,988.27	9,566.9	$ 1,968.03	$ 225,935,859	
JCP&L	$ 2,538,643.18	5,721.0	$ 443.74	$ 30,463,718	
ACE	$ 349,221.95	2,540.8	$ 137.45	$ 4,190,663	
RE	$ 748,486.01	401.7	$ 1,863.30	$ 8,981,832	
Total Impact on NJ Zones	**$ 22,464,339.40**	**18,230.4**		**$ 269,572,073**	
Notes on calculations >>>			= (k) / (l)	= (k) *12	

Notes:

1) Uncompressed rate - assumes implementation on January 1, 2018

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 2018 - December 2018
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 2018 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	$ (11,779,517.00)	1.70%	3.78%	6.22%	0.25%	-$200,252	-$445,266	-$732,686	-$29,449	-$1,407,652
Amos-Bedington 765 kV Circuit (APS)	b0491	Included above	1.70%	3.78%	6.22%	0.25%	$0	$0	$0	$0	$0
Bedington-Kemptown 500 kV Circuit	b0492 & b560	$ (7,202,920.21)	1.70%	3.78%	6.22%	0.25%	-$122,450	-$272,270	-$448,022	-$18,007	-$860,749
Totals		**$ (18,982,437.21)**					**-$322,701**	**-$717,536**	**-$1,180,708**	**-$47,456**	**-$2,268,401**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

Zonal Cost Allocation for New Jersey Zones	**(k)**	**Average Monthly Impact on Zone Customers in 2018**	**(l) 2018 Trans. Peak Load [2]**	**(m) Rate in $/MW-mo. [1]**	**(n) 2018 Impact (12 months)**
PSE&G	$	(98,392.30)	9,566.9	($10.28)	$ (1,180,708)
JCP&L	$	(59,794.68)	5,721.0	($10.45)	$ (717,536)
ACE	$	(26,891.79)	2,540.8	($10.58)	$ (322,701)
RE	$	(3,954.67)	401.7	($9.84)	$ (47,456)
Total Impact on NJ Zones	**$**	**(189,033.44)**	**18,230.4**		**$ (2,268,401)**
Notes on calculations >>>				= (k) / (l)	= (k) *12

Notes:
1) Uncompressed rate - assumes implementation on January 1, 2018
2) Data on PJM website

Attachment 6c
Virginia Electric Power Company Project Charges

Attachment 6c - PJM Schedule 12 - Transmission Enhancement Charges for January 2018 - December 2018
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 2018 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	$212,578.00	1.70%	3.78%	6.22%	0.25%	$3,614	$8,035	$13,222	$531	$25,403
Loudoun 150 MVA capacitor @ 500 kV	b0222	$193,116.00	1.70%	3.78%	6.22%	0.25%	$3,283	$7,300	$12,012	$483	$23,077
500 kV breakers and bus work at Suffolk	b0231	$2,575,740.00	1.70%	3.78%	6.22%	0.25%	$43,788	$97,363	$160,211	$6,439	$307,801
Meadowbrook-Loudon 500kV circuit	b0328.1	$29,730,478.00	1.70%	3.78%	6.22%	0.25%	$505,418	$1,123,812	$1,849,236	$74,326	$3,552,792
Upgrade Mt. Storm 500 KV Substation	b0328.3	$1,774,139.00	1.70%	3.78%	6.22%	0.25%	$30,160	$67,062	$110,351	$4,435	$212,010
Upgrade Loudoun 500 KV Substation	b0328.4	$403,755.00	1.70%	3.78%	6.22%	0.25%	$6,864	$15,262	$25,114	$1,009	$48,249
Carson – Suffolk 500 kV, Suffolk 500/230 kV transformer & build Suffolk – Trascher 230 kV circuit	B0329.2B	$21,121,942.00	1.70%	3.78%	6.22%	0.25%	$359,073	$798,409	$1,313,785	$52,805	$2,524,072
500/230 KV transformer at Bristers, new 230 Bristers - Gainsville circuit	b0227	$2,421,433.00	0.71%	0.00%	0.00%	0.00%	$17,192	$0	$0	$0	$17,192
Rebuild Mt Storm-Doubs 500 KV circuit	b1507	$42,465,014.00	1.70%	3.78%	6.22%	0.25%	$721,905	$1,605,178	$2,641,324	$106,163	$5,074,569
Replace wave traps on Dooms-Lexington 500KV circuit	b0457	$13,302.00	1.70%	3.78%	6.22%	0.25%	$226	$503	$827	$33	$1,590
Morrisville H1T573	b1647	$2,031.00	1.70%	3.78%	6.22%	0.25%	$35	$77	$126	$5	$243
Morrisville H2T545	b1648	$2,031.00	1.70%	3.78%	6.22%	0.25%	$35	$77	$126	$5	$243
Morrisville H1T580	b1649	$107,165.00	1.70%	3.78%	6.22%	0.25%	$1,822	$4,051	$6,666	$268	$12,806
Morrisville H2T569	b1650	$107,166.00	1.70%	3.78%	6.22%	0.25%	$1,822	$4,051	$6,666	$268	$12,806
Replace wave traps on North Anna-Ladysmith 500KV circuit	b0784	$9,229.00	1.70%	3.78%	6.22%	0.25%	$157	$349	$574	$23	$1,103
Reconductor the Dickerson-Pleasant View 230 KV circuit	b0467.2	$672,705.00	1.75%	0.71%	0.00%	0.00%	$11,772	$4,776	$0	$0	$16,549
Install 500/230 kV transformer and two 230 kV breakers at Brambleton	b1188.6	$2,155,053.00	0.22%	0.00%	0.00%	0.00%	$4,741	$0	$0	$0	$4,741
New Brambleton 500 kV line, 3 ring bus, to Loudon to Pleasant View 500 kV	b1188	($1,121,752.00)	1.70%	3.78%	6.22%	0.25%	-$19,070	-$42,402	-$69,773	-$2,804	-$134,049
500 kV breaker at Brambleton	b1698.1	($39,426.00)	1.70%	3.78%	6.22%	0.25%	-$670	-$1,490	-$2,452	-$99	-$4,711
Install 2 500kV breakers at Chancellor 500 kV	b0756.1	$527,047.00	1.70%	3.78%	6.22%	0.25%	$8,960	$19,922	$32,782	$1,318	$62,982
Wreck and Rebuild 7 miles of Cloverdale - Lexington 500 kV Line	b1797	$2,340,070.00	1.70%	3.78%	6.22%	0.25%	$39,781	$88,455	$145,552	$5,850	$279,638
Build 450 MVAR SVC and 300 MVAR switched shunt at Loudoun 500 kV	b1798	$15,235,076.00	1.70%	3.78%	6.22%	0.25%	$258,996	$575,886	$947,622	$38,088	$1,820,592
Build 150 MVAR Switched Shunt at Pleasant View 500 kV Line	b1799	$3,439,571.00	1.70%	3.78%	6.22%	0.25%	$58,473	$130,016	$213,941	$8,599	$411,029
Install 250 MVAR SVC at Mt. Storm 500 kV Substation	b1805	$4,821,484.00	1.70%	3.78%	6.22%	0.25%	$81,965	$182,252	$299,896	$12,054	$576,167
At Yadkin 500 kV, install six 500 kV Breakers	b1906.1	$1,425,661.00	1.70%	3.78%	6.22%	0.25%	$24,236	$53,890	$88,676	$3,564	$170,366
Rebuild Lexington-Dooms 500 kV Line	b1908	$18,245,673.00	1.70%	3.78%	6.22%	0.25%	$310,176	$689,686	$1,134,881	$45,614	$2,180,358

Attachment 6c - PJM Schedule 12 - Transmission Enhancement Charges for January 2018 - December 2018
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 2018 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								
Surry 500 kV Station Work	b1905.2	$238,665.00	1.70%	3.78%	6.22%	0.25%	$4,057	$9,022	$14,845	$597	$28,520
Mt Storm - Replace MOD with breaker on 500kV side of Transformer	b0837	$90,849.00	1.70%	3.78%	6.22%	0.25%	$1,544	$3,434	$5,651	$227	$10,856
Uprate Section between Possum and Dumfries Substation	b1328	$522,961.00	0.66%	0.00%	0.00%	0.00%	$3,452	$0	$0	$0	$3,452
Rebuild Loudoun - Brambleto 500kV	b1694	$8,978,237.00	1.70%	3.78%	6.22%	0.25%	$152,630	$339,377	$558,446	$22,446	$1,072,899
R/P Midlothian 500kV 3 breaker Ring Bus	b2471	$1,181,405.00	0.85%	1.89%	3.11%	0.13%	$10,042	$22,329	$36,742	$1,536	$70,648
Surry to Skiffes Creek 500kV Line	b1905.1	$1,175,932.00	1.70%	3.78%	6.22%	0.25%	$19,991	$44,450	$73,143	$2,940	$140,524
Install Breaker and half scheme with minimum of eight 230kV Breakers	b1696	$616,785.00	0.46%	0.64%	0.00%	0.00%	$2,837	$3,947	$0	$0	$6,785
Build a second Loudon - Brambleton 500kV line	b2373	$11,269,057.00	0.85%	1.89%	3.11%	0.13%	$95,787	$212,985	$350,468	$14,650	$673,890
Rebuild Carson Rogers 500kV Ckt	b2744	$4,394,557.00	0.85%	1.89%	3.11%	0.13%	$37,354	$83,057	$136,671	$5,713	$262,795
Totals		**$177,308,729.00**					**$2,802,448**	**$6,151,121**	**$10,107,331**	**$407,085**	**$19,467,986**
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 2018**	**2018 Trans. Peak Load [2]**	**Rate in $/MW-mo. [1]**	**2018 Impact (12 months)**
PSE&G	$ 842,277.58	9,566.9	$ 88.04	$10,107,331
JCP&L	$ 512,593.41	5,721.0	$ 89.60	$ 6,151,121
ACE	$ 233,537.35	2,540.8	$ 91.91	$ 2,802,448
RE	$ 33,923.79	401.7	$ 84.45	$ 407,085
Total Impact on NJ Zones	**$ 1,622,332.13**	**18,230.4**		**$19,467,986**
Notes on calculations >>>			= (k) / (l)	= (k) *12

Attachment 6d
AEP East Company Project Charges

Attachment 6d PJM Schedule 12 - Transmission Enhancement Charges for January 2018 - December 2018
Calculation of costs and monthly PJM charges for AEP -East Projects

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				Estimated New Jersey EDC Zone Charges by Project				
Required Transmission Enhancement *per PJM website*	**PJM Upgrade ID** *per PJM spreadsheet*	**Jan - Dec 2018 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share**[1] *per PJM Open Access Transmission Tariff*	**JCP&L Zone Share**[1]	**PSE&G Zone Share**[1]	**RE Zone Share**[1]	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
New 765 KV circuit breakers at Hanging Rock Sub	b0504	$ 939,995	1.70%	3.78%	6.22%	0.25%	$15,980	$35,532	$58,468	$2,350	$112,329
Rockport Reactor Bank	b1465.2	$ 1,965,688	1.70%	3.78%	6.22%	0.25%	$33,417	$74,303	$122,266	$4,914	$234,900
Transpose Rockport- Sullivan 765KV line	b1465.3	$ 2,981,701	1.70%	3.78%	6.22%	0.25%	$50,689	$112,708	$185,462	$7,454	$356,313
Switching changes Sullivan 765KV station	b1465.4	$ 2,615,476	1.70%	3.78%	6.22%	0.25%	$44,463	$98,865	$162,683	$6,539	$312,549
765kV circuit breaker at Wyoming station	b1661	$ 554,795	1.70%	3.78%	6.22%	0.25%	$9,432	$20,971	$34,508	$1,387	$66,298
Term Tsfmr #2 @ SW Lima - new bay position	b1957	$ 2,150,455	0.00%	0.00%	4.52%	0.18%	$0	$0	$97,201	$3,871	$101,071
Reconductor/Rebuild Sporn-Waterford-Muskingham River 345 kV Line	b2017	$ 11,999,332	0.00%	1.39%	2.00%	0.08%	$0	$166,791	$239,987	$9,599	$416,377
Add four 765 kV Breakers at Kammar	b1962	$ 2,845,266	1.70%	3.78%	6.22%	0.25%	$48,370	$107,551	$176,976	$7,113	$340,009
Ft. Wayne Relocate	b1659.14	$ 12,058,807	1.70%	3.78%	6.22%	0.25%	$205,000	$455,823	$750,058	$30,147	$1,441,027
Sorenson 765/500kV Transformer	b1659	$ 7,781,244	0.00%	0.00%	0.92%	0.04%	$0	$0	$71,587	$3,112	$74,700
Sorenson Work 765kV	b1659.13	$ 9,894,917	1.70%	3.78%	6.22%	0.25%	$168,214	$374,028	$615,464	$24,737	$1,182,443
Baker Station 765/500kV Transformer	b1495	$ 7,581,997	0.41%	0.90%	1.48%	0.06%	$31,086	$68,238	$112,214	$4,549	$216,087
Cloverdale 765/500kV Transformer	b1660	$ (2,261,574)	1.70%	3.78%	6.22%	0.25%	($38,447)	($85,487)	($140,670)	($5,654)	($270,258)
Cloverdale 500kV Station	b1660.1	$ (1,736,972)	0.85%	1.89%	3.11%	0.13%	($14,764)	($32,829)	($54,020)	($2,171)	($103,784)
Jacksons-Ferry 765kV Breakers	b1663.2	$ 1,245,257	1.70%	3.78%	6.22%	0.25%	$21,169	$47,071	$77,455	$3,113	$148,808
Reconductor Cloverdale-Lexington 500kV	b1797.1	$ 11,200,620	0.85%	1.89%	3.11%	0.13%	$95,205	$211,692	$348,339	$14,001	$669,237
Reconductor West Bellaire	b1970	$ 2,845,706	0.00%	1.68%	2.87%	0.11%	$0	$47,808	$81,672	$3,130	$132,610
Add a 3rd 2250 MVA 765/345 kV transformer at Sullivan station	b1465.1	$ 4,244,665	0.71%	1.58%	2.62%	0.10%	$30,137	$67,066	$111,210	$4,245	$212,658
Replace existing 150 MVAR reactor at Amos 765 kV sub	b2230	$ 2,976,875	0.85%	1.89%	3.11%	0.13%	$25,303	$56,263	$92,581	$3,721	$177,868
Install a 300 MVAR shunt reactor at AEP's Wyoming 765 kV station	b2423	$ 2,477,088	0.85%	1.89%	3.11%	0.13%	$21,055	$46,817	$77,037	$3,096	$148,006
Install a 450 MVAR SVC Jackson's Ferry 765kV Substation	b2687.1	$ 9,725,135	0.85%	1.89%	3.11%	0.13%	$82,664	$183,805	$302,452	$12,156	$581,077
Install 300 MVAR shunt line reactor	b2687.2	$ 1,387,434	0.85%	1.89%	3.11%	0.13%	$11,793	$26,223	$43,149	$1,734	$82,899
Totals							**$840,765**	**$2,083,237**	**$3,566,077**	**$143,145**	**$6,633,225**
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 2018**	**2018TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2018 Impact (12 months)**
PSE&G	$ 297,173.10	9,566.9	$ 31.06	$ 3,566,077
JCP&L	$ 173,603.09	5,721.0	$ 30.34	$ 2,083,237
ACE	$ 70,063.78	2,540.8	$ 27.58	$ 840,765
RE	$ 11,928.79	401.7	$ 29.70	$ 143,145
Total Impact on NJ Zones	**$ 552,768.76**			**$ 6,633,225**
Notes on calculations >>>			= (k) * (l)	= (k) *12

Notes:
1) 2018 allocation share percentages are from PJM OATT

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
Attachment 7d – Responsible Customer Shares for AEP Schedule 12 Projects
Source – PJM OATT

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%) / JCPL (47.76%) / PSEG (50.88%)
b0134	Upgrade or Retension PSEG portion of Kittatinny – Newton 230 kVcircuit		JCPL (51.11%) / PSEG (45.96%) / RE (2.93%)

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0145	Build new Essex – Aldene 230 kV cable connected through a phase angle regulator at Essex		PSEG (21.78%) / JCPL (73.45%) /RE (4.77%)
b0157	Add 100MVAR capacitor at West Orange 138kV substation		PSEG (100%)
b0158	Close the Sunnymeade "C" and "F" bus tie		PSEG (100%)
b0159	Make the Bayonne reactor permanent installation		PSEG (100%)
b0160	Relocate the X-2250 circuit from Hudson 1-6 bus to Hudson 7-12 bus		PSEG (100%)
b0161	Install 230/138kV transformer at Metuchen substation		PSEG (99.80%) / RE (0.20%)
b0162	Upgrade the Edison – Meadow Rd 138kV “Q” circuit		PSEG (100%)
b0163	Upgrade the Edison – Meadow Rd 138kV “R” circuit		PSEG (100%)
b0169	Build a new 230 kV section from Branchburg – Flagtown and move the Flagtown – Somerville 230 kV circuit to the new section		AEC (1.72%) / JCPL (25.94%) / Neptune* (10.62%) / PSEG (59.59%) / ECP** (2.13%)
b0170	Reconductor the Flagtown-Somerville-Bridgewater 230 kV circuit with 1590 ACSS		JCLP (42.95%) / Neptune* (17.90%) / PSEG (38.36%) RE (0.79%)

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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 (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (_1.82_%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0._42_%) / PECO (5.30%) / PENELEC (1._84_%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0._25_%) / 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		PSEG (96.77%) / ECP** (3.23%)
b0275	Upgrade the two 138 kV circuits between Roseland and West Orange		PSEG (100%)
b0278	Install 228 MVAR capacitor at Roseland 230 kV substation		PSEG (100%)
b0290	Install 400 MVAR capacitor in the Branchburg 500 kV vicinity		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (1.82%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.30%) / PENELEC (1.84%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.25%) / 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		ECP (2.06%) / PSEG (94.41%) / RE (3.53%)
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 (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)†

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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)
b489.1	Replace Athenia 230 kV breaker 31H		PSEG (100%)
b489.2	Replace Bergen 230 kV breaker 10H		PSEG (100%)
b489.3	Replace Saddlebrook 230 kV breaker 21P		PSEG (100%)
b0489.4	Install two Roseland 500/230 kV transformers as part of the Susquehanna – Roseland 500 kV project		AEC (5.09%) / ComEd (0.29%) / Dayton (0.03%) / DPL (1.76%) / JCPL (32.73%) / Neptune* (6.32%) / PECO (10.04%) / PENELEC (0.56%) / ECP** (0.95%) / PSEG (40.71%) / RE (1.52%) ††
b0489.5	Replace Roseland 230 kV breaker '42H' with 80 kA		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0489.6	Replace Roseland 230 kV breaker '51H' with 80 kA		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)
b0489.7	Replace Roseland 230 kV breaker '71H' with 80 kA		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0489.8	Replace Roseland 230 kV breaker '31H' with 80 kA		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (_1.82_%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0._42_%) / PECO (5.30%) / PENELEC (1._84_%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0._25_%) / 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 (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (1.82%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.30%) / PENELEC (1.84%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.25%) / ECP** (0.20%)
b0489.10	Replace Roseland 230 kV breaker '21H'		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (1.82%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.30%) / PENELEC (1.84%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.25%) / 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 (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)
b0489.12	Replace Roseland 230 kV breaker '12H'		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / 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 (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)
b0489.14	Replace Roseland 230 kV breaker '41H'		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0489.15	Replace Roseland 230 kV breaker '72H'		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (1.82%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.30%) / PENELEC (1.84%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.25%) / ECP** (0.20%)
b0498	Loop the 5021 circuit into New Freedom 500 kV substation		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (1.82%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.30%) / PENELEC (1.84%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.25%) / ECP** (0.20%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
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 (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (1.82%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.30%) / PENELEC (1.84%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.25%) / ECP** (0.20%)
b0565	Install 100 MVAR capacitor at Cox's Corner 230 kV substation		PSEG (100%)

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Public Service Electric and Gas Company (cont.)

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

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
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 (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)
b0829.6	Replace Branchburg 500 kV breaker 91X		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / 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 (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / 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%)
b0830.3	Replace Roseland 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)
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 (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)
b0833	Build Roseland 500 kV switching station as part of Branchburg – Hudson 500 kV project		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / 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		JCPL (29.01%) / NEPTUNE* (2.74%) / PSEG (64.85%) / RE (2.53%) / ECP** (0.87%)
b1018	Reconductor South Mahwah - Waldwick 345 kV K-3411 circuit		JCPL (29.18%) / NEPTUNE* (2.74%) / PSEG (64.68%) / RE (2.53%) / ECP** (0.87%)
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%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1019.7	Replace 2-4 and 4-5 section disconnect and ground switches at Clifton on the B-2258 circuit		PSEG (100%)
b1019.8	Replace 1-2 and 2-3 section disconnect and ground switches at Clifton on the K-2263 circuit		PSEG (100%)
b1019.9	Replace line, ground, 230 kV main bus disconnects at Athenia on the B-2258 circuit		PSEG (100%)
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%)

Public Service Electric and Gas Company (cont.)

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

Public Service Electric and Gas Company (cont.)

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

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
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 (0.23%) / BGE (0.97%) / ComEd (2.32%) / Dayton (0.13%) / JCPL (1.17%) / Neptune (0.07%) / HTP (16.05%) / PENELEC (2.97%) / PEPCO (1.04%) / ECP (2.11%) / PSEG (70.16%) / RE (2.78%)

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 (0.23%) / BGE (0.97%) / ComEd (2.32%) / Dayton (0.13%) / JCPL (1.17%) / Neptune (0.07%) / HTP (16.05%) / PENELEC (2.97%) / PEPCO (1.04%) / ECP (2.11%) / PSEG (70.16%) / RE (2.78%)
b1304.3	Build second 230 kV underground cable from Bergen to Athenia		AEC (0.23%) / BGE (0.97%) / ComEd (2.32%) / Dayton (0.13%) / JCPL (1.17%) / Neptune (0.07%) / HTP (16.05%) / PENELEC (2.97%) / PEPCO (1.04%) / ECP (2.11%) / PSEG (70.16%) / RE (2.78%)
b1304.4	Build second 230 kV underground cable from Hudson to South Waterfront		AEC (0.23%) / BGE (0.97%) / ComEd (2.32%) / Dayton (0.13%) / JCPL (1.17%) / Neptune (0.07%) / HTP (16.05%) / PENELEC (2.97%) / PEPCO (1.04%) / ECP (2.11%) / PSEG (70.16%) / RE (2.78%)

Public Service Electric and Gas Company (cont.)

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

Public Service Electric and Gas Company (cont.)

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
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 (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (1.82%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.30%) / PENELEC (1.84%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.25%) / ECP** (0.20%)
b1411	Replace Salem 500 kV breaker ‘12X’		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (1.82%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.30%) / PENELEC (1.84%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.25%) / ECP** (0.20%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1412	Replace Salem 500 kV breaker ‘20X’		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)
b1413	Replace Salem 500 kV breaker ‘21X’		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)

* 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)
b1414	Replace Salem 500 kV breaker ‘31X’		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)
b1415	Replace Salem 500 kV breaker ‘32X’		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)

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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%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1752	Advance n0666.10 (Replace Hudson 230 kV breaker '2HB' with 80 kA (without TRV cap, so actually 63 kA))		PSEG (100%)
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%)

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Public Service Electric and Gas Company (cont.)

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

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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%)

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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		*PSEG (100%)*
b2276.1	Convert the two 138 kV circuits from Sewaren – Metuchen to 230 kV circuits including Lafayette and Woodbridge substation		*PSEG (100%)*
b2276.2	Reconfigure the Metuchen 230 kV station to accommodate the two converted circuits		*PSEG (100%)*
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%)

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
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-Ratio Share Allocation:** AEC (*1.70*%) / AEP (*14.25*%) / APS (*5.53*%) / ATSI (*8.09*%) / BGE (*4.19*%) / ComEd (*13.43*%) / Dayton (*2.12*%) / DEOK (*3.37*%) / DL (*1.77*%) / Dominion (*12.39*%) / DPL (*2.62*%) / ECP** (0.20%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (*3.78*%) / ME (*1.87*%) / NEPTUNE* (0.*42*%) / PECO (*5.30*%) / PENELEC (1.*84*%) / PEPCO (*4.18*%) / PPL (*4.46*%) / PSEG (*6.22*%) / RE (0.*25*%)
			DFAX Allocation: ECP (*89.85*%) / HTP (*2.18*%) / PSEG (*7.66*%) / RE (*0.31*%)
b2436.21	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades		**Load-Ratio Share Allocation:** AEC (*1.70*%) / AEP (*14.25*%) / APS (*5.53*%) / ATSI (*8.09*%) / BGE (*4.19*%) / ComEd (*13.43*%) / Dayton (*2.12*%) / DEOK (*3.37*%) / DL (*1.77*%) / Dominion (*12.39*%) / DPL (*2.62*%) / ECP** (0.20%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (*3.78*%) / ME (*1.87*%) / NEPTUNE* (0.*42*%) / PECO (*5.30*%) / PENELEC (1.*84*%) / PEPCO (*4.18*%) / PPL (*4.46*%) / PSEG (*6.22*%) / RE (0.*25*%)
			DFAX Allocation: HTP*** (*99.40*%) / ECP** (0.60 %)

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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 (*1.70*%) / AEP (*14.25*%) / APS (*5.53*%) / ATSI (*8.09*%) / BGE (*4.19*%) / ComEd (*13.43*%) / Dayton (*2.12*%) / DEOK (*3.37*%) / DL (*1.77*%) / Dominion (*12.39*%) / DPL (*2.62*%) / ECP** (0.20%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (*3.78*%) / ME (*1.87*%) / NEPTUNE* (0.*42*%) / PECO (*5.30*%) / PENELEC (1.*84*%) / PEPCO (*4.18*%) / PPL (*4.46*%) / PSEG (*6.22*%) / RE (0.*25*%)
			DFAX Allocation: HTP*** (*99.40*%) / ECP** (0.60 %)
b2436.33	Construct a new Bayway – Bayonne 345 kV circuit and any associated substation upgrades		ECP (0.30%) / HTP (*99.70*%)
b2436.34	Construct a new North Ave – Bayonne 345 kV circuit and any associated substation upgrades		ECP (0.33%) / HTP (*99.67*%)

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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		HTP*** (*99.44*%) / 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		HTP*** (*99.84*%) / ECP** (0.16 %)
b2436.70	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades		HTP*** (*99.92*%) / ECP** (0.08 %)
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 (*1.70*%) / AEP (*14.25*%) / APS (*5.53*%) / ATSI (*8.09*%) / BGE (*4.19*%) / ComEd (*13.43*%) / Dayton (*2.12*%) / DEOK (*3.37*%) / DL (*1.77*%) / Dominion (*12.39*%) / DPL (*2.62*%) / ECP** (0.20%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (*3.78*%) / ME (*1.87*%) / NEPTUNE* (0.*42*%) / PECO (*5.30*%) / PENELEC (1.*84*%) / PEPCO (*4.18*%) / PPL (*4.46*%) / PSEG (*6.22*%) / RE (0.*25*%)
			DFAX Allocation: HTP*** (*7.57*%) / ECP** (0.02%) / PSEG (*88.90*%) / RE (*3.51*%)

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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 (*1.70*%) / AEP (*14.25*%) / APS (*5.53*%) / ATSI (*8.09*%) / BGE (*4.19*%) / ComEd (*13.43*%) / Dayton (*2.12*%) / DEOK (*3.37*%) / DL (*1.77*%) / Dominion (*12.39*%) / DPL (*2.62*%) / ECP** (0.20%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (*3.78*%) / ME (*1.87*%) / NEPTUNE* (0.*42*%) / PECO (*5.30*%) / PENELEC (1.*84*%) / PEPCO (*4.18*%) / PPL (*4.46*%) / PSEG (*6.22*%) / RE (0.*25*%)
			DFAX Allocation: HTP*** (7.56%) / ECP** (0.02%) / PSEG (*88.91*%) / RE (*3.51*%)
b2436.84	Convert the Bayway – Linden “W” 138 kV circuit to 345 kV and any associated substation upgrades		**Load-Ratio Share Allocation:** AEC (*1.70*%) / AEP (*14.25*%) / APS (*5.53*%) / ATSI (*8.09*%) / BGE (4*4.19*%) / ComEd (*13.43*%) / Dayton (*2.12*%) / DEOK (*3.37*%) / DL (*1.77*%) / Dominion (*12.39*%) / DPL (*2.62*%) / ECP** (0.20%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (*3.78*%) / ME (*1.87*%) / NEPTUNE* (0.*42*%) / PECO (*5.30*%) / PENELEC (1.*84*%) / PEPCO (*4.18*%) / PPL (*4.46*%) / PSEG (*6.22*%) / RE (0.*25*%)
			DFAX Allocation: ECP (0.02%) / HTP (*99.98*%)

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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-Ratio Share Allocation:** AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (44.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / Dominion (12.39%) / DPL (2.62%) / ECP** (0.20%) / EKPC (1.82%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.30%) / PENELEC (1.84%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.25%)
			DFAX Allocation: ECP (0.02%) / HTP (99.98%)
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 (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (44.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / Dominion (12.39%) / DPL (2.62%) / ECP** (0.20%) / EKPC (1.82%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.30%) / PENELEC (1.84%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.25%)
			DFAX Allocation: HTP (5.83%) / PSEG (90.60%) / RE (3.57%)
b2436.91	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades		PSEG (100%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2437.10	New Bergen 345/230 kV transformer and any associated substation upgrades		HTP*** (_1.99_%) / ECP** (_92.41_%) / PSEG (_5.38_%) / RE (_0.22_%)
b2437.11	New Bergen 345/138 kV transformer #1 and any associated substation upgrades		ECP (_72.43_%) _/ HTP*** (27.57%)_
b2437.20	New Bayway 345/138 kV transformer #1 and any associated substation upgrades		ECP (_0.35_%) / HTP (_3.28_%) / PSEG (_92.71_%) / RE (3.66%)
b2437.21	New Bayway 345/138 kV transformer #2 and any associated substation upgrades		ECP (_0.17_%) / HTP (_2.92_%) / PSEG (_93.23_%) / RE (3.68%)
b2437.30	New Linden 345/230 kV transformer and any associated substation upgrades		HTP*** (_10.53_%) / ECP** (0.25%) / Neptune (0.05%) / PSEG (_85.78_%) / RE (_3.39_%)
b2437.33	New Bayonne 345/69 kV transformer and any associated substation upgrades		_PSEG (100%)_
b2438	Install two reactors at Tosco 230 kV		PSEG (100.00%)
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%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2633.3	Install an SVC at New Freedom 500 kV substation		**Load-Ratio Share Allocation:** AEC (*1.70*%) / AEP (*14.25*%) / APS (*5.53*%) / ATSI (*8.09*%) / BGE (4*4.19*%) / ComEd (*13.43*%) / Dayton (*2.12*%) / DEOK (*3.37*%) / DL (*1.77*%) / Dominion (*12.39*%) / DPL (*2.62*%) / ECP** (0.20%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (*3.78*%) / ME (*1.87*%) / NEPTUNE* (0.*42*%) / PECO (*5.30*%) / PENELEC (1.*84*%) / PEPCO (*4.18*%) / PPL (*4.46*%) / PSEG (*6.22*%) / RE (0.*25*%)
			DFAX Allocation: AEC (0.01%) / DPL (99.98%) / JCPL (0.01%)
b2633.4	Add a new 500 kV bay at Salem (Expansion of Salem substation)		AEC (0.01%) / DPL (99.98%) / JCPL (0.01%)
b2633.5	Add a new 500/230 kV autotransformer at Salem		AEC (0.01%) / DPL (99.98%) / JCPL (0.01%)
b2633.8	Implement high speed relaying utilizing OPGW on Salem – Orchard 500 kV, Hope Creek – New Freedom 500 kV, New Freedom - Salem 500 kV, Hope Creek – Salem 500 kV, and New Freedom – Orchard 500 kV lines		**Load-Ratio Share Allocation:** AEC (*1.70*%) / AEP (*14.25*%) / APS (*5.53*%) / ATSI (*8.09*%) / BGE (4*4.19*%) / ComEd (*13.43*%) / Dayton (*2.12*%) / DEOK (*3.37*%) / DL (*1.77*%) / Dominion (*12.39*%) / DPL (*2.62*%) / ECP** (0.20%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (*3.78*%) / ME (*1.87*%) / NEPTUNE* (0.*42*%) / PECO (*5.30*%) / PENELEC (1.*84*%) / PEPCO (*4.18*%) / PPL (*4.46*%) / PSEG (*6.22*%) / RE (0.*25*%)
			DFAX Allocation: AEC (0.01%) / DPL (99.98%) / JCPL (0.01%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2633.91	Implement changes to the tap settings for the two Salem units' step up transformers		AEC (0.01%) / DPL (99.98%) / JCPL (0.01%)
b2633.92	Implement changes to the tap settings for the Hope Creek unit's step up transformers		AEC (0.01%) / DPL (99.98%) / JCPL (0.01%)
b2702	Install a 350 MVAR reactor at Roseland 500 kV		**Load-Ratio Share Allocation:** AEC (_1.70_%) / AEP (_14.25_%) / APS (_5.53_%) / ATSI (_8.09_%) / BGE (4_4.19_%) / ComEd (_13.43_%) / Dayton (_2.12_%) / DEOK (3.37%) / DL (_1.77_%) / Dominion (_12.39_%) / DPL (_2.62_%) / ECP** (0.20%) / EKPC (_1.82_%) / HTP*** (0.20%) / JCPL (_3.78_%) / ME (_1.87_%) / NEPTUNE* (0._42_%) / PECO (_5.30_%) / PENELEC (1._84_%) / PEPCO (_4.18_%) / PPL (_4.46_%) / PSEG (_6.22_%) / RE (0._25_%)
			DFAX Allocation: PSEG (100%)
b2703	Install a 100 MVAR reactor at Bergen 230 kV		PSEG (100%)
b2704	Install a 150 MVAR reactor at Essex 230 kV		PSEG (100%)
b2705	Install a 200 MVAR reactor (variable) at Bergen 345 kV		PSEG (100%)
b2706	Install a 200 MVAR reactor (variable) at Bayway 345 kV		PSEG (100%)
b2707	Install a 100 MVAR reactor at Bayonne 345 kV		PSEG (100%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2712	*Replace the Bergen 138 kV '40P'breaker with 80kA breaker*		*PSEG (100%)*
b2713	*Replace the Bergen 138 kV '90P' breaker with 80kA breaker*		*PSEG (100%)*
b2722	Reconductor the 1 mile Bergen – Bergen GT 138 kV circuit (B-1302)		PSEG (100%)
b2755	Build a third 345 kV source into Newark Airport		PSEG (100%)
b2810.1	Install second 230/69 kV transformer at Cedar Grove		PSEG (100%)
b2810.2	Build a new 69 kV circuit from Cedar Grove to Great Notch		PSEG (100%)
b2811	Build 69 kV circuit from Locust Street to Delair		PSEG (100%)
b2812	Construct River Road to Tonnelle Avenue 69kV Circuit		PSEG (100%)
b2825.1	Install 2X50 MVAR shunt reactors at Kearny 230 kV substation		PSEG (100%)
b2825.2	Increase the size of the Hudson 230 kV, 2X50 MVAR shunt reactors to 2X100 MVAR		PSEG (100%)
b2825.3	Install 2X100 MVAR shunt reactors at Bayway 345 kV substation		PSEG (100%)
b2825.4	Install 2X100 MVAR shunt reactors at Linden 345 kV substation		PSEG (100%)
b2835	Convert the R-1318 and Q1317 (Edison – Metuchen) 138 kV circuits to one 230 kV circuit		PSEG (100%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2836	Convert the N-1340 and T-1372/D-1330 (Brunswick – Trenton) 138 kV circuits to 230 kV circuits		PSEG (100%)
b2837	Convert the F-1358/Z1326 and K1363/Y-1325 (Trenton – Burlington) 138 kV circuits to 230 kV circuits		PSEG (100%)

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 (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)
b0222	Install 150 MVAR capacitor at Loudoun 500 kV		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / 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 (3.36%) / BGE (10.93%) / DPL (1.66%) / Dominion (67.38%) / ME (0.89%) / PECO (2.33%) / PEPCO (12.20%) / 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 (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / 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 (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)

* 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)

b0328.3	Upgrade Mt. Storm 500 kV substation		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)
b0328.4	Upgrade Loudoun 500 kV substation		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)

* 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)
b0329	Build Carson – Suffolk 500 kV, install 2nd Suffolk 500/230 kV transformer & build Suffolk – Fentress 230 kV circuit		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (_1.82_%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0._42_%) / PECO (5.30%) / PENELEC (1._84_%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0._25_%) / 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%)

* Neptune Regional Transmission System, LLC

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

*** Hudson Transmission Partners, LLC

†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 (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (_1.82_%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0._42_%) / PECO (5.30%) / PENELEC (1._84_%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0._25_%) / 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%)

* Neptune Regional Transmission System, LLC

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
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 (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)
b0467.2	Reconductor the Dickerson – Pleasant View 230 kV circuit		AEC (1.75%) / APS (19.70%) / BGE (22.13%) / DPL (3.70%) / JCPL (0.71%) / ME (2.48%) / Neptune* (0.06%) / PECO (5.54%) / PEPCO (41.86%) / PPL (2.07%)

* Neptune Regional Transmission System, LLC

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0492.6	Replace Mount Storm 500 kV breaker 55072		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)
b0492.7	Replace Mount Storm 500 kV breaker 55172		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)
b0492.8	Replace Mount Storm 500 kV breaker H1172-2		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)

* 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)
b0492.*9*	Replace Mount Storm 500 kV breaker G2T550		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)
b0492.10	Replace Mount Storm 500 kV breaker G2T554		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)
b0492.11	Replace Mount Storm 500 kV breaker G1T551		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)

* 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)
b0492.12	Upgrade nameplate rating of Mount Storm 500 kV breakers 55472, 57272, SX172, G3TSX1, G1TH11, G3T572, and SX22		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / 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 (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)
b0512.5	Advance n0716 (Ox - Replace 230kV breaker L242)		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)

* 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)
b0512.6	Advance n0717 (Possum Point - Replace 230kV breaker SC192)		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (1.82%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.30%) / PENELEC (1.84%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.25%) / 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 (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (1.82%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.30%) / PENELEC (1.84%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.25%) / ECP** (0.20%)

* 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)
b0757	Reconductor one mile of Chesapeake – Reeves Avenue 115 kV line		Dominion (100%)
b0758	Install a second Fredericksburg 230/115 kV autotransformer		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%)

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

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

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%)
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%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
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%)
b0784	Replace wave traps on North Anna to Ladysmith 500 kV		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (_1.82_%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0._42_%) / PECO (5.30%) / PENELEC (1._84_%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0._25_%) / ECP** (0.20%)
b0785	Rebuild the Chase City – Crewe 115 kV line		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0786	Reconductor the Moran DP – Crewe 115 kV segment		Dominion (100%)
b0787	Upgrade the Chase City – Twitty's Creek 115 kV segment		Dominion (100%)
b0788	Reconductor the line from Farmville – Pamplin 115 kV		Dominion (100%)
b0793	Close switch 145T183 to network the lines. Rebuild the section of the line #145 between Possum Point – Minnieville DP 115 kV		Dominion (100%)
b0815	Replace Elmont 230 kV breaker '22192'		Dominion (100%)
b0816	Replace Elmont 230 kV breaker '21692'		Dominion (100%)
b0817	Replace Elmont 230 kV breaker '200992'		Dominion (100%)
b0818	Replace Elmont 230 kV breaker '2009T2032'		Dominion (100%)
b0837	At Mt. Storm, replace the existing MOD on the 500 kV side of the transformer with a circuit breaker		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)

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Virginia Electric and Power Company (cont.)

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

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
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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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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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 (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / 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%)

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Virginia Electric and Power Company (cont.)

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

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Virginia Electric and Power Company (cont.)

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

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
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%)
b1323	Install a 224 MVA 230/115 kV transformer at Staunton. Rebuild the 115 kV line #43 section Staunton - Verona		Dominion (100%)

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Virginia Electric and Power Company (cont.)

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

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1506.1	At Gainesville Substation, create two 115 kV straight-buses with a normally open tie-breaker		Dominion (100%)
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%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1507	Rebuild Mt Storm – Doubs 500 kV		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)
b1508.1	Build a 2nd 230 kV Line Harrisonburg to Endless Caverns		APS (37.05%) / Dominion (62.95%)
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%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
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 (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)
b1648	Upgrade name plate rating at Morrisville 500kV breaker ‘H2T545’ with 50kA breaker		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / 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 (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)
b1650	Replace Morrisville 500kV breaker ‘H2T569’ with 50kA breaker		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)
b1651	Replace Loudoun 230kV breaker ‘295T2030’ with 63kA breaker		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
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%)
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 (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / 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%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
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%)
b1698.1	Install a 500 kV breaker at Brambleton		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)

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Virginia Electric and Power Company (cont.)

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
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 (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)
b1798	Build a 450 MVAR SVC and 300 MVAR switched shunt at Loudoun 500 kV		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / 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)
b1799	Build 150 MVAR Switched Shunt at Pleasant View 500 kV		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)
b1805	Install a 250 MVAR SVC at the existing Mt. Storm 500kV substation		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / 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 (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)
b1905.2	Surry 500 kV Station Work		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / 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%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1905.6	Yorktown 230 kV work		Dominion (99.84%) / PEPCO (0.16%)
b1905.7	Lanexa 115 kV work		Dominion (99.84%) / PEPCO (0.16%)
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 (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / 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%)

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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 (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / 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%)

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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%)

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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%)
b1696.1	*Replace the Idylwood 230 kV ‘25112’ breaker with 50kA breaker*		*Dominion (100%)*
b1696.2	*Replace the Idylwood 230 kV ‘209712’ breaker with 50kA breaker*		*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%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		*Annual Revenue Requirement*	*Responsible Customer(s)*
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		*Dominion (100%)*
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%)

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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 (*1.70*%) / AEP (*14.25*%) / APS (*5.53*%) / ATSI (*8.09*%) / BGE (4*4.19*%) / ComEd (*13.43*%) / Dayton (*2.12*%) / DEOK (*3.37*%) / DL (*1.77*%) / Dominion (*12.39*%) / DPL (*2.62*%) / ECP** (0.20%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (*3.78*%) / ME (*1.87*%) / NEPTUNE* (0.*42*%) / PECO (*5.30*%) / PENELEC (1.*84*%) / PEPCO (*4.18*%) / PPL (*4.46*%) / PSEG (*6.22*%) / RE (0.*25*%)
			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%)
b2565	Reconductor wave trap at Carver Substation with a 2000A wave trap		Dominion (100%)
b2566	Reconductor 1.14 miles of existing line between ACCA and Hermitage and upgrade associated terminal equipment		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		Dominion (100%)
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		Dominion (100%)
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%)

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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%)
b2717.1	De-energize Davis – Rosslyn #179 and #180 69 kV lines		Dominion (100%)
b2717.2	Remove splicing and stop joints in manholes		Dominion (100%)
b2717.3	Evacuate and dispose of insulating fluid from various reservoirs and cables		Dominion (100%)
b2717.4	Remove all cable along the approx. 2.5 mile route, swab and cap-off conduits for future use, leave existing communication fiber in place		Dominion (100%)
b2719.1	Expand Perth substation and add a 115 kV four breaker ring		Dominion (100%)
b2719.2	Extend the Hickory Grove DP tap 0.28 miles to Perth and terminate it at Perth		Dominion (100%)
b2719.3	Split Line #31 at Perth and terminate it into the new ring bus with 2 breakers separating each of the line terminals to prevent a breaker failure from taking out both 115 kV lines		Dominion (100%)
b2720	Replace the Loudoun 500 kV 'H1T569' breakers with 50kA breaker		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 (2.51%) / Neptune (0.63%) / PECO (6.26%) / PEPCO (20.23%) / PPL (3.94%) /PSEG (7.29%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2744	Rebuild the Carson – Rogers Rd 500 kV circuit		**Load-Ratio Share Allocation:** AEC (*1.70*%) / AEP (*14.25*%) / APS (*5.53*%) / ATSI (*8.09*%) / BGE (4*4.19*%) / ComEd (*13.43*%) / Dayton (*2.12*%) / DEOK (*3.37*%) / DL (*1.77*%) / Dominion (*12.39*%) / DPL (*2.62*%) / ECP** (0.20%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (*3.78*%) / ME (*1.87*%) / NEPTUNE* (0.*42*%) / PECO (*5.30*%) / PENELEC (1.*84*%) / PEPCO (*4.18*%) / PPL (*4.46*%) / PSEG (*6.22*%) / RE (0.*25*%)
			DFAX Allocation: Dominion (100%)
b2745	Rebuild 21.32 miles of existing line between Chesterfield – Lakeside 230 kV		Dominion (100%)
b2746.1	*Rebuild Line #137 Ridge Rd – Kerr Dam 115 kV, 8.0 miles, for 346 MVA summer emergency rating*		*Dominion (100%)*
b2746.2	*Rebuild Line #1009 Ridge Rd – Chase City 115 kV, 9.5 miles, for 346 MVA summer emergency rating*		*Dominion (100%)*
b2746.3	*Install a second 4.8 MVAR capacitor bank on the 13.8 kV bus of each transformer at Ridge Rd*		*Dominion (100%)*
b2747	*Install a Motor Operated Switch and SCADA control between Dominion's Gordonsville 115 kV bus and FirstEnergy's 115 kV line*		*Dominion (100%)*

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2757	Install a +/-125 MVAr Statcom at Colington 230 kV		Dominion (100%)
b2758	Rebuild Line #549 Dooms – Valley 500kV		Dominion (100%)
b2759	Rebuild Line #550 Mt. Storm – Valley 500kV		Dominion (100%)
b2802	Rebuild Line #171 from Chase City – Boydton Plank Road tap by removing end-of-life facilities and installing 9.4 miles of new conductor. The conductor used will be at current standards with a summer emergency rating of 393 MVA at 115kV		Dominion (100%)
b2815	Build a new Pinewood 115kV switching station at the tap serving North Doswell DP with a 115kV four breaker ring bus		Dominion (100%)

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

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 (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / 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 (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / 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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**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)
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 (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)
b0560	Install 250 MVAR capacitor at Kemptown 500 kV substation		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)

* Neptune Regional Transmission System, LLC

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

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 (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)

* Neptune Regional Transmission System, LLC

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

Attachment 7d – Responsible Customer Shares for AEP Schedule 12 Projects

Source – PJM OATT

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 (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)

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** 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 (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)
b0490.3	Replace Amos 138 kV breaker ‘B1’		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / 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 (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)
b0490.5	Replace Amos 138 kV breaker ‘C1’		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)

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

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0490.6	Replace Amos 138 kV breaker ‘D’		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)
b0490.7	Replace Amos 138 kV breaker ‘D2’		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)

* Neptune Regional Transmission System, LLC

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

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0490.8	Replace Amos 138 kV breaker ‘E’		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)
b0490.9	Replace Amos 138 kV breaker ‘E2’		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / 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)
b0504	Add two advanced technology circuit breakers at Hanging Rock 765 kV to improve operational performance		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)
b0570	Reconductor East Side Lima – Sterling 138 kV		AEP (41.99%) / ComEd (58.01%)
b0571	Reconductor West Millersport – Millersport 138 kV		AEP (73.83%) / ComEd (19.26%) / Dayton (6.91%)
b0748	Establish a new 69 kV circuit between the Canal Road and East Wooster stations, establish a new 69 kV circuit between the West Millersburg and Moreland Switch stations (via Shreve), add reactive support via cap banks		AEP (100%)
b0838	Hazard Area 138 kV and 69 kV Improvement Projects		AEP (100%)
b0839	Replace existing 450 MVA transformer at Twin Branch 345 / 138 kV with a 675 MVA transformer		AEP (99.73%) / Dayton (0.27%)

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** 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)
b0840	String a second 138 kV circuit on the open tower position between Twin Branch and East Elkhart		AEP (100%)
b0840.1	Establish a new 138/69-34.5kV Station to interconnect the existing 34.5kV network		AEP (100%)
b0917	Replace Baileysville 138 kV breaker 'P'		AEP (100%)
b0918	Replace Riverview 138 kV breaker '634'		AEP (100%)
b0919	Replace Torrey 138 kV breaker 'W'		AEP (100%)
b1032.1	Construct a new 345/138kV station on the Marquis-Bixby 345kV line near the intersection with Ross - Highland 69kV		AEP (89.97%) / Dayton (10.03%)
b1032.2	Construct two 138kV outlets to Delano 138kV station and to Camp Sherman station		AEP (89.97%) / Dayton (10.03%)
b1032.3	Convert Ross - Circleville 69kV to 138kV		AEP (89.97%) / Dayton (10.03%)
b1032.4	Install 138/69kV transformer at new station and connect in the Ross - Highland 69kV line		AEP (89.97%) / Dayton (10.03%)
b1033	Add a third delivery point from AEP’s East Danville Station to the City of Danville.		AEP (100%)

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)
b1034.1	Establish new South Canton - West Canton 138kV line (replacing Torrey - West Canton) and Wagenhals – Wayview 138kV		AEP (96.01%) / APS (0.62%) / ComEd (0.19%) / Dayton (0.44%) / DL (0.13%) / PENELEC (2.61%)
b1034.2	Loop the existing South Canton - Wayview 138kV circuit in-and-out of West Canton		AEP (96.01%) / APS (0.62%) / ComEd (0.19%) / Dayton (0.44%) / DL (0.13%) / PENELEC (2.61%)
b1034.3	Install a 345/138kV 450 MVA transformer at Canton Central		AEP (96.01%) / APS (0.62%) / ComEd (0.19%) / Dayton (0.44%) / DL (0.13%) / PENELEC (2.61%)
b1034.4	Rebuild/reconductor the Sunnyside - Torrey 138kV line		AEP (96.01%) / APS (0.62%) / ComEd (0.19%) / Dayton (0.44%) / DL (0.13%) / PENELEC (2.61%)
b1034.5	Disconnect/eliminate the West Canton 138kV terminal at Torrey Station		AEP (96.01%) / APS (0.62%) / ComEd (0.19%) / Dayton (0.44%) / DL (0.13%) / PENELEC (2.61%)
b1034.6	Replace all 138kV circuit breakers at South Canton Station and operate the station in a breaker and a half configuration		AEP (96.01%) / APS (0.62%) / ComEd (0.19%) / Dayton (0.44%) / DL (0.13%) / PENELEC (2.61%)
b1034.7	Replace all obsolete 138kV circuit breakers at the Torrey and Wagenhals stations		AEP (96.01%) / APS (0.62%) / ComEd (0.19%) / Dayton (0.44%) / DL (0.13%) / PENELEC (2.61%)

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)
b1034.8	Install additional 138kV circuit breakers at the West Canton, South Canton, Canton Central, and Wagenhals stations to accommodate the new circuits		AEP (96.01%) / APS (0.62%) / ComEd (0.19%) / Dayton (0.44%) / DL (0.13%) / PENELEC (2.61%)
b1035	Establish a third 345kV breaker string in the West Millersport Station. Construct a new West Millersport – Gahanna 138kV circuit. Miscellaneous improvements to 138kV transmission system.		AEP (100%)
b1036	Upgrade terminal equipment at Poston Station and update remote end relays		AEP (100%)
b1037	Sag check Bonsack–Cloverdale 138 kV, Cloverdale–Centerville 138kV, Centerville–Ivy Hill 138kV, Ivy Hill–Reusens 138kV, Bonsack–Reusens 138kV and Reusens–Monel–Gomingo–Joshua Falls 138 kV.		AEP (100%)
b1038	Check the Crooksville - Muskingum 138 kV sag and perform the required work to improve the emergency rating		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1039	Perform a sag study for the Madison – Cross Street 138 kV line and perform the required work to improve the emergency rating		AEP (100%)
b1040	Rebuild an 0.065 mile section of the New Carlisle – Olive 138 kV line and change the 138 kV line switches at New Carlisle		AEP (100%)
b1041	Perform a sag study for the Moseley - Roanoke 138 kV to increase the emergency rating		AEP (100%)
b1042	Perform sag studies to raise the emergency rating of Amos – Poca 138kV		AEP (100%)
b1043	Perform sag studies to raise the emergency rating of Turner - Ruth 138kV		AEP (100%)
b1044	Perform sag studies to raise the emergency rating of Kenova – South Point 138kV		AEP (100%)
b1045	Perform sag studies of Tri State - Darrah 138 kV		AEP (100%)
b1046	Perform sag study of Scottsville – Bremo 138kV to raise the emergency rating		AEP (100%)
b1047	Perform sag study of Otter Switch - Altavista 138kV to raise the emergency rating		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1048	Reconductor the Bixby - Three C - Groves and Bixby - Groves 138 kV tower line		AEP (100%)
b1049	Upgrade the risers at the Riverside station to increase the rating of Benton Harbor – Riverside 138kV		AEP (100%)
b1050	Rebuilding and reconductor the Bixby – Pickerington Road - West Lancaster 138 kV line		AEP (100%)
b1051	Perform a sag study for the Kenzie Creek – Pokagon 138 kV line and perform the required work to improve the emergency rating		AEP (100%)
b1052	Unsix-wire the existing Hyatt - Sawmill 138 kV line to form two Hyatt - Sawmill 138 kV circuits		AEP (100%)
b1053	Perform a sag study and remediation of 32 miles between Claytor and Matt Funk.		AEP (100%)
b1091	Add 28.8 MVAR 138 kV capacitor bank at Huffman and 43.2 MVAR 138 kV Bank at Jubal Early and 52.8 MVAR 138 kV Bank at Progress Park Stations		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1092	Add 28.8 MVAR 138 kV capacitor bank at Sullivan Gardens and 52.8 MVAR 138 kV Bank at Reedy Creek Stations		AEP (100%)
b1093	Add a 43.2 MVAR capacitor bank at the Morgan Fork 138 kV Station		AEP (100%)
b1094	Add a 64.8 MVAR capacitor bank at the West Huntington 138 kV Station		AEP (100%)
b1108	Replace Ohio Central 138 kV breaker ‘C2’		AEP (100%)
b1109	Replace Ohio Central 138 kV breaker ‘D1’		AEP (100%)
b1110	Replace Sporn A 138 kV breaker ‘J’		AEP (100%)
b1111	Replace Sporn A 138 kV breaker ‘J2’		AEP (100%)
b1112	Replace Sporn A 138 kV breaker ‘L’		AEP (100%)
b1113	Replace Sporn A 138 kV breaker ‘L1’		AEP (100%)
b1114	Replace Sporn A 138 kV breaker ‘L2’		AEP (100%)
b1115	Replace Sporn A 138 kV breaker ‘N’		AEP (100%)
b1116	Replace Sporn A 138 kV breaker ‘N2’		AEP (100%)
b1227	Perform a sag study on Altavista – Leesville 138 kV circuit		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1231	Replace the existing 138/69-12 kV transformer at West Moulton Station with a 138/69 kV transformer and a 69/12 kV transformer		AEP (96.69%) / Dayton (3.31%)
b1375	Replace Roanoke 138 kV breaker 'T'		AEP (100%)
b1376	Replace Roanoke 138 kV breaker 'E'		AEP (100%)
b1377	Replace Roanoke 138 kV breaker 'F'		AEP (100%)
b1378	Replace Roanoke 138 kV breaker 'G'		AEP (100%)
b1379	Replace Roanoke 138 kV breaker 'B'		AEP (100%)
b1380	Replace Roanoke 138 kV breaker 'A'		AEP (100%)
b1381	Replace Olive 345 kV breaker 'E'		AEP (100%)
b1382	Replace Olive 345 kV breaker 'R2'		AEP (100%)
b1416	Perform a sag study on the Desoto – Deer Creek 138 kV line to increase the emergency rating		AEP (100%)
b1417	Perform a sag study on the Delaware – Madison 138 kV line to increase the emergency rating		AEP (100%)
b1418	Perform a sag study on the Rockhill – East Lima 138 kV line to increase the emergency rating		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1419	Perform a sag study on the Findlay Center – Fostoria Ctl 138 kV line to increase the emergency rating		AEP (100%)
b1420	A sag study will be required to increase the emergency rating for this line. Depending on the outcome of this study, more action may be required in order to increase the rating		AEP (100%)
b1421	Perform a sag study on the Sorenson – McKinley 138 kV line to increase the emergency rating		AEP (100%)
b1422	Perform a sag study on John Amos – St. Albans 138 kV line to allow for operation up to its conductor emergency rating		AEP (100%)
b1423	A sag study will be performed on the Chemical – Capitol Hill 138 kV line to determine if the emergency rating can be utilized		AEP (100%)
b1424	Perform a sag study for Benton Harbor – West Street – Hartford 138 kV line to improve the emergency rating		AEP (100%)
b1425	Perform a sag study for the East Monument – East Danville 138 kV line to allow for operation up to the conductor's maximum operating temperature		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1426	Perform a sag study for the Reusens – Graves 138 kV line to allow for operation up to the conductor's maximum operating temperature		AEP (100%)
b1427	Perform a sag study on Smith Mountain – Leesville – Altavista – Otter 138 kV and on Boones – Forest – New London – JohnsMT – Otter		AEP (100%)
b1428	Perform a sag study on Smith Mountain – Candlers Mountain 138 kV and Joshua Falls – Cloverdale 765 kV to allow for operation up to		AEP (100%)
b1429	Perform a sag study on Fremont – Clinch River 138 kV to allow for operation up to its conductor emergency ratings		AEP (100%)
b1430	Install a new 138 kV circuit breaker at Benton Harbor station and move the load from Watervliet 34.5 kV station to West street 138 kV		AEP (100%)
b1432	Perform a sag study on the Kenova – Tri State 138 kV line to allow for operation up to their conductor emergency rating		AEP (100%)
b1433	Replace risers in the West Huntington Station to increase the line ratings which would eliminate the overloads for the contingencies listed		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1434	Perform a sag study on the line from Desoto to Madison. Replace bus and risers at Daleville station and replace bus and risers at Madison		AEP (100%)
b1435	Replace the 2870 MCM ACSR riser at the Sporn station		AEP (100%)
b1436	Perform a sag study on the Sorenson – Illinois Road 138 kV line to increase the emergency MOT for this line. Replace bus and risers at Illinois Road		AEP (100%)
b1437	Perform sag study on Rock Cr. – Hummel Cr. 138 kV to increase the emergency MOT for the line, replace bus and risers at Huntington J., and replace relays for Hummel Cr. – Hunt – Soren. Line at Soren		AEP (100%)
b1438	Replacement of risers at McKinley and Industrial Park stations and performance of a sag study for the 4.53 miles of 795 ACSR section is expected to improve the Summer Emergency rating to 335 MVA		AEP (100%)
b1439	By replacing the risers at Lincoln both the Summar Normal and Summer Emergency ratings will improve to 268 MVA		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1440	By replacing the breakers at Lincoln the Summer Emergency rating will improve to 251 MVA		AEP (100%)
b1441	Replacement of risers at South Side and performance of a sag study for the 1.91 miles of 795 ACSR section is expected to improve the Summer Emergency rating to 335 MVA		AEP (100%)
b1442	Replacement of 954 ACSR conductor with 1033 ACSR and performance of a sag study for the 4.54 miles of 2-636 ACSR section is expected		AEP (100%)
b1443	Station work at Thelma and Busseyville Stations will be performed to replace bus and risers		AEP (100%)
b1444	Perform electrical clearance studies on Clinch River – Clinchfield 139 kV line (a.k.a. sag studies) to determine if the emergency ratings can be utilized		AEP (100%)
b1445	Perform a sag study on the Addison (Buckeye CO-OP) – Thinever and North Crown City – Thivener 138 kV sag study and switch		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1446	Perform a sag study on the Parkersburg (Allegheny Power) – Belpre (AEP) 138 kV		AEP (100%)
b1447	Dexter – Elliot tap 138 kV sag check		AEP (100%)
b1448	Dexter – Meigs 138 kV Electrical Clearance Study		AEP (100%)
b1449	Meigs tap – Rutland 138 kV sag check		AEP (100%)
b1450	Muskingum – North Muskingum 138 kV sag check		AEP (100%)
b1451	North Newark – Sharp Road 138 kV sag check		AEP (100%)
b1452	North Zanesville – Zanesville 138 kV sag check		AEP (100%)
b1453	North Zanesville – Powelson and Ohio Central – Powelson 138 kV sag check		AEP (100%)
b1454	Perform an electrical clearance study on the Ross – Delano – Scioto Trail 138 kV line to determine if the emergency rating can be utilized		AEP (100%)
b1455	Perform a sag check on the Sunny – Canton Central – Wagenhals 138 kV line to determine if all circuits can be operated at their summer emergency rating		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1456	The Tidd – West Bellaire 345 kV circuit has been de-rated to its normal rating and would need an electrical clearance study to determine if the emergency rating can be utilized		AEP (100%)
b1457	The Tiltonsville – Windsor 138 kV circuit has been derated to its normal rating and would need an electrical clearance study to determine if the emergency rating could be utilized		AEP (100%)
b1458	Install three new 345 kV breakers at Bixby to separate the Marquis 345 kV line and transformer #2. Operate Circleville – Harrison 138 kV and Harrison – Zuber 138 kV up to conductor emergency ratings		AEP (100%)
b1459	Several circuits have been de-rated to their normal conductor ratings and could benefit from electrical clearance studies to determine if the emergency rating could be utilized		AEP (100%)
b1460	Replace 2156 & 2874 risers		AEP (100%)
b1461	Replace meter, metering CTs and associated equipment at the Paden City feeder		AEP (100%)
b1462	Replace relays at both South Cadiz 138 kV and Tidd 138 kV		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1463	Reconductor the Bexley – Groves 138 kV circuit		AEP (100%)
b1464	Corner 138 kV upgrades		AEP (100%)
b1465.1	Add a 3rd 2250 MVA 765/345 kV transformer at Sullivan station		AEC (0.71%) / AEP (75.06%) / APS (1.25%) / BGE (1.81%) / ComEd (5.91%) / Dayton (0.86%) / DL (1.23%) / DPL (0.95%) / Dominion (3.89%) / JCPL (1.58%) / NEPTUNE (0.15%) / HTP (0.07%) / PECO (2.08%) / PEPCO (1.66%) / ECP (0.07%)** / PSEG (2.62%) / RE (0.10%)
b1465.2	Replace the 100 MVAR 765 kV shunt reactor bank on Rockport – Jefferson 765 kV line with a 300 MVAR bank at Rockport Station		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1465.3	Transpose the Rockport – Sullivan 765 kV line and the Rockport – Jefferson 765 kV line		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)
b1465.4	Make switching improvements at Sullivan and Jefferson 765 kV stations		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)
b1466.1	Create an in and out loop at Adams Station by removing the hard tap that currently exists		AEP (100%)
b1466.2	Upgrade the Adams transformer to 90 MVA		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1466.3	At Seaman Station install a new 138 kV bus and two new 138 kV circuit breakers		AEP (100%)
b1466.4	Convert South Central Co-op's New Market 69 kV Station to 138 kV		AEP (100%)
b1466.5	The Seaman – Highland circuit is already built to 138 kV, but is currently operating at 69 kV, which would now increase to 138 kV		AEP (100%)
b1466.6	At Highland Station, install a new 138 kV bus, three new 138 kV circuit breakers and a new 138/69 kV 90 MVA transformer		AEP (100%)
b1466.7	Using one of the bays at Highland, build a 138 kV circuit from Hillsboro – Highland 138 kV, which is approximately 3 miles		AEP (100%)
b1467.1	Install a 14.4 MVAr Capacitor Bank at New Buffalo station		AEP (100%)
b1467.2	Reconfigure the 138 kV bus at LaPorte Junction station to eliminate a contingency resulting in loss of two 138 kV sources serving the LaPorte area		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1468.1	Expand Selma Parker Station and install a 138/69/34.5 kV transformer		AEP (100%)
b1468.2	Rebuild and convert 34.5 kV line to Winchester to 69 kV, including Farmland Station		AEP (100%)
b1468.3	Retire the 34.5 kV line from Haymond to Selma Wire		AEP (100%)
b1469.1	Conversion of the Newcomerstown – Cambridge 34.5 kV system to 69 kV operation		AEP (100%)
b1469.2	Expansion of the Derwent 69 kV Station (including reconfiguration of the 69 kV system)		AEP (100%)
b1469.3	Rebuild 11.8 miles of 69 kV line, and convert additional 34.5 kV stations to 69 kV operation		AEP (100%)
b1470.1	Build a new 138 kV double circuit off the Kanawha – Bailysville #2 138 kV circuit to Skin Fork Station		AEP (100%)
b1470.2	Install a new 138/46 kV transformer at Skin Fork		AEP (100%)
b1470.3	Replace 5 Moab's on the Kanawha – Baileysville line with breakers at the Sundial 138 kV station		AEP (100%)
b1471	Perform a sag study on the East Lima – For Lima – Rockhill 138 kV line to increase the emergency rating		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1472	Perform a sag study on the East Lima – Haviland 138 kV line to increase the emergency rating		AEP (100%)
b1473	Perform a sag study on the East New Concord – Muskingum River section of the Muskingum River – West Cambridge 138 kV circuit		AEP (100%)
b1474	Perform a sag study on the Ohio Central – Prep Plant tap 138 kV circuit		AEP (100%)
b1475	Perform a sag study on the S73 – North Delphos 138 kV line to increase the emergency rating		AEP (100%)
b1476	Perform a sag study on the S73 – T131 138 kV line to increase the emergency rating		AEP (100%)
b1477	The Natrium – North Martin 138 kV circuit would need an electrical clearance study among other equipment upgrades		AEP (100%)
b1478	Upgrade Strouds Run – Strounds Tap 138 kV relay and riser		AEP (100%)
b1479	West Hebron station upgrades		AEP (100%)
b1480	Perform upgrades and a sag study on the Corner – Layman 138 kV section of the Corner – Muskingum River 138 kV circuit		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1481	Perform a sag study on the West Lima – Eastown Road – Rockhill 138 kV line and replace the 138 kV risers at Rockhill station to increase the emergency rating		AEP (100%)
b1482	Perform a sag study for the Albion – Robison Park 138 kV line to increase its emergency rating		AEP (100%)
b1483	Sag study 1 mile of the Clinch River – Saltville 138 kV line and replace the risers and bus at Clinch River, Lebanon and Elk Garden Stations		AEP (100%)
b1484	Perform a sag study on the Hacienda – Harper 138 kV line to increase the emergency rating		AEP (100%)
b1485	Perform a sag study on the Jackson Road – Concord 183 kV line to increase the emergency rating		AEP (100%)
b1486	The Matt Funk – Poages Mill – Starkey 138 kV line requires		AEP (100%)
b1487	Perform a sag study on the New Carlisle – Trail Creek 138 kV line to increase the emergency rating		AEP (100%)
b1488	Perform a sag study on the Olive – LaPorte Junction 138 kV line to increase the emergency rating		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1489	A sag study must be performed for the 5.40 mile Tristate – Chadwick 138 kV line to determine if a higher emergency rating can be used		AEP (100%)
b1490.1	Establish a new 138/69 kV Butler Center station		AEP (100%)
b1490.2	Build a new 14 mile 138 kV line from Auburn station to Woods Road station VIA Butler Center station		AEP (100%)
b1490.3	Replace the existing 40 MVA 138/69 kV transformer at Auburn station with a 90 MVA 138/96 kV transformer		AEP (100%)
b1490.4	Improve the switching arrangement at Kendallville station		AEP (100%)
b1491	Replace bus and risers at Thelma and Busseyville stations and perform a sag study for the Big Sandy – Busseyville 138 kV line		AEP (100%)
b1492	Reconductor 0.65 miles of the Glen Lyn – Wythe 138 kV line with 3 – 1590 ACSR		AEP (100%)
b1493	Perform a sag study for the Bellfonte – Grantston 138 kV line to increase its emergency rating		AEP (100%)
b1494	Perform a sag study for the North Proctorville – Solida – Bellefonte 138 kV line to increase its emergency rating		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1495	Add an additional 765/345 kV transformer at Baker Station		AEC (0.41%) / AEP (87.22%) / BGE (1.03%) / ComEd (3.38%) / Dayton (1.23%) / DL (1.46%) / DPL (0.54%) / JCPL (0.90%) / NEPTUNE (0.09%) / HTP (0.04%) / PECO (1.18%) / PEPCO (0.94%) / ECP** (0.04%) / PSEG (1.48%) / RE (0.06%)
b1496	Replace 138 kV bus and risers at Johnson Mountain Station		AEP (100%)
b1497	Replace 138 kV bus and risers at Leesville Station		AEP (100%)
b1498	Replace 138 kV risers at Wurno Station		AEP (100%)
b1499	Perform a sag study on Sporn A – Gavin 138 kV to determine if the emergency rating can be improved		AEP (100%)
b1500	The North East Canton – Wagenhals 138 kV circuit would need an electrical clearance study to determine if the emergency rating can be utilized		AEP (100%)
b1501	The Moseley – Reusens 138 kV circuit requires a sag study to determine if the emergency rating can be utilized to address a thermal loading issue for a category C3		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1502	Reconductor the Conesville East – Conesville Prep Plant Tap 138 kV section of the Conesville – Ohio Central to fix Reliability N-1-1 thermal overloads		AEP (100%)
b1659	Establish Sorenson 345/138 kV station as a 765/345 kV station		AEP (93.61%) / ATSI (2.99%) / ComEd (2.07%) / HTP (0.03%) / PENELEC (0.31%) / ECP** (0.03%) / PSEG (0.92%) / RE (0.04%)
b1659.1	Replace Sorenson 138 kV breaker 'L1'		AEP (100%)
b1659.2	Replace Sorenson 138 kV breaker 'L2' breaker		AEP (100%)
b1659.3	Replace Sorenson 138 kV breaker 'M1'		AEP (100%)
b1659.4	Replace Sorenson 138 kV breaker 'M2'		AEP (100%)
b1659.5	Replace Sorenson 138 kV breaker 'N1'		AEP (100%)
b1659.6	Replace Sorenson 138 kV breaker 'N2'		AEP (100%)
b1659.7	Replace Sorenson 138 kV breaker 'O1'		AEP (100%)
b1659.8	Replace Sorenson 138 kV breaker 'O2'		AEP (100%)
b1659.9	Replace Sorenson 138 kV breaker 'M'		AEP (100%)
b1659.10	Replace Sorenson 138 kV breaker 'N'		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1659.11	Replace Sorenson 138 kV breaker 'O'		AEP (100%)
b1659.12	Replace McKinley 138 kV breaker 'L1'		AEP (100%)
b1659.13	Establish 765 kV yard at Sorenson and install four 765 kV breakers		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (1.82%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.30%) / PENELEC (1.84%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.25%) / ECP** (0.20%)
b1659.14	Build approximately 14 miles of 765 kV line from existing Dumont - Marysville line		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (1.82%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.30%) / PENELEC (1.84%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.25%) / ECP** (0.20%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1660	Install a 765/500 kV transformer at Cloverdale		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)
b1661	Install a 765 kV circuit breaker at Wyoming station		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1662	Rebuild 4 miles of 46 kV line to 138 kV from Pemberton to Cherry Creek		AEP (100%)
b1662.1	Circuit Breakers are installed at Cherry Creek (facing Pemberton) and at Pemberton (facing Tams Mtn. and Cherry Creek)		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1662.2	Install three 138 kV breakers at Grandview Station (facing Cherry Creek, Hinton, and Bradley Stations)		AEP (100%)
b1662.3	Remove Sullivan Switching Station (46 kV)		AEP (100%)
b1663	Install a new 765/138 kV transformer at Jackson Ferry substation		AEP (100%)
b1663.1	Establish a new 10 mile double circuit 138 kV line between Jackson Ferry and Wythe		AEP (100%)
b1663.2	Install 2 765 kV circuit breakers, breaker disconnect switches and associated bus work for the new 765 kV breakers, and new relays for the 765 kV breakers at Jackson's Ferry		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.*42*%) / PECO (5.30%) / PENELEC (1.*84*%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.*25*%) / ECP** (0.20%)
b1664	Install switched capacitor banks at Kenwood 138 kV stations		AEP (100%)
b1665	Install a second 138/69 kV transformer at Thelma station		AEP (100%)
b1665.1	Construct a single circuit 69 kV line from West Paintsville to the new Paintsville station		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1665.2	Install new 7.2 MVAR, 46 kV bank at Kenwood Station		AEP (100%)
b1666	Build an 8 breaker 138 kV station tapping both circuits of the Fostoria - East Lima 138 kV line		AEP (90.65%) / Dayton (9.35%)
b1667	Establish Melmore as a switching station with both 138 kV circuits terminating at Melmore. Extend the double circuit 138 kV line from Melmore to Fremont Center		AEP (100%)
b1668	Revise the capacitor setting at Riverside 138 kV station		AEP (100%)
b1669	Capacitor setting changes at Ross 138 kV stations		AEP (100%)
b1670	Capacitor setting changes at Wooster 138 kV station		AEP (100%)
b1671	Install four 138 kV breakers in Danville area		AEP (100%)
b1676	Replace Natrium 138 kV breaker 'G (rehab)'		AEP (100%)
b1677	Replace Huntley 138 kV breaker '106'		AEP (100%)
b1678	Replace Kammer 138 kV breaker 'G'		AEP (100%)
b1679	Replace Kammer 138 kV breaker 'H'		AEP (100%)
b1680	Replace Kammer 138 kV breaker 'J'		AEP (100%)
b1681	Replace Kammer 138 kV breaker 'K'		AEP (100%)
b1682	Replace Kammer 138 kV breaker 'M'		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1683	Replace Kammer 138 kV breaker 'N'		AEP (100%)
b1684	Replace Clinch River 138 kV breaker 'E1'		AEP (100%)
b1685	Replace Lincoln 138 kV breaker 'D'		AEP (100%)
b1687	Advance s0251.7 (Replace Corrid 138 kV breaker '104S')		AEP (100%)
b1688	Advance s0251.8 (Replace Corrid 138 kV breaker '104C')		AEP (100%)
b1712.1	Perform sag study on Altavista - Leesville 138 kV line		Dominion (75.30%) / PEPCO (24.70%)
b1712.2	Rebuild the Altavista - Leesville 138 kV line		Dominion (75.30%) / PEPCO (24.70%)
b1733	Perform a sag study of the Bluff Point - Jauy 138 kV line. Upgrade breaker, wavetrap, and risers at the terminal ends		AEP (100%)
b1734	Perform a sag study of Randoph - Hodgins 138 kV line. Upgrade terminal equipment		AEP (100%)
b1735	Perform a sag study of R03 - Magely 138 kV line. Upgrade terminal equipment		AEP (100%)
b1736	Perform a sag study of the Industrial Park - Summit 138 kV line		AEP (100%)
b1737	Sag study of Newcomerstown - Hillview 138 kV line. Upgrade - terminal equipment		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1738	Perform a sag study of the Wolf Creek - Layman 138 kV line. -Upgrade terminal equipment including a 138 kV breaker and wavetrap		AEP (100%)
b1739	Perform a sag study of the Ohio Central - West Trinway 138 kV line		AEP (100%)
b1741	Replace Beatty 138 kV breaker '2C(IPP)'		AEP (100%)
b1742	Replace Beatty 138 kV breaker '1E'		AEP (100%)
b1743	Replace Beatty 138 kV breaker '2E'		AEP (100%)
b1744	Replace Beatty 138 kV breaker '3C'		AEP (100%)
b1745	Replace Beatty 138 kV breaker '2W'		AEP (100%)
b1746	Replace St. Claire 138 kV breaker '8'		AEP (100%)
b1747	Replace Cloverdale 138 kV breaker 'C'		AEP (100%)
b1748	Replace Cloverdale 138 kV breaker 'D1'		AEP (100%)
b1780	Install two 138kV breakers and two 138kV circuit switchers at South Princeton Station and one 138kV breaker and one 138kV circuit switcher at Switchback Station		AEP (100%)
b1781	Install three 138 kV breakers and a 138kV circuit switcher at Trail Fork Station in Pineville, WV		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1782	Install a 46kV Moab at Montgomery Station facing Carbondale (on the London - Carbondale 46 kV circuit)		AEP (100%)
b1783	Add two 138 kV Circuit Breakers and two 138 kV circuit switchers on the Lonesome Pine - South Bluefield 138 kV line		AEP (100%)
b1784	Install a 52.8 MVAR capacitor bank at the Clifford 138 kV station		AEP (100%)
b1811.1	Perform a sag study of 4 miles of the Waterford - Muskingum line		AEP (100%)
b1811.2	Rebuild 0.1 miles of Waterford - Muskingum 345 kV with 1590 ACSR		AEP (100%)
b1812	Reconductor the AEP portion of the South Canton - Harmon 345 kV with 954 ACSR and upgrade terminal equipment at South Canton. Expected rating is 1800 MVA S/N and 1800 MVA S/E		AEP (100%)
b1817	Install (3) 345 kV circuit breakers at East Elkhart station in ring bus designed as a breaker and half scheme		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1818	Expand the Allen station by installing a second 345/138 kV transformer and adding four 138 kV exits by cutting in the Lincoln - Sterling and Milan - Timber Switch 138 kV double circuit tower line		AEP (88.30%) / ATSI (8.86%) / Dayton (2.84%)
b1819	Rebuild the Robinson Park - Sorenson 138 kV line corridor as a 345 kV double circuit line with one side operated at 345 kV and one side at 138 kV		AEP (87.18%) / ATSI (10.06%) / Dayton (2.76%)
b1859	Perform a sag study for Hancock - Cave Spring - Roanoke 138 kV circuit to reach new SE ratings of 272MVA (Cave Spring-Hancock), 205MVA (Cave Spring-Sunscape), 245MVA (ROANO2-Sunscape)		AEP (100%)
b1860	Perform a sag study on the Crooksville - Spencer Ridge section (14.3 miles) of the Crooksville-Poston-Strouds Run 138 kV circuit to see if any remedial action needed to reach the SE rating (175MVA)		AEP (100%)
b1861	Reconductor 0.83 miles of the Dale - West Canton 138 kV Tie-line and upgrade risers at West Canton 138 kV		AEP (100%)
b1862	Perform a sag study on the Grant - Greentown 138 kV circuit and replace the relay CT at Grant 138 kV station to see if any remedial action needed to reach the new ratings of 251/286MVA		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1863	Perform a sag study of the Kammer - Wayman SW 138 kV line to see if any remedial action needed to reach the new SE rating of 284MVA		AEP (100%)
b1864.1	Add two additional 345/138 kV transformers at Kammer		AEP (87.22%) / APS (8.22%) / ATSI (3.52%) / DL (1.04%)
b1864.2	Add second West Bellaire - Brues 138 kV circuit		AEP (87.22%) / APS (8.22%) / ATSI (3.52%) / DL (1.04%)
b1864.3	Replace Kammer 138 kV breaker 'E'		AEP (100%)
b1865	Perform a sag study on the Kanawha - Carbondale 138 kV line to see if any remedial action needed to reach the new ratings of 251/335MVA		AEP (100%)
b1866	Perform a sag study on the Clinch River-Lock Hart-Dorton 138kV line,increase the Relay Compliance Trip Limit at Clinch River on the C.R.-Dorton 138kV line to 310 and upgrade the risers with 1590ACSR		AEP (100%)
b1867	Perform a sag study on the Newcomerstown - South Coshocton 138 kV line to see if any remedial action is needed to reach the new SE rating of 179MVA		AEP (100%)
b1868	Perform sag study on the East Lima - new Liberty 138 kV line to see if any remedial action is needed to reach the new SE rating of 219MVA		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1869	Perform a sag study of the Ohio Central - South Coshocton 138 kV circuit to see if any remedial action needed to reach the new SE ratings of 250MVA		AEP (100%)
b1870	Replace the Ohio Central transformer #1 345/138/12 kV 450 MVA for a 345/138/34.5 kV 675 MVA transformer		AEP (68.16%) / ATSI (25.27%) / Dayton (3.88%) / PENELEC (1.59%) / DEOK (1.10%)
b1871	Perform a sag study on the Central - West Coshocton 138 kV line (improving the emergency rating of this line to 254 MVA)		AEP (100%)
b1872	Add a 57.6 MVAr capacitor bank at East Elkhart 138 kv station in Indiana		AEP (100%)
b1873	Install two 138 kV circuit breakers at Cedar Creek Station and primary side circuit switcher on the 138/69/46 kV transformer		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1874	Install two 138 kV circuit breakers and one 138 kV circuit switcher at Magely 138 kV station in Indiana		AEP (100%)
b1875	Build 25 miles of new 138 kV line from Bradley Station through Tower 117 Station and terminating at McClung 138 kV station. Existing 69 kV distribution transformers will be replaced with 138 kV transformers		AEP (100%)
b1876	Install a 14.4 MVAr capacitor bank at Capital Avenue (AKA Currant Road) 34.5 kV bus		AEP (100%)
b1877	Relocate 138 kV Breaker G to the West Kingsport - Industry Drive 138 kV line and Remove 138 kV MOAB		AEP (100%)
b1878	Perform a sag study on the Lincoln - Robinson Park 138 kV line (Improve the emergency rating to 244 MVA)		AEP (100%)
b1879	Perform a sag study on the Hansonville - Meadowview 138 kV line (Improve the emergency rating to 245 MVA)		AEP (100%)
b1880	Rebuild the 15 miles of the Moseley - Roanoke 138 kV line. This project would consist of rebuilding both circuits on the double circuit line		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1881	Replace existing 600 Amp switches, station risers and increase the CT ratios associated with breaker 'G' at Sterling 138 kV Station. It will increase the rating to 296 MVA S/N and 384 MVA S/E		AEP (100%)
b1882	Perform a sag study on the Bluff Point - Randolf 138 kV line to see if any remedial action needed to reach the new SE rating of 255 MVA		AEP (100%)
b1883	Switch the breaker position of transformer #1 and SW Lima at East Lima 345 kV bus		AEP (100%)
b1884	Perform a sag study on Strawton station - Fisher Body - Deer Creek 138 kV line to see if any remedial action needed to reach the new SE rating of 250 MVA		AEP (100%)
b1887	Establish a new 138/69 kV source at Carrollton and construct two new 69 kV lines from Carrollton to tie into the Dennison - Miller SW 69 kV line and to East Dover 69 kV station respectively		AEP (100%)
b1888	Install a 69 kV line breaker at Blue Pennant 69 kV Station facing Bim Station and 14.4 MVAr capacitor bank		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1889	Install a 43.2 MVAR capacitor bank at Hinton 138 kV station (APCO WV)		AEP (100%)
b1901	Rebuild the Ohio Central - West Trinway (4.84 miles) section of the Academia - Ohio Central 138 kV circuit. Upgrade the Ohio Central riser, Ohio Central switch and the West Trinway riser		AEP (100%)
b1904.1	Construct new 138/69 Michiana Station near Bridgman by tapping the new Carlisle - Main Street 138 kV and the Bridgman - Buchanan Hydro 69 kV line		AEP (100%)
b1904.2	Establish a new 138/12 kV New Galien station by tapping the Olive - Hickory Creek 138 kV line		AEP (100%)
b1904.3	Retire the existing Galien station and move its distribution load to New Galien station. Retire the Buchanan Hydro - New Carlisile 34.5 kV line		AEP (100%)
b1904.4	Implement an in and out scheme at Cook 69 kV by eliminating the Cook 69 kV tap point and by installing two new 69 kV circuit breakers		AEP (100%)
b1904.5	Rebuild the Bridgman - Cook 69 kV and the Derby - Cook 69 kV lines		AEP (100%)
b1946	Perform a sag study on the Brues – West Bellaire 138 kV line		AEP (100%)
b1947	A sag study of the Dequine - Meadowlake 345 kV line #1 line may improve the emergency rating to 1400 MVA		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1948	Establish a new 765/345 interconnection at Sporn. Install a 765/345 kV transformer at Mountaineer and build ¾ mile of 345 kV to Sporn		ATSI (61.08%) / DL (21.87%) / Dominion (13.97%) / PENELEC (3.08%)
b1949	Perform a sag study on the Grant Tap – Deer Creek 138 kV line and replace bus and risers at Deer Creek station		AEP (100%)
b1950	Perform a sag study on the Kammer – Ormet 138 kV line of the conductor section		AEP (100%)
b1951	Perform a sag study of the Maddox- Convoy 345 kV line to improve the emergency rating to 1400 MVA		AEP (100%)
b1952	Perform a sag study of the Maddox – T130 345 kV line to improve the emergency rating to 1400 MVA		AEP (100%)
b1953	Perform a sag study of the Meadowlake - Olive 345 kV line to improve the emergency rating to 1400 MVA		AEP (100%)
b1954	Perform a sag study on the Milan - Harper 138 kV line and replace bus and switches at Milan Switch station		AEP (100%)
b1955	Perform a sag study of the R-049 - Tillman 138 kV line may improve the emergency rating to 245 MVA		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1956	Perform a sag study of the Tillman - Dawkins 138 kV line may improve the emergency rating to 245 MVA		AEP (100%)
b1957	Terminate Transformer #2 at SW Lima in a new bay position		AEP (69.41%) / ATSI (23.11%) / ECP** (0.17%) / HTP (0.19%) / PENELEC (2.42%) / PSEG (4.52%) / RE (0.18%)
b1958	Perform a sag study on the Brookside - Howard 138 kV line and replace bus and risers at AEP Howard station		AEP (100%)
b1960	Sag Study on 7.2 miles SE Canton-Canton Central 138kV ckt		AEP (100%)
b1961	Sag study on the Southeast Canton – Sunnyside 138kV line		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1962	Add four 765 kV breakers at Kammer		AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (4.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / DPL (2.62%) / Dominion (12.39%) / EKPC (1.82%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.30%) / PENELEC (1.84%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.25%) / ECP** (0.20%)
b1963	Build approximately 1 mile of circuit comprising of 2-954 ACSR to get the rating of Waterford-Muskinum 345 kV higher		AEP (100%)
b1970	Reconductor 13 miles of the Kammer – West Bellaire 345kV circuit		APS (33.51%) / ATSI (32.21%) / DL (18.64%) / Dominion (6.01%) / ECP** (0.10%) / HTP (0.11%) / JCPL (1.68%) / Neptune* (0.18%) / PENELEC (4.58%) / PSEG (2.87%) / RE (0.11%)
b1971	Perform a sag study to improve the emergency rating on the Bridgville – Chandlersville 138 kV line		AEP (100%)
b1972	Replace disconnect switch on the South Canton 765/345 kV transformer		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1973	Perform a sag study to improve the emergency rating on the Carrollton – Sunnyside 138 kV line		AEP (100%)
b1974	Perform a sag study to improve the emergency rating on the Bethel Church – West Dover 138 kV line		AEP (100%)
b1975	Replace a switch at South Millersburg switch station		AEP (100%)
b2017	Reconductor or rebuild Sporn - Waterford - Muskingum River 345 kV line		ATSI (37.04%) / AEP (34.35%) / DL (10.41%) / Dominion (6.19%) / APS (3.94%) / PENELEC (3.09%) / JCPL (1.39%) / Dayton (1.20%) / Neptune* (0.14%) / HTP (0.09%) / ECP** (0.08%) / PSEG (2.00%) / RE (0.08%)
b2018	Loop Conesville - Bixby 345 kV circuit into Ohio Central		ATSI (58.58%) / AEP (14.16%) / APS (12.88%) / DL (7.93%) / PENELEC (5.73%) / Dayton (0.72%)
b2019	Establish Burger 345/138 kV station		AEP (93.74%) / APS (4.40%) / DL (1.11%) / ATSI (0.74%) / PENELEC (0.01%)
b2020	Rebuild Amos - Kanawah River 138 kV corridor		AEP (88.39%) / APS (7.12%) / ATSI (2.89%) / DEOK (1.58%) / PEPCO (0.02%)
b2021	Add 345/138 transformer at Sporn, Kanawah River & Muskingum River stations		AEP (91.92%) / DEOK (3.60%) / APS (2.19%) / ATSI (1.14%) / DL (1.08%) / PEPCO (0.04%) / BGE (0.03%)
b2021.1	Replace Kanawah 138 kV breaker 'L'		AEP (100%)
b2021.2	Replace Muskingum 138 kV breaker 'HG'		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2021.3	Replace Muskingum 138 kV breaker 'HJ'		AEP (100%)
b2021.4	Replace Muskingum 138 kV breaker 'HE'		AEP (100%)
b2021.5	Replace Muskingum 138 kV breaker 'HD'		AEP (100%)
b2021.6	Replace Muskingum 138 kV breaker 'HF'		AEP (100%)
b2021.7	Replace Muskingum 138 kV breaker 'HC'		AEP (100%)
b2021.8	Replace Sporn 138 kV breaker 'D1'		AEP (100%)
b2021.9	Replace Sporn 138 kV breaker 'D2'		AEP (100%)
b2021.10	Replace Sporn 138 kV breaker 'F1'		AEP (100%)
b2021.11	Replace Sporn 138 kV breaker 'F2'		AEP (100%)
b2021.12	Replace Sporn 138 kV breaker 'G'		AEP (100%)
b2021.13	Replace Sporn 138 kV breaker 'G2'		AEP (100%)
b2021.14	Replace Sporn 138 kV breaker 'N1'		AEP (100%)
b2021.15	Replace Kanawah 138 kV breaker 'M'		AEP (100%)
b2022	Terminate Tristate - Kyger Creek 345 kV line at Sporn		AEP (97.99%) / DEOK (2.01%)
b2027	Perform a sag study of the Tidd - Collier 345 kV line		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2028	Perform a sag study on East Lima - North Woodcock 138 kV line to improve the rating		AEP (100%)
b2029	Perform a sag study on Bluebell - Canton Central 138 kV line to improve the rating		AEP (100%)
b2030	Install 345 kV circuit breakers at West Bellaire		AEP (100%)
b2031	Sag study on Tilton - W. Bellaire section 1 (795 ACSR), about 12 miles		AEP (100%)
b2032	Rebuild 138 kV Elliot tap - Poston line		ATSI (73.02%) / Dayton (19.39%) / DL (7.59%)
b2033	Perform a sag study of the Brues - W. Bellaire 138 kV line		AEP (100%)
b2046	Adjust tap settings for Muskingum River transformers		AEP (100%)
b2047	Replace relay at Greenlawn		AEP (100%)
b2048	Replace both 345/138 kV transformers with one bigger transformer		AEP (92.49%) / Dayton (7.51%)
b2049	Replace relay		AEP (100%)
b2050	Perform sag study		AEP (100%)
b2051	Install 3 138 kV breakers and a circuit switcher at Dorton station		AEP (100%)
b2052	Replace transformer		AEP (67.17%) / ATSI (27.37%) / Dayton (3.73%) / PENELEC (1.73%)
b2054	Perform a sag study of Sporn - Rutland 138 kV line		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2069	Replace George Washington 138 kV breaker 'A' with 63kA rated breaker		AEP (100%)
b2070	Replace Harrison 138 kV breaker '6C' with 63kA rated breaker		AEP (100%)
b2071	Replace Lincoln 138 kV breaker 'L' with 63kA rated breaker		AEP (100%)
b2072	Replace Natrum 138 kV breaker 'I' with 63kA rated breaker		AEP (100%)
b2073	Replace Darrah 138 kV breaker 'B' with 63kA rated breaker		AEP (100%)
b2074	Replace Wyoming 138 kV breaker 'G' with 80kA rated breaker		AEP (100%)
b2075	Replace Wyoming 138 kV breaker 'G1' with 80kA rated breaker		AEP (100%)
b2076	Replace Wyoming 138 kV breaker 'G2' with 80kA rated breaker		AEP (100%)
b2077	Replace Wyoming 138 kV breaker 'H' with 80kA rated breaker		AEP (100%)
b2078	Replace Wyoming 138 kV breaker 'H1' with 80kA rated breaker		AEP (100%)
b2079	Replace Wyoming 138 kV breaker 'H2' with 80kA rated breaker		AEP (100%)
b2080	Replace Wyoming 138 kV breaker 'J' with 80kA rated breaker		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2081	Replace Wyoming 138 kV breaker 'J1' with 80kA rated breaker		AEP (100%)
b2082	Replace Wyoming 138 kV breaker 'J2' with 80kA rated breaker		AEP (100%)
b2083	Replace Natrum 138 kV breaker 'K' with 63kA rated breaker		AEP (100%)
b2084	Replace Tanner Creek 345 kV breaker 'P' with 63kA rated breaker		AEP (100%)
b2085	Replace Tanner Creek 345 kV breaker 'P2' with 63kA rated breaker		AEP (100%)
b2086	Replace Tanner Creek 345 kV breaker 'Q1' with 63kA rated breaker		AEP (100%)
b2087	Replace South Bend 138 kV breaker 'T' with 63kA rated breaker		AEP (100%)
b2088	Replace Tidd 138 kV breaker 'L' with 63kA rated breaker		AEP (100%)
b2089	Replace Tidd 138 kV breaker 'M2' with 63kA rated breaker		AEP (100%)
b2090	Replace McKinley 138 kV breaker 'A' with 40kA rated breaker		AEP (100%)
b2091	Replace West Lima 138 kV breaker 'M' with 63kA rated breaker		AEP (100%)
b2092	Replace George Washington 138 kV breaker 'B' with 63kA rated breaker		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2093	Replace Turner 138 kV breaker 'W' with 63kA rated breaker		AEP (100%)
b2135	Build a new 138 kV line from Falling Branch to Merrimac and add a 138/69 kV transformer at Merrimac Station		AEP (100%)
b2160	Add a fourth circuit breaker to the station being built for the U4-038 project (Conelley), rebuild U4-038 - Grant Tap line as double circuit tower line		AEP (100%)
b2161	Rebuild approximately 20 miles of the Allen - S073 double circuit 138 kV line (with one circuit from Allen - Tillman - Timber Switch - S073 and the other circuit from Allen - T-131 - S073) utilizing 1033 ACSR		AEP (100%)
b2162	Perform a sag study to improve the emergency rating of the Belpre - Degussa 138 kV line		AEP (100%)
b2163	Replace breaker and wavetrap at Jay 138 kV station		AEP (100%)

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SCHEDULE 12 – APPENDIX A

(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)
b1660.1	Cloverdale: install 6-765 kV breakers, incremental work for 2 additional breakers, reconfigure and relocate miscellaneous facilities, establish 500 kV station and 500 kV tie with 765 kV station		**Load-Ratio Share Allocation:** AEC (*1.70*%) / AEP (*14.25*%) / APS (*5.53*%) / ATSI (*8.09*%) / BGE (*4.19*%) / ComEd (*13.43*%) / Dayton (*2.12*%) / DEOK (*3.37*%) / DL (1.77%) / DPL (2.62%) _/ ECP** (0.20%)_ / Dominion (*12.39*%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (*3.78*%) / ME (*1.87*%) / NEPTUNE* (0.*42*%) / PECO (*5.30*%) / PENELEC (1.*84*%) / PEPCO (*4.18*%) / PPL (*4.46*%) / PSEG (*6.22*%) / RE (0.*25*%)
			DFAX Allocation: APS (48.49%) / DEOK (0.24%) / Dominion (0.65%) / EKPC (0.07%) / PEPCO (50.55%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1797.1	Reconductor the AEP portion of the Cloverdale - Lexington 500 kV line with 2-1780 ACSS		**Load-Ratio Share Allocation:** AEC (*1.70*%) / AEP (*14.25*%) / APS (*5.53*%) / ATSI (*8.09*%) / BGE (*4.19*%) / ComEd (*13.43*%) / Dayton (*2.12*%) / DEOK (*3.37*%) / DL (*1.77*%) / DPL (*2.62*%) / ECP** (0.20%) / Dominion (*12.39*%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (*3.78*%) / ME (*1.87*%) / NEPTUNE* (0*.42*%) / PECO (*5.30*%) / PENELEC (1*.84*%) / PEPCO (*4.18*%) / PPL (*4.46*%) / PSEG (*6.22*%) / RE (0*.25*%)
			DFAX Allocation: AEP (*0.28*%) / APS (*42.58*%) / ATSI (*0.13*%) / BGE (*21.34*%) / Dayton (*0.05*%) / DEOK (*0.15*%) / Dominion (*0.32*%) / EKPC (*0.04*%) / PEPCO (*35.11*%)
b2055	Upgrade relay at Brues station		AEP (100%)
b2122.3	Upgrade terminal equipment at Howard on the Howard - Brookside 138 kV line to achieve ratings of 252/291 (SN/SE)		AEP (100%)
b2122.4	Perform a sag study on the Howard - Brookside 138 kV line		AEP (100%)
b2229	Install a 300 MVAR reactor at Dequine 345 kV		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2230	Replace existing 150 MVAR reactor at Amos 765 kV substation on Amos - N. Proctorville - Hanging Rock with 300 MVAR reactor		**Load-Ratio Share Allocation:** AEC (1.70%) / AEP (14.25%) / APS (5.53%) / ATSI (8.09%) / BGE (44.19%) / ComEd (13.43%) / Dayton (2.12%) / DEOK (3.37%) / DL (1.77%) / Dominion (12.39%) / DPL (2.62%) / ECP** (0.20%) / EKPC (1.82%) / HTP*** (0.20%) / JCPL (3.78%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.30%) / PENELEC (1.84%) / PEPCO (4.18%) / PPL (4.46%) / PSEG (6.22%) / RE (0.25%)
			DFAX Allocation: AEP (100%)
b2231	Install 765 kV reactor breaker at Dumont 765 kV substation on the Dumont - Wilton Center line		AEP (100%)
b2232	Install 765 kV reactor breaker at Marysville 765 kV substation on the Marysville - Maliszewski line		AEP (100%)
b2233	Change transformer tap settings for the Baker 765/345 kV transformer		AEP (100%)
b2252	Loop the North Muskingum - Crooksville 138 kV line into AEP's Philo 138 kV station which lies approximately 0.4 miles from the line		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2253	Install an 86.4 MVAR capacitor bank at Gorsuch 138 kV station in Ohio		AEP (100%)
b2254	Rebuild approximately 4.9 miles of Corner - Degussa 138 kV line in Ohio		AEP (100%)
b2255	Rebuild approximately 2.8 miles of Maliszewski - Polaris 138 kV line in Ohio		AEP (100%)
b2256	Upgrade approximately 36 miles of 138 kV through path facilities between Harrison 138 kV station and Ross 138 kV station in Ohio		AEP (100%)
b2257	Rebuild the Pokagon - Corey 69 kV line as a double circuit 138 kV line with one side at 69 kV and the other side as an express circuit between Pokagon and Corey stations		AEP (100%)
b2258	Rebuild 1.41 miles of #2 CU 46 kV line between Tams Mountain - Slab Fork to 138 kV standards. The line will be strung with 1033 ACSR		AEP (100%)
b2259	Install a new 138/69 kV transformer at George Washington 138/69 kV substation to provide support to the 69 kV system in the area		AEP (100%)
b2286	Rebuild 4.7 miles of Muskingum River - Wolf Creek 138 kV line and remove the 138/138 kV transformer at Wolf Creek Station		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2287	Loop in the Meadow Lake - Olive 345 kV circuit into Reynolds 765/345 kV station		AEP (100%)
b2344.1	Establish a new 138/12 kV station, transfer and consolidate load from its Nicholsville and Marcellus 34.5 kV stations at this new station		AEP (100%)
b2344.2	Tap the Hydramatic – Valley 138 kV circuit (~ structure 415), build a new 138 kV line (~3.75 miles) to this new station		AEP (100%)
b2344.3	From this station, construct a new 138 kV line (~1.95 miles) to REA’s Marcellus station		AEP (100%)
b2344.4	From REA’s Marcellus station construct new 138 kV line (~2.35 miles) to a tap point on Valley – Hydramatic 138 kV ckt (~structure 434)		AEP (100%)
b2344.5	Retire sections of the 138 kV line in between structure 415 and 434 (~ 2.65 miles)		AEP (100%)
b2344.6	Retire AEP’s Marcellus 34.5/12 kV and Nicholsville 34.5/12 kV stations and also the Marcellus – Valley 34.5 kV line		AEP (100%)
b2345.1	Construct a new 69 kV line from Hartford to Keeler (~8 miles)		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2345.2	Rebuild the 34.5 kV lines between Keeler - Sister Lakes and Glenwood tap switch to 69 kV (~12 miles)		AEP (100%)
b2345.3	Implement in - out at Keeler and Sister Lakes 34.5 kV stations		AEP (100%)
b2345.4	Retire Glenwood tap switch and construct a new Rothadew station. These new lines will continue to operate at 34.5 kV		AEP (100%)
b2346	Perform a sag study for Howard - North Bellville - Millwood 138 kV line including terminal equipment upgrades		AEP (100%)
b2347	Replace the North Delphos 600A switch. Rebuild approximately 18.7 miles of 138 kV line North Delphos - S073. Reconductor the line and replace the existing tower structures		AEP (100%)
b2348	Construct a new 138 kV line from Richlands Station to intersect with the Hales Branch - Grassy Creek 138 kV circuit		AEP (100%)
b2374	Change the existing CT ratios of the existing equipment along Bearskin - Smith Mountain 138kV circuit		AEP (100%)
b2375	Change the existing CT ratios of the existing equipment along East Danville-Banister 138kV circuit		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2376	Replace the Turner 138 kV breaker 'D'		AEP (100%)
b2377	Replace the North Newark 138 kV breaker 'P'		AEP (100%)
b2378	Replace the Sporn 345 kV breaker 'DD'		AEP (100%)
b2379	Replace the Sporn 345 kV breaker 'DD2'		AEP (100%)
b2380	Replace the Muskingum 345 kV breaker 'SE'		AEP (100%)
b2381	Replace the East Lima 138 kV breaker 'E1'		AEP (100%)
b2382	Replace the Delco 138 kV breaker 'R'		AEP (100%)
b2383	Replace the Sporn 345 kV breaker 'AA2'		AEP (100%)
b2384	Replace the Sporn 345 kV breaker 'CC'		AEP (100%)
b2385	Replace the Sporn 345 kV breaker 'CC2'		AEP (100%)
b2386	Replace the Astor 138 kV breaker '102'		AEP (100%)
b2387	Replace the Muskingum 345 kV breaker 'SH'		AEP (100%)
b2388	Replace the Muskingum 345 kV breaker 'SI'		AEP (100%)
b2389	Replace the Hyatt 138 kV breaker '105N'		AEP (100%)
b2390	Replace the Muskingum 345 kV breaker 'SG'		AEP (100%)
b2391	Replace the Hyatt 138 kV breaker '101C'		AEP (100%)
b2392	Replace the Hyatt 138 kV breaker '104N'		AEP (100%)
b2393	Replace the Hyatt 138 kV breaker '104S'		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2394	Replace the Sporn 345 kV breaker 'CC1'		AEP (100%)
b2409	Install two 56.4 MVAR capacitor banks at the Melmore 138 kV station in Ohio		AEP (100%)
b2410	Convert Hogan Mullin 34.5 kV line to 138 kV, establish 138 kV line between Jones Creek and Strawton, rebuild existing Mullin Elwood 34.5 kV and terminate line into Strawton station, retire Mullin station		AEP (100%)
b2411	Rebuild the 3/0 ACSR portion of the Hadley - Kroemer Tap 69 kV line utilizing 795 ACSR conductor		AEP (100%)
b2423	Install a 300 MVAR shunt reactor at AEP's Wyoming 765 kV station		**Load-Ratio Share Allocation:** AEC (*1.70*%) / AEP (*14.25*%) / APS (*5.53*%) / ATSI (*8.09*%) / BGE (4*4.19*%) / ComEd (*13.43*%) / Dayton (*2.12*%) / DEOK (*3.37*%) / DL (*1.77*%) / Dominion (*12.39*%) / DPL (*2.62*%) / ECP** (0.20%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (*3.78*%) / ME (*1.87*%) / NEPTUNE* (0.*42*%) / PECO (*5.30*%) / PENELEC (1.*84*%) / PEPCO (*4.18*%) / PPL (*4.46*%) / PSEG (*6.22*%) / RE (0.*25*%)
			DFAX Allocation: AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2444	Willow - Eureka 138 kV line: Reconductor 0.26 mile of 4/0 CU with 336 ACSS		AEP (100%)
b2445	Complete a sag study of Tidd - Mahans Lake 138 kV line		AEP (100%)
b2449	Rebuild the 7-mile 345 kV line between Meadow Lake and Reynolds 345 kV stations		AEP (100%)
b2462	Add two 138 kV circuit breakers at Fremont station to fix tower contingency ‘408_2’		AEP (100%)
b2501	Construct a new 138/69 kV Yager station by tapping 2-138 kV FE circuits (Nottingham-Cloverdale, Nottingham-Harmon)		AEP (100%)
b2501.2	Build a new 138 kV line from new Yager station to Azalea station		AEP (100%)
b2501.3	Close the 138 kV loop back into Yager 138 kV by converting part of local 69 kV facilities to 138 kV		AEP (100%)
b2501.4	Build 2 new 69 kV exits to reinforce 69 kV facilities and upgrade conductor between Irish Run 69 kV Switch and Bowerstown 69 kV Switch		AEP (100%)

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2502.1	Construct new 138 kV switching station Nottingham tapping 6-138 kV FE circuits (Holloway-Brookside, Holloway-Harmon #1 and #2, Holloway-Reeds, Holloway-New Stacy, Holloway-Cloverdale). Exit a 138 kV circuit from new station to Freebyrd station		AEP (100%)
b2502.2	Convert Freebyrd 69 kV to 138 kV		AEP (100%)
b2502.3	Rebuild/convert Freebyrd-South Cadiz 69 kV circuit to 138 kV		AEP (100%)
b2502.4	Upgrade South Cadiz to 138 kV breaker and a half		AEP (100%)
b2530	Replace the Sporn 138 kV breaker ‘G1’ with 80kA breaker		AEP (100%)
b2531	Replace the Sporn 138 kV breaker ‘D’ with 80kA breaker		AEP (100%)
b2532	Replace the Sporn 138 kV breaker ‘O1’ with 80kA breaker		AEP (100%)
b2533	Replace the Sporn 138 kV breaker ‘P2’ with 80kA breaker		AEP (100%)
b2534	Replace the Sporn 138 kV breaker ‘U’ with 80kA breaker		AEP (100%)
b2535	Replace the Sporn 138 kV breaker ‘O’ with 80 kA breaker		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2536	Replace the Sporn 138 kV breaker ‘O2’ with 80 kA breaker		AEP (100%)
b2537	Replace the Robinson Park 138 kV breakers A1, A2, B1, B2, C1, C2, D1, D2, E1, E2, and F1 with 63 kA breakers		AEP (100%)
b2555	Reconductor 0.5 miles Tiltonsville – Windsor 138 kV and string the vacant side of the 4.5 mile section using 556 ACSR in a six wire configuration		AEP (100%)
b2556	Install two 138 kV prop structures to increase the maximum operating temperature of the Clinch River- Clinch Field 138 kV line		AEP (100%)
b2581	Temporary operating procedure for delay of upgrade b1464. Open the Corner 138 kV circuit breaker 86 for an overload of the Corner – Washington MP 138 kV line. The tower contingency loss of Belmont – Trissler 138 kV and Belmont – Edgelawn 138 kV should be added to Operational contingency		AEP (100%)

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2591	Construct a new 69 kV line approximately 2.5 miles from Colfax to Drewry's. Construct a new Drewry's station and install a new circuit breaker at Colfax station.		AEP (100%)
b2592	Rebuild existing East Coshocton – North Coshocton double circuit line which contains Newcomerstown – N. Coshocton 34.5 kV Circuit and Coshocton – North Coshocton 69 kV circuit		AEP (100%)
b2593	Rebuild existing West Bellaire – Glencoe 69 kV line with 138 kV & 69 kV circuits and install 138/69 kV transformer at Glencoe Switch		AEP (100%)
b2594	Rebuild 1.0 mile of Brantley – Bridge Street 69 kV Line with 1033 ACSR overhead conductor		AEP (100%)
b2595.1	Rebuild 7.82 mile Elkhorn City – Haysi S.S 69 kV line utilizing 1033 ACSR built to 138 kV standards		AEP (100%)
b2595.2	Rebuild 5.18 mile Moss – Haysi SS 69 kV line utilizing 1033 ACSR built to 138 kV standards		AEP (100%)
b2596	Move load from the 34.5 kV bus to the 138 kV bus by installing a new 138/12 kV XF at New Carlisle station in Indiana		AEP (100%)

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)

b2597	Rebuild approximately 1 mi. section of Dragoon-Virgil Street 34.5 kV line between Dragoon and Dodge Tap switch and replace Dodge switch MOAB to increase thermal capability of Dragoon-Dodge Tap branch		AEP (100%)
b2598	Rebuild approximately 1 mile section of the Kline-Virgil Street 34.5 kV line between Kline and Virgil Street tap. Replace MOAB switches at Beiger, risers at Kline, switches and bus at Virgil Street.		AEP (100%)
b2599	Rebuild approximately 0.1 miles of 69 kV line between Albion and Albion tap		AEP (100%)
b2600	Rebuild Fremont – Pound line as 138 kV		AEP (100%)
b2601	Fremont Station Improvements		AEP (100%)
b2601.1	Replace MOAB towards Beaver Creek with 138 kV breaker		AEP (100%)
b2601.2	Replace MOAB towards Clinch River with 138 kV breaker		AEP (100%)
b2601.3	Replace 138 kV Breaker A with new bus-tie breaker		AEP (100%)
b2601.4	Re-use Breaker A as high side protection on transformer #1		AEP (100%)
b2601.5	Install two (2) circuit switchers on high side of transformers # 2 and 3 at Fremont Station		AEP (100%)

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)
b2602.1	Install 138 kV breaker E2 at North Proctorville		AEP (100%)
b2602.2	Construct 2.5 Miles of 138 kV 1033 ACSR from East Huntington to Darrah 138 kV substations		AEP (100%)
b2602.3	Install breaker on new line exit at Darrah towards East Huntington		AEP (100%)
b2602.4	Install 138 kV breaker on new line at East Huntington towards Darrah		AEP (100%)
b2602.5	Install 138 kV breaker at East Huntington towards North Proctorville		AEP (100%)
b2603	Boone Area Improvements		AEP (100%)
b2603.1	Purchase approximately a 200X300 station site near Slaughter Creek 46 kV station (Wilbur Station)		AEP (100%)
b2603.2	Install 3 138 kV circuit breakers, Cabin Creek to Hernshaw 138 kV circuit		AEP (100%)
b2603.3	Construct 1 mi. of double circuit 138 kV line on Wilbur – Boone 46 kV line with 1590 ACSS 54/19 conductor @ 482 Degree design temp. and 1-159 12/7 ACSR and one 86 Sq.MM. 0.646” OPGW Static wires		AEP (100%)
b2604	Bellefonte Transformer Addition		AEP (100%)

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)
b2605	Rebuild and reconductor Kammer – George Washington 69 kV circuit and George Washington – Moundsville ckt #1, designed for 138kV. Upgrade limiting equipment at remote ends and at tap stations		AEP (100%)
b2606	Convert Bane – Hammondsville from 23 kV to 69 kV operation		AEP (100%)
b2607	Pine Gap Relay Limit Increase		AEP (100%)
b2608	Richlands Relay Upgrade		AEP (100%)
b2609	Thorofare – Goff Run – Powell Mountain 138 kV Build		AEP (100%)
b2610	Rebuild Pax Branch – Scaraboro as 138 kV		AEP (100%)
b2611	Skin Fork Area Improvements		AEP (100%)
b2611.1	New 138/46 kV station near Skin Fork and other components		AEP (100%)
b2611.2	Construct 3.2 miles of 1033 ACSR double circuit from new Station to cut into Sundial-Baileysville 138 kV line		AEP (100%)
b2634.1	Replace metering BCT on Tanners Creek CB T2 with a slip over CT with higher thermal rating in order to remove 1193 MVA limit on facility (Miami Fort-Tanners Creek 345 kV line)		AEP (100%)

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)
b2643	Replace the Darrah 138 kV breaker 'L' with 40kA rated breaker		AEP (100%)
b2645	Ohio Central 138 kV Loop		AEP (100%)
b2667	Replace the Muskingum 138 kV bus # 1 and 2		AEP (100%)
b2668	Reconductor Dequine to Meadow Lake 345 kV circuit #1 utilizing dual 954 ACSR 54/7 cardinal conductor		AEP (100%)
b2669	Install a second 345/138 kV transformer at Desoto		AEP (100%)
b2670	Replace switch at Elk Garden 138 kV substation (on the Elk Garden – Lebanon 138 kV circuit)		AEP (100%)
b2671	Replace/upgrade/add terminal equipment at Bradley, Mullensville, Pinnacle Creek, Itmann, and Tams Mountain 138 kV substations. Sag study on Mullens – Wyoming and Mullens – Tams Mt. 138 kV circuits		AEP (100%)

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)

b2687.1	Install a +/- 450 MVAR SVC at Jacksons Ferry 765 kV substation		**Load-Ratio Share Allocation:** AEC (*1.70*%) / AEP (*14.25*%) / APS (*5.53*%) / ATSI (*8.09*%) / BGE (4*4.19*%) / ComEd (*13.43*%) / Dayton (*2.12*%) / DEOK (*3.37*%) / DL (*1.77*%) / Dominion (*12.39*%) / DPL (*2.62*%) / ECP** (0.20%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (*3.78*%) / ME (*1.87*%) / NEPTUNE* (0.*42*%) / PECO (*5.30*%) / PENELEC (1.*84*%) / PEPCO (*4.18*%) / PPL (*4.46*%) / PSEG (*6.22*%) / RE (0.*25*%)
			DFAX Allocation: AEP (100%)

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

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)

b2687.2	Install a 300 MVAR shunt line reactor on the Broadford end of the Broadford – Jacksons Ferry 765 kV line		**Load-Ratio Share Allocation:** AEC (*1.70*%) / AEP (*14.25*%) / APS (*5.53*%) / ATSI (*8.09*%) / BGE (4*4.19*%) / ComEd (*13.43*%) / Dayton (*2.12*%) / DEOK (*3.37*%) / DL (*1.77*%) / Dominion (*12.39*%) / DPL (*2.62*%) / ECP** (0.20%) / EKPC (*1.82*%) / HTP*** (0.20%) / JCPL (*3.78*%) / ME (*1.87*%) / NEPTUNE* (0.*42*%) / PECO (*5.30*%) / PENELEC (1.*84*%) / PEPCO (*4.18*%) / PPL (*4.46*%) / PSEG (*6.22*%) / RE (0.*25*%)
			DFAX Allocation: AEP (100%)
b2697.1	Mitigate violations identified by sag study to operate Fieldale-Thornton-Franklin 138 kV overhead line conductor at its max. operating temperature. 6 potential line crossings to be addressed.		AEP (100%)
b2697.2	Replace terminal equipment at AEP's Danville and East Danville substations to improve thermal capacity of Danville – East Danville 138 kV circuit		AEP (100%)

*Neptune Regional Transmission System, LLC

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

*** Hudson Transmission Partners, LLC

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)
b2698	Replace relays at AEP's Cloverdale and Jackson's Ferry substations to improve the thermal capacity of Cloverdale – Jackson's Ferry 765 kV line		AEP (100%)
b2701.1	Construct Herlan station as breaker and a half configuration with 9-138 kV CB's on 4 strings and with 2-28.8 MVAR capacitor banks		AEP (100%)
b2701.2	Construct new 138 kV line from Herlan station to Blue Racer station. Estimated approx. 3.2 miles of 1234 ACSS/TW Yukon and OPGW		AEP (100%)
2701.3	Install 1-138 kV CB at Blue Racer to terminate new Herlan circuit		AEP (100%)
b2714	Rebuild/upgrade line between Glencoe and Willow Grove Switch 69 kV		AEP (100%)
b2715	Build approximately 11.5 miles of 34.5 kV line with 556.5 ACSR 26/7 Dove conductor on wood poles from Flushing station to Smyrna station		AEP (100%)
b2727	*Replace the South Canton 138 kV breakers 'K', 'J', 'J1', and 'J2' with 80kA breakers*		*AEP (100%)*

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)

b2731	Convert the Sunnyside – East Sparta – Malvern 23 kV sub-transmission network to 69 kV. The lines are already built to 69 kV standards		AEP (100%)
b2733	Replace South Canton 138 kV breakers ‘L’ and ‘L2’ with 80 kA rated breakers		AEP (100%)
b2750.1	*Retire Betsy Layne 138/69/43 kV station and replace it with the greenfield Stanville station about a half mile north of the existing Betsy Layne station*		*AEP (100%)*
b2750.2	*Relocate the Betsy Layne capacitor bank to the Stanville 69 kV bus and increase the size to 14.4 MVAR*		*AEP (100%)*
b2753.1	*Replace existing George Washington station 138 kV yard with GIS 138 kV breaker and a half yard in existing station footprint. Install 138 kV revenue metering for new IPP connection*		*AEP (100%)*
b2753.2	*Replace Dilles Bottom 69/4 kV Distribution station as breaker and a half 138 kV yard design including AEP Distribution facilities but initial configuration will constitute a 3 breaker ring bus*		*AEP (100%)*

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)

b2753.3	*Connect two 138 kV 6-wired circuits from "Point A" (currently de-energized and owned by FirstEnergy) in circuit positions previously designated Burger #1 & Burger #2 138 kV. Install interconnection settlement metering on both circuits exiting Holloway*		*AEP (100%)*
b2753.6	*Build double circuit 138 kV line from Dilles Bottom to "Point A". Tie each new AEP circuit in with a 6-wired line at Point A. This will create a Dilles Bottom – Holloway 138 kV circuit and a George Washington – Holloway 138 kV circuit*		*AEP (100%)*
b2753.7	*Retire line sections (Dilles Bottom – Bellaire and Moundsville – Dilles Bottom 69 kV lines) south of FirstEnergy 138 kV line corridor, near "Point A". Tie George Washington – Moundsville 69 kV circuit to George Washington – West Bellaire 69 kV circuit*		*AEP (100%)*
b2753.8	*Rebuild existing 69 kV line as double circuit from George Washington – Dilles Bottom 138 kV. One circuit will cut into Dilles Bottom 138 kV initially and the other will go past with future plans to cut in*		*AEP (100%)*

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)*

b2760	*Perform a Sag Study of the Saltville – Tazewell 138 kV line to increase the thermal rating of the line*		*AEP (100%)*
b2761.1	*Replace the Hazard 161/138 kV transformer*		*AEP (100%)*
b2761.2	*Perform a Sag Study of the Hazard – Wooten 161 kV line to increase the thermal rating of the line*		*AEP (100%)*
b2762	*Perform a Sag Study of Nagel – West Kingsport 138 kV line to increase the thermal rating of the line*		*AEP (100%)*
b2776	*Reconductor the entire Dequine – Meadow Lake 345 kV circuit #2*		*AEP (100%)*
b2777	*Reconductor the entire Dequine – Eugene 345 kV circuit #1*		*AEP (100%)*
b2779.1	Construct a new 138 kV station, Campbell Road, tapping into the Grabill – South Hicksville138 kV line		AEP (100%)
b2779.2	Reconstruct sections of the Butler-N.Hicksville and Auburn-Butler 69 kV circuits as 138 kV double circuit and extend 138 kV from Campbell Road station		AEP (100%)
b2779.3	Construct a new 345/138 kV SDI Wilmington Station which will be sourced from Collingwood 345 kV and serve the SDI load at 345 kV and 138 kV, respectively		AEP (100%)

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)

b2779.4	Loop 138 kV circuits in-out of the new SDI Wilmington 138 kV station resulting in a direct circuit to Auburn 138 kV and an indirect circuit to Auburn and Rob Park via Dunton Lake, and a circuit to Campbell Road; Reconductor 138 kV line section between Dunton Lake – SDI Wilmington		AEP (100%)
b2779.5	Expand Auburn 138 kV bus		AEP (100%)
b2817	Replace Delaware 138 kV breaker ‘P’ with a 40 kA breaker		AEP (100%)
b2818	Replace West Huntington 138 kV breaker ‘F’ with a 40 kA breaker		AEP (100%)
b2819	Replace Madison 138 kV breaker ‘V’ with a 63 kA breaker		AEP (100%)
b2820	Replace Sterling 138 kV breaker ‘G’ with a 40 kA breaker		AEP (100%)
b2821	Replace Morse 138 kV breakers ‘103’, ‘104’, ‘105’, and ‘106’ with 63 kA breakers		AEP (100%)
b2822	Replace Clinton 138 kV breakers ‘105’ and ‘107’ with 63 kA breakers		AEP (100%)
b2831.1	Upgrade the Tanner Creek – Miami Fort 345 kV circuit (AEP portion)		**DFAX Allocation:** Dayton (34.34%) / DEOK (56.45%) / EKPC (9.21%)
b2832	Six wire the Kyger Creek – Sporn 345 kV circuits #1 and #2 and convert them to one circuit		AEP (100%)

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)
b2833	Reconductor the Maddox Creek – East Lima 345 kV circuit with 2-954 ACSS Cardinal conductor		**DFAX Allocation:** Dayton (100%)
b2834	Reconductor and string open position and sixwire 6.2 miles of the Chemical – Capitol Hill 138 kV circuit		AEP (100%)

Attachment 8

PATH Formula Rate for January 1, 2018 to December 31, 2018

Attachment 8

ALSTON&BIRD LLP

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September 1, 2017

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 2018

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 2018 ("2018 PTRR") to PJM for posting.

The 2018 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 2018 PTRR to the transmission service 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 2018 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.

Attachment H

PATH SUMMARY OF REFUNDS/(SURCHARGES), Regulatory Order No. 554 WITH INTEREST

to be included in 2018 PTRR

	PATH-AYE			
	Over/(Under) Recovery	**Interest [2]**	**Total Refund/(Surcharge)**	
2008	$ 11,613	$ 6,462	$ 18,075	
2009	$ 1,111,955	$ 363,810	$ 1,475,764	
2010	$ 997,603	$ 273,307	$ 1,270,910	
2011	$ 230,779	$ 55,483	$ 286,261	
2012	$ 3,178,853	$ 657,194	$ 3,836,047	
2013	$ 195,196	$ 33,630	$ 228,825	
2014	$ 84,387	$ 11,664	$ 96,051	
2015	$ (8,863)	$ (937)	$ (9,800)	
2016	$ (71,308)	$ (5,409)	$ (76,718)	
	$ 5,730,213	$ 1,395,203	$ 7,125,416	**[3]**
2016TU [1]	$ 336,289	$ 25,511	$ 361,800	**[4]**
	$ 6,066,503	$ 1,420,714	$ 7,487,216	

	PATH-WV			
	Over/(Under) Recovery	**Interest [2]**	**Total Refund/(Surcharge)**	
2008	$ 111,527	$ 62,059	$ 173,586	
2009	$ 2,308,994	$ 755,457	$ 3,064,451	
2010	$ 1,524,450	$ 417,644	$ 1,942,094	
2011	$ 552,488	$ 132,827	$ 685,315	
2012	$ 3,069,482	$ 634,583	$ 3,704,065	
2013	$ 627,004	$ 108,024	$ 735,028	
2014	$ 497,799	$ 68,807	$ 566,606	
2015	$ 396,483	$ 41,916	$ 438,399	
2016	$ 88,814	$ 6,737	$ 95,552	
	$ 9,177,043	$ 2,228,054	$ 11,405,096	**[5]**
2016TU [1]	$ 949,382	$ 72,020	$ 1,021,402	**[6]**
	$ 10,126,424	$ 2,300,074	$ 12,426,498	

Total Refund/(Surcharge), with Interest **19,913,715**

NOTES:

[1] *Over/(Under) Recovery is the variance between the 2016 PTRR and the 2016 ATRR calculated using filed Form No. 1 data.*

[2] *When the PATH 2016 ATRR was filed on June 1, 2017 as noted on attachment H1 titled "PATH Summary of Refunds/(Surcharges), With Interest" footnote [1], the 2016 interest amounts were subject to change based on FERC interest rates available at the time of the 2018 PTRR filing. The FERC Interest Rates for Third Quarter 2017 were updated June 22, 2017, so the interest for PATH's 2016 true-up and for the 2016 over/(under) recovery resulting from FERC Order Opinion No. 554 have been updated.*

[3] Attachment H-19A, page 1, line 5, col 2

[4] Attachment H-19A, page 7, line 3, col 3

[5] Attachment H-19A, page 1, line 5, col 1

[6] Attachment H-19A, page 2, line 3, col 3

For the 12 months ended 12/31/2018

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	-$374,421	(A)	-$77,504	(B)	-$451,925
2	PJM Project No.					
3	b0490 & b0491	-$374,421	(C)			-$374,421
4	b0492 & b0560			-$77,504	(D)	-$77,504
5	Order 554 True-up	-$11,405,096	(E)	-$7,125,416	(E)	-$18,530,512
6	Total (Sum lines 3 to 5)	-$11,779,517		-$7,202,920		-$18,982,437

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)
	(E)	Attachment H - Summary of True-up and Interest Calculations

Formula Rate - Non-Levelized

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2018

PATH West Virginia Transmission Company, LLC

Line No.			(1)	(2)			(3) Allocated Amount
1	GROSS REVENUE REQUIREMENT	(line 86)			12 months	$	646,981
	REVENUE CREDITS		Total	Allocator			
2	Total Revenue Credits	Attachment 1, line 12	0	TP	1.00000	$	-
3	True-up Adjustment with Interest	Protocols	-1,021,402	DA	1.00000	$	(1,021,402)
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)				$	(374,421)

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2018

PATH West Virginia Transmission Company, LLC

Line No.	(1) **RATE BASE:**	(2) **Form No. 1 Page, Line, Col.**	(3) **Company Total**	(4) **Allocator**		(5) **Transmission** (Col 3 times Col 4)
	GROSS PLANT IN SERVICE					
6	Production	(Attachment 4)	-	NA	0.00000	-
7	Transmission	(Attachment 4)	-	TP	1.00000	-
8	Distribution	(Attachment 4)	-	NA	0.00000	-
9	General & Intangible	(Attachment 4)	-	W/S	1.00000	-
10	Common	(Attachment 4)	-	CE	1.00000	-
11	TOTAL GROSS PLANT (sum lines 6-10)	(GP=1 if plant =0)	-	GP=	1.00000	-
12	ACCUMULATED DEPRECIATION					
13	Production	(Attachment 4)	-	NA	0.00000	-
14	Transmission	(Attachment 4)	-	TP	1.00000	-
15	Distribution	(Attachment 4)	-	NA	0.00000	-
16	General & Intangible	(Attachment 4)	-	W/S	1.00000	-
17	Common	(Attachment 4)	-	CE	1.00000	-
18	TOTAL ACCUM. DEPRECIATION (sum lines 13-17)		-			-
19	NET PLANT IN SERVICE					
20	Production	(line 6- line 13)	-			-
21	Transmission	(line 7- line 14)	-			-
22	Distribution	(line 8- line 15)	-			-
23	General & Intangible	(line 9- line 16)	-			-
24	Common	(line 10- line 17)	-			-
25	TOTAL NET PLANT (sum lines 20-24)	(NP=1 if plant =0)	-	NP=	1.0000	-
26	ADJUSTMENTS TO RATE BASE (Note A)					
27	Account No. 281 (enter negative)	(Attachment 4)	-	NA	0.00000	-
28	Account No. 282 (enter negative)	(Attachment 4)	(364)	NP	1.00000	(364)
29	Account No. 283 (enter negative)	(Attachment 4)	(932,776)	NP	1.00000	(932,776)
30	Account No. 190	(Attachment 4)	2,697,610	NP	1.00000	2,697,610
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)	-	DA	1.00000	-
35	TOTAL ADJUSTMENTS (sum lines 27-34)		1,764,470			1,764,470
36	LAND HELD FOR FUTURE USE	(Attachment 4)	-	TP	1.00000	-
37	WORKING CAPITAL (Note C)					
38	CWC	calculated	60,294			60,294
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)		60,294			60,294
42	RATE BASE (sum lines 25, 35, 36, & 41)		1,824,763			1,824,763

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2018

PATH West Virginia Transmission Company, LLC

	(1)	(2)	(3)	(4)		(5)
		Form No. 1 Page, Line, Col.	**Company Total**	**Allocator**		**Transmission** (Col 3 times Col 4)
43	O&M					
44	Transmission	321.112.b	-	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	464,488	W/S	1.00000	464,488
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)	17,861			17,861
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)		482,349			482,349
58	DEPRECIATION EXPENSE					
59	Transmission	336.7.b & c	-	TP	1.00000	-
60	General and Intangible	336.1.d&e + 336.10.b&c	-	W/S	1.00000	-
61	Common	336.11.b&c	-	CE	1.00000	-
62	Amortization of Abandoned Plant	(Attachment 4)	-	DA	1.00000	-
63	TOTAL DEPRECIATION (Sum lines 59-62)		-			-
64	TAXES OTHER THAN INCOME TAXES (Note E)					
65	LABOR RELATED					
66	Payroll	263i	-	W/S	1.00000	-
67	Highway and vehicle	263i	-	W/S	1.00000	-
68	PLANT RELATED					
69	Property	263i	-	GP	1.00000	-
70	Gross Receipts	263i	-	NA	0.00000	-
71	Other	263i	-	GP	1.00000	-
72	Payments in lieu of taxes		-	GP	1.00000	-
73	TOTAL OTHER TAXES (sum lines 66-72)		-			-
74	INCOME TAXES	(Note F)				
75	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		39.23%			
76	CIT=(T/1-T) * (1-(WCLTD/R)) =		40.86%			
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		47,757	NA		47,757
82	ITC adjustment (line 79 * line 80)		0	NP	1.00000	-
83	Total Income Taxes	(line 81 plus line 82)	47,757			47,757
84	RETURN					
85	[Rate Base (line 42) * Rate of Return (line 121)]		116,876	NA		116,876
86	REV. REQUIREMENT (sum lines 57, 63, 73, 83, 85)		646,981			646,981

Formula Rate - Non-Levelized

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2018

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%	4.70%	0.0235	=WCLTD
119	Preferred Stock	(Attachment 4)	0	0%	0.00%	0.0000	
120	Common Stock (Note J)	(Attachment 4)	0	50%	8.11%	0.0406	
121	Total (sum lines 118-120)		0			0.0641	=R

SUPPORTING CALCULATIONS AND NOTES

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2018

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	Effective Janaury 19, 2017, the ROE will be 8.11%. The true up for Rate Year 2017 will be computed using an ROE that is a time-weighted average of the pre-January 19, 2017 ROE and the post-January 19, 2017 ROE. Examaple Calculation: For the first 18 days of 2017, the authorized ROE will be 10.4%, and for the remaining 347 days of 2017, the authorized ROE will be 8.11%. Therefore, the weighted ROE = (18 days* 10.40% + 347 days*8.11%)/365 days=8.22%.
K	The percentage shown for Long Term Debt is subject to the Annual Update and Attachment 9. Pursuant to the Stipulation Agreement entered into on April 6, 2015 in FERC Docket Nos. ER09-1256-002 and ER12-2708-003, the Long Term Debt rate is 4.70% effective December 1, 2012.

Formula Rate - Non-Levelized

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2018

PATH Allegheny Transmission Company, LLC

Line No.			(1)	(2)		(3) Allocated Amount
1	GROSS REVENUE REQUIREMENT	(line 86)		12 months		$ 284,296
	REVENUE CREDITS		Total	Allocator		
2	Total Revenue Credits	Attachment 1, line 12	0	TP	1.00000	-
3	True-up Adjustment with Interest	Protocols	-361,800	DA	1.00000	$ (361,800)
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)				$ (77,504)

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2018

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)	1,543,220	NP	1.00000	1,543,220
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)	-	DA	1.00000	-
35	TOTAL ADJUSTMENTS (sum lines 27-34)		1,543,220			1,543,220
36	LAND HELD FOR FUTURE USE	(Attachment 4)	-	TP	1.00000	-
37	WORKING CAPITAL (Note C)					
38	CWC	calculated	18,503			18,503
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)		18,503			18,503
42	RATE BASE (sum lines 25, 35, 36, & 41)		1,561,723			1,561,723

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2018

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	91,643	TE	1.00000	91,643
45	Less Account 565	321.96.b	-	TE	1.00000	-
46	Less Account 566	Line 56	91,643	DA	1.00000	91,643
47	A&G	323.197.b	56,384	W/S	1.00000	56,384
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	91,643	DA	1.00000	91,643
56	Total Account 566		91,643			91,643
57	TOTAL O&M (sum lines 44, 47, 49, 50, 51, 52, 56 less lines 45,46, 48)		148,027			148,027
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)	-	DA	1.00000	-
63	TOTAL DEPRECIATION (Sum lines 59-62)		-			-
64	TAXES OTHER THAN INCOME TAXES (Note E)					
65	LABOR RELATED					
66	Payroll	263i	-	W/S	1.00000	-
67	Highway and vehicle	263i	-	W/S	1.00000	-
68	PLANT RELATED					
69	Property	263i	-	GP	1.00000	-
70	Gross Receipts	263i	-	NA	0.00000	-
71	Other	263i	-	GP	1.00000	-
72	Payments in lieu of taxes		-	GP	1.00000	-
73	TOTAL OTHER TAXES (sum lines 66-72)		-			-
74	INCOME TAXES	(Note F)				
75	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		36.40%			
76	CIT=(T/1-T) * (1-(WCLTD/R)) =		36.23%			
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)		1.5723			
80	Amortized Investment Tax Credit	(266.8f) (enter negative)	0			
81	Income Tax Calculation = line 76 * line 85		36,240	NA		36,240
82	ITC adjustment (line 79 * line 80)		0	NP	1.00000	-
83	Total Income Taxes	(line 81 plus line 82)	36,240			36,240
84	RETURN					
85	[Rate Base (line 42) * Rate of Return (line 121)]		100,028	NA		100,028
86	REV. REQUIREMENT (sum lines 57, 63, 73, 83, 85)		284,296			284,296

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

For the 12 months ended 12/31/2018

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)						91,643		
96	Less transmission expenses included in OATT Ancillary Services (Note G)						0		
97	Included transmission expenses (line 95 less line 96)						91,643		
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%	4.70%		0.0235	=WCLTD	
119	Preferred Stock	(Attachment 4)	0	0%	0.00%		0.0000		
120	Common Stock (Note J)	(Attachment 4)	0	50%	8.11%		0.0406		
121	Total (sum lines 118-120)		0				0.0641	=R	

SUPPORTING CALCULATIONS AND NOTES

Formula Rate - Non-Levelized

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2018

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=	2.15%	(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	Effective Janaury 19, 2017, the ROE will be 8.11%. The true up for Rate Year 2017 will be computed using an ROE that is a time-weighted average of the pre-January 19, 2017 ROE and the post-January 19, 2017 ROE. Examaple Calculation: For the first 18 days of 2017, the authorized ROE will be 10.4%, and for the remaining 347 days of 2017, the authorized ROE will be 8.11%. Therefore, the weighted ROE = (18 days* 10.40% + 347 days*8.11%)/365 days=8.22%.
K	The percentage shown for Long Term Debt is subject to the Annual Update and Attachment 9. Pursuant to the Stipulation Agreement entered into on April 6, 2015 in FERC Docket Nos. ER09-1256-002 and ER12-2708-003, the Long Term Debt rate is 4.70% effective December 1, 2012.

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 2 has been removed and intentionally left blank.

Attachment 2 has been removed and intentionally left blank.

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	2017	-
3	January	company records	2018	-
4	February	company records	2018	-
5	March	company records	2018	-
6	April	company records	2018	-
7	May	company records	2018	-
8	June	company records	2018	-
9	July	company records	2018	-
10	August	company records	2018	-
11	September	company records	2018	-
12	October	company records	2018	-
13	November	company records	2018	-
14	December	p207.58.g	2018	-
15	**Transmission Plant In Service**	(sum lines 2-14) /13		-
16	**Calculation of Distribution Plant In Service**	Source		
17	December	p206.75.b	2017	-
18	January	company records	2018	-
19	February	company records	2018	-
20	March	company records	2018	-
21	April	company records	2018	-
22	May	company records	2018	-
23	June	company records	2018	-
24	July	company records	2018	-
25	August	company records	2018	-
26	September	company records	2018	-
27	October	company records	2018	-
28	November	company records	2018	-
29	December	p207.75.g	2018	-
30	**Distribution Plant In Service**	(sum lines 17-29) /13		-
31	**Calculation of Intangible Plant In Service**	Source		
32	December	p204.5.b	2017	-
33	December	p205.5.g	2018	-
34	**Intangible Plant In Service**	(sum lines 32 & 33) /2		-
35	**Calculation of General Plant In Service**	Source		
36	December	p206.99.b	2017	-
37	December	p207.99.g	2018	-
38	**General Plant In Service**	(sum lines 36 & 37) /2		-
39	**Calculation of Production Plant In Service**	Source		
40	December	p204.46b	2017	-
41	January	company records	2018	-
42	February	company records	2018	-
43	March	company records	2018	-
44	April	company records	2018	-
45	May	company records	2018	-
46	March	Attachment 6	2018	-
47	April	company records	2018	-
48	August	company records	2018	-
49	September	company records	2018	-
50	October	company records	2018	-
51	November	company records	2018	-
52	December	p205.46.g	2018	-
53	**Production Plant In Service**	(sum lines 40-52) /13		-

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

		Source	Year	Balance
54	**Calculation of Common Plant In Service**	Source	Year	Balance
55	December (Electric Portion)	p356	2017	-
56	December (Electric Portion)	p356	2018	-
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	2017	-	
61	January	company records	2018	-	
62	February	company records	2018	-	
63	March	company records	2018	-	
64	April	company records	2018	-	
65	May	company records	2018	-	
66	June	company records	2018	-	
67	July	company records	2018	-	
68	August	company records	2018	-	
69	September	company records	2018	-	
70	October	company records	2018	-	
71	November	company records	2018	-	
72	December	p219.25	2018	-	
73	**Transmission Accumulated Depreciation**	(sum lines 60-72) /13		-	
74	**Calculation of Distribution Accumulated Depreciation**	Source			
75	December	Prior year p219.26	2017	-	
76	January	company records	2018	-	
77	February	company records	2018	-	
78	March	company records	2018	-	
79	April	company records	2018	-	
80	May	company records	2018	-	
81	June	company records	2018	-	
82	July	company records	2018	-	
83	August	company records	2018	-	
84	September	company records	2018	-	
85	October	company records	2018	-	
86	November	company records	2018	-	
87	December	p219.26	2018	-	
88	**Distribution Accumulated Depreciation**	(sum lines 75-87) /13		-	
89	**Calculation of Intangible Accumulated Depreciation**	Source			
90	December	Prior year p200.21.c	2017	-	
91	December	p200.21c	2018	-	
92	**Accumulated Intangible Depreciation**	(sum lines 90 & 91) /2		-	
93	**Calculation of General Accumulated Depreciation**	Source			
94	December	Prior year p219.28	2017	-	
95	December	p219.28	2018	-	
96	**Accumulated General Depreciation**	(sum lines 94 & 95) /2		-	

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

97	**Calculation of Production Accumulated Depreciation**	Source	Year	Balance
98	December	Prior year p219	2017	-
99	January	company records	2018	-
100	February	company records	2018	-
101	March	company records	2018	-
102	April	company records	2018	-
103	May	company records	2018	-
104	June	company records	2018	-
105	July	company records	2018	-
106	August	company records	2018	-
107	September	company records	2018	-
108	October	company records	2018	-
109	November	company records	2018	-
110	December	p219.20 thru 219.24	2018	-
111	**Production Accumulated Depreciation**	(sum lines 98-110) /13		-
112	**Calculation of Common Accumulated Depreciation**	Source		
113	December (Electric Portion)	p356	2017	-
114	December (Electric Portion)	p356	2018	-
115	**Common Plant Accumulated Depreciation (Electric Only)**	(sum lines 113 & 114) /2		-
116	**Total Accumulated Depreciation**	(sum lines 73, 88, 92, 96, 111, & 115)		-

ADJUSTMENTS TO RATE BASE (Note A)

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions					**Details**
			Beginning of Year	End of Year	Average Balance	
117	Account No. 281 (enter negative)	273.8.k	-	-	0	
118	Account No. 282 (enter negative)	275.2.k	(364)	(364)	-364	
119	Account No. 283 (enter negative)	277.9.k	(524,403)	(1,341,149)	-932,776	
120	Account No. 190	234.8.c	4,753,609	641,610	2,697,610	
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)	0				-
125	January	company records		-		-	-
126	February	company records		-		-	-
127	March	company records		-		-	-
128	April	company records		-		-	-
129	May	company records		-		-	-
130	June	company records		-		-	-
131	July	company records		-		-	-
132	August	company records		-		-	-
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			$0.00	-	$0.00
					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	-	-	-

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

139	**Calculation of Transmission CWIP**	Source				Amos Substation Upgrade	Amos to Welton Spring Line	Welton Spring Substation and SVC	Welton Spring to Interconnection with PATH Allegheny	Total
140	December	216.b	2017	$	-	-	-	-	-	-
141	January	company records	2018		-	-	-	-	-	-
142	February	company records	2018		-	-	-	-	-	-
143	March	company records	2018		-	-	-	-	-	-
144	April	company records	2018		-	-	-	-	-	-
145	May	company records	2018		-	-	-	-	-	-
146	June	company records	2018		-	-	-	-	-	-
147	July	company records	2018		-	-	-	-	-	-
148	August	company records	2018		-	-	-	-	-	-
149	September	company records	2018		-	-	-	-	-	-
150	October	company records	2018		-	-	-	-	-	-
151	November	company records	2018		-	-	-	-	-	-
152	December	216.b	2018		-	-	-	-	-	-
153	**Transmission CWIP**	(sum lines 140-152) /13			-	-	-	-	-	-

LAND HELD FOR FUTURE USE

				Beg of year	End of Year	Average	Details
	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions						
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

			Form 1 Amount	Transmission Related	Non-transmission Related	Details
	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions					
	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

170	Monthly Balances for Capital Structure				
171		Year	Debt	Preferred Stock	Common Stock
172	January	2018	0	-	0
173	February	2018	-	-	-
174	March	2018	-	-	-
175	April	2018	-	-	-
176	May	2018	-	-	-
177	June	2018	-	-	-
178	July	2018	-	-	-
179	August	2018	-	-	-
180	September	2018	-	-	-
181	October	2018	-	-	-
182	November	2018	-	-	-
183	December	2018	-	-	-
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		134,865	
196	PATH WV PBOP Expense for current year		$13,728	
197	PATH WV PBOP Expense in Account 926 for current year		-$4,133	
198	PBOP Adjustment for Appendix A, Line 50		$17,861	
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)	$17,861	

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	2017	-
3	January	company records	2018	-
4	February	company records	2018	-
5	March	company records	2018	-
6	April	company records	2018	-
7	May	company records	2018	-
8	June	company records	2018	-
9	July	company records	2018	-
10	August	company records	2018	-
11	September	company records	2018	-
12	October	company records	2018	-
13	November	company records	2018	-
14	December	p207.58.g	2018	-
15	**Transmission Plant In Service**	(sum lines 2-14) /13		-
16	**Calculation of Distribution Plant In Service**	Source		
17	December	p206.75.b	2017	-
18	January	company records	2018	-
19	February	company records	2018	-
20	March	company records	2018	-
21	April	company records	2018	-
22	May	company records	2018	-
23	June	company records	2018	-
24	July	company records	2018	-
25	August	company records	2018	-
26	September	company records	2018	-
27	October	company records	2018	-
28	November	company records	2018	-
29	December	p207.75.g	2018	-
30	**Distribution Plant In Service**	(sum lines 17-29) /13		-
31	**Calculation of Intangible Plant In Service**	Source		
32	December	p204.5b	2017	-
33	December	p205.5.g	2018	-
34	**Intangible Plant In Service**	(sum lines 32 & 33) /2		-
35	**Calculation of General Plant In Service**	Source		
36	December	p206.99.b	2017	-
37	December	p207.99.g	2018	-
38	**General Plant In Service**	(sum lines 36 & 37) /2		-
39	**Calculation of Production Plant In Service**	Source		
40	December	p204.46b	2017	-
41	January	company records	2018	-
42	February	company records	2018	-
43	March	company records	2018	-
44	April	company records	2018	-
45	May	company records	2018	-
46	March	Attachment 6	2018	-
47	April	company records	2018	-
48	August	company records	2018	-
49	September	company records	2018	-
50	October	company records	2018	-
51	November	company records	2018	-
52	December	p205.46.g	2018	-
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	2017	-
56	December (Electric Portion)	p356	2018	-
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	2017	-	
61	January	company records	2018	-	
62	February	company records	2018	-	
63	March	company records	2018	-	
64	April	company records	2018	-	
65	May	company records	2018	-	
66	June	company records	2018	-	
67	July	company records	2018	-	
68	August	company records	2018	-	
69	September	company records	2018	-	
70	October	company records	2018	-	
71	November	company records	2018	-	
72	December	p219.25	2018	-	
73	**Transmission Accumulated Depreciation**	(sum lines 60-72) /13		-	
74	**Calculation of Distribution Accumulated Depreciation**	Source			
75	December	Prior year p219.26	2017	-	
76	January	company records	2018	-	
77	February	company records	2018	-	
78	March	company records	2018	-	
79	April	company records	2018	-	
80	May	company records	2018	-	
81	June	company records	2018	-	
82	July	company records	2018	-	
83	August	company records	2018	-	
84	September	company records	2018	-	
85	October	company records	2018	-	
86	November	company records	2018	-	
87	December	p219.26	2018	-	
88	**Distribution Accumulated Depreciation**	(sum lines 75-87) /13		-	
89	**Calculation of Intangible Accumulated Depreciation**	Source			
90	December	Prior year p200.21.c	2017	-	
91	December	p200.21c	2018	-	
92	**Accumulated Intangible Depreciation**	(sum lines 90 & 91) /2		-	
93	**Calculation of General Accumulated Depreciation**	Source			
94	December	Prior year p219.28	2017	-	
95	December	p219.28	2018	-	
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	2017	-
99	January	company records	2018	-
100	February	company records	2018	-
101	March	company records	2018	-
102	April	company records	2018	-
103	May	company records	2018	-
104	June	company records	2018	-
105	July	company records	2018	-
106	August	company records	2018	-
107	September	company records	2018	-
108	October	company records	2018	-
109	November	company records	2018	-
110	December	p219.20 thru 219.24	2018	-
111	**Production Accumulated Depreciation**	(sum lines 98-110) /13		-
112	**Calculation of Common Accumulated Depreciation**	Source		
113	December (Electric Portion)	p356	2017	-
114	December (Electric Portion)	p356	2018	-
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	-	-	-
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	2,789,295	297,145	1,543,220
121	Account No. 255 (enter negative)	267.8.h	-	-	-

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)	0				
125	January	company records		-	-	-	-
126	February	company records		-	-	-	-
127	March	company records		-	-	-	-
128	April	company records		-	-	-	-
129	May	company records		-	-	-	-
130	June	company records		-	-	-	-
131	July	company records		-	-	-	-
132	August	company records		-	-	-	-
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			$0.00	-	$0.00
					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	-	-	-

Attachment 4 - Cost Support
PATH Allegheny Transmission Company, LLC

							Kemptown to Interconnection with PATH West Virginia		
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	2017	$	-				
141	January	company records	2018		-				
142	February	company records	2018		-				
143	March	company records	2018		-				
144	April	company records	2018		-				
145	May	company records	2018		-				
146	June	company records	2018		-				
147	July	company records	2018		-				
148	August	company records	2018		-				
149	September	company records	2018		-				
150	October	company records	2018		-				
151	November	company records	2018		-				
152	December	216.b	2018		-				
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 Allocated General & Common Expenses	EPRI Dues	Common Expenses	EPRI Dues	Common Expenses	Details
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%			2.150%

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

		Year	Debt	Preferred Stock	Common Stock
170	Monthly Balances for Capital Structure				
171		Year	Debt	Preferred Stock	Common Stock
172	January	2018	0	-	0
173	February	2018	-	-	-
174	March	2018	-	-	-
175	April	2018	-	-	-
176	May	2018	-	-	-
177	June	2018	-	-	-
178	July	2018	-	-	-
179	August	2018	-	-	-
180	September	2018	-	-	-
181	October	2018	-	-	-
182	November	2018	-	-	-
183	December	2018	-	-	-
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		91,643
187	Total Account 566	Footnote Data: Schedule Page 320 b. 97	91,643

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	(374,421)
4	21	NET TRANSMISSION PLANT IN SERVICE	-
5	32	CWIP	-
6	34	Unamortized Abandoned Plant	-
7		**Carrying charge (line 3/sum of lines 4, 5 and 6)**	**-**

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		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	
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	-	-	-	-	-	**-**
		Revenue Requirement		-	-	-	-	-	-	**(374,421)**

Attachment 5 - Transmission Enhancement Charge Worksheet

PATH Allegheny Transmission Company, LLC

1 New Plant Carrying Charge

	Formula Line	Item	
2	Formula Line	Item	
3	5	NET REVENUE REQUIREMENT	(77,504)
4	21	NET TRANSMISSION PLANT IN SERVICE	-
5	32	CWIP	-
6	34	Unamortized Abandoned Plant	-
7		**Carrying charge (line 3/sum of lines 4, 5and 6)**	**-**

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		0.0%	0.0%	0.0%	0.0%	0.0%	
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		-	-	-	-	-	-
		Revenue Requirement		-	-	-	-	-	**(77,504.21)**

Attachment 6 has been removed and intentionally left blank.

Attachment 6 has been removed and intentionally left blank.

Attachment 7

PATH West Virginia Transmission Company, LLC

Potomac-Appalachian Transmission Highline, LLC

CALCULATION OF COST OF DEBT AFTER CONSTRUCTION PHASE

YEAR ENDED **12/31/2014**

(HYPOTHETICAL EXAMPLE)

	Amount Outstanding	Unamortized Debt Issue Expense	Unamortized Debt Premium/ (Discount)	Unamortized Losses on Reacquired Debt	Net Amount Outstanding	Effective Cost Rate[1]	Annualized Cost
Debt:							
First Mortgage Bonds:							
	$ 300,000,000	$2,900,000	($2,320,000)	$0	$294,780,000	#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 2016 Available June 1, 2017		2016 Revenue Requirement Forecast by Sept 1, 2015		True-up Adjustment - Over (Under) Recovery
$13,422,695	-	$14,372,077	=	$949,382

		Over (Under) Recovery Plus Interest	Average Monthly Interest Rate	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
Interest Rate on Amount of Refunds or Surcharges from 35.19a			0.2960%				
An over or under collection will be recovered prorata over 2016, held for 2017 and returned prorate over 2018							
Calculation of Interest					**Monthly**		
January	Year 2016	79,115	0.2960%	12	(2,810)		(81,925)
February	Year 2016	79,115	0.2960%	11	(2,576)		(81,691)
March	Year 2016	79,115	0.2960%	10	(2,342)		(81,457)
April	Year 2016	79,115	0.2960%	9	(2,108)		(81,223)
May	Year 2016	79,115	0.2960%	8	(1,873)		(80,989)
June	Year 2016	79,115	0.2960%	7	(1,639)		(80,754)
July	Year 2016	79,115	0.2960%	6	(1,405)		(80,520)
August	Year 2016	79,115	0.2960%	5	(1,171)		(80,286)
September	Year 2016	79,115	0.2960%	4	(937)		(80,052)
October	Year 2016	79,115	0.2960%	3	(703)		(79,818)
November	Year 2016	79,115	0.2960%	2	(468)		(79,584)
December	Year 2016	79,115	0.2960%	1	(234)		(79,349)
					(18,266)		**(967,648)**
					Annual		
January through December	Year 2017	(967,648)	0.2960%	12	(34,371)		**(1,002,019)**
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
January	Year 2018	**1,002,019**	0.2960%		(2,966)	85,117	(919,868)
February	Year 2018	919,868	0.2960%		(2,723)	85,117	(837,474)
March	Year 2018	837,474	0.2960%		(2,479)	85,117	(754,836)
April	Year 2018	754,836	0.2960%		(2,234)	85,117	(671,954)
May	Year 2018	671,954	0.2960%		(1,989)	85,117	(588,826)
June	Year 2018	588,826	0.2960%		(1,743)	85,117	(505,452)
July	Year 2018	505,452	0.2960%		(1,496)	85,117	(421,831)
August	Year 2018	421,831	0.2960%		(1,249)	85,117	(337,963)
September	Year 2018	337,963	0.2960%		(1,000)	85,117	(253,846)
October	Year 2018	253,846	0.2960%		(751)	85,117	(169,481)
November	Year 2018	169,481	0.2960%		(502)	85,117	(84,866)
December	Year 2018	84,866	0.2960%		(251)	85,117	0
					(19,383)		

True-Up Adjustment with Interest*	(1,021,402)
Less Over (Under) Recovery	949,382
Total Interest	(72,020)

*This amount plus Account 190 correction relating to a federal NOL carryforward (see Workpaper 1) corresponds to PATH-WV Attachment A, Line 3

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

Reconciliation Revenue Requirement For Year 2016 Available June 1, 2017		2016 Revenue Requirement Forecast by Sept 1, 2015		True-up Adjustment - Over (Under) Recovery
$13,934,152	-	$14,270,441	=	$336,289

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			0.2960%				
An over or under collection will be recovered prorata over 2014, held for 20145and returned prorate over 2016							
Calculation of Interest					**Monthly**		
January	Year 2015	28,024	0.2960%	12	(995)		(29,019)
February	Year 2015	28,024	0.2960%	11	(912)		(28,937)
March	Year 2015	28,024	0.2960%	10	(830)		(28,854)
April	Year 2015	28,024	0.2960%	9	(747)		(28,771)
May	Year 2015	28,024	0.2960%	8	(664)		(28,688)
June	Year 2015	28,024	0.2960%	7	(581)		(28,605)
July	Year 2015	28,024	0.2960%	6	(498)		(28,522)
August	Year 2015	28,024	0.2960%	5	(415)		(28,439)
September	Year 2015	28,024	0.2960%	4	(332)		(28,356)
October	Year 2015	28,024	0.2960%	3	(249)		(28,273)
November	Year 2015	28,024	0.2960%	2	(166)		(28,190)
December	Year 2015	28,024	0.2960%	1	(83)		(28,107)
					(6,470)		**(342,759)**
					Annual		
January through December	Year 2016	(342,759)	0.2960%	12	(12,175)		**(354,934)**
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
January	Year 2017	**354,934**	0.2960%		(1,051)	30,150	(325,835)
February	Year 2017	325,835	0.2960%		(964)	30,150	(296,649)
March	Year 2017	296,649	0.2960%		(878)	30,150	(267,377)
April	Year 2017	267,377	0.2960%		(791)	30,150	(238,019)
May	Year 2017	238,019	0.2960%		(705)	30,150	(208,573)
June	Year 2017	208,573	0.2960%		(617)	30,150	(179,041)
July	Year 2017	179,041	0.2960%		(530)	30,150	(149,421)
August	Year 2017	149,421	0.2960%		(442)	30,150	(119,713)
September	Year 2017	119,713	0.2960%		(354)	30,150	(89,917)
October	Year 2017	89,917	0.2960%		(266)	30,150	(60,033)
November	Year 2017	60,033	0.2960%		(178)	30,150	(30,061)
December	Year 2017	30,061	0.2960%		(89)	30,150	0
					(6,866)		

True-Up Adjustment with Interest	$	(361,800)
Less Over (Under) Recovery	$	336,289
Total Interest	$	(25,511)

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

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.d&e)	-		

INTANGIBLE PLANT		**Accrual Rate (Annual) Percent**	**Annual Depreciation Expense**
303	Miscellaneous Intangible Plant	20.00	-
Total Intangible Plant			-
Total Intangible Plant Amortization (must tie to p336.1 d & e)	-		

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

Attachment 9
AEP Formula Rate for January 1, 2018 to December 31, 2018

Attachment 9

Projected Formula Rate for AEP East subsidiaries in PJM

To be Effective January 1, 2018 through December 31, 2018
Docket No ER17-405

Pursuant to PJM OATT Attachment H-14A (Formula Rate Implementation Protocols), AEP has calculated its Projected Transmission Revenue Requirements (PTRR) for the Rate Year beginning January 1, 2018 through December 31, 2018. All the files pertaining to the PTRR are to be posted on the PJM website in PDF format. The first file provides the PTRR and rates for Network transmission service and Scheduling System Control and Dispatch Service (Schedule 1A), and the annual transmission revenue requirement for RTEP projects (Schedule 12). An informational filing will also be submitted to the FERC.

AEP network service rate will increase effective January 1, 2018 from $36,366.48 per MW per year to $41,276.13 per MW per year with the AEP annual revenue requirement increasing from $817,362,162 to $894,041,051.

The AEP Schedule 1A rate decreased from $.1000 per MWh to $.0906 per MWh.

An annual revenue requirement of $47,509,853 for RTEP projects (including true-up and interest) is to be collected under PJM Tariff Schedule 12. The RTEP Projected revenue requirement includes:

1. b0839 (Twin Branch) $1,061,773
2. b0318 (Amos 765/138 kV Transformer) $1,844,977
3. b0504 (Hanging Rock) $939,995
4. b0570 (East Side Lima) $210,943
5. b1034.1 (Torrey-West Canton) $1,310,073
6. b1034.6 (138kV circuit South Canton Station) $452,651
7. b1231 (West Moulton Station) $1,241,923
8. b1465.2 (Rockport Jefferson 300 MVAR bank) $88,868
9. b1465.3 (Rockport Jefferson 765 kV line) $2,981,701
10. b1712.2 (Altavista-Leesville 138kV line) $663,077
11. b1864.1 (OPCo Kammer 345/138 kV transformers) $(72,890)
12. b1864.2 (West Bellaire-Brues 138 kV circuit) of $223,002
13. b2020 (Rebuild Amos-Kanawha River) $2,995,968
14. b2021 (APCo Kanawha River Gen Retirement Upgrades) $390,406
15. b2017 (APCo Rebuild Sporn-Waterford Muskingum River 345kV line) $2,019,107
16. b1659.14 (Ft. Wayne Relocate) $(100,185)
17. b2048 (Tanners Creek-Transformer Replacement) $113,634
18. b1818 (Expand the Allen Station) $1,536,982
19. b1819 (Rebuild Robinson Park 138kV line corridor) $565,261
20. b1465.4 (Switching imp at Sullivan Jefferson 765kV station) $27,352
21. b2021 (OPCo 345/138kV Transformer) $954,402
22. b2032 (Rebuild 138kV Elliott Tap-Poston) $25,317
23. b1034.2 (Loop South Canton-Wayview) $737,021

Projected Formula Rate for AEP East subsidiaries in PJM

To be Effective January 1, 2018 through December 31, 2018
Docket No ER17-405

24.	b1034.7	(Replace circuit breakers Torrey/Wagenhals) $877,975
25.	b1970	(Reconductor Kammer-West Bellaire) $164,042
26.	b2018	(Loop Conesville-Bixby 345kV) $2,816,835
27.	b1032.4	(Loop the existing South Canton-Wayview 138kV circuit) $260,669
28.	b1666	(Build an 8 breaker 138kV station Fosteria-East Lima) $665,312
29.	b1957	(Terminate transformer #2 SW Lima) $478,588
30.	b1962	(Add four 765kV breakers Kammer) $(34,095)
31.	b2019	(Burger 345/138kV Station) $1,606,229
32.	b2017	(OPCo Reconductor Sporn-Waterford-Muskingum River) $1,446,671
33.	b1032.3	(Convert Ross-Circleville 138kV) $(503,136)
34.	b1660	(Install 765/500 kV transformer Cloverdale) $(2,621,574)
35.	b1660.1	(Cloverdale Establish 500 kV station) $(1,736,972)
36.	b1663.2	(Jacksons-Ferry 765kV breakers) $1,245,257
37.	b1875	(138 kV Bradley to McClung upgrades) $125,263
38.	b1797.1	(Reconductor Cloverdale-Lexington 500 kV line) $11,200,620
39.	b1712.1	(Altavista-Leesville 138kV line) $77,576
40.	b1032.2	(Two 138kV outlets to Delano&Camp) $10,648
41.	b1818	(Expand Allen w/345/138kV xfmr) $102,456
42.	b2687.1	(Install a 450 MVAR SVC Jacksons Ferry 765kV Substation) $9,725,135
43.	b2687.2	(Install 300MVAR shunt line reactor) $1,387,434
44.	b1870	(Replace Ohio Central Tfmr) $3,561

Projected Formula Rate for

AEP Appalachian Transmission Company, Inc.
AEP Indiana Michigan Transmission Company, Inc.
AEP Kentucky Transmission Company, Inc.
AEP Ohio Transmission Company, Inc.
AEP West Virginia Transmission Company, Inc.

To be Effective January 1, 2018
Docket No ER17-405

Pursuant to Attachment H-20A (Formula Rate Implementation Protocols) in PJM Tariff, AEP has calculated its Projected Transmission Revenue Requirements (PTRR) to produce the Rates beginning January 1, 2018 through December 31, 2018. All the files pertaining to the PTRR are also posted on the PJM website in PDF format along with supporting workpapers. The first file provides the PTRR and rates for Network transmission service and Scheduling System Control and Dispatch Service, Schedule 1A.

AEP network service rate will increase effective January 1, 2018 from $20,624.88 per MW per year to $28,877.87 per MW per year with the AEP annual revenue requirement increasing from $463,558,513 to $625,494,728.

The AEP Transmission Companies' Schedule 1A rates are not applicable because they are handled via AEP Operating Companies.

An annual revenue requirement of $188,413,987 for RTEP projects (including true-up and interest) is to be collected under PJM Tariff Schedule 12. The RTEP Project revenue requirement includes:

1. b1465.4 (Rockport Jefferson) of $2,588,124
2. b1465.2 (Rockport Jefferson-MVAR Bank) $1,876,820
3. b2048 (Tanners Creek 345/138 kV transformer) $726,504
4. b1818 (Expand the Allen station) $7,993,707
5. b1819 (Rebuild Robinson Park) $19,281,585
6. b1659 (Sorenson Add 765/345 kV transformer) $7,781,244
7. b1659.13 (Sorenson Exp. Work 765kV) $9,894,917
8. b1659.14 (Sorenson 14miles 765 line) $12,158,992
9. b1465.1 (Add a 3rd 2250 MVA 765/345kV transformer Sullivan) $4,244,665
10. b0570 (Lima-Sterling) $2,162,116
11. b1231 (Wapakoneta-West Moulton) $648,245
12. b1034.1 (South Canton-Wagenhals-Wayview 138 kV) $1,633,243
13. b1034.8 (South Canton Wagenhals Station) $841,676
14. b1864.2 (West Bellaire-Brues 138 kV Circuit) $209,957
15. b1870 (Ohio Central Transformer) $1,338,903
16. b1032.2 (Two 138kV outlets to Delano/Camp Sherman) $3,924,922

Projected Formula Rate for

AEP Appalachian Transmission Company, Inc.
AEP Indiana Michigan Transmission Company, Inc.
AEP Kentucky Transmission Company, Inc.
AEP Ohio Transmission Company, Inc.
AEP West Virginia Transmission Company, Inc.

To be Effective January 1, 2018
Docket No ER17-405

17. b1034.2 (Loop existing South Canton-Wayview 138kV) $1,352,378
18. b1034.3 (345/138kV 450 MVA transformer Canton Central) $2,706,888
19. b1970 (Reconductor Kammer-West Bellaire) $2,681,664
20. b2018 (Loop Conesville-Bixby 345 kV) $2,690,585
21. b2021 (OHTCo - Add 345/138kV trans. Sporn, Kanawha & Muskingum River stations) $4,239,935
22. b2032 (Rebuild 138kV Elliott Tap Poston line) $751,910
23. b1032.1 (Construct new 345/138kV station Marquis-Bixby) $6,312,206
24. b1032.4 (Install 138/69kV transformer Ross Highland) $1,366,145
25. b1666 (Build 8 breaker 138kV station Fostoria-East Lima) $825,143
26. b1819 (Rebuild Robinson Park 345kV double circuit) $(2,157,606)
27. b1957 (Terminate Transformer #2 SW Lima) $1,671,867
28. b2019 (Establish Burger 345/138kV station) $10,437,781
29. b2017 (OHTCo Rebuild Sporn-Waterford-Muskingum River) $10,385,505
30. b1818 (Allen Station Expansion) $783,910
31. b1661 (765kV circuit breaker Wyoming station) $554,795
32. b1864.1 (Add 2 345/138kV transformers at Kammer) $10,686,726
33. b2021 (WVTCo - Add 345/138kV trans. Sporn, Kanawha & Muskingum River stations) $2,472,455
34. b1948 (New 765/345 interconnection Sporn) $7,082,819
35. b1962 (Add four 765kV breakers Kammer) $2,879,361
36. b2017 (WVTCo Rebuild Sporn-Waterford-Muskingum River) $167,156
37. b2020 (Rebuild Amos-Kanawha River 138 kV corridor) $28,967,516
38. b2022 (Tristate-Kyger Creek 345kV line at Sporn) $650,079
39. b1875 (138 kV Bradley to McClung upgrades) $563,191
40. b2230 (Replace 3 765kV reactors Amos-Hanging Rock) $2,976,875
41. b2423 (Install 300 MVAR shunt reactor Wyoming 765kV station) $2,477,088
42. b1495 (Add 765/345 kV transf. Baker Station) $7,581,997

Attachment 10

VEPCo Formula Rate for January 1, 2018 to December 31, 2018

Attachment 10

VIRGINA ELECTRIC AND POWER COMPANY

2018 ATRR with True-Up Adjustment

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

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

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

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

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

Regarding item (i) above, the information ("2018 Projection") is provided in the form of an Excel file posted along with this document on www.pjm.com.

Regarding item (ii) above, VEPCO has estimated the Network Service Peak Load of the Dominion Zone that will be used by the Transmission Provider to determine each Network Customer's Zone Network Load pursuant to Section 34.1 and Attachment H-16 for the next calendar year. The estimate value is included in the Excel file provided pursuant to item (i) above, in the Appendix A tab at line number (*not* Excel row number) 169.

Regarding item (iii) above, there were no Material Accounting Changes during the twelve months ending August 31, 2017. Interested Parties may review VEPCO's Form 10-Q and Form

10-K filings, which are consolidated with the Dominion Energy, Inc.[1] and Dominion Energy Gas Holding, LLC[2] filings, at https://dominionenergy.com/investors/sec-filings-and-reports.

In Docket No. ER17-479-000, Dominion Energy filed certain changes to the Formula Rate to accommodate the recovery of any acquisition adjustments on purchased transmission facilities approved by the Federal Energy Regulatory Commission ("FERC" or the "Commission"). The Commission approved those changes in a delegated letter order on January 25, 2017 to be effective February 1, 2017. These changes are used in the 2018 projection as provided in the Excel file.

In Docket No. ER17-714-000, Dominion Energy filed with the Commission changes to the Formula Rate to implement a simplified process related to the Accumulated Deferred Income Taxes ("ADIT") rate base component of the Formula Rate. The Commission accepted these changes on February 28, 2017, to be effective January 1, 2017. In Docket No. ER17-714-001, Dominion Energy submitted a compliance filing to correct certain tariff record issues described in the Commission's February 28, 2017 delegated letter order in Docket No. ER17-714-000. These changes became effective on February 1, 2017 and are used in the 2018 projection as provided in the Excel file.

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[1] Formerly Known As Dominion Resources, Inc.

[2] Formerly Known As Dominion Gas Holdings, LLC.

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)		2018 (000's)
	Allocators				
	Wages & Salary Allocation Factor				
1	Transmission Wages Expense		p354.21b/ Attachment 5	$	43,403
2	Less Generator Step-ups		Attachment 5		15
3	Net Transmission Wage Expenses		(Line 1 - 2)		43,388
4	Total Wages Expense		p354.28b/Attachment 5		660,520
5	Less A&G Wages Expense		p354.27b/Attachment 5		94,087
6	Total		(Line 4 - 5)	$	566,433
7	**Wages & Salary Allocator**	(Note B)	(Line 3 / 6)		**7.6599%**
	Plant Allocation Factors				
8	Electric Plant in Service	(Notes A& Q)	p207.104.g/Attachment 5	$	39,306,478
9	Common Plant In Service - Electric		(Line 26)		0
10	Total Plant In Service		(Sum Lines 8 & 9)		39,306,478
11	Accumulated Depreciation (Total Electric Plant)	(Notes A & Q)	(Line 15 - 14 - 13 -12)		13,894,190
12	Accumulated Intangible Amortization	(Notes A & Q)	p200.21c/Attachment 5		120,807
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		14,014,996
16	Net Plant		(Line 10 - 15)		25,291,482
17	Transmission Gross Plant		(Line 31 - 30)		8,301,407
18	**Gross Plant Allocator**	(Note B)	(Line 17 / 10)		**21.1197%**
19	Transmission Net Plant		(Line 44 - 30)	$	6,831,975
20	**Net Plant Allocator**	(Note B)	(Line 19 / 16)		**27.0129%**
	Plant Calculations				
	Plant In Service				
21	Transmission Plant In Service	(Notes A & Q)	p207.58.g/Attachment 5	$	8,734,216
22	Less: Generator Step-ups	(Notes A & Q)	Attachment 5		343,975
23	Less: Interconnect Facilities Installed After March 15, 2000	(Notes A & Q)	Attachment 5		169,985
24	**Total Transmission Plant In Service**		(Lines 21 - 22 - 23)		**8,220,256**
25	General & Intangible	(Notes A & Q)	p205.5.g + p207.99.g/Attachment 5		1,059,419
26	Common Plant (Electric Only)		p356/Attachment 5		0
27	Total General & Common		(Line 25 + 26)		1,059,419
28	Wage & Salary Allocation Factor		(Line 7)		7.6599%
29	**General & Common Plant Allocated to Transmission**		(Line 27 * 28)	**$**	**81,150**
30	**Plant Held for Future Use (Including Land)**	(Notes C & Q)	p214.47.d/Attachment 5	**$**	**3,729**
31	**TOTAL Plant In Service**		**(Line 24 + 29 + 30)**	**$**	**8,305,135**
	Accumulated Depreciation				
32	Transmission Accumulated Depreciation	(Notes A & Q)	p219.25.c/Attachment 5	$	1,543,134
33	Less Accumulated Depreciation for Generator Step-ups	(Notes A & Q)	Attachment 5		91,888
34	Less Accumulated Depreciation for Interconnect Facilities Installed After March 15, 2000	(Notes A & Q)	Attachment 5		18,540
35	Total Accumulated Depreciation for Transmission		(Line 32 - 33 - 34)		1,432,706
36	Accumulated General Depreciation	(Notes A & Q)	p219.28.b/Attachment 5		358,651
37	Accumulated Intangible Amortization	(Notes A & Q)	(Line 12)		120,807
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)		479,458
41	Wage & Salary Allocation Factor		(Line 7)		7.6599%
42	**General & Common Allocated to Transmission**		(Line 40 * 41)		**36,726**
43	**TOTAL Accumulated Depreciation**		**(Line 35 + 42)**	**$**	**1,469,431**
44	**TOTAL Net Property, Plant & Equipment**		**(Line 31 - 43)**	**$**	**6,835,704**

Virginia Electric and Power Company
ATTACHMENT H-16A

Formula Rate -- Appendix A

		Notes	FERC Form 1 Page # or Instruction (Note H)		2018
Adjustment To Rate Base					
	Accumulated Deferred Income Taxes				
45	Average Balance	(Note U)	Attachment 1	$	(1,492,680)
45A	Accumulated Deferred Income Taxes Attributable To Acquisition Adjustments		Attachment 5	$	(139)
46	**Accumulated Deferred Income Taxes Allocated To Transmission**		(Line 45 + 45A)	**$**	**(1,492,819)**
	Transmission O&M Reserves				
47	**Total Balance Transmission Related Account 242 Reserves**	Enter Negative	Attachment 5	**$**	**(13,580)**
	Unamortized Excess/Deficient Deferred Income Taxes				
47A	**Unamortized Exc/Def Deferral**		Attachment 5	**$**	**(2,432)**
	Prepayments				
48	Prepayments	(Notes A & R)	Attachment 5	$	1,783
49	**Total Prepayments Allocated to Transmission**		(Line 48)	**$**	**1,783**
	Materials and Supplies				
50	Undistributed Stores Exp	(Notes A & R)	p227.6c & 16.c	$	-
51	Wage & Salary Allocation Factor		(Line 7)		7.6599%
52	Total Transmission Allocated Materials and Supplies		(Line 50 * 51)		0
53	Transmission Materials & Supplies		p227.8c/2		28,236
54	**Total Materials & Supplies Allocated to Transmission**		(Line 52 + 53)	**$**	**28,236**
	Cash Working Capital				
55	Transmission Operation & Maintenance Expense		(Line 85)	$	119,361
56	1/8th Rule		x 1/8		12.5%
57	**Total Cash Working Capital Allocated to Transmission**		(Line 55 * 56)	**$**	**14,920**
	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**
	Electric Plant Acquisition Adjustments Approved by FERC				
60A	Acquisition Adjustments Amount		Attachment 5	$	8,616
60B	Acummulated Provision for Amortization of Line 60A Amount		Attachment 5		188
60C	Transmission Plant Unamortized Acquisition Adjustments Amount		(Line 60A - 60B)	**$**	**8,428**
61	**TOTAL Adjustment to Rate Base**		(Line 46 + 47 + 47A + 49 + 54 + 57 - 60 + 60C)	**$**	**(1,455,463)**
62	**Rate Base**		(Line 44 + 61)	**$**	**5,380,240**
O&M					
	Transmission O&M				
63	Transmission O&M		p321.112.b/Attachment 5	$	27,047
64	Less GSU Maintenance		Attachment 5		19
65	Less Account 565 - Transmission by Others		p321.96.b/Attachment 5		(66,218)
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)	**$**	**93,246**
	Allocated General & Common Expenses				
68	Common Plant O&M	(Note A)	p356		0
69	Total A&G		Attachment 5		352,433
70	Less Property Insurance Account 924		p323.185b		10,880
71	Less Regulatory Commission Exp Account 928	(Note E)	p323.189b/Attachment 5		33,689
72	Less General Advertising Exp Account 930.1		p323.911b/Attachment 5		5,287
73	Less EPRI Dues	(Note D)	p352-353/Attachment 5		3,515
74	**General & Common Expenses**		(Lines 68 + 69) - Sum (70 to 73)	$	299,062
75	Wage & Salary Allocation Factor		(Line 7)		7.6599%
76	**General & Common Expenses Allocated to Transmission**		(Line 74 * 75)	**$**	**22,908**
	Directly Assigned A&G				
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b/Attachment 5	$	268
78	General Advertising Exp Account 930.1	(Note K)	p323.191b		0
79	Subtotal - Transmission Related		(Line 77 + 78)		**268**
80	Property Insurance Account 924		p323.185b		10,880
81	General Advertising Exp Account 930.1	(Note F)	Attachment 5		0
82	Total		(Line 80 + 81)		10,880
83	Net Plant Allocation Factor		(Line 20)		27.0129%
84	**A&G Directly Assigned to Transmission**		(Line 82 * 83)	**$**	**2,939**
85	**Total Transmission O&M**		**(Line 67 + 76 + 79 + 84)**	**$**	**119,361**

Virginia Electric and Power Company
ATTACHMENT H-16A

Formula Rate -- Appendix A

			Notes	FERC Form 1 Page # or Instruction (Note H)		2018
Depreciation & Amortization Expense						
	Depreciation Expense					
86	Transmission Depreciation Expense		(Notes A and S)	p336.7b&c/Attachment 5	**$**	**201,908**
87	Less: GSU Depreciation			Attachment 5		**9,947**
88	Less Interconnect Facilities Depreciation			Attachment 5		**4,916**
89	Extraordinary Property Loss			Attachment 5		**0**
90	Total Transmission Depreciation			(Line 86 - 87 - 88 + 89)		**187,044**
90A	Amortization of Acquisition Adjustments			Attachment 5		**205**
91	General Depreciation		(Note A)	p336.10b&c&d/Attachment 5		27,215
92	Intangible Amortization		(Note A)	p336.1d&e/Attachment 5		31,962
93	Total			(Line 91 + 92)		**59,177**
94	Wage & Salary Allocation Factor			(Line 7)		7.6599%
95	**General and Intangible Depreciation Allocated to Transmission**			(Line 93 * 94)		**4,533**
96	Common Depreciation - Electric Only		(Note A)	p336.11.b		0
97	Common Amortization - Electric Only		(Note A)	p356 or p336.11d		0
98	Total			(Line 96 + 97)		0
99	Wage & Salary Allocation Factor			(Line 7)		7.6599%
100	**Common Depreciation - Electric Only Allocated to Transmission**			(Line 98 * 99)		**0**
101	**Total Transmission Depreciation & Amortization**			**(Line 90 + 90A + 95 + 100)**	**$**	**191,782**
Taxes Other than Income						
102	**Taxes Other than Income**			Attachment 2	**$**	**56,799**
103	**Total Taxes Other than Income**			**(Line 102)**	**$**	**56,799**
Return / Capitalization Calculations						
	Long Term Interest					
104	Long Term Interest		(Note T)	p117.62c through 67c/Attachment 5	$	464,165
105	Less LTD Interest on Securitization Bonds		(Note P)	Attachment 8		0
106	**Long Term Interest**			(Line 104 - 105)	$	464,165
107	**Preferred Dividends**		(Note T), enter positive	p118.29c	$	-
	Common Stock					
108	Proprietary Capital			p112.16c,d/2	$	11,252,327
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	$	(43,101)
111	**Common Stock**			(Sum Lines 108 to 110)	$	11,209,226
	Capitalization					
112	Long Term Debt			p112.24c,d/2	$	10,009,839
113	Less Loss on Reacquired Debt		(Note T), enter negative	p111.81c,d/2	$	(3,366)
114	Plus Gain on Reacquired Debt		(Note T), enter positive	p113.61c,d/2	$	3,475
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)		10,009,948
117	Preferred Stock		(Note T), enter positive	p112.3c,d/2		0
118	Common Stock			(Line 111)		11,209,226
119	**Total Capitalization**			(Sum Lines 116 to 118)	$	21,219,174
120	Debt %	Total Long Term Debt		(Line 116 / 119)		47.2%
121	Preferred %	Preferred Stock		(Line 117 / 119)		0.0%
122	Common %	Common Stock		(Line 118 / 119)		52.8%
123	Debt Cost	Total Long Term Debt		(Line 106 / 116)		0.0464
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)		0.0219
127	Weighted Cost of Preferred	Preferred Stock		(Line 121 * 124)		0.0000
128	Weighted Cost of Common	Common Stock		(Line 122 * 125)		0.0602
129	**Total Return (R)**			(Sum Lines 126 to 128)		**0.0821**
130	**Investment Return = Rate Base * Rate of Return**			**(Line 62 * 129)**		**441,698**

Virginia Electric and Power Company
ATTACHMENT H-16A

Formula Rate -- Appendix A

		Notes	FERC Form 1 Page # or Instruction (Note H)		2018
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		5.91%
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)} =			38.84%
135	T/ (1-T)				63.51%
	Transmission Related Income Tax Adjustments				
136	Amortized Investment Tax Credit (ITC)	(Note I) enter negative	Attachment 1	$	-
136A	Other Income Tax Adjustments		Attachment 5	$	1,611
137	T/(1-T)		(Line 135)		63.51%
138	**Transmission Income Taxes - Income Tax Adjustments**		((Line 136 + 136A) * (1 + Line 137))	**$**	**2,634**
139	**Transmission Income Taxes - Equity Return =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =	[Line 135 * 130 * (1-(126 / 129))]		**205,770**
140	**Total Transmission Income Taxes**		**(Line 138 + 139)**		**208,404**
REVENUE REQUIREMENT					
	Summary				
141	Net Property, Plant & Equipment		(Line 44)	$	6,835,704
142	Adjustment to Rate Base		(Line 61)		(1,455,463)
143	**Rate Base**		(Line 62)	**$**	**5,380,240**
144	O&M		(Line 85)		119,361
145	Depreciation & Amortization		(Line 101)		191,782
146	Taxes Other than Income		(Line 103)		56,799
147	Investment Return		(Line 130)		441,698
148	Income Taxes		(Line 140)		208,404
149					
150	**Revenue Requirement**		**(Sum Lines 144 to 149)**	**$**	**1,018,044**
	Acquisition Adjustments Revenue Requirement				
150A	Acquisition Adjustments Return		Line 129 * (60C + 45A)	$	681
150B	Acquisition Adjustments Income Taxes		[Line 135 * 150A * (1- (126 / 129))]		317
150C	Amortization of Acquisition Adjustments		(Line 90A)		205
150D	**Acquisition Adjustments Revenue Requirement**		(Line 150A + 150B + 150C)	**$**	**1,202**
	Net Plant Carrying Charge				
151	Revenue Requirement excluding Acquisition Adjustments Revenue Requirement		(Line 150 - 150D)	**$**	**1,016,842**
152	Net Transmission Plant		(Line 24 - 35)		**6,787,551**
153	Net Plant Carrying Charge without Acquisition Adjustments		(Line 151 / 152)		**14.9810%**
154	Net Plant Carrying Charge without Acquisition Adjustments and Depreciation		(Line 151 - 86) / 152		**12.0063%**
155	Net Plant Carrying Charge without Acquisition Adjustments, Depreciation, Return or Income Taxes		(Line 150 - 86 - 90A - 130 - 140) / 152		**2.4431%**
	Net Plant Carrying Charge Calculation with 100 Basis Point increase in ROE				
156	Gross Revenue Requirement Less Return, Income Taxes, and Amortization of Acquisition Adjustments		(Line 150 - 147 - 148 - 90A)	**$**	**367,737**
157	Increased Return and Taxes		Attachment 4		**695,505**
158	Net Revenue Requirement excluding Acquisition Adjustments Rev. Req. with 100 Basis Point increase in ROE		(Line 156 + 157)		**1,063,242**
159	Net Transmission Plant		(Line 152)		**6,787,551**
160	Net Plant Carrying Charge with 100 Basis Point increase in ROE without Acquisition Adjustments		(Line 158 / 159)		**15.6646%**
161	Net Plant Carrying Charge with 100 Basis Point increase in ROE without Acquisition Adjustments and Depreciation		(Line 158 - 86) / 159		**12.6899%**
162	**Revenue Requirement**		(Line 150)	**$**	**1,018,044**
163	True-up Adjustment		Attachment 6		**23,467**
164	Plus any increased ROE calculated on Attachment 7 other than PJM Schedule 12 projects.		Attachment 7		**-**
165	Facility Credits under Section 30.9 of the PJM OATT.		Attachment 5		**3,184**
166	Revenue Credits		Attachment 3		**(12,101)**
167	Interest on Network Credits		PJM data		0
168	**Annual Transmission Revenue Requirement (ATRR)**		(Line 162 + 163 +164 + 165 + 166 + 167)	**$**	**1,032,594**
	Rate for Network Integration Transmission Service				
169	1 CP Peak	(Note L)	PJM Data		**19,661.4**
170	Rate ($/MW-Year)		(Line 168 / 169)		**52,518.83**
171	**Rate for Network Integration Transmission Service ($/MW/Year)**		**(Line 170)**		**52,518.83**

Virginia Electric and Power Company
ATTACHMENT H-16A

FERC Form 1 Page # or

Formula Rate -- Appendix A **Notes** **Instruction (Note H)** **2018**

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.

U ADIT amounts included on Line 45A are not to be included on Line 45 or in the underlying attachments in which the Line 45 amount is computed.

Virginia Electric and Power Company

Attachment 1 - Accumulated Deferred Income Tax (ADIT) Worksheet - December 31 of the Current Year

(In Thousands)

Current Year: **2018**

Wage and Salary Allocator from Line 7 of Appendix A for the Current Year	7.6599%
Gross Plant Allocator from Line 18 of Appendix A for the Current Year	21.1197%

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
						Transmission		
Line		Account 190	Account 282	Account 283	Total	Allocation / Assignment Method	Allocation / Assignment %	Transmission Total
	ADIT - Liberalized Depreciation (Amounts Including Adjustments)							
1	Liberalized Depreciation - Transmission		$ (1,490,553)		(1,490,553)	Assigned	100.0000%	(1,490,553)
2	Liberalized Depreciation - General Plant		$ (68,073)		(68,073)	Wages & Salaries	7.6599%	(5,214)
3	Liberalized Depreciation - Computer Software (Reverse Book Depreciation)		$ 42,614		42,614	Wages & Salaries	7.6599%	3,264
4	Liberalized Depreciation - Computer Software (Tax Depreciation)		$ (62,066)		(62,066)	Wages & Salaries	7.6599%	(4,754)
5	**Total Liberalized Depreciation Amounts including Adjustments (Sum of Lines 1 - 4)**	$ -	$ (1,578,079)		$ (1,578,079)			$ (1,497,257)
	ADIT - Plant Related Other than Liberalized Depreciation							
6	Transmission Plant (net of GSU/GI Proportion)	81,830	(216,200)	-	(134,370)	Assigned	100.0000%	(134,370)
7	General Plant	8,252	(28,997)	-	(20,745)	Wages & Salaries	7.6599%	(1,589)
8	Plant - Other	292,259	(25,932)	(360)	265,967	Gross Plant	21.1197%	56,171
9	**Total Plant Related Other than Liberalized Depreciation (Sum of Lines 6 - 8)**	$ 382,342	$ (271,129)	$ (360)	$ 110,852			$ (79,788)
	ADIT - Not Plant Related							
10	Employee Benefits	196,489	-	(67,688)	128,801	Wages & Salaries	7.6599%	9,866
11	Other Operating	11,994	-	(603)	11,391	Wages & Salaries	7.6599%	873
12	**Total Not Plant Related (Sum of Lines 10 - 11)**	$ 208,483	$ -	$ (68,291)	$ 140,192			$ 10,739
13	**Total ADIT used for Assignment or Allocation to Transmission (Sum of Lines 5, 9 & 12)**	**$ 590,824**	**$ (1,849,208)**	**$ (68,652)**	**$ (1,327,035)**			**$ (1,566,306)**
	Reconciliation to FERC Form 1 Accounts:							
14	Liberalized Depreciation not Allocated or Assigned to Transmission	-	(4,148,943)					
15	Total Amount of Excluded ADIT in Line 5 due to Adjustments	-	34,699					
16	Excluded Amounts (see Explanations below)	1,942,743	(188,850)	(1,379,846)				
17	**Total ADIT Not Used for Assignment or Allocation to Transmission (Sum of Lines 14-16)**	1,942,743	(4,303,093)	(1,379,846)				
18	**Total FERC Form 1 Balance (Sum of Lines 13 & 17)**	$ 2,533,567	$ (6,152,301)	$ (1,448,498)				

Explanations:

A detailed set of work papers supporting these inputs shall be included with the work papers posted on the PJM website and included in the informational filing with the Commission.

Lines 1-4 inputs are from Attachment 1B if the inputs are for a projected rate calculation or from Attachment 1C if the inputs are for a true-up calculation.

Lines 6-8, 10-11 and 14 inputs are totals for each category by account obtained from work papers maintained by the Tax Department.

Line 15 represents the impact of proration and the removal of ADIT associated with generator step-up transformers as determined on Attachment 1B or 1C, as applicable. It is the mathematical difference between the inputs for Lines 1-4 and the unadjusted amounts provided in the applicable Attachment 1B or 1C.

Line 16 inputs are excluded ADIT items (not otherwise listed in Lines 14 and 15) from the Formula Rate such as ADIT associated with the production and distribution functions, non-operating income and deductions, and other comprehensive income entries or unfunded ADIT balances primarily due to the adoption of SFAS No. 109.

Virginia Electric and Power Company

Attachment 1 -- Continued

(In Thousands)

Line

ADIT Summary and Calculation of Average Balance

Line	Description	Balance Date	Amount
19	Transmission Total ADIT from Attachment 1, Line 13	December 31 of the Current Year	$ (1,566,306)
20	Transmission Total ADIT from Attachment 1A, Line 13 (Note 1)	December 31 of the Previous Year	$ (1,419,053)
21	Average Balance for Entry on Line 45 of Appendix A		$ (1,492,680)

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

Line	Item	Amortization
22	Amortization of Transmission Related for Entry on Line 136 of Appendix A	
23	Amortization, Other	$ -
24	Current Year Amortization (Line 22 + 23)	$ -
25	Current Year Amortization from Form 1 (Current Year Items from p266.8f-g)	
26	Difference (Line 24 - 25) (Must be Zero)	$ -

Note (1): For the true-up of 2017 only, the value entered on Line 20 shall be the December 31, 2016 ADIT balance from the 2016 true-up population of the formula rate in effect on December 31, 2016.

Virginia Electric and Power Company

Attachment 1A - Accumulated Deferred Income Tax (ADIT) Worksheet - December 31 of the Previous Year

(In Thousands)

Previous Year: 2017

For the true-up of 2017, this Attachment 1A shall not be populated. The December 31, 2016 ADIT balance used in Attachment 1 of the 2017 true-up population shall be the December 31, 2016 ADIT balance from the 2016 true-up population of the formula rate in effect on December 31, 2016.

Wage and Salary Allocator from Line 7 of Appendix A for the Previous Year	6.7538%
Gross Plant Allocator from Line 18 of Appendix A for the Previous Year	20.2526%

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
						Transmission		
Line		Account 190	Account 282	Account 283	Total	Allocation / Assignment Method	Allocation / Assignment %	Transmission Total
	ADIT - Liberalized Depreciation (Amounts Including Adjustments)							
1	Liberalized Depreciation - Transmission		$ (1,348,863)		(1,348,863)	Assigned	100.0000%	(1,348,863)
2	Liberalized Depreciation - General Plant		$ (66,366)		(66,366)	Wages & Salaries	6.7538%	(4,482)
3	Liberalized Depreciation - Computer Software (Reverse Book Depreciation)		$ 37,521		37,521	Wages & Salaries	6.7538%	2,534
4	Liberalized Depreciation - Computer Software (Tax Depreciation)		$ (60,055)		(60,055)	Wages & Salaries	6.7538%	(4,056)
5	**Total Liberalized Depreciation Amounts including Adjustments (Sum of Lines 1 - 4)**	$ -	$ (1,437,763)		$ (1,437,763)			$ (1,354,867)
	ADIT - Plant Related Other than Liberalized Depreciation							
6	Transmission Plant (net of GSU/GI Proportion)	90,082	(216,200)	-	(126,118)	Assigned	100.0000%	(126,118)
7	General Plant	8,252	(28,997)	-	(20,745)	Wages & Salaries	6.7538%	(1,401)
8	Plant - Other	292,259	(25,932)	(360)	265,967	Gross Plant	20.2526%	53,865
9	**Total Plant Related Other than Liberalized Depreciation (Sum of Lines 6 - 8)**	$ 390,593	$ (271,129)	$ (360)	$ 119,104			$ (73,654)
	ADIT - Not Plant Related							
10	Employee Benefits	196,489	-	(67,688)	128,801	Wages & Salaries	6.7538%	8,699
11	Other Operating	11,994	-	(603)	11,391	Wages & Salaries	6.7538%	769
12	**Total Not Plant Related (Sum of Lines 10 - 11)**	$ 208,483	$ -	$ (68,291)	$ 140,192			$ 9,468
13	**Total ADIT used for Assignment or Allocation to Transmission (Sum of Lines 5, 9 & 12)**	**$ 599,076**	**$ (1,708,892)**	**$ (68,652)**	**$ (1,178,468)**			**$ (1,419,053)**
	Reconciliation to FERC Form 1 Accounts:							
14	Liberalized Depreciation not Allocated or Assigned to Transmission		(4,148,943)					
15	Total Amount of Excluded ADIT in Line 5 due to Adjustments		(105,617)					
16	Excluded Amounts (see Explanations below)	1,943,259	(188,850)	(1,379,846)				
17	**Total ADIT Not Used for Assignment or Allocation to Transmission (Sum of Lines 14-16)**	1,943,259	(4,443,409)	(1,379,846)				
18	**Total FERC Form 1 Balance (Sum of Lines 13 & 17)**	$ 2,542,335	$ (6,152,301)	$ (1,448,498)				

Explanations:

A detailed set of work papers supporting these inputs shall be included with the work papers posted on the PJM website and included in the informational filing with the Commission.

Lines 1-4 inputs are from Attachment 1B if the inputs are for a projected rate calculation or from Attachment 1C if the inputs are for a true-up calculation.

Lines 6-8, 10-11 and 14 inputs are totals for each category by account obtained from work papers maintained by the Tax Department.

Line 15 represents the impact of proration and the removal of ADIT associated with generator step-up transformers as determined on Attachment 1B or 1C, as applicable. It is the mathematical difference between the inputs for Lines 1-4 and the unadjusted amounts provided in the applicable Attachment 1B or 1C.

Line 16 inputs are excluded ADIT items (not otherwise listed in Lines 14 and 15) from the Formula Rate such as ADIT associated with the production and distribution functions, non-operating income and deductions, and other comprehensive income entries or unfunded ADIT balances primarily due to the adoption of SFAS No. 109.

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: 2018
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	2017	Dec	(1,497,431,879)					(1,497,431,879)
4	2018	Jan	(1,512,959,375)	(15,527,496)	335	0.917808	(14,251,263)	(1,511,683,142)
5	2018	Feb	(1,528,486,871)	(15,527,496)	307	0.841096	(13,060,113)	(1,524,743,255)
6	2018	Mar	(1,544,014,367)	(15,527,496)	276	0.756164	(11,741,339)	(1,536,484,594)
7	2018	Apr	(1,559,541,863)	(15,527,496)	246	0.673973	(10,465,107)	(1,546,949,701)
8	2018	May	(1,575,069,359)	(15,527,496)	215	0.589041	(9,146,333)	(1,556,096,034)
9	2018	Jun	(1,590,596,855)	(15,527,496)	185	0.506849	(7,870,101)	(1,563,966,135)
10	2018	Jul	(1,606,124,351)	(15,527,496)	154	0.421918	(6,551,327)	(1,570,517,462)
11	2018	Aug	(1,621,651,847)	(15,527,496)	123	0.336986	(5,232,553)	(1,575,750,015)
12	2018	Sep	(1,637,179,343)	(15,527,496)	93	0.254795	(3,956,321)	(1,579,706,336)
13	2018	Oct	(1,652,706,838)	(15,527,496)	62	0.169863	(2,637,547)	(1,582,343,883)
14	2018	Nov	(1,668,234,334)	(15,527,496)	32	0.087671	(1,361,315)	(1,583,705,198)
15	2018	Dec	(1,683,761,830)	(15,527,496)	1	0.002740	(42,541)	(1,583,747,739)

16 Total Transmission Plant In Service Net of GSU and GI Plant as a Percentage of Total Transmission Plant In Service: 94.12%

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: (1,409,316,364)

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: (1,490,553,017)

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)
2018
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	2017	Dec	(68,073,278)					(68,073,278)
2	2018	Jan	(68,073,278)	0	335	0.917808	0	(68,073,278)
3	2018	Feb	(68,073,278)	0	307	0.841096	0	(68,073,278)
4	2018	Mar	(68,073,278)	0	276	0.756164	0	(68,073,278)
5	2018	Apr	(68,073,278)	0	246	0.673973	0	(68,073,278)
6	2018	May	(68,073,278)	0	215	0.589041	0	(68,073,278)
7	2018	Jun	(68,073,278)	0	185	0.506849	0	(68,073,278)
8	2018	Jul	(68,073,278)	0	154	0.421918	0	(68,073,278)
9	2018	Aug	(68,073,278)	0	123	0.336986	0	(68,073,278)
10	2018	Sep	(68,073,278)	0	93	0.254795	0	(68,073,278)
11	2018	Oct	(68,073,278)	0	62	0.169863	0	(68,073,278)
12	2018	Nov	(68,073,278)	0	32	0.087671	0	(68,073,278)
13	2018	Dec	(68,073,278)	0	1	0.002740	0	(68,073,278)
14	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:							(68,073,278)
15	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:							(68,073,278)

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)
2018
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	2017	Dec	42,613,728					42,613,728
2	2018	Jan	42,613,728	0	335	0.917808	0	42,613,728
3	2018	Feb	42,613,728	0	307	0.841096	0	42,613,728
4	2018	Mar	42,613,728	0	276	0.756164	0	42,613,728
5	2018	Apr	42,613,728	0	246	0.673973	0	42,613,728
6	2018	May	42,613,728	0	215	0.589041	0	42,613,728
7	2018	Jun	42,613,728	0	185	0.506849	0	42,613,728
8	2018	Jul	42,613,728	0	154	0.421918	0	42,613,728
9	2018	Aug	42,613,728	0	123	0.336986	0	42,613,728
10	2018	Sep	42,613,728	0	93	0.254795	0	42,613,728
11	2018	Oct	42,613,728	0	62	0.169863	0	42,613,728
12	2018	Nov	42,613,728	0	32	0.087671	0	42,613,728
13	2018	Dec	42,613,728	0	1	0.002740	0	42,613,728

14 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: 42,613,728

15 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: 42,613,728

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	2017	Dec	(62,066,443)					(62,066,443)
2	2018	Jan	(62,066,443)	0	335	0.917808	0	(62,066,443)
3	2018	Feb	(62,066,443)	0	307	0.841096	0	(62,066,443)
4	2018	Mar	(62,066,443)	0	276	0.756164	0	(62,066,443)
5	2018	Apr	(62,066,443)	0	246	0.673973	0	(62,066,443)
6	2018	May	(62,066,443)	0	215	0.589041	0	(62,066,443)
7	2018	Jun	(62,066,443)	0	185	0.506849	0	(62,066,443)
8	2018	Jul	(62,066,443)	0	154	0.421918	0	(62,066,443)
9	2018	Aug	(62,066,443)	0	123	0.336986	0	(62,066,443)
10	2018	Sep	(62,066,443)	0	93	0.254795	0	(62,066,443)
11	2018	Oct	(62,066,443)	0	62	0.169863	0	(62,066,443)
12	2018	Nov	(62,066,443)	0	32	0.087671	0	(62,066,443)
13	2018	Dec	(62,066,443)	0	1	0.002740	0	(62,066,443)

14 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: (62,066,443)

15 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: (62,066,443)

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: -

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 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 D 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 D 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)
-
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 D 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 D 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 D 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 D 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).

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Line	Year	Month	Actual Transmission Plant In Service 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
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. 11	The sum of col. 8, col. 9, and col. 10.
Col. 4	Monthly change in ADIT balance.	Col. 12, Line 3	Amount from col. 3, line 3.
Col. 6	Col. 4 minus col. 5	Col. 12, Lines 4-15	Col. 12 of previous month plus col. 11 of current month.
Col. 7	The portion of the amount in col. 6 included in original projection but not realized.	Col. 12, Line 16	Appendix A, Line 24 ÷ Appendix A, Line 21 (from the true-up population of the formula)
Col. 8	The portion of the amount in col. 6 not included in original projection.	Col. 12, Line 17	Col. 12, Line 15g multiplied by line 16.
Col. 9	The amount in col. 7 multiplied by the ratio from col. 6 of Attachment 1B, Part 1.	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).

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	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.

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Line	Year	Month	Actual Computer Software Tax Amount 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:	-

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 2 - Taxes Other Than Income Worksheet
2018 (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)	$ 53,253	100.0000%	$ 53,253
1a	Other Plant Related Taxes	0	21.1197%	-
2				-
3				-
4				-
5				-
				-
	Total Plant Related	$ 53,253		$ 53,253
	Labor Related		***Wages & Salary Allocator***	
6	Federal FICA & Unemployment & State Unemployment	$ 46,296		
	Total Labor Related	$ 46,296	7.6599%	$ 3,546
	Other Included		***Gross Plant Allocator***	
7	Sales and Use Tax	$ -		
	Total Other Included	$ -	21.1197%	$ -
	Total Included	$ 99,549		$ 56,799
	Currently Excluded			
8	Business and Occupation Tax - West Virginia	$ 20,673		
9	Gross Receipts Tax	0		
10	IFTA Fuel Tax	16		
11	Property Taxes - Other	190,862		
12	Property Taxes - Generator Step-Ups and Interconnects	1,749		
13	Sales and Use Tax - not allocated to Transmission	5,344		
14	Sales and Use Tax - Retail	0		
15	Other	11,139		
16		0		
17		0		
18		0		
19		0		
20		0		
21	Total "Other" Taxes (included on p. 263)	$ 229,783		
22	Total "Taxes Other Than Income Taxes" - acct 408.10 (p. 114.14)	$ 329,331		
23	Difference	$ (99,549)		

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
2018 (000's)

Directly Assigned Property Taxes	$	245,864
Production Property Tax		100,691
Transmission Property Tax		53,118
GSU/Interconnect Facilities		1,749
Distribution Property tax		88,546
General Property Tax		1,761
Total check		245,864

Allocation of General Property Tax to Transmission

General Property Tax	$	1,761
Wages & Salary Allocator		7.6599%
Trans General		135

Total Transmission Property Taxes		
Transmission	$	53,118
General		135
Total Transmission Property Taxes	$	53,253

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 3 - Revenue Credit Workpaper
2018 (000's)

			Transmission Related	Production/Other Related	Total
	Account 454 - Rent from Electric Property				
1	Rent from Electric Property - Transmission Related (Note 3)		13,722		13,722
2	Total Rent Revenues	(Sum Lines 1)	13,722	-	13,722
	Account 456 - Other Electric Revenues (Note 1)				
3	Schedule 1A				
4	Net revenues associated with Network Integration Transmission Service (NITS) and for the transmission component of the NCEMPA contract rate for which the load is not included in the divisor. (Note 4)		2,042		2,042
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)		3,634		3,634
9	Revenues from Directly Assigned Transmission Facility Charges (Note 2)		3,204		3,204
10	Rent or Attachment Fees associated with Transmission Facilities (Note 3)				-
11	Gross Revenue Credits (Accounts 454 and 456)	(Sum Lines 2-10)	22,602	-	22,602
12	Less line 14g		(10,502)	-	(10,502)
13	Total Revenue Credits		12,101	-	12,101
	Revenue Adjustment to Determine Revenue Credit				
14a	Revenues included in lines 1-11 which are subject to 50/50 sharing. (Lines 1 + 8 + 10)		17,356	-	17,356
14b	Costs associated with revenues in line 14a		3,647	-	3,647
14c	Net Revenues (14a - 14b)		13,710	-	13,710
14d	50% Share of Net Revenues (14c / 2)		6,855	-	6,855
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)		6,855	-	6,855
14g	Line 14f less line 14a		(10,502)	-	(10,502)

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
2018 (000's)

	Return and Taxes with Basis Point increase in ROE				
A		Basis Point increase in ROE and Income Taxes		(Line 130 + 140)	695,505
B		100 Basis Point increase in ROE (Note J from Appendix A)		Fixed	1.00%

Return Calculation

Line Ref.					
62	Rate Base excluding Acquisition Adjustments Amount and Associated ADIT		Appendix A	(Line 44 + 61 - 60C - 45A)	5,371,951
	Long Term Interest				
104		**Long Term Interest**		p117.62c through 67c	464,165
105		Less LTD Interest on Securitization (Note P)		Attachment 8	0
106		Long Term Interest		(Line 104 - 105)	464,165
107	Preferred Dividends		enter positive	p118.29c	0
	Common Stock				
108		Proprietary Capital		p112.16c,d/2	11,252,327
109		Less Preferred Stock	enter negative	(Line 117)	0
110		Less Account 219 - Accumulated Other Comprehensive Income	enter negative	p112.15c,d/2	-43,101
111		Common Stock		(Sum Lines 108 to 110)	11,209,226
	Capitalization				
112		Long Term Debt		p112.24c,d/2	10,009,839
113		Less Loss on Reacquired Debt	enter negative	p111.81c,d/2	-3,366
114		Plus Gain on Reacquired Debt	enter positive	p113.61c,d/2	3,475
115		Less LTD on Securitization Bonds	enter negative	Attachment 8	0
116		Total Long Term Debt		(Sum Lines 112 to 115)	10,009,948
117		Preferred Stock		p112.3c,d/2	0
118		Common Stock		(Line 111)	11,209,226
119		Total Capitalization		(Sum Lines 116 to 118)	21,219,174
120		Debt %	Total Long Term Debt	(Line 116 / 119)	47.2%
121		Preferred %	Preferred Stock	(Line 117 / 119)	0.0%
122		Common %	Common Stock	(Line 118 / 119)	52.8%
123		Debt Cost	Total Long Term Debt	(Line 106 / 116)	0.0464
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)	0.0219
127		Weighted Cost of Preferred	Preferred Stock	(Line 121 * 124)	0.0000
128		Weighted Cost of Common	Common Stock	(Line 122 * 125)	0.0655
129	Total Return (R)			**(Sum Lines 126 to 128)**	**0.0874**
130	Investment Return = Rate Base * Rate of Return			**(Line 62 * 129)**	**469,395**

Composite Income Taxes

	Income Tax Rates				
131		FIT=Federal Income Tax Rate			0.3500
132		SIT=State Income Tax Rate or Composite			0.0591
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)} =		0.3884
135		T/ (1-T)			0.6351
	Transmission Related Income Tax Adjustments				
136	Amortized Investment Tax Credit (ITC)	(Note I) enter negative	Attachment 1		$ -
136A	Other Income Tax Adjustments		Attachment 5		$ 1,611
137	T/(1-T)		(Line 135)		63.51%
138	**Transmission Income Taxes - Income Tax Adjustments**		((Line 136 + 136A) * (1 + Line 137))		**$ 2,634**
139	**Transmission Income Taxes - Equity Return =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =	[Line 135 * 130 * (1-(126 / 129))]		**223,475**
140	**Total Transmission Income Taxes**		**(Line 138 + 139)**		**226,109**

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 5 - Cost Support
2018 - 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	38,289,909	38,459,355	38,530,230	38,637,436	38,743,341	38,851,920	39,012,730	39,229,067	39,628,776	39,741,138	39,857,759	40,018,338	41,984,216	39,306,478	0	
15	Accumulated Depreciation (Total Electric Plant)	(Notes A & Q)	p219.29c	13,449,184	13,544,310	13,638,127	13,730,741	13,822,428	13,915,523	14,010,354	14,106,043	14,202,228	14,298,683	14,395,857	14,489,823	14,591,653	14,014,996	0	
12	Accumulated Intangible Amortization	(Notes A & Q)	p200.21c	115,222	116,153	117,084	118,015	118,945	119,876	120,807	121,738	122,668	123,599	124,530	125,461	126,391	120,807	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	8,381,568	8,453,254	8,463,864	8,493,352	8,534,609	8,571,688	8,646,908	8,774,705	8,890,425	8,904,826	8,959,352	9,001,771	9,468,490	8,734,216	0	
15	Generator Step-Ups		Trans. Input Sht	343,975	343,975	343,975	343,975	343,975	343,975	343,975	343,975	343,975	343,975	343,975	343,975	343,975	343,975	0	
23	Generator Interconnect Facilities		Input Sht	169,985	169,985	169,985	169,985	169,985	169,985	169,985	169,985	169,985	169,985	169,985	169,985	169,985	169,985		
25	General & Intangible		p205.5.g & p207.99.g/G&I Wksht	1,036,284	1,040,140	1,043,996	1,047,852	1,051,708	1,055,563	1,059,419	1,063,275	1,067,131	1,070,987	1,074,843	1,078,698	1,082,554	1,059,419	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	1,454,762	1,469,120	1,483,566	1,498,054	1,512,618	1,527,266	1,542,033	1,557,014	1,572,253	1,587,629	1,603,079	1,618,632	1,634,721	1,543,134	0	
33	Transmission Accumulated Depreciation - Generator Step-Ups		GSU Input Sht	86,915	87,744	88,573	89,401	90,230	91,059	91,888	92,717	93,546	94,375	95,204	96,033	96,862	91,888	0	
34	Transmission Accumulated Depreciation - Interconnection Facilities		Input Sht	16,083	16,492	16,902	17,312	17,721	18,131	18,540	18,950	19,360	19,769	20,179	20,589	20,998	18,540		
36	Accumulated General Depreciation	(Notes A & Q)	p219.28.b	352,590	353,600	354,610	355,621	356,631	357,641	358,651	359,662	360,672	361,682	362,692	363,703	364,713	358,651	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														201,908	0	
91	Depreciation-General	(Note A)															27,215	0	
92	Depreciation-Intangible	(Note A)	p336.1d&e/Attachment 5														31,962	0	Respondent is Electric Utility only.
87	Depreciation - Generator Step-Ups																9,947	0	
88	Depreciation - Interconnection Facilities																4,916	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	-	1,136	1,996	1,936	1,459	1,219	2,713	2,590	2,664	3,355	2,866	2,539	2,576	27,047	25,076	Excludes PJM admin & ODEC ancillary revenue
64	Generator Step-Ups		Input Sheet		-	-	-	-	-	-	-	-	-	-	-	-	19	0	reimbursements, VA Sales & Use Tax, trans. deferrals,
65	Transmission by Others		p321.96.b	-	(5,518)	(5,518)	(5,518)	(5,518)	(5,518)	(5,518)	(5,518)	(5,518)	(5,518)	(5,518)	(5,518)	(5,518)	(66,218)	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														660,520	0	
5	Total A&G Wages Expense	(Note A)	p354.27b/Trans. Wksht														94,087	0	
1	Transmission Wages	(Note A)	p354.21b/Trans. Wksht														43,403	0	
2	Generator Step-Ups		Trans. Wksht														15	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	14,590	14,590	14,590	14,590	14,590	14,590	14,590	14,590	14,590	14,590	14,590	14,590	14,590	14,590	10,862	Specific identification based on plant records. The following plant investments are included:
																Form 1 Amount	Transmission Related	Non-transmission Related	
																14,590	3,729	10,862	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		$3,515	3,515	See Form 1

Regulatory Expense Related to Transmission Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1 Amount	Transmission Related	Non-transmission Related	Details
	Allocated General & Common Expenses						
71	Less Regulatory Commission Exp Account 928	(Note E)	p323.189b/Attachment 5	$ 33,689	268	33,421	See FERC Form 1 pages 350-351.
	Directly Assigned A&G						
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b/Attachment 5		268		

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	5,287	-	5,287	

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)		5.60%	0.15%	0.16%			5.91%

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	5,287	-	5,287 -	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:

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			$ 7,551	$ 16,995	$ 12,273	100%	12,273		
	Labor Related, General plant related or Common Plant related			$ 749	$ 573	$ 661	7.660%	51		
	Plant Related			$ 6,467	$ 5,433	$ 5,950	21.12%	1,257		
	Other			$ 148,983	$ 180,581	$ 164,782	0.00%	-		
	Total Transmission Related Reserves			$ -	$ -	$ -		13,580	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								7.660%		
	Pension Liabilities, if any, in Account 242			$ 18	$ 14			$ 16	7.660%	1	
				$ -	$ -			$ -			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	$ 28,051	$ 26,419	$ 27,235	$ 3,980	$ 23,255	7.660%	1,781	Projections.
	Prepaid Pensions if not included in Prepayments							$ -	7.660%	-	

[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

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 5 - Cost Support
2018 - Projection

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.			3,184	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	19,661.4	

A&G Expenses - Other Post Employment Benefits

Line #s	Descriptions	Notes	Page #'s & Instructions	Amount
	Total A&G Expenses		p323.197b	336,966
	Less OPEB Current Year			38,838
	Plus: Stated OPEB		Fixed (from FERC accepted § 205 Filing)	(23,371)
69	Current Year Total A&G Expenses			352,433

Interest on Long-Term Debt

Line #s	Descriptions	Notes	Page #'s & Instructions	Amount
	Interest on Long-Term Debt		p117.62c through 67c	466,251
	Less Interest on Short-Term Debt Included in Account 430			(2,086)
104	Total Interest on Long-Term Debt			464,165

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	$ 4,265	X	38.84%	=	$ 1,657			
	Amortization of Excess/Deficient Deferred Taxes -- Transmission Component										
	Amortized Excess Deferred Taxes	(Note C)	Inst. 1, 3, 4, below (Enter Negative)					$ (46)	$ (2,455)	$ (2,409)	$ (2,432)
	Amortized Deficient Deferred Taxes	(Note C)	Inst. 1, 3, 4, below (Enter Positive)								$ -
136A	Total Other Income Tax Adjustments to Line 136A							$ 1,611			
47A	Unamortized Exc/Def Deferral to Line 47A										$ (2,432)

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.

Electric Plant Acquisition Adjustments Approved by FERC

				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
60A	Acquisition Adjustments Amount		Inst. 1	8,718	8,701	8,684	8,667	8,650	8,633	8,616	8,599	8,582	8,565	8,548	8,531	8,514	8,616	0	
60B	Accumulated Provision for Amortization of Line 60A Amount		Inst. 2	85	102	119	136	154	171	188	205	222	239	256	273	290	188	0	
90A	Amortization of Acquisition Adjustments Amount		Inst. 3														205		
45A	Accumulated Deferred Income Taxes Attributable to Acquisition Adjustments	Note 1	Inst. 4	(63)												(215)	(139)		

Inst. 1 For each month enter the amount included in FERC Account 114 attributable to the Wheeler Line Acquisition Adjustment for the applicable month.

Inst. 2 For each month enter the amount included in FERC Account 115 attributable to the Wheeler Line Acquisition Adjustment for the applicable month.

Inst. 3 For each year enter the amount of amortization included in FERC Account 406 attributable to the Wheeler Line Acquisition Adjustment but exclude the portion of any such amount that is amortized prior to the effective date..

Inst. 4 For each year enter the amount of Accumulated Deferred Income Tax ("ADIT")attributable to the Wheeler Line Acquisition Adjustment for the applicable year.

Note 1 This amount is not to be included in the ADIT allocated to transmission shown on line 45 but is to be included on line 45A only if the associated acquisition adjustment is approved by the FERC.

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.

Summary of Formula Rate Process including True-Up Adjustment

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

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

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

Calendar Year Do for Each Calendar Year beginning in 2009

A	ATRR based on actual costs included for the previous calendar year but excludes the true-up adjustment.	897,673.93
B	ATRR based on projected costs included for the previous calendar year but excludes the true-up adjustment.	875,782.95
C	Difference (A-B)	21,891
D	Future Value Factor (1+i)^24	1.07197
E	True-up Adjustment (C*D)	23,467

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

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

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

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

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

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

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

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

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

Summary of Formula Rate Process including True-Up Adjustment

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

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

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

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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 Acquisition Adjustments and Depreciation	12.0063%
4	B	161	Net Plant Carrying Charge with 100 Basis Point increase in ROE without Acquisition Adjustments and Depreciation	12.6899%
5	C		Line B less Line A	0.6836%

6 **FCR if a CIAC**

7	D	155	Net Plant Carrying Charge without Acquisition Adjustments, Depreciation, Return or Income Taxes	2.4431%

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.**

					Project A		Project A-1	
10			10	Details				
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	12.0063%		12.0063%	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)	12.0063%		12.0063%	
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		859,678	21,205	838,474	
43	W incentive	2017	43	W incentive	2017	840,844	24,170	816,674		859,678	21,205	838,474	
44	W / O incentive	2018	44	W / O incentive	2018	816,674	24,170	792,504	120,772	838,474	21,205	817,269	120,602
45	W incentive	2018	45	W incentive	2018	816,674	24,170	792,504	120,772	838,474	21,205	817,269	120,602

46 Lines continue as new rate years are added.
47

48 In the formulas used in the Columns for lines 19+ are as follows:
49 "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.
50 "Beginning" is the investment on line 16 for the first year and is the "Ending" for the prior year after the first year.
51 "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.
52 "Ending" is "Beginning" less "Depreciation"
53 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
54 plus "Depreciation" for the first year and ("Beginning" plus "Ending") divided by two times line 13 plus "Depreciation" thereafter.
55 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
56 plus "Depreciation" for the first year and ("Beginning" plus "Ending") divided by two times line 15 plus "Depreciation" thereafter.
57 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	Proj Rev Req w/o Incentive PCY*	Projected Revenue Requirement without Incentive for Previous Calendar Year*	154,741	133,475
B	Proj Rev Req w/ Incentive PCY*	Projected Revenue Requirement with Incentive for Previous Calendar Year*	154,741	133,475
C	Actual Rev Req w/o Incentive PCY*	Actual Revenue Requirement without Incentive for Previous Calendar Year *	131,072	130,282
D	Actual Rev Req w/ Incentive PCY*	Actual Revenue Requirement with Incentive for Previous Calendar Year *	131,072	130,282
E	TUA w/o Int w/o Incentive PCY (C-A)	True-Up Adjustment Before Interest without Incentive for Previous Calendar Year (C-A)	(23,668)	(3,193)
F	TUA w/o Int w/ Incentive PCY (B-D)	True-Up Adjustment Before Interest with Incentive for Previous Calendar Year (B-D)	(23,668)	(3,193)
G	Future Value Factor (1+i)^24 mo (ATT6)	Future Value Factor (1+i)^24 months from Attachment 6	1.07197	1.07197
H	True-Up Adjustment w/o Incentive (E*G)	True-Up Adjustment without Incentive (E*G)	(25,372)	(3,423)
I	True-Up Adjustment w/ Incentive (F*G)	True-Up Adjustment with Incentive (F*G)	(25,372)	(3,423)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

* 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	95,400	117,178
W incentive	W incentive	95,400	117,178

Virginia Electric and Power Company
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(dollars)

These Three Columns
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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	12.0063%	at Loudoun			12.0063%	at Loudoun - Replacement of			12.0063%	Clifton and Clifton 500 KV 150 MVAR		
14	Incentive Factor (Basis Points /100)		0				0	Circuit Breaker			0	capacitor		
15	FCR W incentive L.13 +(L.14*L.5)		12.0063%				12.0063%				12.0063%			
16	Investment		1,077,246				591,996				7,624,974			
17	Annual Depreciation Exp		25,052				13,767				177,325			
18	In Service Month (1-12)		9				4				8			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006	1,077,246	6,161	1,071,085									
21	W incentive	2006	1,077,246	6,161	1,071,085									
22	W / O incentive	2007	1,071,085	21,122	1,049,963						7,624,974	56,066	7,568,908	
23	W incentive	2007	1,071,085	21,122	1,049,963						7,624,974	56,066	7,568,908	
24	W / O incentive	2008	1,049,963	21,122	1,028,840						7,568,908	149,509	7,419,399	
25	W incentive	2008	1,049,963	21,122	1,028,840						7,568,908	149,509	7,419,399	
26	W / O incentive	2009	1,028,840	21,122	1,007,718						7,419,399	149,509	7,269,889	
27	W incentive	2009	1,028,840	21,122	1,007,718						7,419,399	149,509	7,269,889	
28	W / O incentive	2010	1,007,718	21,122	986,595						7,269,889	149,509	7,120,380	
29	W incentive	2010	1,007,718	21,122	986,595						7,269,889	149,509	7,120,380	
30	W / O incentive	2011	986,595	21,122	965,473						7,120,380	149,509	6,970,871	
31	W incentive	2011	986,595	21,122	965,473						7,120,380	149,509	6,970,871	
32	W / O incentive	2012	965,473	21,122	944,350						6,970,871	149,509	6,821,362	
33	W incentive	2012	965,473	21,122	944,350						6,970,871	149,509	6,821,362	
34	W / O incentive	2013	944,350	24,070	920,281		591,996	9,752	582,244		6,821,362	170,371	6,650,990	
35	W incentive	2013	944,350	24,070	920,281		591,996	9,752	582,244		6,821,362	170,371	6,650,990	
36	W / O incentive	2014	920,281	25,052	895,228		582,244	13,767	568,477		6,650,990	177,325	6,473,666	
37	W incentive	2014	920,281	25,052	895,228		582,244	13,767	568,477		6,650,990	177,325	6,473,666	
38	W / O incentive	2015	895,228	25,052	870,176		568,477	13,767	554,709		6,473,666	177,325	6,296,341	
39	W incentive	2015	895,228	25,052	870,176		568,477	13,767	554,709		6,473,666	177,325	6,296,341	
40	W / O incentive	2016	870,176	25,052	845,124		554,709	13,767	540,942		6,296,341	177,325	6,119,016	
41	W incentive	2016	870,176	25,052	845,124		554,709	13,767	540,942		6,296,341	177,325	6,119,016	
42	W / O incentive	2017	845,124	25,052	820,072		540,942	13,767	527,175		6,119,016	177,325	5,941,691	
43	W incentive	2017	845,124	25,052	820,072		540,942	13,767	527,175		6,119,016	177,325	5,941,691	
44	W / O incentive	2018	820,072	25,052	795,020	122,009	527,175	13,767	513,407	76,235	5,941,691	177,325	5,764,366	880,058
45	W incentive	2018	820,072	25,052	795,020	122,009	527,175	13,767	513,407	76,235	5,941,691	177,325	5,764,366	880,058
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54														
55														
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57														

		Project B	Project B-1	Project E
A	Proj Rev Req w/o Incentive PCY*	135,444	84,315	1,042,158
B	Proj Rev Req w/ Incentive PCY*	135,444	84,315	1,042,158
C	Actual Rev Req w/o Incentive PCY*	132,546	82,429	955,365
D	Actual Rev Req w/ Incentive PCY*	132,546	82,429	955,365
E	TUA w/o Int w/o Incentive PCY (C-A)	(2,898)	(1,886)	(86,793)
F	TUA w/o Int w/ Incentive PCY (B-D)	(2,898)	(1,886)	(86,793)
G	Future Value Factor (1+i)^24 mo (ATT6)	1.07197	1.07197	1.07197
H	True-Up Adjustment w/o Incentive (E*G)	(3,107)	(2,021)	(93,039)
I	True-Up Adjustment w/ Incentive (F*G)	(3,107)	(2,021)	(93,039)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	118,902	74,214	787,018
W incentive	118,902	74,214	787,018

Virginia Electric and Power Company
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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 E-1**				**Project G-1**				**Project G-1A**			
11	Schedule 12	(Yes or No)	Yes	B0226			Yes	B0403			Yes	B0403		
12	Life		43	Install 500/230 kV transformer at			43	2nd Dooms 500/230 kV transformer			43	2nd Dooms 500/230 kV transformer		
13	FCR W/O incentive	Line 3	12.0063%	Clifton and Clifton 500 KV 150 MVAR			12.0063%	addition			12.0063%	addition		
14	Incentive Factor (Basis Points /100)		0	capacitor			0				0			
15	FCR W incentive L.13 +(L.14*L.5)		12.0063%				12.0063%				12.0063%			
16	Investment		906,822				6,810,242				516,125			
17	Annual Depreciation Exp		21,089				158,378				12,003			
18	In Service Month (1-12)		10				11				4			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007					6,810,242	16,692	6,793,550					
23	W incentive	2007					6,810,242	16,692	6,793,550					
24	W / O incentive	2008					6,793,550	133,534	6,660,016					
25	W incentive	2008					6,793,550	133,534	6,660,016					
26	W / O incentive	2009					6,660,016	133,534	6,526,482					
27	W incentive	2009					6,660,016	133,534	6,526,482					
28	W / O incentive	2010					6,526,482	133,534	6,392,948					
29	W incentive	2010					6,526,482	133,534	6,392,948					
30	W / O incentive	2011					6,392,948	133,534	6,259,414					
31	W incentive	2011					6,392,948	133,534	6,259,414					
32	W / O incentive	2012					6,259,414	133,534	6,125,879					
33	W incentive	2012					6,259,414	133,534	6,125,879					
34	W / O incentive	2013					6,125,879	152,167	5,973,713					
35	W incentive	2013					6,125,879	152,167	5,973,713					
36	W / O incentive	2014					5,973,713	158,378	5,815,335					
37	W incentive	2014					5,973,713	158,378	5,815,335					
38	W / O incentive	2015					5,815,335	158,378	5,656,957					
39	W incentive	2015					5,815,335	158,378	5,656,957					
40	W / O incentive	2016	906,822	4,394	902,428		5,656,957	158,378	5,498,579		516,125	8,502	507,623	
41	W incentive	2016	906,822	4,394	902,428		5,656,957	158,378	5,498,579		516,125	8,502	507,623	
42	W / O incentive	2017	902,428	21,089	881,340		5,498,579	158,378	5,340,202		507,623	12,003	495,620	
43	W incentive	2017	902,428	21,089	881,340		5,498,579	158,378	5,340,202		507,623	12,003	495,620	
44	W / O incentive	2018	881,340	21,089	860,251	125,639	5,340,202	158,378	5,181,824	790,031	495,620	12,003	483,617	70,788
45	W incentive	2018	881,340	21,089	860,251	125,639	5,340,202	158,378	5,181,824	790,031	495,620	12,003	483,617	70,788
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49														
50														
51														
52														
53														
54														
55														
56														
57														
A	Proj Rev Req w/o Incentive PCY*					-				926,906				-
B	Proj Rev Req w/ Incentive PCY*					-				926,906				-
C	Actual Rev Req w/o Incentive PCY*					28,015				857,468				53,946
D	Actual Rev Req w/ Incentive PCY*					28,015				857,468				53,946
E	TUA w/o Int w/o Incentive PCY (C-A)					28,015				(69,438)				53,946
F	TUA w/o Int w/ Incentive PCY (B-D)					28,015				(69,438)				53,946
G	Future Value Factor (1+i)^24 mo (ATT6)					1.07197				1.07197				1.07197
H	True-Up Adjustment w/o Incentive (E*G)					30,031				(74,435)				57,828
I	True-Up Adjustment w/ Incentive (F*G)					30,031				(74,435)				57,828

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive		155,670	715,596	128,616
W incentive		155,670	715,596	128,616

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

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Line Number
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10			Project G-2		Project G-2A		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 500kV circuit
13	FCR W/O incentive	Line 3	12.0063%	addition	12.0063%	addition	12.0063%	(30 of 50 miles)
14	Incentive Factor (Basis Points /100)		0		0		1.5	
15	FCR W incentive L.13 +(L.14*L.5)		12.0063%	Spare Transformer Addition	12.0063%	Spare Transformer Addition	13.0317%	line 2101 v11
16	Investment		2,245,293		257,907		21,850,320	
17	Annual Depreciation Exp		52,216		5,998		508,147	
18	In Service Month (1-12)		4		4		6	

19			Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	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	2,245,293	31,185	2,214,108						21,850,320	232,070	21,618,250	
27	W incentive	2009	2,245,293	31,185	2,214,108						21,850,320	232,070	21,618,250	
28	W / O incentive	2010	2,214,108	44,025	2,170,083						21,618,250	428,438	21,189,812	
29	W incentive	2010	2,214,108	44,025	2,170,083						21,618,250	428,438	21,189,812	
30	W / O incentive	2011	2,170,083	44,025	2,126,058						21,189,812	428,438	20,761,374	
31	W incentive	2011	2,170,083	44,025	2,126,058						21,189,812	428,438	20,761,374	
32	W / O incentive	2012	2,126,058	44,025	2,082,032						20,761,374	428,438	20,332,937	
33	W incentive	2012	2,126,058	44,025	2,082,032						20,761,374	428,438	20,332,937	
34	W / O incentive	2013	2,082,032	50,168	2,031,864						20,332,937	488,220	19,844,717	
35	W incentive	2013	2,082,032	50,168	2,031,864						20,332,937	488,220	19,844,717	
36	W / O incentive	2014	2,031,864	52,216	1,979,648						19,844,717	508,147	19,336,570	
37	W incentive	2014	2,031,864	52,216	1,979,648						19,844,717	508,147	19,336,570	
38	W / O incentive	2015	1,979,648	52,216	1,927,432						19,336,570	508,147	18,828,423	
39	W incentive	2015	1,979,648	52,216	1,927,432						19,336,570	508,147	18,828,423	
40	W / O incentive	2016	1,927,432	52,216	1,875,216		257,907	4,248	253,659		18,828,423	508,147	18,320,276	
41	W incentive	2016	1,927,432	52,216	1,875,216		257,907	4,248	253,659		18,828,423	508,147	18,320,276	
42	W / O incentive	2017	1,875,216	52,216	1,822,999		253,659	5,998	247,661		18,320,276	508,147	17,812,129	
43	W incentive	2017	1,875,216	52,216	1,822,999		253,659	5,998	247,661		18,320,276	508,147	17,812,129	
44	W / O incentive	2018	1,822,999	52,216	1,770,783	267,956	247,661	5,998	241,663	35,373	17,812,129	508,147	17,303,982	2,616,221
45	W incentive	2018	1,822,999	52,216	1,770,783	267,956	247,661	5,998	241,663	35,373	17,812,129	508,147	17,303,982	2,796,263
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A	Proj Rev Req w/o Incentive PCY*	319,423	-	2,900,104
B	Proj Rev Req w/ Incentive PCY*	319,423	-	3,104,032
C	Actual Rev Req w/o Incentive PCY*	290,519	26,957	2,836,165
D	Actual Rev Req w/ Incentive PCY*	290,519	26,957	3,033,272
E	TUA w/o Int w/o Incentive PCY (C-A)	(28,905)	26,957	(63,938)
F	TUA w/o Int w/ Incentive PCY (B-D)	(28,905)	26,957	(70,760)
G	Future Value Factor (1+i)^24 mo (ATT6)	1.07197	1.07197	1.07197
H	True-Up Adjustment w/o Incentive (E*G)	(30,985)	28,897	(68,540)
I	True-Up Adjustment w/ Incentive (F*G)	(30,985)	28,897	(75,853)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	236,972	64,269	2,547,681
W incentive	236,972	64,269	2,720,410

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 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 500kV circuit		
13	FCR W/O incentive	Line 3	12.0063%	(30 of 50 miles)			12.0063%	(30 of 50 miles)			12.0063%	(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)		13.0317%	Line 2030 & 559 v12 & v13			13.0317%	Line 580 - Phase 1			13.0317%	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**	**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	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		11,675,397	315,837	11,359,560		9,594,338	261,030	9,333,309	
43	W incentive	2017	38,246,841	1,048,586	37,198,255		11,675,397	315,837	11,359,560		9,594,338	261,030	9,333,309	
44	W / O incentive	2018	37,198,255	1,048,586	36,149,668	5,451,775	11,359,560	315,837	11,043,723	1,660,741	9,333,309	261,030	9,072,279	1,365,946
45	W incentive	2018	37,198,255	1,048,586	36,149,668	5,827,832	11,359,560	315,837	11,043,723	1,775,603	9,333,309	261,030	9,072,279	1,460,312
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A	Proj Rev Req w/o Incentive PCY*	6,041,433	1,839,701	1,513,371
B	Proj Rev Req w/ Incentive PCY*	6,467,102	1,969,619	1,620,141
C	Actual Rev Req w/o Incentive PCY*	5,907,971	1,798,967	1,479,896
D	Actual Rev Req w/ Incentive PCY*	6,319,401	1,924,539	1,583,093
E	TUA w/o Int w/o Incentive PCY (C-A)	(133,461)	(40,734)	(33,476)
F	TUA w/o Int w/ Incentive PCY (B-D)	(147,702)	(45,080)	(37,048)
G	Future Value Factor (1+i)^24 mo (ATT6)	1.07197	1.07197	1.07197
H	True-Up Adjustment w/o Incentive (E*G)	(143,067)	(43,665)	(35,885)
I	True-Up Adjustment w/ Incentive (F*G)	(158,332)	(48,324)	(39,714)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	5,308,708	1,617,075	1,330,061
W incentive	5,669,501	1,727,279	1,420,598

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

These Three Columns
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Line Number
References on All Pages

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 500kV circuit		
13	FCR W/O incentive	Line 3	12.0063%	(30 of 50 miles)			12.0063%	(30 of 50 miles)			12.0063%	(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)		13.0317%	Line 114			13.0317%	Clevenger DP/580			13.0317%	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**	**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	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		14,584,615	393,042	14,191,573		9,861,249	264,250	9,596,998	
43	W incentive	2017	12,575,234	340,827	12,234,407		14,584,615	393,042	14,191,573		9,861,249	264,250	9,596,998	
44	W / O incentive	2018	12,234,407	340,827	11,893,580	1,789,267	14,191,573	393,042	13,798,531	2,073,331	9,596,998	264,250	9,332,748	1,400,632
45	W incentive	2018	12,234,407	340,827	11,893,580	1,912,972	14,191,573	393,042	13,798,531	2,216,837	9,596,998	264,250	9,332,748	1,497,686
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A	Proj Rev Req w/o Incentive PCY*					1,982,178				2,296,518				1,551,171
B	Proj Rev Req w/ Incentive PCY*					2,122,113				2,458,801				1,660,889
C	Actual Rev Req w/o Incentive PCY*					1,938,304				2,245,637				1,516,771
D	Actual Rev Req w/ Incentive PCY*					2,073,558				2,402,491				1,622,818
E	TUA w/o Int w/o Incentive PCY (C-A)					(43,874)				(50,881)				(34,400)
F	TUA w/o Int w/ Incentive PCY (B-D)					(48,556)				(56,310)				(38,071)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.07197				1.07197				1.07197
H	True-Up Adjustment w/o Incentive (E*G)					(47,032)				(54,543)				(36,876)
I	True-Up Adjustment w/ Incentive (F*G)					(52,050)				(60,363)				(40,810)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	W / O incentive					1,742,235				2,018,788				1,363,756
	W incentive					1,860,922				2,156,475				1,456,875

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			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 Substation		
13	FCR W/O incentive	Line 3	12.0063%	(30 of 50 miles)			12.0063%				12.0063%			
14	Incentive Factor (Basis Points /100)		1.5				1.5				1.5			
15	FCR W incentive L.13 +(L.14*L.5)		13.0317%	Line 535			13.0317%				13.0317%			
16	Investment		95,015,133				13,726,825				3,123,926			
17	Annual Depreciation Exp		2,209,654				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**	**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	95,015,133	1,319,655	93,695,478		13,726,825	168,221	13,558,604		3,123,926	38,283	3,085,643	
31	W incentive	2011	95,015,133	1,319,655	93,695,478		13,726,825	168,221	13,558,604		3,123,926	38,283	3,085,643	
32	W / O incentive	2012	93,695,478	1,863,042	91,832,437		13,558,604	269,153	13,289,451		3,085,643	61,253	3,024,389	
33	W incentive	2012	93,695,478	1,863,042	91,832,437		13,558,604	269,153	13,289,451		3,085,643	61,253	3,024,389	
34	W / O incentive	2013	91,832,437	2,123,001	89,709,435		13,289,451	306,710	12,982,741		3,024,389	69,800	2,954,589	
35	W incentive	2013	91,832,437	2,123,001	89,709,435		13,289,451	306,710	12,982,741		3,024,389	69,800	2,954,589	
36	W / O incentive	2014	89,709,435	2,209,654	87,499,781		12,982,741	319,228	12,663,512		2,954,589	72,649	2,881,939	
37	W incentive	2014	89,709,435	2,209,654	87,499,781		12,982,741	319,228	12,663,512		2,954,589	72,649	2,881,939	
38	W / O incentive	2015	87,499,781	2,209,654	85,290,127		12,663,512	319,228	12,344,284		2,881,939	72,649	2,809,290	
39	W incentive	2015	87,499,781	2,209,654	85,290,127		12,663,512	319,228	12,344,284		2,881,939	72,649	2,809,290	
40	W / O incentive	2016	85,290,127	2,209,654	83,080,473		12,344,284	319,228	12,025,055		2,809,290	72,649	2,736,640	
41	W incentive	2016	85,290,127	2,209,654	83,080,473		12,344,284	319,228	12,025,055		2,809,290	72,649	2,736,640	
42	W / O incentive	2017	83,080,473	2,209,654	80,870,818		12,025,055	319,228	11,705,827		2,736,640	72,649	2,663,991	
43	W incentive	2017	83,080,473	2,209,654	80,870,818		12,025,055	319,228	11,705,827		2,736,640	72,649	2,663,991	
44	W / O incentive	2018	80,870,818	2,209,654	78,661,164	11,786,605	11,705,827	319,228	11,386,599	1,705,502	2,663,991	72,649	2,591,341	388,135
45	W incentive	2018	80,870,818	2,209,654	78,661,164	12,604,531	11,705,827	319,228	11,386,599	1,823,898	2,663,991	72,649	2,591,341	415,079
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A	Proj Rev Req w/o Incentive PCY*					12,652,105				1,888,339				429,745
B	Proj Rev Req w/ Incentive PCY*					13,548,141				2,022,115				460,189
C	Actual Rev Req w/o Incentive PCY*					12,761,029				1,846,396				420,199
D	Actual Rev Req w/ Incentive PCY*					13,654,382				1,975,696				449,625
E	TUA w/o Int w/o Incentive PCY (C-A)					108,924				(41,943)				(9,545)
F	TUA w/o Int w/ Incentive PCY (B-D)					106,241				(46,418)				(10,564)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.07197				1.07197				1.07197
H	True-Up Adjustment w/o Incentive (E*G)					116,764				(44,962)				(10,232)
I	True-Up Adjustment w/ Incentive (F*G)					113,888				(49,759)				(11,324)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	11,903,368	1,660,540	377,903
W incentive	12,718,418	1,774,139	403,755

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			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		12.0063%	Suffolk 500/230 # 2 transformer +			12.0063%	Suffolk 500/230 # 2 transformer +			12.0063%	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)		13.0317%				13.0317%				13.0317%			
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 Facilities and		
17	Annual Depreciation Exp		56,624				905,262				3,800,287	Necessary Lower Voltage Facilities.		
18	In Service Month (1-12)		12				6				5			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**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	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		34,164,018	905,262	33,258,756		143,153,441	3,800,287	139,353,154	
43	W incentive	2017	2,065,357	56,624	2,008,733		34,164,018	905,262	33,258,756		143,153,441	3,800,287	139,353,154	
44	W / O incentive	2018	2,008,733	56,624	1,952,108	294,400	33,258,756	905,262	32,353,494	4,844,066	139,353,154	3,800,287	135,552,868	20,303,318
45	W incentive	2018	2,008,733	56,624	1,952,108	314,707	33,258,756	905,262	32,353,494	5,180,463	139,353,154	3,800,287	135,552,868	21,712,771
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A	Proj Rev Req w/o Incentive PCY*	326,242	5,369,326	22,478,576
B	Proj Rev Req w/ Incentive PCY*	349,228	5,749,824	24,071,029
C	Actual Rev Req w/o Incentive PCY*	319,035	5,243,944	21,980,596
D	Actual Rev Req w/ Incentive PCY*	341,252	5,611,287	23,519,867
E	TUA w/o Int w/o Incentive PCY (C-A)	(7,207)	(125,382)	(497,980)
F	TUA w/o Int w/ Incentive PCY (B-D)	(7,976)	(138,538)	(551,162)
G	Future Value Factor (1+i)^24 mo (ATT6)	1.07197	1.07197	1.07197
H	True-Up Adjustment w/o Incentive (E*G)	(7,726)	(134,406)	(533,820)
I	True-Up Adjustment w/ Incentive (F*G)	(8,550)	(148,508)	(590,830)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	286,674	4,709,660	19,769,498
W incentive	306,157	5,031,954	21,121,942

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

			Project J				Project K-1				Project K-2			
10														
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	12.0063%				12.0063%	replacement			12.0063%	replacement		
14	Incentive Factor (Basis Points /100)		1.5				1.5				1.5			
15	FCR W incentive L.13 +(L.14*L.5)		13.0317%				13.0317%				13.0317%			
16	Investment						12,786,365				14,388,779			
17	Annual Depreciation Exp		-				297,357				334,623			
18	In Service Month (1-12)						12				5			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**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					12,786,365	10,446	12,775,919					
27	W incentive	2009					12,786,365	10,446	12,775,919					
28	W / O incentive	2010					12,775,919	250,713	12,525,206		14,388,779	176,333	14,212,446	
29	W incentive	2010					12,775,919	250,713	12,525,206		14,388,779	176,333	14,212,446	
30	W / O incentive	2011					12,525,206	250,713	12,274,493		14,212,446	282,133	13,930,313	
31	W incentive	2011					12,525,206	250,713	12,274,493		14,212,446	282,133	13,930,313	
32	W / O incentive	2012	-	-	-		12,274,493	250,713	12,023,780		13,930,313	282,133	13,648,180	
33	W incentive	2012	-	-	-		12,274,493	250,713	12,023,780		13,930,313	282,133	13,648,180	
34	W / O incentive	2013	-	-	-		12,023,780	285,696	11,738,083		13,648,180	321,500	13,326,680	
35	W incentive	2013	-	-	-		12,023,780	285,696	11,738,083		13,648,180	321,500	13,326,680	
36	W / O incentive	2014	-	-	-		11,738,083	297,357	11,440,726		13,326,680	334,623	12,992,057	
37	W incentive	2014	-	-	-		11,738,083	297,357	11,440,726		13,326,680	334,623	12,992,057	
38	W / O incentive	2015	-	-	-		11,440,726	297,357	11,143,369		12,992,057	334,623	12,657,434	
39	W incentive	2015	-	-	-		11,440,726	297,357	11,143,369		12,992,057	334,623	12,657,434	
40	W / O incentive	2016	-	-	-		11,143,369	297,357	10,846,011		12,657,434	334,623	12,322,811	
41	W incentive	2016	-	-	-		11,143,369	297,357	10,846,011		12,657,434	334,623	12,322,811	
42	W / O incentive	2017	-	-	-		10,846,011	297,357	10,548,654		12,322,811	334,623	11,988,189	
43	W incentive	2017	-	-	-		10,846,011	297,357	10,548,654		12,322,811	334,623	11,988,189	
44	W / O incentive	2018	-	-	-	-	10,548,654	297,357	10,251,297	1,546,010	11,988,189	334,623	11,653,566	1,753,874
45	W incentive	2018	-	-	-	-	10,548,654	297,357	10,251,297	1,652,652	11,988,189	334,623	11,653,566	1,875,086
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A	Proj Rev Req w/o Incentive PCY*	-	1,831,891	1,975,261
B	Proj Rev Req w/ Incentive PCY*	-	1,960,963	2,114,663
C	Actual Rev Req w/o Incentive PCY*	-	1,675,378	1,900,074
D	Actual Rev Req w/ Incentive PCY*	-	1,792,051	2,032,616
E	TUA w/o Int w/o Incentive PCY (C-A)	-	(156,513)	(75,187)
F	TUA w/o Int w/ Incentive PCY (B-D)	-	(168,912)	(82,047)
G	Future Value Factor (1+i)^24 mo (ATT6)	1.07197	1.07197	1.07197
H	True-Up Adjustment w/o Incentive (E*G)	-	(167,777)	(80,599)
I	True-Up Adjustment w/ Incentive (F*G)	-	(181,069)	(87,952)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	-	1,378,233	1,673,275
W incentive	-	1,471,584	1,787,134

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			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			43	Ox Bank # 1 transformer			43	Ox Bank # 2 transformer		
13	FCR W/O incentive	Line 3	12.0063%	replacement			12.0063%	spare			12.0063%	replacement		
14	Incentive Factor (Basis Points /100)		1.5				1.5				1.5			
15	FCR W incentive L.13 +(L.14*L.5)		13.0317%				13.0317%				13.0317%			
16	Investment		10,056,166				2,857,132				11,501,538			
17	Annual Depreciation Exp		233,864				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**	**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	10,056,166	90,374	9,965,792		2,857,132	2,334	2,854,798		11,501,538	178,537	11,323,001	
27	W incentive	2009	10,056,166	90,374	9,965,792		2,857,132	2,334	2,854,798		11,501,538	178,537	11,323,001	
28	W / O incentive	2010	9,965,792	197,180	9,768,612		2,854,798	56,022	2,798,776		11,323,001	225,520	11,097,481	
29	W incentive	2010	9,965,792	197,180	9,768,612		2,854,798	56,022	2,798,776		11,323,001	225,520	11,097,481	
30	W / O incentive	2011	9,768,612	197,180	9,571,433		2,798,776	56,022	2,742,753		11,097,481	225,520	10,871,960	
31	W incentive	2011	9,768,612	197,180	9,571,433		2,798,776	56,022	2,742,753		11,097,481	225,520	10,871,960	
32	W / O incentive	2012	9,571,433	197,180	9,374,253		2,742,753	56,022	2,686,731		10,871,960	225,520	10,646,440	
33	W incentive	2012	9,571,433	197,180	9,374,253		2,742,753	56,022	2,686,731		10,871,960	225,520	10,646,440	
34	W / O incentive	2013	9,374,253	224,693	9,149,560		2,686,731	63,839	2,622,892		10,646,440	256,988	10,389,452	
35	W incentive	2013	9,374,253	224,693	9,149,560		2,686,731	63,839	2,622,892		10,646,440	256,988	10,389,452	
36	W / O incentive	2014	9,149,560	233,864	8,915,695		2,622,892	66,445	2,556,447		10,389,452	267,478	10,121,974	
37	W incentive	2014	9,149,560	233,864	8,915,695		2,622,892	66,445	2,556,447		10,389,452	267,478	10,121,974	
38	W / O incentive	2015	8,915,695	233,864	8,681,831		2,556,447	66,445	2,490,002		10,121,974	267,478	9,854,496	
39	W incentive	2015	8,915,695	233,864	8,681,831		2,556,447	66,445	2,490,002		10,121,974	267,478	9,854,496	
40	W / O incentive	2016	8,681,831	233,864	8,447,967		2,490,002	66,445	2,423,557		9,854,496	267,478	9,587,019	
41	W incentive	2016	8,681,831	233,864	8,447,967		2,490,002	66,445	2,423,557		9,854,496	267,478	9,587,019	
42	W / O incentive	2017	8,447,967	233,864	8,214,102		2,423,557	66,445	2,357,112		9,587,019	267,478	9,319,541	
43	W incentive	2017	8,447,967	233,864	8,214,102		2,423,557	66,445	2,357,112		9,587,019	267,478	9,319,541	
44	W / O incentive	2018	8,214,102	233,864	7,980,238	1,206,035	2,357,112	66,445	2,290,667	345,458	9,319,541	267,478	9,052,064	1,370,353
45	W incentive	2018	8,214,102	233,864	7,980,238	1,289,064	2,357,112	66,445	2,290,667	369,288	9,319,541	267,478	9,052,064	1,464,545
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A	Proj Rev Req w/o Incentive PCY*	1,424,334	411,637	1,519,292
B	Proj Rev Req w/ Incentive PCY*	1,524,523	440,641	1,626,016
C	Actual Rev Req w/o Incentive PCY*	1,307,347	374,366	1,485,830
D	Actual Rev Req w/ Incentive PCY*	1,398,235	400,436	1,588,984
E	TUA w/o Int w/o Incentive PCY (C-A)	(116,987)	(37,272)	(33,462)
F	TUA w/o Int w/ Incentive PCY (B-D)	(126,287)	(40,204)	(37,032)
G	Future Value Factor (1+i)^24 mo (ATT6)	1.07197	1.07197	1.07197
H	True-Up Adjustment w/o Incentive (E*G)	(125,406)	(39,954)	(35,870)
I	True-Up Adjustment w/ Incentive (F*G)	(135,377)	(43,098)	(39,697)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	1,080,629	305,504	1,334,483
W incentive	1,153,688	326,190	1,424,848

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			**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		12.0063%	replacement			12.0063%	replacement			12.0063%	replacement		
14	Incentive Factor (Basis Points /100)		1.5				1.5				1.5			
15	FCR W incentive L.13 +(L.14*L.5)		13.0317%				13.0317%				13.0317%			
16	Investment		16,357,858				19,286,602				9,761,643			
17	Annual Depreciation Exp		380,415				448,526				227,015			
18	In Service Month (1-12)		6				5				12			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**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	16,357,858	173,735	16,184,123		19,286,602	236,355	19,050,247					
29	W incentive	2010	16,357,858	173,735	16,184,123		19,286,602	236,355	19,050,247					
30	W / O incentive	2011	16,184,123	320,742	15,863,380		19,050,247	378,169	18,672,078		9,761,643	7,975	9,753,668	
31	W incentive	2011	16,184,123	320,742	15,863,380		19,050,247	378,169	18,672,078		9,761,643	7,975	9,753,668	
32	W / O incentive	2012	15,863,380	320,742	15,542,638		18,672,078	378,169	18,293,909		9,753,668	191,405	9,562,263	
33	W incentive	2012	15,863,380	320,742	15,542,638		18,672,078	378,169	18,293,909		9,753,668	191,405	9,562,263	
34	W / O incentive	2013	15,542,638	365,497	15,177,141		18,293,909	430,936	17,862,973		9,562,263	218,112	9,344,151	
35	W incentive	2013	15,542,638	365,497	15,177,141		18,293,909	430,936	17,862,973		9,562,263	218,112	9,344,151	
36	W / O incentive	2014	15,177,141	380,415	14,796,726		17,862,973	448,526	17,414,447		9,344,151	227,015	9,117,136	
37	W incentive	2014	15,177,141	380,415	14,796,726		17,862,973	448,526	17,414,447		9,344,151	227,015	9,117,136	
38	W / O incentive	2015	14,796,726	380,415	14,416,310		17,414,447	448,526	16,965,922		9,117,136	227,015	8,890,121	
39	W incentive	2015	14,796,726	380,415	14,416,310		17,414,447	448,526	16,965,922		9,117,136	227,015	8,890,121	
40	W / O incentive	2016	14,416,310	380,415	14,035,895		16,965,922	448,526	16,517,396		8,890,121	227,015	8,663,106	
41	W incentive	2016	14,416,310	380,415	14,035,895		16,965,922	448,526	16,517,396		8,890,121	227,015	8,663,106	
42	W / O incentive	2017	14,035,895	380,415	13,655,480		16,517,396	448,526	16,068,870		8,663,106	227,015	8,436,091	
43	W incentive	2017	14,035,895	380,415	13,655,480		16,517,396	448,526	16,068,870		8,663,106	227,015	8,436,091	
44	W / O incentive	2018	13,655,480	380,415	13,275,064	1,997,097	16,068,870	448,526	15,620,345	2,350,878	8,436,091	227,015	8,209,076	1,226,250
45	W incentive	2018	13,655,480	380,415	13,275,064	2,135,171	16,068,870	448,526	15,620,345	2,513,350	8,436,091	227,015	8,209,076	1,311,590
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A	Proj Rev Req w/o Incentive PCY*					2,239,684				2,550,535				1,455,915
B	Proj Rev Req w/ Incentive PCY*					2,397,798				2,730,536				1,559,279
C	Actual Rev Req w/o Incentive PCY*					2,163,446				2,546,844				1,327,033
D	Actual Rev Req w/ Incentive PCY*					2,314,409				2,724,502				1,420,168
E	TUA w/o Int w/o Incentive PCY (C-A)					(76,239)				(3,691)				(128,882)
F	TUA w/o Int w/ Incentive PCY (B-D)					(83,389)				(6,034)				(139,111)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.07197				1.07197				1.07197
H	True-Up Adjustment w/o Incentive (E*G)					(81,726)				(3,957)				(138,158)
I	True-Up Adjustment w/ Incentive (F*G)					(89,390)				(6,468)				(149,123)
	TUA = True-Up Adjusment													
	PCY = Previous Calendar Year													
	W / O incentive					1,915,372				2,346,921				1,088,092
	W incentive					2,045,781				2,506,882				1,162,468

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			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	12.0063%	replacement			12.0063%	replacement			12.0063%	Phase 1		
14	Incentive Factor (Basis Points /100)		1.5				1.5				1.25			
15	FCR W incentive L.13 +(L.14*L.5)		13.0317%				13.0317%				12.8608%			
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**	**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					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		10,463,232	280,382	10,182,850		78,328,744	2,122,946	76,205,798	
43	W incentive	2017	16,647,470	439,480	16,207,990		10,463,232	280,382	10,182,850		78,328,744	2,122,946	76,205,798	
44	W / O incentive	2018	16,207,990	439,480	15,768,509	2,359,079	10,182,850	280,382	9,902,468	1,486,134	76,205,798	2,122,946	74,082,852	11,145,005
45	W incentive	2018	16,207,990	439,480	15,768,509	2,523,023	10,182,850	280,382	9,902,468	1,589,112	76,205,798	2,122,946	74,082,852	11,787,118
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A	Proj Rev Req w/o Incentive PCY*					2,611,596				1,645,863				12,346,613
B	Proj Rev Req w/ Incentive PCY*					2,796,782				1,762,278				13,072,970
C	Actual Rev Req w/o Incentive PCY*					2,553,534				1,609,363				12,073,329
D	Actual Rev Req w/ Incentive PCY*					2,732,525				1,721,884				12,775,387
E	TUA w/o Int w/o Incentive PCY (C-A)					(58,062)				(36,500)				(273,284)
F	TUA w/o Int w/ Incentive PCY (B-D)					(64,257)				(40,395)				(297,583)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.07197				1.07197				1.07197
H	True-Up Adjustment w/o Incentive (E*G)					(62,241)				(39,127)				(292,953)
I	True-Up Adjustment w/ Incentive (F*G)					(68,882)				(43,302)				(319,001)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	2,296,838	1,447,007	10,852,053
W incentive	2,454,142	1,545,811	11,468,117

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

These Three Columns
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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	12.0063%	Phase 2			12.0063%	Phase 3			12.0063%	transmission line		
14	Incentive Factor (Basis Points /100)		1.25				1.25				1.25			
15	FCR W incentive L.13 +(L.14*L.5)		12.8608%				12.8608%				12.8608%			
16	Investment		32,204,664				13,426,813				84,131,836			
17	Annual Depreciation Exp		748,946				312,251				1,956,554			
18	In Service Month (1-12)		6				2				10			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**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									84,131,836	343,676	83,788,160	
29	W incentive	2010									84,131,836	343,676	83,788,160	
30	W / O incentive	2011	32,204,664	342,043	31,862,621						83,788,160	1,649,644	82,138,516	
31	W incentive	2011	32,204,664	342,043	31,862,621						83,788,160	1,649,644	82,138,516	
32	W / O incentive	2012	31,862,621	631,464	31,231,157		13,426,813	230,362	13,196,451		82,138,516	1,649,644	80,488,873	
33	W incentive	2012	31,862,621	631,464	31,231,157		13,426,813	230,362	13,196,451		82,138,516	1,649,644	80,488,873	
34	W / O incentive	2013	31,231,157	719,575	30,511,582		13,196,451	300,006	12,896,445		80,488,873	1,879,827	78,609,046	
35	W incentive	2013	31,231,157	719,575	30,511,582		13,196,451	300,006	12,896,445		80,488,873	1,879,827	78,609,046	
36	W / O incentive	2014	30,511,582	748,946	29,762,636		12,896,445	312,251	12,584,193		78,609,046	1,956,554	76,652,491	
37	W incentive	2014	30,511,582	748,946	29,762,636		12,896,445	312,251	12,584,193		78,609,046	1,956,554	76,652,491	
38	W / O incentive	2015	29,762,636	748,946	29,013,690		12,584,193	312,251	12,271,942		76,652,491	1,956,554	74,695,937	
39	W incentive	2015	29,762,636	748,946	29,013,690		12,584,193	312,251	12,271,942		76,652,491	1,956,554	74,695,937	
40	W / O incentive	2016	29,013,690	748,946	28,264,745		12,271,942	312,251	11,959,690		74,695,937	1,956,554	72,739,383	
41	W incentive	2016	29,013,690	748,946	28,264,745		12,271,942	312,251	11,959,690		74,695,937	1,956,554	72,739,383	
42	W / O incentive	2017	28,264,745	748,946	27,515,799		11,959,690	312,251	11,647,439		72,739,383	1,956,554	70,782,829	
43	W incentive	2017	28,264,745	748,946	27,515,799		11,959,690	312,251	11,647,439		72,739,383	1,956,554	70,782,829	
44	W / O incentive	2018	27,515,799	748,946	26,766,853	4,007,617	11,647,439	312,251	11,335,187	1,691,934	70,782,829	1,956,554	68,826,274	10,337,504
45	W incentive	2018	27,515,799	748,946	26,766,853	4,239,541	11,647,439	312,251	11,335,187	1,790,128	70,782,829	1,956,554	68,826,274	10,933,988
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A	Proj Rev Req w/o Incentive PCY*	4,437,030	1,872,495	11,531,092
B	Proj Rev Req w/ Incentive PCY*	4,699,056	1,983,345	12,210,342
C	Actual Rev Req w/o Incentive PCY*	4,338,446	1,830,789	11,195,967
D	Actual Rev Req w/ Incentive PCY*	4,591,706	1,937,930	11,847,861
E	TUA w/o Int w/o Incentive PCY (C-A)	(98,584)	(41,706)	(335,126)
F	TUA w/o Int w/ Incentive PCY (B-D)	(107,350)	(45,414)	(362,482)
G	Future Value Factor (1+i)^24 mo (ATT6)	1.07197	1.07197	1.07197
H	True-Up Adjustment w/o Incentive (E*G)	(105,680)	(44,708)	(359,245)
I	True-Up Adjustment w/ Incentive (F*G)	(115,076)	(48,683)	(388,570)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	3,901,937	1,647,226	9,978,259
W incentive	4,124,465	1,741,445	10,545,418

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			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 substation project		
13	FCR W/O incentive	Line 3	12.0063%	transmission line			12.0063%				12.0063%			
14	Incentive Factor (Basis Points /100)		1.25				1.25	Loop Line 251 Idylwood -- Arlington into			1.25	Loop Line 251 Idylwood -- Arlington into		
15	FCR W incentive L.13 +(L.14*L.5)		12.8608%				12.8608%	the GIS sub			12.8608%	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**	**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					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		176,397	4,781	171,616		20,610,601	546,130	20,064,471	
43	W incentive	2017	1,134,193	30,279	1,103,914		176,397	4,781	171,616		20,610,601	546,130	20,064,471	
44	W / O incentive	2018	1,103,914	30,279	1,073,635	161,000	171,616	4,781	166,835	25,099	20,064,471	546,130	19,518,341	2,922,347
45	W incentive	2018	1,103,914	30,279	1,073,635	170,304	171,616	4,781	166,835	26,545	20,064,471	546,130	19,518,341	3,091,466
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A	Proj Rev Req w/o Incentive PCY*					178,287				27,805				3,235,474
B	Proj Rev Req w/ Incentive PCY*					188,802				29,440				3,426,543
C	Actual Rev Req w/o Incentive PCY*					174,331				27,189				3,163,587
D	Actual Rev Req w/ Incentive PCY*					184,494				28,770				3,348,263
E	TUA w/o Int w/o Incentive PCY (C-A)					(3,956)				(615)				(71,888)
F	TUA w/o Int w/ Incentive PCY (B-D)					(4,308)				(670)				(78,280)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.07197				1.07197				1.07197
H	True-Up Adjustment w/o Incentive (E*G)					(4,241)				(660)				(77,061)
I	True-Up Adjustment w/ Incentive (F*G)					(4,618)				(718)				(83,913)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	W / O incentive	156,759	24,439	2,845,286
	W incentive	165,686	25,826	3,007,552

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

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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	12.0063%	115kV to 230kV			12.0063%				12.0063%			
14	Incentive Factor (Basis Points /100)		1.25				1.25				1.25			
15	FCR W incentive L.13 +(L.14*L.5)		12.8608%				12.8608%				12.8608%			
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**	**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									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		11,544,391	299,759	11,244,633		5,325,945	148,594	5,177,351	
43	W incentive	2017	1,270,791	34,247	1,236,544		11,544,391	299,759	11,244,633		5,325,945	148,594	5,177,351	
44	W / O incentive	2018	1,236,544	34,247	1,202,297	180,654	11,244,633	299,759	10,944,874	1,631,829	5,177,351	148,594	5,028,757	761,282
45	W incentive	2018	1,236,544	34,247	1,202,297	191,074	11,244,633	299,759	10,944,874	1,726,634	5,177,351	148,594	5,028,757	804,888
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A	Proj Rev Req w/o Incentive PCY*	200,101	1,895,460	846,365
B	Proj Rev Req w/ Incentive PCY*	211,884	2,007,771	895,909
C	Actual Rev Req w/o Incentive PCY*	195,667	1,765,462	825,434
D	Actual Rev Req w/ Incentive PCY*	207,057	1,868,876	873,189
E	TUA w/o Int w/o Incentive PCY (C-A)	(4,433)	(129,998)	(20,931)
F	TUA w/o Int w/ Incentive PCY (B-D)	(4,828)	(138,895)	(22,721)
G	Future Value Factor (1+i)^24 mo (ATT6)	1.07197	1.07197	1.07197
H	True-Up Adjustment w/o Incentive (E*G)	(4,752)	(139,355)	(22,437)
I	True-Up Adjustment w/ Incentive (F*G)	(5,175)	(148,892)	(24,356)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	175,902	1,492,474	738,845
W incentive	185,899	1,577,743	780,532

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

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10			**Project W**				**Project X**				**Project AA - 1**			
11	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	12.0063%	View 230 kV circuit			12.0063%	230 kV			12.0063%	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)		12.8608%				12.8608%				12.0063%			
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**	**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					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		2,690,624	74,340	2,616,284		18,551,257	509,588	18,041,669	
43	W incentive	2017	4,607,170	122,079	4,485,091		2,690,624	74,340	2,616,284		18,551,257	509,588	18,041,669	
44	W / O incentive	2018	4,485,091	122,079	4,363,013	653,244	2,616,284	74,340	2,541,945	383,996	18,041,669	509,588	17,532,081	2,645,135
45	W incentive	2018	4,485,091	122,079	4,363,013	691,048	2,616,284	74,340	2,541,945	406,035	18,041,669	509,588	17,532,081	2,645,135
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A	Proj Rev Req w/o Incentive PCY*					722,873				425,618				2,931,383
B	Proj Rev Req w/ Incentive PCY*					765,561				450,575				2,931,383
C	Actual Rev Req w/o Incentive PCY*					707,169				416,228				2,866,647
D	Actual Rev Req w/ Incentive PCY*					748,451				440,350				2,866,647
E	TUA w/o Int w/o Incentive PCY (C-A)					(15,704)				(9,390)				(64,736)
F	TUA w/o Int w/ Incentive PCY (B-D)					(17,111)				(10,225)				(64,736)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.07197				1.07197				1.07197
H	True-Up Adjustment w/o Incentive (E*G)					(16,834)				(10,066)				(69,395)
I	True-Up Adjustment w/ Incentive (F*G)					(18,342)				(10,961)				(69,395)
	W / O incentive					636,410				373,931				2,575,740
	W incentive					672,705				395,074				2,575,740

TUA = True-Up Adjusment
PCY = Previous Calendar Year

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 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. Jacks			43	Install 500/230 kV transformer at Bristers;			43	Add 2nd Endless Caverns 230/115kV		
13	FCR W/O incentive	Line 3	12.0063%	115 kV			12.0063%	build new 230 kV Bristers- Gainesville circuit,			12.0063%	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)		12.0063%				12.0063%				12.0063%			
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**	**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	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		17,705,567	491,097	17,214,470		2,865,756	79,642	2,786,113	
43	W incentive	2017	4,097,600	112,558	3,985,042		17,705,567	491,097	17,214,470		2,865,756	79,642	2,786,113	
44	W / O incentive	2018	3,985,042	112,558	3,872,485	584,257	17,214,470	491,097	16,723,374	2,528,438	2,786,113	79,642	2,706,471	409,371
45	W incentive	2018	3,985,042	112,558	3,872,485	584,257	17,214,470	491,097	16,723,374	2,528,438	2,786,113	79,642	2,706,471	409,371
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A	Proj Rev Req w/o Incentive PCY*	647,484	2,840,823	471,049
B	Proj Rev Req w/ Incentive PCY*	647,484	2,840,823	471,049
C	Actual Rev Req w/o Incentive PCY*	633,185	2,741,002	443,813
D	Actual Rev Req w/ Incentive PCY*	633,185	2,741,002	443,813
E	TUA w/o Int w/o Incentive PCY (C-A)	(14,299)	(99,820)	(27,236)
F	TUA w/o Int w/ Incentive PCY (B-D)	(14,299)	(99,820)	(27,236)
G	Future Value Factor (1+i)^24 mo (ATT6)	1.07197	1.07197	1.07197
H	True-Up Adjustment w/o Incentive (E*G)	(15,328)	(107,005)	(29,196)
I	True-Up Adjustment w/ Incentive (F*G)	(15,328)	(107,005)	(29,196)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	568,929	2,421,433	380,174
W incentive	568,929	2,421,433	380,174

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			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 230 kV
13	FCR W/O incentive	Line 3	12.0063%		12.0063%	the 500 kV side of the transformer with a	12.0063%	
14	Incentive Factor (Basis Points /100)		1.25		0	circuit breaker	0	
15	FCR W incentive L.13 +(L.14*L.5)		12.8608%		12.0063%		12.0063%	
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	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	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		653,292	18,120	635,172		5,339,843	144,451	5,195,392	
43	W incentive	2017	2,829,859	78,035	2,751,824		653,292	18,120	635,172		5,339,843	144,451	5,195,392	
44	W / O incentive	2018	2,751,824	78,035	2,673,789	403,743	635,172	18,120	617,052	93,293	5,195,392	144,451	5,050,941	759,554
45	W incentive	2018	2,751,824	78,035	2,673,789	426,924	635,172	18,120	617,052	93,293	5,195,392	144,451	5,050,941	759,554
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A	Proj Rev Req w/o Incentive PCY*	447,482	103,416	841,403
B	Proj Rev Req w/ Incentive PCY*	473,730	103,416	841,403
C	Actual Rev Req w/o Incentive PCY*	437,606	101,136	822,773
D	Actual Rev Req w/ Incentive PCY*	462,976	101,136	822,773
E	TUA w/o Int w/o Incentive PCY (C-A)	(9,875)	(2,280)	(18,630)
F	TUA w/o Int w/ Incentive PCY (B-D)	(10,754)	(2,280)	(18,630)
G	Future Value Factor (1+i)^24 mo (ATT6)	1.07197	1.07197	1.07197
H	True-Up Adjustment w/o Incentive (E*G)	(10,586)	(2,444)	(19,971)
I	True-Up Adjustment w/ Incentive (F*G)	(11,528)	(2,444)	(19,971)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	393,157	90,849	739,583
W incentive	415,397	90,849	739,583

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 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	12.0063%				12.0063%				12.0063%			
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		12.0063%				12.0063%				12.0063%			
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**	**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	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		19,516,766	506,768	19,009,998		110,233,111	2,799,571	107,433,540	
43	W incentive	2017	21,252,668	556,922	20,695,746		19,516,766	506,768	19,009,998		110,233,111	2,799,571	107,433,540	
44	W / O incentive	2018	20,695,746	556,922	20,138,824	3,008,284	19,009,998	506,768	18,503,231	2,758,745	107,433,540	2,799,571	104,633,969	15,530,310
45	W incentive	2018	20,695,746	556,922	20,138,824	3,008,284	19,009,998	506,768	18,503,231	2,758,745	107,433,540	2,799,571	104,633,969	15,530,310
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A	Proj Rev Req w/o Incentive PCY*	3,329,645	3,052,716	17,175,367
B	Proj Rev Req w/ Incentive PCY*	3,329,645	3,052,716	17,175,367
C	Actual Rev Req w/o Incentive PCY*	3,255,529	2,984,662	16,791,094
D	Actual Rev Req w/ Incentive PCY*	3,255,529	2,984,662	16,791,094
E	TUA w/o Int w/o Incentive PCY (C-A)	(74,116)	(68,055)	(384,272)
F	TUA w/o Int w/ Incentive PCY (B-D)	(74,116)	(68,055)	(384,272)
G	Future Value Factor (1+i)^24 mo (ATT6)	1.07197	1.07197	1.07197
H	True-Up Adjustment w/o Incentive (E*G)	(79,451)	(72,952)	(411,929)
I	True-Up Adjustment w/ Incentive (F*G)	(79,451)	(72,952)	(411,929)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	2,928,833	2,685,792	15,118,381
W incentive	2,928,833	2,685,792	15,118,381

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 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	12.0063%				12.0063%				12.0063%			
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		12.0063%				12.0063%				12.0063%			
16	Investment		150,057,630				15,394,401				515,816			
17	Annual Depreciation Exp		3,489,712				358,009				11,996			
18	In Service Month (1-12)		5				5				6			
19			Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	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	150,057,630	2,181,070	147,876,560									
37	W incentive	2014	150,057,630	2,181,070	147,876,560									
38	W / O incentive	2015	147,876,560	3,489,712	144,386,847		15,394,401	223,756	15,170,645					
39	W incentive	2015	147,876,560	3,489,712	144,386,847		15,394,401	223,756	15,170,645					
40	W / O incentive	2016	144,386,847	3,489,712	140,897,135		15,170,645	223,756	14,946,889		515,816	6,498	509,318	
41	W incentive	2016	144,386,847	3,489,712	140,897,135		15,170,645	223,756	14,946,889		515,816	6,498	509,318	
42	W / O incentive	2017	140,897,135	3,489,712	137,407,423		14,946,889	223,756	14,723,134		509,318	11,996	497,323	
43	W incentive	2017	140,897,135	3,489,712	137,407,423		14,946,889	223,756	14,723,134		509,318	11,996	497,323	
44	W / O incentive	2018	137,407,423	3,489,712	133,917,710	19,777,778	14,723,134	223,756	14,499,378	1,978,028	497,323	11,996	485,327	70,986
45	W incentive	2018	137,407,423	3,489,712	133,917,710	19,777,778	14,723,134	223,756	14,499,378	1,978,028	497,323	11,996	485,327	70,986
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A	Proj Rev Req w/o Incentive PCY*	20,377,022	3,231,607	-
B	Proj Rev Req w/ Incentive PCY*	20,377,022	3,231,607	-
C	Actual Rev Req w/o Incentive PCY*	21,367,764	2,111,148	41,296
D	Actual Rev Req w/ Incentive PCY*	21,367,764	2,111,148	41,296
E	TUA w/o Int w/o Incentive PCY (C-A)	990,742	(1,120,459)	41,296
F	TUA w/o Int w/ Incentive PCY (B-D)	990,742	(1,120,459)	41,296
G	Future Value Factor (1+i)^24 mo (ATT6)	1.07197	1.07197	1.07197
H	True-Up Adjustment w/o Incentive (E*G)	1,062,047	(1,201,099)	44,268
I	True-Up Adjustment w/ Incentive (F*G)	1,062,047	(1,201,099)	44,268

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	20,839,825	776,929	115,254
W incentive	20,839,825	776,929	115,254

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

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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 Anna to		
13	FCR W/O incentive	Line 3	12.0063%				12.0063%	Dooms - Lexington 500 kV			12.0063%	Ladysmith 500 kV		
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		12.0063%				12.0063%				12.0063%			
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**	**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					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		66,929	1,760	65,169	
43	W incentive	2017	-	-	-	0	96,523	2,529	93,994		66,929	1,760	65,169	
44	W / O incentive	2018	-	-	-	-	93,994	2,529	91,464	13,663	65,169	1,760	63,409	9,479
45	W incentive	2018	-	-	-	-	93,994	2,529	91,464	13,663	65,169	1,760	63,409	9,479
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A	Proj Rev Req w/o Incentive PCY*					-				15,122				10,493
B	Proj Rev Req w/ Incentive PCY*					-				15,122				10,493
C	Actual Rev Req w/o Incentive PCY*					-				14,786				10,259
D	Actual Rev Req w/ Incentive PCY*					-				14,786				10,259
E	TUA w/o Int w/o Incentive PCY (C-A)					-				(337)				(233)
F	TUA w/o Int w/ Incentive PCY (B-D)					-				(337)				(233)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.07197				1.07197				1.07197
H	True-Up Adjustment w/o Incentive (E*G)					-				(361)				(250)
I	True-Up Adjustment w/ Incentive (F*G)					-				(361)				(250)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	Project AK-7	Project AL	Project AM
W / O incentive	-	13,302	9,229
W incentive	-	13,302	9,229

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

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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 capacitor banks		
13	FCR W/O incentive	Line 3	12.0063%	kV transformer and a 150			12.0063%	at Merck and Edinburg			12.0063%	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)		12.0063%				12.0063%	Merck			12.0063%	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	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					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		459,347	11,884	447,463		672,536	17,559	654,977	
43	W incentive	2017	12,939,296	329,314	12,609,982		459,347	11,884	447,463		672,536	17,559	654,977	
44	W / O incentive	2018	12,609,982	329,314	12,280,668	1,823,538	447,463	11,884	435,579	64,894	654,977	17,559	637,418	95,144
45	W incentive	2018	12,609,982	329,314	12,280,668	1,823,538	447,463	11,884	435,579	64,894	654,977	17,559	637,418	95,144
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		Project AO	Project AP-1	Project AP-2
A	Proj Rev Req w/o Incentive PCY*	2,016,807	71,803	105,297
B	Proj Rev Req w/ Incentive PCY*	2,016,807	71,803	105,297
C	Actual Rev Req w/o Incentive PCY*	1,971,700	70,201	102,952
D	Actual Rev Req w/ Incentive PCY*	1,971,700	70,201	102,952
E	TUA w/o Int w/o Incentive PCY (C-A)	(45,108)	(1,602)	(2,345)
F	TUA w/o Int w/ Incentive PCY (B-D)	(45,108)	(1,602)	(2,345)
G	Future Value Factor (1+i)^24 mo (ATT6)	1.07197	1.07197	1.07197
H	True-Up Adjustment w/o Incentive (E*G)	(48,354)	(1,717)	(2,514)
I	True-Up Adjustment w/ Incentive (F*G)	(48,354)	(1,717)	(2,514)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	Project AO	Project AP-1	Project AP-2
W / O incentive	1,775,184	63,177	92,629
W incentive	1,775,184	63,177	92,629

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

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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	12.0063%	rating at Morrisville 500 kV			12.0063%	at Morrisville 500 kV			12.0063%	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)		12.0063%	50kA breaker			12.0063%	50kA breaker			12.0063%			
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**	**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	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		14,792	379	14,413		780,466	19,974	760,493	
43	W incentive	2017	14,792	379	14,413		14,792	379	14,413		780,466	19,974	760,493	
44	W / O incentive	2018	14,413	379	14,035	2,086	14,413	379	14,035	2,086	760,493	19,974	740,519	110,082
45	W incentive	2018	14,413	379	14,035	2,086	14,413	379	14,035	2,086	760,493	19,974	740,519	110,082
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A	Proj Rev Req w/o Incentive PCY*	2,308	2,308	121,766
B	Proj Rev Req w/ Incentive PCY*	2,308	2,308	121,766
C	Actual Rev Req w/o Incentive PCY*	2,256	2,256	119,045
D	Actual Rev Req w/ Incentive PCY*	2,256	2,256	119,045
E	TUA w/o Int w/o Incentive PCY (C-A)	(52)	(52)	(2,721)
F	TUA w/o Int w/ Incentive PCY (B-D)	(52)	(52)	(2,721)
G	Future Value Factor (1+i)^24 mo (ATT6)	1.07197	1.07197	1.07197
H	True-Up Adjustment w/o Incentive (E*G)	(55)	(55)	(2,917)
I	True-Up Adjustment w/ Incentive (F*G)	(55)	(55)	(2,917)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	2,031	2,031	107,165
W incentive	2,031	2,031	107,165

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

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Line			**Project AT**				**Project AU-1**				**Project AU-2**			
10														
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		12.0063%	breaker 'H2T569' with			12.0063%	transformer and two 230 kV breakers			12.0063%	transformer and two 230 kV breakers		
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)		12.0063%				12.0063%				12.0063%			
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**	**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					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		211,658	5,486	206,172		15,535,243	388,786	15,146,457	
43	W incentive	2017	780,466	19,974	760,493		211,658	5,486	206,172		15,535,243	388,786	15,146,457	
44	W / O incentive	2018	760,493	19,974	740,519	110,082	206,172	5,486	200,687	29,910	15,146,457	388,786	14,757,671	2,183,977
45	W incentive	2018	760,493	19,974	740,519	110,082	206,172	5,486	200,687	29,910	15,146,457	388,786	14,757,671	2,183,977
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		Project AT	Project AU-1	Project AU-2
A	Proj Rev Req w/o Incentive PCY*	121,766	33,096	2,414,408
B	Proj Rev Req w/ Incentive PCY*	121,766	33,096	2,414,408
C	Actual Rev Req w/o Incentive PCY*	119,045	32,358	2,360,262
D	Actual Rev Req w/ Incentive PCY*	119,045	32,358	2,360,262
E	TUA w/o Int w/o Incentive PCY (C-A)	(2,721)	(738)	(54,146)
F	TUA w/o Int w/ Incentive PCY (B-D)	(2,721)	(738)	(54,146)
G	Future Value Factor (1+i)^24 mo (ATT6)	1.07197	1.07197	1.07197
H	True-Up Adjustment w/o Incentive (E*G)	(2,917)	(791)	(58,043)
I	True-Up Adjustment w/ Incentive (F*G)	(2,917)	(791)	(58,043)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	Project AT	Project AU-1	Project AU-2
W / O incentive	107,165	29,119	2,125,934
W incentive	107,165	29,119	2,125,934

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

These Three Columns
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References on All Pages

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	12.0063%	ring bus connected to the Loudoun			12.0063%	connected to the Loudoun to Pleasant View			12.0063%	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)		12.0063%				12.0063%				12.0063%			
16	Investment		-				1,604,454				-			
17	Annual Depreciation Exp		-				37,313				-			
18	In Service Month (1-12)						1							
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**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												
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26	W / O incentive	2009												
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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	-	-	-		1,604,454	35,758	1,568,696					
37	W incentive	2014	-	-	-		1,604,454	35,758	1,568,696					
38	W / O incentive	2015	-	-	-		1,568,696	37,313	1,531,383		-	-	-	
39	W incentive	2015	-	-	-		1,568,696	37,313	1,531,383		-	-	-	
40	W / O incentive	2016	-	-	-		1,531,383	37,313	1,494,070		-	-	-	
41	W incentive	2016	-	-	-		1,531,383	37,313	1,494,070		-	-	-	
42	W / O incentive	2017	-	-	-		1,494,070	37,313	1,456,757		-	-	-	
43	W incentive	2017	-	-	-		1,494,070	37,313	1,456,757		-	-	-	
44	W / O incentive	2018	-	-	-	-	1,456,757	37,313	1,419,444	209,976	-	-	-	-
45	W incentive	2018	-	-	-	-	1,456,757	37,313	1,419,444	209,976	-	-	-	-
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A	Proj Rev Req w/o Incentive PCY*					1,235,212				234,015				36,779
B	Proj Rev Req w/ Incentive PCY*					1,235,212				234,015				36,779
C	Actual Rev Req w/o Incentive PCY*					-				226,911				-
D	Actual Rev Req w/ Incentive PCY*					-				226,911				-
E	TUA w/o Int w/o Incentive PCY (C-A)					(1,235,212)				(7,105)				(36,779)
F	TUA w/o Int w/ Incentive PCY (B-D)					(1,235,212)				(7,105)				(36,779)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.07197				1.07197				1.07197
H	True-Up Adjustment w/o Incentive (E*G)					(1,324,112)				(7,616)				(39,426)
I	True-Up Adjustment w/ Incentive (F*G)					(1,324,112)				(7,616)				(39,426)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive		(1,324,112)	202,360	(39,426)
W incentive		(1,324,112)	202,360	(39,426)

Virginia Electric and Power Company
ATTACHMENT H-16A
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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	12.0063%	Green and install a 224 MVA 230/115			12.0063%	Green and install a 224 MVA 230/115			12.0063%	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)		12.0063%				12.0063%				12.0063%			
16	Investment		30,988,685				6,370,238				4,076,165			
17	Annual Depreciation Exp		720,667				148,145				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**	**Rev Req**
20	W / O incentive	2006												
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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	30,988,685	570,528	30,418,157		6,370,238	80,245	6,289,993		3,922,124	94,795	3,827,329	
39	W incentive	2015	30,988,685	570,528	30,418,157		6,370,238	80,245	6,289,993		3,922,124	94,795	3,827,329	
40	W / O incentive	2016	30,418,157	720,667	29,697,490		6,289,993	148,145	6,141,848		3,827,329	94,795	3,732,535	
41	W incentive	2016	30,418,157	720,667	29,697,490		6,289,993	148,145	6,141,848		3,827,329	94,795	3,732,535	
42	W / O incentive	2017	29,697,490	720,667	28,976,823		6,141,848	148,145	5,993,703		3,732,535	94,795	3,637,740	
43	W incentive	2017	29,697,490	720,667	28,976,823		6,141,848	148,145	5,993,703		3,732,535	94,795	3,637,740	
44	W / O incentive	2018	28,976,823	720,667	28,256,156	4,156,451	5,993,703	148,145	5,845,558	858,874	3,637,740	94,795	3,542,946	525,862
45	W incentive	2018	28,976,823	720,667	28,256,156	4,156,451	5,993,703	148,145	5,845,558	858,874	3,637,740	94,795	3,542,946	525,862
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A	Proj Rev Req w/o Incentive PCY*					4,555,981				1,116,852				581,564
B	Proj Rev Req w/ Incentive PCY*					4,555,981				1,116,852				581,564
C	Actual Rev Req w/o Incentive PCY*					4,487,968				927,218				568,553
D	Actual Rev Req w/ Incentive PCY*					4,487,968				927,218				568,553
E	TUA w/o Int w/o Incentive PCY (C-A)					(68,012)				(189,634)				(13,012)
F	TUA w/o Int w/ Incentive PCY (B-D)					(68,012)				(189,634)				(13,012)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.07197				1.07197				1.07197
H	True-Up Adjustment w/o Incentive (E*G)					(72,907)				(203,282)				(13,948)
I	True-Up Adjustment w/ Incentive (F*G)					(72,907)				(203,282)				(13,948)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	4,083,544	655,592	511,914
W incentive	4,083,544	655,592	511,914

Virginia Electric and Power Company
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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 at Pleasant		
13	FCR W/O incentive	Line 3	12.0063%	Chancellor 500 kV			12.0063%	Dominion owned section of Cloverdale -			12.0063%	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)		12.0063%				12.0063%				12.0063%			
16	Investment		116,523				18,459,911				26,048,344			
17	Annual Depreciation Exp		2,710				429,300				605,775			
18	In Service Month (1-12)		12				10				11			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**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					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		26,048,344	75,722	25,972,622	
37	W incentive	2014	116,523	113	116,410		18,370,473	429,300	17,941,173		26,048,344	75,722	25,972,622	
38	W / O incentive	2015	116,410	2,710	113,700		17,941,173	429,300	17,511,873		25,972,622	605,775	25,366,847	
39	W incentive	2015	116,410	2,710	113,700		17,941,173	429,300	17,511,873		25,972,622	605,775	25,366,847	
40	W / O incentive	2016	113,700	2,710	110,990		17,511,873	429,300	17,082,573		25,366,847	605,775	24,761,071	
41	W incentive	2016	113,700	2,710	110,990		17,511,873	429,300	17,082,573		25,366,847	605,775	24,761,071	
42	W / O incentive	2017	110,990	2,710	108,281		17,082,573	429,300	16,653,272		24,761,071	605,775	24,155,296	
43	W incentive	2017	110,990	2,710	108,281		17,082,573	429,300	16,653,272		24,761,071	605,775	24,155,296	
44	W / O incentive	2018	108,281	2,710	105,571	15,548	16,653,272	429,300	16,223,972	2,402,972	24,155,296	605,775	23,549,520	3,469,569
45	W incentive	2018	108,281	2,710	105,571	15,548	16,653,272	429,300	16,223,972	2,402,972	24,155,296	605,775	23,549,520	3,469,569
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A	Proj Rev Req w/o Incentive PCY*					17,177				2,655,928				3,775,154
B	Proj Rev Req w/ Incentive PCY*					17,177				2,655,928				3,775,154
C	Actual Rev Req w/o Incentive PCY*					16,791				2,597,250				3,747,170
D	Actual Rev Req w/ Incentive PCY*					16,791				2,597,250				3,747,170
E	TUA w/o Int w/o Incentive PCY (C-A)					(387)				(58,678)				(27,984)
F	TUA w/o Int w/ Incentive PCY (B-D)					(387)				(58,678)				(27,984)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.07197				1.07197				1.07197
H	True-Up Adjustment w/o Incentive (E*G)					(415)				(62,902)				(29,998)
I	True-Up Adjustment w/ Incentive (F*G)					(415)				(62,902)				(29,998)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	W / O incentive	15,133	2,340,070	3,439,571
	W incentive	15,133	2,340,070	3,439,571

Virginia Electric and Power Company
ATTACHMENT H-16A
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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 MVAR
13	FCR W/O incentive	Line 3	12.0063%	switched shunt at Loudoun 500 kV	12.0063%	switched shunt at Loudoun 500 kV	12.0063%	switched shunt at Loudoun 500 kV
14	Incentive Factor (Basis Points /100)		0		0		0	
15	FCR W incentive L.13 +(L.14*L.5)		12.0063%		12.0063%		12.0063%	
16	Investment		3,131,641		35,213,766		17,960,921	
17	Annual Depreciation Exp		72,829		818,925		417,696	
18	In Service Month (1-12)		12		5		6	

19			Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	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	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		35,213,766	511,828	34,701,938		17,960,921	226,252	17,734,669	
37	W incentive	2014	3,128,606	72,829	3,055,778		35,213,766	511,828	34,701,938		17,960,921	226,252	17,734,669	
38	W / O incentive	2015	3,055,778	72,829	2,982,949		34,701,938	818,925	33,883,013		17,734,669	417,696	17,316,973	
39	W incentive	2015	3,055,778	72,829	2,982,949		34,701,938	818,925	33,883,013		17,734,669	417,696	17,316,973	
40	W / O incentive	2016	2,982,949	72,829	2,910,120		33,883,013	818,925	33,064,088		17,316,973	417,696	16,899,277	
41	W incentive	2016	2,982,949	72,829	2,910,120		33,883,013	818,925	33,064,088		17,316,973	417,696	16,899,277	
42	W / O incentive	2017	2,910,120	72,829	2,837,291		33,064,088	818,925	32,245,164		16,899,277	417,696	16,481,582	
43	W incentive	2017	2,910,120	72,829	2,837,291		33,064,088	818,925	32,245,164		16,899,277	417,696	16,481,582	
44	W / O incentive	2018	2,837,291	72,829	2,764,462	409,111	32,245,164	818,925	31,426,239	4,641,217	16,481,582	417,696	16,063,886	2,371,450
45	W incentive	2018	2,837,291	72,829	2,764,462	409,111	32,245,164	818,925	31,426,239	4,641,217	16,481,582	417,696	16,063,886	2,371,450
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A	Proj Rev Req w/o Incentive PCY*	452,276	5,709,262	2,691,239
B	Proj Rev Req w/ Incentive PCY*	452,276	5,709,262	2,691,239
C	Actual Rev Req w/o Incentive PCY*	442,133	5,014,337	2,561,945
D	Actual Rev Req w/ Incentive PCY*	442,133	5,014,337	2,561,945
E	TUA w/o Int w/o Incentive PCY (C-A)	(10,143)	(694,925)	(129,294)
F	TUA w/o Int w/ Incentive PCY (B-D)	(10,143)	(694,925)	(129,294)
G	Future Value Factor (1+i)^24 mo (ATT6)	1.07197	1.07197	1.07197
H	True-Up Adjustment w/o Incentive (E*G)	(10,873)	(744,940)	(138,599)
I	True-Up Adjustment w/ Incentive (F*G)	(10,873)	(744,940)	(138,599)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	398,238	3,896,277	2,232,851
W incentive	398,238	3,896,277	2,232,851

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 MVAR		
13	FCR W/O incentive Line 3		12.0063%	switched shunt at Loudoun 500 kV			12.0063%	switched shunt at Loudoun 500 kV			12.0063%	switched shunt at Loudoun 500 kV		
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		12.0063%				12.0063%				12.0063%			
16	Investment		38,026,755				12,272,537				4,574,038			
17	Annual Depreciation Exp		884,343				285,408				106,373			
18	In Service Month (1-12)		8				12				1			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**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												
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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	38,026,755	331,629	37,695,126		12,272,537	11,892	12,260,645					
37	W incentive	2014	38,026,755	331,629	37,695,126		12,272,537	11,892	12,260,645					
38	W / O incentive	2015	37,695,126	884,343	36,810,783		12,260,645	285,408	11,975,237		4,574,038	101,941	4,472,097	
39	W incentive	2015	37,695,126	884,343	36,810,783		12,260,645	285,408	11,975,237		4,574,038	101,941	4,472,097	
40	W / O incentive	2016	36,810,783	884,343	35,926,440		11,975,237	285,408	11,689,829		4,472,097	106,373	4,365,724	
41	W incentive	2016	36,810,783	884,343	35,926,440		11,975,237	285,408	11,689,829		4,472,097	106,373	4,365,724	
42	W / O incentive	2017	35,926,440	884,343	35,042,097		11,689,829	285,408	11,404,421		4,365,724	106,373	4,259,351	
43	W incentive	2017	35,926,440	884,343	35,042,097		11,689,829	285,408	11,404,421		4,365,724	106,373	4,259,351	
44	W / O incentive	2018	35,042,097	884,343	34,157,754	5,038,517	11,404,421	285,408	11,119,014	1,637,524	4,259,351	106,373	4,152,978	611,378
45	W incentive	2018	35,042,097	884,343	34,157,754	5,038,517	11,404,421	285,408	11,119,014	1,637,524	4,259,351	106,373	4,152,978	611,378
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A	Proj Rev Req w/o Incentive PCY*					5,181,264				688,166				676,901
B	Proj Rev Req w/ Incentive PCY*					5,181,264				688,166				676,901
C	Actual Rev Req w/o Incentive PCY*					5,442,608				1,768,440				660,218
D	Actual Rev Req w/ Incentive PCY*					5,442,608				1,768,440				660,218
E	TUA w/o Int w/o Incentive PCY (C-A)					261,344				1,080,274				(16,683)
F	TUA w/o Int w/ Incentive PCY (B-D)					261,344				1,080,274				(16,683)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.07197				1.07197				1.07197
H	True-Up Adjustment w/o Incentive (E*G)					280,153				1,158,022				(17,884)
I	True-Up Adjustment w/ Incentive (F*G)					280,153				1,158,022				(17,884)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	W / O incentive					5,318,669				2,795,547				593,494
	W incentive					5,318,669				2,795,547				593,494

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

			Project BC				Project BD-1				Project BD-2			
10														
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 Harrisonburg to		
13	FCR W/O incentive	Line 3	12.0063%	Storm 500 kV substation			12.0063%	Endless Caverns			12.0063%	Endless Caverns		
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		12.0063%				12.0063%				12.0063%			
16	Investment		37,153,276				4,829,987				51,208,945			
17	Annual Depreciation Exp		864,030				112,325				1,190,906			
18	In Service Month (1-12)		6				10				9			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**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												
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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		51,208,945	347,347	50,861,598	
37	W incentive	2014	37,153,276	468,016	36,685,260		4,806,586	112,325	4,694,261		51,208,945	347,347	50,861,598	
38	W / O incentive	2015	36,685,260	864,030	35,821,230		4,694,261	112,325	4,581,935		50,861,598	1,190,906	49,670,692	
39	W incentive	2015	36,685,260	864,030	35,821,230		4,694,261	112,325	4,581,935		50,861,598	1,190,906	49,670,692	
40	W / O incentive	2016	35,821,230	864,030	34,957,201		4,581,935	112,325	4,469,610		49,670,692	1,190,906	48,479,786	
41	W incentive	2016	35,821,230	864,030	34,957,201		4,581,935	112,325	4,469,610		49,670,692	1,190,906	48,479,786	
42	W / O incentive	2017	34,957,201	864,030	34,093,171		4,469,610	112,325	4,357,285		48,479,786	1,190,906	47,288,880	
43	W incentive	2017	34,957,201	864,030	34,093,171		4,469,610	112,325	4,357,285		48,479,786	1,190,906	47,288,880	
44	W / O incentive	2018	34,093,171	864,030	33,229,141	4,905,492	4,357,285	112,325	4,244,960	628,731	47,288,880	1,190,906	46,097,975	6,797,062
45	W incentive	2018	34,093,171	864,030	33,229,141	4,905,492	4,357,285	112,325	4,244,960	628,731	47,288,880	1,190,906	46,097,975	6,797,062
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A	Proj Rev Req w/o Incentive PCY*	5,377,909	645,952	7,480,107
B	Proj Rev Req w/ Incentive PCY*	5,377,909	645,952	7,480,107
C	Actual Rev Req w/o Incentive PCY*	5,299,541	679,564	7,341,757
D	Actual Rev Req w/ Incentive PCY*	5,299,541	679,564	7,341,757
E	TUA w/o Int w/o Incentive PCY (C-A)	(78,367)	33,611	(138,350)
F	TUA w/o Int w/ Incentive PCY (B-D)	(78,367)	33,611	(138,350)
G	Future Value Factor (1+i)^24 mo (ATT6)	1.07197	1.07197	1.07197
H	True-Up Adjustment w/o Incentive (E*G)	(84,007)	36,031	(148,307)
I	True-Up Adjustment w/ Incentive (F*G)	(84,007)	36,031	(148,307)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	4,821,484	664,762	6,648,755
W incentive	4,821,484	664,762	6,648,755

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

			Project BD-3				**Project BD-4**				**Project BD-5**			
10														
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 Harrisonburg to		
13	FCR W/O incentive	Line 3	12.0063%	Endless Caverns			12.0063%	Endless Caverns			12.0063%	Endless Caverns		
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		12.0063%				12.0063%				12.0063%			
16	Investment		2,000,000				6,192,407				1,164,215			
17	Annual Depreciation Exp		46,512				144,009				27,075			
18	In Service Month (1-12)		12				6				7			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**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												
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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		6,192,407	78,005	6,114,402					
39	W incentive	2015	1,998,062	46,512	1,951,550		6,192,407	78,005	6,114,402					
40	W / O incentive	2016	1,951,550	46,512	1,905,039		6,114,402	144,009	5,970,392		1,164,215	12,409	1,151,806	
41	W incentive	2016	1,951,550	46,512	1,905,039		6,114,402	144,009	5,970,392		1,164,215	12,409	1,151,806	
42	W / O incentive	2017	1,905,039	46,512	1,858,527		5,970,392	144,009	5,826,383	852,188	1,151,806	27,075	1,124,731	
43	W incentive	2017	1,905,039	46,512	1,858,527		5,970,392	144,009	5,826,383	852,188	1,151,806	27,075	1,124,731	
44	W / O incentive	2018	1,858,527	46,512	1,812,016	266,860	5,826,383	144,009	5,682,373	834,898	1,124,731	27,075	1,097,656	160,488
45	W incentive	2018	1,858,527	46,512	1,812,016	266,860	5,826,383	144,009	5,682,373	834,898	1,124,731	27,075	1,097,656	160,488
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A	Proj Rev Req w/o Incentive PCY*					294,832				808,260				173,253
B	Proj Rev Req w/ Incentive PCY*					294,832				808,260				173,253
C	Actual Rev Req w/o Incentive PCY*					288,195				871,529				78,931
D	Actual Rev Req w/ Incentive PCY*					288,195				871,529				78,931
E	TUA w/o Int w/o Incentive PCY (C-A)					(6,638)				63,269				(94,321)
F	TUA w/o Int w/ Incentive PCY (B-D)					(6,638)				63,269				(94,321)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.07197				1.07197				1.07197
H	True-Up Adjustment w/o Incentive (E*G)					(7,115)				67,822				(101,109)
I	True-Up Adjustment w/ Incentive (F*G)					(7,115)				67,822				(101,109)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive				259,744				902,720				59,379
W incentive				259,744				902,720				59,379

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 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	12.0063%	Endless Caverns			12.0063%	(Altavista - Skimmer, 115kV)			12.0063%	(Altavista - Skimmer, 115kV)		
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		12.0063%				12.0063%				12.0063%			
16	Investment		11,994,009				6,782,738				23,185,874			
17	Annual Depreciation Exp		278,930				157,738				539,206			
18	In Service Month (1-12)		9				11				3			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**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	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		23,185,874	426,872	22,759,002	
39	W incentive	2015	11,912,654	278,930	11,633,724		6,763,021	157,738	6,605,283		23,185,874	426,872	22,759,002	
40	W / O incentive	2016	11,633,724	278,930	11,354,793		6,605,283	157,738	6,447,545		22,759,002	539,206	22,219,796	
41	W incentive	2016	11,633,724	278,930	11,354,793		6,605,283	157,738	6,447,545		22,759,002	539,206	22,219,796	
42	W / O incentive	2017	11,354,793	278,930	11,075,863		6,447,545	157,738	6,289,806		22,219,796	539,206	21,680,590	
43	W incentive	2017	11,354,793	278,930	11,075,863		6,447,545	157,738	6,289,806		22,219,796	539,206	21,680,590	
44	W / O incentive	2018	11,075,863	278,930	10,796,933	1,591,988	6,289,806	157,738	6,132,068	903,442	21,680,590	539,206	21,141,383	3,109,875
45	W incentive	2018	11,075,863	278,930	10,796,933	1,591,988	6,289,806	157,738	6,132,068	903,442	21,680,590	539,206	21,141,383	3,109,875
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A	Proj Rev Req w/o Incentive PCY*					1,760,782				998,193				2,879,558
B	Proj Rev Req w/ Incentive PCY*					1,760,782				998,193				2,879,558
C	Actual Rev Req w/o Incentive PCY*					1,719,565				975,727				3,357,918
D	Actual Rev Req w/ Incentive PCY*					1,719,565				975,727				3,357,918
E	TUA w/o Int w/o Incentive PCY (C-A)					(41,217)				(22,466)				478,360
F	TUA w/o Int w/ Incentive PCY (B-D)					(41,217)				(22,466)				478,360
G	Future Value Factor (1+i)^24 mo (ATT6)					1.07197				1.07197				1.07197
H	True-Up Adjustment w/o Incentive (E*G)					(44,184)				(24,083)				512,788
I	True-Up Adjustment w/ Incentive (F*G)					(44,184)				(24,083)				512,788

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive		1,547,804	879,360	3,622,663
W incentive		1,547,804	879,360	3,622,663

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

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Line Number
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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 kV breakers		
13	FCR W/O incentive	Line 3	12.0063%	(Altavista - Skimmer, 115kV)			12.0063%	(Altavista - Skimmer, 115kV)			12.0063%			
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		12.0063%				12.0063%				12.0063%			
16	Investment		12,490,289				1,006,355				4,398,307			
17	Annual Depreciation Exp		290,472				23,404				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**	**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	12,490,289	157,339	12,332,950		1,006,355	975	1,005,380		4,398,307	63,929	4,334,378	
39	W incentive	2015	12,490,289	157,339	12,332,950		1,006,355	975	1,005,380		4,398,307	63,929	4,334,378	
40	W / O incentive	2016	12,332,950	290,472	12,042,478		1,005,380	23,404	981,976		4,334,378	102,286	4,232,092	
41	W incentive	2016	12,332,950	290,472	12,042,478		1,005,380	23,404	981,976		4,334,378	102,286	4,232,092	
42	W / O incentive	2017	12,042,478	290,472	11,752,006		981,976	23,404	958,573		4,232,092	102,286	4,129,806	
43	W incentive	2017	12,042,478	290,472	11,752,006		981,976	23,404	958,573		4,232,092	102,286	4,129,806	
44	W / O incentive	2018	11,752,006	290,472	11,461,535	1,684,016	958,573	23,404	935,169	137,088	4,129,806	102,286	4,027,519	591,983
45	W incentive	2018	11,752,006	290,472	11,461,535	1,684,016	958,573	23,404	935,169	137,088	4,129,806	102,286	4,027,519	591,983
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A	Proj Rev Req w/o Incentive PCY*					1,887,469				-				653,870
B	Proj Rev Req w/ Incentive PCY*					1,887,469				-				653,870
C	Actual Rev Req w/o Incentive PCY*					1,818,021				147,946				639,126
D	Actual Rev Req w/ Incentive PCY*					1,818,021				147,946				639,126
E	TUA w/o Int w/o Incentive PCY (C-A)					(69,449)				147,946				(14,744)
F	TUA w/o Int w/ Incentive PCY (B-D)					(69,449)				147,946				(14,744)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.07197				1.07197				1.07197
H	True-Up Adjustment w/o Incentive (E*G)					(74,447)				158,594				(15,805)
I	True-Up Adjustment w/ Incentive (F*G)					(74,447)				158,594				(15,805)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	1,609,569	295,682	576,178
W incentive	1,609,569	295,682	576,178

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
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 kV		
13	FCR W/O incentive	Line 3	12.0063%				12.0063%				12.0063%			
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		12.0063%				12.0063%				12.0063%			
16	Investment		5,644,742				73,994,322				30,071,381			
17	Annual Depreciation Exp		131,273				1,720,798				699,334			
18	In Service Month (1-12)		11				5				12			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**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	5,644,742	16,409	5,628,333		73,994,322	1,075,499	72,918,823		30,071,381	29,139	30,042,242	
39	W incentive	2015	5,644,742	16,409	5,628,333		73,994,322	1,075,499	72,918,823		30,071,381	29,139	30,042,242	
40	W / O incentive	2016	5,628,333	131,273	5,497,060		72,918,823	1,720,798	71,198,025		30,042,242	699,334	29,342,908	
41	W incentive	2016	5,628,333	131,273	5,497,060		72,918,823	1,720,798	71,198,025		30,042,242	699,334	29,342,908	
42	W / O incentive	2017	5,497,060	131,273	5,365,787		71,198,025	1,720,798	69,477,227		29,342,908	699,334	28,643,573	
43	W incentive	2017	5,497,060	131,273	5,365,787		71,198,025	1,720,798	69,477,227		29,342,908	699,334	28,643,573	
44	W / O incentive	2018	5,365,787	131,273	5,234,514	767,625	69,477,227	1,720,798	67,756,429	9,959,146	28,643,573	699,334	27,944,239	4,096,388
45	W incentive	2018	5,365,787	131,273	5,234,514	767,625	69,477,227	1,720,798	67,756,429	9,959,146	28,643,573	699,334	27,944,239	4,096,388
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A	Proj Rev Req w/o Incentive PCY*	752,113	-	7,503,996
B	Proj Rev Req w/ Incentive PCY*	752,113	-	7,503,996
C	Actual Rev Req w/o Incentive PCY*	828,474	10,752,250	4,420,857
D	Actual Rev Req w/ Incentive PCY*	828,474	10,752,250	4,420,857
E	TUA w/o Int w/o Incentive PCY (C-A)	76,361	10,752,250	(3,083,139)
F	TUA w/o Int w/ Incentive PCY (B-D)	76,361	10,752,250	(3,083,139)
G	Future Value Factor (1+i)^24 mo (ATT6)	1.07197	1.07197	1.07197
H	True-Up Adjustment w/o Incentive (E*G)	81,857	11,526,103	(3,305,036)
I	True-Up Adjustment w/ Incentive (F*G)	81,857	11,526,103	(3,305,036)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	849,483	21,485,249	791,352
W incentive	849,483	21,485,249	791,352

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 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 Line		
13	FCR W/O incentive Line 3		12.0063%				12.0063%	at Brambleton			12.0063%	(7 miles overhead)		
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		12.0063%				12.0063%				12.0063%			
16	Investment		19,570,156				21,947,953				197,000,000			
17	Annual Depreciation Exp		455,120				510,418				4,581,395			
18	In Service Month (1-12)		12				6				12			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**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												
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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	19,570,156	18,963	19,551,193		21,947,953	276,476	21,671,477					
41	W incentive	2016	19,570,156	18,963	19,551,193		21,947,953	276,476	21,671,477					
42	W / O incentive	2017	19,551,193	455,120	19,096,073		21,947,953	510,418	21,437,535					
43	W incentive	2017	19,551,193	455,120	19,096,073		21,947,953	510,418	21,437,535					
44	W / O incentive	2018	19,096,073	455,120	18,640,953	2,720,532	21,437,535	510,418	20,927,118	3,053,633	197,000,000	190,891	196,809,109	1,175,932
45	W incentive	2018	19,096,073	455,120	18,640,953	2,720,532	21,437,535	510,418	20,927,118	3,053,633	197,000,000	190,891	196,809,109	1,175,932
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A	Proj Rev Req w/o Incentive PCY*	6,400,869	1,580,274	-
B	Proj Rev Req w/ Incentive PCY*	6,400,869	1,580,274	-
C	Actual Rev Req w/o Incentive PCY*	102,696	1,757,135	-
D	Actual Rev Req w/ Incentive PCY*	102,696	1,757,135	-
E	TUA w/o Int w/o Incentive PCY (C-A)	(6,298,172)	176,861	-
F	TUA w/o Int w/ Incentive PCY (B-D)	(6,298,172)	176,861	-
G	Future Value Factor (1+i)^24 mo (ATT6)	1.07197	1.07197	1.07197
H	True-Up Adjustment w/o Incentive (E*G)	(6,751,460)	189,590	-
I	True-Up Adjustment w/ Incentive (F*G)	(6,751,460)	189,590	-

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	(4,030,928)	3,243,223	1,175,932
W incentive	(4,030,928)	3,243,223	1,175,932

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 BL				Project BM			
11	Schedule 12	(Yes or No)	Yes	B1905.2			Yes	B1905.3			Yes	B1905.4		
12	Life		43	Surry 500 kV Station Work			43	Skiffes Creek 500-230 kV Tx			43	Skiffes Creek - Whealton 230 kV line		
13	FCR W/O incentive	Line 3	12.0063%				12.0063%	and Switching Station			12.0063%			
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		12.0063%				12.0063%				12.0063%			
16	Investment		1,834,471				60,000,000				35,000,000			
17	Annual Depreciation Exp		42,662				1,395,349				813,953			
18	In Service Month (1-12)		5				12				6			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**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	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									
41	W incentive	2016	1,765,145	42,662	1,722,483									
42	W / O incentive	2017	1,722,483	42,662	1,679,821									
43	W incentive	2017	1,722,483	42,662	1,679,821									
44	W / O incentive	2018	1,679,821	42,662	1,637,159	241,786	60,000,000	58,140	59,941,860	358,152	35,000,000	440,891	34,559,109	2,702,751
45	W incentive	2018	1,679,821	42,662	1,637,159	241,786	60,000,000	58,140	59,941,860	358,152	35,000,000	440,891	34,559,109	2,702,751
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A	Proj Rev Req w/o Incentive PCY*					264,134								443,248
B	Proj Rev Req w/ Incentive PCY*					264,134								443,248
C	Actual Rev Req w/o Incentive PCY*					261,223								-
D	Actual Rev Req w/ Incentive PCY*					261,223								-
E	TUA w/o Int w/o Incentive PCY (C-A)					(2,911)				-				(443,248)
F	TUA w/o Int w/ Incentive PCY (B-D)					(2,911)				-				(443,248)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.07197				1.07197				1.07197
H	True-Up Adjustment w/o Incentive (E*G)					(3,120)				-				(475,149)
I	True-Up Adjustment w/ Incentive (F*G)					(3,120)				-				(475,149)
	TUA = True-Up Adjusment													
	PCY = Previous Calendar Year													
	W / O incentive					238,665				358,152				2,227,601
	W incentive					238,665				358,152				2,227,601

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 BN**				**Project BS**				**Project BT-1**			
11	Schedule 12	(Yes or No)	Yes	B1905.5			Yes	B1907			Yes	B1909		
12	Life		43	Whealton 230 kV breakers			43	Install a 3rd 500/230 kV TX at Clover			43	Uprate Bremo – Midlothian 230 kV to		
13	FCR W/O incentive	Line 3	12.0063%				12.0063%				12.0063%	its maximum operating temperature		
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		12.0063%				12.0063%				12.0063%			
16	Investment		5,093,483				19,001,824				764,184			
17	Annual Depreciation Exp		118,453				441,903				17,772			
18	In Service Month (1-12)		6				4				6			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**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									764,184	9,626	754,558	
39	W incentive	2015									764,184	9,626	754,558	
40	W / O incentive	2016	5,093,483	64,162	5,029,321		19,001,824	313,015	18,688,809		754,558	17,772	736,786	
41	W incentive	2016	5,093,483	64,162	5,029,321		19,001,824	313,015	18,688,809		754,558	17,772	736,786	
42	W / O incentive	2017	5,093,483	118,453	4,975,030		19,001,824	441,903	18,559,921		736,786	17,772	719,014	
43	W incentive	2017	5,093,483	118,453	4,975,030		19,001,824	441,903	18,559,921		736,786	17,772	719,014	
44	W / O incentive	2018	4,975,030	118,453	4,856,577	708,660	18,559,921	441,903	18,118,018	2,643,736	719,014	17,772	701,242	103,032
45	W incentive	2018	4,975,030	118,453	4,856,577	708,660	18,559,921	441,903	18,118,018	2,643,736	719,014	17,772	701,242	103,032
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A	Proj Rev Req w/o Incentive PCY*	-	1,289,534	327,875
B	Proj Rev Req w/ Incentive PCY*	-	1,289,534	327,875
C	Actual Rev Req w/o Incentive PCY*	405,729	1,986,084	111,231
D	Actual Rev Req w/ Incentive PCY*	405,729	1,986,084	111,231
E	TUA w/o Int w/o Incentive PCY (C-A)	405,729	696,550	(216,645)
F	TUA w/o Int w/ Incentive PCY (B-D)	405,729	696,550	(216,645)
G	Future Value Factor (1+i)^24 mo (ATT6)	1.07197	1.07197	1.07197
H	True-Up Adjustment w/o Incentive (E*G)	434,930	746,681	(232,237)
I	True-Up Adjustment w/ Incentive (F*G)	434,930	746,681	(232,237)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	1,143,589	3,390,417	(129,205)
W incentive	1,143,589	3,390,417	(129,205)

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 BT-2				Project BU				Project BV-1A			
11	Schedule 12	(Yes or No)	Yes	B1909			Yes	B1328			Yes	B1912		
12	Life		43	Uprate Bremo – Midlothian 230 kV to			43	Uprate the 3.63 mile line section between			43	Install a 500 MVAR SVC at		
13	FCR W/O incentive	Line 3	12.0063%	its maximum operating temperature			12.0063%	Possum and Dumfries substations,			12.0063%	Landstown 230 kV		
14	Incentive Factor (Basis Points /100)		0				0	Replace 1600 amp wave trap at Possum Point			0	(Includes project modifications.)		
15	FCR W incentive L.13 +(L.14*L.5)		12.0063%				12.0063%				12.0063%			
16	Investment		1,205,878				3,879,636				19,951,279			
17	Annual Depreciation Exp		28,044				90,224				463,983			
18	In Service Month (1-12)		6				12				4			
19			Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	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					3,879,636	3,759	3,875,877					
39	W incentive	2015					3,879,636	3,759	3,875,877					
40	W / O incentive	2016	1,205,878	15,190	1,190,688		3,875,877	90,224	3,785,653		19,951,279	328,655	19,622,624	
41	W incentive	2016	1,205,878	15,190	1,190,688		3,875,877	90,224	3,785,653		19,951,279	328,655	19,622,624	
42	W / O incentive	2017	1,205,878	28,044	1,177,834		3,785,653	90,224	3,695,428		19,951,279	463,983	19,487,296	
43	W incentive	2017	1,205,878	28,044	1,177,834		3,785,653	90,224	3,695,428		19,951,279	463,983	19,487,296	
44	W / O incentive	2018	1,177,834	28,044	1,149,791	167,775	3,695,428	90,224	3,605,204	528,492	19,487,296	463,983	19,023,313	2,775,834
45	W incentive	2018	1,177,834	28,044	1,149,791	167,775	3,695,428	90,224	3,605,204	528,492	19,487,296	463,983	19,023,313	2,775,834
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A	Proj Rev Req w/o Incentive PCY*					-				575,513				2,144,735
B	Proj Rev Req w/ Incentive PCY*					-				575,513				2,144,735
C	Actual Rev Req w/o Incentive PCY*					96,542				570,353				2,085,322
D	Actual Rev Req w/ Incentive PCY*					96,542				570,353				2,085,322
E	TUA w/o Int w/o Incentive PCY (C-A)					96,542				(5,160)				(59,413)
F	TUA w/o Int w/ Incentive PCY (B-D)					96,542				(5,160)				(59,413)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.07197				1.07197				1.07197
H	True-Up Adjustment w/o Incentive (E*G)					103,490				(5,531)				(63,689)
I	True-Up Adjustment w/ Incentive (F*G)					103,490				(5,531)				(63,689)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	271,264	522,961	2,712,145
W incentive	271,264	522,961	2,712,145

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			Project BV-1B				Project BV-1C				Project BV-2			
11	Schedule 12	(Yes or No)	Yes	B1912			Yes	B1912			Yes	B1912		
12	Life		43	Install a 500 MVAR SVC at			43	Install a 500 MVAR SVC at			43	125 MVAr STATCOM at Lynnhaven		
13	FCR W/O incentive	Line 3	12.0063%	Landstown 230 kV			12.0063%	Landstown 230 kV			12.0063%			
14	Incentive Factor (Basis Points /100)		0	(Includes project modifications.)			0	(Includes project modifications.)			0			
15	FCR W incentive L.13 +(L.14*L.5)		12.0063%				12.0063%				12.0063%			
16	Investment		25,073,698				24,246,213				28,188,813			
17	Annual Depreciation Exp		583,109				563,865				655,554			
18	In Service Month (1-12)		6				11				1			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**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	25,073,698	315,851	24,757,847		24,246,213	70,483	24,175,730					
41	W incentive	2016	25,073,698	315,851	24,757,847		24,246,213	70,483	24,175,730					
42	W / O incentive	2017	25,073,698	583,109	24,490,589		24,246,213	563,865	23,682,348		28,188,813	628,239	27,560,574	
43	W incentive	2017	25,073,698	583,109	24,490,589		24,246,213	563,865	23,682,348		28,188,813	628,239	27,560,574	
44	W / O incentive	2018	24,490,589	583,109	23,907,479	3,488,520	23,682,348	563,865	23,118,482	3,373,391	27,560,574	655,554	26,905,020	3,925,207
45	W incentive	2018	24,490,589	583,109	23,907,479	3,488,520	23,682,348	563,865	23,118,482	3,373,391	27,560,574	655,554	26,905,020	3,925,207
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A	Proj Rev Req w/o Incentive PCY*					-				-				-
B	Proj Rev Req w/ Incentive PCY*					-				-				-
C	Actual Rev Req w/o Incentive PCY*					2,007,379				449,794				-
D	Actual Rev Req w/ Incentive PCY*					2,007,379				449,794				-
E	TUA w/o Int w/o Incentive PCY (C-A)					2,007,379				449,794				-
F	TUA w/o Int w/ Incentive PCY (B-D)					2,007,379				449,794				-
G	Future Value Factor (1+i)^24 mo (ATT6)					1.07197				1.07197				1.07197
H	True-Up Adjustment w/o Incentive (E*G)					2,151,853				482,166				-
I	True-Up Adjustment w/ Incentive (F*G)					2,151,853				482,166				-

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive		5,640,373	3,855,557	3,925,207
W incentive		5,640,373	3,855,557	3,925,207

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

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Line Number
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10			Project BW				Project BX				Project BY-1			
11	Schedule 12	(Yes or No)	Yes	B1701			Yes	B1791			Yes	B1694		
12	Life		43	Reconductor line #2104			43	Wreck and rebuild 2.1 mile section of			43	Rebuild Loudoun - Brambleton 500 kV		
13	FCR W/O incentive	Line 3	12.0063%	(Fredericksburg - Cranes Corner 230 kV)			12.0063%	Gordonsville and Somerset (Line #11)			12.0063%			
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		12.0063%				12.0063%				12.0063%			
16	Investment		3,172,543				3,441,461				27,773,469			
17	Annual Depreciation Exp		73,780				80,034				645,895			
18	In Service Month (1-12)		11				5				2			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**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					3,441,461	50,021	3,391,440					
39	W incentive	2015					3,441,461	50,021	3,391,440					
40	W / O incentive	2016	3,172,543	9,223	3,163,320		3,391,440	80,034	3,311,406		27,773,469	565,158	27,208,311	
41	W incentive	2016	3,172,543	9,223	3,163,320		3,391,440	80,034	3,311,406		27,773,469	565,158	27,208,311	
42	W / O incentive	2017	3,172,543	73,780	3,098,763		3,311,406	80,034	3,231,372		27,208,311	645,895	26,562,417	
43	W incentive	2017	3,172,543	73,780	3,098,763		3,311,406	80,034	3,231,372		27,208,311	645,895	26,562,417	
44	W / O incentive	2018	3,098,763	73,780	3,024,983	441,398	3,231,372	80,034	3,151,338	463,198	26,562,417	645,895	25,916,522	3,796,286
45	W incentive	2018	3,098,763	73,780	3,024,983	441,398	3,231,372	80,034	3,151,338	463,198	26,562,417	645,895	25,916,522	3,796,286
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A	Proj Rev Req w/o Incentive PCY*	400,590	468,898	2,682,633
B	Proj Rev Req w/ Incentive PCY*	400,590	468,898	2,682,633
C	Actual Rev Req w/o Incentive PCY*	58,854	500,085	3,580,035
D	Actual Rev Req w/ Incentive PCY*	58,854	500,085	3,580,035
E	TUA w/o Int w/o Incentive PCY (C-A)	(341,736)	31,187	897,403
F	TUA w/o Int w/ Incentive PCY (B-D)	(341,736)	31,187	897,403
G	Future Value Factor (1+i)^24 mo (ATT6)	1.07197	1.07197	1.07197
H	True-Up Adjustment w/o Incentive (E*G)	(366,331)	33,431	961,990
I	True-Up Adjustment w/ Incentive (F*G)	(366,331)	33,431	961,990

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	75,067	496,629	4,758,276
W incentive	75,067	496,629	4,758,276

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 BY-2				Project BY-3				Project BY-4			
11	Schedule 12 (Yes or No)		Yes	B1694			Yes	B1694			Yes	B1694		
12	Life		43	Rebuild Loudoun - Brambleton 500 kV			43	Rebuild Loudoun - Brambleton 500 kV			43	Rebuild Loudoun - Brambleton 500 kV		
13	FCR W/O incentive Line 3		12.0063%				12.0063%				12.0063%			
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		12.0063%				12.0063%				12.0063%			
16	Investment		2,652,366				15,638,395				469,760			
17	Annual Depreciation Exp		61,683				363,684				10,925			
18	In Service Month (1-12)		5				6				7			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**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	2,652,366	38,552	2,613,814		15,638,395	196,995	15,441,400		469,760	5,007	464,753	
41	W incentive	2016	2,652,366	38,552	2,613,814		15,638,395	196,995	15,441,400		469,760	5,007	464,753	
42	W / O incentive	2017	2,613,814	61,683	2,552,131		15,441,400	363,684	15,077,716		464,753	10,925	453,828	
43	W incentive	2017	2,613,814	61,683	2,552,131		15,441,400	363,684	15,077,716		464,753	10,925	453,828	
44	W / O incentive	2018	2,552,131	61,683	2,490,448	364,397	15,077,716	363,684	14,714,033	2,152,128	453,828	10,925	442,904	64,757
45	W incentive	2018	2,552,131	61,683	2,490,448	364,397	15,077,716	363,684	14,714,033	2,152,128	453,828	10,925	442,904	64,757
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A	Proj Rev Req w/o Incentive PCY*					-				-				-
B	Proj Rev Req w/ Incentive PCY*					-				-				-
C	Actual Rev Req w/o Incentive PCY*					244,814				1,251,997				31,849
D	Actual Rev Req w/ Incentive PCY*					244,814				1,251,997				31,849
E	TUA w/o Int w/o Incentive PCY (C-A)					244,814				1,251,997				31,849
F	TUA w/o Int w/ Incentive PCY (B-D)					244,814				1,251,997				31,849
G	Future Value Factor (1+i)^24 mo (ATT6)					1.07197				1.07197				1.07197
H	True-Up Adjustment w/o Incentive (E*G)					262,433				1,342,105				34,141
I	True-Up Adjustment w/ Incentive (F*G)					262,433				1,342,105				34,141

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	626,830	3,494,233	98,898
W incentive	626,830	3,494,233	98,898

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 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 500 kV within		
13	FCR W/O incentive	Line 3	12.0063%	a minimum of eight 230 kV breakers			12.0063%	existing ROW. The Loudoun - Brambleton			12.0063%	existing ROW. The Loudoun - Brambleton		
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 underbuild on the		
15	FCR W incentive L.13 +(L.14*L.5)		12.0063%				12.0063%	new 500 kV line.			12.0063%	new 500 kV line.		
16	Investment		2,144,083				28,794,395				13,935,893			
17	Annual Depreciation Exp		49,862				669,637				324,091			
18	In Service Month (1-12)		1				12				9			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**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					28,794,395	27,902	28,766,493					
39	W incentive	2015					28,794,395	27,902	28,766,493					
40	W / O incentive	2016	2,144,083	47,785	2,096,298		28,766,493	669,637	28,096,856		13,935,893	94,526	13,841,367	
41	W incentive	2016	2,144,083	47,785	2,096,298		28,766,493	669,637	28,096,856		13,935,893	94,526	13,841,367	
42	W / O incentive	2017	2,096,298	49,862	2,046,436		28,096,856	669,637	27,427,219		13,841,367	324,091	13,517,276	
43	W incentive	2017	2,096,298	49,862	2,046,436		28,096,856	669,637	27,427,219		13,841,367	324,091	13,517,276	
44	W / O incentive	2018	2,046,436	49,862	1,996,573	292,570	27,427,219	669,637	26,757,582	3,922,434	13,517,276	324,091	13,193,186	1,927,561
45	W incentive	2018	2,046,436	49,862	1,996,573	292,570	27,427,219	669,637	26,757,582	3,922,434	13,517,276	324,091	13,193,186	1,927,561
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A	Proj Rev Req w/o Incentive PCY*	-	-	-
B	Proj Rev Req w/ Incentive PCY*	-	-	-
C	Actual Rev Req w/o Incentive PCY*	302,447	4,233,125	602,240
D	Actual Rev Req w/ Incentive PCY*	302,447	4,233,125	602,240
E	TUA w/o Int w/o Incentive PCY (C-A)	302,447	4,233,125	602,240
F	TUA w/o Int w/ Incentive PCY (B-D)	302,447	4,233,125	602,240
G	Future Value Factor (1+i)^24 mo (ATT6)	1.07197	1.07197	1.07197
H	True-Up Adjustment w/o Incentive (E*G)	324,214	4,537,788	645,584
I	True-Up Adjustment w/ Incentive (F*G)	324,214	4,537,788	645,584

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	616,785	8,460,222	2,573,145
W incentive	616,785	8,460,222	2,573,145

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 CA-3**				**Project CB-1**				**Project CB-2**			
11	Schedule 12	(Yes or No)	Yes	B2373			Yes	B2582			Yes	B2582		
12	Life		43	Build 2nd Loudoun - Brambleton 500 kV within existing ROW. The Loudoun - Brambleton 231 kV line relocated as an underbuild on the new 500 kV line.			43	Rebuild the Elmont - Cunningham 500 kV line			43	Rebuild the Elmont - Cunningham 500 kV line		
13	FCR W/O incentive	Line 3	12.0063%				12.0063%				12.0063%			
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		12.0063%				12.0063%				12.0063%			
16	Investment		1,618,208				59,000,000				45,595,595			
17	Annual Depreciation Exp		37,633				1,372,093				1,060,363			
18	In Service Month (1-12)		12				5				12			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**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	1,618,208	1,568	1,616,640									
41	W incentive	2016	1,618,208	1,568	1,616,640									
42	W / O incentive	2017	1,616,640	37,633	1,579,007		59,000,000	857,558	58,142,442		45,595,595	44,182	45,551,413	
43	W incentive	2017	1,616,640	37,633	1,579,007		59,000,000	857,558	58,142,442		45,595,595	44,182	45,551,413	
44	W / O incentive	2018	1,579,007	37,633	1,541,374	224,954	58,142,442	1,372,093	56,770,349	8,270,485	45,551,413	1,060,363	44,491,051	6,465,750
45	W incentive	2018	1,579,007	37,633	1,541,374	224,954	58,142,442	1,372,093	56,770,349	8,270,485	45,551,413	1,060,363	44,491,051	6,465,750
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A	Proj Rev Req w/o Incentive PCY*	-	-	-
B	Proj Rev Req w/ Incentive PCY*	-	-	-
C	Actual Rev Req w/o Incentive PCY*	10,015	-	-
D	Actual Rev Req w/ Incentive PCY*	10,015	-	-
E	TUA w/o Int w/o Incentive PCY (C-A)	10,015	-	-
F	TUA w/o Int w/ Incentive PCY (B-D)	10,015	-	-
G	Future Value Factor (1+i)^24 mo (ATT6)	1.07197	1.07197	1.07197
H	True-Up Adjustment w/o Incentive (E*G)	10,735	-	-
I	True-Up Adjustment w/ Incentive (F*G)	10,735	-	-

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	235,690	8,270,485	6,465,750
W incentive	235,690	8,270,485	6,465,750

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 CC**				**Project CE**				**Project CJ**			
11	Schedule 12 (Yes or No)		Yes	B1911			Yes	B2471			Yes	B2744		
12	Life		43	Add a second Valley 500/230 kV TX			43	R/P Midlothian 500 kV breaker and			43	Rebuild the Carson-Rogers rd 500 kV circuit		
13	FCR W/O incentive Line 3		12.0063%				12.0063%	M.O. switches with 3 breaker 500 kV ring bus.			12.0063%			
14	Incentive Factor (Basis Points /100)		0				0	Terminate Lines #563 Carson - Midlothian,			0			
15	FCR W incentive L.13 +(L.14*L.5)		12.0063%				12.0063%	#576 Midlothian - North Anna,			12.0063%			
16	Investment		21,877,813				7,894,870	Transformer #2 in new ring			25,000,000			
17	Annual Depreciation Exp		508,786				183,602				581,395			
18	In Service Month (1-12)		6				11				12			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**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					7,894,870	22,950	7,871,920					
39	W incentive	2015					7,894,870	22,950	7,871,920					
40	W / O incentive	2016	21,877,813	275,593	21,602,220		7,871,920	183,602	7,688,318					
41	W incentive	2016	21,877,813	275,593	21,602,220		7,871,920	183,602	7,688,318					
42	W / O incentive	2017	21,602,220	508,786	21,093,434		7,688,318	183,602	7,504,717		25,000,000	24,225	24,975,775	
43	W incentive	2017	21,602,220	508,786	21,093,434		7,688,318	183,602	7,504,717		25,000,000	24,225	24,975,775	
44	W / O incentive	2018	21,093,434	508,786	20,584,648	3,010,786	7,504,717	183,602	7,321,115	1,073,619	24,975,775	581,395	24,394,380	3,545,162
45	W incentive	2018	21,093,434	508,786	20,584,648	3,010,786	7,504,717	183,602	7,321,115	1,073,619	24,975,775	581,395	24,394,380	3,545,162
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A	Proj Rev Req w/o Incentive PCY*					1,294,913				1,058,174				
B	Proj Rev Req w/ Incentive PCY*					1,294,913				1,058,174				
C	Actual Rev Req w/o Incentive PCY*					1,751,519				1,158,724				
D	Actual Rev Req w/ Incentive PCY*					1,751,519				1,158,724				
E	TUA w/o Int w/o Incentive PCY (C-A)					456,607				100,549				-
F	TUA w/o Int w/ Incentive PCY (B-D)					456,607				100,549				-
G	Future Value Factor (1+i)^24 mo (ATT6)					1.07197				1.07197				1.07197
H	True-Up Adjustment w/o Incentive (E*G)					489,469				107,786				-
I	True-Up Adjustment w/ Incentive (F*G)					489,469				107,786				-
	W / O incentive					3,500,255				1,181,405				3,545,162
	W incentive					3,500,255				1,181,405				3,545,162

TUA = True-Up Adjusment
PCY = Previous Calendar Year

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 CJ**						
11	Schedule 12 (Yes or No)		Yes	B2744			If Yes for Schedule 12 Include in this Total.	If No for Schedule 12 include in this Sum.	
12	Life		43	Rebuild the Carson-Rogers rd 500 kV circuit					
13	FCR W/O incentive Line 3		12.0063%						
14	Incentive Factor (Basis Points /100)		0						
15	FCR W incentive L.13 +(L.14*L.5)		12.0063%						
16	Investment		28,505,575					Annual Revenue Requirement including Incentive if Applicable	Annual Revenue Requirement excluding Incentive
17	Annual Depreciation Exp		662,920						
18	In Service Month (1-12)		10						
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							
39	W incentive	2015							
40	W / O incentive	2016							
41	W incentive	2016							
42	W / O incentive	2017							
43	W incentive	2017							
44	W / O incentive	2018	28,505,575	138,108	28,367,467	849,395	247,456,556		42,984,229
45	W incentive	2018	28,505,575	138,108	28,367,467	849,395	251,717,991	45,643,961	

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A	Proj Rev Req w/o Incentive PCY*	
B	Proj Rev Req w/ Incentive PCY*	
C	Actual Rev Req w/o Incentive PCY*	
D	Actual Rev Req w/ Incentive PCY*	
E	TUA w/o Int w/o Incentive PCY (C-A)	-
F	TUA w/o Int w/ Incentive PCY (B-D)	-
G	Future Value Factor (1+i)^24 mo (ATT6)	1.07197
H	True-Up Adjustment w/o Incentive (E*G)	-
I	True-Up Adjustment w/ Incentive (F*G)	-

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	849,395
W incentive	849,395

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 11

PSE&G Formula Rate for January 1, 2018 to December 31, 2018

Attachment 11

Hesser G. McBride, Jr.
Associate General Regulatory Counsel

Law Department
80 Park Plaza, T5G, Newark, NJ 07102-4194
tel: 973.430.5333 fax: 973.430.5983
Hesser.McBride@PSEG.com

PSEG
Services Corporation

October 27, 2017

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 2018 Formula Rate Annual Update (Errata)

Dear Secretary Bose:

Subsequent to the October 16, 2017, filing of Public Service Electric and Gas Company's ("PSE&G") 2018 Formula Rate Annual Update ("Annual Update") in the above-captioned docket, PSE&G identified incorrect values posted in Excel Rows 41 and 48 of Attachment 6A – Estimate and Reconcile to the Annual Update. On behalf of PSE&G, enclosed please find an updated version of Exhibit 1 of the Annual Update, which includes a corrected version of Attachment 6A– Estimate and Reconcile.

The October 16, 2017 Annual Update filing remains unchanged in all other respects and this errata does not affect the annual revenue requirement forecasted in the Annual Update.

The revised formula rate template in Exhibit 1 is also being provided to PJM Interconnection, L.L.C. for posting on its website. Consistent with the Commission Staff's Guidance on Formula Rate Updates, PSE&G is submitting the updated formula rate template in Microsoft Excel format.

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 12/31/2018**
	Allocators			
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense	(Note O)	Attachment 5	31,626,000
2	Total Wages Expense	(Note O)	Attachment 5	207,395,000
3	Less A&G Wages Expense	(Note O)	Attachment 5	9,733,000
4	Total Wages Less A&G Wages Expense		(Line 2 - Line 3)	197,662,000
5	**Wages & Salary Allocator**		(Line 1 / Line 4)	**16.0000%**
	Plant Allocation Factors			
6	Electric Plant in Service	(Note B)	Attachment 5	20,900,387,637
7	Common Plant in Service - Electric		(Line 22)	180,548,962
8	Total Plant in Service		(Line 6 + 7)	21,080,936,599
9	Accumulated Depreciation (Total Electric Plant)	(Note B & J)	Attachment 5	3,736,217,375
10	Accumulated Intangible Amortization - Electric	(Note B)	Attachment 5	6,181,302
11	Accumulated Common Plant Depreciation & Amortization - Electric	(Note B & J)	Attachment 5	29,686,389
12	Accumulated Common Amortization - Electric	(Note B)	Attachment 5	49,202,101
13	Total Accumulated Depreciation		(Line 9 + Line 10 + Line 11 + Line 12)	3,821,287,167
14	Net Plant		(Line 8 - Line 13)	17,259,649,432
15	Transmission Gross Plant		(Line 31)	11,254,947,402
16	**Gross Plant Allocator**		(Line 15 / Line 8)	**53.3892%**
17	Transmission Net Plant		(Line 43)	10,235,109,330
18	**Net Plant Allocator**		(Line 17 / Line 14)	**59.3008%**
	Plant Calculations			
	Plant In Service			
19	Transmission Plant In Service	(Note B)	Attachment 5	11,162,840,225
20	General	(Note B)	Attachment 5	332,299,612
21	Intangible - Electric	(Note B)	Attachment 5	15,038,477
22	Common Plant - Electric	(Note B)	Attachment 5	180,548,962
23	Total General, Intangible & Common Plant		(Line 20 + Line 21 + Line 22)	527,887,051
24	Less: General Plant Account 397 -- Communications	(Note B)	Attachment 5	36,924,263
25	Less: Common Plant Account 397 -- Communications	(Note B)	Attachment 5	35,209,921
26	General and Intangible Excluding Acct. 397		(Line 23 - Line 24 - Line 25)	455,752,867
27	Wage & Salary Allocator		(Line 5)	16.0000%
28	General and Intangible Plant Allocated to Transmission		(Line 26 * Line 27)	72,920,643
29	Account No. 397 Directly Assigned to Transmission	(Note B)	Attachment 5	19,186,533
30	Total General and Intangible Functionalized to Transmission		(Line 28 + Line 29)	92,107,177
31	**Total Plant In Rate Base**		(Line 19 + Line 30)	**11,254,947,402**
	Accumulated Depreciation			
32	Transmission Accumulated Depreciation	(Note B & J)	Attachment 5	968,854,890
33	Accumulated General Depreciation	(Note B & J)	Attachment 5	139,970,808
34	Accumulated Common Plant Depreciation - Electric	(Note B & J)	Attachment 5	78,888,490
35	Less: Amount of General Depreciation Associated with Acct. 397	(Note B & J)	Attachment 5	30,305,351
36	Balance of Accumulated General Depreciation		(Line 33 + Line 34 - Line 35)	188,553,948
37	Accumulated Intangible Amortization - Electric	(Note B)	(Line 10)	6,181,302
38	Accumulated General and Intangible Depreciation Ex. Acct. 397		(Line 36 + 37)	194,735,249
39	Wage & Salary Allocator		(Line 5)	16.0000%
40	Subtotal General and Intangible Accum. Depreciation Allocated to Transmission		(Line 38 * Line 39)	31,157,719
41	Accumulated General Depreciation Associated with Acct. 397 Directly Assigned to Transmis	(Note B & J)	Attachment 5	19,825,463
42	**Total Accumulated Depreciation**		(Lines 32 + 40 + 41)	**1,019,838,072**
43	**Total Net Property, Plant & Equipment**		(Line 31 - Line 42)	**10,235,109,330**

Public Service Electric and Gas Company

ATTACHMENT H-10A

	Formula Rate -- Appendix A	**Notes**	**FERC Form 1 Page # or Instruction**	**12 Months Ended 12/31/2018**
	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	-2,502,792,692
	CWIP for Incentive Transmission Projects			
45	CWIP Balances for Current Rate Year	(Note B & H)	Attachment 6	102,222,422
	Abandoned Transmission Projects			
45a	Unamortized Abandoned Transmission Projects	(Note R)	Attachment 5	0
46	**Plant Held for Future Use**	(Note C & Q)	Attachment 5	18,085,194
	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)	16.0000%
50	Total Undistributed Stores Expense Allocated to Transmission		(Line 48 * Line 49)	0
51	Transmission Materials & Supplies	(Note N & Q))	Attachment 5	48,632,000
52	Total Materials & Supplies Allocated to Transmission		(Line 50 + Line 51)	48,632,000
	Cash Working Capital			
53	Operation & Maintenance Expense		(Line 80)	133,933,189
54	1/8th Rule		1/8	12.5%
55	Total Cash Working Capital Allocated to Transmission		(Line 53 * Line 54)	16,741,649
	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)**	**(2,317,111,428)**
58	**Rate Base**		(Line 43 + Line 57)	**7,917,997,903**
	Operations & Maintenance Expense			
	Transmission O&M			
59	Transmission O&M	(Note O)	Attachment 5	107,887,010
60	Plus Transmission Lease Payments	(Note O)	Attachment 5	0
61	**Transmission O&M**		(Lines 59 + 60)	**107,887,010**
	Allocated Administrative & General Expenses			
62	Total A&G	(Note O)	Attachment 5	172,512,000
63	Plus: Actual PBOP expense	(Note J)	Attachment 5	26,864,000
64	Less: Actual PBOP expense	(Note O)	Attachment 5	37,487,000
65	Less Property Insurance Account 924	(Note O)	Attachment 5	3,032,000
66	Less Regulatory Commission Exp Account 928	(Note E & O)	Attachment 5	10,400,000
67	Less General Advertising Exp Account 930.1	(Note O)	Attachment 5	2,125,000
68	Less EPRI Dues	(Note D & O)	Attachment 5	0
69	**Administrative & General Expenses**		Sum (Lines 62 to 63) - Sum (Lines 64 to 68)	146,332,000
70	Wage & Salary Allocator		(Line 5)	16.0000%
71	**Administrative & General Expenses Allocated to Transmission**		(Line 69 * Line 70)	**23,413,179**
	Directly Assigned A&G			
72	Regulatory Commission Exp Account 928	(Note G & O)	Attachment 5	835,000
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)	835,000
75	Property Insurance Account 924		(Line 65)	3,032,000
76	General Advertising Exp Account 930.1	(Note F & O)	Attachment 5	0
77	Total Accounts 928 and 930.1 - General		(Line 75 + Line 76)	3,032,000
78	Net Plant Allocator		(Line 18)	59.3008%
79	**A&G Directly Assigned to Transmission**		(Line 77 * Line 78)	**1,798,000**
80	**Total Transmission O&M**		**(Lines 61 + 71 + 74 + 79)**	**133,933,189**

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 12/31/2018**
	Depreciation & Amortization Expense				
	Depreciation Expense				
81	Transmission Depreciation Expense Including Amortization of Limited Term Plant		(Note J & O)	Attachment 5	266,279,924
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	27,729,088
83	Less: Amount of General Depreciation Expense Associated with Acct. 397		(Note J & O)	Attachment 5	7,252,148
84	Balance of General Depreciation Expense			(Line 82 - Line 83)	20,476,940
85	Intangible Amortization		(Note A & O)	Attachment 5	11,136,699
86	Total			(Line 84 + Line 85)	31,613,639
87	Wage & Salary Allocator			(Line 5)	16.00%
88	General Depreciation & Intangible Amortization Allocated to Transmission			(Line 86 * Line 87)	5,058,195
89	General Depreciation Expense for Acct. 397 Directly Assigned to Transmission		(Note J & O)	Attachment 5	1,908,451
90	**General Depreciation and Intangible Amortization Functionalized to Transmission**			(Line 88 + Line 89)	**6,966,646**
91	**Total Transmission Depreciation & Amortization**			**(Lines 81 + 81a + 90)**	**273,246,570**
	Taxes Other than Income Taxes				
92	Taxes Other than Income Taxes		(Note O)	Attachment 2	10,432,800
93	**Total Taxes Other than Income Taxes**			(Line 92)	**10,432,800**
	Return \ Capitalization Calculations				
94	**Long Term Interest**			p117.62.c through 67.c	299,596,596
95	**Preferred Dividends**		enter positive	p118.29.d	0
	Common Stock				
96	Proprietary Capital		(Note P)	Attachment 5	8,201,697,087
97	Less Accumulated Other Comprehensive Income Account 219		(Note P)	Attachment 5	1,021,739
98	Less Preferred Stock			(Line 106)	0
99	Less Account 216.1		(Note P)	Attachment 5	3,331,169
100	**Common Stock**			(Line 96 - 97 - 98 - 99)	8,197,344,179
	Capitalization				
101	Long Term Debt		(Note P)	Attachment 5	7,362,278,245
102	Less Loss on Reacquired Debt		(Note P)	Attachment 5	63,934,374
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)	7,281,361,756
106	Preferred Stock		(Note P)	Attachment 5	0
107	Common Stock			(Line 100)	8,197,344,179
108	**Total Capitalization**			(Sum Lines 105 to 107)	15,478,705,935
109	Debt %	Total Long Term Debt		(Line 105 / Line 108)	47.04%
110	Preferred %	Preferred Stock		(Line 106 / Line 108)	0.00%
111	Common %	Common Stock		(Line 107 / Line 108)	52.96%
112	Debt Cost	Total Long Term Debt		(Line 94 / Line 105)	0.0411
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)	0.0194
116	Weighted Cost of Preferred	Preferred Stock		(Line 110 * Line 113)	0.0000
117	Weighted Cost of Common	Common Stock		(Line 111 * Line 114)	0.0619
118	**Rate of Return on Rate Base (ROR)**			(Sum Lines 115 to 117)	**0.0812**
119	**Investment Return = Rate Base * Rate of Return**			**(Line 58 * Line 118)**	**643,031,192**

Public Service Electric and Gas Company

ATTACHMENT H-10A

	Formula Rate -- Appendix A		**Notes**	**FERC Form 1 Page # or Instruction**	**12 Months Ended 12/31/2018**
	Shaded cells are input cells				
	Composite Income Taxes				
	Income Tax Rates				
120	FIT=Federal Income Tax Rate		(Note I)		35.00%
121	SIT=State Income Tax Rate or Composite				9.00%
122	p	(percent of federal income tax deductible for state purposes)		Per State Tax Code	0.00%
123	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			40.85%
124	T / (1-T)				69.06%
	ITC Adjustment				
125	Amortized Investment Tax Credit	enter negative	(Note O)	Attachment 5	-561,000
126	1/(1-T)			1 / (1 - Line 123)	169.06%
127	Net Plant Allocation Factor			(Line 18)	59.30%
128	**ITC Adjustment Allocated to Transmission**			(Line 125 * Line 126 * Line 127)	**-562,430**
129	**Income Tax Component =**	(T/1-T) * Investment Return * (1-(WCLTD/ROR)) =		[Line 124 * Line 119 * (1- (Line 115 / Line 118))]	**338,247,081**
130	**Total Income Taxes**			**(Line 128 + Line 129)**	**337,684,651**
	Revenue Requirement				
	Summary				
131	Net Property, Plant & Equipment			(Line 43)	10,235,109,330
132	Total Adjustment to Rate Base			(Line 57)	-2,317,111,428
133	**Rate Base**			(Line 58)	**7,917,997,903**
134	Total Transmission O&M			(Line 80)	133,933,189
135	Total Transmission Depreciation & Amortization			(Line 91)	273,246,570
136	Taxes Other than Income			(Line 93)	10,432,800
137	Investment Return			(Line 119)	643,031,192
138	Income Taxes			(Line 130)	337,684,651
139	**Gross Revenue Requirement**			**(Sum Lines 134 to 138)**	**1,398,328,402**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
140	Transmission Plant In Service			(Line 19)	11,162,840,225
141	Excluded Transmission Facilities		(Note B & M)	Attachment 5	0
142	Included Transmission Facilities			(Line 140 - Line 141)	11,162,840,225
143	Inclusion Ratio			(Line 142 / Line 140)	100.00%
144	Gross Revenue Requirement			(Line 139)	1,398,328,402
145	**Adjusted Gross Revenue Requirement**			(Line 143 * Line 144)	**1,398,328,402**
	Revenue Credits & Interest on Network Credits				
146	**Revenue Credits**		(Note O)	Attachment 3	20,901,756
147	**Interest on Network Credits**		(Note N & O)	Attachment 5	0
148	**Net Revenue Requirement**			**(Line 145 - Line 146 + Line 147)**	**1,377,426,647**
	Net Plant Carrying Charge				
149	Gross Revenue Requirement			(Line 144)	**1,398,328,402**
150	Net Transmission Plant, CWIP and Abandoned Plant			(Line 19 - Line 32 + Line 45 + Line 45a)	**10,296,207,758**
151	Net Plant Carrying Charge			(Line 149 / Line 150)	**13.5810%**
152	Net Plant Carrying Charge without Depreciation			(Line 149 - Line 81) / Line 150	**10.9948%**
153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes			(Line 149 - Line 81 - Line 119 - Line 130) / Line 15	**1.4698%**
	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)	**417,612,559**
155	Increased Return and Taxes			Attachment 4	**1,051,608,157**
156	Net Revenue Requirement per 100 Basis Point increase in ROE			(Line 154 + Line 155)	**1,469,220,717**
157	Net Transmission Plant, CWIP and Abandoned Plant			(Line 19 - Line 32 + Line 45 + Line 45a)	**10,296,207,758**
158	Net Plant Carrying Charge per 100 Basis Point increase in ROE			(Line 156 / Line 157)	**14.2695%**
159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation			(Line 156 - Line 81) / Line 157	**11.6833%**
160	**Net Revenue Requirement**			(Line 148)	**1,377,426,647**
161	True-up amount			Attachment 6	**12,591,534**
162	Plus any increased ROE calculated on Attachment 7 other than PJM Sch. 12 projects not paid by other PJM transmission :			Attachment 7	**7,036,291**
163	Facility Credits under Section 30.9 of the PJM OATT			Attachment 5	**0**
164	**Net Zonal Revenue Requirement**			(Line 160 + 161 + 162 + 163)	**1,397,054,472**
	Network Zonal Service Rate				
165	1 CP Peak		(Note L)	Attachment 5	**9,566.9**
166	Rate ($/MW-Year)			(Line 164 / 165)	**146,029.78**
167	**Network Service Rate ($/MW/Year)**			**(Line 166)**	**146,029.78**

Public Service Electric and Gas Company ATTACHMENT H-10A Formula Rate -- Appendix A	Notes	FERC Form 1 Page # or Instruction	12 Months Ended 12/31/2018

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 31,2018

	Only Transmission Related	*Plant Related*	*Labor Related*	*Total ADIT*	
ADIT- 282	(2,597,832,425)	0	(36,267,968)		From Acct. 282 total, below
ADIT-283	0	(14,192,780)	0		From Acct. 283 total, below
ADIT-190	0	0	12,168,870		From Acct. 190 total, below
Subtotal	(2,597,832,425)	(14,192,780)	(24,099,098)		
Wages & Salary Allocator			16.0000%		
Net Plant Allocator		59.3008%			
End of Year ADIT	(2,597,832,425)	(8,416,431)	(3,855,865)	**(2,610,104,721)**	
End of Previous Year ADIT (from Sheet 1A-ADIT (3))	(2,383,691,531)	(8,797,786)	(2,991,346)	**(2,395,480,663)**	
Average Beginning and End of Year ADIT	(2,490,761,978)	(8,607,109)	(3,423,606)	**(2,502,792,692)**	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
(14,192,780) < 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 - Contribution In Aid of Construction	33,971,473	33,971,473	-	-	-	Represents the estimated IRC 118 amount (CIAC)
Vacation Pay	631,750	-	-	-	631,750	Vacation pay earned and expensed for books, tax deduction when paid - employees in all functions
OPEB	180,153,245	-	-	-	180,153,245	FASB 106 - Post Retirement Obligation, labor related.
Deferred Dividend Equivalents	3,105,261	-	-	-	3,105,261	Book accrual of dividends on employee stock options affecting all functions
Deferred Compensation	395,586	-	-	-	395,586	Book estimate accrued and expensed, tax deduction when paid - employees in all functions
ADIT - Unallowable PIP Accrual	-	-	-	-	-	Book estimate accrued and expensed, tax deduction when paid - employees in all functions
Bankruptcies $ Acfc	189,384	189,384	-	-	-	Book estimate accrued and expensed, tax deduction when paid - Generation Related
Federal Taxes Deferred	5,554,630	-	-	5,554,630	-	FASB 109 - deferred tax asset primarily associated with items previously flowed through due to regulation
Miscellaneous	(1,631,739)	(9,668,012)	-	-	8,036,273	-
Subtotal - p234	**222,369,590**	**24,492,845**		**5,554,630**	**192,322,115**	
Less FASB 109 Above if not separately removed	5,554,630			5,554,630		
Less FASB 106 Above if not separately removed	180,153,245				180,153,245	
Total	**36,661,715**	**24,492,845**		**0**	**12,168,870**	

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 31,2018

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)	(4,004,267,788)	(1,595,753,854)	(2,375,774,816)	-	(32,739,118)	For federal - Column D represents the direct assignment of prorated ADIT associated with Transmission assets,, column F represents ADIT associated with the allocation of common plant and column C represents estimated electrical distribution ADIT
Depreciation - Liberalized Depreciation (State)	(412,147,501)	(186,561,043)	(222,057,608)	-	(3,528,850)	For state - Column D represents the direct assignment of prorated ADIT associated with Transmission assets,, column F represents ADIT associated with the allocation of common plant and column C represents estimated electrical distribution ADIT
Accounting for Income Taxes	(317,127,352)	(267,274,356)	(49,588,141)	-	(264,855)	FASB 109 - deferred tax liability primarily associated with plant related items previously flowed through due to regulation
Subtotal - p275	**(4,733,542,641)**	**(2,049,589,252)**	**(2,647,420,566)**	**0**	**(36,532,823)**	
Less FASB 109 Above if not separately removed	(49,852,996)		(49,588,141)	0	(264,855)	
Less FASB 106 Above if not separately removed						
Total	**(4,683,689,644)**	**(2,049,589,252)**	**(2,597,832,425)**	**0**	**(36,267,968)**	

Instructions for Account 282:

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

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

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

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

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

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31,2018

A	B	C	D	E	F	G
ADIT-283	*Total*	Gas, Prod or Other Related	Only Transmission Related	Plant	Labor	
Environmental Cleanup Costs	(61,165,265)	(61,165,265)	-	-	-	Book estimate accrued and expensed, tax deduction when paid - Manufactured Gas Plants
New Jersey Corporation Business Tax	11,114,837	11,114,837	-	-	-	New Jersey Corporate Income Tax - Plant Related- Contra Account of 190 NJCBT
Accelerated Activity Plan	(105,453,531)	(105,453,531)	-	-	-	Demand Side management and Associated Programs - Retail Related
Loss on Reacquired Debt	(14,192,780)	-	-	(14,192,780)	-	Tax deduction when reacquired, booked amortizes to expense
Additional Pension Deduction	(158,168,868)	(158,168,868)	-	-	-	Associated with Pension Liability not in rates
Sales Tax Reserve	-	-	-	-	-	Sales tax audit reserve
Miscellaneous	37,177,610	37,177,610	-	-	-	Miscellaneous Tax Adjustments
Deferred Gain	(46,845,469)	(46,845,469)	-	-	-	Deferred gain resulted from 2000 deregulation step up basis
Accounting for Income Taxes (FAS109) - Federal	(232,692,205)	-	-	(232,692,205)	-	FASB 109 - deferred tax liability primarily non-plant related items previously flowed through due to regulation
Subtotal - p277	**(570,225,671)**	**(323,340,687)**		**(246,884,985)**		
Less FASB 109 Above if not separately removed	(232,692,205)			(232,692,205)		
Less FASB 106 Above if not separately removed						
Total	**(337,533,467)**	**(323,340,687)**		**(14,192,780)**		

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 31,2017

	Only Transmission Related	Plant Related	Labor Related	Total ADIT	
ADIT- 282	(2,383,691,531)	0	(30,864,733)		From Acct. 282 total, below
ADIT-283	0	(14,835,865)	0		From Acct. 283 total, below
ADIT-190	0	0	12,168,870		From Acct. 190 total, below
Subtotal	(2,383,691,531)	(14,835,865)	(18,695,863)		
Wages & Salary Allocator			16.0000%		
Net Plant Allocator		59.3008%			
End of Year ADIT	(2,383,691,531)	(8,797,786)	(2,991,346)	**(2,395,480,663)**	

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

(14,835,865) < 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 - Contribution In Aid of Construction	37,748,575	37,748,575	-	-	-	Represents the estimated IRC 118 amount (CIAC)
Vacation Pay	631,750	-	-	-	631,750	Vacation pay earned and expensed for books, tax deduction when paid - employees in all functions
OPEB	179,879,275	-	-	-	179,879,275	FASB 106 - Post Retirement Obligation, labor related.
Deferred Dividend Equivalents	3,105,261	-	-	-	3,105,261	Book accrual of dividends on employee stock options affecting all functions
Deferred Compensation	395,586	-	-	-	395,586	Book estimate accrued and expensed, tax deduction when paid - employees in all functions
ADIT - Unallowable PIP Accrual	-	-	-	-	-	Book estimate accrued and expensed, tax deduction when paid - employees in all functions
Bankruptcies $ Acfc	189,384	189,384	-	-	-	Book estimate accrued and expensed, tax deduction when paid - Generation Related
Federal Taxes Deferred	5,554,630	-	-	5,554,630	-	FASB 109 - deferred tax asset primarily associated with items previously flowed through due to regulation
Miscellaneous	(1,631,739)	(9,668,012)	-	-	8,036,273	0
Subtotal - p234	**225,872,721**	**28,269,947**		**5,554,630**	**192,048,144**	
Less FASB 109 Above if not separately removed	5,554,630			5,554,630		
Less FASB 106 Above if not separately removed	179,879,275				179,879,275	
Total	**40,438,817**	**28,269,947**		**0**	**12,168,870**	

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)	(3,710,135,516)	(1,484,577,833)	(2,198,221,800)	-	(27,335,883)	For Federal - Column D represents the direct assignment of ADIT, unprorated, associated with Transmission assets, column F represents ADIT associated with the allocation of common plant and column C represents estimated electrical distribution ADIT
Depreciation - Liberalized Depreciation (State)	(360,901,871)	(171,903,290)	(185,469,731)	-	(3,528,850)	For State - Column D represents the direct assignment of ADIT, unprorated, associated with Transmission assets, column F represents ADIT associated with the allocation of common plant and column C represents estimated electrical distribution ADIT
Accounting for Income Taxes	(49,852,996)	-	(49,588,141)	-	(264,855)	FASB 109 - deferred tax liability primarily associated with plant related items previously flowed through due to regulation
Subtotal - p275	**(4,120,890,383)**	**(1,656,481,123)**	**(2,433,279,672)**	**0**	**(31,129,588)**	
Less FASB 109 Above if not separately removed	(49,852,996)		(49,588,141)	0	(264,855)	
Less FASB 106 Above if not separately removed						
Total	**(4,071,037,387)**	**(1,656,481,123)**	**(2,383,691,531)**	**0**	**(30,864,733)**	

Instructions for Account 282:

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

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

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

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

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

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31,2017

A	B	C	D	E	F	G
ADIT-283	*Total*	Gas, Prod or Other Related	Only Transmission Related	Plant	Labor	
Environmental Cleanup Costs	(61,165,265)	(61,165,265)	-	-	-	Book estimate accrued and expensed, tax deduction when paid - Manufactured Gas Plants
New Jersey Corporation Business Tax	11,699,896	11,699,896	-	-	-	New Jersey Corporate Income Tax - Plant Related- Contra Account of 190 NJCBT
Accelerated Activity Plan	(104,257,965)	(104,257,965)	-	-	-	Demand Side management and Associated Programs - Retail Related
Loss on Reacquired Debt	(14,835,865)	-	-	(14,835,865)	-	Tax deduction when reacquired, booked amortizes to expense
Additional Pension Deduction	(158,168,868)	(158,168,868)	-	-	-	Associated with Pension Liability not in rates
Sales Tax Reserve	-	-	-	-	-	Sales tax audit reserve
Miscellaneous	32,730,151	32,730,151	-	-	-	Miscellaneous Tax Adjustments
Deferred Gain	(46,845,469)	(46,845,469)	-	-	-	Deferred gain resulted from 2000 deregulation step up basis
Accounting for Income Taxes (FAS109) - Federal	(232,692,205)	-	-	(232,692,205)	-	FASB 109 - deferred tax liability primarily non-plant related items previously flowed through due to regulation
Subtotal - p277	**(573,535,590)**	**(326,007,521)**		**(247,528,070)**		
Less FASB 109 Above if not separately removed	(232,692,205)			(232,692,205)		
Less FASB 106 Above if not separately removed						
Total	**(340,843,386)**	**(326,007,521)**		**(14,835,865)**		

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, 2018

	Other Taxes	*Page 263 Col (i)*	*Allocator*	*Allocated Amount*	
	Plant Related				
1	Real Estate	21,308,000			Attachment #5
2	***Total Plant Related***	21,308,000	N/A	7,881,000	
	Labor Related		***Wages & Salary Allocator***		
3	FICA	14,264,750			
4	Federal Unemployment Tax	322,070			
5	New Jersey Unemployment Tax	687,790			
6	New Jersey Workforce Development	674,100			
7					
8	***Total Labor Related***	15,948,710	16.0000%	2,551,800	
	Other Included		***Net Plant Allocator***		
9					
10					
11					
12					
13	***Total Other Included***	0	59.3008%	0	
14	***Total Included (Lines 8 + 14 + 19)***	37,256,710		10,432,800	
	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)**	37,256,710			
24	**Total Other Taxes from p114.14.g - Actual**	37,256,710			
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, 2018

	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		4,665,000
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		6,650,000
7	Professional Services (Note 2)		45,000
8	Revenues from Directly Assigned Transmission Facility Charges (Note 1)		7,962,979
9	Rent or Attachment Fees associated with Transmission Facilities (Note 2)		4,845,371
10	Gross Revenue Credits	(Sum Lines 1-9)	24,768,349
11	Less line 18	- line 18	(3,866,593)
12	Total Revenue Credits	line 10 + line 11	20,901,756
13	Revenues associated with lines 2, 7, and 9 (Note 2)		5,490,371
14	Income Taxes associated with revenues in line 13		2,242,816
15	One half margin (line 13 - line 14)/2		1,623,777
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		1,623,777
18	Line 13 less line 17		3,866,593

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	1,051,608,157
B	100 Basis Point increase in ROE		1.00%

Return Calculation

			Appendix A Line or Source Reference	
1	**Rate Base**		(Line 43 + Line 57)	7,917,997,903
2	**Long Term Interest**		p117.62.c through 67.c	299,596,596
3	**Preferred Dividends**	enter positive	p118.29.d	0
	Common Stock			
4	Proprietary Capital		Attachment 5	8,201,697,087
5	Less Accumulated Other Comprehensive Income Account 219		p112.15.c	1,021,739
6	Less Preferred Stock		(Line 106)	0
7	Less Account 216.1		Attachment 5	3,331,169
8	Common Stock		(Line 96 - 97 - 98 - 99)	8,197,344,179
	Capitalization			
9	Long Term Debt		Attachment 5	7,362,278,245
10	Less Loss on Reacquired Debt		Attachment 5	63,934,374
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)	7,281,361,756
14	Preferred Stock		Attachment 5	0
15	Common Stock		(Line 100)	8,197,344,179
16	Total Capitalization		(Sum Lines 105 to 107)	15,478,705,935
17	Debt %	Total Long Term Debt	(Line 105 / Line 108)	47.0%
18	Preferred %	Preferred Stock	(Line 106 / Line 108)	0.0%
19	Common %	Common Stock	(Line 107 / Line 108)	53.0%
20	Debt Cost	Total Long Term Debt	(Line 94 / Line 105)	0.0411
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)	0.0194
24	Weighted Cost of Preferred	Preferred Stock	(Line 110 * Line 113)	0.0000
25	Weighted Cost of Common	Common Stock	(Line 111 * Line 114)	0.0672
26	**Rate of Return on Rate Base (ROR)**		**(Sum Lines 115 to 117)**	**0.0865**
27	**Investment Return = Rate Base * Rate of Return**		**(Line 58 * Line 118)**	**684,963,996**

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	-561,000
38	1/(1-T)		1 / (1 - Line 123)	169%
39	Net Plant Allocation Factor		(Line 18)	59.3008%
40	**ITC Adjustment Allocated to Transmission**		(Line 125 * Line 126 * Line 127)	**-562,430**
41	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		367,206,591
42	**Total Income Taxes**			**366,644,161**

Public Service Electric and Gas Company

ATTACHMENT H-10A

Attachment 5 - Cost Support - December 31, 2018

Electric / Non-electric Cost Support

				Previous Year	Current Year - 2018													
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	19,742,890,957	19,825,595,886	20,104,813,744	20,326,447,804	20,629,167,815	20,938,813,587	21,251,316,482	21,275,826,367	21,310,782,349	21,361,638,363	21,392,735,723	21,488,874,616	22,056,135,585	20,900,387,637	
7	Common Plant in Service - Electric	(Note B)	p356	166,892,472	174,040,289	175,018,338	175,371,682	177,520,426	178,196,663	183,353,886	183,803,836	184,182,556	184,503,100	184,138,849	184,739,613	195,374,795	180,548,962	
9	Accumulated Depreciation (Total Electric Plant)	(Note B & J)	p219.29c	3,575,858,512	3,602,342,995	3,624,829,494	3,648,313,023	3,672,223,218	3,698,796,132	3,725,777,927	3,754,325,988	3,787,335,889	3,820,361,059	3,852,958,335	3,887,247,801	3,920,455,502	3,736,217,375	
10	Accumulated Intangible Amortization	(Note B)	p200.21c	5,106,935	5,257,546	5,408,158	5,558,770	5,709,382	5,859,994	6,089,439	6,319,170	6,549,187	6,779,346	7,009,506	7,239,665	7,469,825	6,181,302	
11	Accumulated Common Plant Depreciation - Electric	(Note B & J)	p356	26,784,199	27,457,199	28,135,932	28,228,175	28,909,914	29,458,853	30,106,466	30,706,076	31,152,681	31,616,888	31,348,042	32,065,970	29,952,655	29,686,389	
12	Accumulated Common Amortization - Electric	(Note B)	p356	44,901,775	45,593,505	46,288,901	46,986,589	47,707,734	48,432,088	49,160,796	49,893,170	50,630,128	51,371,669	52,117,564	52,867,814	53,675,584	49,202,101	
	Plant In Service																	
19	Transmission Plant in Service (Excludes Asset Retirement Costs - ARC)	(Note B)	p207.58.g	10,365,352,227	10,418,460,440	10,654,754,333	10,803,752,626	11,047,483,689	11,197,875,412	11,396,279,745	11,402,371,078	11,409,839,411	11,442,672,744	11,453,360,077	11,528,537,410	11,996,183,743	11,162,840,225	
20	General (Excludes Asset Retirement Costs - ARC)	(Note B)	p207.99.g	283,648,204	282,074,003	282,991,051	296,126,545	317,361,077	334,115,384	359,257,530	357,382,915	358,669,946	359,343,461	360,848,977	363,831,120	364,244,743	332,299,612	
21	Intangible - Electric	(Note B)	p205.5.g	11,449,861	11,449,861	11,449,861	11,449,861	11,449,861	11,449,861	18,069,861	18,093,861	18,117,861	18,129,861	18,129,861	18,129,861	18,129,861	15,038,477	
22	Common Plant in Service - Electric	(Note B)	p356	166,892,472	174,040,289	175,018,338	175,371,682	177,520,426	178,196,663	183,353,886	183,803,836	184,182,556	184,503,100	184,138,849	184,739,613	195,374,795	180,548,962	
24	General Plant Account 397 -- Communications	(Note B)	p207.94g	32,169,518	31,810,056	31,876,056	31,943,056	31,436,763	31,502,763	42,721,534	40,247,165	40,412,165	40,515,165	40,582,125	42,738,947	42,060,110	36,924,263	
25	Common Plant Account 397 -- Communications	(Note B)	p356	35,317,165	35,317,165	35,317,165	35,317,165	35,317,165	35,317,165	35,317,165	35,265,190	35,265,190	35,000,156	35,000,156	34,992,175	34,985,952	35,209,921	
29	Account No. 397 Directly Assigned to Transmission	(Note B)	Company Records	20,410,777	20,410,777	20,410,777	20,410,777	20,410,777	20,410,777	20,409,814	17,787,788	17,787,788	17,787,788	17,787,747	17,777,570	17,621,777	19,186,533	
	Accumulated Depreciation																	
32	Transmission Accumulated Depreciation	(Note B & J)	p219.25.c	892,839,935	905,106,797	917,307,248	928,910,694	938,625,603	949,517,295	961,072,796	976,553,613	993,348,882	1,009,381,169	1,024,313,830	1,040,675,847	1,057,459,855	968,854,890	
33	Accumulated General Depreciation	(Note B & J)	p219.28.b	143,531,156	142,881,390	139,215,665	137,245,265	137,612,587	138,829,382	139,517,055	137,607,804	138,477,823	139,342,936	140,970,309	142,263,293	142,125,843	139,970,808	
34	Accumulated Common Plant Depreciation & Amortization - Electric	(Note B & J)	p356	71,685,975	73,050,704	74,424,833	75,214,764	76,617,648	77,890,941	79,267,262	80,599,246	81,782,809	82,988,557	83,465,606	84,933,784	83,628,239	78,888,490	
35	Accumulated General Depreciation Associated with Acct. 397	(Note B & J)	Company Records	28,475,982	28,693,363	29,337,757	29,982,709	30,050,149	30,691,431	31,416,975	29,436,351	30,151,445	30,600,156	31,314,418	32,028,469	31,790,354	30,305,351	
41	Acc. Deprec. Acct. 397 Directly Assigned to Transmission	(Note B & J)	Company Records	20,064,602	20,234,691	20,404,781	20,574,871	20,744,961	20,915,051	21,084,169	18,610,375	18,758,606	18,906,838	19,055,029	19,192,998	19,184,053	19,825,463	

Wages & Salary

Line #s	**Descriptions**	**Notes**	**Page #'s & Instructions**	**End of Year**
2	Total Wage Expense	(Note A)	p354.28b	207,395,000
3	Total A&G Wages Expense	(Note A)	p354.27b	9,733,000
1	Transmission Wages		p354.21b	31,626,000

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			17,076,194	19,094,194	18,085,194

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	16.000%	-

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	48,632,000	48,632,000	48,632,000

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	107,887,010
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	3,032,000

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Adjustments to A & G Expense

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
62	Total A&G Expenses (Benefit Costs determined in accordance with ASU 2017-17)		p323.197b	172,512,000
				-
63	Actual PBOP expense	(Note J)	Company Records	26,864,000
64	Actual PBOP expense	(Note O)	Company Records	37,487,000

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	10,400,000	-
	Directly Assigned A&G				
72	Regulatory Commission Exp Account 928	(Note G & O)	p351.11-13h	835,000	835,000

General & Common Expenses

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

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	2,125,000	-	2,125,000

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	2,125,000	-	2,125,000

Depreciation Expense

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
	Depreciation Expense			
81	Depreciation-Transmission	(Note J & O)	p336.7.f	266,279,924
82	Depreciation-General & Common	(Note J & O)	p336.10&11.f	27,729,088
83	Depreciation-General Expense Associated with Acct. 397	(Note J & O)	Company Records	7,252,148
85	Depreciation-Intangible	(Note A & O)	p336.1.f	11,136,699
89	Transmission Depreciation Expense for Acct. 397	(Note J & O)	Company Records	1,908,451

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	21,308,000	7,881,000	13,427,000

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.

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Return \ Capitalization

Line #s	Descriptions	Notes	Page #'s & Instructions	2015 End of Year	2016 End of Year	Average
96	Proprietary Capital	(Note P)	p112.16.c,d	7,629,005,378	8,774,388,796	8,201,697,087
97	Accumulated Other Comprehensive Income Account 219	(Note P)	p112.15.c,d	1,227,004	816,474	1,021,739
99	Account 216.1	(Note P)	p119.53.c&d	3,474,616	3,187,722	3,331,169
101	Long Term Debt	(Note P)	p112.18.c,d thru 23.c,d	6,861,859,145	7,862,697,345	7,362,278,245
102	Loss on Reacquired Debt	(Note P)	p111.81.c,d	66,774,576	61,094,172	63,934,374
103	Gain on Reacquired Debt	(Note P)	p113.61.c,d	-	-	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

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	561,000

Excluded Transmission Facilities

Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Form 1 Dec	Average
141	Excluded Transmission Facilities	(Note B & M)		-	-	-	-	-	-	-	-	-	-	-	-	-	0

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)		-

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			-

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	9,566.9

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
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Attachment 6 - True-up Adjustment for Network Integration Transmission Service - December 31, 2018

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
June	2017	TO populates the formula with Year 2016 actual data and calculates the 2016 True-Up Adjustment Before Interest
October	2017	TO calculates the Interest to include in the 2016 True-Up Adjustment
October	2017	TO populates the formula with Year 2018 estimated data and 2016 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.	1,075,953,704	
B	ATRR based on projected costs included for the previous calendar year but excludes the true-up adjustment.	1,064,228,952	
C	Difference (A-B)	11,724,752	<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	1.07393	
E	True-up Adjustment (C*D)	12,591,534	

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	0.2600%
March	Year 1	0.2800%
April	Year 1	0.2800%
May	Year 1	0.2900%
June	Year 1	0.2800%
July	Year 1	0.3000%
August	Year 1	0.3000%
September	Year 1	0.2900%
October	Year 1	0.3000%
November	Year 1	0.2900%
December	Year 1	0.3000%
January	Year 2	0.3000%
February	Year 2	0.2700%
March	Year 2	0.3000%
April	Year 2	0.3000%
May	Year 2	0.3200%
June	Year 2	0.3000%
July	Year 2	0.3400%
August	Year 2	0.3400%
September	Year 2	0.3300%
Average Interest Rate		0.2976%

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2018

	Estimated Additions - 2018												
	(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)	Reconfigure Kearny- Loop in P2216 Ckt (B1589) (monthly additions)	Reconfigure Brunswick Sw-New 69kVCkt-T (B2146) (monthly additions)	350 MVAR Reactor Hopatcong 500kV (B2702) (monthly additions)	Mickleton-Gloucester-Camden(B1398-B1398.7) (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)	(in service)	(in service)	(in service)	(in service)	(in service)
Dec-17	9,222,677,668	33,382,127	1,530,376	74,949,196	-	438,784,743	174,641,754	43,133,750	24,754,173	15,218,118	-	-	15,218,118
Jan	22,521,913	191,572	-	-	-	5,000	16,938	1,137	1,137	200,524	-	-	200,524
Feb	39,984,029	190,217	-	-	-	5,000	72,474	13,156,649	13,156,649	141,962,430	13,155,532	-	43,884
Mar	48,273,703	594,143	-	-	-	5,000	60,637	430,421	430,421	799,071	386,938	26,103,784	22,171
Apr	55,032,865	223,817	-	-	-	5,000	17,253	8,786,110	581,716	843,679	105,436,138	36,175,259	33,149,302
May	123,826,918	129,299	19,584,758	1,947,000	-	80,000	18,211	687,981	420,170	701,225	711,485	298,021	316,633
Jun	150,159,437	18,565	106,000	9,641,161	21,224,080	100,000	19,771	562,066	8,535,382	614,707	729,092	390,579	378,065
Jul	4,051,043	-	35,000	-	18,000	100,000	23,267	260,922	387,476	345,990	93,225	51,796	22,392
Aug	3,662,511	-	88,000	-	18,000	100,000	18,258	259,612	363,825	367,208	125,010	24,657	681
Sep	30,948,506	-	37,000	-	15,000	100,000	23,797	252,489	308,420	321,919	73,336	20,202	888
Oct	8,829,690	-	36,000	-	9,000	100,000	25,867	254,326	302,616	310,929	75,766	20,349	-
Nov	14,165,647	-	35,000	59,287,359	9,000	-	16,108	257,297	306,151	310,860	66,590	14,480	-
Dec	465,669,098	-	35,000	426,000	8,000	-	15,017	277,237	66,677	332,611	69,412	13,262	-
Total	**10,189,803,028**	**34,729,740**	**21,487,134**	**146,250,715**	**21,301,080**	**439,384,743**	**174,969,351**	**68,319,997**	**49,614,813**	**162,329,270**	**120,922,525**	**63,112,389**	**49,352,658**

Public Service Electric and Gas Company
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Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2018

Estimated Transmission Enhancement Charges (Before True-Up) - 2018

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)
572,757,940	**2,111,886**	**859,260**	**9,205,426**	**2,333,821**	**2,966,159**	**2,859,539**	**1,748,857**	**764,348**	**2,340,178**	**2,999**	**1,055,185**	**2,402,026**

Actual Transmission Enhancement Charges - 2016

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)
549,724,505	**2,293,690**	**930,448**	**9,968,442**	**2,528,394**	**3,208,097**	**3,110,954**	**1,890,650**	**826,705**	**2,529,913**	**3,247**	**1,139,246**	**2,592,387**

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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)
	28,517,873	**(22,848)**	**(8,620)**	**(106,012)**	**(23,351)**	**(29,948)**	**(30,044)**	**(17,700)**	**(7,717)**	**(31,969)**	**(30)**	**(10,755)**	**(24,532)**
Interest		1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393

True Up by Project (with interest) -2016

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)
30,626,128	**(24,537)**	**(9,257)**	**(113,849)**	**(25,077)**	**(32,162)**	**(32,265)**	**(19,009)**	**(8,287)**	**(34,332)**	**(32)**	**(11,550)**	**(26,346)**

Estimated Transmission Enhancement Charges (After True-Up) -2018

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)
603,384,068	**2,087,349**	**850,003**	**9,091,577**	**2,308,744**	**2,933,997**	**2,827,274**	**1,729,848**	**756,061**	**2,305,846**	**2,966**	**1,043,635**	**2,375,680**

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ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2018

Estimated Additions - 2018													
(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)
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 additions)	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)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (monthly additions)
(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(CWIP)
15,218,118	30,700,815	30,700,815	44,419,189	44,419,189	29,425,776	24,754,173	26,818,736	26,818,736	15,218,118	15,218,118	17,350,419	-	704,837
200,524	14,291,067	14,291,067	321,453	321,453	23,885	1,137	-	-	200,524	200,524	117,832	-	-
43,884	264,809	264,809	255,631	255,631	29,038	1,117	-	-	43,884	43,884	208,810	13,155,532	(50,196)
71,111,339	32,666	32,666	46,245	46,245	147,489	43,483	1,100	1,100	22,171	22,171	(1,607)	386,938	-
239,947	141,110	141,110	84,275	84,275	354,519	1,159	-	-	31,610	31,610	1,789,753	580,558	-
251,153	139,928	139,928	69,727	69,727	344,120	1,223	-	-	45,975	45,975	143,322	418,947	-
221,639	17,158	17,158	13,175	13,175	5,112,642	1,328	-	-	9,958	9,958	166,226	343,014	(654,641)
237,835	4,654	4,654	4,654	4,654	212,487	1,562	-	-	868	868	179,989	49,997	-
201,868	3,652	3,652	3,652	3,652	1,993,527	1,226	-	-	681	681	122,848	105,132	-
308,736	4,760	4,760	4,760	4,760	189,367	1,598	-	-	888	888	160,123	51,137	-
310,087	3,900	3,900	3,900	3,900	190,744	1,610	-	-	-	-	153,239	51,509	-
307,603	3,946	3,946	3,946	3,946	184,830	1,628	-	-	-	-	146,887	52,111	-
329,102	3,438	3,438	3,438	3,438	192,764	1,755	-	-	-	-	140,496	56,149	-
88,981,836	**45,611,902**	**45,611,902**	**45,234,044**	**45,234,044**	**38,401,188**	**24,812,999**	**26,819,837**	**26,819,837**	**15,574,675**	**15,574,675**	**20,678,337**	**15,251,024**	**0**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2018

Estimated Transmission Enhancement Charges (Before True-Up) - 2018

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)
2,495,036	**9,165,280**	**1,715,077**	**2,217,406**	**764,867**	**5,542,861**	**1,931,455**	**2,650,154**	**7,726,536**	**9,053,208**	**1,415,854**	**720,032**	**5,288,879**	**95,250,419**

Actual Transmission Enhancement Charges - 2016

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)
2,691,625	**9,901,291**	**1,849,551**	**2,391,449**	**824,687**	**5,978,667**	**2,083,057**	**2,856,436**	**9,096,222**	**9,746,523**	**1,524,089**	**776,124**	**5,688,534**	**102,755,603**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2018

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)
(25,540)	**(517,088)**	**(17,589)**	**(22,732)**	**(7,964)**	**(59,384)**	**(80,284)**	**(69,701)**	**(147,778)**	**(85,367)**	**6,830**	**(7,274)**	**(53,963)**	**(1,059,483)**
1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393

True Up by Project (with interest) -2016

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)
(27,428)	**(555,315)**	**(18,890)**	**(24,412)**	**(8,553)**	**(63,774)**	**(86,219)**	**(74,854)**	**(158,703)**	**(91,678)**	**7,335**	**(7,811)**	**(57,952)**	**(1,137,808)**

Estimated Transmission Enhancement Charges (After True-Up) -2018

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)
2,467,608	**8,609,965**	**1,696,187**	**2,192,993**	**756,314**	**5,479,087**	**1,845,236**	**2,575,300**	**7,567,834**	**8,961,530**	**1,423,188**	**712,221**	**5,230,927**	**94,112,611**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2018

Estimated Additions - 2018

(AB)	(AC)	(AD)	(AE)	(AF)	(AG)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)	(AN)	(AO)	(AP)	(AQ)	(AR)	(AS)	(AT)		(AU)
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)	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)	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)				Ridge Road 69kV Breaker Station (B1255)
(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)				(in service)
15,873,514	14,614,183	133,132,128	103,234,243	53,061,761	27,376,832	59,546,744	1,074,767	1,034,193	1,703,883	13,549	763,249	763,249	16,545	16,545	25,613,549	12,374,116		**Dec-17**	9,222,677,668	33,382,127
652,831	(1,557,054)	1,815,939	1,055,192	509,173	686,858	657,991	(1,074,767)	(1,034,193)	330,990	-	-	-	-	-	(22,742,030)	85,192		**Jan**	22,521,913	33,573,699
(11,470,385)	(10,596,791)	(134,948,067)	(10,669,451)	1,210,747	1,145,475	319,400	-	-	131,819	1,113	(58,480)	(58,480)	(1,199)	(1,199)	264,924	(12,459,152)		**Feb**	39,984,029	33,763,916
1,295,284	1,599,104	-	288,524	(22,682,892)	312,521	(60,524,135)	-	-	754,485	-	-	-	-	-	(1,558,855)	-		**Mar**	48,273,703	34,358,059
(6,351,243)	624,357	-	(93,908,509)	(32,098,788)	(29,521,685)	-	-	-	804,726	-	-	-	-	-	(1,577,588)	-		**Apr**	55,032,865	34,581,876
-	307,672	-	-	-	-	-	-	-	710,942	-	-	-	-	-	-	-		**May**	123,826,918	34,711,175
-	(4,991,470)	-	-	-	-	-	-	-	(4,436,845)	(14,662)	(704,769)	(704,769)	(15,346)	(15,346)	-	(156)		**Jun**	150,159,437	34,729,740
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		**Jul**	4,051,043	34,729,740
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		**Aug**	3,662,511	34,729,740
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		**Sep**	30,948,506	34,729,740
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		**Oct**	8,829,690	34,729,740
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		**Nov**	14,165,647	34,729,740
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		**Dec**	465,669,098	34,729,740
(0)	**(0)**	**(0)**	**0**	**0**	**(0)**	**(0)**	**0**	**(0)**	**(0)**	**0**	**0**	**0**	**(0)**	**(0)**	**0**	**(0)**		**Total**	**10,189,803,028**	**447,479,030**
																		13 Month Average CWIP to Appendix A. line 45	**783,831,002**	**34,421,464** **12.88**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2018

Estimated Transmission Enhancement Charges (Before True-Up) - 2018

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)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34)	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)
43,837,359	**55,588,180**	**45,059,821**	**80,480,326**	**-**	**22,658,724**	**8,180,418**	**5,536,025**	**18,443,893**	**11,422,990**	**6,094,733**	**5,168,751**	**9,480,127**	**5,893,466**	**5,893,466**	**5,975,564**	**5,975,564**	**4,417,628**	**3,280,954**	**3,475,420**	**3,475,420**

Actual Transmission Enhancement Charges - 2016

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)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34)	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)
47,233,422	**60,066,502**	**48,529,997**	**74,236,857**	**49,268,709**	**14,148,115**	**1,874,846**	**1,874,846**	**47,577**	**-**	**-**	**47,577**	**47,577**	**71,227**	**71,227**	**71,227**	**71,227**	**2,252,189**	**1,874,846**	**2,363,328**	**2,363,328**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2018

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)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34)	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)
(241,416)	**1,274,783**	**(244,661)**	**(29,570,588)**	**49,268,709**	**2,507,949**	**394,617**	**394,617**	**47,577**	**-**	**-**	**47,577**	**47,577**	**71,227**	**71,227**	**71,227**	**71,227**	**204,949**	**394,615**	**464,535**	**464,535**
1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393

True Up by Project (with interest) -2016

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)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34)	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)
(259,263)	**1,369,024**	**(262,749)**	**(31,756,668)**	**52,911,022**	**2,693,356**	**423,790**	**423,790**	**51,095**	**-**	**-**	**51,095**	**51,095**	**76,493**	**76,493**	**76,493**	**76,493**	**220,101**	**423,788**	**498,877**	**498,877**

Estimated Transmission Enhancement Charges (After True -Up) - 2018

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)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34)	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)
43,578,096	**56,957,204**	**44,797,073**	**48,723,659**	**52,911,022**	**25,352,079**	**8,604,208**	**5,959,815**	**18,494,988**	**11,422,990**	**6,094,733**	**5,219,846**	**9,531,222**	**5,969,959**	**5,969,959**	**6,052,057**	**6,052,057**	**4,637,729**	**3,704,742**	**3,974,297**	**3,974,297**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2018

Estimated Additions - 2018													
(AV)	(AW)	(AX)	(AY)	(AZ)	(BA)	(BB)	(BC)	(BD)	(BE)	(BF)	(BG)	(BH)	(BI)
Reconfigure Kearny- Loop in P2216 Ckt (B1589)	Reconfigure Brunswick Sw-New 69kVCkt-T (B2146)	350 MVAR Reactor Hopatcong 500kV (B2702)	Mickleton-Gloucester-Camden(B1398-B1398.7)	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)	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)
(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)
1,530,376	74,949,196	-	438,784,743	174,641,754	43,133,750	24,754,173	15,218,118	-	-	15,218,118	15,218,118	30,700,815	30,700,815
1,530,376	74,949,196	-	438,789,743	174,658,692	43,134,887	24,755,311	15,418,642	-	-	15,418,642	15,418,642	44,991,882	44,991,882
1,530,376	74,949,196	-	438,794,743	174,731,166	56,291,536	37,911,960	157,381,072	13,155,532	-	15,462,526	15,462,526	45,256,691	45,256,691
1,530,376	74,949,196	-	438,799,743	174,791,803	56,721,957	38,342,381	158,180,143	13,542,470	26,103,784	15,484,696	86,573,865	45,289,358	45,289,358
1,530,376	74,949,196	-	438,804,743	174,809,056	65,508,067	38,924,097	159,023,821	118,978,608	62,279,043	48,633,998	86,813,812	45,430,467	45,430,467
21,115,134	76,896,196	-	438,884,743	174,827,266	66,196,048	39,344,267	159,725,046	119,690,093	62,577,064	48,950,631	87,064,965	45,570,395	45,570,395
21,221,134	86,537,356	21,224,080	438,984,743	174,847,038	66,758,114	47,879,648	160,339,753	120,419,185	62,967,643	49,328,697	87,286,605	45,587,553	45,587,553
21,256,134	86,537,356	21,242,080	439,084,743	174,870,305	67,019,036	48,267,125	160,685,743	120,512,411	63,019,439	49,351,089	87,524,440	45,592,207	45,592,207
21,344,134	86,537,356	21,260,080	439,184,743	174,888,562	67,278,648	48,630,949	161,052,951	120,637,420	63,044,096	49,351,770	87,726,308	45,595,858	45,595,858
21,381,134	86,537,356	21,275,080	439,284,743	174,912,360	67,531,137	48,939,370	161,374,870	120,710,757	63,064,298	49,352,658	88,035,044	45,600,618	45,600,618
21,417,134	86,537,356	21,284,080	439,384,743	174,938,226	67,785,463	49,241,985	161,685,799	120,786,523	63,084,647	49,352,658	88,345,131	45,604,518	45,604,518
21,452,134	145,824,715	21,293,080	439,384,743	174,954,334	68,042,760	49,548,136	161,996,659	120,853,113	63,099,127	49,352,658	88,652,734	45,608,464	45,608,464
21,487,134	146,250,715	21,301,080	439,384,743	174,969,351	68,319,997	49,614,813	162,329,270	120,922,525	63,112,389	49,352,658	88,981,836	45,611,902	45,611,902
178,325,947	**1,176,404,387**	**148,879,560**	**5,707,551,661**	**2,272,839,913**	**803,721,399**	**546,154,215**	**1,794,411,887**	**1,110,208,636**	**592,351,530**	**504,610,798**	**923,104,026**	**576,440,730**	**576,440,730**
13,717,381 **8.30**	**90,492,645** **8.04**	**11,452,274** **6.99**	**439,042,435** **12.99**	**174,833,839** **12.99**	**61,824,723** **11.76**	**42,011,863** **11.01**	**138,031,684** **11.05**	**85,400,664** **9.18**	**45,565,502** **9.39**	**38,816,215** **10.22**	**71,008,002** **10.37**	**44,341,595** **12.64**	**44,341,595** **12.64**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2018

Estimated Transmission Enhancement Charges (Before True-Up) - 2018													
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)	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)	Install Conemaugh 250MVAR Cap Bank (B0376)	Reconfigure Kearny-Loop in P2216 Ckt (B1589)	Reconfigure Brunswick Sw-New 69kVCkt-T (B2146)	350 MVAR Reactor Hopatcong 500kV (B2702)	Susquehanna Roseland < 500KV (B0489.4) (CWIP)	Susquehanna Roseland >= 500KV (B0489) (CWIP)
2,053,372	**2,053,342**	**2,489,574**	**1,655,539**	**1,529,720**	**2,452,091**	**4,605,457**	**4,095,805**	**145,310**	**1,834,804**	**12,104,081**	**1,531,829**	**-**	**-**

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							Actual Transmission Enhancement Charges - 2016						
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)	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)	Install Conemaugh 250MVAR Cap Bank (B0376)	Reconfigure Kearny-Loop in P2216 Ckt (B1589)	Reconfigure Brunswick Sw-New 69kVCkt-T (B2146)	350 MVAR Reactor Hopatcong 500kV (B2702)	Susquehanna Roseland < 500KV (B0489.4) (CWIP)	Susquehanna Roseland >= 500KV (B0489) (CWIP)
25,899	**27,513**	**141,823**	**-**	**1,646,241**	**2,637,556**	**556,391**	**4,451,390**	**153,181**	**-**	**-**	**-**	**-**	**-**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2018

Reconciliation by Project (without interest)

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)	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)	Install Conemaugh 250MVAR Cap Bank (B0376)	Reconfigure Kearny-Loop in P2216 Ckt (B1589)	Reconfigure Brunswick Sw-New 69kVCkt-T (B2146)	350 MVAR Reactor Hopatcong 500kV (B2702)	Susquehanna Roseland < 500KV (B0489.4) (CWIP)	Susquehanna Roseland >= 500KV (B0489) (CWIP)
25,899	**27,513**	**141,823**	**-**	**(7,964)**	**112,364**	**(2,251,480)**	**325,597**	**153,181**	**-**	**-**	**-**	**-**	**-**

1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393

True Up by Project (with interest) -2016

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)	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)	Install Conemaugh 250MVAR Cap Bank (B0376)	Reconfigure Kearny-Loop in P2216 Ckt (B1589)	Reconfigure Brunswick Sw-New 69kVCkt-T (B2146)	350 MVAR Reactor Hopatcong 500kV (B2702)	Susquehanna Roseland < 500KV (B0489.4) (CWIP)	Susquehanna Roseland >= 500KV (B0489) (CWIP)
27,813	**29,547**	**152,308**	**-**	**(8,552)**	**120,671**	**(2,417,927)**	**349,668**	**164,506**	**-**	**-**	**-**	**-**	**-**

Estimated Transmission Enhancement Charges (After True -Up)- 2018

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)	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)	Install Conemaugh 250MVAR Cap Bank (B0376)	Reconfigure Kearny-Loop in P2216 Ckt (B1589)	Reconfigure Brunswick Sw-New 69kVCkt-T (B2146)	350 MVAR Reactor Hopatcong 500kV (B2702)	Susquehanna Roseland < 500KV (B0489.4) (CWIP)	Susquehanna Roseland >= 500KV (B0489) (CWIP)
2,081,185	**2,082,889**	**2,641,882**	**1,655,539**	**1,521,168**	**2,572,761**	**2,187,531**	**4,445,472**	**309,816**	**1,834,804**	**12,104,081**	**1,531,829**	**-**	**-**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2018

Estimated Additions - 2018													
(BJ)	(BK)	(BL)	(BM)	(BN)	(BO)	(BP)	(BQ)	(BR)	(BS)	(BT)	(BU)	(BV)	(BW)
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)	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)
(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(CWIP)	(CWIP)	(CWIP)	(CWIP)
44,419,189	44,419,189	29,425,776	24,754,173	26,818,736	26,818,736	15,218,118	15,218,118	17,350,419	-	704,837	15,873,514	14,614,183	133,132,128
44,740,642	44,740,642	29,449,661	24,755,311	26,818,736	26,818,736	15,418,642	15,418,642	17,468,251	-	704,837	16,526,345	13,057,129	134,948,067
44,996,273	44,996,273	29,478,699	24,756,428	26,818,736	26,818,736	15,462,526	15,462,526	17,677,062	13,155,532	654,641	5,055,960	2,460,338	(0)
45,042,518	45,042,518	29,626,188	24,799,911	26,819,837	26,819,837	15,484,696	15,484,696	17,675,454	13,542,470	654,641	6,351,244	4,059,442	(0)
45,126,793	45,126,793	29,980,708	24,801,069	26,819,837	26,819,837	15,516,306	15,516,306	19,465,207	14,123,028	654,641	(0)	4,683,799	(0)
45,196,520	45,196,520	30,324,827	24,802,292	26,819,837	26,819,837	15,562,281	15,562,281	19,608,529	14,541,974	654,641	(0)	4,991,471	(0)
45,209,694	45,209,694	35,437,469	24,803,620	26,819,837	26,819,837	15,572,239	15,572,239	19,774,755	14,884,989	0	(0)	(0)	(0)
45,214,348	45,214,348	35,649,956	24,805,182	26,819,837	26,819,837	15,573,107	15,573,107	19,954,744	14,934,986	0	(0)	(0)	(0)
45,218,000	45,218,000	37,643,482	24,806,408	26,819,837	26,819,837	15,573,788	15,573,788	20,077,592	15,040,118	0	(0)	(0)	(0)
45,222,759	45,222,759	37,832,849	24,808,006	26,819,837	26,819,837	15,574,675	15,574,675	20,237,715	15,091,255	0	(0)	(0)	(0)
45,226,660	45,226,660	38,023,594	24,809,616	26,819,837	26,819,837	15,574,675	15,574,675	20,390,954	15,142,764	0	(0)	(0)	(0)
45,230,605	45,230,605	38,208,424	24,811,244	26,819,837	26,819,837	15,574,675	15,574,675	20,537,842	15,194,875	0	(0)	(0)	(0)
45,234,044	45,234,044	38,401,188	24,812,999	26,819,837	26,819,837	15,574,675	15,574,675	20,678,337	15,251,024	0	(0)	(0)	(0)
586,078,044	**586,078,044**	**439,482,822**	**322,326,260**	**348,654,574**	**348,654,574**	**201,680,405**	**201,680,405**	**250,896,862**	**160,903,014**	**4,028,239**	**43,807,061**	**43,866,358**	**268,080,194**
45,082,926 **12.96**	**45,082,926** **12.96**	**33,806,371** **11.44**	**24,794,328** **12.99**	**26,819,583** **13.00**	**26,819,583** **13.00**	**15,513,877** **12.95**	**15,513,877** **12.95**	**19,299,759** **12.13**	**12,377,155** **10.55**	**13.00** **309,865**	**13.00** **3,369,774**	**13.00** **3,374,335**	**13.00** **20,621,553**

Public Service Electric and Gas Company
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Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2018

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Estimated Transmission Enhancement Charges (Before True-Up) - 2018													
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)	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)
-	-	-	-	-	-	-	**36,008**	**370,901**	**482,318**	**2,270,858**	**3,341,783**	**1,637,529**	**966,968**

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							Actual Transmission Enhancement Charges - 2016						
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)	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)
-	-	-	-	-	**11,982,038**	**4,104,014**	**5,126,158**	**857,240**	**921,870**	**3,473,891**	**1,695,242**	**1,011,439**	**749,927**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2018

Reconciliation by Project (without interest)

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)	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)
-	**-**	**-**	**-**	**-**	**3,522,083**	**3,748,178**	**(700,564)**	**(569,315)**	**(143,008)**	**586,708**	**59,227**	**(538,073)**	**(257,986)**

1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393

True Up by Project (with interest) -2016

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)	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)
-	**-**	**-**	**-**	**-**	**3,782,462**	**4,025,272**	**(752,355)**	**(611,403)**	**(153,580)**	**630,082**	**63,605**	**(577,852)**	**(277,058)**

Estimated Transmission Enhancement Charges (After True-Up) - 2018

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)	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)
-	**-**	**-**	**-**	**-**	**3,782,462**	**4,025,272**	**(716,347)**	**(240,503)**	**328,738**	**2,900,940**	**3,405,388**	**1,059,677**	**689,910**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2018

(BX)	(BY)	(BZ)	(CA)	(CB)	(CC)	(CD)	(CE)	(CF)	(CG)	(CH)	(CI)	(CJ)	(CK)
Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34)	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)	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) (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)	(CWIP)
103,234,243	53,061,761	27,376,832	59,546,744	1,074,767	1,034,193	1,703,883	13,549	763,249	763,249	16,545	16,545	25,613,549	12,374,116
104,289,435	53,570,934	28,063,690	60,204,735	0	(0)	2,034,872	13,549	763,249	763,249	16,545	16,545	2,871,520	12,459,308
93,619,985	54,781,681	29,209,165	60,524,134	0	(0)	2,166,691	14,662	704,769	704,769	15,346	15,346	3,136,443	156
93,908,509	32,098,788	29,521,686	(0)	0	(0)	2,921,177	14,662	704,769	704,769	15,346	15,346	1,577,588	156
0	0	(0)	(0)	0	(0)	3,725,903	14,662	704,769	704,769	15,346	15,346	0	156
0	0	(0)	(0)	0	(0)	4,436,845	14,662	704,769	704,769	15,346	15,346	0	156
0	0	(0)	(0)	0	(0)	(0)	0	0	0	(0)	(0)	0	(0)
0	0	(0)	(0)	0	(0)	(0)	0	0	0	(0)	(0)	0	(0)
0	0	(0)	(0)	0	(0)	(0)	0	0	0	(0)	(0)	0	(0)
0	0	(0)	(0)	0	(0)	(0)	0	0	0	(0)	(0)	0	(0)
0	0	(0)	(0)	0	(0)	(0)	0	0	0	(0)	(0)	0	(0)
0	0	(0)	(0)	0	(0)	(0)	0	0	0	(0)	(0)	0	(0)
0	0	(0)	(0)	0	(0)	(0)	0	0	0	(0)	(0)	0	(0)
395,052,176	**193,513,166**	**114,171,370**	**180,275,609**	**1,074,771**	**1,034,189**	**16,989,371**	**85,746**	**4,345,571**	**4,345,571**	**94,474**	**94,474**	**33,199,102**	**24,834,045**
13.00	**13.00**	**13.00**	**13.00**	**13.00**	**13.00**	**13.00**	**13.00**	**13.00**	**13.00**	**13.00**	**13.00**	**13.00**	**13.00**
30,388,629	**14,885,628**	**8,782,413**	**13,867,355**	**82,675**	**79,553**	**1,306,875**	**6,596**	**334,275**	**334,275**	**7,267**	**7,267**	**2,553,777**	**1,910,311**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2018

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Estimated Transmission Enhancement Charges (Before True-Up) - 2018												
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)
1,526,070	**9,243**	**8,889**	**-**	**-**	**156,325**	**806**	**38,765**	**38,765**	**844**	**844**	**183,996**	**210,526**

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							Actual Transmission Enhancement Charges - 2016					
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)
2,311,095	**1,295,020**	**1,295,020**	**1,342,797**	**1,342,797**	**868,195**	**704,952**	**908,856**	**915,296**	**597,380**	**597,124**	**2,125,894**	**157,609**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2018

Reconciliation by Project (without interest)

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)
517,581	**175,506**	**175,506**	**66,363**	**66,363**	**(213,626)**	**(158,798)**	**(417,851)**	**(408,383)**	**(41,915)**	**(42,254)**	**1,274,130**	**11,628**

1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393

True Up by Project (with interest) -2016

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)
555,844	**188,481**	**188,481**	**71,269**	**71,269**	**(229,419)**	**(170,537)**	**(448,742)**	**(438,574)**	**(45,014)**	**(45,378)**	**1,368,323**	**12,488**

Estimated Transmission Enhancement Charges (After True -Up) - 2018

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)
2,081,914	**197,724**	**197,370**	**71,269**	**71,269**	**(73,094)**	**(169,731)**	**(409,977)**	**(399,809)**	**(44,169)**	**(44,534)**	**1,552,319**	**223,013**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

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	10.99%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.68%
5	C		Line B less Line A	0.69%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

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		10.99%			10.99%			10.99%			10.99%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		10.99%			10.99%			10.99%			10.99%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		20,645,602			8,069,022			86,467,721			22,188,863		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		491,562			192,120			2,058,755			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	15,743,650	492,086	2,293,690	6,452,016	192,120	930,448	69,120,244	2,058,755	9,968,442	17,478,132	528,306	2,528,394
43		W Increased ROE	2016	15,743,650	492,086	2,293,690	6,452,016	192,120	930,448	69,120,244	2,058,755	9,968,442	17,478,132	528,306	2,528,394
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
46		W 11.68 % ROE	2018	14,737,169	491,562	2,111,886	6,067,776	192,120	859,260	65,000,402	2,058,755	9,205,426	16,421,520	528,306	2,333,821
47		W Increased ROE	2018	14,737,169	491,562	2,111,886	6,067,776	192,120	859,260	65,000,402	2,058,755	9,205,426	16,421,520	528,306	2,333,821

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

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	10.99%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.68%
5	C		Line B less Line A	0.69%

6 **FCR if a CIAC**

7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

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 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		10.99%	10.99%	10.99%	10.99%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		10.99%	10.99%	10.99%	10.99%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		27,005,248	25,654,455	15,731,554	6,961,495
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		642,982	610,820	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	3,208,097	21,819,123	614,111	3,110,954	13,248,621	374,561	1,890,650	5,775,874	165,750	826,705
43	W Increased ROE	2016	22,415,723	642,982	3,208,097	21,819,123	614,111	3,110,954	13,248,621	374,561	1,890,650	5,775,874	165,750	826,705
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
46	W 11.68 % ROE	2018	21,129,759	642,982	2,966,159	20,452,549	610,820	2,859,539	12,499,499	374,561	1,748,857	5,444,374	165,750	764,348
47	W Increased ROE	2018	21,129,759	642,982	2,966,159	20,452,549	610,820	2,859,539	12,499,499	374,561	1,748,857	5,444,374	165,750	764,348

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

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	10.99%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.68%
5	C		Line B less Line A	0.69%

6 **FCR if a CIAC**

7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

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		10.99%			10.99%			10.99%			10.99%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		10.99%			10.99%			10.99%			10.99%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		21,014,433			27,988			9,158,918			20,626,991		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		500,344			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	17,735,762	500,344	2,529,913	22,547	666	3,247	8,049,871	218,069	1,139,246	18,362,318	491,119	2,592,387
43		W Increased ROE	2016	17,735,762	500,344	2,529,913	22,547	666	3,247	8,049,871	218,069	1,139,246	18,362,318	491,119	2,592,387
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
46		W 11.68 % ROE	2018	16,733,664	500,344	2,340,178	21,214	666	2,999	7,613,732	218,069	1,055,185	17,380,080	491,119	2,402,026
47		W Increased ROE	2018	16,733,664	500,344	2,340,178	21,214	666	2,999	7,613,732	218,069	1,055,185	17,380,080	491,119	2,402,026

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

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	10.99%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.68%
5	C		Line B less Line A	0.69%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

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		10.99%	10.99%	10.99%	10.99%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		10.99%	10.99%	10.99%	10.99%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		21,170,273	77,352,830	14,404,842	18,664,931
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		504,054	1,841,734	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	2,691,625	70,419,117	1,842,970	9,901,291	13,165,512	342,972	1,849,551	17,014,619	444,403	2,391,449
43	W Increased ROE	2016	19,116,490	504,054	2,691,625	70,419,117	1,842,970	9,901,291	13,165,512	342,972	1,849,551	17,014,619	444,403	2,391,449
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
46	W 11.68 % ROE	2018	18,108,382	504,054	2,495,036	66,609,121	1,841,734	9,165,280	12,479,567	342,972	1,715,077	16,125,813	444,403	2,217,406
47	W Increased ROE	2018	18,108,382	504,054	2,495,036	66,609,121	1,841,734	9,165,280	12,479,567	342,972	1,715,077	16,125,813	444,403	2,217,406

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

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	10.99%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.68%
5	C		Line B less Line A	0.69%

6 **FCR if a CIAC**

7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

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		10.99%			10.99%			10.99%			10.99%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		10.99%			10.99%			10.99%			10.99%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		6,390,403			46,035,637			15,865,267			21,736,918		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		152,152			1,096,087			377,744			517,546		
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	5,877,066	152,152	824,687	42,662,264	1,096,665	5,978,667	14,899,633	378,036	2,083,057	20,438,822	517,546	2,856,436
43		W Increased ROE	2016	5,877,066	152,152	824,687	42,662,264	1,096,665	5,978,667	14,899,633	378,036	2,083,057	20,438,822	517,546	2,856,436
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
46		W 11.68 % ROE	2018	5,572,761	152,152	764,867	40,444,309	1,096,087	5,542,861	14,131,308	377,744	1,931,455	19,396,499	517,546	2,650,154
47		W Increased ROE	2018	5,572,761	152,152	764,867	40,444,309	1,096,087	5,542,861	14,131,308	377,744	1,931,455	19,396,499	517,546	2,650,154

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

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	10.99%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.68%
5		C		Line B less Line A	0.69%
6	**FCR if a CIAC**				
7		D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

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		10.99%	10.99%	10.99%	10.99%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		10.99%	10.99%	10.99%	11.86%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		62,937,256	72,380,453	11,276,183	5,857,687
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		1,498,506	1,723,344	268,481	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

			Branchburg-Middlesex Switch Rack (B1155)			Aldene-Springfield Rd. Conversion (B1399)			Upgrade Camden-Richmond 230kV Circuit (B1590)			Susquehanna Roseland Breakers (b0489.5-B0489.15)		
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	65,275,261	1,626,531	9,096,222	70,112,484	1,723,291	9,746,523	10,972,368	268,481	1,524,089	5,175,948	139,469	731,772
43	W Increased ROE	2016	65,275,261	1,626,531	9,096,222	70,112,484	1,723,291	9,746,523	10,972,368	268,481	1,524,089	5,175,948	139,469	776,124
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
46	W 11.68 % ROE	2018	56,645,182	1,498,506	7,726,536	66,666,584	1,723,344	9,053,208	10,435,588	268,481	1,415,854	4,897,011	139,469	677,886
47	W Increased ROE	2018	56,645,182	1,498,506	7,726,536	66,666,584	1,723,344	9,053,208	10,435,588	268,481	1,415,854	4,897,011	139,469	720,032

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

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	10.99%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.68%
5	C		Line B less Line A	0.69%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

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		10.99%			10.99%			10.99%			10.99%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.86%			11.86%			10.99%			10.99%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		40,538,248			720,620,844			356,333,540			439,384,743		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		965,196			17,157,639			8,484,132			10,461,542		
19	Months in service for depreciation expense from			13.00			13.00			13.00			12.99		
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	5,359,489	694,520,844	17,213,677	96,796,429	338,712,254	8,485,957	47,233,422	430,951,154	10,495,692	60,066,502
43		W Increased ROE	2016	38,400,330	965,196	5,688,534	694,520,844	17,213,677	102,755,603	338,712,254	8,485,957	47,233,422	430,951,154	10,495,692	60,066,502
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
46		W 11.68 % ROE	2018	36,469,937	965,196	4,974,997	658,706,710	17,157,639	89,581,190	321,544,683	8,484,132	43,837,359	410,830,010	10,453,391	55,588,180
47		W Increased ROE	2018	36,469,937	965,196	5,288,879	658,706,710	17,157,639	95,250,419	321,544,683	8,484,132	43,837,359	410,830,010	10,453,391	55,588,180

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

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	10.99%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.68%
5	C		Line B less Line A	0.69%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

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		10.99%			10.99%			10.99%			10.99%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		10.99%			11.17%			11.17%			10.99%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		370,006,995			625,390,228			-			174,969,351		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		8,809,690			14,890,244			-			4,165,937		
19	Months in service for depreciation expense from			13.00			13.00						12.99		
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	347,072,992	8,805,472	48,529,997	615,905,487	12,804,341	73,330,415	352,027,464	8,381,606	48,665,417	178,685,539	2,436,719	14,148,115
43		W Increased ROE	2016	347,072,992	8,805,472	48,529,997	615,905,487	12,804,341	74,236,857	352,027,464	8,381,606	49,268,709	178,685,539	2,436,719	14,148,115
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
46		W 11.68 % ROE	2018	329,702,206	8,809,690	45,059,821	587,359,389	14,890,244	79,469,292	-	-	-	168,355,336	4,162,710	22,658,724
47		W Increased ROE	2018	329,702,206	8,809,690	45,059,821	587,359,389	14,890,244	80,480,326	-	-	-	168,355,336	4,162,710	22,658,724

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

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	10.99%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.68%
5	C		Line B less Line A	0.69%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

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)**			**Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34)**		
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		10.99%			10.99%			10.99%			10.99%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		10.99%			10.99%			10.99%			10.99%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		68,319,997			49,614,813			162,329,270			120,922,525		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		1,626,667			1,181,305			3,864,983			2,879,108		
19	Months in service for depreciation expense from			11.76			11.01			11.05			9.18		
20	Year placed in Service (0 if CWIP)			2016			2016			2015			2018		
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	23,849,835	322,903	1,874,846	23,849,835	322,903	1,874,846	349,923	8,202	47,577			
43		W Increased ROE	2016	23,849,835	322,903	1,874,846	23,849,835	322,903	1,874,846	349,923	8,202	47,577			
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			
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			
46		W 11.68 % ROE	2018	67,424,378	1,472,017	8,180,418	48,719,195	1,000,282	5,536,025	162,127,145	3,286,469	18,443,893	120,922,525	2,033,349	11,422,990
47		W Increased ROE	2018	67,424,378	1,472,017	8,180,418	48,719,195	1,000,282	5,536,025	162,127,145	3,286,469	18,443,893	120,922,525	2,033,349	11,422,990

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

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	10.99%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.68%
5	C		Line B less Line A	0.69%

6 **FCR if a CIAC**

7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

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 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)**
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		10.99%	10.99%	10.99%	10.99%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		10.99%	10.99%	10.99%	10.99%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		63,112,389	49,352,658	88,981,836	45,611,902
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		1,502,676	1,175,063	2,118,615	1,085,998
19	Months in service for depreciation expense from			9.39	10.22	10.37	12.64
20	Year placed in Service (0 if CWIP)			2018	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
41	W Increased ROE	2015				225,037	412	2,441	225,037	412	2,441	225,037	412	2,441
42	W 11.68 % ROE	2016				349,923	8,202	47,577	349,923	8,202	47,577	723,468	12,273	71,227
43	W Increased ROE	2016				349,923	8,202	47,577	349,923	8,202	47,577	723,468	12,273	71,227
44	W 11.68 % ROE	2017				48,229,026	259,831	1,464,046	15,071,025	193,511	1,090,341	24,740,340	338,724	1,908,566
45	W Increased ROE	2017				48,229,026	259,831	1,464,046	15,071,025	193,511	1,090,341	24,740,340	338,724	1,908,566
46	W 11.68 % ROE	2018	63,112,389	1,084,893	6,094,733	49,084,212	924,196	5,168,751	88,779,710	1,690,667	9,480,127	45,260,492	1,055,752	5,893,466
47	W Increased ROE	2018	63,112,389	1,084,893	6,094,733	49,084,212	924,196	5,168,751	88,779,710	1,690,667	9,480,127	45,260,492	1,055,752	5,893,466

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

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	10.99%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.68%
5	C		Line B less Line A	0.69%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

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 "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)**		
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		10.99%			10.99%			10.99%			10.99%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		10.99%			10.99%			10.99%			10.99%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		45,611,902			45,234,044			45,234,044			38,401,188		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		1,085,998			1,077,001			1,077,001			914,314		
19	Months in service for depreciation expense from			12.64			12.96			12.96			11.44		
20	Year placed in Service (0 if CWIP)			2015			2015			2015			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	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			
42		W 11.68 % ROE	2016	723,468	12,273	71,227	723,468	12,273	71,227	723,468	12,273	71,227	28,441,681	387,893	2,252,189
43		W Increased ROE	2016	723,468	12,273	71,227	723,468	12,273	71,227	723,468	12,273	71,227	28,441,681	387,893	2,252,189
44		W 11.68 % ROE	2017	24,740,340	338,724	1,908,566	36,209,684	485,767	2,737,100	36,209,684	485,767	2,737,100	28,907,314	688,967	3,843,966
45		W Increased ROE	2017	24,740,340	338,724	1,908,566	36,209,684	485,767	2,737,100	36,209,684	485,767	2,737,100	28,907,314	688,967	3,843,966
46		W 11.68 % ROE	2018	45,260,492	1,055,752	5,893,466	44,735,591	1,073,403	5,975,564	44,735,591	1,073,403	5,975,564	37,324,329	804,914	4,417,628
47		W Increased ROE	2018	45,260,492	1,055,752	5,893,466	44,735,591	1,073,403	5,975,564	44,735,591	1,073,403	5,975,564	37,324,329	804,914	4,417,628

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

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	10.99%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.68%
5	C		Line B less Line A	0.69%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

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 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)**		
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		10.99%			10.99%			10.99%			10.99%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		10.99%			10.99%			10.99%			10.99%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		24,812,999			26,819,837			26,819,837			15,574,675		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		590,786			638,568			638,568			370,826		
19	Months in service for depreciation expense from			12.99			13.00			13.00			12.95		
20	Year placed in Service (0 if CWIP)			2016			2016			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										225,037	412	2,441
41		W Increased ROE	2015										225,037	412	2,441
42		W 11.68 % ROE	2016	23,849,835	322,903	1,874,846	27,523,727	407,034	2,363,328	27,523,727	407,034	2,363,328	349,923	4,465	25,899
43		W Increased ROE	2016	23,849,835	322,903	1,874,846	27,523,727	407,034	2,363,328	27,523,727	407,034	2,363,328	349,923	4,465	25,899
44		W 11.68 % ROE	2017				25,328,064	610,761	3,405,679	25,328,064	610,761	3,405,679	15,071,025	193,511	1,090,341
45		W Increased ROE	2017				25,328,064	610,761	3,405,679	25,328,064	610,761	3,405,679	15,071,025	193,511	1,090,341
46		W 11.68 % ROE	2018	24,490,096	590,341	3,280,954	25,802,041	638,561	3,475,420	25,802,041	638,561	3,475,420	15,376,287	369,378	2,053,372
47		W Increased ROE	2018	24,490,096	590,341	3,280,954	25,802,041	638,561	3,475,420	25,802,041	638,561	3,475,420	15,376,287	369,378	2,053,372

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

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	10.99%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.68%
5	C		Line B less Line A	0.69%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

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 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)**			**Upgrade Eagle Point-Gloucester 230kV Circuit (B1588)**		
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		10.99%			10.99%			10.99%			10.99%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		10.99%			10.99%			10.99%			10.99%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		15,574,675			20,678,337			15,251,024			12,087,537		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		370,826			492,341			363,120			287,798		
19	Months in service for depreciation expense from			12.95			12.13			10.55			13.00		
20	Year placed in Service (0 if CWIP)			2015			2017			2018			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							11,980,348	216,491	1,282,387
41		W Increased ROE	2015	225,037	412	2,441							11,980,348	216,491	1,282,387
42		W 11.68 % ROE	2016	349,923	4,743	27,513	2,241,267	24,426	141,823				11,871,005	287,798	1,646,241
43		W Increased ROE	2016	349,923	4,743	27,513	2,241,267	24,426	141,823				11,871,005	287,798	1,646,241
44		W 11.68 % ROE	2017	15,071,025	193,511	1,090,341	58,015,888	871,281	4,909,357				11,583,195	287,722	1,565,912
45		W Increased ROE	2017	15,071,025	193,511	1,090,341	58,015,888	871,281	4,909,357				11,583,195	287,722	1,565,912
46		W 11.68 % ROE	2018	15,376,009	369,378	2,053,342	19,782,631	459,518	2,489,574	15,251,024	294,694	1,655,539	11,295,526	287,798	1,529,720
47		W Increased ROE	2018	15,376,009	369,378	2,053,342	19,782,631	459,518	2,489,574	15,251,024	294,694	1,655,539	11,295,526	287,798	1,529,720

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

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	10.99%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.68%
5	C		Line B less Line A	0.69%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

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 230kV Circuit (B2139)**			**Ridge Road 69kV Breaker Station (B1255)**			**Cox's Corner-Lumberton 230kV Circuit (B1787)**			**Sewaren Switch 230kV Conversion (B2276)**		
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		10.99%			10.99%			10.99%			10.99%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		10.99%			10.99%			10.99%			10.99%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		19,272,633			34,729,740			32,027,160			-		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		458,872			826,899			762,551			-		
19	Months in service for depreciation expense from			13.00			13.00			13.00			-		
20	Year placed in Service (0 if CWIP)			2015			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	18,260,361	232,128	1,375,013	-	-	-	17,370,246	185,057	1,096,185	13,591,177	156,762	928,580
41		W Increased ROE	2015	18,260,361	232,128	1,375,013	-	-	-	17,370,246	185,057	1,096,185	13,591,177	156,762	928,580
42		W 11.68 % ROE	2016	19,039,119	458,839	2,637,556	4,024,723	95,827	556,391	32,167,824	770,307	4,451,390	118,288,759	2,820,131	16,356,354
43		W Increased ROE	2016	19,039,119	458,839	2,637,556	4,024,723	95,827	556,391	32,167,824	770,307	4,451,390	118,288,759	2,820,131	16,356,354
44		W 11.68 % ROE	2017	18,357,357	452,946	2,478,656	35,212,643	267,164	1,488,600	30,829,183	755,191	4,157,150	116,563,457	2,815,636	15,669,479
45		W Increased ROE	2017	18,357,357	452,946	2,478,656	35,212,643	267,164	1,488,600	30,829,183	755,191	4,157,150	116,563,457	2,815,636	15,669,479
46		W 11.68 % ROE	2018	18,128,720	458,872	2,452,091	34,366,749	826,899	4,605,457	30,316,606	762,551	4,095,805	-	-	-
47		W Increased ROE	2018	18,128,720	458,872	2,452,091	34,366,749	826,899	4,605,457	30,316,606	762,551	4,095,805	-	-	-

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

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	10.99%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.68%
5	C		Line B less Line A	0.69%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

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		**Install Conemaugh 250MVAR Cap Bank (B0376)**	**Reconfigure Kearny- Loop in P2216 Ckt (B1589)**	**Reconfigure Brunswick Sw-New 69kVCkt-T (B2146)**	**350 MVAR Reactor Hopatcong 500kV (B2702)**
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		10.99%	10.99%	10.99%	10.99%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		10.99%	10.99%	10.99%	10.99%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		1,108,058	21,487,134	146,250,715	21,301,080
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		26,382	511,598	3,482,160	507,169
19	Months in service for depreciation expense from			13.00	8.30	8.04	6.99
20	Year placed in Service (0 if CWIP)			2016	2018	2017	2018

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												
41	W Increased ROE	2015												
42	W 11.68 % ROE	2016	1,108,058	26,382	153,181									
43	W Increased ROE	2016	1,108,058	26,382	153,181									
44	W 11.68 % ROE	2017												
45	W Increased ROE	2017												
46	W 11.68 % ROE	2018	1,081,675	26,382	145,310	21,487,134	326,604	1,834,804	146,250,715	2,154,587	12,104,081	21,301,080	272,673	1,531,829
47	W Increased ROE	2018	1,081,675	26,382	145,310	21,487,134	326,604	1,834,804	146,250,715	2,154,587	12,104,081	21,301,080	272,673	1,531,829

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

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	10.99%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.68%
5	C		Line B less Line A	0.69%

6 **FCR if a CIAC**

7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

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) (CWIP)	Susquehanna Roseland >= 500kV (B0489) (CWIP)	North Central Reliability (West Orange Conversion) (B1154) (CWIP)	Mickleton-Gloucester-Camden(B1398-B1398.7) (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)		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		10.99%	10.99%	10.99%	10.99%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.86%	11.86%	10.99%	10.99%
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				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	1,648,851		56,106
33	W Increased ROE	2011	30,831,150		3,565,874	133,618,838		20,775,227	19,588,655		1,299,846	1,648,851		56,106
34	W 11.68 % ROE	2012	38,077,851		5,359,127	264,235,891		27,190,938	139,052,337		10,137,161	22,706,717		1,587,335
35	W Increased ROE	2012	38,077,851		5,676,479	264,235,891		28,801,108	139,052,337		10,137,161	22,706,717		1,587,335
36	W 11.68 % ROE	2013	40,538,248		5,381,625	567,928,477		56,420,758	79,292,223		21,408,869	117,558,986		7,924,475
37	W Increased ROE	2013	40,538,248		5,730,133	567,928,477		60,074,507	79,292,223		21,408,869	117,558,986		7,924,475
38	W 11.68 % ROE	2014	12,476,737		1,537,307	34,481,067		28,945,163	31,617,517		3,895,715	160,260,925		16,099,944
39	W Increased ROE	2014	12,476,737		1,646,580	34,481,067		31,002,624	31,617,517		3,895,715	160,260,925		16,099,944
40	W 11.68 % ROE	2015	-		-	15,544,417		1,822,213	-		-	81,558,947		9,560,846
41	W Increased ROE	2015	-		-	15,544,417		1,955,563	-		-	81,558,947		9,560,846
42	W 11.68 % ROE	2016	-		-	-		-	-		-	-		-
43	W Increased ROE	2016	-		-	-		-	-		-	-		-
44	W 11.68 % ROE	2017	-		-	-		-	-		-	-		-
45	W Increased ROE	2017	-		-	-		-	-		-	-		-
46	W 11.68 % ROE	2018	-		-	-		-	-		-	-		-
47	W Increased ROE	2018	-		-	-		-	-		-	-		-

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

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	10.99%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.68%
5	C		Line B less Line A	0.69%

6 **FCR if a CIAC**

7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

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 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)
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	25
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		10.99%	10.99%	10.99%	10.99%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		10.99%	10.99%	10.99%	11.17%
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				22,089,378		1,874,440						
33		W Increased ROE	2011				22,089,378		1,874,440						
34		W 11.68 % ROE	2012	532,375		24,600	128,653,138		10,501,318	9,231,712		791,084	81,587,177		6,341,372
35		W Increased ROE	2012	532,375		24,600	128,653,138		10,501,318	9,231,712		791,084	81,587,177		6,416,475
36		W 11.68 % ROE	2013	532,375		73,965	155,344,760		22,819,788	8,854,018		1,275,855	184,611,449		18,512,179
37		W Increased ROE	2013	532,375		73,965	155,344,760		22,819,788	8,854,018		1,275,855	184,611,449		18,751,945
38		W 11.68 % ROE	2014	532,375		65,596	56,976,438		7,020,285	3,745,932		461,551	211,553,988		28,743,491
39		W Increased ROE	2014	532,375		65,596	56,976,438		7,020,285	3,745,932		461,551	211,553,988		29,152,116
40		W 11.68 % ROE	2015	204,760		24,003	-		-	-		-	232,789,181		31,313,982
41		W Increased ROE	2015	204,760		24,003	-		-	-		-	232,789,181		31,772,294
42		W 11.68 % ROE	2016	-		-	-		-	-		-	103,162,268		11,805,242
43		W Increased ROE	2016	-		-	-		-	-		-	103,162,268		11,982,038
44		W 11.68 % ROE	2017	-		-	-		-	-		-	-		-
45		W Increased ROE	2017	-		-	-		-	-		-	-		-
46		W 11.68 % ROE	2018	-		-	-		-	-		-	-		-
47		W Increased ROE	2018	-		-	-		-	-		-	-		-

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

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	10.99%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.68%
5		C		Line B less Line A	0.69%
6	**FCR if a CIAC**				
7		D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

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 (B1304.5-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)**
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	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		10.99%	10.99%	10.99%	10.99%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.17%	10.99%	10.99%	10.99%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		-	327,500	3,373,416	4,386,778
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		-	7,798	80,319	104,447
19	Months in service for depreciation expense from				13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)						

			Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
21		Invest Yr												
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	5,537,185		457,198									
35	W Increased ROE	2012	5,537,185		462,613									
36	W 11.68 % ROE	2013	18,052,410		1,627,531									
37	W Increased ROE	2013	18,052,410		1,648,610									
38	W 11.68 % ROE	2014	33,293,621		3,699,551	9,496,612		391,383	1,589,541		61,526	1,531,032		58,653
39	W Increased ROE	2014	33,293,621		3,752,145	9,496,612		391,383	1,589,541		61,526	1,531,032		58,653
40	W 11.68 % ROE	2015	31,157,349		2,302,742	79,833,944		3,818,309	14,281,935		836,684	14,081,213		819,896
41	W Increased ROE	2015	31,157,349		2,336,445	79,833,944		3,818,309	14,281,935		836,684	14,081,213		819,896
42	W 11.68 % ROE	2016	35,334,506		4,043,459	518,235		5,126,158	11,570,665		857,240	2,658,598		921,870
43	W Increased ROE	2016	35,334,506		4,104,014	518,235		5,126,158	11,570,665		857,240	2,658,598		921,870
44	W 11.68 % ROE	2017	-		-	2,271,018		519,803	23,927,668		2,300,724	13,263,928		1,087,121
45	W Increased ROE	2017	-		-	2,271,018		519,803	23,927,668		2,300,724	13,263,928		1,087,121
46	W 11.68 % ROE	2018	-		-	327,500		36,008	3,373,416		370,901	4,386,778		482,318
47	W Increased ROE	2018	-		-	327,500		36,008	3,373,416		370,901	4,386,778		482,318

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

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	10.99%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.68%
5	C		Line B less Line A	0.69%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

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 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)**			**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)**		
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		10.99%			10.99%			10.99%			10.99%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		10.99%			10.99%			10.99%			10.99%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		20,653,909			30,394,186			14,893,653			8,794,765		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		491,760			723,671			354,611			209,399		
19	Months in service for depreciation expense from			13.00			13.00			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	2,114,342		74,197	1,476,460		58,912	838,906		41,991	433,918		21,259
39		W Increased ROE	2014	2,114,342		74,197	1,476,460		58,912	838,906		41,991	433,918		21,259
40		W 11.68 % ROE	2015	7,520,100		530,656	1,567,639		105,699	3,286,307		178,025	3,386,828		209,207
41		W Increased ROE	2015	7,520,100		530,656	1,567,639		105,699	3,286,307		178,025	3,386,828		209,207
42		W 11.68 % ROE	2016	65,119,433		3,473,891	36,960,137		1,695,242	24,980,240		1,011,439	14,073,743		749,927
43		W Increased ROE	2016	65,119,433		3,473,891	36,960,137		1,695,242	24,980,240		1,011,439	14,073,743		749,927
44		W 11.68 % ROE	2017	103,139,173		8,457,930	100,004,406		7,165,306	50,261,443		4,476,177	4,257,610		1,981,744
45		W Increased ROE	2017	103,139,173		8,457,930	100,004,406		7,165,306	50,261,443		4,476,177	4,257,610		1,981,744
46		W 11.68 % ROE	2018	20,653,909		2,270,858	30,394,186		3,341,783	14,893,653		1,637,529	8,794,765		966,968
47		W Increased ROE	2018	20,653,909		2,270,858	30,394,186		3,341,783	14,893,653		1,637,529	8,794,765		966,968

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

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	10.99%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.68%
5	C		Line B less Line A	0.69%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%
			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) (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)**
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		10.99%	10.99%	10.99%	10.99%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		10.99%	10.99%	10.99%	10.99%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		13,879,908	84,069	80,847	(0)
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		330,474	2,002	1,925	(0)
19	Months in service for depreciation expense from Year placed in Service (0 if CWIP)			13.00	13.00	13.00	
20							

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	1,370,003		56,093	597,317		24,145	597,317		24,145	569,297		24,114
39	W Increased ROE	2014	1,370,003		56,093	597,317		24,145	597,317		24,145	569,297		24,114
40	W 11.68 % ROE	2015	7,110,556		414,795	4,018,145		249,912	4,018,145		249,912	3,852,871		236,839
41	W Increased ROE	2015	7,110,556		414,795	4,018,145		249,912	4,018,145		249,912	3,852,871		236,839
42	W 11.68 % ROE	2016	45,554,419		2,311,095	21,015,450		1,295,020	21,015,450		1,295,020	22,912,843		1,342,797
43	W Increased ROE	2016	45,554,419		2,311,095	21,015,450		1,295,020	21,015,450		1,295,020	22,912,843		1,342,797
44	W 11.68 % ROE	2017	55,639,039		5,480,161	53,134		937,564	53,134		937,564	11,129,698		1,228,147
45	W Increased ROE	2017	55,639,039		5,480,161	53,134		937,564	53,134		937,564	11,129,698		1,228,147
46	W 11.68 % ROE	2018	13,879,908		1,526,070	84,069		9,243	80,847		8,889	(0)		-
47	W Increased ROE	2018	13,879,908		1,526,070	84,069		9,243	80,847		8,889	(0)		-

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

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	10.99%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.68%
5		C		Line B less Line A	0.69%
6	**FCR if a CIAC**				
7		D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

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) (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)**		
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		10.99%			10.99%			10.99%			10.99%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		10.99%			10.99%			10.99%			10.99%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		(0)			1,421,804			7,334			352,578		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		(0)			33,852			175			8,395		
19	Months in service for depreciation expense from						13.00			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	569,297		24,114	1,581,597		63,898	1,286,903		48,434	4,799,334		220,160
39		W Increased ROE	2014	569,297		24,114	1,581,597		63,898	1,286,903		48,434	4,799,334		220,160
40		W 11.68 % ROE	2015	3,852,871		236,839	14,750,089		849,382	13,603,685		780,003	20,855,739		1,506,352
41		W Increased ROE	2015	3,852,871		236,839	14,750,089		849,382	13,603,685		780,003	20,855,739		1,506,352
42		W 11.68 % ROE	2016	22,912,843		1,342,797	946,989		868,195	34,036		704,952	210,981		908,856
43		W Increased ROE	2016	22,912,843		1,342,797	946,989		868,195	34,036		704,952	210,981		908,856
44		W 11.68 % ROE	2017	11,129,698		1,228,147	2,422,164		197,896	777,902		85,840	1,212,870		130,718
45		W Increased ROE	2017	11,129,698		1,228,147	2,422,164		197,896	777,902		85,840	1,212,870		130,718
46		W 11.68 % ROE	2018	(0)		-	1,421,804		156,325	7,334		806	352,578		38,765
47		W Increased ROE	2018	(0)		-	1,421,804		156,325	7,334		806	352,578		38,765

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

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	10.99%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.68%
5	C		Line B less Line A	0.69%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%
			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) (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)**		
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		10.99%			10.99%			10.99%			10.99%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		10.99%			10.99%			10.99%			10.99%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		352,578			7,678			7,678			1,673,479		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		8,395			183			183			39,845		
19	Months in service for depreciation expense from			13.00			13.00			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	5,002,105		223,171	123,509		4,946	124,051		4,952	337,481		13,854
39		W Increased ROE	2014	5,002,105		223,171	123,509		4,946	124,051		4,952	337,481		13,854
40		W 11.68 % ROE	2015	21,058,511		1,530,122	2,601,853		148,281	2,602,395		148,345	2,972,226		101,157
41		W Increased ROE	2015	21,058,511		1,530,122	2,601,853		148,281	2,602,395		148,345	2,972,226		101,157
42		W 11.68 % ROE	2016	96,330		915,296	9,752,687		597,380	9,750,168		597,124	35,618,949		2,125,894
43		W Increased ROE	2016	96,330		915,296	9,752,687		597,380	9,750,168		597,124	35,618,949		2,125,894
44		W 11.68 % ROE	2017	1,241,892		133,921	4,472,474		493,532	4,472,773		493,565	15,327,955		1,691,419
45		W Increased ROE	2017	1,241,892		133,921	4,472,474		493,532	4,472,773		493,565	15,327,955		1,691,419
46		W 11.68 % ROE	2018	352,578		38,765	7,678		844	7,678		844	1,673,479		183,996
47		W Increased ROE	2018	352,578		38,765	7,678		844	7,678		844	1,673,479		183,996

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2018

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	10.99%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	11.68%
5		C		Line B less Line A	0.69%
6	**FCR if a CIAC**				
7		D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

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 Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33) (CWIP)**
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes
12	Useful life of the project	Life		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
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		10.99%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		10.99%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		1,914,773
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		45,590
19	Months in service for depreciation expense from			13.00
20	Year placed in Service (0 if CWIP)			

21			**Invest Yr**	**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		$ 39,261
28		W 11.68 % ROE	2009				$ 51,356,608		$ 51,356,608	
29		W Increased ROE	2009				$ 51,588,883	$ 51,588,883		$ 232,275
30		W 11.68 % ROE	2010				$ 61,349,032		$ 61,349,032	
31		W Increased ROE	2010				$ 62,015,568	$ 62,015,568		$ 666,536
32		W 11.68 % ROE	2011				$ 78,438,322		$ 78,438,322	$ -
33		W Increased ROE	2011				$ 79,823,709	$ 79,823,709		$ 1,385,386
34		W 11.68 % ROE	2012				$ 129,728,618		$ 129,728,618	
35		W Increased ROE	2012				$ 131,858,773	$ 131,858,773		$ 2,130,155
36		W 11.68 % ROE	2013				$ 279,708,533		$ 279,708,533	
37		W Increased ROE	2013				$ 284,314,797	$ 284,314,797		$ 4,606,265
38		W 11.68 % ROE	2014	133,460		5,677	$ 342,977,142		$ 342,977,142	
39		W Increased ROE	2014	133,460		5,677	$ 349,823,024	$ 349,823,024		$ 6,845,883
40		W 11.68 % ROE	2015	258,129		20,804	$ 434,110,713		$ 434,110,713	
41		W Increased ROE	2015	258,129		20,804	$ 441,614,467	$ 441,614,467		$ 7,503,754
42		W 11.68 % ROE	2016	2,173,541		157,609	$ 558,001,204		$ 558,001,204	
43		W Increased ROE	2016	2,173,541		157,609	$ 566,080,859	$ 566,080,859		$ 8,079,655
44		W 11.68 % ROE	2017	14,065,098		934,008	$ 576,209,051		576,209,051	
45		W Increased ROE	2017	14,065,098		934,008	$ 583,935,997	$ 583,935,997		$ 7,726,945
46		W 11.68 % ROE	2018	1,914,773		210,526	$ 565,721,649		$ 565,721,649	
47		W Increased ROE	2018	1,914,773		210,526	$ 572,757,940	$ 572,757,940		$ 7,036,291

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 8 - Depreciation Rates

Plant Type	PSE&G
Transmission	2.40
Distribution	
High Voltage Distribution	2.49
Meters	2.49
Line Transformers	2.49
All Other Distribution	2.49
General & Common	
Structures and Improvements	1.40
Office Furniture	5.00
Office Equipment	25.00
Computer Equipment	14.29
Personal Computers	33.33
Store Equipment	14.29
Tools, Shop, Garage and Other Tangible Equipment	14.29
Laboratory Equipment	20.00
Communications Equipment	10.00
Miscellaneous Equipment	14.29

Public Service Electric and Gas Company
Projected Costs of Plant in Forecasted Rate Base and In-Service Dates
12 Months Ended December 31, 2018

Required Transmission Enhancements

Upgrade ID	RTEP Baseline Project Description	Estimated/Actual Project Cost (thru 2018) *	Anticipated/Actual In-Service Date *
b0130	Replace all derated Branchburg 500/230 kv transformers	$ 20,645,602	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	$ 86,467,721	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	$ 25,654,455	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	$ 21,014,433	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	$ 77,352,830	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	$ 46,035,637	Dec-10
b1410-b1415	Replace Salem 500 kV breakers	$ 15,865,267	Oct-12
b1228	230kV Lawrence Switching Station Upgrade	$ 21,736,918	May-11
b1155	Branchburg-Middlesex Swich Rack	$ 62,937,256	Dec-11
b1399	Aldene-Springfield Rd. Conversion	$ 72,380,453	Dec-12
b1590	Upgrade Camden-Richmond 230kV Circuit (B1590)	$ 11,276,183	Apr-13
b1588	Uprate EaglePoint-Gloucester 230kV Circuit	$ 12,087,537	May-11
b2139	Build Mickleton-Gloucester Corridor Ultimate Design	$ 19,272,633	Dec-13
b1255	Ridge Road 69kV Breaker Station	$ 34,729,740	Jun-16
b1787	New Cox's Corner-Lumberton 230kV Circuit	$ 32,027,160	Nov-13
b0376	Install Conemaugh 250MVAR Cap Bank (B0376)	$ 1,108,058	Mar-16
b1589	Reconfigure Kearny- Loop in P2216 Ckt (B1589)	$ 21,487,134	May-18
b2146	Reconfigure Brunswick Sw-New 69kVCkt-T (B2146)	$ 146,250,715	Oct-17
b2702	350 MVAR Reactor Hopatcong 500kV (B2702)	$ 21,301,080	Jun-18
b0489.5-b0489.15	Susquehanna Roseland Breakers(In-Service)	$ 5,857,687	Jun-14
b0489.4	Build new 500 kV transmission facilities from Pennsylvania - New Jersey border at Bushkill to Roseland (Below 500 kV elements of the project) (In-Service)	$ 40,538,248	Nov-11
b0489	Build new 500 kV transmission facilities from Pennsylvania - New Jersey border at Bushkill to Roseland (500kV and above elements of the project) (In-Service)	$ 720,620,844	Mar-15
b1156	Burlington - Camden 230kV Conversion (In-Service)	$ 356,333,540	Oct-14
b1398 - b1398.7	Mickleton-Gloucester-Camden(In-Service)	$ 439,384,743	Jun-15
b1154	North Central Reliability (West Orange Conversion) (In-Service)	$ 370,006,995	Jun-15
b1304.1-b1304.4	Northeast Grid Reliability Project (In-Service)	$ 625,390,228	Jun-15
b2436.10	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)	$ 174,969,351	Jan-16
b2436.21	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades	$ 68,319,997	May-16
b2436.22	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades	$ 49,614,813	May-16
b2436.33	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades	$ 162,329,270	Dec-15
b2436.34	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34)	$ 120,922,525	Feb-18
b2436.50	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50)	$ 63,112,389	Mar-18
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 (B2436.60)	$ 49,352,658	Dec-15
b2437.10	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10)	$ 26,819,837	May-16
b2437.11	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11)	$ 26,819,837	May-16
b2437.20	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20)	$ 15,574,675	Dec-15
b2437.21	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21)	$ 15,574,675	Dec-15
b2437.30	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30)	$ 20,678,337	Jul-16
	Total	**$ 4,581,326,904**	

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

Public Service Electric and Gas Company

Accumulated Deferred Income Taxes Using The Proration Methodology - Tax Basis

Amounts reflected in Annual Update Filing

2017 EOY Amount	(2,383,691,531)	A
2018 EOY Amount	(2,597,832,425)	B

Account 282, Transmission Plant-related Liberalized Depreciation, for 2018

Line	(1) Year	(2) Month	(3) Projected Monthly (Increase) In ADIT - Depreciable Tax Basis	(4) Days Outstanding During the Year	(5) Proration Percentage	(6) Monthly Prorated Amount	(7) Cumulative "prorated" ADIT	(8) Beginning & Ending ADIT Balance	
1	2017	Dec						(2,383,691,531)	A
2	2018	Jan	(23,167,070)	335	91.78%	(21,262,928)	(2,404,954,459)		
3	2018	Feb	(23,640,412)	307	84.11%	(19,883,853)	(2,424,838,312)		
4	2018	Mar	(24,080,123)	276	75.62%	(18,208,531)	(2,443,046,843)		
5	2018	Apr	(25,252,039)	246	67.40%	(17,019,182)	(2,460,066,025)		
6	2018	May	(24,392,170)	215	58.90%	(14,367,991)	(2,474,434,016)		
7	2018	Jun	(24,900,952)	185	50.68%	(12,621,031)	(2,487,055,047)		
8	2018	Jul	(23,470,852)	154	42.19%	(9,902,771)	(2,496,957,818)		
9	2018	Aug	(23,044,552)	123	33.70%	(7,765,698)	(2,504,723,516)		
10	2018	Sep	(23,177,202)	93	25.48%	(5,905,424)	(2,510,628,940)		
11	2018	Oct	(23,569,552)	62	16.99%	(4,003,595)	(2,514,632,535)		
12	2018	Nov	(23,121,902)	32	8.77%	(2,027,126)	(2,516,659,661)		
13	2018	Dec	(23,576,902)	1	0.27%	(64,594)	(2,516,724,255)		
		Total	(285,393,730)			(133,032,724)			
14			Projected 2018 Liberalized Depreciation based on ADIT Proration Methodology:					(133,032,724)	
15			Plus: Projected 2018 ADIT associated with Liberalized Deprecation not subject to Proration Methodology:					(81,108,169)	
16			Projected 2018 EOY Federal and State Liberalized Depreciation ADIT included in the FERC Formula Filing:					(2,597,832,425)	B

Explanations:

Col. 8, Line 1	Represents the estimated beginning plant-related Liberalized Depreciation ADIT balance as of 1/1/2018.
Lines 2 - 13	Represents the Forecasted Rate period (e.g. 2018).
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.

Public Service Electric and Gas Company

Accumulated Deferred Income Taxes Using The Proration Methodology - Tax Basis

Amounts reflected in Annual Update Filing

2017 EOY Amount	(30,864,733)	A
2018 EOY Amount	(36,267,968)	B

Account 282, Common Plant-related Liberalized Depreciation, for 2018

(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

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)	(2)	(3)	(4)	(5)	(6)
1	2017	Dec						(30,864,733) A
2	2018	Jan	(337,186)	335	91.78%	(309,472)	(31,174,205)	
3	2018	Feb	(337,186)	307	84.11%	(283,606)	(31,457,811)	
4	2018	Mar	(337,186)	276	75.62%	(254,968)	(31,712,779)	
5	2018	Apr	(337,186)	246	67.40%	(227,254)	(31,940,033)	
6	2018	May	(337,186)	215	58.90%	(198,616)	(32,138,649)	
7	2018	Jun	(337,186)	185	50.68%	(170,903)	(32,309,552)	
8	2018	Jul	(337,186)	154	42.19%	(142,265)	(32,451,817)	
9	2018	Aug	(337,186)	123	33.70%	(113,627)	(32,565,444)	
10	2018	Sep	(337,186)	93	25.48%	(85,913)	(32,651,357)	
11	2018	Oct	(337,186)	62	16.99%	(57,275)	(32,708,632)	
12	2018	Nov	(337,186)	32	8.77%	(29,562)	(32,738,194)	
13	2018	Dec	(337,186)	1	0.27%	(924)	(32,739,118)	
		Total	(4,046,234)			(1,874,385)		

14	Projected 2018 Liberalized Depreciation based on ADIT Proration Methodology:	(1,874,385)
15	Plus: Projected 2018 ADIT associated with Liberalized Deprecation not subject to Proration Methodology:	(3,528,850)
16	Projected 2018 EOY Federal and State Liberalized Depreciation ADIT included in the FERC Formula Filing:	(36,267,968) B

Explanations:

Col. 8, Line 1	Represents the estimated beginning plant-related Liberalized Depreciation ADIT balance as of 1/1/2018.
Lines 2 - 13	Represents the Forecasted Rate period (e.g. 2018).
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.