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PSEG
Services Corporation

VIA ELECTRONIC MAIL & OVERNIGHT MAIL

December 9, 2019

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, 2017
-and-
In the Matter of the Provision of
Basic Generation Service for the Period Beginning June 1, 2018
-and-
In the Matter of the Provision of
Basic Generation Service for the Period Beginning June 1, 2019

Docket Nos. EO03050394, ER16040337, ER17040335, ER18040356
+++
Compliance Tariff Filing Reflecting Changes to Schedule 12 Charges in PJM Open Access
Transmission Tariff Docket No. _______________

Aida Camacho-Welch
Secretary of the Board
Board of Public Utilities
44 South Clinton Ave., 9th Floor
Trenton, New Jersey 08625-0350

Dear Secretary Camacho-Welch:

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 two 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 Mid-Atlantic Interstate Transmission , LLC ("MAIT") in FERC Docket No. ER17-211-000 and ER17-211-001, Potomac-Appalachian Transmission Highline, L.L.C. ("PATH") in 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.

This filing also includes an update to the EL05-121 rate component currently in place in the Basic Generation Service ("BGS") tariff of each EDC associated with each zone's 10 year Black Box settlement and reflects the lower cost that will be in effect for the remaining six years under the settlement approved in the FERC Order issued on May 31, 2018, in Docket No. EL05-121-009 ("7th Circuit Settlement Order") and shown on Attachment 13 as Schedule 12C Appendix C. The New Jersey Board of Public Utilities ("Board") last ruled and subsequently approved collection from customers and payment to BGS suppliers for these costs by Order dated May 28, 2019 in I/M/O the Provision of Basic Generation Service and Compliance Tariff Filing Reflecting Changes to Schedule 12 Charges in PJM Open Access Transmission Tariff –April 2019 Joint Filing, Docket No. ER19040440. This rate component has been adjusted again to reflect lower costs associated with the Black Box settlement. This document has also been uploaded to the Board of Public Utilities E-Filing system.

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 November 13, 2019 in BPU Docket No. ER19040428, 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, 2020, 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 MAIT, PATH, VEPCo, AEP, and PSE&G, annual formula rate updates filed with FERC on or about October 7, 2019, September 3, 2019, September 19, 2019, October 31, 2019, and October 15, 2019, respectively. The specific additional PJM transmission charges related to the MAIT, PATH, VEPCo, AEP, and PSE&G filings are found in Schedule 12 of the PJM OATT. On November 1, 2019, 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 2020, 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, 2020. 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 ("Derived NITS Charge"). The translation of the transmission zone rate impact to the BGS rates of each of the EDCs, assuming implementation on January 1, 2020, 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 2020 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 PSE&G, VEPCo, PATH, MAIT, and AEP 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, 11, and 12 provide the formula rate updates for PSE&G, VEPCo, PATH, MAIT, AEP, respectively.

The EDCs also request that BGS Suppliers be compensated for the changes to the OATT resulting from the implementation of the PSE&G, VEPCo, PATH, MAIT, , and AEP project annual formula updates, as well as the EL05-121 rate update, effective on January 1, 2020. 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,

Matthew Weissman

Matthew M. Weissman

Attachments

C 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

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
BGS TRANSMISSION ENHANCEMENT CHARGE

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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, 2020 through December 31, 2020

Line #	Description	Rate		Source
(1)	Transmission Service Annual Revenue Requirement	$ 1,526,297,807.55		Page 4 of Attachment 8 -Line 164
(2)	Total Schedule 12 TEC Included in above	$ (471,249,143.00)		Attachment 6a Column (a)
(3)	PSE&G Customer Share of Schedule 12 TEC	$ 295,644,150.27		Attachment 6a Column (h)
(4)	Total Transmission Costs Borne by PSE&G customers	$ 1,350,692,814.82		=(1) +(2) +(3)
(5)	2020 PSE&G Network Service Peak	9,752.5	MW	Page 4 of Attachment 8 - -Line 165
(6)	2020 Derived Network Integration Transmission Service Rate	$ 138,497.08	per MW-year	
	Resulting 2020 BGS Firm Transmission Service Supplier Rate	$ 378.41	per MW-day	= (6)/366

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 MAIT Schedule 12 (Transmission Enhancement)
Charges into Customer Rates

Attachment 2f
PSE&G Translation of AEP East Schedule 12 (Transmission
Enhancement) Charges into Customer Rates

Attachment 2g
PSE&G Translation of EL05-121 Schedule 12 (Transmission
Enhancement) Charges into Customer Rates

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 75**
Superseding
B.P.U.N.J. No. 16 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 kilowatt-hour:

	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	$0.118171	$0.126000	$0.117050	$0.124805
RS – in excess of 600 kWh	0.118171	0.126000	0.126047	0.134398
RHS – first 600 kWh	0.092388	0.098509	0.087400	0.093190
RHS – in excess of 600 kWh	0.092388	0.098509	0.099430	0.106017
RLM On-Peak	0.205849	0.219486	0.216756	0.231116
RLM Off-Peak	0.062241	0.066364	0.057296	0.061092
WH	0.052270	0.055733	0.050561	0.053911
WHS	0.052817	0.056316	0.050658	0.054014
HS	0.118918	0.126796	0.120370	0.128345
BPL	0.050905	0.054277	0.046186	0.049246
BPL-POF	0.050905	0.054277	0.046186	0.049246
PSAL	0.050905	0.054277	0.046186	0.049246

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. 16 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 ....$ 4.8274
Charge including New Jersey Sales and Use Tax (SUT) ....$ 5.1472

Charge applicable in the months of October through May..$ 4.8274
Charge including New Jersey Sales and Use Tax (SUT) ....$ 5.1472

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 .... $138,497.08 per MW per year
EL05-121……...$ 80.67 per MW per month
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 .... $ 58.78 per MW per month
Virginia Electric and Power Company ....$ 83.11 per MW per month
Potomac-Appalachian Transmission Highline L.L.C. .... ($ 0.65) per MW per month
PPL Electric Utilities Corporation...$ 226.26 per MW per month
American Electric Power Service Corporation ....$ 12.61 per MW per month
Atlantic City Electric Company. ....$ 8.86 per MW per month
Delmarva Power and Light Company...$ 0.15 per MW per month
Potomac Electric Power Company. ....$ 3.14 per MW per month
Baltimore Gas and Electric Company...$ 3.52 per MW per month
Jersey Central Power and Light ....$ 69.17 per MW per month
Mid Atlantic Interstate Transmission...$ 21.83 per MW per month
PECO Energy Company……………………………….................$ 22.32 per MW per month

Above rates converted to a charge per kW of Transmission
Obligation, applicable in all months...$ 12.1312
Charge including New Jersey Sales and Use Tax (SUT) ....$ 12.9349

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

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 83**
Superseding
B.P.U.N.J. No. 16 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	$138,497.08 per MW per year
EL05-121	$ 80.67 per MW per month
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	$ 58.78 per MW per month
Virginia Electric and Power Company	$ 83.11 per MW per month
Potomac-Appalachian Transmission Highline L.L.C.	($ 0.65) per MW per month
PPL Electric Utilities Corporation	$ 226.26 per MW per month
American Electric Power Service Corporation	$ 12.61 per MW per month
Atlantic City Electric Company.	$ 8.86 per MW per month
Delmarva Power and Light Company	$ 0.15 per MW per month
Potomac Electric Power Company.	$ 3.14 per MW per month
Baltimore Gas and Electric Company	$ 3.52 per MW per month
Jersey Central Power and Light	$ 69.17 per MW per month
Mid Atlantic Interstate Transmission	$ 21.83 per MW per month
PECO Energy Company	$ 22.32 per MW per month
Above rates converted to a charge per kW of Transmission Obligation, applicable in all months	$ 12.1312
Charge including New Jersey Sales and Use Tax (SUT)	$ 12.9349

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.

Network Integration Service Calculation - BGS-RSCP
Revised NITS Charges for January 2020 - December 2020

		Effective 1/1/2020 - 12/31/2020	
PSE&G Annual Transmission Service Revenue Requirement	$	1,526,297,807.55	
Total Schedule 12 TEC Included in above	$	(471,249,143.00)	
PSE&G Customer Share of Schedule 12 NITS	$	295,644,150.27	
NITS Charges for Jan 2020 - Dec 2020	$	1,350,692,814.82	
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,752.50	
Term (Months)		12	
OATT rate	$	11,541.42	/MW/month

all values show w/o NJ SUT

converted to $/MW/yr =	$	138,497.08	/MW/yr	**Jan 20 - Dec 20 NITS Charge**			
	$	102,309.43	/MW/yr	**2017- 2019 Weighted Average of:**	**$ 91,224.18**	**$ 110,695.46**	**$ 104,709.15**
	$	117,881.68	/MW/yr	**2018- 2020 Weighted Average of:**	**$ 110,695.46**	**$ 104,709.15**	**$ 138,497.08**
	$	111,393.24	/MW/yr	**Jan 20 - Dec 20 Weighted Average**			
Resulting Increase in Transmission Rate	$	27,103.84	/MW/yr				
Resulting Increase in Transmission Rate	$	2,258.65	/MW/month				

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4,205.0	21.8	74.0	0.0	0.0	4.2	0.0	0.0
Total Annual Energy - MWh	12,332,838.9	109,600.5	190,365.8	998.0	17.0	12,526.2	153,089.0	284,612.0
Change in energy charge								
in $/MWh	$ 9.2413	$ 5.3911	$ 10.5360	$ -	$ -	$ 9.0878	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.009241**	**$ 0.005391**	**$ 0.010536**	**$ -**	**$ -**	**$ 0.009088**	**$ -**	**$ -**

Line #						
1	Total BGS-RSCP Trans Obl		6,976.3	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust		24,465,276	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes		25,829,484.7	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	189,084,532		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl adjusted for migration
5	Change in Average Supplier Payment Rate	$	7.3205	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	7.32	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	189,071,828		unrounded	= (6) * (3)
8	Difference due to rounding	$	(12,704)		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges effective January 1, 2020
Calculation of costs and monthly PJM charges for VEPCO Projects

TEC Charges for Jan 2020 - Dec 2020	$	9,726,373.56	
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,752.5	
Term (Months)		12	
OATT rate	$	83.11	/MW/month
Resulting Increase in Transmission Rate	$	997.32	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4,205.0	21.8	74.0	0.0	0.0	4.2	0.0	0.0
Total Annual Energy - MWh	12,332,838.9	109,600.5	190,365.8	998.0	17.0	12,526.2	153,089.0	284,612.0
Energy charge								
in $/MWh	$ 0.3400	$ 0.1984	$ 0.3877	$ -	$ -	$ 0.3344	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000340**	**$ 0.000198**	**$ 0.000388**	**$ -**	**$ -**	**$ 0.000334**	**$ -**	**$ -**

Line #						
1	Total BGS-RSCP Trans Obl		6,976.3	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust		24,465,276.4	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes		25,829,484.7	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	6,957,604		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.2694	/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	$	6,973,961		unrounded	= (6) * (3)
8	Difference due to rounding	$	16,357		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges effective January 1, 2020
Calculation of costs and monthly PJM charges for PATH Project

TEC Charges for Jan 2020 - Dec 2020	$	(76,277.57)	
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,752.5	
Term (Months)		12	
OATT rate	$	(0.65)	/MW/month
Resulting Increase in Transmission Rate	$	(7.80)	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4,205.0	21.8	74.0	0.0	0.0	4.2	0.0	0.0
Total Annual Energy - MWh	12,332,838.9	109,600.5	190,365.8	998.0	17.0	12,526.2	153,089.0	284,612.0
Energy charge								
in $/MWh	$ (0.0027)	$ (0.0016)	$ (0.0030)	$ -	$ -	$ (0.0026)	$ -	$ -
in $/kWh - rounded to 6 places	**$ (0.000003)**	**$ (0.000002)**	**$ (0.000003)**	**$ -**	**$ -**	**$ (0.000003)**	**$ -**	**$ -**

Line #						
1	Total BGS-RSCP Trans Obl		6,976.3	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust		24,465,276.4	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes		25,829,484.7	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	(54,415)		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	(0.0021)	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	-	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	-		unrounded	= (6) * (3)
8	Difference due to rounding	$	54,415		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges effective January 1, 2020
Calculation of costs and monthly PJM charges for Mid Atlantic Interstate Transmission Projects

TEC Charges for Jan 2020 - Dec 2020	$	2,554,731.11	
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,752.5	
Term (Months)		12	
OATT rate	$	21.83	/MW/month
Resulting Increase in Transmission Rate	$	261.96	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4,205.0	21.8	74.0	0.0	0.0	4.2	0.0	0.0
Total Annual Energy - MWh	12,332,838.9	109,600.5	190,365.8	998.0	17.0	12,526.2	153,089.0	284,612.0
Energy charge								
in $/MWh	$ 0.0893	$ 0.0521	$ 0.1018	$ -	$ -	$ 0.0878	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000089**	**$ 0.000052**	**$ 0.000102**	**$ -**	**$ -**	**$ 0.000088**	**$ -**	**$ -**

Line #						
1	Total BGS-RSCP Trans Obl		6,976.3	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust		24,465,276.4	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes		25,829,484.7	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	1,827,512		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.0708	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	0.07	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	1,808,064		unrounded	= (6) * (3)
8	Difference due to rounding	$	(19,448)		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges effective January 1, 2020
Calculation of costs and monthly PJM charges for AEP - East Projects

TEC Charges for Jan 2020 - Dec 2020	$	1,475,554.38	
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,752.5	
Term (Months)		12	
OATT rate	$	12.61	/MW/month
Resulting Increase in Transmission Rate	$	151.32	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4,205.0	21.8	74.0	0.0	0.0	4.2	0.0	0.0
Total Annual Energy - MWh	12,332,838.9	109,600.5	190,365.8	998.0	17.0	12,526.2	153,089.0	284,612.0
Energy charge								
in $/MWh	$ 0.0516	$ 0.0301	$ 0.0588	$ -	$ -	$ 0.0507	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000052**	**$ 0.000030**	**$ 0.000059**	**$ -**	**$ -**	**$ 0.000051**	**$ -**	**$ -**

Line #						
1	Total BGS-RSCP Trans Obl		6,976.3	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust		24,465,276.4	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes		25,829,484.7	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	1,055,654		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.0409	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	0.04	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	1,033,179		unrounded	= (6) * (3)
8	Difference due to rounding	$	(22,474)		unrounded	= (7) - (4)

Incremental Network Integration Service Calculation - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges effective January 1, 2020
Summary of EL05-121 Settlement Adjustments for January 2020 - December 2020

Summary of EL05-121 Settlement Adjustments for January 2020 - December 2020	$ 9,440,981.76		
PSE&G Zonal Transmission Load for Effective Yr. (MW)	9,752.50		
Term (Months)	12		
OATT rate	$ 80.67	/MW/month	all values show w/o NJ SUT
converted to $/MW/yr =	$ 968.06	/MW/yr	
Resulting Increase in Transmission Rate	$ 968.06	/MW/yr	
Resulting Increase in Transmission Rate	$ 161.34	/MW/month	

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4,205.0	21.8	74.0	0.0	0.0	4.2	0.0	0.0
Total Annual Energy - MWh	12,332,838.9	109,600.5	190,365.8	998.0	17.0	12,526.2	153,089.0	284,612.0
Change in energy charge								
in $/MWh	$ 0.3301	$ 0.1926	$ 0.3763	$ -	$ -	$ 0.3246	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000330**	**$ 0.000193**	**$ 0.000376**	**$ -**	**$ -**	**$ 0.000325**	**$ -**	**$ -**

Line #					
1	Total BGS-RSCP Trans Obl	6,976.3	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust	24,465,276.4	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes	25,829,484.7	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 6,753,460		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl adjusted for migration
5	Change in Average Supplier Payment Rate	$ 0.2615	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ 0.26	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ 6,715,666		unrounded	= (6) * (3)
8	Difference due to rounding	$ (37,794)		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 3b
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 MAIT Schedule 12 (Transmission Enhancement)
Charges into Customer Rates

Attachment 3f
JCP&L Translation of AEP East Schedule 12 (Transmission
Enhancement) Charges into Customer Rates

Attachment 3g
JCP&L Translation of EL05-121 Schedule 12 (Transmission
Enhancement) Charges into Customer Rates

JERSEY CENTRAL POWER & LIGHT COMPANY

XX Rev. Sheet No. 36
BPU No. 12 ELECTRIC - PART III **Superseding XX Rev. Sheet No. 36**

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, 2019, a RMR surcharge of **$0.000000** per KWH (includes Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage.

Effective **September 1, 2019**, 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 **$0.000234** per KWH
Delmarva-TEC surcharge of **$0.000001** per KWH
ACE-TEC surcharge of **$0.000069** per KWH
PEPCO-TEC surcharge of **$0.000014** per KWH
PPL-TEC surcharge of **$0.000729** per KWH
BG&E-TEC surcharge of **$0.000016** per KWH
PECO-TEC surcharge of **$0.000065** per KWH

Effective **January 1, 2020**, 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:

PSEG-TEC surcharge of **$0.002588** per KWH
VEPCO-TEC surcharge of **$0.000181** per KWH
PATH-TEC surcharge of **($0.000003)** per KWH
AEP-East-TEC surcharge of **$0.000046** per KWH
MAIT-TEC surcharge of **$0.000096** per KWH
EL05-121-TEC surcharge of **$0.000228** per KWH

3) BGS Reconciliation Charge per KWH: $0.001367 (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-ups.

Issued: **Effective:**

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

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

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 12 ELECTRIC - PART III

XX Rev. Sheet No. 38
Superseding XX Rev. Sheet No. 38

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, 2019**, 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	Delmarva-TEC	ACE-TEC
GS and GST	**$0.000234**	**$0.000001**	**$0.000069**
GP	**$0.000151**	**$0.000000**	**$0.000046**
GT	**$0.000133**	**$0.000000**	**$0.000041**
GT – High Tension Service	**$0.000031**	**$0.000000**	**$0.000010**

	PEPCO-TEC	PPL-TEC	BG&E-TEC
GS and GST	**$0.000014**	**$0.000729**	**$0.000016**
GP	**$0.000010**	**$0.000474**	**$0.000011**
GT	**$0.000009**	**$0.000419**	**$0.000010**
GT – High Tension Service	**$0.000002**	**$0.000098**	**$0.000002**

	PECO-TEC
GS and GST	**$0.000065**
GP	**$0.000043**
GT	**$0.000037**
GT – High Tension Service	**$0.000009**

Effective **January 1, 2020**, 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:

	PSEG-TEC	VEPCO-TEC	PATH-TEC
GS and GST	**$0.002588**	**$0.000181**	**($0.000003)**
GP	**$0.001691**	**$0.000118**	**($0.000002)**
GT	**$0.001482**	**$0.000103**	**($0.000002)**
GT – High Tension Service	**$0.000341**	**$0.000023**	**($0.000000)**

	AEP-East-TEC	MAIT-TEC	EL05-121-TEC
GS and GST	**$0.000046**	**$0.000096**	**$0.000228**
GP	**$0.000030**	**$0.000063**	**$0.000149**
GT	**$0.000027**	**$0.000054**	**$0.000131**
GT – High Tension Service	**$0.000006**	**$0.000013**	**$0.000030**

4) BGS Reconciliation Charge per KWH: ($0.002392) (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-ups.

Attachment 3b

Jersey Central Power & Light Company
Proposed PSEG Project Transmission Enhancement Charge (PSEG-TEC Surcharge) effective January 1, 2020
To reflect FERC-approved PSEG Project Transmission Enhancement Charge (Schedule 12 PJM OATT) for January - December 2020

2020 Average Monthly PSEG-TEC Costs Allocated to JCP&L Zone	$	3,850,188.74	(1)
2020 JCP&L Zone Transmission Peak Load (MW)		6,057.1	
PSEG-Transmission Enhancement Rate ($/MW-month)	$	635.65	

Effective January 1, 2020:

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)	5230.8	39,899,425	16,436,772,225	$ 0.002427	$ 0.002588
Primary	364.5	2,780,328	1,753,331,479	$ 0.001586	$ 0.001691
Transmission @ 34.5 kV	293.2	2,236,467	1,609,440,889	$ 0.001390	$ 0.001482
Transmission @ 230 kV	15.1	115,180	359,605,443	$ 0.000320	$ 0.000341
Total	5903.6	45,031,400	20,159,150,036		

(1) Cost Allocation of PSEG Project Schedule 12 Charges to JCP&L Zone for 2020
(2) Based on 12 months PSEG Project costs from January through December 2020
(3) January 2020 through December 2020

BGS-RSCP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales January through December @ Customer		15,389,564	MWH
2	BGS-RSCP Eligible Sales January through December @ Transmission Node		17,073,576	MWH
3	BGS-RSCP Eligible Transmission Obligation		4,932	MW
4	PSEG-Transmission Enhancement Costs to RSCP Suppliers	$	37,621,463	Line 3 x $635.65 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	2.20	= Line 4 / Line 2

Attachment 3c

Jersey Central Power & Light Company
Proposed VEPCO Project Transmission Enhancement Charge (VEPCO-TEC Surcharge) effective January 1, 2020
To reflect FERC-approved VEPCO Project Transmission Enhancement Charge (Schedule 12 PJM OATT) for January - December 2020

2020 Average Monthly VEPCO-TEC Costs Allocated to JCP&L Zone	$	269,584.23	(1)
2020 JCP&L Zone Transmission Peak Load (MW)		6,057.1	
VEPCO-Transmission Enhancement Rate ($/MW-month)	$	44.51	

				Effective January 1, 2020:			
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)	5230.8	2,793,696	16,436,772,225	$	0.000170	$	0.000181
Primary	364.5	194,674	1,753,331,479	$	0.000111	$	0.000118
Transmission @ 34.5 kV	293.2	156,594	1,609,440,889	$	0.000097	$	0.000103
Transmission @ 230 kV	15.1	8,065	359,605,443	$	0.000022	$	0.000023
Total	5903.6	3,153,029	20,159,150,036				

(1) Cost Allocation of VEPCO Project Schedule 12 Charges to JCP&L Zone for 2020
(2) Based on 12 months VEPCO Project costs from January through December 2020
(3) January 2020 through December 2020

BGS-RSCP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales January through December @ Customer		15,389,564	MWH
2	BGS-RSCP Eligible Sales January through December @ Transmission Node		17,073,576	MWH
3	BGS-RSCP Eligible Transmission Obligation		4,932	MW
4	VEPCO-Transmission Enhancement Costs to RSCP Suppliers	$	2,634,196	Line 3 x $44.51 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.15	= Line 4 / Line 2

Attachment 3d

Jersey Central Power & Light Company
Proposed PATH Project Transmission Enhancement Charge (PATH-TEC Surcharge) effective January 1, 2020
To reflect FERC-approved PATH Project Transmission Enhancement Charge (Schedule 12 PJM OATT) for January - December 2020

2020 Average Monthly PATH-TEC Costs Allocated to JCP&L Zone	$	(4,452.02)	(1)
2020 JCP&L Zone Transmission Peak Load (MW)		6,057.1	
PATH-Transmission Enhancement Rate ($/MW-month)	$	(0.74)	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	Effective January 1, 2020: PATH-TEC Surcharge ($/kWh)	PATH-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5230.8	(46,136)	16,436,772,225	$ (0.000003)	$ (0.000003)
Primary	364.5	(3,215)	1,753,331,479	$ (0.000002)	$ (0.000002)
Transmission @ 34.5 kV	293.2	(2,586)	1,609,440,889	$ (0.000002)	$ (0.000002)
Transmission @ 230 kV	15.1	(133)	359,605,443	$ -	$ -
Total	5903.6	(52,070)	20,159,150,036		

(1) Cost Allocation of PATH Project Schedule 12 Charges to JCP&L Zone for 2020
(2) Based on 12 months PATH Project costs from January through December 2020
(3) January 2020 through December 2020

BGS-RSCP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales January through December @ Customer		15,389,564	MWH
2	BGS-RSCP Eligible Sales January through December @ Transmission Node		17,073,576	MWH
3	BGS-RSCP Eligible Transmission Obligation		4,932	MW
4	PATH-Transmission Enhancement Costs to RSCP Suppliers	$	(43,502)	Line 3 x $-0.74 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	-	= Line 4 / Line 2

Attachment 3e

Jersey Central Power & Light Company
Proposed MAIT Project Transmission Enhancement Charge (MAIT-TEC Surcharge) effective January 1, 2020
To reflect FERC-approved MAIT Project Transmission Enhancement Charge (Schedule 12 PJM OATT) for January - December 2020

2020 Average Monthly MAIT-TEC Costs Allocated to JCP&L Zone	$	142,678.71	(1)
2020 JCP&L Zone Transmission Peak Load (MW)		6,057.1	
MAIT-Transmission Enhancement Rate ($/MW-month)	$	23.56	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	Effective January 1, 2020: MAIT-TEC Surcharge ($/kWh)	MAIT-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5230.8	1,478,576	16,436,772,225	$ 0.000090	$ 0.000096
Primary	364.5	103,032	1,753,331,479	$ 0.000059	$ 0.000063
Transmission @ 34.5 kV	293.2	82,878	1,609,440,889	$ 0.000051	$ 0.000054
Transmission @ 230 kV	15.1	4,268	359,605,443	$ 0.000012	$ 0.000013
Total	5903.6	1,668,755	20,159,150,036		

(1) Cost Allocation of MAIT Project Schedule 12 Charges to JCP&L Zone for 2020
(2) Based on 12 months MAIT Project costs from January through December 2020
(3) January 2020 through December 2020

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

Line No.				
1	BGS-RSCP Eligible Sales January through December @ Customer		15,389,564	MWH
2	BGS-RSCP Eligible Sales January through December @ Transmission Node		17,073,576	MWH
3	BGS-RSCP Eligible Transmission Obligation		4,932	MW
4	MAIT-Transmission Enhancement Costs to RSCP Suppliers	$	1,394,161	Line 3 x $23.56 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.08	= Line 4 / Line 2

Attachment 3f

Jersey Central Power & Light Company
Proposed AEP-East Project Transmission Enhancement Charge (AEP-East-TEC Surcharge) effective January 1, 2020
To reflect FERC-approved AEP-East Project Transmission Enhancement Charge (Schedule 12 PJM OATT) for January - December 2020

2020 Average Monthly AEP-East-TEC Costs Allocated to JCP&L Zone	$	68,322.74	(1)
2020 JCP&L Zone Transmission Peak Load (MW)		6,057.1	
AEP-East-Transmission Enhancement Rate ($/MW-month)	$	11.28	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	**Effective January 1, 2020:** AEP-East-TEC Surcharge ($/kWh)	AEP-East-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5230.8	708,027	16,436,772,225	$ 0.000043	$ 0.000046
Primary	364.5	49,338	1,753,331,479	$ 0.000028	$ 0.000030
Transmission @ 34.5 kV	293.2	39,687	1,609,440,889	$ 0.000025	$ 0.000027
Transmission @ 230 kV	15.1	2,044	359,605,443	$ 0.000006	$ 0.000006
Total	5903.6	799,096	20,159,150,036		

(1) Cost Allocation of AEP-East Project Schedule 12 Charges to JCP&L Zone for 2020
(2) Based on 12 months AEP-East Project costs from January through December 2020
(3) January 2020 through December 2020

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

Line No.				
1	BGS-RSCP Eligible Sales January through December @ Customer		15,389,564	MWH
2	BGS-RSCP Eligible Sales January through December @ Transmission Node		17,073,576	MWH
3	BGS-RSCP Eligible Transmission Obligation		4,932	MW
4	AEP-East-Transmission Enhancement Costs to RSCP Suppliers	$	667,604	Line 3 x $11.28 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.04	= Line 4 / Line 2

Attachment 3g

Jersey Central Power & Light Company
Proposed EL05-121 Settlement Adjustment Transmission Enhancement Charge (EL05-121-TEC Surcharge) effective January 1, 2020
To reflect FERC-approved EL05-121 Settlement Adjustment for January 2020 - December 2020:

2020 Average Monthly EL05-121 Settlement Adjustment Allocated to JCP&L Zone	$	339,684.16	(1)
2020 JCP&L Zone Transmission Peak Load (MW)		6,057.1	
EL05-121 Settlement Adjustment Transmission Enhancement Charge Rate ($/MW-month)	$	56.08	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	Effective January 1, 2020: EL05-121-TEC Surcharge ($/kWh)	EL05-121-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5230.8	3,520,140	16,436,772,225	$ 0.000214	$ 0.000228
Primary	364.5	245,295	1,753,331,479	$ 0.000140	$ 0.000149
Transmission @ 34.5 kV	293.2	197,313	1,609,440,889	$ 0.000123	$ 0.000131
Transmission @ 230 kV	15.1	10,162	359,605,443	$ 0.000028	$ 0.000030
Total	5903.6	3,972,910	20,159,150,036		

(1) Monthly Cost Allocation of EL05-121 Settlement Adjustments to JCP&L Zone
(2) Based on 12 months EL05-121 Settlement Adjustment Allocation from January 2020 through December 2020
(3) January 2020 through December 2020

BGS-RSCP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales January through December @ Customer		15,389,564	MWH
2	BGS-RSCP Eligible Sales January through December @ Transmission Node		17,073,576	MWH
3	BGS-RSCP Eligible Transmission Obligation		4,932	MW
4	AEP-East-Transmission Enhancement Costs to RSCP Suppliers	$	3,319,166	Line 3 x $56.08 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.19	= 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 MAIT Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 4f
ACE Translation of AEP East Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 4g
ACE Translation of EL05-121 Schedule 12 (Transmission Enhancement) Charges into Customer Rates

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV Revised Sheet Replaces Revised Sheet No. 60b

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	0.000202	0.000160	0.000122	0.000116	0.000096	0.000090	-	0.000073
TrAILCo	0.000297	0.000236	0.000179	0.000172	0.000142	0.000131	-	0.000107
PSE&G	0.000454	0.000359	0.000273	0.000261	0.000216	0.000200	-	0.000163
PATH	(0.000003)	(0.000002)	(0.000002)	(0.000002)	(0.000001)	(0.000001)	-	(0.000001)
PPL	0.000106	0.000083	0.000064	0.000061	0.000050	0.000047	-	0.000038
PECO	0.000155	0.000123	0.000094	0.000090	0.000074	0.000068	-	0.000055
Pepco	0.000020	0.000016	0.000012	0.000012	0.000010	0.000009	-	0.000007
MAIT	0.000021	0.000017	0.000013	0.000012	0.000010	0.000010	-	0.000007
JCP&L	0.000003	0.000002	0.000002	0.000002	0.000001	0.000001	-	0.000001
EL05-121	0.000016	0.000013	0.000010	0.000010	0.000007	0.000007	-	0.000006
Delmarva	0.000001	0.000001	0.000001	0.000001	-	-	-	-
BG&E	0.000039	0.000032	0.000025	0.000023	0.000019	0.000017	-	0.000014
AEP - East	0.000042	0.000033	0.000026	0.000025	0.000020	0.000018	-	0.000015
Total	0.001353	0.001073	0.000819	0.000783	0.000644	0.000597		0.000485

Date of Issue: **Effective Date:**

Issued by:

Atlantic City Electric Company
Proposed PSE&G Projects Transmission Enhancement Charge (PSE&G-TEC Surcharge) effective January 1, 2020
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 1, 2020

Transmission Enhancement Costs Allocated to ACE Zone (2020)	$	269,892
	$	269,892
2020 ACE Zone Transmission Peak Load (MW)		2,737
Transmission Enhancement Rate ($/MW)	$	98.60

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2019 - May 2020 (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	1,464	$	1,732,433	4,080,911,660	$	0.000425	$	0.000426	$	0.000454
MGS Secondary	356	$	420,807	1,251,541,658	$	0.000336	$	0.000337	$	0.000359
MGS Primary	6	$	7,109	27,739,655	$	0.000256	$	0.000256	$	0.000273
AGS Secondary	380	$	449,734	1,833,118,746	$	0.000245	$	0.000245	$	0.000261
AGS Primary	95	$	112,708	556,105,782	$	0.000203	$	0.000203	$	0.000216
TGS	147	$	173,815	926,628,369	$	0.000188	$	0.000188	$	0.000200
SPL/CSL	0	$	-	67,696,364	$	-	$	-	$	-
DDC	2	$	2,069	13,542,140	$	0.000153	$	0.000153	$	0.000163
	2,450	$	2,898,675	8,757,284,374						

Atlantic City Electric Company
Proposed VEPCO Projects Transmission Enhancement Charge (VEPCO-TEC Surcharge) effective January 1, 2020
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 1, 2020

Transmission Enhancement Costs Allocated to ACE Zone (2020)	$	120,286
	$	120,286
2020 ACE Zone Transmission Peak Load (MW)		2,737
Transmission Enhancement Rate ($/MW)	$	43.94

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2019 - May 2020 (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	1,464	$	772,114	4,080,911,660	$	0.000189	$	0.000189	$	0.000202
MGS Secondary	356	$	187,546	1,251,541,658	$	0.000150	$	0.000150	$	0.000160
MGS Primary	6	$	3,168	27,739,655	$	0.000114	$	0.000114	$	0.000122
AGS Secondary	380	$	200,438	1,833,118,746	$	0.000109	$	0.000109	$	0.000116
AGS Primary	95	$	50,232	556,105,782	$	0.000090	$	0.000090	$	0.000096
TGS	147	$	77,466	926,628,369	$	0.000084	$	0.000084	$	0.000090
SPL/CSL	0	$	-	67,696,364	$	-	$	-	$	-
DDC	2	$	922	13,542,140	$	0.000068	$	0.000068	$	0.000073
	2,450	$	1,291,886	8,757,284,374						

Atlantic City Electric Company
Proposed PATH Projects Transmission Enhancement Charge (PATH-TEC Surcharge) effective January 1, 2020
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 1, 2020

Transmission Enhancement Costs Allocated to ACE Zone (2020)	$	(1,908)
	$	(1,908)
2020 ACE Zone Transmission Peak Load (MW)		2,737
Transmission Enhancement Rate ($/MW)	$	(0.70)

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2019 - May 2020 (kWh)		Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)		l. 5 = Col. 4 x 1/(1-Effective Rate) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)		Col. 6 = Col. 5 x 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,464	$	(12,250)	4,080,911,660	$	(0.000003)	$	(0.000003)	$	(0.000003)
MGS Secondary	356	$	(2,975)	1,251,541,658	$	(0.000002)	$	(0.000002)	$	(0.000002)
MGS Primary	6	$	(50)	27,739,655	$	(0.000002)	$	(0.000002)	$	(0.000002)
AGS Secondary	380	$	(3,180)	1,833,118,746	$	(0.000002)	$	(0.000002)	$	(0.000002)
AGS Primary	95	$	(797)	556,105,782	$	(0.000001)	$	(0.000001)	$	(0.000001)
TGS	147	$	(1,229)	926,628,369	$	(0.000001)	$	(0.000001)	$	(0.000001)
SPL/CSL	0	$	-	67,696,364	$	-	$	-	$	-
DDC	2	$	(15)	13,542,140	$	(0.000001)	$	(0.000001)	$	(0.000001)
	2,450	$	(20,496)	8,757,284,374						

Atlantic City Electric Company
Proposed MAIT Projects Transmission Enhancement Charge (MAIT Project-TEC Surcharge) effective January 1, 2020
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 1, 2020

Transmission Enhancement Costs Allocated to ACE Zone (2020)	$	12,642
	$	12,642
2020 ACE Zone Transmission Peak Load (MW)		2,737
Transmission Enhancement Rate ($/MW-Month)	$	4.62

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2019 - May 2020 (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	1,464	$	81,146	4,080,911,660	$	0.000020	$	0.000020	$	0.000021
MGS Secondary	356	$	19,710	1,251,541,658	$	0.000016	$	0.000016	$	0.000017
MGS Primary	6	$	333	27,739,655	$	0.000012	$	0.000012	$	0.000013
AGS Secondary	380	$	21,065	1,833,118,746	$	0.000011	$	0.000011	$	0.000012
AGS Primary	95	$	5,279	556,105,782	$	0.000009	$	0.000009	$	0.000010
TGS	147	$	8,141	926,628,369	$	0.000009	$	0.000009	$	0.000010
SPL/CSL	0	$	-	67,696,364	$	-	$	-	$	-
DDC	2	$	97	13,542,140	$	0.000007	$	0.000007	$	0.000007
	2,450	$	135,773	8,757,284,374						

Atlantic City Electric Company
Proposed AEP Projects Transmission Enhancement Charge (AEP Project-TEC Surcharge) effective January 1, 2020
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 1, 2020

Transmission Enhancement Costs Allocated to ACE Zone (2020)	$	24,956
	$	24,956
2020 ACE Zone Transmission Peak Load (MW)		2,737
Transmission Enhancement Rate ($/MW-Month)	$	9.12

Rate Class	Col. 1 Transmission Obligation (MW)	Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales Jun 2019 - May 2020 (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	1,464	$ 160,189.91	4,080,911,660	$ 0.000039	$ 0.000039	$ 0.000042
MGS Secondary	356	$ 38,910	1,251,541,658	$ 0.000031	$ 0.000031	$ 0.000033
MGS Primary	6	$ 657	27,739,655	$ 0.000024	$ 0.000024	$ 0.000026
AGS Secondary	380	$ 41,585	1,833,118,746	$ 0.000023	$ 0.000023	$ 0.000025
AGS Primary	95	$ 10,422	556,105,782	$ 0.000019	$ 0.000019	$ 0.000020
TGS	147	$ 16,072	926,628,369	$ 0.000017	$ 0.000017	$ 0.000018
SPL/CSL	0	$ -	67,696,364	$ -	$ -	$ -
DDC	2	$ 191	13,542,140	$ 0.000014	$ 0.000014	$ 0.000015
	2,450	$ 268,027	8,757,284,374			

Atlantic City Electric Company
Proposed EL05-121 Transmission Enhancement Charge effective January 1st, 2020

Transmission Enhancement Costs Allocated to ACE Zone (January 2020 - December 2020)	$	9,802
	$	9,802
2019 ACE Zone Transmission Peak Load (MW)		2,737
Transmission Enhancement Rate ($/MW)	$	3.58

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2019 - May 2020 (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	1,464	$	62,920	4,080,911,660	$	0.000015	$	0.000015	$	0.000016
MGS Secondary	356	$	15,283	1,251,541,658	$	0.000012	$	0.000012	$	0.000013
MGS Primary	6	$	258	27,739,655	$	0.000009	$	0.000009	$	0.000010
AGS Secondary	380	$	16,334	1,833,118,746	$	0.000009	$	0.000009	$	0.000010
AGS Primary	95	$	4,093	556,105,782	$	0.000007	$	0.000007	$	0.000007
TGS	147	$	6,313	926,628,369	$	0.000007	$	0.000007	$	0.000007
SPL/CSL	-	$	-	67,696,364	$	-	$	-	$	-
DDC	2		75	13,542,140	$	0.000006	$	0.000006	$	0.000006
	2,450	$	105,277	8,757,284,374						

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 MAIT Schedule 12 (Transmission Enhancement) Charges into Customer Rates

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

Attachment 5g
RECO Translation of EL05-121 Schedule 12 (Transmission Enhancement) Charges into Customer Rates

ROCKLAND ELECTRIC COMPANY
B.P.U. NO. 3 - ELECTRICITY

DRAFT

Revised Leaf No. 83
Superseding Leaf No. 83

SERVICE CLASSIFICATION NO. 1
RESIDENTIAL SERVICE (Continued)

RATE – MONTHLY (Continued)

(3) Transmission Charges

(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
All kWh .... @	1.515 ¢ per kWh	1.515 ¢ 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, EL05-121 Settlement and Transmission Enhancement Charges.

All kWh .... @	1.272 ¢ per kWh	1.272 ¢ per kWh

(4) Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, Securitization Charges, Temporary Tax Act Credit, and Zero Emission Certificate Recovery Charge.

The provisions of the Company's Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, Securitization Charges, Temporary Tax Act Credit, and Zero Emission Certificate Recovery Charge as described in General Information Section Nos. 33, 34, 35, 36, and 37 respectively, shall be assessed on all kWh delivered hereunder.

* Definition of Summer Billing Months - June through September

(Continued)

DRAFT

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, EL05-121 Settlement and Transmission Enhancement Charges.

	Summer Months*	Other Months
Secondary Voltage Service Only		
All kWh ....@	0.872 ¢ per kWh	0.872 ¢ per kWh
Primary Voltage Service Only		
All kWh ....@	0.794 ¢ per kWh	0.794 ¢ per kWh

(4) Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, Securitization Surcharges, Temporary Tax Act Credit, and Zero Emission Certificate Recovery Charge.

The provisions of the Company's Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, Securitization Charges, Temporary Tax Act Credit, and Zero Emission Certificate Recovery Charge as described in General Information Section Nos. 33, 34, 35, 36, and 37 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 ......@	1.515 ¢ per kWh	1.515 ¢ per kWh
Off-Peak All other kWh ......@	1.515 ¢ per kWh	1.515 ¢ 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, EL05-121 Settlement and Transmission Enhancement Charges.

All kWh .....@	0.945 ¢ per kWh	0.945 ¢ per kWh

(4) Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, Securitization Charges, Temporary Tax Act Credit, and Zero Emission Certificate Recovery Charge.

The provisions of the Company’s Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, Securitization Charges, Temporary Tax Act Credit, and Zero Emission Certificate Recovery Charge as described in General Information Section Nos. 33, 34, 35, 36, and 37 respectively, shall be assessed on all kWh delivered hereunder.

* Definition of Summer Billing Months - June through September

(Continued)

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

RATE - MONTHLY (Continued)

(3) Transmission Charge

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

	Summer Months*	Other Months
All kWh ……….. @	1.515 ¢ per kWh	1.515 ¢ 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, EL05-121 Settlement and Transmission Enhancement Charges.

All kWh ……….. @	0.763 ¢ per kWh	0.763 ¢ per kWh

(4) Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, Securitization Charges, Temporary Tax Act Credit, and Zero Emission Certificate Recovery Charge.

The provisions of the Company’s Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, Securitization Charges, Temporary Tax Act Credit, and Zero Emission Certificate Recovery Charge as described in General Information Section Nos. 33, 34, 35, 36, and 37 respectively, shall be assessed on all kWh delivered hereunder.

* Definition of Summer Billing Months - June through September

(Continued)

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

RATE– MONTHLY (Continued)

(3) Transmission Charges (Continued)

(a) (Continued)

		Primary	High Voltage Distribution
Demand Charge			
Period I	All kW @	$2.41 per kW	$2.41 per kW
Period II	All kW @	0.64 per kW	0.64 per kW
Period III	All kW @	2.41 per kW	2.41 per kW
Period IV	All kW @	0.64 per kW	0.64 per kW
Usage Charge			
Period I	All kWh @	0.404 ¢ per kWh	0.404 ¢ per kWh
Period II	All kWh @	0.404 ¢ per kWh	0.404 ¢ per kWh
Period III	All kWh @	0.404 ¢ per kWh	0.404 ¢ per kWh
Period IV	All kWh @	0.404 ¢ per kWh	0.404 ¢ 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, EL05-121 Settlement and Transmission Enhancement Charges.

		Primary	High Voltage Distribution
All Periods	All kWh @	0.480 ¢ per kWh	0.480 ¢ per kWh

(4) Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, Securitization Charges, Temporary Tax Act Credit, and Zero Emission Certificate Recovery Charge.

The provisions of the Company's Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, Securitization Charges, Temporary Tax Act Credit, and Zero Emission Certificate Recovery Charge as described in General Information Section Nos. 33, 34, 35, 36, and 37 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 2.902 ¢ per kWh during the billing months of October through May and 4.693 ¢ per kWh during the summer billing months, a Transmission Charge of 0.404 ¢ per kWh and a Transmission Surcharge of 0.480 ¢ per kWh during all billing months. The applicability of Transmission Charges and the Transmission Surcharge is described in Part (3) of RATE – MONTHLY.

When this option is requested it shall apply for at least 12 months and shall be subject to a minimum charge of $26.87 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)

Rockland Electric Company

Calculation of Transmission Surcharges reflecting proposed changes effective January 1, 2020

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)
FERC-approved JCP&L Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved PECO Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved EL05-121 Project Schedule 12 Charges (Schedule 12 PJM OATT)

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

Transmission Project	Note	SC1	SC2 Sec	SC2 Pri	SC3	SC4	SC5	SC6	SC7
Reliability Must Run	(1)	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
ACE - TEC	(2)	0.00003	0.00002	0.00002	0.00002	0.00000	0.00002	0.00000	0.00001
AEP-East - TEC	(3)	0.00005	0.00004	0.00003	0.00004	0.00000	0.00003	0.00000	0.00002
BG&E- TEC	(4)	0.00001	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00001
Delmarva - TEC	(5)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
PATH - TEC	(6)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
PEPCO - TEC	(7)	0.00001	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00000
PPL - TEC	(8)	0.00098	0.00061	0.00055	0.00066	0.00000	0.00058	0.00000	0.00036
PSE&G - TEC	(9)	0.00963	0.00670	0.00611	0.00729	0.00000	0.00578	0.00000	0.00366
TrAILCo - TEC	(10)	0.00026	0.00016	0.00014	0.00017	0.00000	0.00015	0.00000	0.00009
VEPCo - TEC	(11)	0.00019	0.00013	0.00012	0.00015	0.00000	0.00012	0.00000	0.00007
MAIT -TEC	(12)	0.00008	0.00006	0.00005	0.00006	0.00000	0.00005	0.00000	0.00003
JCP&L -TEC	(13)	0.00030	0.00019	0.00018	0.00018	0.00000	0.00019	0.00000	0.00011
PECO -TEC	(14)	0.00009	0.00006	0.00005	0.00006	0.00000	0.00005	0.00000	0.00003
EL05-121	(15)	0.00030	0.00021	0.00019	0.00023	0.00000	0.00018	0.00000	0.00012
Total ($/kWh and excl SUT)		$0.01193	$0.00820	$0.00746	$0.00888	$0.00000	$0.00717	$0.00000	$0.00451
Total (¢/kWh and excl SUT)		1.193 ¢	0.820 ¢	0.746 ¢	0.888 ¢	0.000 ¢	0.717 ¢	0.000 ¢	0.451 ¢

(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)	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
ACE - TEC	(2)	0.00003	0.00002	0.00002	0.00002	0.00000	0.00002	0.00000	0.00001
AEP-East - TEC	(3)	0.00005	0.00004	0.00003	0.00004	0.00000	0.00003	0.00000	0.00002
BG&E- TEC	(4)	0.00001	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00001
Delmarva - TEC	(5)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
PATH - TEC	(6)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
PEPCO - TEC	(7)	0.00001	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00000
PPL - TEC	(8)	0.00104	0.00065	0.00059	0.00070	0.00000	0.00062	0.00000	0.00038
PSE&G - TEC	(9)	0.01027	0.00714	0.00651	0.00777	0.00000	0.00616	0.00000	0.00390
TrAILCo - TEC	(10)	0.00028	0.00017	0.00015	0.00018	0.00000	0.00016	0.00000	0.00010
VEPCo - TEC	(11)	0.00020	0.00014	0.00013	0.00016	0.00000	0.00013	0.00000	0.00007
MAIT -TEC	(12)	0.00009	0.00006	0.00005	0.00006	0.00000	0.00005	0.00000	0.00003
JCP&L -TEC	(13)	0.00032	0.00020	0.00019	0.00019	0.00000	0.00020	0.00000	0.00012
PECO -TEC	(14)	0.00010	0.00006	0.00005	0.00006	0.00000	0.00005	0.00000	0.00003
EL05-121	(15)	0.00032	0.00022	0.00020	0.00025	0.00000	0.00019	0.00000	0.00013
Total ($/kWh and incl SUT)		$0.01272	$0.00872	$0.00794	$0.00945	$0.00000	$0.00763	$0.00000	$0.00480
Total (¢/kWh and incl SUT)		1.272 ¢	0.872 ¢	0.794 ¢	0.945 ¢	0.000 ¢	0.763 ¢	0.000 ¢	0.480 ¢

Notes:

(1) RMR rates based on allocation by transmission zone.
(2) ACE-TEC rates rates pursuant to the Board’s Order dated August 7, 2019 in Docket No. ER19060763.
(3) AEP-East-TEC rates calculated in Attachment 6E of the joint filing.
(4) BG&E-TEC rates pursuant to the Board’s Order dated August 7, 2019 in Docket No. ER19060763.
(5) Delmarva-TEC rates pursuant to the Board’s Order dated August 7, 2019 in Docket No. ER19060763.
(6) PATH-TEC rates calculated in Attachment 6C of the joint filing.
(7) PEPCO-TEC rates pursuant to the Board’s Order dated August 7, 2019 in Docket No. ER19060763.
(8) PPL-TEC rates pursuant to the Board’s Order dated August 7, 2019 in Docket No. ER19060763.
(9) PSE&G-TEC rates calculated in Attachment 6A of the joint filing.
(10) TrAILCo-TEC rates pursuant to the Board’s Order dated August 7, 2019 in Docket No. ER19060763.
(11) VEPCo-TEC rates calculated in Attachment 6B of the joint filing.
(12) MAIT-TEC rates calculated in Attachment 6D of the joint filing.
(13) JCP&L-TEC rates pursuant to the Board’s Order dated January 17, 2019 in Docket No. ER18121290.
(14) PECO-TEC rates pursuant to the Board’s Order dated August 7, 2019 in Docket No. ER19060763..
(15) EL05-121 rates calculated in Attachment 6F of the joint filing.

Rockland Electric Company

Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (PSE&G Project) effective January 1, 2020.
To reflect FERC-approved PSE&G Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period January 2020 - December 2020.

2020 Average Monthly PSE&G-TEC Costs Allocated to RECO	$	926,167	(1)
2020 RECO Zone Transmission Peak Load (MW)		459.6	(2)
Transmission Enhancement Rate ($/MW-month)	$	2,015.09	
SUT		6.625%	

	Col. 1	Col. 2		Col.3=Col.2 x $926,167 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales January 2020 - December 2020(kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	273.7	59.55%	$	6,618,936	687,049,000	$	0.00963	$	0.01027
SC2 Secondary	131.7	28.65%	$	3,184,068	475,247,000	$	0.00670	$	0.00714
SC2 Primary	15.3	3.33%	$	369,785	60,494,000	$	0.00611	$	0.00651
SC3	0.1	0.02%	$	1,997	274,000	$	0.00729	$	0.00777
SC4	0.0	0.00%	$	-	6,441,000	$	-	$	-
SC5	3.5	0.75%	$	83,628	14,472,000	$	0.00578	$	0.00616
SC6	0.0	0.00%	$	-	5,600,000	$	-	$	-
SC7	35.4	7.70%	$	855,588	233,488,000	$	0.00366	$	0.00390
Total	459.6 (2)	100.00%	$	11,114,002	1,483,065,000				

(1) Attachment 6a - Cost Allocation of PSE&G Project Schedule 12 Charges to RECO Zone for the period January 2020 - December 2020.
(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)		1,198,920	MWH
2	BGS-RSCP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)		1,115,768	MWH
3	BGS-RSCP Eligible Transmission Obligation		426	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	10,291,288.22	= Line 3 x $2015.09 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	9.22	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (VEPCo) effective January 1, 2020.
To reflect FERC-approved VEPCo Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period January 2020 - December 2020.

2020 Average Monthly VEPCo-TEC Costs Allocated to RECO	$	18,530	(1)
2020 RECO Zone Transmission Peak Load (MW)		459.6	(2)
Transmission Enhancement Rate ($/MW-month)	$	40.32	
SUT		6.625%	

	Col. 1	Col. 2		Col.3=Col.2 x $18,530 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales January 2020 - December 2020 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	273.7	59.55%	$	132,425	687,049,000	$	0.00019	$	0.00020
SC2 Secondary	131.7	28.65%	$	63,704	475,247,000	$	0.00013	$	0.00014
SC2 Primary	15.3	3.33%	$	7,398	60,494,000	$	0.00012	$	0.00013
SC3	0.1	0.02%	$	40	274,000	$	0.00015	$	0.00016
SC4	0.0	0.00%	$	-	6,441,000	$	-	$	-
SC5	3.5	0.75%	$	1,673	14,472,000	$	0.00012	$	0.00013
SC6	0.0	0.00%	$	-	5,600,000	$	-	$	-
SC7	35.4	7.70%	$	17,118	233,488,000	$	0.00007	$	0.00007
Total	459.6 (2)	100.00%	$	222,358	1,483,065,000				

(1) Attachment 6c - Cost Allocation of VEPCo Schedule 12 Charges to RECO Zone for the period January 2020 - December 2020.
(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)		1,198,920	MWH
2	BGS-RSCP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)		1,115,768	MWH
3	BGS-RSCP Eligible Transmission Obligation		426	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	205,918.71	= Line 3 x $40.32 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.18	= Line 4/Line 2

Rockland Electric Company

Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (PATH) effective January 1, 2020.

To reflect FERC-approved PATH Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period January 2020 - December 2020.

2020 Average Monthly PATH-TEC Costs Allocated to RECO	$	(245)	(1)
2020 RECO Zone Transmission Peak Load (MW)		459.6	(2)
Transmission Enhancement Rate ($/MW-month)	$	(0.53)	
SUT		6.625%	

	Col. 1	Col. 2		Col.3=Col.2 x $-245 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales January 2020 - December 2020 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	273.7	59.55%	$	(1,751)	687,049,000	$	-	$	-
SC2 Secondary	131.7	28.65%	$	(842)	475,247,000	$	-	$	-
SC2 Primary	15.3	3.33%	$	(98)	60,494,000	$	-	$	-
SC3	0.1	0.02%	$	(1)	274,000	$	-	$	-
SC4	0.0	0.00%	$	-	6,441,000	$	-	$	-
SC5	3.5	0.75%	$	(22)	14,472,000	$	-	$	-
SC6	0.0	0.00%	$	-	5,600,000	$	-	$	-
SC7	35.4	7.70%	$	(226)	233,488,000	$	-	$	-
Total	459.6 (2)	100.00%	$	(2,940)	1,483,065,000				

(1) Attachment 6d - Cost Allocation of PATH Project Schedule 12 Charges to RECO Zone for the period January 2020 - December 2020.
(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)		1,198,920	MWH
2	BGS-RSCP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)		1,115,768	MWH
3	BGS-RSCP Eligible Transmission Obligation		426	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	(2,706.77)	= Line 3 x $-0.53 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	-	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (MAIT) effective January 1, 2020.
To reflect FERC-approved MAIT Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period January 2020 - December 2020.

2020 Average Monthly MAIT-TEC Costs Allocated to RECO	$	7,903	(1)
2020 RECO Zone Transmission Peak Load (MW)		459.6	(2)
Transmission Enhancement Rate ($/MW-month)	$	17.20	
SUT		6.625%	

	Col. 1	Col. 2		Col.3=Col.2 x $7,903 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales January 2020 - December 2020 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	273.7	59.55%	$	56,482	687,049,000	$	0.00008	$	0.00009
SC2 Secondary	131.7	28.65%	$	27,171	475,247,000	$	0.00006	$	0.00006
SC2 Primary	15.3	3.33%	$	3,156	60,494,000	$	0.00005	$	0.00005
SC3	0.1	0.02%	$	17	274,000	$	0.00006	$	0.00006
SC4	0.0	0.00%	$	-	6,441,000	$	-	$	-
SC5	3.5	0.75%	$	714	14,472,000	$	0.00005	$	0.00005
SC6	0.0	0.00%	$	-	5,600,000	$	-	$	-
SC7	35.4	7.70%	$	7,301	233,488,000	$	0.00003	$	0.00003
Total	459.6 (2)	100.00%	$	94,841	1,483,065,000				

(1) Attachment 6e - Cost Allocation of MAIT Schedule 12 Charges to RECO Zone for the period January 2020 - December 2020.
(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)		1,198,920	MWH
2	BGS-RSCP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)		1,115,768	MWH
3	BGS-RSCP Eligible Transmission Obligation		426	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	87,842.31	= Line 3 x $17.2 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.08	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (AEP East) effective January 1, 2020.
To reflect FERC-approved AEP-East Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period January 2020 - December 2020.

2020 Average Monthly AEP-East-TEC Costs Allocated to RECO	$	5,089	(1)
2020 RECO Zone Transmission Peak Load (MW)		459.6	(2)
Transmission Enhancement Rate ($/MW-month)	$	11.07	
SUT		6.625%	

	Col. 1	Col. 2		Col.3=Col.2 x $5,089 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales January 2020 - December 2020 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	273.7	59.55%	$	36,370	687,049,000	$	0.00005	$	0.00005
SC2 Secondary	131.7	28.65%	$	17,496	475,247,000	$	0.00004	$	0.00004
SC2 Primary	15.3	3.33%	$	2,032	60,494,000	$	0.00003	$	0.00003
SC3	0.1	0.02%	$	11	274,000	$	0.00004	$	0.00004
SC4	0.0	0.00%	$	-	6,441,000	$	-	$	-
SC5	3.5	0.75%	$	460	14,472,000	$	0.00003	$	0.00003
SC6	0.0	0.00%	$	-	5,600,000	$	-	$	-
SC7	35.4	7.70%	$	4,701	233,488,000	$	0.00002	$	0.00002
Total	459.6 (2)	100.00%	$	61,070	1,483,065,000				

(1) Attachment 6f - Cost Allocation of AEP East Schedule 12 Charges to RECO Zone for the period January 2020 - December 2020.
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales Jun - May @ cust (RECO Eastern Division)		1,198,920	MWH
2	BGS-RSCP Eligible Sales Jun - may @ trans node (RECO Eastern Division)		1,115,768	MWH
3	BGS-RSCP Eligible Transmission Obligation		426	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	56,535.72	= Line 3 x $11.07 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.05	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (EL05-121 Project) effective January 1, 2020
To reflect FERC-approved EL05-121 Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period January 2020 - December 2020

2020Average Monthly EL05-121-TEC Costs Allocated to RECO	$	29,203	(1)
2020 RECO Zone Transmission Peak Load (MW)		459.6	(2)
Transmission Enhancement Rate ($/MW-month)	$	63.54	
SUT		6.625%	

	Col. 1	Col. 2		Col.3=Col.2 x $29,203 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales January 2020 - December 2020 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	273.7	59.55%	$	208,699	687,049,000	$	0.00030	$	0.00032
SC2 Secondary	131.7	28.65%	$	100,396	475,247,000	$	0.00021	$	0.00022
SC2 Primary	15.3	3.33%	$	11,660	60,494,000	$	0.00019	$	0.00020
SC3	0.1	0.02%	$	63	274,000	$	0.00023	$	0.00025
SC4	0.0	0.00%	$	-	6,441,000	$	-	$	-
SC5	3.5	0.75%	$	2,637	14,472,000	$	0.00018	$	0.00019
SC6	0.0	0.00%	$	-	5,600,000	$	-	$	-
SC7	35.4	7.70%	$	26,977	233,488,000	$	0.00012	$	0.00013
Total	459.6 (2)	100.00%	$	350,432	1,483,065,000				

(1) Attachment 3 - Cost Allocation of EL05-121 Project Schedule 12 Charges to RECO Zone for January 2020 - December 2020
(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)		1,198,920	MWH
2	BGS-RSCP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)		1,115,768	MWH
3	BGS-RSCP Eligible Transmission Obligation		426	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	324,505.83	= Line 3 x $63.54 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.29	= Line 4/Line 2

Attachment 6 – PJM Schedule 12 (Transmission Enhancement) Charges

Attachment 6a
PSE&G Project Charges

Attachment 6b
Virginia Electric Power Company Project Charges

Attachment 6c
Potomac-Appalachian Transmission Highline Project Charges

Attachment 6d
Mid Atlantic Interstate Transmission Project
Charges

Attachment 6e
AEP Ease Project Charges

Attachment 6f
EL05-121 Charges

Attachment 6a -PJM Schedule 12 - Transmission Enhancement Charges for January 2020 - December 2020 Attachment 6a
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 2020 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
Replace all derated Branchburg 500/230 kava transformers	b0130	$ 1,870,610.00	1.36%	47.76%	50.88%	0.00%	$25,440	$893,403	$951,766	$0	$1,870,610
Reconductor Kittatinny - Newtown 230 kV with 1590 ACSS	b0134	$ 761,829.00	0.00%	51.11%	45.96%	2.93%	$0	$389,371	$350,137	$22,322	$761,829
Build new Essex - Aldene 230 kV cable connected through phase angle regulator at Essex	b0145	$ 8,162,045.00	0.00%	73.45%	21.78%	4.77%	$0	$5,995,022	$1,777,693	$389,330	$8,162,045
Install 4th 500/230 kV transformer at New Freedom	b0411	$ 2,068,529.00	47.01%	7.04%	22.31%	0.00%	$972,415	$145,624	$461,489	$0	$1,579,529
Install 230-138kV transformer at Metuchen substation	b0161	$ 2,538,904.00	0.00%	0.00%	99.80%	0.20%	$0	$0	$2,533,826	$5,078	$2,538,904
Build a new 230 kV section from Branchburg - Flagtown and move the Flagtown - Somerville 230 kV circuit to the new section	b0169	$ 1,552,237.00	1.76%	26.50%	60.89%	0.00%	$27,319	$411,343	$945,157	$0	$1,383,819
Reconductor the Flagtown-Somerville-Bridgewater 230 kV circuit with 1590 ACSS	b0170	$ 678,205.00	0.00%	42.95%	38.36%	0.79%	$0	$291,289	$260,159	$5,358	$556,806
Replace wave trap at Branchburg 500kV substation	b0172.2	$ 1,329.50	1.61%	3.71%	6.19%	0.26%	$21	$49	$82	$3	$156
Replace wave trap at Branchburg 500kV substation	b0172.2_dfax	$ 1,329.50	3.72%	26.83%	52.82%	2.16%	$49	$357	$702	$29	$1,137
Branchburg 400 MVAR Capacitor	b0290	$ 4,066,304.00	1.61%	3.71%	6.19%	0.26%	$65,467	$150,860	$251,704	$10,572	$478,604
Branchburg 400 MVAR Capacitor	b0290_dfax	$ 4,066,304.00	3.72%	26.83%	52.82%	2.16%	$151,267	$1,090,989	$2,147,822	$87,832	$3,477,910
Inst Conemaugh 250 MVAR Cap	b0376	$ 62,085.50	1.61%	3.71%	6.19%	0.26%	$1,000	$2,303	$3,843	$161	$7,307
Inst Conemaugh 250 MVAR Cap	b0376_dfax	$ 62,085.50	0.00%	32.79%	0.00%	0.00%	$0	$20,358	$0	$0	$20,358
Saddle Brook - Athenia Upgrade Cable	b0472	$ 1,524,743.00	0.00%	0.00%	96.40%	3.60%	$0	$0	$1,469,852	$54,891	$1,524,743
Build new 500 kV transmission facilities from Pennsylvania - New Jersey border at Bushkill to Roseland (500kV and above elements of the project)	b0489	$ 42,404,941.50	1.61%	3.71%	6.19%	0.26%	$682,720	$1,573,223	$2,624,866	$110,253	$4,991,062
Build new 500 kV transmission facilities from Pennsylvania - New Jersey border at Bushkill to Roseland (500kV and above elements of the project)	b0489_dfax	$ 42,404,941.50	0.00%	35.98%	58.08%	2.37%	$0	$15,257,298	$24,628,790	$1,004,997	$40,891,085
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	$ 4,690,410.00	5.14%	33.04%	41.10%	1.53%	$241,087	$1,549,711	$1,927,759	$71,763	$3,790,320
Susquehanna Roseland Breakers (In-Service)	b0489.5	$ 318,812.50	1.61%	3.71%	6.19%	0.26%	$5,133	$11,828	$19,734	$829	$37,524
Susquehanna Roseland Breakers (In-Service)	b0489.5_dfax	$ 318,812.50	0.00%	35.98%	56.08%	2.37%	$0	$114,709	$178,790	$7,556	$301,055
Loop the 5021 circuit into New Freedom 500 kV substation	b0498	$ 1,315,947.00	1.61%	3.71%	6.19%	0.26%	$21,187	$48,822	$81,457	$3,421	$154,887

Attachment 6a -PJM Schedule 12 - Transmission Enhancement Charges for January 2020 - December 2020 **Attachment 6a**
Calculation of costs and monthly PJM charges for PSE&G Projects

Required Transmission Enhancement *per PJM website*	PJM Upgrade ID *per PJM spreadsheet*	(a) Jan - Dec 2020 Annual Revenue Requirement *per PJM website*	(b) Responsible Customers - Schedule 12 Appendix: ACE Zone Share	(c) JCP&L Zone Share	(d) PSE&G Zone Share1,2	(e) RE Zone Share *(per PJM Open Access Transmission Tariff)*	(f) Estimated New Jersey EDC Zone Charges by Project: ACE Zone Charges	(g) JCP&L Zone Charges	(h) PSE&G Zone Charges	(i) RE Zone Charges	(j) Total NJ Zones Charges
Loop the 5021 circuit into New Freedom 500 kV substation	b0498_dfax	$ 1,315,947.00	8.35%	23.15%	43.44%	1.77%	$109,882	$304,642	$571,647	$23,292	$1,009,463
Branchburg-Somerville-Flagtown Reconductor	b0664-b0665	$ 1,971,224.00	0.00%	36.35%	43.24%	1.61%	$0	$716,540	$852,357	$31,737	$1,600,634
Somerville -Bridgewater Reconductor	b0668	$ 680,066.00	0.00%	39.41%	38.76%	1.45%	$0	$268,014	$263,594	$9,861	$541,469
Reconductor Hudson - South Waterfront 230kV circuit	b0813	$ 937,362.00	0.00%	9.92%	83.73%	3.12%	$0	$92,986	$784,853	$29,246	$907,085
New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie	b0814	$ 4,929,169.00	0.00%	23.49%	67.03%	2.50%	$0	$1,157,862	$3,304,022	$123,229	$4,585,113
Reconductor South Mahwah 345 kV J-3410 Circuit	b1017	$ 2,134,354.00	0.00%	29.27%	65.42%	2.55%	$0	$624,725	$1,396,294	$54,426	$2,075,446
Reconductor South Mahwah 345 kV K-3411 Circuit	b1018	$ 2,217,622.00	0.00%	29.44%	65.25%	2.55%	$0	$652,868	$1,446,998	$56,549	$2,156,416
West Orange Conversion (North Central Reliability)	b1154	$ 40,080,672.00	0.00%	0.00%	96.18%	3.82%	$0	$0	$38,549,590	$1,531,082	$40,080,672
Branchburg-Middlesex Sw Rack	b1155	$ 7,580,817.00	0.00%	4.61%	91.75%	3.64%	$0	$349,476	$6,955,400	$275,942	$7,580,817
Conversion	b1156	$ 39,002,141.00	0.00%	0.00%	96.18%	3.82%	$0	$0	$37,512,259	$1,489,882	$39,002,141
Reconf Kearny Loop in P2216	b1589	$ 2,956,038.00	0.00%	0.00%	77.16%	3.08%	$0	$0	$2,280,879	$91,046	$2,371,925
230kV Lawrence Switching Station Upgrade	b1228	$ 2,357,604.00	0.00%	0.00%	96.18%	3.82%	$0	$0	$2,267,544	$90,060	$2,357,604
Ridge Rd 69kV Breaker Station	b1255	$ 6,000,252.00	0.00%	0.00%	96.18%	3.82%	$0	$0	$5,771,042	$229,210	$6,000,252
Northeast Grid Reliability Project	b1304.1-b1304.4	$ 71,567,505.00	0.28%	1.43%	85.73%	3.40%	$200,389	$1,023,415	$61,354,822	$2,433,295	$65,011,922
Mickleton-Gloucester-Camden	b1398-b1398.7	$ 49,472,297.00	0.00%	13.03%	31.99%	1.27%	$0	$6,446,240	$15,826,188	$628,298	$22,900,726
Aldene-Springfield Rd. Conv	b1399	$ 8,056,841.00	0.00%	0.00%	96.18%	3.82%	$0	$0	$7,749,070	$307,771	$8,056,841
Replace Salem 500 kV breakers	b1410-b1415	$ 859,015.50	1.61%	3.71%	6.19%	0.26%	$13,830	$31,869	$53,173	$2,233	$101,106
Replace Salem 500 kV breakers	b1410-b1416_dfax	$ 859,015.50	0.00%	0.00%	96.13%	3.87%	$0	$0	$825,772	$33,244	$859,016
Uprate Eagle Point-Gloucester 230 kV Circuit	b1588	$ 1,361,002.00	0.00%	10.48%	55.03%	2.19%	$0	$142,633	$748,959	$29,806	$921,398
Upgrade Camden Richmon 230kV	b1590	$ 1,260,186.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
New Cox's Corner-Lumberton 230kV Circuit	b1787	$ 3,646,046.00	4.97%	44.34%	48.23%	1.93%	$181,208	$1,616,657	$1,758,488	$70,369	$3,626,722
Build Mickleton-Gloucester Corridor Ultimate Design	b2139	$ 2,240,329.00	0.00%	0.00%	61.11%	2.44%	$0	$0	$1,369,065	$54,664	$1,423,729
Reconfigure Brunswick New 69kV	b2146	$ 19,389,918.00	0.00%	0.00%	96.16%	3.84%	$0	$0	$18,645,345	$744,573	$19,389,918
Convert Bergen Marion 138 kV to double circuit 345kV and Sub	b2436.10_dfax	$ 10,668,262.00	0.00%	0.00%	100.00%	0.00%	$0	$0	$10,668,262	$0	$10,668,262
Convert Bergen Marion 138 kV to double circuit 345kV and Sub	b2436.10	$ 10,668,262.00	1.61%	3.71%	6.19%	0.26%	$171,759	$395,793	$660,365	$27,737	$1,255,654
Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.21_dfax	$ 3,805,090.00	0.00%	0.00%	100.00%	0.00%	$0	$0	$3,805,090	$0	$3,805,090
Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.21	$ 3,805,090.00	1.61%	3.71%	6.19%	0.26%	$61,262	$141,169	$235,535	$9,893	$447,859
Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.22_dfax	$ 2,656,169.50	0.00%	0.00%	100.00%	0.00%	$0	$0	$2,656,170	$0	$2,656,170
Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.22	$ 2,656,169.50	1.61%	3.71%	6.19%	0.26%	$42,764	$98,544	$164,417	$6,906	$312,631

Attachment 6a -PJM Schedule 12 - Transmission Enhancement Charges for January 2020 - December 2020
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 2020 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
New 500 kV bay at Hope Creek (Expansion of Hope Creek sub)	b2633.4	$ 119,964.00	0.81%	1.86%	3.09%	0.13%	$972	$2,231	$3,707	$156	$7,066
New 500/230 kV autotransformer at Hope Creek and a new Hope Creek 230 kV substation	b2633.5	$ 491,171.00	0.01%	0.01%	0.00%	0.00%	$49	$49	$0	$0	$98
Rebuild Aldene-Warinanco-Linden VFT 230kV Circuit	b2955	$ 3,820,197.00	0.00%	93.78%	0.00%	0.00%	$0	$3,582,581	$0	$0	$3,582,581
Reconductor L-2238 Cedar Grove - Jackson Rd 230kV	b2956	$ 501,301.00	0.00%	0.05%	96.07%	3.87%	$0	$251	$481,600	$19,400	$501,251
Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation	b2436.81_dfax	$ 3,403,094.50	0.00%	0.00%	96.08%	3.92%	$0	$0	$3,269,693	$133,401	$3,403,095
Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation	b2436.81	$ 3,403,094.50	1.61%	3.71%	6.19%	0.26%	$54,790	$126,255	$210,652	$8,848	$400,544
Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.83_dfax	$ 3,403,256.00	0.00%	0.00%	96.08%	3.92%	$0	$0	$3,269,848	$133,408	$3,403,256
Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.83	$ 3,403,256.00	1.61%	3.71%	6.19%	0.26%	$54,792	$126,261	$210,662	$8,848	$400,563
Convert Bayway-Linden "W" to 138kV circuit to 345kV	b2436.84_dfax	$ 3,198,721.00	0.00%	0.00%	96.08%	3.92%	$0	$0	$3,073,331	$125,390	$3,198,721
Convert Bayway-Linden "W" to 138kV circuit to 345kV	b2436.84	$ 3,198,721.00	1.61%	3.71%	6.19%	0.26%	$51,499	$118,673	$198,001	$8,317	$376,489
Convert Bayway-Linden "M" to 138kV circuit to 345kV	b2436.85_dfax	$ 3,198,721.00	0.00%	0.00%	96.08%	3.92%	$0	$0	$3,073,331	$125,390	$3,198,721
Convert Bayway-Linden "M" to 138kV circuit to 345kV	b2436.85	$ 3,198,721.00	1.61%	3.71%	6.19%	0.26%	$51,499	$118,673	$198,001	$8,317	$376,489
Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades	b2436.90_dfax	$ 1,607,425.00	0.00%	0.00%	100.00%	0.00%	$0	$0	$1,607,425	$0	$1,607,425
Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades	b2436.90	$ 1,607,425.00	1.61%	3.71%	6.19%	0.26%	$25,880	$59,635	$99,500	$4,179	$189,194
New Bergen 345/230 kV transformer and any associated substation upgrades	b2437.10	$ 3,303,514.00	0.00%	0.00%	96.08%	3.92%	$0	$0	$3,174,016	$129,498	$3,303,514
New Bayway 345/138 kV transformer #1 and any associated substation upgrades	b2437.20	$ 1,051,024.00	0.00%	0.00%	96.08%	3.92%	$0	$0	$1,009,824	$41,200	$1,051,024
New Bayway 345/138 kV transformer #2 and any associated substation upgrades	b2437.21	$ 1,050,975.00	0.00%	0.00%	96.08%	3.92%	$0	$0	$1,009,777	$41,198	$1,050,975
New Linden 345/230 kV transformer and any associated substation upgrades	b2437.30	$ 4,175,124.00	0.00%	0.00%	96.08%	3.92%	$0	$0	$4,011,459	$163,665	$4,175,124
Install two 175 MVAR Re at Hptcg	b2702_dfax	$ 1,554,283.50	0.00%	0.00%	100.00%	0.00%	$0	$0	$1,554,284	$0	$1,554,284
Install two 175 MVAR Re at Hptcg	b2702	$ 1,554,283.50	1.61%	3.71%	6.19%	0.26%	$25,024	$57,664	$96,210	$4,041	$182,939
Totals		**$ 471,249,143.00**					**$3,238,706**	**$46,202,265**	**$295,644,150**	**$11,114,003**	**$356,199,124**

Attachment 6a -PJM Schedule 12 - Transmission Enhancement Charges for January 2020 - December 2020 **Attachment 6a**
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 2020 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*								
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 2020**	**2020 Trans. Peak Load [2]**	**Rate in \$/MW-mo. [1]**	**2020 Impact (12 months)**	
	PSE&G	$ 24,637,012.52	9,752.5	$ 2,526.23	$ 295,644,150	
	JCP&L	$ 3,850,188.74	6,057.1	$ 635.65	$ 46,202,265	
	ACE	$ 269,892.15	2,737.3	$ 98.60	$ 3,238,706	
	RE	$ 926,166.93	393.1	$ 2,356.06	$ 11,114,003	
	Total Impact on NJ Zones	**$ 29,683,260.34**	**18,940.0**		**$ 356,199,124**	
Notes on calculations >>>				= (k) / (l)	= (k) *12	

Notes:
1) Uncompressed rate - assumes implementation on January 1, 2020
2) Data on PJM website

Attachment 6c - PJM Schedule 12 - Transmission Enhancement Charges for January 2020 - December 2020 **Attachment 6b**
Calculation of costs and monthly PJM charges for VEPCO Projects

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				Estimated New Jersey EDC Zone Charges by Project				
Required Transmission Enhancement	**PJM Upgrade ID**	**Jan - Dec 2020 Annual Revenue Requirement**	**ACE Zone Share**	**JCP&L Zone Share**	**PSE&G Zone Share1**	**RE Zone Share**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
per PJM website	*per PJM spreadsheet*	*per PJM website*	*per PJM Open Access Transmission Tariff*								
Upgrade Mt Storm - Doubs 500kV	b0217	$93,550.00	1.61%	3.71%	6.19%	0.26%	$1,506	$3,471	$5,791	$243	$11,011
Upgrade Mt Storm - Doubs 500kV	b0217_dfax	$93,550.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Loudoun 150 MVA capacitor @ 500 kV	b0222	$76,281.50	1.61%	3.71%	6.19%	0.26%	$1,228	$2,830	$4,722	$198	$8,978
Loudoun 150 MVA capacitor @ 500 kV	b0222_dfax	$76,281.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
500 kV breakers and bus work at Suffolk	b0231	$1,135,830.50	1.61%	3.71%	6.19%	0.26%	$18,287	$42,139	$70,308	$2,953	$133,687
500 kV breakers and bus work at Suffolk	b0231_dfax	$1,135,830.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Meadowbrook-Loudon 500kV circuit	b0328.1	$11,474,344.50	1.61%	3.71%	6.19%	0.26%	$184,737	$425,698	$710,262	$29,833	$1,350,530
Meadowbrook-Loudon 500kV circuit	b0328.1_dfax	$11,474,344.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Upgrade Mt. Storm 500 KV Substation	b0328.3	$708,946.00	1.61%	3.71%	619.00%	0.26%	$11,414	$26,302	$4,388,376	$1,843	$4,427,935
Upgrade Mt. Storm 500 KV Substation	b0328.3_dfax	$708,946.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Upgrade Loudoun 500 KV Substation	b0328.4	$158,126.50	1.61%	3.71%	6.19%	0.26%	$2,546	$5,866	$9,788	$411	$18,611
Upgrade Loudoun 500 KV Substation	b0328.4_dfax	$158,126.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Carson – Suffolk 500 kV, Suffolk 500/230 kV transformer & build Suffolk – Trascher 230 kV circuit	B0329.2B	$8,327,213.00	1.61%	3.71%	6.19%	0.26%	$134,068	$308,940	$515,454	$21,651	$980,113
Carson – Suffolk 500 kV, Suffolk 500/230 kV transformer & build Suffolk – Trascher 230 kV circuit	B0329.2B_dfax	$8,327,213.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
500/230 KV transformer at Bristers, new 230 Bristers - Gainsville circuit	b0227	$1,962,493.00	0.71%	0.00%	0.00%	0.00%	$13,934	$0	$0	$0	$13,934
Rebuild Mt Storm-Doubs 500 KV circuit	b1507	$16,766,127.50	1.61%	3.71%	6.19%	0.26%	$269,935	$622,023	$1,037,823	$43,592	$1,973,373
Rebuild Mt Storm-Doubs 500 KV circuit	b1507_dfax	$16,766,127.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Replace wave traps on Dooms-Lexington 500KV circuit	b0457	$5,292.00	1.61%	3.71%	6.19%	0.26%	$85	$196	$328	$14	$623
Replace wave traps on Dooms-Lexington 500KV circuit	b0457_dfax	$5,292.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Morrisville H1T573	b1647	$807.50	1.61%	3.71%	6.19%	0.26%	$13	$30	$50	$2	$95
Morrisville H1T573	b1647_dfax	$807.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Morrisville H2T545	b1648	$807.50	1.61%	3.71%	6.19%	0.26%	$13	$30	$50	$2	$95
Morrisville H2T545	b1648_dfax	$807.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Morrisville H1T580	b1649	$42,606.00	1.61%	3.71%	6.19%	0.26%	$686	$1,581	$2,637	$111	$5,015
Morrisville H1T580	b1649_dfax	$42,606.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Morrisville H2T569	b1650	$42,606.00	1.61%	3.71%	6.19%	0.26%	$686	$1,581	$2,637	$111	$5,015
Morrisville H2T569	b1650_dfax	$42,606.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Replace wave traps on North Anna-Ladysmith 500KV circuit	b0784	$3,672.00	1.61%	3.71%	6.19%	0.26%	$59	$136	$227	$10	$432
Replace wave traps on North Anna-Ladysmith 500KV circuit	b0784_dfax	$3,672.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0

Attachment 6c - PJM Schedule 12 - Transmission Enhancement Charges for January 2020 - December 2020 **Attachment 6b**
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 2020 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share**	**JCP&L Zone Share**	**PSE&G Zone Share1**	**RE Zone Share** *per PJM Open Access Transmission Tariff*	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
Reconductor the Dickerson-Pleasant View 230 KV circuit	b0467.2	$527,912.00	1.75%	0.71%	0.00%	0.00%	$9,238	$3,748	$0	$0	$12,987
Install 500/230 kV transformer and two 230 kV breakers at Brambleton	b1188.6	$1,712,499.00	0.22%	0.00%	0.00%	0.00%	$3,767	$0	$0	$0	$3,767
New Brambleton 500 kV line, 3 ring bus, to Loudon to Pleasant View 500 kV	b1188	$80,143.50	1.61%	3.71%	6.19%	0.26%	$1,290	$2,973	$4,961	$208	$9,433
New Brambleton 500 kV line, 3 ring bus, to Loudon to Pleasant View 500 kV	b1188_dfax	$80,143.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
500 kV breaker at Brambleton	b1698.1	$0.00	1.61%	3.71%	6.19%	0.26%	$0	$0	$0	$0	$0
500 kV breaker at Brambleton	b1698.1_dfax	$0.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Install 2 500kV breakers at Chancellor 500 kV	b0756.1	$209,486.00	1.61%	3.71%	6.19%	0.26%	$3,373	$7,772	$12,967	$545	$24,657
Install 2 500kV breakers at Chancellor 500 kV	b0756.1_dfax	$209,486.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Wreck and Rebuild 7 miles of Cloverdale - Lexington 500 kV Line	b1797	$929,491.50	1.61%	3.71%	6.19%	0.26%	$14,965	$34,484	$57,536	$2,417	$109,401
Wreck and Rebuild 7 miles of Cloverdale - Lexington 500 kV Line	b1797_dfax	$929,491.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Build 450 MVAR SVC and 300 MVAR switched shunt at Loudoun 500 kV	b1798	$5,709,975.50	1.61%	3.71%	6.19%	0.26%	$91,931	$211,840	$353,447	$14,846	$672,064
Build 450 MVAR SVC and 300 MVAR switched shunt at Loudoun 500 kV	b1798_dfax	$5,709,975.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Build 150 MVAR Switched Shunt at Pleasant View 500 kV Line	b1799	$1,343,727.00	1.61%	3.71%	6.19%	0.26%	$21,634	$49,852	$83,177	$3,494	$158,157
Build 150 MVAR Switched Shunt at Pleasant View 500 kV Line	b1799_dfax	$1,343,727.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Install 250 MVAR SVC at Mt. Storm 500 kV Substation	b1805	$1,896,478.00	1.61%	3.71%	6.19%	0.26%	$30,533	$70,359	$117,392	$4,931	$223,215
Install 250 MVAR SVC at Mt. Storm 500 kV Substation	b1805_dfax	$1,896,478.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
At Yadkin 500 kV, install six 500 kV Breakers	b1906.1	$525,144.50	1.61%	3.71%	6.19%	0.26%	$8,455	$19,483	$32,506	$1,365	$61,810
At Yadkin 500 kV, install six 500 kV Breakers	b1906.1_dfax	$525,144.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Rebuild Lexington-Dooms 500 kV Line	b1908	$6,724,764.50	1.61%	3.71%	6.19%	0.26%	$108,269	$249,489	$416,263	$17,484	$791,505
Rebuild Lexington-Dooms 500 kV Line	b1908_dfax	$6,724,764.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Surry 500 kV Station Work	b1905.2	$93,481.00	1.61%	3.71%	6.19%	0.26%	$1,505	$3,468	$5,786	$243	$11,003
Surry 500 kV Station Work	b1905.2_dfax	$93,481.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Mt Storm - Replace MOD with breaker on 500kV side of Transformer	b0837	$36,205.50	1.61%	3.71%	6.19%	0.26%	$583	$1,343	$2,241	$94	$4,261
Mt Storm - Replace MOD with breaker on 500kV side of Transformer	b0837_dfax	$36,205.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0

Attachment 6c - PJM Schedule 12 - Transmission Enhancement Charges for January 2020 - December 2020 **Attachment 6b**

Calculation of costs and monthly PJM charges for VEPCO Projects

Required Transmission Enhancement *per PJM website*	PJM Upgrade ID *per PJM spreadsheet*	(a) Jan - Dec 2020 Annual Revenue Requirement *per PJM website*	(b) Responsible Customers - Schedule 12 Appendix: ACE Zone Share *per PJM Open Access Transmission Tariff*	(c) JCP&L Zone Share	(d) PSE&G Zone Share1	(e) RE Zone Share	(f) Estimated New Jersey EDC Zone Charges by Project: ACE Zone Charges	(g) JCP&L Zone Charges	(h) PSE&G Zone Charges	(i) RE Zone Charges	(j) Total NJ Zones Charges
Uprate Section between Possum and Dumfries Substation	b1328	$408,519.00	0.66%	0.00%	0.00%	0.00%	$2,696	$0	$0	$0	$2,696
Rebuild Loudoun - Brambleto 500kV	b1694	$2,496,878.50	1.61%	3.71%	6.19%	0.26%	$40,200	$92,634	$154,557	$6,492	$293,883
Rebuild Loudoun - Brambleto 500kV	b1694_dfax	$2,496,878.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
R/P Midlothian 500kV 3 breaker Ring Bus	b2471	$414,782.50	1.61%	3.71%	6.19%	0.26%	$6,678	$15,388	$25,675	$1,078	$48,820
R/P Midlothian 500kV 3 breaker Ring Bus	b2471_dfax	$414,782.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Surry to Skiffes Creek 500kV Line	b1905.1	$14,565,525.00	1.61%	3.71%	6.19%	0.26%	$234,505	$540,381	$901,606	$37,870	$1,714,362
Surry to Skiffes Creek 500kV Line	b1905.1_dfax	$14,565,525.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Install Breaker and half scheme with minimum of eight 230kV Breakers	b1696	$2,881,323.00	0.46%	0.64%	0.00%	0.00%	$13,254	$18,440	$0	$0	$31,695
Build a second Loudon - Brambleton 500kV line	b2373	$2,359,099.50	1.61%	3.71%	6.19%	0.26%	$37,982	$87,523	$146,028	$6,134	$277,666
Build a second Loudon - Brambleton 500kV line	b2373_dfax	$2,359,099.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Rebuild Carson Rogers 500kV Ckt	b2744	$9,300,673.00	1.61%	3.71%	6.19%	0.26%	$149,741	$345,055	$575,712	$24,182	$1,094,689
Optimal Capacitors Configuaration	b2729	$1,199,805.00	1.97%	3.33%	7.34%	0.00%	$23,636	$39,954	$88,066	$0	$151,655
Totals		**$169,236,205.00**					**$1,443,431**	**$3,235,011**	**$9,726,374**	**$222,357**	**$14,627,173**
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 2020	(l) 2020 Trans. Peak Load [2]	(m) Rate in \$/MW-mo. [1]	(n) 2020 Impact (12 months)
PSE&G	$ 810,531.13	9,752.5	$ 83.11	$ 9,726,374
JCP&L	$ 269,584.23	6,057.1	$ 44.51	$ 3,235,011
ACE	$ 120,285.95	2,737.3	$ 43.94	$ 1,443,431
RE	$ 18,529.78	393.1	$ 47.14	$ 222,357
Total Impact on NJ Zones	**$ 1,218,931.09**	**18,940.0**		**$14,627,173**
Notes on calculations >>>			= (k) / (l)	= (k) *12

Attachment 6d PJM Schedule 12 - Transmission Enhancement Charges for January 2020 - December 2020
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 2020 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 &b 0491	$	(220,136.50)	1.61%	3.71%	6.19%	0.26%	-$3,544	-$8,167	-$13,626	-$572	-$25,910
Amos-Bedington 765 kV Circuit (AEP)	b0490 & b0491_dfax	$	(220,136.50)	5.01%	11.64%	15.86%	0.59%	-$11,029	-$25,624	-$34,914	-$1,299	-$72,865
Bedington-Kemptown 500 kV Circuit	b0492 & b560	$	(125,793.50)	1.61%	3.71%	6.19%	0.26%	-$2,025	-$4,667	-$7,787	-$327	-$14,806
Bedington-Kemptown 500 kV Circuit	b0492 & b560_dfax	$	(125,793.50)	5.01%	11.64%	15.86%	0.59%	-$6,302	-$14,642	-$19,951	-$742	-$41,638
Totals		**$**	**(691,860.00)**					**-$22,901**	**-$53,100**	**-$76,278**	**-$2,940**	**-$155,219**
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 2020**	**2020 Trans. Peak Load[2]**	**Rate in \$/MW-mo.[1]**		**2020 Impact (12 months)**
PSE&G	$	(6,356.46)	9,752.5	(\$0.65)	$	(76,278)
JCP&L	$	(4,425.02)	6,057.1	(\$0.73)	$	(53,100)
ACE	$	(1,908.38)	2,737.3	(\$0.70)	$	(22,901)
RE	$	(245.03)	393.1	(\$0.62)	$	(2,940)
Total Impact on NJ Zones	**$**	**(12,934.90)**	**18,940.0**		**$**	**(155,219)**
Notes on calculations >>>				= (k) / (l)		= (k) *12

Notes:
1) Uncompressed rate - assumes implementation on January 1, 2020
2) Data on PJM website

Attachment 6e - Transmission Enhancement Charges for January 2020 - December 2020 **Attachment 6d**
Calculation of costs and monthly PJM charges for Mid Atlantic Interstate Transmission 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 2020 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**
Install 230kV series reactor and 2-100MVAR PLC switched capacitors at Hunterstown	b0215	$ 1,350,447.00	6.75%	16.96%	22.82%	0.34%	$91,155	$229,036	$308,172	$4,592	$632,955
Replace wave trap at Kestone 500kV Sub	b2688.1	$ 1,502,687.00	0.00%	0.00%	0.00%	0.12%	$0	$0	$0	$1,803	$1,803
Install 250 MVAR Capacitor at Keystone 500kV Sub	b0549	$ 175,075.00	1.61%	3.71%	6.19%	0.26%	$2,819	$6,495	$10,837	$455	$20,606
Install 250 MVAR Capacitor at Keystone 500kV Sub	b0549_dfax	$ 175,075.00	0.00%	19.99%	0.00%	0.00%	$0	$34,997	$0	$0	$34,997
Install 25 MVAR capacitor at Saxton 115 kV Sub	b0551	$ 143,377.00	8.64%	18.30%	26.32%	0.98%	$12,388	$26,238	$37,737	$1,405	$77,768
Install 50 MVAR capacitor at Altoona 230 kV Sub	b0552	$ 115,214.00	8.64%	18.30%	26.32%	0.98%	$9,954	$21,084	$30,324	$1,129	$62,492
Install 50 MVAR capacitor at Raystoon 230 kV Sub	b0553	$ 101,288.00	8.64%	18.30%	26.32%	0.98%	$8,751	$18,536	$26,659	$993	$54,939
Install 75 MVAR capacitor at East Towanda 230 kV Sub	b0557	$ 237,837.00	8.64%	18.30%	26.32%	0.98%	$20,549	$43,524	$62,599	$2,331	$129,003
Relocate the Erie South 345 kV Line Terminal	b1993	$ 1,205,508.00	0.00%	5.19%	12.21%	0.48%	$0	$62,566	$147,193	$5,786	$215,545
Conver Lewis Run-Farmers Valley to 230kV using 1033.5 Conductor	b1994	$ 13,956,274.00	0.00%	8.72%	13.67%	0.54%	$0	$1,216,987	$1,907,823	$75,364	$3,200,174
Loop the 2026 kV Line to Laushtown Substation	b2006.1.1	$ 377,834.00	1.61%	3.71%	6.19%	0.26%	$6,083	$14,018	$23,388	$982	$44,471
Loop the 2026 kV Line to Laushtown Substation	b2006.1.1_dfax	$ 329,649.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
South Lebanon 230/69 kv Bank 1 - Upgrade 69 kv Terminal Facilities	b1364	$ 24,499.00	0.00%	100.00%	0.00%	0.00%	$0	$24,499	$0	$0	$24,499
Middletown Sub - 69 kv Capacitor Bank	b1362	$ 14,164.36	0.00%	100.00%	0.00%	0.00%	$0	$14,164	$0	$0	$14,164
							$151,700	**$1,712,145**	**$2,554,731**	**$94,840**	**$4,513,416**
		$ 19,708,928									
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 2020**	**2020TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2020 Impact (12 months)**
PSE&G	$ 212,894.26	9,752.5	$ 21.83	$ 2,554,731
JCP&L	$ 142,678.71	6,057.1	$ 23.56	$ 1,712,145
ACE	$ 12,641.64	2,737.3	$ 4.62	$ 151,700
RE	$ 7,903.35	393.1	$ 20.11	$ 94,840
Total Impact on NJ Zones	**$ 376,117.97**			**$ 4,513,416**
Notes on calculations >>>			= (k) * (l)	= (k) *12

Notes:
1) 2020 allocation share percentages are from PJM OATT

Attachment 6f PJM Schedule 12 - Transmission Enhancement Charges for January 2020 - December 2020 **Attachment 6e**
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	**PJM Upgrade ID**	**Jan - Dec 2020 Annual Revenue Requirement**	**ACE Zone Share[1]**	**JCP&L Zone Share[1]**	**PSE&G Zone Share[1]**	**RE Zone Share[1]**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
per PJM website	*per PJM spreadsheet*	*per PJM website*	*per PJM Open Access Transmission Tariff*								
New 765 KV circuit breakers at Hanging Rock Sub	b0504	$ 378,611	1.61%	3.71%	6.19%	0.26%	$6,096	$14,046	$23,436	$984	$44,562
New 765 KV circuit breakers at Hanging Rock Sub	b0504_dfax	$ 378,611	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Rockport Reactor Bank	b1465.2	$ 940,352	1.61%	3.71%	6.19%	0.26%	$15,140	$34,887	$58,208	$2,445	$110,679
Rockport Reactor Bank	b1465.2_dfax	$ 940,352	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Transpose Rockport- Sullivan 765KV line	b1465.3	$ 1,107,912	1.61%	3.71%	6.19%	0.26%	$17,837	$41,104	$68,580	$2,881	$130,401
Transpose Rockport- Sullivan 765KV line	b1465.3_dfax	$ 1,107,912	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Switching changes Sullivan 765KV station	b1465.4	$ (138,876)	1.61%	3.71%	6.19%	0.26%	-$2,236	-$5,152	-$8,596	-$361	-$16,346
Switching changes Sullivan 765KV station	b1465.4_dfax	$ (138,876)	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Sullivan Inst Baker 765kV Trnsf.	b1465.5	$ 1,138,437	1.61%	3.71%	6.19%	0.26%	-$2,236	-$5,152	-$8,596	-$361	-$16,346
Sullivan Inst Baker 765kV Trnsf.	b1465.5_dfax	$ 1,138,437	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
765kV circuit breaker at Wyoming station	b1661	$ (1,281)	1.61%	3.71%	6.19%	0.26%	-$21	-$48	-$79	-$3	-$151
765kV circuit breaker at Wyoming station	b1661_dfax	$ (1,281)	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Term Tsfmr #2 @ SW Lima - new bay position	b1957	$ 1,625,291	0.00%	0.00%	4.54%	0.18%	$0	$0	$73,788	$2,926	$76,714
Reconductor/Rebuild Sporn-Waterford-Muskingham River 345 kV Line	b2017	$ 11,540,442	0.00%	1.39%	2.00%	0.08%	$0	$160,412	$230,809	$9,232	$400,453
Add four 765 kV Breakers at Kammar	b1962	$ 1,422,508	1.61%	3.71%	6.19%	0.26%	$22,902	$52,775	$88,053	$3,699	$167,429
Add four 765 kV Breakers at Kammar	b1962_dfax	$ 1,422,508	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Ft. Wayne Relocate	b1659.14	$ 2,309,000	1.61%	3.71%	6.19%	0.26%	$37,175	$85,664	$142,927	$6,003	$271,769
Ft. Wayne Relocate	b1659.14_dfax	$ 2,309,000	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Sorenson 765/500kV Transformer	b1659	$ 7,952,328	0.00%	0.00%	0.92%	0.04%	$0	$0	$73,161	$3,181	$76,342
Sorenson Work 765kV	b1659.13	$ 3,214,938	1.61%	3.71%	6.19%	0.26%	$51,761	$119,274	$199,005	$8,359	$378,398
Sorenson Work 765kV	b1659.13_dfax	$ 3,214,938	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Baker Station 765/500kV Transformer	b1495	$ 4,771,714	0.41%	0.90%	1.48%	0.06%	$19,564	$42,945	$70,621	$2,863	$135,994
Cloverdale 765/500kV Transformer	b1660	$ (588,304)	1.61%	3.71%	6.19%	0.26%	($9,472)	($21,826)	($36,416)	($1,530)	($69,243)
Cloverdale 765/500kV Transformer	b1660_dfax	$ (588,304)	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Cloverdale 500kV Station	b1660.1	$ 1,496,129	1.61%	3.71%	6.19%	0.26%	$24,088	$55,506	$92,610	$3,890	$176,094
Cloverdale 500kV Station	b1660.1_dfax	$ 1,496,129	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Jacksons-Ferry 765kV Breakers	b1663.2	$ 306,069	1.61%	3.71%	6.19%	0.26%	$4,928	$11,355	$18,946	$796	$36,024
Jacksons-Ferry 765kV Breakers	b1663.2_dfax	$ 306,069	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Reconductor Cloverdale-Lexington 500kV	b1797.1	$ 2,898,729	1.61%	3.71%	6.19%	0.26%	$46,670	$107,543	$179,431	$7,537	$341,180
Reconductor Cloverdale-Lexington 500kV	b1797.1_dfax	$ 2,898,729	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0

Attachment 6f PJM Schedule 12 - Transmission Enhancement Charges for January 2020 - December 2020 Attachment 6e

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 2020 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**
Reconductor West Bellaire	b1970	$ (2,413,072)	0.00%	1.68%	2.88%	0.11%	$0	-$40,540	-$69,496	-$2,654	-$112,690
Add a 3rd 2250 MVA 765/345 kV transformer at Sullivan station	b1465.1	$ 4,271,272	0.71%	1.58%	2.63%	0.10%	$30,326	$67,486	$112,334	$4,271	$214,418
Replace existing 150 MVAR reactor at Amos 765 kV sub	b2230	$ 860,412	1.61%	3.71%	6.19%	0.26%	$13,853	$31,921	$53,259	$2,237	$101,270
Replace existing 150 MVAR reactor at Amos 765 kV sub	b2230_dfax	$ 860,412	0.00%	1.68%	2.88%	0.11%	$0	$14,455	$24,780	$946	$40,181
Install a 300 MVAR shunt reactor at AEP's Wyoming 765 kV station	b2423	$ 1,275,003	1.61%	3.71%	6.19%	0.26%	$20,528	$47,303	$78,923	$3,315	$150,068
Install a 300 MVAR shunt reactor at AEP's Wyoming 765 kV station	b2423_dfax	$ 1,275,003	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Install a 450 MVAR SVC Jackson's Ferry 765kV Substation	b2687.1	$ (378,019)	1.61%	3.71%	6.19%	0.26%	-$6,086	-$14,025	-$23,399	-$983	-$44,493
Install a 450 MVAR SVC Jackson's Ferry 765kV Substation	b2687.1_dfax	$ (378,019)	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Install a 450 MVAR SVC Jackson's Ferry 765kV Substation	b2687.2	$ 537,419	1.61%	3.71%	6.19%	0.26%	$8,652	$19,938	$33,266	$1,397	$63,254
Install 300 MVAR shunt line reactor	b2687.2_dfax	$ 537,419	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Totals							**$299,468**	**$819,873**	**$1,475,554**	**$61,070**	**$2,655,965**
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 2020**	(l) **2020Tx Peak Load** *per PJM website*	(m) **Rate in $/MW-mo.**	(n) **2020 Impact (12 months)**
PSE&G	$ 122,962.87	9,752.5	$ 12.61	$ 1,475,554
JCP&L	$ 68,322.74	6,057.1	$ 11.28	$ 819,873
ACE	$ 24,955.65	2,737.3	$ 9.12	$ 299,468
RE	$ 5,089.14	393.1	$ 12.95	$ 61,070
Total Impact on NJ Zones	**$ 221,330.40**			**$ 2,655,965**
Notes on calculations >>>			= (k) * (l)	= (k) *12

Notes:

1) 2019 allocation share percentages are from PJM OATT

Attachment 6f Summary of EL05-121 Settlement Adjustments for January 2020 - December 2020

Total - January 2020 - December 2020	AE	JCPL	PSEG	Rockland
BLI-1108A - Current Aggregate Recovery Charge Transitional Period - Catch-up	$ -	$ -	$ -	$ -
BLI-1108A - Estimated Interest August 2018 - June 2019	$ -	$ -	$ -	$ -
BLI-1115 - Transmission Enhancement Charge Adjustments (Black Box) Transitional Period - Catch-up	$ -	$ -	$ -	$ -
BLI-1115 - Transmission Enhancement Charge Adjustments (Black Box)	$ 117,627.00	$ 4,076,209.92	$ 9,440,981.76	$ 350,431.44
BLI-1115 - Estimated Transmission Enhancement Charge Adjustment (Black Box) Interest August 2018 - June 2019	$ -	$ -	$ -	$ -
Total Adjustments Allocated to NJ Zones	$ 117,627.00	$ 4,076,209.92	$ 9,440,981.76	$ 350,431.44

Monthly Total - January 2020 - December 2020	AE	JCPL	PSEG	Rockland
BLI-1108A - Current Aggregate Recovery Charge Transitional Period - Catch-up	$ -	$ -	$ -	$ -
BLI-1108A - Estimated Interest August 2018 - June 2019	$ -	$ -	$ -	$ -
BLI-1115 - Transmission Enhancement Charge Adjustments (Black Box) Transitional Period - Catch-up	$ -	$ -	$ -	$ -
BLI-1115 - Transmission Enhancement Charge Adjustments (Black Box)	$ 9,802.25	$ 339,684.16	$ 786,748.48	$ 29,202.62
BLI-1115 - Estimated Transmission Enhancement Charge Adjustment (Black Box) Interest August 2018 - June 2019	$ -	$ -	$ -	$ -
Total Monthly Adjustments Allocated to NJ Zones	$ 9,802.25	$ 339,684.16	$ 786,748.48	$ 29,202.62

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 MAIT Schedule 12 Projects
Source – PJM OATT

Attachment 7e – 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 (*1.76*%) / JCPL (*26.50*%) / Neptune* (*10.85*%) / PSEG (*60.89*%)
b0170	Reconductor the Flagtown-Somerville-Bridgewater 230 kV circuit with 1590 ACSS		JCLP (42.95%) / Neptune* (17.90%) / PSEG (38.36%) RE (0.79%)

* Neptune Regional Transmission System, LLC

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		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *AEC (3.72%) / JCPL (26.83%) / NEPTUNE (4.75%) /* PECO (9.72%) / *PSEG (52.82%) / RE (2.16%)*
b0184	Replace Hudson 230kV circuit breakers #1-2		PSEG (100%)
b0185	Replace Deans 230kV circuit breakers #9-10		PSEG (100%)
b0186	Replace Essex 230kV circuit breaker #5-6		PSEG (100%)
b1082	Install 230/138 kV transformer at Bergen substation		PENELEC (16.52%) / PSEG (80.29%) / RE (3.19%)

* Neptune Regional Transmission System, LLC

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 (*100*%)
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		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *AEC (3.72%) / JCPL (26.83%) / NEPTUNE (4.75%)* / PECO (9.72%) / *PSEG (52.82%) / RE (2.16%)*
b0358	Reconductor the PSEG portion of Buckingham – Pleasant Valley 230 kV, replace wave trap and metering transformer		PSEG (100%)

* Neptune Regional Transmission System, LLC

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 (*42.63*%) / Neptune* (*3.65*%) / PSEG (*51.45*%) / RE (*2.27*%)
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%)
b0446.3	Upgrade Bayway 138 kV breaker #6-7		PSEG (100%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
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		PSEG (*96.40*%) / RE (*3.60*%)
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		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)†
			DFAX Allocation: *JCPL (35.98%) / NEPTUNE (3.57%) / PSEG (58.08%) / RE (2.37%)*

* Neptune Regional Transmission System, 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

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 (*5.14*%) / ComEd (0.29%) / Dayton (0.03%) / DPL (*1.78*%) / JCPL (*33.04*%) / Neptune* (*6.38*%) / PECO (*10.14*%) / PENELEC (*0.57*%) / PSEG (*41.10*%) / RE (*1.53*%) ††
b0489.5	Replace Roseland 230 kV breaker '42H' with 80 kA		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *JCPL (35.98%) / NEPTUNE (3.57%) / PSEG (58.08%) / RE (2.37%)*

* Neptune Regional Transmission System, LLC

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		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *JCPL (35.98%) / NEPTUNE (3.57%) / PSEG (58.08%) / RE (2.37%)*
b0489.7	Replace Roseland 230 kV breaker '71H' with 80 kA		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *JCPL (35.98%) / NEPTUNE (3.57%) / PSEG (58.08%) / RE (2.37%)*

* Neptune Regional Transmission System, LLC

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		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *JCPL (35.98%) / NEPTUNE (3.57%) / PSEG (58.08%) / RE (2.37%)*

* Neptune Regional Transmission System, LLC

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		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *JCPL (35.98%) / NEPTUNE (3.57%) / PSEG (58.08%) / RE (2.37%)*
b0489.10	Replace Roseland 230 kV breaker '21H'		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *JCPL (35.98%) / NEPTUNE (3.57%) / PSEG (58.08%) / RE (2.37%)*

* Neptune Regional Transmission System, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0489.11	Replace Roseland 230 kV breaker '32H'		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *JCPL (35.98%) / NEPTUNE (3.57%) / PSEG (58.08%) / RE (2.37%)*
b0489.12	Replace Roseland 230 kV breaker '12H'		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *JCPL (35.98%) / NEPTUNE (3.57%) / PSEG (58.08%) / RE (2.37%)*

* Neptune Regional Transmission System, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0489.13	Replace Roseland 230 kV breaker '52H'		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *JCPL (35.98%) / NEPTUNE (3.57%) / PSEG (58.08%) / RE (2.37%)*
b0489.14	Replace Roseland 230 kV breaker '41H'		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *JCPL (35.98%) / NEPTUNE (3.57%) / PSEG (58.08%) / RE (2.37%)*

* Neptune Regional Transmission System, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0489.15	Replace Roseland 230 kV breaker '72H'		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *JCPL (35.98%) / NEPTUNE (3.57%) / PSEG (58.08%) / RE (2.37%)*
b0498	Loop the 5021 circuit into New Freedom 500 kV substation		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *AEC (8.35%) / JCPL (23.15%) / NEPTUNE (2.79%) / PECO (20.50%) / PSEG (43.44%) / RE (1.77%)*

* Neptune Regional Transmission System, LLC

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 (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
b0565	Install 100 MVAR capacitor at Cox's Corner 230 kV substation		PSEG (100%)

* Neptune Regional Transmission System, LLC

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%)

* Neptune Regional Transmission System, LLC

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%)

*Neptune Regional Transmission System, LLC

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%)

*Neptune Regional Transmission System, LLC

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 (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
b0829.6	Replace Branchburg 500 kV breaker 91X		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *PSEG (96.13%) / RE (3.87%)*
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 (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
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 (*2.57*%) / Dayton (0.09%) / PENELEC (*2.82*%) / PSEG (*90.97*%) / RE (*3.55*%)
b0832	Build Hudson 500 kV switching station as part of Branchburg – Hudson 500 kV project		AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
b0833	Build Roseland 500 kV switching station as part of Branchburg – Hudson 500 kV project		AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)

*Neptune Regional Transmission System, LLC

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 (2.57%) / Dayton (0.09%) / PENELEC (2.82%) / PSEG (90.97%) / RE (3.55%)
b0835	Build Hudson 230 kV transmission lines as part of Roseland – Hudson 500 kV project as part of Branchburg – Hudson 500 kV project		ComEd (2.57%) / Dayton (0.09%) / PENELEC (2.82%) / PSEG (90.97%) / RE (3.55%)
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 (2.57%) / Dayton (0.09%) / PENELEC (2.82%) / PSEG (90.97%) / RE (3.55%)
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%)

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 (*29.27*%) / NEPTUNE* (*2.76*%) / PSEG (*65.42*%) / RE (*2.55*%)
b1018	Reconductor South Mahwah - Waldwick 345 kV K-3411 circuit		JCPL (*29.44*%) / NEPTUNE* (*2.76*%) / PSEG (*65.25*%) / RE (*2.55*%)
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%)

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		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *APS (19.80%) / BGE (9.71%) / Dominion (59.40%) / PEPCO (11.09%)*
b0222	Install 150 MVAR capacitor at Loudoun 500 kV		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *Dominion (91.48%)* / PEPCO (8.52%)

* Neptune Regional Transmission System, 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		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%) ***DFAX Allocation:*** *Dominion (100%)*
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%)

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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)		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *Dominion (*91.48*%)* / PEPCO (8.52%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0328.3	Upgrade Mt. Storm 500 kV substation		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *APS (*40.83*%) / Dominion (*59.17*%)*
b0328.4	Upgrade Loudoun 500 kV substation		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *Dominion (*91.48*%)* / PEPCO (8.52%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0329	Build Carson – Suffolk 500 kV, install 2nd Suffolk 500/230 kV transformer & build Suffolk – Fentress 230 kV circuit		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *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%)
b0329.5	Install 2nd Suffolk 500/230 kV transformer & build Suffolk – Thrasher 230 kV circuit		Dominion (100%)††
b0330	Install Crewe 115 kV breaker and shift load from line 158 to 98		Dominion (100%)
b0331	Upgrade/resag Shell Bank – Whealton 115 kV (Line 165)		Dominion (100%)

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

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0412	Retension Pruntytown – Mt. Storm 500 kV to a 3502 MVA rating		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *PEPCO (100%)*
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 Remington – 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%)

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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		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: DEOK (13.36%) / *Dominion (86.64%)*
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%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0492.6	Replace Mount Storm 500 kV breaker 55072		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)*
b0492.7	Replace Mount Storm 500 kV breaker 55172		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)*

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0492.8	Replace Mount Storm 500 kV breaker H1172-2		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)*
b0492.9	Replace Mount Storm 500 kV breaker G2T550		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)*

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0492.10	Replace Mount Storm 500 kV breaker G2T554		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)*
b0492.11	Replace Mount Storm 500 kV breaker G1T551		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)*

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0492.12	Upgrade nameplate rating of Mount Storm 500 kV breakers 55472, 57272, SX172, G3TSX1, G1TH11, G3T572, and SX22		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)*
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 (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.5	Advance n0716 (Ox - Replace 230kV breaker L242)		**Load-Ratio Share Allocation:** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: AEC (3.94%) / APS (0.33%) / BGE (34.54%) / DPL (14.69%) / Dominion (0.30%) / JCPL (9.43%) / ME (2.16%) / NEPTUNE (0.90%) / PECO (10.52%) / PEPCO (2.44%) / PPL (5.50%) / PSEG (14.71%) / RE (0.54%)
b0512.6	Advance n0717 (Possum Point - Replace 230kV breaker SC192)		**Load-Ratio Share Allocation:** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: AEC (3.94%) / APS (0.33%) / BGE (34.54%) / DPL (14.69%) / Dominion (0.30%) / JCPL (9.43%) / ME (2.16%) / NEPTUNE (0.90%) / PECO (10.52%) / PEPCO (2.44%) / PPL (5.50%) / PSEG (14.71%) / RE (0.54%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
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		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *Dominion (100%)*

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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%)

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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		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *Dominion (100%)*
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		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *Dominion (100%)*

* Neptune Regional Transmission System, LLC

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		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *Dominion (100%)*
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		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *APS (19.80%) / BGE (9.71%) / Dominion (59.40%) / PEPCO (11.09%)*
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		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *Dominion (100%)*
b1648	Upgrade name plate rating at Morrisville 500kV breaker ‘H2T545’ with 50kA breaker		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *Dominion (100%)*

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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		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *Dominion (100%)*
b1650	Replace Morrisville 500kV breaker 'H2T569' with 50kA breaker		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *Dominion (100%)*
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		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *Dominion (100%)*
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		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *Dominion (100%)*

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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%)

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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		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *ATSI (5.74%) / Dayton (1.97%) / DEOK (4.40%) / Dominion (9.97%) / EKPC (1.12%) / PEPCO (76.80%)*
b1798	Build a 450 MVAR SVC and 300 MVAR switched shunt at Loudoun 500 kV		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *Dominion (91.48%)* / PEPCO (8.52%)

* Neptune Regional Transmission System, LLC

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		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *Dominion (100%)*
b1805	Install a 250 MVAR SVC at the existing Mt. Storm 500kV substation		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *APS (65.36%) / PEPCO (34.64%)*
b1809	Replace Brambleton 230 kV Breaker ‘22702’		Dominion (100%)
b1810	Replace Brambleton 230 kV Breaker ‘227T2094’		Dominion (100%)

* Neptune Regional Transmission System, LLC

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)		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *Dominion (100%)*
b1905.2	Surry 500 kV Station Work		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *Dominion (100%)*
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%)

* Neptune Regional Transmission System, LLC

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		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *Dominion (100%)*
b1906.2	Install a 2nd 230/115 kV TX at Yadkin		Dominion (100%)
b1906.3	Install a 2nd 230/115 kV TX at Chesapeake		Dominion (100%)
b1906.4	Uprate Yadkin – Chesapeake 115 kV		Dominion (100%)
b1906.5	Install a third 500/230 kV TX at Yadkin		Dominion (100%)
b1907	Install a 3rd 500/230 kV TX at Clover		APS (5.83%) / BGE (4.74%) / Dominion (81.79%) / PEPCO (7.64%)

* Neptune Regional Transmission System, LLC

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1908	Rebuild Lexington – Dooms 500 kV		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: DEOK (13.36%) / *Dominion (*86.64*%)*
b1909	Uprate Bremo – Midlothian 230 kV to its maximum operating temperature		APS (6.31%) / BGE (3.81%) / Dominion (81. 90%) / PEPCO (7.98%)
b1910	Build a Suffolk – Yadkin 230 kV line (14 miles) and install 4 breakers		Dominion (100%)
b1911	Add a second Valley 500/230 kV TX		APS (14.85%) / BGE (3.10%) / Dominion (74.12%) / PEPCO (7.93%)
b1912	Install a 500 MVAR SVC at Landstown 230 kV		DEOK (0.46%) / Dominion (99.54%)
b2053	Rebuild 28 mile line		AEP (100%)
b2125	Install four additional 230 kV 100 MVAR variable shunt reactor banks at Clifton, Gallows Road, Garrisonville, and Virginia Hills substations		Dominion (100%)
b2126	Install two additional 230 kV 100 MVAR variable shunt reactor banks at Churchland and Shawboro substations		Dominion (100%)

* Neptune Regional Transmission System, LLC

Virginia Electric and Power Company (cont.)

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

* Neptune Regional Transmission System, LLC

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%)
b2373	Build a 2nd Loudoun - Brambleton 500 kV line within the existing ROW. The Loudoun - Brambleton 230 kV line will be relocated as an underbuild on the new 500 kV line		**Load-Ratio Share Allocation:** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: 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%)

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.

*Neptune Regional Transmission System, LLC

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2404	Replace the Beaumeade 230 kV breaker '227T2095' with 63kA		Dominion (100%)
b2405	Replace the Pleasant view 230 kV breaker '203T274' with 63kA		Dominion (100%)
b2443	Construct new underground 230 kV line from Glebe to Station C, rebuild Glebe Substation, construct 230 kV high side bus at Station C with option to install 800 MVA PAR		Dominion (97.11%) / ME (0.18%) / PEPCO (2.71%)
b2443.1	Replace the Idylwood 230 kV breaker ‘203512’ with 50kA		Dominion (100%)
b2443.2	Replace the Ox 230 kV breaker ‘206342’ with 63kA breaker		Dominion (100%)
b2443.3	Glebe – Station C PAR		**DFAX Allocation:** Dominion (22.57%) / PEPCO (77.43%)
b2443.6	Install a second 500/230 kV transformer at Possum Point substation and replace bus work and associated equipment as needed		Dominion (100%)
b2443.7	Replace 19 63kA 230 kV breakers with 19 80kA 230 kV breakers		Dominion (100%)
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%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
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%)
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 (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			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%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2649.1	Rebuild of 1.7 mile tap to Metcalf and Belfield DP (MEC) due to poor condition. The existing summer rating of the tap is 48 MVA and existing conductor is 4/0 ACSR on wood H-frames. The proposed new rating is 176 MVA using 636 ACSR conductor		Dominion (100%)
b2649.2	Rebuild of 4.1 mile tap to Brinks DP (MEC) due to wood poles built in 1962. The existing summer rating of the tap is 48 MVA and existing conductor is 4/0 ACSR and 393.6 ACSR on wood H-frames. The proposed new rating is 176 MVA using 636 ACSR conductor		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%)

*Neptune Regional Transmission System, LLC

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 (1.97%) / BGE (14.46%) / Dominion (35.33%) / DPL (3.78%) / JCPL (3.33%) / ME (2.53%) / Neptune (0.63%) / PECO (6.30%) / PEPCO (20.36%) / PPL (3.97%) / PSEG (7.34%)

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 (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			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%)
b2800	The 7 mile section from Dozier to Thompsons Corner of line #120 will be rebuilt to current standards using 768.2 ACSS conductor with a summer emergency rating of 346 MVA at 115 kV. Line is proposed to be rebuilt on single circuit steel monopole structure		Dominion (100%)
b2801	Lines #76 and #79 will be rebuilt to current standard using 768.2 ACSS conductor with a summer emergency rating of 346 MVA at 115 kV. Proposed structure for rebuild is double circuit steel monopole structure		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%)
b2842	Update the nameplate for Mount Storm 500 kV "57272" to be 50kA breaker		Dominion (100%)
b2843	Replace the Mount Storm 500 kV "G2TY" with 50kA breaker		Dominion (100%)
b2844	Replace the Mount Storm 500 kV "G2TZ" with 50kA breaker		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2845	Update the nameplate for Mount Storm 500 kV "G3TSX1" to be 50kA breaker		Dominion (100%)
b2846	Update the nameplate for Mount Storm 500 kV "SX172" to be 50kA breaker		Dominion (100%)
b2847	Update the nameplate for Mount Storm 500 kV "Y72" to be 50kA breaker		Dominion (100%)
b2848	Replace the Mount Storm 500 kV "Z72" with 50kA breaker		Dominion (100%)
b2871	Rebuild 230 kV line #247 from Swamp to Suffolk (31 miles) to current standards with a summer emergency rating of 1047 MVA at 230 kV		Dominion (100%)
b2876	Rebuild line #101 from Mackeys – Creswell 115 kV, 14 miles, with double circuit structures. Install one circuit with provisions for a second circuit. The conductor used will be at current standards with a summer emergency rating of 262 MVA at 115 kV		Dominion (100%)
b2877	Rebuild line #112 from Fudge Hollow – Lowmoor 138 kV (5.16 miles) to current standards with a summer emergency rating of 314 MVA at 138 kV		Dominion (100%)
b2899	Rebuild 230 kV line #231 to current standard with a summer emergency rating of 1046 MVA. Proposed conductor is 2-636 ACSR		Dominion (100%)
b2900	Build a new 230/115 kV switching station connecting to 230 kV network line #2014 (Earleys – Everetts). Provide a 115 kV source from the new station to serve Windsor DP		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2922	Rebuild 8 of 11 miles of 230 kV lines #211 and #228 to current standard with a summer emergency rating of 1046 MVA for rebuilt section. Proposed conductor is 2-636 ACSR		Dominion (100%)
b2928	Rebuild four structures of 500 kV line #567 from Chickahominy to Surry using galvanized steel and replace the river crossing conductor with 3-1534 ACSR. This will increase the line #567 line rating from 1954 MVA to 2600 MVA		Dominion (100%)
b2929	Rebuild 230 kV line #2144 from Winfall to Swamp (4.3 miles) to current standards with a standard conductor (bundled 636 ACSR) having a summer emergency rating of 1047 MVA at 230 kV		Dominion (100%)
b2960	Replace fixed series capacitors on 500 kV Line #547 at Lexington and on 500 kV Line #548 at Valley		Dominion (100%)
b2961	Rebuild approximately 3 miles of Line #205 & Line #2003 from Chesterfield to Locks & Poe respectively		Dominion (100%)
b2962	Split Line #227 (Brambleton – Beaumeade 230 kV) and terminate into existing Belmont substation		Dominion (100%)
b2962.1	Replace the Beaumeade 230 kV breaker “274T2081” with 63kA breaker		Dominion (100%)
b2962.2	Replace the NIVO 230 kV breaker “2116T2130” with 63kA breaker		Dominion (100%)
b2963	Reconductor the Woodbridge to Occoquan 230 kV line segment of Line #2001 with 1047 MVA conductor and replace line terminal equipment at Possum Point, Woodbridge, and Occoquan		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2978	Install 2-125 MVAR STATCOMs at Rawlings and 1-125 MVAR STATCOM at Clover 500 kV substations		**Load-Ratio Share Allocation:** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%) **DFAX Allocation:** Dominion (100%)
b2980	Rebuild 115 kV Line #43 between Staunton and Harrisonburg (22.8 miles) to current standards with a summer emergency rating of 261 MVA at 115 kV		Dominion (100%)
b2981	Rebuild 115 kV Line #29 segment between Fredericksburg and Aquia Harbor to current 230 kV standards (operating at 115 kV) utilizing steel H-frame structures with 2-636 ACSR to provide a normal continuous summer rating of 524 MVA at 115 kV (1047 MVA at 230 kV)		Dominion (100%)

*Neptune Regional Transmission System, LLC

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2989	Install a second 230/115 kV Transformer (224 MVA) approximately 1 mile north of Bremo and tie 230 kV Line #2028 (Bremo – Charlottesville) and 115 kV Line #91 (Bremo - Sherwood) together. A three breaker 230 kV ring bus will split Line #2028 into two lines and Line #91 will also be split into two lines with a new three breaker 115 kV ring bus. Install a temporary 230/115 kV transformer at Bremo substation for the interim until the new substation is complete		Dominion (100%)
b2990	Chesterfield to Basin 230 kV line – Replace 0.14 miles of 1109 ACAR with a conductor which will increase the line rating to approximately 706 MVA		Dominion (100%)
b2991	Chaparral to Locks 230 kV line – Replace breaker lead		Dominion (100%)
b2994	Acquire land and build a new switching station (Skippers) at the tap serving Brink DP with a 115 kV four breaker ring to split Line #130 and terminate the end points		Dominion (100%)
b3018	Rebuild Line #49 between New Road and Middleburg substations with single circuit steel structures to current 115 kV standards with a minimum summer emergency rating of 261 MVA		Dominion (100%)
b3019	Rebuild 500 kV Line #552 Bristers to Chancellor – 21.6 miles long		Dominion (100%)
b3019.1	Update the nameplate for Morrisville 500 kV breaker “H1T594” to be 50kA		Dominion (100%)
b3019.2	Update the nameplate for Morrisville 500 kV breaker “H1T545” to be 50kA		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b3020	Rebuild 500 kV Line #574 Ladysmith to Elmont – 26.2 miles long		Dominion (100%)
b3021	Rebuild 500 kV Line #581 Ladysmith to Chancellor – 15.2 miles long		Dominion (100%)
b3026	Reconductor Line #274 (Pleasant View – Ashburn – Beaumeade 230 kV) with a minimum rating of 1200 MVA. Also upgrade terminal equipment		Dominion (100%)
b3027.1	Add a 2nd 500/230 kV 840 MVA transformer at Dominion's Ladysmith substation		Dominion (100%)
b3027.2	Reconductor 230 kV Line #2089 between Ladysmith and Ladysmith CT substations to increase the line rating from 1047 MVA to 1225 MVA		Dominion (100%)
b3027.3	Replace the Ladysmith 500 kV breaker "H1T581" with 50kA breaker		Dominion (100%)
b3027.4	Update the nameplate for Ladysmith 500 kV breaker "H1T575" to be 50kA breaker		Dominion (100%)
b3027.5	Update the nameplate for Ladysmith 500 kV breaker "568T574" (will be renumbered as "H2T568") to be 50kA breaker		Dominion (100%)
b3055	Install spare 230/69 kV transformer at Davis substation		Dominion (100%)
b3056	Partial rebuild 230 kV Line #2113 Waller to Lightfoot		Dominion (100%)
b3057	Rebuild 230 kV Lines #2154 and #19 Waller to Skiffes Creek		Dominion (100%)
b3058	Partial rebuild of 230 kV Lines #265, #200 and #2051		Dominion (100%)
b3059	Rebuild 230 kV Line #2173 Loudoun to Elklick		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b3060	Rebuild 4.6 mile Elklick – Bull Run 230 kV Line #295 and the portion (3.85 miles) of the Clifton – Walney 230 kV Line #265 which shares structures with Line #295		Dominion (100%)
b3088	Rebuild 4.75 mile section of Line #26 between Lexington and Rockbridge with a minimum summer emergency rating of 261 MVA		Dominion (100%)
b3089	Rebuild 230 kV Line #224 between Lanexa and Northern Neck utilizing double circuit structures to current 230 kV standards. Only one circuit is to be installed on the structures with this project with a minimum summer emergency rating of 1047 MVA		Dominion (100%)
b3090	Convert the overhead portion (approx. 1500 feet) of 230 kV Lines #248 & #2023 to underground and convert Glebe substation to gas insulated substation		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	***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)*

**Neptune Regional Transmission System, LLC*

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

Required Transmission Enhancements		*Annual Revenue Requirement*	*Responsible Customer(s)*
b0492	Construct a Welton Spring to Kemptown 765 kV line (APS equipment)	As specified under the procedures detailed in Attachment H-19B	***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)*
b0492.3	Replace Eastalco 230 kV breaker D-26		APS (100%)
b0492.4	Replace Eastalco 230 kV breaker D-28		APS (100%)

*Neptune Regional Transmission System, LLC

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)
b0545	Remove instantaneous reclose from Eastalco circuit breaker D-28		APS (100%)
b0559	Install 200 MVAR capacitor at Meadow Brook 500 kV substation		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *APS (40.83%) / Dominion (59.17%)*
b0560	Install 250 MVAR capacitor at Kemptown 500 kV substation		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)*

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	***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)*

* Neptune Regional Transmission System, LLC

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

SCHEDULE 12 – APPENDIX

(5) Mid-Atlantic Interstate Transmission, LLC for the Metropolitan Edison Company Zone

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0215	Install 230Kv series reactor and 2- 100MVAR PLC switched capacitors at Hunterstown		AEC (*6.75*%) / APS (*4.00*%) / DPL (*9.16*%) / JCPL (*16.96*%) / ME (*10.60*%) / Neptune* (*1.70*%) / PECO (*19.12*%) / PPL (*8.55*%) / PSEG (*22.82*%) / RE (0.34%)
b0404.1	Replace South Reading 230 kV breaker 107252		ME (100%)
b0404.2	Replace South Reading 230 kV breaker 100652		ME (100%)
b0575.1	Rebuild Hunterstown – Texas Eastern Tap 115 kV		ME (100%)
b0575.2	Rebuild Texas Eastern Tap – Gardners 115 kV and associated upgrades at Gardners including disconnect switches		ME (100%)
b0650	Reconductor Jackson – JE Baker – Taxville 115 kV line		ME (100%)
b0652	Install bus tie circuit breaker on Yorkana 115 kV bus and expand the Yorkana 230 kV ring bus by one breaker so that the Yorkana 230/115 kV banks 1, 3, and 4 cannot be lost for either B-14 breaker fault or a 230 kV line or bank fault with a stuck breaker		ME (100%)

* Neptune Regional Transmission System, LLC

(5) Mid-Atlantic Interstate Transmission, LLC for the Metropolitan Edison Company Zone

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0653	Construct a 230 kV Bernville station by tapping the North Temple – North Lebanon 230 kV line. Install a 230/69 kV transformer at existing Bernville 69 kV station		ME (100%)
b1000	Replace Portland 115kV breaker ‘95312’		ME (100%)
b1001	Replace Portland 115kV breaker ‘92712’		ME (100%)
b1002	Replace Hunterstown 115 kV breaker '96392'		ME (100%)
b1003	Replace Hunterstown 115 kV breaker '96292'		ME (100%)
b1004	Replace Hunterstown 115 kV breaker '99192'		ME (100%)
b1061	Replace existing Yorkana 230/115 kV transformer banks 1 and 4 with a single, larger transformer similar to transformer bank #3		ME (100%)
b1061.1	Replace the Yorkana 115 kV breaker ‘97282’		ME (100%)
b1061.2	Replace the Yorkana 115 kV breaker ‘B282’		ME (100%)
b1302	Replace the limiting bus conductor and wave trap at the Jackson 115 kV terminal of the Jackson – JE Baker Tap 115 kV line		ME (100%)
b1365	Reconductor the Middletown – Collins 115 kV (975) line 0.32 miles of 336 ACSR		ME (100%)

* Neptune Regional Transmission System, LLC

(5) Mid-Atlantic Interstate Transmission, LLC for the Metropolitan Edison Company Zone

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1366	Reconductor the Collins – Cly – Newberry 115 kV (975) line 5 miles with 795 ACSR		ME (100%)
b1727	Reconductor 2.4 miles of existing 556 and 795 ACSR from Harley Davidson to Pleasureville 115 kV with 795 ACSS to raise the ratings		ME (100%)
b1800	Install a 500 MVAR SVC at the existing Hunterstown 500kV substation		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *APS (*2.17*%)* / DL (0.83%) / *DPL (*19.06*%)* / JCPL (1.44%) */ ME (*30.29*%)* / Neptune* (0.17%) */ PSEG (*44.23*%)* / RE (1.81%)
b1801	Build a 250 MVAR SVC at Altoona 230 kV		AEC (*6.48*%) / AEP (2.58%) / APS (*6.89*%) / BGE (*6.58*%) / DPL (*12.40*%) / Dominion (*14.90*%) / JCPL (*8.15*%) / ME (6.21%) / Neptune* (0.82%) / PECO (*21.58*%) / PPL (4.89%) / PSEG (*8.19*%) / RE (0.33%)

*Neptune Regional Transmission System, LLC

(5) Mid-Atlantic Interstate Transmission, LLC for the Metropolitan Edison Company Zone

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1816.5	Replace SCCIR (Sub-conductor) at Hunterstown Substation on the No. 1, 230/115 kV transformer		ME (100%)
b1999	Replace limiting wave trap, circuit breaker, substation conductor, relay and current transformer components at Northwood		ME (100%)
b2000	Replace limiting wave trap on the Glendon - Hosensack line		ME (100%)
b2001	Replace limiting circuit breaker and substation conductor transformer components at Portland 230kV		ME (100%)
b2002	Northwood 230/115 kV Transformer upgrade		ME (100%)
b2023	Construct a new North Temple - Riverview - Cartech 69 kV line (4.7 miles) with 795 ACSR		ME (100%)
b2024	Upgrade 4/0 substation conductors at Middletown 69 kV		ME (100%)
b2025	Upgrade 4/0 and 350 Cu substation conductors at the Middletown Junction terminal of the Middletown Junction - Wood Street Tap 69 kV line		ME (100%)
b2026	Upgrade an OC protection relay at the Baldy 69 kV substation		ME (100%)
b2148	Install a 115 kV 28.8 MVAR capacitor at Pleasureville substation		ME (100%)

(5) Mid-Atlantic Interstate Transmission, LLC for the Metropolitan Edison Company Zone

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2149	Upgrade substation riser on the Smith St. - York Inc. 115 kV line		ME (100%)
b2150	Upgrade York Haven structure 115 kV bus conductor on Middletown Jct. - Zions View 115 kV		ME (100%)

* Neptune Regional Transmission System, LLC

SCHEDULE 12 – APPENDIX

(7) Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0284.1	Build 500 kV substation in PENELEC – Tap the Keystone – Juniata and Conemaugh – Juniata 500 kV, connect the circuits with a breaker and half scheme, and install new 400 MVAR capacitor		AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
b0284.3	Replace wave trap and upgrade a bus section at Keystone 500 kV – on the Keystone – Airydale 500 kV		AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)

* Neptune Regional Transmission System, LLC

Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0285.1	Replace wave trap at Keystone 500 kV – on the Keystone – Conemaugh 500 kV		AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
b0285.2	Replace wave trap and relay at Conemaugh 500 kV – on the Conemaugh – Keystone 500 kV		AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)

* Neptune Regional Transmission System, LLC

Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0349	Upgrade Rolling Meadows-Gore Jct 115 kV		PENELEC (100%)
b0360	Construction of a ring bus on the 345 kV side of Wayne substation		PENELEC (100%)
b0365	Add a 50 MVAR, 230 kV cap bank at Altoona 230 kV		PENELEC (100%)
b0369	Install 100 MVAR Dynamic Reactive Device at Airydale 500 kV substation		AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
b0370	Install 500 MVAR Dynamic Reactive Device at Airydale 500 kV substation		AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)

* Neptune Regional Transmission System, LLC

Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0376	Install 300 MVAR capacitor at Conemaugh 500 kV substation		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%) ***DFAX Allocation:*** *BGE (34.75%) / DL (0.58%) / JCPL (32.79%) / ME (28.17%) / NEPTUNE (3.71%)*
b0442	Spare Keystone 500/230 kV transformer		PENELEC (100%)
b0515	Replace Lewistown circuit breaker 1LY Yeagertown		PENELEC (100%)
b0516	Replace Lewistown circuit breaker 2LY Yeagertown		PENELEC (100%)
b0517	Replace Shawville bus section circuit breaker		PENELEC (100%)
b0518	Replace Homer City circuit breaker 201 Johnstown		PENELEC (100%)

* Neptune Regional Transmission System, LLC

Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0519	Replace Keystone circuit breaker 4 Transformer - 20		PENELEC (100%)
b0549	Install 250 MVAR capacitor at Keystone 500 kV		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: ATSI (1.04%) / *BGE* (32.57%) / DL (0.44%) / *JCPL* (19.99%) / *ME* (22.25%) / *NEPTUNE* (2.26%) / *PECO* (21.45%)
b0550	Install 25 MVAR capacitor at Lewis Run 115 kV substation		AEC (*8.64*%) / APS (*1.70*%) / DPL (*12.33*%) / JCPL (*18.30*%) / ME (*1.56*%) / Neptune* (*1.78*%) / PECO (*21.94*%) / PPL (*6.45*%) / PSEG (*26.32*%) / RE (*0.98*%)
b0551	Install 25 MVAR capacitor at Saxton 115 kV substation		AEC (*8.64*%) / APS (*1.70*%) / DPL (*12.33*%) / JCPL (*18.30*%) / ME (*1.56*%) / Neptune* (*1.78*%) / PECO (*21.94*%) / PPL (*6.45*%) / PSEG (*26.32*%) / RE (*0.98*%)
b0552	Install 50 MVAR capacitor at Altoona 230 kV substation		AEC (*8.64*%) / APS (*1.70*%) / DPL (*12.33*%) / JCPL (*18.30*%) / ME (*1.56*%) / Neptune* (*1.78*%) / PECO (*21.94*%) / PPL (*6.45*%) / PSEG (*26.32*%) / RE (*0.98*%)

* Neptune Regional Transmission System, LLC

Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0553	Install 50 MVAR capacitor at Raystown 230 kV substation		AEC (*8.64*%) / APS (*1.70*%) / DPL (*12.33*%) / JCPL (*18.30*%) / ME (*1.56*%) / Neptune* (*1.78*%) / PECO (*21.94*%) / PPL (*6.45*%) / PSEG (*26.32*%) / RE (*0.98*%)
b0555	Install 100 MVAR capacitor at Johnstown 230 kV substation		AEC (*8.64*%) / APS (*1.70*%) / DPL (*12.33*%) / JCPL (*18.30*%) / ME (*1.56*%) / Neptune* (*1.78*%) / PECO (*21.94*%) / PPL (*6.45*%) / PSEG (*26.32*%) / RE (*0.98*%)
b0556	Install 50 MVAR capacitor at Grover 230 kV substation		AEC (*8.64*%) / APS (*1.70*%) / DPL (*12.33*%) / JCPL (*18.30*%) / ME (*1.56*%) / Neptune* (*1.78*%) / PECO (*21.94*%) / PPL (*6.45*%) / PSEG (*26.32*%) / RE (*0.98*%)
b0557	Install 75 MVAR capacitor at East Towanda 230 kV substation		AEC (*8.64*%) / APS (*1.70*%) / DPL (*12.33*%) / JCPL (*18.30*%) / ME (*1.56*%) / Neptune* (*1.78*%) / PECO (*21.94*%) / PPL (*6.45*%) / PSEG (*26.32*%) / RE (*0.98*%)
b0563	Install 25 MVAR capacitor at Farmers Valley 115 kV substation		PENELEC (100%)
b0564	Install 10 MVAR capacitor at Ridgeway 115 kV substation		PENELEC (100%)

* Neptune Regional Transmission System, LLC

Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0654	Reconfigure the Cambria Slope 115 kV and Wilmore Junction 115 kV stations to eliminate Wilmore Junction 115 kV 3-terminal line		PENELEC (100%)
b0655	Reconfigure and expand the Glade 230 kV ring bus to eliminate the Glade Tap 230 kV 3-terminal line		PENELEC (100%)
b0656	Add three breakers to form a ring bus at Altoona 230 kV		PENELEC (100%)
b0794	Upgrade the Homer City 230 kV breaker 'Pierce Road'		PENELEC (100%)
b1005	Replace Glory 115 kV breaker '#7 XFMR'		PENELEC (100%)
b1006	Replace Shawville 115 kV breaker 'NO.14 XFMR'		PENELEC (100%)
b1007	Replace Shawville 115 kV breaker 'NO.15 XFMR'		PENELEC (100%)
b1008	Replace Shawville 115 kV breaker '#1B XFMR'		PENELEC (100%)
b1009	Replace Shawville 115 kV breaker '#2B XFMR'		PENELEC (100%)
b1010	Replace Shawville 115 kV breaker 'Dubois'		PENELEC (100%)

* Neptune Regional Transmission System, LLC

Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1011	Replace Shawville 115 kV breaker 'Philipsburg'		PENELEC (100%)
b1012	Replace Shawville 115 kV breaker 'Garman'		PENELEC (100%)
b1059	Replace a CRS relay at Hooversville 115 kV station		PENELEC (100%)
b1060	Replace a CRS relay at Rachel Hill 115 kV station		PENELEC (100%)
b1153	Upgrade Conemaugh 500/230 kV transformer and add a new line from Conemaugh-Seward 230 kV		AEC (*3.86*%) / APS (*6.45*%) / BGE (*17.33*%) / DL (*0.33*%) / JCPL (*12.95*%) / ME (*7.10*%) / PECO (*11.88*%) / PEPCO (*0.57*%) / PPL (*15.89*%) / PSEG (*21.15*%) / RE (*0.74*%) / NEPTUNE* (*1.75*%)
b1153.1	Revise the reclosing on the Shelocta 115 kV breaker ‘Lucerne’		PENELEC (100%)
b1169	Replace Shawville 115 kV breaker ‘#1A XFMR’		PENELEC (100%)
b1170	Replace Shawville 115 kV breaker ‘#2A XFMR’		PENELEC (100%)
b1277	Build a new Osterburg East – Bedford North 115 kV Line, 5.7 miles of 795 ACSR		PENELEC (100%)
b1278	Install 25 MVAR Capacitor Bank at Somerset 115 kV		PENELEC (100%)

Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1367	Replace the Cambria Slope 115/46 kV 50 MVA transformer with 75 MVA		PENELEC (100%)
b1368	Replace the Claysburg 115/46 kV 30 MVA transformer with 75 MVA		PENELEC (100%)
b1369	Replace the 4/0 CU substation conductor with 795 ACSR on the Westfall S21 Tap 46 kV line		PENELEC (100%)
b1370	Install a 3rd 115/46 kV transformer at Westfall		PENELEC (100%)
b1371	Reconductor 2.6 miels of the Claysburg – HCR 46 kV line with 636 ACSR		PENELEC (100%)
b1372	Replace 4/0 CU substation conductor with 795 ACSR on the Hollidaysburg – HCR 46 kV		PENELEC (100%)
b1373	Re-configure the Erie West 345 kV substation, add a new circuit breaker and relocate the Ashtabula line exit		PENELEC (100%)
b1374	Replace wave traps at Raritan River and Deep Run 115 kV substations with higher rated equipment for both B2 and C3 circuits		PENELEC (100%)
b1535	Reconductor 0.8 miles of the Gore Junction – ESG Tap 115 kV line with 795 ACSS		PENELEC (100%)

* Neptune Regional Transmission System, LLC

Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1607	Reconductor the New Baltimore - Bedford North 115 kV		PENELEC (100%)
b1608	Construct a new 345/115 kV substation and loop the Mansfield - Everts 115 kV		APS (8.61%) / PECO (1.72%) / PENELEC (89.67%)
b1609	Construct Four Mile Junction 230/115 kV substation. Loop the Erie South - Erie East 230 kV line, Buffalo Road - Corry East and Buffalo Road - Erie South 115 kV lines		APS (4.86%) / PENELEC (95.14%)
b1610	Install a new 230 kV breaker at Yeagertown		PENELEC (100%)
b1713	Install a 345 kV breaker at Erie West and relocate Ashtabula 345 kV line		PENELEC (100%)
b1769	Install a 75 MVAR cap bank on the Four Mile 230 kV bus		PENELEC (100%)
b1770	Install a 50 MVAR cap bank on the Buffalo Road 115 kV bus		PENELEC (100%)
b1802	Build a 100 MVAR Fast Switched Shunt and 200 MVAR Switched Shunt at Mansfield 345 kV		AEC (*6.48*%) / AEP (2.58%) / APS (*6.89*%) / BGE (*6.58*%) / DPL (*12.40*%) / Dominion (*14.90*%) / JCPL (*8.15*%) / ME (6.21%) / NEPTUNE* (0.82%) / PECO (*21.58*%) / PPL (4.89%) / PSEG (*8.19*%) / RE (0.33%)

* Neptune Regional Transmission System, LLC

Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1821	Replace the Erie South 115 kV breaker 'Union City'		PENELEC (100%)
b1943	Construct a 115 kV ring bus at Claysburg Substation. Bedford North and Saxton lines will no longer share a common breaker		PENELEC (100%)
b1944	Reconductor Eclipse substation 115 kV bus with 1033 kcmil conductor		PENELEC (100%)
b1945	Install second 230/115 kV autotransformer at Johnstown		PENELEC (100%)
b1966	Replace the 1200 Amp Line trap at Lewistown on the Raystown-Lewistown 230 kV line and replace substation conductor at Lewistown		PENELEC (100%)
b1967	Replace the Blairsville 138/115 kV transformer		PENELEC (100%)
b1990	Install a 25 MVAR 115 kV Capacitor at Grandview		PENELEC (100%)
b1991	Construct Farmers Valley 345/230 kV and 230/115 kV substation. Loop the Homer City-Stolle Road 345 kV line into Farmers Valley		PENELEC (100%)
b1992	Reconductor Cambria Slope-Summit 115kV with 795 ACSS Conductor		PENELEC (100%)

* Neptune Regional Transmission System, LLC

Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1993	Relocate the Erie South 345 kV line terminal		APS (*10.19*%) / JCPL (*5.19*%) / Neptune* (*0.55*%) / PENELEC (*71.38*%) / PSEG (*12.21*%) / RE (0.48%)
b1994	Convert Lewis Run-Farmers Valley to 230 kV using 1033.5 ACSR conductor. Project to be completed in conjunction with new Farmers Valley 345/230 kV transformation		APS (*33.49*%) / JCPL (*8.72*%) / ME (*5.57*%) / Neptune (*0.87*%) / PENELEC (*37.14*%) / PSEG (*13.67*%) / RE (0.54%)
b1995	Change CT Ratio at Claysburg		PENELEC (100%)
b1996.1	Replace 600 Amp Disconnect Switches on Ridgeway-Whetstone 115 kV line with 1200 Amp Disconnects		PENELEC (100%)
b1996.2	Reconductor Ridgway and Whetstone 115 kV Bus		PENELEC (100%)
b1996.3	Replace Wave Trap at Ridgway		PENELEC (100%)
b1996.4	Change CT Ratio at Ridgway		PENELEC (100%)
b1997	Replace 600 Amp Disconnect Switches on Dubois-Harvey Run-Whetstone 115 kV line with 1200 Amp Disconnects		PENELEC (100%)

Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1998	Install a 75 MVAR 115 kV Capacitor at Shawville		PENELEC (100%)
b2016	Reconductor bus at Wayne 115 kV station		PENELEC (100%)

* Neptune Regional Transmission System, LLC

SCHEDULE 12 – APPENDIX A

(5) Mid-Atlantic Interstate Transmission, LLC for the Metropolitan Edison Company Zone

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2006.1.1	Loop the 2026 (TMI – Hosensack 500 kV) line in to the Lauschtown		**Load-Ratio Share Allocation:** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: PPL (100%)
b2006.2.1	Upgrade relay at South Reading on the 1072 230 V line		ME (100%)
b2006.4	Replace the South Reading 69 kV ‘81342’ breaker with 40kA breaker		ME (100%)
b2006.5	Replace the South Reading 69 kV ‘82842’ breaker with 40kA breaker		ME (100%)
b2452	Install 2nd Hunterstown 230/115 kV transformer		APS (8.30%) / BGE (14.70%) / DEOK (0.48%) / Dominion (36.92%) / ME (23.85%) / PEPCO (15.75%)

Mid-Atlantic Interstate Transmission, LLC for the Metropolitan Edison Company Zone (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2452.1	Reconductor Hunterstown - Oxford 115 kV line		APS (8.30%) / BGE (14.70%) / DEOK (0.48%) / Dominion (36.92%) / ME (23.85%) / PEPCO (15.75%)
b2452.3	Replace the Hunterstown 115 kV breaker ‘96192’ with 40 kA		ME (100%)
b2588	Install a 36.6 MVAR 115 kV capacitor at North Bangor substation		ME (100%)
b2637	Convert Middletown Junction 230 kV substation to nine bay double breaker configuration.		ME (100%)
b2644	Install a 28.8 MVAR 115 kV capacitor at the Mountain substation		ME (100%)
b2688.1	Lincoln Substation: Upgrade the bus conductor and replace CTs.		AEP (12.91%) / APS (19.04%)/ ATSI (1.24%) / ComEd (0.35%) / Dayton (1.45%) / DEOK (2.30%) / DL (1.11%)/ Dominion (44.85%) / EKPC (0.78%)/ PEPCO (15.85%) / RECO (0.12%)
b2688.2	Germantown Substation: Replace 138/115 kV transformer with a 135/180/224 MVA bank. Replace Lincoln 115 kV breaker, install new 138 kV breaker, upgrade bus conductor and adjust/replace CTs.		AEP (12.91%) / APS (19.04%)/ ATSI (1.24%) / ComEd (0.35%) / Dayton (1.45%) / DEOK (2.30%) / DL (1.11%)/ Dominion (44.85%) / EKPC (0.78%)/ PEPCO (15.85%) / RECO (0.12%)

Mid-Atlantic Interstate Transmission, LLC for the Metropolitan Edison Company Zone (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2743.4	Upgrade terminal equipment at Hunterstown 500 kV on the Conemaugh – Hunterstown 500 kV circuit		AEP (6.46%) / APS (8.74%) / BGE (19.74%) / ComEd (2.16%) / Dayton (0.59%) / DEOK (1.02%) / DL (0.01%) / Dominion (39.95%) / EKPC (0.45%) / PEPCO (20.88%)
b2752.4	Upgrade terminal equipment and required relay communication at TMI 500 kV: on the Beach Bottom – TMI 500 kV circuit		AEP (6.46%) / APS (8.74%) / BGE (19.74%) / ComEd (2.16%) / Dayton (0.59%) / DEOK (1.02%) / DL (0.01%) / Dominion (39.95%) / EKPC (0.45%) / PEPCO (20.88%)
b2749	Replace relay at West Boyertown 69 kV station on the West Boyertown – North Boyertown 69 kV circuit		ME (100%)
b2765	Upgrade bus conductor at Gardners 115 kv substation; Upgrade bus conductor and adjust CT ratios at Carlisle Pike 115 kV		ME (100%)
b2950	Upgrade limiting 115 kV switches on the 115 kV side of the 230/115 kV Northwood substation and adjust setting on limiting ZR relay		ME (100%)

SCHEDULE 12 – APPENDIX A

(7) Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2212	Shawville Substation: Relocate 230 kV and 115 kV controls from the generating station building to new control building		PENELEC (100%)
b2293	Replace the Erie South 115 kV breaker 'Buffalo Rd' with 40kA breaker		PENELEC (100%)
b2294	Replace the Johnstown 115 kV breaker 'Bon Aire' with 40kA breaker		PENELEC (100%)
b2302	Replace the Erie South 115 kV breaker 'French #2' with 40kA breaker		PENELEC (100%)
b2304	Replace the substation conductor and switch at South Troy 115 kV substation		PENELEC (100%)
b2371	Install 75 MVAR capacitor at the Erie East 230 kV substation		PENELEC (100%)
b2441	Install +250/-100 MVAR SVC at the Erie South 230 kV station		PENELEC (100%)
b2442	Install three 230 kV breakers on the 230 kV side of the Lewistown #1, #2 and #3 transformers		PENELEC (100%)
b2450	Construct a new 115 kV line from Central City West to Bedford North		PENELEC (100%)
b2463	Rebuild and reconductor 115 kV line from East Towanda to S. Troy and upgrade terminal equipment at East Towanda, Tennessee Gas and South Troy		PENELEC (100%)

Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2494	Construct Warren 230 kV ring bus and install a second Warren 230/115 kV transformer		PENELEC (100%)
b2552.1	Reconductor the North Meshoppen – Oxbow-Lackawanna 230 kV circuit and upgrade terminal equipment (MAIT portion)		PENELEC (100%)
b2573	Replace the Warren 115 kV ‘B12’ breaker with a 40kA breaker		PENELEC (100%)
b2587	Reconfigure Pierce Brook 345 kV station to a ring bus and install a 125 MVAR shunt reactor at the station		PENELEC (100%)
b2621	Replace relays at East Towanda and East Sayre 115 kV substations (158/191 MVA SN/SE)		PENELEC (100%)
b2677	Replace wave trap, bus conductor and relay at Hilltop 115 kV substation. Replace relays at Prospect and Cooper substations		PENELEC (100%)
b2678	Convert the East Towanda 115 kV substation to breaker and half configuration		PENELEC (100%)
b2679	Install a 115 kV Venango Jct. line breaker at Edinboro South		PENELEC (100%)
b2680	Install a 115 kV breaker on Hooversville #1 115/23 kV transformer		PENELEC (100%)
b2681	Install a 115 kV breaker on the Eclipse #2 115/34.5 kV transformer		PENELEC (100%)

Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2682	Install two 21.6 MVAR capacitors at the Shade Gap 115 kV substation		PENELEC (100%)
b2683	Install a 36 MVAR 115 kV capacitor and associated equipment at Morgan Street substation		PENELEC (100%)
b2684	Install a 36 MVAR 115 kV capacitor at Central City West substation		PENELEC (100%)
b2685	Install a second 115 kV 3000A bus tie breaker at Hooversville substation		PENELEC (100%)
b2735	Replace the Warren 115 kV ‘NO. 2 XFMR’ breaker with 40kA breaker		PENELEC (100%)
b2736	Replace the Warren 115 kV ‘Warren #1’ breaker with 40kA breaker		PENELEC (100%)
b2737	Replace the Warren 115 kV ‘A TX #1’ breaker with 40kA breaker		PENELEC (100%)
b2738	Replace the Warren 115 kV ‘A TX #2’ breaker with 40kA breaker		PENELEC (100%)
b2739	Replace the Warren 115 kV ‘Warren #2’ breaker with 40kA breaker		PENELEC (100%)
b2740	Revise the reclosing of the Hooversville 115 kV ‘Ralphton’ breaker		PENELEC (100%)
b2741	Revise the reclosing of the Hooversville 115 kV ‘Statler Hill’ breaker		PENELEC (100%)

Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2743.2	Tie in new Rice substation to Conemaugh – Hunterstown 500 kV		AEP (6.46%) / APS (8.74%) / BGE (19.74%) / ComEd (2.16%) / Dayton (0.59%) / DEOK (1.02%) / DL (0.01%) / Dominion (39.95%) / EKPC (0.45%) / PEPCO (20.88%)
b2743.3	Upgrade terminal equipment at Conemaugh 500 kV on the Conemaugh – Hunterstown 500 kV circuit		AEP (6.46%) / APS (8.74%) / BGE (19.74%) / ComEd (2.16%) / Dayton (0.59%) / DEOK (1.02%) / DL (0.01%) / Dominion (39.95%) / EKPC (0.45%) / PEPCO (20.88%)
b2748	Install two 28 MVAR capacitors at Tiffany 115 kV substation		PENELEC (100%)
b2767	Construct a new 345 kV breaker string with three (3) 345 kV breakers at Homer City and move the North autotransformer connection to this new breaker string		PENELEC (100%)
b2803	Reconductor 3.7 miles of the Bethlehem – Leretto 46 kV circuit and replace terminal equipment at Summit 46 kV		PENELEC (100%)
b2804	Install a new relay and replace 4/0 CU bus conductor at Huntingdon 46 kV station, on the Huntingdon – C tap 46 kV circuit		PENELEC (100%)
b2805	Install a new relay and replace 4/0 CU & 250 CU substation conductor at Hollidaysburg 46 kV station, on the Hollidaysburg – HCR Tap 46 kV circuit		PENELEC (100%)

Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2806	Install a new relay and replace meter at the Raystown 46 kV substation, on the Raystown – Smithfield 46 kV circuit		PENELEC (100%)
b2807	Replace the CHPV and CRS relay, and adjust the IAC overcurrent relay trip setting; or replace the relay at Eldorado 46 kV substation, on the Eldorado – Gallitzin 46 kV circuit		PENELEC (100%)
b2808	Adjust the JBC overcurrent relay trip setting at Raystown 46 kV, and replace relay and 4/0 CU bus conductor at Huntingdon 46 kV substations, on the Raystown – Huntingdon 46 kV circuit		PENELEC (100%)
b2865	Replace Seward 115 kV breaker "Jackson Road" with 63kA breaker		PENELEC (100%)
b2866	Replace Seward 115 kV breaker "Conemaugh N." with 63kA breaker		PENELEC (100%)
b2867	Replace Seward 115 kV breaker "Conemaugh S." with 63kA breaker		PENELEC (100%)
b2868	Replace Seward 115 kV breaker "No.8 Xfmr" with 63kA breaker		PENELEC (100%)
b2944	Install two 345 kV 80 MVAR shunt reactors at Mainesburg station		PENELEC (100%)

Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2951	Seward, Blairsville East, Shelocta work		PENELEC (100%)
b2951.1	Upgrade Florence 115 kV line terminal equipment at Seward SS		PENELEC (100%)
b2951.2	Replace Blairsville East / Seward 115 kV line tuner, coax, line relaying and carrier set at Shelocta SS		PENELEC (100%)
b2951.3	Replace Seward / Shelocta 115 kV line CVT, tuner, coax, and line relaying at Blairsville East SS		PENELEC (100%)
b2952	Replace the North Meshoppen #3 230/115 kV transformer eliminating the old reactor and installing two breakers to complete a 230 kV ring bus at North Meshoppen		PENELEC (100%)
b2953	Replace the Keystone 500 kV breaker "NO. 14 Cabot" with 50kA breaker		PENELEC (100%)
b2954	Replace the Keystone 500 kV breaker "NO. 16 Cabot" with 50kA breaker		PENELEC (100%)
b2984	Reconfigure the bus at Glory and install a 50.4 MVAR 115 kV capacitor		PENELEC (100%)
b3007.2	Reconductor the Blairsville East to Social Hall 138 kV line and upgrade terminal equipment - PENELEC portion. 4.8 miles total. The new conductor will be 636 ACSS replacing the existing 636 ACSR conductor. At Blairsville East, the wave trap and breaker disconnects will be replaced		PENELEC (100%)

Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b3008	Upgrade Blairsville East 138/115 kV transformer terminals. This project is an upgrade to the tap of the Seward – Shelocta 115 kV line into Blairsville substation. The project will replace the circuit breaker and adjust relay settings		PENELEC (100%)
b3009	Upgrade Blairsville East 115 kV terminal equipment. Replace 115 kV circuit breaker and disconnects		PENELEC (100%)
b3014	Replace the existing Shelocta 230/115 kV transformer and construct a 230 kV ring bus		PENELEC (100%)
b3016	Upgrade terminal equipment at Corry East 115 kV to increase rating of Four Mile to Corry East 115 kV line. Replace bus conductor		PENELEC (100%)
b3017.1	Rebuild Glade to Warren 230 kV line with hi-temp conductor and substation terminal upgrades. 11.53 miles. New conductor will be 1033 ACSS. Existing conductor is 1033 ACSR		ATSI (61.61%) / PENELEC (38.39%)
b3017.2	Glade substation terminal upgrades. Replace bus conductor, wave traps, and relaying		ATSI (61.61%) / PENELEC (38.39%)
b3017.3	Warren substation terminal upgrades. Replace bus conductor, wave traps, and relaying		ATSI (61.61%) / PENELEC (38.39%)
b3022	Replace Saxton 115 kV breaker ‘BUS TIE’ with a 40kA breaker		PENELEC (100%)

Mid-Atlantic Interstate Transmission, LLC for the Pennsylvania Electric Company Zone (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b3024	Upgrade terminal equipment at Corry East 115 kV to increase rating of Warren to Corry East 115 kV line. Replace bus conductor		PENELEC (100%)
b3043	*Install one 115 kV 36 MVAR capacitor at West Fall 115 kV substation*		*PENELEC (100%)*
b3073	Replace the Blairsville East 138/115 kV transformer and associated equipment such as breaker disconnects and bus conductor		PENELEC (100%)
b3077	Reconductor the Franklin Pike B – Wayne 115 kV line (6.78 miles)		PENELEC (100%)
b3078	Reconductor the 138 kV bus and replace the line trap, relays Morgan Street. Reconductor the 138 kV bus at Venango Junction		PENELEC (100%)
b3082	Construct 4-breaker 115 kV ring bus at Geneva		PENELEC (100%)

Attachment 7e – 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	***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)*

* Neptune Regional Transmission System, 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)

b0490.2	Replace Amos 138 kV breaker 'B'		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)*
b0490.3	Replace Amos 138 kV breaker 'B1'		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)*

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'		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)*
b0490.5	Replace Amos 138 kV breaker 'C1'		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)*

* Neptune Regional Transmission System, 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)
b0490.6	Replace Amos 138 kV breaker 'D'		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)*
b0490.7	Replace Amos 138 kV breaker 'D2'		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)*

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0490.8	Replace Amos 138 kV breaker 'E'		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)*
b0490.9	Replace Amos 138 kV breaker 'E2'		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)*

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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		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *AEP (100%)*
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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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%)

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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%)

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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 (*75.17*%) / APS (1.25%) / BGE (1.81%) / ComEd (*5.92*%) / Dayton (0.86%) / DL (1.23%) / DPL (0.95%) / Dominion (*3.90*%) / JCPL (1.58%) / NEPTUNE (0.15%) / PECO (2.08%) / PEPCO (1.66%) / PSEG (*2.63*%) / 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		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *AEP (100%)*

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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		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *AEP (100%)*
b1465.4	Make switching improvements at Sullivan and Jefferson 765 kV stations		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *AEP (100%)*
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 (*87.29*%) / BGE (1.03%) / ComEd (*3.39*%) / Dayton (1.23%) / DL (1.46%) / DPL (0.54%) / JCPL (0.90%) / NEPTUNE (0.09%) / PECO (1.18%) / PEPCO (0.94%) / 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 (*93.67*%) / ATSI (2.99%) / ComEd (2.07%) / PENELEC (0.31%) / 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		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *AEP (74.91%) / Dayton (11.91%) / DEOK (13.18%)*
b1659.14	Build approximately 14 miles of 765 kV line from existing Dumont - Marysville line		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *AEP (53.47%) / ATSI (17.18%) / Dayton (7.06%) / DL (8.92%) / EKPC (13.37%)*

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1660	Install a 765/500 kV transformer at Cloverdale		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: ATSI (24.65%) / Dayton (8.85%) / *DEOK (*19.91*%) / Dominion (*41.38*%) / EKPC (*5.21*%)*
b1661	Install a 765 kV circuit breaker at Wyoming station		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *AEP (100%)*

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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		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *AEP (100%)*
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		APS (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 (*69.66*%) / ATSI (*23.19*%) / PENELEC (*2.43*%) / PSEG (*4.54*%) / 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		***Load-Ratio Share Allocation:*** AEC (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: *AEP (100%)*
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 (*33.58*%) / ATSI (*32.28*%) / DL (*18.68*%) / Dominion (*6.02*%) / JCPL (1.68%) / Neptune* (0.18%) / PENELEC (*4.59*%) / PSEG (*2.88*%) / 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 (*37.10*%) / AEP (*34.41*%) / DL (*10.43*%) / Dominion (*6.20*%) / APS (*3.95*%) / PENELEC (*3.10*%) / JCPL (1.39%) / Dayton (1.20%) / Neptune* (0.14%) / 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 (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: ATSI (24.65%) / Dayton (8.85%) / DEOK (19.91%) / Dominion (41.38%) / EKPC (5.21%)

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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 (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: ATSI (5.74%) / Dayton (1.97%) / DEOK (4.40%) / Dominion (9.97%) / EKPC (1.12%) / PEPCO (76.80%)
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 (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			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 (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			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%)

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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%)

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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%)

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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%)

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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%)

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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 (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			DFAX Allocation: AEP (100%)

*Neptune Regional Transmission System, 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 (1.61%) / AEP (14.10%) / APS (5.79%) / ATSI (7.95%) / BGE (4.11%) / ComEd (13.24%) / Dayton (2.07%) / DEOK (3.22%) / DL (1.73%) / DPL (2.48%) / Dominion (13.17%) / EKPC (2.13%) / JCPL (3.71%) / ME (1.88%) / NEPTUNE* (0.42%) / PECO (5.34%) / PENELEC (1.86%) / PEPCO (3.98%) / PPL (4.76%) / PSEG (6.19%) / RE (0.26%)
			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%)

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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%)

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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%)

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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%)

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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%)
b2761.3	Rebuild the Hazard – Wooton 161 kV line utilizing 795 26/7 ACSR conductor (300 MVA rating)		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%)

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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%)
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%)
b2787	Reconductor 0.53 miles (14 spans) of the Kaiser Jct. - Air Force Jct. Sw section of the Kaiser - Heath 69 kV circuit/line with 336 ACSR to match the rest of the circuit (73 MVA rating, 78% loading)		AEP (100%)
b2788	Install a new 3-way 69 kV line switch to provide service to AEP's Barnesville distribution station. Remove a portion of the #1 copper T-Line from the 69 kV through-path		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2789	Rebuild the Brues - Glendale Heights 69 kV line section (5 miles) with 795 ACSR (128 MVA rating, 43% loading)		AEP (100%)
b2790	Install a 3 MVAR, 34.5 kV cap bank at Caldwell substation		AEP (100%)
b2791	Rebuild Tiffin – Howard, new transformer at Chatfield		AEP (100%)
b2791.1	Rebuild portions of the East Tiffin - Howard 69 kV line from East Tiffin to West Rockaway Switch (0.8 miles) using 795 ACSR Drake conductor (129 MVA rating, 50% loading)		AEP (100%)
b2791.2	Rebuild Tiffin - Howard 69 kV line from St. Stephen’s Switch to Hinesville (14.7 miles) using 795 ACSR Drake conductor (90 MVA rating, non-conductor limited, 38% loading)		AEP (100%)
b2791.3	New 138/69 kV transformer with 138/69 kV protection at Chatfield		AEP (100%)
b2791.4	New 138/69 kV protection at existing Chatfield transformer		AEP (100%)
b2792	Replace the Elliott transformer with a 130 MVA unit, reconductor 0.42 miles of the Elliott – Ohio University 69 kV line with 556 ACSR to match the rest of the line conductor (102 MVA rating, 73% loading) and rebuild 4 miles of the Clark Street – Strouds R		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2793	Energize the spare Fremont Center 138/69 kV 130 MVA transformer #3. Reduces overloaded facilities to 46% loading		AEP (100%)
b2794	Construct new 138/69/34 kV station and 1-34 kV circuit (designed for 69 kV) from new station to Decliff station, approximately 4 miles, with 556 ACSR conductor (51 MVA rating)		AEP (100%)
b2795	Install a 34.5 kV 4.8 MVAR capacitor bank at Killbuck 34.5 kV station		AEP (100%)
b2796	Rebuild the Malvern - Oneida Switch 69 kV line section with 795 ACSR (1.8 miles, 125 MVA rating, 55% loading)		AEP (100%)
b2797	Rebuild the Ohio Central - Conesville 69 kV line section (11.8 miles) with 795 ACSR conductor (128 MVA rating, 57% loading). Replace the 50 MVA Ohio Central 138/69 kV XFMR with a 90 MVA unit		AEP (100%)
b2798	Install a 14.4 MVAR capacitor bank at West Hicksville station. Replace ground switch/MOAB at West Hicksville with a circuit switcher		AEP (100%)
b2799	Rebuild Valley - Almena, Almena - Hartford, Riverside - South Haven 69 kV lines. New line exit at Valley Station. New transformers at Almena and Hartford		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2799.1	Rebuild 12 miles of Valley – Almena 69 kV line as a double circuit 138/69 kV line using 795 ACSR conductor (360 MVA rating) to introduce a new 138 kV source into the 69 kV load pocket around Almena station		AEP (100%)
b2799.2	Rebuild 3.2 miles of Almena to Hartford 69 kV line using 795 ACSR conductor (90 MVA rating)		AEP (100%)
b2799.3	Rebuild 3.8 miles of Riverside – South Haven 69 kV line using 795 ACSR conductor (90 MVA rating)		AEP (100%)
b2799.4	At Valley station, add new 138 kV line exit with a 3000 A 40 kA breaker for the new 138 kV line to Almena and replace CB D with a 3000 A 40 kA breaker		AEP (100%)
b2799.5	At Almena station, install a 90 MVA 138/69 kV transformer with low side 3000 A 40 kA breaker and establish a new 138 kV line exit towards Valley		AEP (100%)
b2799.6	At Hartford station, install a second 90 MVA 138/69 kV transformer with a circuit switcher and 3000 A 40 kA low side breaker		AEP (100%)

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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%)
b2826.1	Install 300 MVAR reactor at Ohio Central 345 kV substation		AEP (100%)

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2826.2	Install 300 MVAR reactor at West Bellaire 345 kV substation		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%)
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%)
b2872	Replace the South Canton 138 kV breaker ‘K2’ with a 80 kA breaker		AEP (100%)
b2873	Replace the South Canton 138 kV breaker “M” with a 80 kA breaker		AEP (100%)
b2874	Replace the South Canton 138 kV breaker “M2” with a 80 kA breaker		AEP (100%)
b2878	Upgrade the Clifty Creek 345 kV risers		AEP (100%)
b2880	Rebuild approximately 4.77 miles of the Cannonsburg – South Neal 69 kV line section utilizing 795 ACSR conductor (90 MVA rating)		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2881	Rebuild ~1.7 miles of the Dunn Hollow – London 46 kV line section utilizing 795 26/7 ACSR conductor (58 MVA rating, non-conductor limited)		AEP (100%)
b2882	Rebuild Reusens - Peakland Switch 69 kV line. Replace Peakland Switch		AEP (100%)
b2882.1	Rebuild the Reusens - Peakland Switch 69 kV line (approximately 0.8 miles) utilizing 795 ACSR conductor (86 MVA rating, non-conductor limited)		AEP (100%)
b2882.2	Replace existing Peakland S.S with new 3 way switch phase over phase structure		AEP (100%)
b2883	Rebuild the Craneco – Pardee – Three Forks – Skin Fork 46 kV line section (approximately 7.2 miles) utilizing 795 26/7 ACSR conductor (108 MVA rating)		AEP (100%)
b2884	Install a second transformer at Nagel station, comprised of 3 single phase 250 MVA 500/138 kV transformers. Presently, TVA operates their end of the Boone Dam – Holston 138 kV interconnection as normally open preemptively for the loss of the existing Nagel		AEP (100%)
b2885	New delivery point for City of Jackson		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2885.1	Install a new Ironman Switch to serve a new delivery point requested by the City of Jackson for a load increase request		AEP (100%)
b2885.2	Install a new 138/69 kV station (Rhodes) to serve as a third source to the area to help relieve overloads caused by the customer load increase		AEP (100%)
b2885.3	Replace Coalton Switch with a new three breaker ring bus (Heppner)		AEP (100%)
b2886	Install 90 MVA 138/69 kV transformer, new transformer high and low side 3000 A 40 kA CBs, and a 138 kV 40 kA bus tie breaker at West End Fostoria		AEP (100%)
b2887	Add 2-138 kV CB's and relocate 2-138 kV circuit exits to different bays at Morse Road. Eliminate 3 terminal line by terminating Genoa - Morse circuit at Morse Road		AEP (100%)
b2888	Retire Poston substation. Install new Lemaster substation		AEP (100%)
b2888.1	Remove and retire the Poston 138 kV station		AEP (100%)
b2888.2	Install a new greenfield station, Lemaster 138 kV Station, in the clear		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2888.3	Relocate the Trimble 69 kV AEP Ohio radial delivery point to 138 kV, to be served off of the Poston – Strouds Run – Crooksville 138 kV circuit via a new three-way switch. Retire the Poston - Trimble 69 kV line		AEP (100%)
b2889	Expand Cliffview station		AEP (100%)
b2889.1	Cliffview Station: Establish 138 kV bus. Install two 138/69 kV XFRs (130 MVA), six 138 kV CBs (40 kA 3000 A) and four 69 kV CBs (40 kA 3000 A)		AEP (100%)
b2889.2	Byllesby – Wythe 69 kV: Retire all 13.77 miles (1/0 CU) of this circuit (~4 miles currently in national forest)		AEP (100%)
b2889.3	Galax – Wythe 69 kV: Retire 13.53 miles (1/0 CU section) of line from Lee Highway down to Byllesby. This section is currently double circuited with Byllesby – Wythe 69 kV. Terminate the southern 3/0 ACSR section into the newly opened position at Byllesby		AEP (100%)
b2889.4	Cliffview Line: Tap the existing Pipers Gap – Jubal Early 138 kV line section. Construct double circuit in/out (~2 miles) to newly established 138 kV bus, utilizing 795 26/7 ACSR conductor		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2890.1	Rebuild 23.55 miles of the East Cambridge – Smyrna 34.5 kV circuit with 795 ACSR conductor (128 MVA rating) and convert to 69 kV		AEP (100%)
b2890.2	East Cambridge: Install a 2000 A 69 kV 40 kA circuit breaker for the East Cambridge – Smyrna 69 kV circuit		AEP (100%)
b2890.3	Old Washington: Install 69 kV 2000 A two way phase over phase switch		AEP (100%)
b2890.4	Install 69 kV 2000 A two way phase over phase switch		AEP (100%)
b2891	Rebuild the Midland Switch to East Findlay 34.5 kV line (3.31 miles) with 795 ACSR (63 MVA rating) to match other conductor in the area		AEP (100%)
b2892	Install new 138/12 kV transformer with high side circuit switcher at Leon and a new 138 kV line exit towards Ripley. Establish 138 kV at the Ripley station with a new 138/69 kV 130 MVA transformer and move the distribution load to 138 kV service		AEP (100%)
b2936.1	Rebuild approximately 6.7 miles of 69 kV line between Mottville and Pigeon River using 795 ACSR conductor (129 MVA rating). New construction will be designed to 138 kV standards but operated at 69 kV		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)
b2936.2	Pigeon River Station: Replace existing MOAB Sw. 'W' with a new 69 kV 3000 A 40 kA breaker, and upgrade existing relays towards HMD station. Replace CB H with a 3000 A 40 kA breaker		AEP (100%)
b2937	Replace the existing 636 ACSR 138 kV bus at Fletchers Ridge with a larger 954 ACSR conductor		AEP (100%)
b2938	Perform a sag mitigations on the Broadford – Wolf Hills 138 kV circuit to allow the line to operate to a higher maximum temperature		AEP (100%)
b2958.1	Cut George Washington – Tidd 138 kV circuit into Sand Hill and reconfigure Brues & Warton Hill line entrances		AEP (100%)
b2958.2	Add 2 138 kV 3000 A 40 kA breakers, disconnect switches, and update relaying at Sand Hill station		AEP (100%)
b2968	Upgrade existing 345 kV terminal equipment at Tanner Creek station		AEP (100%)
b2969	Replace terminal equipment on Maddox Creek - East Lima 345 kV circuit		AEP (100%)
b2976	Upgrade terminal equipment at Tanners Creek 345 kV station. Upgrade 345 kV bus and risers at Tanners Creek for the Dearborn 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)
b2988	Replace the Twin Branch 345 kV breaker "JM" with 63 kA breaker and associated substation works including switches, bus leads, control cable and new DICM		AEP (100%)
b2993	Rebuild the Torrey – South Gambrinus Switch – Gambrinus Road 69 kV line section (1.3 miles) with 1033 ACSR 'Curlew' conductor and steel poles		AEP (100%)
b3000	Replace South Canton 138 kV breaker 'N' with an 80kA breaker		AEP (100%)
b3001	Replace South Canton 138 kV breaker 'N1' with an 80kA breaker		AEP (100%)
b3002	Replace South Canton 138 kV breaker 'N2' with an 80kA breaker		AEP (100%)
b3036	*Rebuild 15.4 miles of double circuit North Delphos – Rockhill 138 kV line*		*AEP (100%)*
b3037	*Upgrades at the Natrium substation*		*AEP (100%)*
b3038	*Reconductor the Capitol Hill – Coco 138 kV line section*		*AEP (100%)*
b3039	*Line swaps at Muskingum 138 kV station*		*AEP (100%)*
b3040.1	*Rebuild Ravenswood – Racine tap 69 kV line section (~15 miles) to 69 kV standards, utilizing 795 26/7 ACSR conductor*		*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)*

b3040.2	*Rebuild existing Ripley – Ravenswood 69 kV circuit (~9 miles) to 69 kV standards, utilizing 795 26/7 ACSR conductor*		*AEP (100%)*
b3040.3	*Install new 3-way phase over phase switch at Sarah Lane station to replace the retired switch at Cottageville*		*AEP (100%)*
b3040.4	*Install new 138/12 kV 20 MVA transformer at Polymer station to transfer load from Mill Run station to help address overload on the 69 kV network*		*AEP (100%)*
b3040.5	*Retire Mill Run station*		*AEP (100%)*
b3040.6	*Install 28.8 MVAR cap bank at South Buffalo station*		*AEP (100%)*
b3051.2	*Adjust CT tap ratio at Ronceverte 138 kV*		*AEP (100%)*
b3085	Reconductor Kammer – George Washington 138 kV line (approx. 0.08 mile). Replace the wave trap at Kammer 138 kV		AEP (100%)
b3086.1	Rebuild New Liberty – Findlay 34 kV line Str's 1–37 (1.5 miles), utilizing 795 26/7 ACSR conductor		AEP (100%)
b3086.2	Rebuild New Liberty – North Baltimore 34 kV line Str's 1-11 (0.5 mile), utilizing 795 26/7 ACSR conductor		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)
b3086.3	Rebuild West Melrose – Whirlpool 34 kV line Str’s 55–80 (1 mile), utilizing 795 26/7 ACSR conductor		AEP (100%)
b3086.4	North Findlay station: Install a 138 kV 3000A 63kA line breaker and low side 34.5 kV 2000A 40kA breaker, high side 138 kV circuit switcher on T1		AEP (100%)
b3086.5	Ebersole station: Install second 90 MVA 138/69/34 kV transformer. Install two low side (69 kV) 2000A 40kA breakers for T1 and T2		AEP (100%)
b3087.1	Construct a new greenfield station to the west (approx. 1.5 miles) of the existing Fords Branch Station in the new Kentucky Enterprise Industrial Park. This station will consist of six 3000A 40kA 138 kV breakers laid out in a ring arrangement, two 30 MVA 138/34.5 kV transformers, and two 30 MVA 138/12 kV transformers. The existing Fords Branch Station will be retired		AEP (100%)
b3087.2	Construct approximately 5 miles of new double circuit 138 kV line in order to loop the new Kewanee station into the existing Beaver Creek – Cedar Creek 138 kV 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)
b3087.3	Remote end work will be required at Cedar Creek Station		AEP (100%)
b3095	Rebuild Lakin – Racine Tap 69 kV line section (9.2 miles) to 69 kV standards, utilizing 795 26/7 ACSR conductor		AEP (100%)

Attachment 8

PSE&G Formula Rate for January 1, 2020 to December 31, 2020

Public Service Electric and Gas Company

ATTACHMENT H-10A

	Formula Rate -- Appendix A	Notes	FERC Form 1 Page # or Instruction	12 Months Ended 12/31/2020
	Shaded cells are input cells			
	Allocators			
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense	(Note O)	Attachment 5	37,201,805
2	Total Wages Expense	(Note O)	Attachment 5	207,882,635
3	Less A&G Wages Expense	(Note O)	Attachment 5	6,791,797
4	Total Wages Less A&G Wages Expense		(Line 2 - Line 3)	201,090,838
5	**Wages & Salary Allocator**		(Line 1 / Line 4)	**18.5000%**
	Plant Allocation Factors			
6	Electric Plant in Service	(Note B)	Attachment 5	23,861,469,410
7	Common Plant in Service - Electric		(Line 22)	225,788,074
8	Total Plant in Service		(Line 6 + 7)	24,087,257,485
9	Accumulated Depreciation (Total Electric Plant)	(Note B & J)	Attachment 5	4,170,491,387
10	Accumulated Intangible Amortization - Electric	(Note B)	Attachment 5	11,772,005
11	Accumulated Common Plant Depreciation & Amortization - Electric	(Note B & J)	Attachment 5	40,104,641
12	Accumulated Common Amortization - Electric	(Note B)	Attachment 5	63,286,906
13	Total Accumulated Depreciation		(Line 9 + Line 10 + Line 11 + Line 12)	4,285,654,939
14	Net Plant		(Line 8 - Line 13)	19,801,602,546
15	Transmission Gross Plant		(Line 31)	13,555,760,998
16	**Gross Plant Allocator**		(Line 15 / Line 8)	**56.2777%**
17	Transmission Net Plant		(Line 43)	12,261,639,139
18	**Net Plant Allocator**		(Line 17 / Line 14)	**61.9225%**
	Plant Calculations			
	Plant In Service			
19	Transmission Plant In Service	(Note B)	Attachment 5	13,452,583,031
20	General	(Note B)	Attachment 5	334,193,342
21	Intangible - Electric	(Note B)	Attachment 5	18,752,557
22	Common Plant - Electric	(Note B)	Attachment 5	225,788,074
23	Total General, Intangible & Common Plant		(Line 20 + Line 21 + Line 22)	578,733,973
24	Less: General Plant Account 397 -- Communications	(Note B)	Attachment 5	14,291,138
25	Less: Common Plant Account 397 -- Communications	(Note B)	Attachment 5	39,034,243
26	General and Intangible Excluding Acct. 397		(Line 23 - Line 24 - Line 25)	525,408,593
27	Wage & Salary Allocator		(Line 5)	18.5000%
28	General and Intangible Plant Allocated to Transmission		(Line 26 * Line 27)	97,200,590
29	Account No. 397 Directly Assigned to Transmission	(Note B)	Attachment 5	5,977,378
30	Total General and Intangible Functionalized to Transmission		(Line 28 + Line 29)	103,177,967
31	**Total Plant In Rate Base**		(Line 19 + Line 30)	**13,555,760,998**
	Accumulated Depreciation			
32	Transmission Accumulated Depreciation	(Note B & J)	Attachment 5	1,246,778,292
33	Accumulated General Depreciation	(Note B & J)	Attachment 5	137,778,209
34	Accumulated Common Plant Depreciation - Electric	(Note B & J)	Attachment 5	103,069,351
35	Less: Amount of General Depreciation Associated with Acct. 397	(Note B & J)	Attachment 5	24,894,712
36	Balance of Accumulated General Depreciation		(Line 33 + Line 34 - Line 35)	215,952,848
37	Accumulated Intangible Amortization - Electric	(Note B)	(Line 10)	11,772,005
38	Accumulated General and Intangible Depreciation Ex. Acct. 397		(Line 36 + 37)	227,724,853
39	Wage & Salary Allocator		(Line 5)	18.5000%
40	Subtotal General and Intangible Accum. Depreciation Allocated to Transmission		(Line 38 * Line 39)	42,129,098
41	Accumulated General Depreciation Associated with Acct. 397 Directly Assigned to Transmissior	(Note B & J)	Attachment 5	5,214,469
42	**Total Accumulated Depreciation**		(Lines 32 + 40 + 41)	**1,294,121,859**
43	**Total Net Property, Plant & Equipment**		(Line 31 - Line 42)	**12,261,639,139**

Public Service Electric and Gas Company			
ATTACHMENT H-10A			
Formula Rate -- Appendix A	Notes	FERC Form 1 Page # or Instruction	12 Months Ended 12/31/2020
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	-1,952,250,535
Regulatory Assets and Liabilities			
44a Deficient Deferred Taxes Regulatory Asset (Account 182.3)	(Note V)		0
44b Excess Deferred Taxes Regulatory Liability (Account 254)	(Note V)		-700,653,076
44c **Deficient/Excess Deferred Taxes Regulatory Assets and Liabilities Allocated to Transmission**		(Line 44a + 44b)	**-700,653,076**
CWIP for Incentive Transmission Projects			
45 CWIP Balances for Current Rate Year	(Note B & H)	Attachment 6	0
Abandoned Transmission Projects			
45a Unamortized Abandoned Transmission Projects	(Note R)	Attachment 5	0
46 **Plant Held for Future Use**	(Note C & Q)	Attachment 5	24,787,616
Prepayments			
47 Prepayments	(Note A & Q)	Attachment 5	377,686
Materials and Supplies			
48 Undistributed Stores Expense	(Note Q)	Attachment 5	0
49 Wage & Salary Allocator		(Line 5)	18.5000%
50 Total Undistributed Stores Expense Allocated to Transmission		(Line 48 * Line 49)	0
51 Transmission Materials & Supplies	(Note N & Q))	Attachment 5	5,438,864
52 Total Materials & Supplies Allocated to Transmission		(Line 50 + Line 51)	5,438,864
Cash Working Capital			
53 Operation & Maintenance Expense		(Line 80)	136,939,600
54 1/8th Rule		1/8	12.5%
55 Total Cash Working Capital Allocated to Transmission		(Line 53 * Line 54)	17,117,450
Network Credits			
56 Outstanding Network Credits	(Note N & Q))	Attachment 5	0
57 **Total Adjustment to Rate Base**		**(Lines 44 + 44c+ 45 + 45a + 46 + 47 + 52 + 55 - 56)**	**(2,605,181,996)**
58 **Rate Base**		(Line 43 + Line 57)	**9,656,457,143**
Operations & Maintenance Expense			
Transmission O&M			
59 Transmission O&M	(Note O)	Attachment 5	119,900,000
60 Plus Transmission Lease Payments	(Note O)	Attachment 5	0
61 **Transmission O&M**		(Lines 59 + 60)	**119,900,000**
Allocated Administrative & General Expenses			
62 Total A&G	(Note O)	Attachment 5	95,466,338
63 Plus: Actual PBOP expense	(Note J)	Attachment 5	-44,948,588
64 Less: Actual PBOP expense	(Note O)	Attachment 5	-44,948,588
65 Less Property Insurance Account 924	(Note O)	Attachment 5	2,908,029
66 Less Regulatory Commission Exp Account 928	(Note E & O)	Attachment 5	10,698,000
67 Less General Advertising Exp Account 930.1	(Note O)	Attachment 5	2,731,244
68 Less EPRI Dues	(Note D & O)	Attachment 5	0
69 **Administrative & General Expenses**		Sum (Lines 62 to 63) - Sum (Lines 64 to 68)	79,129,065
70 Wage & Salary Allocator		(Line 5)	18.5000%
71 **Administrative & General Expenses Allocated to Transmission**		(Line 69 * Line 70)	**14,638,877**
Directly Assigned A&G			
72 Regulatory Commission Exp Account 928	(Note G & O)	Attachment 5	600,000
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)	600,000
75 Property Insurance Account 924		(Line 65)	2,908,029
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)	2,908,029
78 Net Plant Allocator		(Line 18)	61.9225%
79 **A&G Directly Assigned to Transmission**		(Line 77 * Line 78)	**1,800,723**
80 **Total Transmission O&M**		**(Lines 61 + 71 + 74 + 79)**	**136,939,600**

Public Service Electric and Gas Company

ATTACHMENT H-10A

	Formula Rate -- Appendix A		**Notes**	**FERC Form 1 Page # or Instruction**	**12 Months Ended 12/31/2020**
	Shaded cells are input cells				
	Depreciation & Amortization Expense				
	Depreciation Expense				
81	Transmission Depreciation Expense Including Amortization of Limited Term Plant		(Note J & O)	Attachment 5	314,999,246
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	25,877,721
83	Less: Amount of General Depreciation Expense Associated with Acct. 397		(Note J & O)	Attachment 5	5,322,079
84	Balance of General Depreciation Expense			(Line 82 - Line 83)	20,555,642
85	Intangible Amortization		(Note A & O)	Attachment 5	14,970,855
86	Total			(Line 84 + Line 85)	35,526,497
87	Wage & Salary Allocator			(Line 5)	18.50%
88	General Depreciation & Intangible Amortization Allocated to Transmission			(Line 86 * Line 87)	6,572,402
89	General Depreciation Expense for Acct. 397 Directly Assigned to Transmission		(Note J & O)	Attachment 5	593,444
90	**General Depreciation and Intangible Amortization Functionalized to Transmission**			(Line 88 + Line 89)	**7,165,846**
91	**Total Transmission Depreciation & Amortization**			**(Lines 81 + 81a + 90)**	**322,165,092**
	Taxes Other than Income Taxes				
92	Taxes Other than Income Taxes		(Note O)	Attachment 2	13,745,442
93	**Total Taxes Other than Income Taxes**			(Line 92)	**13,745,442**
	Return \ Capitalization Calculations				
94	**Long Term Interest**			p117.62.c through 67.c	345,679,200
95	**Preferred Dividends**		enter positive	p118.29.d	0
	Common Stock				
96	Proprietary Capital		(Note P)	Attachment 5	10,426,269,000
97	Less Accumulated Other Comprehensive Income Account 219		(Note P)	Attachment 5	-124,929
98	Less Preferred Stock			(Line 106)	0
99	Less Account 216.1		(Note P)	Attachment 5	347,223
100	**Common Stock**			(Line 96 - 97 - 98 - 99)	10,426,046,707
	Capitalization				
101	Long Term Debt		(Note P)	Attachment 5	8,936,676,372
102	Less Loss on Reacquired Debt		(Note P)	Attachment 5	51,694,145
103	Plus Gain on Reacquired Debt		(Note P)	Attachment 5	0
104	Less ADIT associated with Gain or Loss		(Note P)	Attachment 5	11,359,479
105	Total Long Term Debt			(Line 101 - 102 + 103 - 104)	8,873,622,748
106	Preferred Stock		(Note P)	Attachment 5	0
107	Common Stock			(Line 100)	10,426,046,707
108	**Total Capitalization**			(Sum Lines 105 to 107)	19,299,669,455
109	Debt %	Total Long Term Debt		(Line 105 / Line 108)	45.98%
110	Preferred %	Preferred Stock		(Line 106 / Line 108)	0.00%
111	Common %	Common Stock		(Line 107 / Line 108)	54.02%
112	Debt Cost	Total Long Term Debt		(Line 94 / Line 105)	0.0390
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)	0.0179
116	Weighted Cost of Preferred	Preferred Stock		(Line 110 * Line 113)	0.0000
117	Weighted Cost of Common	Common Stock		(Line 111 * Line 114)	0.0631
118	**Rate of Return on Rate Base (ROR)**			(Sum Lines 115 to 117)	**0.0810**
119	**Investment Return = Rate Base * Rate of Return**			**(Line 58 * Line 118)**	**782,257,201**

Public Service Electric and Gas Company

ATTACHMENT H-10A

Formula Rate -- Appendix A

			Notes	FERC Form 1 Page # or Instruction	12 Months Ended 12/31/2020

Shaded cells are input cells

Composite Income Taxes

	Income Tax Rates				
120	FIT=Federal Income Tax Rate		(Note I)		21.00%
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)} =			28.11%
124	T / (1-T)				39.10%
	ITC Adjustment				
125	Amortized Investment Tax Credit	enter negative	(Note O)	Attachment 5	-596,182
126	1/(1-T)			1 / (1 - Line 123)	139.10%
127	Net Plant Allocation Factor			(Line 18)	61.92%
128	**ITC Adjustment Allocated to Transmission**			(Line 125 * Line 126 * Line 127)	**-513,521**
	Deficient/Excess Deferred Taxes Amortization				
128a	Amortized Deficient Deferred Taxes (Account 410.1)		(Note S & V)		0
128b	Amortized Excess Deferred Taxes (Account 411.1)	enter negative	(Note T & V)		-3,054,643
128c	Total			(Line 128a + Line 128b)	-3,054,643
128d	1/(1-T)			1 / (1 - Line 123)	139.10%
128e	**Deficient/Excess Deferred Taxes Allocated to Transmission**			(Line 128c * Line 128d)	**-4,249,051**
	AFUDC Equity Permanent Difference				
128f	Tax Effect of AFUDC Equity Permanent Difference		(Note U)		1,671,969
128g	1/(1-T)			1 / (1 - Line 123)	139.10%
128h	**AFUDC Equity Permanent Difference Tax Adjustment**			(Line 128f * Line 128g)	**2,325,732**
129	**Income Tax Component =**	(T/1-T) * Investment Return * (1-(WCLTD/ROR)) =		[Line 124 * Line 119 * (1- (Line 115 / Line 118))]	**238,244,464**
130	**Total Income Taxes**			**(Lines 128 + 128e + 128h + 129)**	**235,807,623**

Revenue Requirement

	Summary				
131	Net Property, Plant & Equipment			(Line 43)	12,261,639,139
132	Total Adjustment to Rate Base			(Line 57)	-2,605,181,996
133	**Rate Base**			(Line 58)	**9,656,457,143**
134	Total Transmission O&M			(Line 80)	136,939,600
135	Total Transmission Depreciation & Amortization			(Line 91)	322,165,092
136	Taxes Other than Income			(Line 93)	13,745,442
137	Investment Return			(Line 119)	782,257,201
138	Income Taxes			(Line 130)	235,807,623
139	**Gross Revenue Requirement**			**(Sum Lines 134 to 138)**	**1,490,914,959**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
140	Transmission Plant In Service			(Line 19)	13,452,583,031
141	Excluded Transmission Facilities		(Note B & M)	Attachment 5	0
142	Included Transmission Facilities			(Line 140 - Line 141)	13,452,583,031
143	Inclusion Ratio			(Line 142 / Line 140)	100.00%
144	Gross Revenue Requirement			(Line 139)	1,490,914,959
145	**Adjusted Gross Revenue Requirement**			(Line 143 * Line 144)	**1,490,914,959**
	Revenue Credits & Interest on Network Credits				
146	**Revenue Credits**		(Note O)	Attachment 3	25,142,484
147	**Interest on Network Credits**		(Note N & O)	Attachment 5	0
148	**Net Revenue Requirement**			**(Line 145 - Line 146 + Line 147)**	**1,465,772,474**
	Net Plant Carrying Charge				
149	Gross Revenue Requirement			(Line 144)	**1,490,914,959**
150	Net Transmission Plant, CWIP and Abandoned Plant			(Line 19 - Line 32 + Line 45 + Line 45a)	**12,205,804,738**
151	Net Plant Carrying Charge			(Line 149 / Line 150)	**12.2148%**
152	Net Plant Carrying Charge without Depreciation			(Line 149 - Line 81) / Line 150	**9.6341%**
153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes			(Line 149 - Line 81 - Line 119 - Line 130) / Line 150	**1.2932%**
	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)	**472,850,134**
155	Increased Return and Taxes			Attachment 4	**1,090,628,476**
156	Net Revenue Requirement per 100 Basis Point increase in ROE			(Line 154 + Line 155)	**1,563,478,610**
157	Net Transmission Plant, CWIP and Abandoned Plant			(Line 19 - Line 32 + Line 45 + Line 45a)	**12,205,804,738**
158	Net Plant Carrying Charge per 100 Basis Point increase in ROE			(Line 156 / Line 157)	**12.8093%**
159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation			(Line 156 - Line 81) / Line 157	**10.2286%**
160	**Net Revenue Requirement**			(Line 148)	**1,465,772,474**
161	True-up amount			Attachment 6	**54,284,878**
162	Plus any increased ROE calculated on Attachment 7 other than PJM Sch. 12 projects not paid by other PJM transmission zon			Attachment 7	**6,240,455**
163	Facility Credits under Section 30.9 of the PJM OATT			Attachment 5	**0**
164	**Net Zonal Revenue Requirement**			(Line 160 + 161 + 162 + 163)	**1,526,297,808**

Public Service Electric and Gas Company ATTACHMENT H-10A Formula Rate -- Appendix A		Notes	FERC Form 1 Page # or Instruction	12 Months Ended 12/31/2020
Shaded cells are input cells				
	Network Zonal Service Rate			
165	1 CP Peak	(Note L)	Attachment 5	**9,752.5**
166	Rate ($/MW-Year)		(Line 164 / 165)	**156,503.24**
167	**Network Service Rate ($/MW/Year)**		**(Line 166)**	**156,503.24**

Public Service Electric and Gas Company

ATTACHMENT H-10A

Formula Rate -- Appendix A	**Notes**	**FERC Form 1 Page # or Instruction**	**12 Months Ended 12/31/2020**

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

R Unamortized Abandoned Plant and Amortization of Abandoned Plant may only be included pursuant to a Commission Order authorizing such inclusion

S Includes the amortization of any deficient deferred income taxes resulting from changes to income tax laws, income tax rates (including changes in apportionment) and other actions taken by a taxing authority.

Deficient deferred income taxes will increase tax expense by the amount of the deficiency multiplied by (1/1-T) (Line 128e).

T Includes the amortization of any excess deferred income taxes resulting from changes to income tax laws, income tax rates (including changes in apportionment) and other actions taken by a taxing authority.

Excess deferred income taxes will decrease tax expense by the amount of the excess multiplied by (1/1-T) (Line 128e).

U Includes the annual income tax cost or benefits due to the AFUDC Equity permanent difference. (1/1-T) multiplied by the amount of AFUDC Equity permanent difference included in Line 128f and will increase or decrease tax expense by the amount of the expense or benefit included on Line 128f multiplied by (1/1-T) (Line 128h).

V Unamortized Excess/Deficient Deferred Tax Regulatory Liabilities/Assets and the Amortization of those Regulatory Liabilities/Assets arising from future tax changes may only be included pursuant to Commission approval authorizing such inclusion.

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31,2020

	Only Transmission Related	Plant Related	Labor Related	Total ADIT	
ADIT- 282 (Not Subject to Proration)	(643,692,362)	0	(4,977,254)		From Acct. 282 (Not Subject to Proration) total, below
ADIT-283	0	(7,434,037)	0		From Acct. 283 total, below
ADIT-190	0	0	2,421,243		From Acct. 190 total, below
Subtotal	(643,692,362)	(7,434,037)	(2,556,011)		
Wages & Salary Allocator			18.5000%		
Net Plant Allocator		61.9225%			
End of Year ADIT	(643,692,362)	(4,603,338)	(472,862)	**(648,768,563)**	
End of Previous Year ADIT (from Sheet 1A-ADIT)	(589,527,551)	(4,878,080)	(327,522)	**(594,733,153)**	
Average Beginning and End of Year ADIT	(616,609,957)	(4,740,709)	(400,192)	**(621,750,858)**	
ADIT- 282 (Subject to Proration)	(1,327,246,612)	0	(3,253,066)	**(1,330,499,678)**	From Acct. 282 (Subject to Proration) total, below
Total Accumulated Deferred Income Taxes				**(1,952,250,535)**	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
(7,434,037) < From Acct 283, below

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

A	B	C	D	E	F	G
ADIT-190	*Total*	*Gas, Prod Or Other Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
ADIT - Contribution In Aid of Constructior	20,742,133	20,742,133	0	0	0	Represents the estimated IRC 118 amount (CIAC
Vacation Pay	38,850	0	0	0	38,850	Vacation pay earned and expensed for books, tax deduction when paid - employees in all function
OPEB	128,773,864	0	0	0	128,773,864	FASB 106 - Post Retirement Obligation, labor related
Deferred Dividend Equivalents	2,125,749	0	0	0	2,125,749	Book accrual of dividends on employee stock options affecting all function:
Deferred Compensation	256,644	0	0	0	256,644	Book estimate accrued and expensed, tax deduction when paid - employees in all function
Bankruptcies $ Acfc	167,577	167,577	0	0	0	Book estimate accrued and expensed, tax deduction when paid - Generation Relate
Federal Taxes Deferrec	22,269,117	0	0	22,269,117	0	FASB 109 - deferred tax asset primarily associated with items previously flowed through due to regulatio
Miscellaneous	25,000,058	25,000,058	0	0	0	Various
Subtotal - p234	**199,373,992**	**45,909,768**	**0**	**22,269,117**	**131,195,107**	
Less FASB 109 Above if not separately removed	22,269,117			22,269,117		
Less FASB 106 Above if not separately removed	128,773,864				128,773,864	
Total	**48,331,011**	**45,909,768**	**0**	**0**	**2,421,243**	

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 31,2020

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

A	B	C	D	E	F	G
ADIT- 282 (Not Subject to Proration)	*Total*	*Gas, Prod Or Other Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
Depreciation - Liberalized Depreciation (Federal)	(309,275,996)	0	(309,275,996)	0	0	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 ADI
Depreciation - Liberalized Depreciation (State)	(425,809,244)	(86,415,624)	(334,416,366)	0	(4,977,254)	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 ADI
Accounting for Income Taxes	(324,980,204)	(267,274,356)	(57,600,663)	0	(105,185)	FASB 109 - deferred tax liability primarily associated with plant related items previously flowed through due to regulatio
Subtotal - ADIT- 282 (Not Subject to Proration)	**(1,060,065,444)**	**(353,689,980)**	**(701,293,025)**	**0**	**(5,082,439)**	
Less FASB 109 Above if not separately removed	(324,980,204)	(267,274,356)	(57,600,663)	0	(105,185)	
Less FASB 106 Above if not separately removed						
Total ADIT- 282 (Not Subject to Proration)	**(735,085,240)**	**(86,415,624)**	**(643,692,362)**	**0**	**(4,977,254)**	

A	B	C	D	E	F	G
ADIT- 282 (Subject to Proration)	*Total*	*Gas, Prod Or Other Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
Depreciation - Liberalized Depreciation (Federal)	(2,713,961,903)	(1,369,131,152)	(1,327,246,612)	0	(17,584,139)	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 ADI
Subtotal - ADIT- 282 (Subject to Proration)	**(2,713,961,903)**	**(1,369,131,152)**	**(1,327,246,612)**	**0**	**(17,584,139)**	
Less FASB 109 Above if not separately removed						
Less FASB 106 Above if not separately removed						
Total ADIT- 282 (Subject to Proration)	**(2,713,961,903)**	**(1,369,131,152)**	**(1,327,246,612)**	**0**	**(17,584,139)**	

Instructions for Account 282:

1. ADIT items subject to the IRS's proration methodology shall be included in the ADIT- 282 (Subject to Proration) section in order to avoid the two-step averaging of prorated ADIT balances

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

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

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

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

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

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31,2020

A	B	C	D	E	F	G
ADIT- 283	*Total*	*Gas, Prod Or Other Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
New Jersey Corporation Business Tax	(45,055,088)	(45,055,088)	0	0	0	New Jersey Corporate Income Tax - Plant Related- Contra Account of 190 NJCBT
Accelerated Activity Plan	(171,534,069)	(171,534,069)	0	0	0	Demand Side management and Associated Programs - Retail Related
Loss on Reacquired Debt	(7,434,037)	0	0	(7,434,037)	0	Tax deduction when reacquired, booked amortizes to expense
Additional Pension Deduction	(124,271,942)	(124,271,942)	0	0	0	Associated with Pension Liability not in rates
Miscellaneous	(44,009,793)	(44,009,793)	0	0	0	Miscellaneous Tax Adjustments.
Deferred Gain	(18,924,277)	(18,924,277)	0	0	0	Deferred gain resulted from 2000 deregulation step up basis
Accounting for Income Taxes (FAS109) - Federal	(249,118,627)	0	0	(249,118,627)	0	FASB 109 - deferred tax liability primarily non-plant related items previously flowed through due to regulation
Subtotal - p277	**(660,347,833)**	**(403,795,169)**	**0**	**(256,552,664)**	**0**	
Less FASB 109 Above if not separately removed	(249,118,627)			(249,118,627)		
Less FASB 106 Above if not separately removed						
Total	**(411,229,206)**	**(403,795,169)**	**0**	**(7,434,037)**	**0**	

Instructions for Account 283:

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

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

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

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

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

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 1A - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31, 2019

	Only Transmission Related	Plant Related	Labor Related	Total ADIT	
ADIT- 282 (Not Subject to Proration)	(589,527,551)	0	(4,258,644)		From Acct. 282 (Not Subject to Proration) total, below
ADIT-283	0	(7,877,723)	0		From Acct. 283 total, below
ADIT-190	0	0	2,488,255		From Acct. 190 total, below
Subtotal	(589,527,551)	(7,877,723)	(1,770,389)		
Wages & Salary Allocator			18.5000%		
Net Plant Allocator		61.9225%			
End of Year ADIT	(589,527,551)	(4,878,080)	(327,522)	**(594,733,153)**	

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
(7,877,723) < From Acct 283, below

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

A	B	C	D	E	F	G
ADIT-190	*Total*	*Gas, Prod Or Other Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
ADIT - Contribution In Aid of Construction	23,056,800	23,056,800	0	0	0	Represents the estimated IRC 118 amount (CIAC
Vacation Pay	66,921	0	0	0	66,921	Vacation pay earned and expensed for books, tax deduction when paid - employees in all function
OPEB	154,249,940	0	0	0	154,249,940	FASB 106 - Post Retirement Obligation, labor related
Deferred Compensation	2,421,334	0	0	0	2,421,334	Book estimate accrued and expensed, tax deduction when paid - employees in all function
Bankruptcies $ Acfc	215,044	215,044	0	0	0	Book estimate accrued and expensed, tax deduction when paid - Generation Relate
Federal Taxes Deferred	22,269,117	0	0	22,269,117	0	FASB 109 - deferred tax asset primarily associated with items previously flowed through due to regulatio
Miscellaneous	13,347,872	13,347,872	0	0	0	Various
Subtotal - p234	**215,627,028**	**36,619,716**	**0**	**22,269,117**	**156,738,195**	
Less FASB 109 Above if not separately removed	22,269,117			22,269,117		
Less FASB 106 Above if not separately removed	154,249,940				154,249,940	
Total	**39,107,971**	**36,619,716**	**0**	**0**	**2,488,255**	

Instructions for Account 190:

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

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

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

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

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

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 1A - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31, 2019

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

A	B	C	D	E	F	G
ADIT- 282 (Not Subject to Proration)	Total	Gas, Prod Or Other Related	Only Transmission Related	Plant Related	Labor Related	Justification
Depreciation - Liberalized Depreciation (Federal)	(278,636,096)	0	(278,636,096)	0	0	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)	(401,565,723)	(86,415,624)	(310,891,455)	0	(4,258,644)	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	(324,980,204)	(267,274,356)	(57,600,663)	0	(105,185)	FASB 109 - deferred tax liability primarily associated with plant related items previously flowed through due to regulation
Subtotal - ADIT- 282 (Not Subject to Proration)	**(1,005,182,023)**	**(353,689,980)**	**(647,128,214)**	**0**	**(4,363,829)**	
Less FASB 109 Above if not separately removed	(324,980,204)	(267,274,356)	(57,600,663)	0	(105,185)	
Less FASB 106 Above if not separately removed						
Total ADIT- 282 (Not Subject to Proration)	**(680,201,819)**	**(86,415,624)**	**(589,527,551)**	**0**	**(4,258,644)**	

A	B	C	D	E	F	G
ADIT- 282 (Subject to Proration)	Total	Gas, Prod Or Other Related	Only Transmission Related	Plant Related	Labor Related	Justification
Depreciation - Liberalized Depreciation (Federal)	(2,629,727,733)	(1,369,131,152)	(1,247,846,528)	0	(12,750,053)	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
Subtotal - ADIT- 282 (Subject to Proration)	**(2,629,727,733)**	**(1,369,131,152)**	**(1,247,846,528)**	**0**	**(12,750,053)**	
Less FASB 109 Above if not separately removed						
Less FASB 106 Above if not separately removed						
Total ADIT- 282 (Subject to Proration)	**(2,629,727,733)**	**(1,369,131,152)**	**(1,247,846,528)**	**0**	**(12,750,053)**	

Instructions for Account 282:

1. ADIT items subject to the IRS's proration methodology shall be included in the ADIT- 282 (Subject to Proration) section in order to avoid the two-step averaging of prorated ADIT balances

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

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

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

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

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

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 1A - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31, 2019

A	B	C	D	E	F	G
ADIT- 283	*Total*	*Gas, Prod Or Other Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
New Jersey Corporation Business Tax	(35,025,805)	(35,025,805)	0	0	0	New Jersey Corporate Income Tax - Plant Related- Contra Account of 190 NJCBT
Accelerated Activity Plan	(164,616,016)	(164,616,016)	0	0	0	Demand Side management and Associated Programs - Retail Related
Loss on Reacquired Debt	(7,877,723)	0	0	(7,877,723)	0	Tax deduction when reacquired, booked amortizes to expense
Additional Pension Deduction	(135,633,374)	(135,633,374)	0	0	0	Associated with Pension Liability not in rates
Miscellaneous	(41,921,377)	(41,921,377)	0	0	0	Miscellaneous Tax Adjustments.
Deferred Gain	(20,035,617)	(20,035,617)	0	0	0	Deferred gain resulted from 2000 deregulation step up basis
Accounting for Income Taxes (FAS109) - Federal	(245,415,123)	0	0	(245,415,123)	0	FASB 109 - deferred tax liability primarily non-plant related items previously flowed through due to regulation
Subtotal - p277	**(650,525,035)**	**(397,232,189)**	**0**	**(253,292,846)**	**0**	
Less FASB 109 Above if not separately removed	(245,415,123)			(245,415,123)		
Less FASB 106 Above if not separately removed						
Total	**(405,109,912)**	**(397,232,189)**	**0**	**(7,877,723)**	**0**	

Instructions for Account 283:

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

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

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

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

5. Deferred income taxes arise when items are included in taxable income in different periods than 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, 2020

	Other Taxes	Page 263 Col (i)	Allocator	Allocated Amount	
	Plant Related				
1	Real Estate	24,262,000			Attachment #5
2	***Total Plant Related***	24,262,000	N/A	10,788,000	
	Labor Related		***Wages & Salary Allocator***		
3	FICA	14,967,550			
4	Federal Unemployment Tax	83,153			
5	New Jersey Unemployment Tax	623,648			
6	New Jersey Workforce Development	311,824			
7					
8	***Total Labor Related***	15,986,175	18.5000%	2,957,442	
	Other Included		***Net Plant Allocator***		
9		0			
10		0			
11		0			
12		0			
13	***Total Other Included***	0	61.9225%	0	
14	***Total Included (Lines 8 + 14 + 19)***	40,248,175		13,745,442	
	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)**	40,248,175			
24	**Total Other Taxes from p114.14.g - Actual**	40,248,175			
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, 2020

	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)		700,000
	Account 456 - Other Electric Revenues		
3	Transmission for Others		0
4	Schedule 1A		5,225,000
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		10,200,000
7	Professional Services (Note 2)		20,000
8	Revenues from Directly Assigned Transmission Facility Charges (Note 1)		7,811,551
9	Rent or Attachment Fees associated with Transmission Facilities (Note 2)		4,582,359
10	Gross Revenue Credits	(Sum Lines 1-9)	28,538,910
11	Less line 18	- line 18	(3,396,426)
12	Total Revenue Credits	line 10 + line 11	25,142,484
13	Revenues associated with lines 2, 7, and 9 (Note 2)		5,302,359
14	Income Taxes associated with revenues in line 13		1,490,493
15	One half margin (line 13 - line 14)/2		1,905,933
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		1,905,933
18	Line 13 less line 17		3,396,426

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 47 from below	1,090,628,476
B	100 Basis Point increase in ROE			1.00%
Return Calculation				
			Appendix A Line or Source Reference	
1	**Rate Base**		(Line 43 + Line 57)	9,656,457,143
2	**Long Term Interest**		p117.62.c through 67.c	345,679,200
3	**Preferred Dividends**	enter positive	p118.29.d	0
	Common Stock			
4	Proprietary Capital		Attachment 5	10,426,269,000
5	Less Accumulated Other Comprehensive Income Account 219		p112.15.c	-124,929
6	Less Preferred Stock		(Line 106)	0
7	Less Account 216.1		Attachment 5	347,223
8	Common Stock		(Line 96 - 97 - 98 - 99)	10,426,046,707
	Capitalization			
9	Long Term Debt		Attachment 5	8,936,676,372
10	Less Loss on Reacquired Debt		Attachment 5	51,694,145
11	Plus Gain on Reacquired Debt		Attachment 5	0
12	Less ADIT associated with Gain or Loss		Attachment 5	11,359,479
13	Total Long Term Debt		(Line 101 - 102 + 103 - 104)	8,873,622,748
14	Preferred Stock		Attachment 5	0
15	Common Stock		(Line 100)	10,426,046,707
16	Total Capitalization		(Sum Lines 105 to 107)	19,299,669,455
17	Debt %	Total Long Term Debt	(Line 105 / Line 108)	46.0%
18	Preferred %	Preferred Stock	(Line 106 / Line 108)	0.0%
19	Common %	Common Stock	(Line 107 / Line 108)	54.0%
20	Debt Cost	Total Long Term Debt	(Line 94 / Line 105)	0.0390
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)	0.0179
24	Weighted Cost of Preferred	Preferred Stock	(Line 110 * Line 113)	0.0000
25	Weighted Cost of Common	Common Stock	(Line 111 * Line 114)	0.0685
26	**Rate of Return on Rate Base (ROR)**		**(Sum Lines 115 to 117)**	**0.0864**
27	**Investment Return = Rate Base * Rate of Return**		**(Line 58 * Line 118)**	**834,423,210**
Composite Income Taxes				
	Income Tax Rates			
28	FIT=Federal Income Tax Rate			21.00%
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)} =		28.11%
32	CIT = T / (1-T)			39.10%
33	1 / (1-T)			139.10%
	ITC Adjustment			
34	Amortized Investment Tax Credit	enter negative	Attachment 5	-596,182
35	1/(1-T)		1 / (1 - Line 123)	139.10%
36	Net Plant Allocation Factor		(Line 18)	61.9225%
37	**ITC Adjustment Allocated to Transmission**		(Line 125 * Line 126 * Line 127)	**-513,521**
	Deficient/Excess Deferred Taxes Amortization			
38	Amortized Deficient Deferred Taxes (Account 410.1)		(Line 128a)	0
39	Amortized Excess Deferred Taxes (Account 411.1)	enter negative	(Line 128b)	-3,054,643
40	Total		(Line 128a + Line 128b)	-3,054,643
41	1/(1-T)		1 / (1 - Line 123)	139.10%
42	**Deficient/Excess Deferred Taxes Allocated to Transmission**		(Line 128c * Line 128d)	**-4,249,051**
	AFUDC Equity Permanent Difference			
43	Tax Effect of AFUDC Equity Permanent Difference		(Line 128f)	1,671,969
44	1/(1-T)		1 / (1 - Line 123)	139.10%
45	**AFUDC Equity Permanent Difference Tax Adjustment**		(Line 128f * Line 128g)	**2,325,732**
46	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		258,642,106
47	**Total Income Taxes**			**256,205,266**

Public Service Electric and Gas Company

ATTACHMENT H-10A

Attachment 5 - Cost Support - December 31, 2020

Electric / Non-electric Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Previous Year Form 1Dec	Current Year - 2020 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	23,224,073,068	23,265,319,520	23,330,323,758	23,568,991,585	23,616,011,698	23,803,665,292	23,946,300,183	23,971,999,817	24,005,174,590	24,047,606,773	24,207,165,500	24,320,039,658	24,892,430,891	23,861,469,410	
7	Common Plant in Service - Electric	(Note B)	p356	218,915,360	219,257,709	219,463,980	221,470,492	227,392,755	227,236,523	227,912,550	228,433,677	227,603,765	229,019,127	229,570,472	230,576,865	228,391,692	225,788,074	
9	Accumulated Depreciation (Total Electric Plant)	(Note B & J)	p219.29c	3,961,786,245	3,993,119,585	4,028,695,067	4,063,265,563	4,098,344,807	4,132,976,100	4,170,335,383	4,206,132,953	4,241,789,439	4,277,089,328	4,312,371,039	4,348,498,741	4,381,983,775	4,170,491,387	
10	Accumulated Intangible Amortization	(Note B)	p200.21c	10,382,053	10,628,338	10,874,624	11,120,909	11,367,194	11,613,480	11,704,422	11,948,161	12,191,900	12,435,638	12,679,377	12,923,116	13,166,855	11,772,005	
11	Accumulated Common Plant Depreciation - Electric	(Note B & J)	p356	36,586,455	37,209,528	38,068,785	38,538,336	39,375,182	39,783,526	39,653,894	40,278,725	41,209,736	41,832,713	42,125,543	42,893,861	43,804,052	40,104,641	
12	Accumulated Common Amortization - Electric	(Note B)	p356	58,203,458	59,134,650	60,066,070	60,997,720	62,024,382	63,051,503	64,081,282	65,119,081	64,454,282	65,476,665	65,676,724	66,702,724	67,741,236	63,286,906	
	Plant In Service																	
19	Transmission Plant in Service (Excludes Asset Retirement Costs - ARC)	(Note B)	p207.58.g	12,995,721,185	13,019,489,518	13,054,159,851	13,250,208,184	13,264,180,517	13,411,380,850	13,529,499,183	13,530,743,516	13,540,479,849	13,556,739,182	13,692,668,515	13,780,194,848	14,258,114,202	13,452,583,031	
20	General (Excludes Asset Retirement Costs - ARC)	(Note B)	p207.99.g	334,349,318	331,321,895	332,374,336	333,577,056	334,524,740	333,275,101	334,256,730	334,272,308	333,806,955	334,452,123	334,822,794	336,338,193	337,141,896	334,193,342	
21	Intangible - Electric	(Note B)	p205.5.g	18,834,832	18,834,832	18,834,832	18,834,832	18,834,832	18,834,832	18,682,035	18,682,035	18,682,035	18,682,035	18,682,035	18,682,035	18,682,035	18,752,557	
22	Common Plant in Service - Electric	(Note B)	p356	218,915,360	219,257,709	219,463,980	221,470,492	227,392,755	227,236,523	227,912,550	228,433,677	227,603,765	229,019,127	229,570,472	230,576,865	228,391,692	225,788,074	
24	General Plant Account 397 -- Communications	(Note B)	p207.94g	15,574,732	14,643,879	14,423,310	14,284,694	14,284,694	14,096,640	14,068,120	14,068,120	14,068,120	14,068,120	14,068,120	14,068,120	14,068,120	14,291,138	
25	Common Plant Account 397 -- Communications	(Note B)	p356	39,005,755	39,005,755	39,005,755	39,005,755	38,987,235	38,987,235	38,987,235	38,987,235	38,987,235	38,987,235	39,108,785	39,194,970	39,194,970	39,034,243	
29	Account No. 397 Directly Assigned to Transmission	(Note B)	Company Records	6,492,574	6,377,515	6,156,946	6,018,330	6,018,330	5,830,277	5,830,277	5,830,277	5,830,277	5,830,277	5,830,277	5,830,277	5,830,277	5,977,378	
	Accumulated Depreciation																	
32	Transmission Accumulated Depreciation	(Note B & J)	p219.25.c	1,119,587,631	1,140,081,292	1,160,638,293	1,181,800,392	1,202,834,435	1,224,419,878	1,246,291,558	1,268,129,727	1,290,147,369	1,311,016,529	1,332,565,548	1,354,053,620	1,376,551,530	1,246,778,292	
33	Accumulated General Depreciation	(Note B & J)	p219.28.b	140,859,044	137,332,644	137,892,959	138,611,139	139,082,573	137,347,209	137,846,242	137,378,751	136,421,324	136,574,939	136,455,846	137,490,884	137,823,166	137,778,209	
34	Accumulated Common Plant Depreciation & Amortization - Electric	(Note B & J)	p356	94,789,913	96,344,178	98,134,855	99,536,056	101,399,564	102,835,028	103,735,176	105,397,806	105,664,018	107,309,378	107,802,267	109,596,585	107,356,735	103,069,351	
35	Accumulated General Depreciation Associated with Acct. 397	(Note B & J)	Company Records	23,527,617	23,043,844	23,268,518	23,573,989	23,999,402	24,253,714	24,667,322	25,109,450	25,551,578	25,993,706	26,436,847	26,880,706	27,324,565	24,894,712	
41	Acc. Deprec. Acct. 397 Directly Assigned to Transmission	(Note B & J)	Company Records	5,429,348	5,367,435	5,198,174	5,109,711	5,159,863	5,020,395	5,068,981	5,117,567	5,166,152	5,214,738	5,263,323	5,311,909	5,360,495	5,214,469	

Wages & Salary

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
2	Total Wage Expense	(Note A)	p354.28b	207,882,635
3	Total A&G Wages Expense	(Note A)	p354.27b	6,791,797
1	Transmission Wages		p354.21b	37,201,805

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	25,282,793	25,282,793	25,282,793
46	Transmission Only			24,787,616	24,787,616	24,787,616

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	10,176,785	2,041,544	2,041,544	2,041,544	18.500%	377,686

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	5,233,800	5,643,927	5,438,864

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	119,900,000
60	Transmission Lease Payments		p321.96.b	0

Property Insurance Expenses

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
65	Property Insurance Account 924	(Note O)	p323.185b	2,908,029

Adjustments to A & G Expense

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
62	Total A&G Expenses		p323.197b	95,466,338
				0
63	Actual PBOP expense	(Note J)	Company Records	(44,948,588)
64	Actual PBOP expense	(Note O)	Company Records	(44,948,588)

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	10,698,000	-
	Directly Assigned A&G				
72	Regulatory Commission Exp Account 928	(Note G & O)	p351.11-13h	600,000	600,000

General & Common Expenses

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

Safety Related Advertising Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year	Safety Related	Non-safety Related
	Directly Assigned A&G					
73	General Advertising Exp Account 930.1	(Note K & O)	p323.191b	2,731,244	0	2,731,244

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	2,731,244	0	2,731,244

Depreciation Expense

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
	Depreciation Expense			
81	Depreciation-Transmission	(Note J & O)	p336.7.f	314,999,246
82	Depreciation-General & Common	(Note J & O)	p336.10&11.f	25,877,721
83	Depreciation-General Expense Associated with Acct. 397	(Note J & O)	Company Records	5,322,079
85	Depreciation-Intangible	(Note A & O)	p336.1.f	14,970,855
89	Transmission Depreciation Expense for Acct. 397	(Note J & O)	Company Records	593,444

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	24,262,000	10,788,000	13,474,000

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.

Return \ Capitalization

Line #s	Descriptions	Notes	Page #'s & Instructions	2017 End of Year	2018 End of Year	Average
96	Proprietary Capital	(Note P)	p112.16.c,d	9,903,935,472	10,948,602,528	10,426,269,000
97	Accumulated Other Comprehensive Income Account 219	(Note P)	p112.15.c,d	499,494	(749,352)	-124,929
99	Account 216.1	(Note P)	p119.53.c&d	422,555	271,890	347,223
101	Long Term Debt	(Note P)	p112.18.c,d thru 23.c,d	8,637,804,639	9,235,548,104	8,936,676,372
102	Loss on Reacquired Debt	(Note P)	p111.81.c,d	54,827,487	48,560,802	51,694,145
103	Gain on Reacquired Debt	(Note P)	p113.61.c,d	0	0	0
104	ADIT associated with Gain or Loss on Reacquired Debt	(Note P)	p277.3.k (footnote)	11,868,557	10,850,401	11,359,479
106	Preferred Stock	(Note P)	p112.3.c,d	0	0	0

MultiState Workpaper

Line #s	Descriptions	Notes	Page #'s & Instructions	State 1	State 2	State 3
	Income Tax Rates					
				NJ		
121	SIT=State Income Tax Rate or Composite	(Note I)		9.00%		

Amortized Investment Tax Credit

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
125	Amortized Investment Tax Credit	(Note O)	p266.8.f	596,182

Excluded Transmission Facilities

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

Interest on Outstanding Network Credits Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
147	Interest on Network Credits	(Note N & O)		0

Facility Credits under Section 30.9 of the PJM OATT

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
	Revenue Requirement			
163	Facility Credits under Section 30.9 of the PJM OATT			0

PJM Load Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	1 CP Peak
	Network Zonal Service Rate			
165	1 CP Peak	(Note L)	PJM Data	9,752.5

Abandoned Transmission Projects

Line #s		Descriptions		BRH Project	Project X	Project Y
	a	Beginning Balance of Unamortized Transmission Projects	Per FERC Order	$ -	$ -	$ -
Attachment 7	b	Years remaining in Amortization Period	Per FERC Order	$ -	$ -	$ -
81	c	Transmission Depreciation Expense Including Amortization of Limited Term Plant	(line a / line b)	$ -	$ -	$ -
	d	Ending Balance of Unamortized Transmission Projects	(line a - line c)	$ -	$ -	$ -
	e	Average Balance of Unamortized Abandoned Transmission Projects	(line a + d)/2	$ -	$ -	$ -
	g	Non Incentive Return and Income Taxes	(Appendix A line 137+ line 138)	$ -	$ -	$ -
	h	Rate Base	(Appendix A line 58)	$ -	$ -	$ -
Attachment 7	i	Non Incentive Return and Income Taxes	(line g / line h)	-	-	-
		Docket No. ER12-2274-000 authorizing $3,500,000 amortization over one-year recovery of BRH Abandoned Transmission Project		ER12-2274		

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6 - True-up Adjustment for Network Integration Transmission Service - December 31, 2020

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

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

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

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

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

Where: i = Sum of (the monthly rates for the 10 months ending October 31 of the current year and the monthly rates for the 12 months ending December 31 of the preceding year) divided by 21 months.

Summary of Formula Rate Process including True-Up Adjustment

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

1 No True-Up Adjustment will be included in the Annual Transmission Revenue Requirement for 2008 or 2009 since 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	1,300,562,584	
B	ATRR based on projected costs included for the previous calendar year but excludes the true	1,248,819,352	
C	Difference (A-B)	51,743,232	<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	1.04912	
E	True-up Adjustment (C*D)	54,284,878	

Where:
i = average interest rate as calculated below

Interest on Amount of Refunds or Surcharges

Month	Yr	Month
January	Year 1	
February	Year 1	0.1300%
March	Year 1	0.1900%
April	Year 1	0.1900%
May	Year 1	0.1800%
June	Year 1	0.1800%
July	Year 1	0.1900%
August	Year 1	0.1800%
September	Year 1	0.1800%
October	Year 1	0.2000%
November	Year 1	0.2000%
December	Year 1	0.2500%
January	Year 2	0.2400%
February	Year 2	0.2100%
March	Year 2	0.2400%
April	Year 2	0.2200%
May	Year 2	0.2200%
June	Year 2	0.2100%
July	Year 2	0.2100%
August	Year 2	0.2000%
September	Year 2	0.1800%
Average Interest Rate		0.2000%

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2020

Estimated Additions - 2020

	(A)	(B)	(C)	(D)	(E)	(F)
	Other Projects PIS (monthly additions)	New 500 kV bay at Hope Creek (Expansion of Hope Creek substation) (B2633.4) (Monthly Additions)	New 500/230 kV autotransformer at Hope Creek and a new Hope Creek 230 kV substation (B2633.5) (Monthly Additions)	Rebuild Aldene-Warinanco-Linden VFT 230kV Circuit (B2955) (Monthly Additions)	Reconductor L-2238 Cedar Grove - Jackson Rd 230kV (B2956) (Monthly Additions)	
		(in service)	(in service)	(in service)	(in service)	
Dec-19	12,995,721,185	0	0	0	0	
Jan	23,768,333	0	0	0	0	
Feb	34,670,333	0	0	0	0	
Mar	196,048,333	0	0	0	0	
Apr	13,972,333	0	0	0	0	
May	147,200,333	0	0	0	0	
Jun	65,428,266	0	0	52,690,067	0	
Jul	944,709	0	0	299,624	0	
Aug	9,439,824	0	0	296,509	0	
Sep	15,979,324	0	0	280,009	0	
Oct	135,670,842	0	0	258,491	0	
Nov	87,270,699	0	0	255,634	0	
Dec	318,736,480	12,979,846	53,143,656	38,819,681	54,239,691	
Total	14,044,850,994	12,979,846	53,143,656	92,900,015	54,239,691	

(G)	(H)	(I)	(J)	(K)	(L)
	Other Projects PIS (monthly additions)	New 500 kV bay at Hope Creek (Expansion of Hope Creek substation) (B2633.4)	New 500/230 kV autotransformer at Hope Creek and a new Hope Creek 230 kV substation (B2633.5)	Rebuild Aldene-Warinanco-Linden VFT 230kV Circuit (B2955)	Reconductor L-2238 Cedar Grove - Jackson Rd 230kV (B2956)
		(in service)	(in service)	(in service)	(in service)
Dec-19	12,995,721,185	0	0	0	0
Jan	23,768,333	0	0	0	0
Feb	34,670,333	0	0	0	0
Mar	196,048,333	0	0	0	0
Apr	13,972,333	0	0	0	0
May	147,200,333	0	0	0	0
Jun	65,428,266	0	0	52,690,067	0
Jul	944,709	0	0	52,989,691	0
Aug	9,439,824	0	0	53,286,200	0
Sep	15,979,324	0	0	53,566,209	0
Oct	135,670,842	0	0	53,824,700	0
Nov	87,270,699	0	0	54,080,334	0
Dec	318,736,480	12,979,846	53,143,656	92,900,015	54,239,691
Total	**14,044,850,994**	12,979,846	53,143,656	413,337,216	54,239,691
Average 13 Month Balance	**1,080,373,153**	998,450	4,087,974	31,795,170	4,172,284
Average 13 Month in service		**1.00**	**1.00**	**4.45**	**1.00**
13 Month Average CWIP to Appendix A, line 45					

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2020

Estimated Transmission Enhancement Charges (Before True-Up) - 2020

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)	Reconductor South Mahwah K-3411 Circuit (B1018)
557,792,331	1,816,716	739,676	7,924,480	2,008,572	2,554,747	2,463,871	1,506,600	658,328	2,016,205	2,582	909,564	2,070,898	2,151,506

Actual Transmission Enhancement Charges - 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)	Reconductor South Mahwah K-3411 Circuit (B1018)
526,176,658	1,953,369	793,960	8,506,133	2,157,095	2,738,764	2,639,774	1,614,339	705,757	2,160,233	2,771	973,247	2,214,984	2,300,157

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2020

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)	Reconductor South Mahwah K-3411 Circuit (B1018)
	18,922,618	**51,370**	**21,117**	**226,442**	**57,149**	**73,535**	**71,520**	**43,500**	**18,947**	**58,375**	**73**	**26,497**	**60,485**	**63,020**
Interest		1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912

True Up by Project (with interest) -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)	Reconductor South Mahwah K-3411 Circuit (B1018)
19,852,104	**53,893**	**22,154**	**237,565**	**59,956**	**77,147**	**75,033**	**45,637**	**19,878**	**61,242**	**77**	**27,799**	**63,456**	**66,116**

Estimated Transmission Enhancement Charges (After True-Up) - 2020

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)	Reconductor South Mahwah K-3411 Circuit (B1018)
577,644,435	**1,870,610**	**761,830**	**8,162,045**	**2,068,528**	**2,631,894**	**2,538,904**	**1,552,237**	**678,205**	**2,077,448**	**2,658**	**937,362**	**2,134,354**	**2,217,622**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2020

Estimated Transmission Enhancement Charges (Before True-Up) - 2020

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)	Burlington - Camden 230kV Conversion (B1156)
7,897,105	**1,479,178**	**1,912,347**	**659,719**	**4,781,410**	**1,666,407**	**2,286,639**	**6,667,112**	**7,813,732**	**1,222,104**	**618,695**	**4,549,433**	**82,109,464**	**37,827,676**

Actual Transmission Enhancement Charges - 2018

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)	Burlington - Camden 230kV Conversion (B1156)
8,441,111	**1,580,774**	**2,043,862**	**704,894**	**5,107,695**	**1,779,404**	**2,441,551**	**7,790,721**	**8,335,470**	**1,303,530**	**660,864**	**4,848,227**	**87,438,438**	**40,377,399**

Reconciliation by Project (without interest)

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)	Burlington - Camden 230kV Conversion (B1156)
224,477	**43,431**	**56,120**	**19,394**	**140,841**	**49,207**	**67,642**	**870,925**	**231,726**	**36,300**	**18,044**	**134,377**	**2,573,984**	**1,119,475**

1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912

True Up by Project (with interest) -2018

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)	Burlington - Camden 230kV Conversion (B1156)
235,503	**45,564**	**58,877**	**20,347**	**147,759**	**51,624**	**70,965**	**913,705**	**243,108**	**38,083**	**18,930**	**140,978**	**2,700,419**	**1,174,464**

Estimated Transmission Enhancement Charges (After True-Up) - 2020

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)	Burlington - Camden 230kV Conversion (B1156)
8,132,608	**1,524,743**	**1,971,224**	**680,066**	**4,929,169**	**1,718,031**	**2,357,604**	**7,580,817**	**8,056,840**	**1,260,187**	**637,626**	**4,690,410**	**84,809,883**	**39,002,140**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2020

Estimated Transmission Enhancement Charges (Before True-Up) - 2020

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)
47,986,044	**38,876,415**	**69,412,039**	**39,417,609**	**20,086,787**	**7,561,879**	**5,585,111**	**18,329,401**	**14,698,486**	**7,644,939**	**4,884,265**	**9,433,963**	**6,320,199**	**6,320,199**

Actual Transmission Enhancement Charges - 2018

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)
51,158,369	**41,512,081**	**73,990,538**	**-**	**21,470,382**	**6,824,760**	**4,648,728**	**15,752,824**	**10,529,391**	**5,038,025**	**4,592,318**	**7,365,226**	**5,721,000**	**5,721,000**

Reconciliation by Project (without interest)

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)
1,416,666	1,147,874	2,054,546	0	1,207,516	(486,694)	(299,765)	(727,672)	322,676	(407,765)	(26,620)	(1,105,904)	454,182	454,182

1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912

True Up by Project (with interest) -2018

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)
1,486,253	1,204,258	2,155,466	-	1,266,830	(510,601)	(314,490)	(763,416)	338,526	(427,795)	(27,928)	(1,160,226)	476,492	476,492

Estimated Transmission Enhancement Charges (After True-Up) - 2020

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)
49,472,297	40,080,673	71,567,505	39,417,609	21,353,617	7,051,279	5,270,621	17,565,986	15,037,012	7,217,145	4,856,337	8,273,737	6,796,691	6,796,691

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2020

Public Service Electric and Gas Company
ATTACHMENT H-10A
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Estimated Transmission Enhancement Charges (Before True-Up) - 2020

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)	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)
6,142,767	**6,142,767**	**3,507,445**	**2,801,044**	**3,121,750**	**3,121,750**	**994,130**	**994,104**	**3,939,723**	**1,697,623**	**1,320,595**	**2,145,003**	**4,943,629**	**3,535,865**

Actual Transmission Enhancement Charges - 2018

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)	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)
5,578,331	**5,578,331**	**3,734,130**	**-**	**3,303,681**	**3,303,681**	**1,890,122**	**1,890,095**	**2,404,813**	**-**	**1,407,364**	**2,284,765**	**5,123,159**	**3,769,058**

Public Service Electric and Gas Company
ATTACHMENT H-10A
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Reconciliation by Project (without interest)

Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90)	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)	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)
237,762	**237,762**	**(215,530)**	0	**195,730**	**195,730**	**54,884**	**54,883**	**178,200**	0	**38,515**	**90,863**	**1,007,151**	**105,022**

1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912

True Up by Project (with interest) -2018

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)	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)
249,441	**249,441**	**(226,117)**	**-**	**205,344**	**205,344**	**57,580**	**57,579**	**186,953**	0	**40,407**	**95,326**	**1,056,623**	**110,181**

Estimated Transmission Enhancement Charges (After True-Up) - 2020

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)	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)
6,392,208	**6,392,208**	**3,281,328**	**2,801,044**	**3,327,094**	**3,327,094**	**1,051,710**	**1,051,682**	**4,126,676**	**1,697,623**	**1,361,002**	**2,240,329**	**6,000,252**	**3,646,046**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2020

Estimated Transmission Enhancement Charges (Before True-Up) - 2020

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)	New 500 kV bay at Hope Creek (Expansion of Hope Creek substation) (B2633.4)	New 500/230 kV autotransformer at Hope Creek and a new Hope Creek 230 kV substation (B2633.5)	Rebuild Aldene-Warinanco-Linden VFT 230kV Circuit (B2955)	Reconductor L-2238 Cedar Grove - Jackson Rd 230kV (B2956)	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)
122,967	**2,567,335**	**18,305,678**	**2,583,419**	**119,964**	**491,171**	**3,820,197**	**501,301**	0	0	0	0	0	0

Actual Transmission Enhancement Charges - 2018

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)	New 500 kV bay at Hope Creek (Expansion of Hope Creek substation) (B2633.4)	New 500/230 kV autotransformer at Hope Creek and a new Hope Creek 230 kV substation (B2633.5)	Rebuild Aldene-Warinanco-Linden VFT 230kV Circuit (B2955)	Reconductor L-2238 Cedar Grove - Jackson Rd 230kV (B2956)	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)
131,053	**2,009,945**	**11,848,761**	**1,869,286**	0	0	0	0	**15,052**	**855,590**	**459,606**	**3,262,961**	**3,681,896**	**2,296,570**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2020

Reconciliation by Project (without interest)

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)	New 500 kV bay at Hope Creek (Expansion of Hope Creek substation) (B2633.4)	New 500/230 kV autotransformer at Hope Creek and a new Hope Creek 230 kV substation (B2633.5)	Rebuild Aldene-Warinanco-Linden VFT 230kV Circuit (B2955)	Reconductor L-2238 Cedar Grove - Jackson Rd 230kV (B2956)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (CWIP)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (CWIP)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (CWIP)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33) (CWIP)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34) (CWIP)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50) (CWIP)
1,148	**370,504**	**1,033,475**	**500,560**	0	0	0	0	**(16,292)**	**532,733**	**39,765**	**1,286,256**	**772,987**	**871,156**

1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912

True Up by Project (with interest) -2018

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)	New 500 kV bay at Hope Creek (Expansion of Hope Creek substation) (B2633.4)	New 500/230 kV autotransformer at Hope Creek and a new Hope Creek 230 kV substation (B2633.5)	Rebuild Aldene-Warinanco-Linden VFT 230kV Circuit (B2955)	Reconductor L-2238 Cedar Grove - Jackson Rd 230kV (B2956)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (CWIP)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (CWIP)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (CWIP)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33) (CWIP)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34) (CWIP)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50) (CWIP)
1,204	**388,703**	**1,084,240**	525,148	0	0	0	0	**(17,092)**	**558,901**	**41,718**	**1,349,437**	**810,956**	**913,947**

Estimated Transmission Enhancement Charges (After True-Up) - 2020

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)	New 500 kV bay at Hope Creek (Expansion of Hope Creek substation) (B2633.4)	New 500/230 kV autotransformer at Hope Creek and a new Hope Creek 230 kV substation (B2633.5)	Rebuild Aldene-Warinanco-Linden VFT 230kV Circuit (B2955)	Reconductor L-2238 Cedar Grove - Jackson Rd 230kV (B2956)	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)
124,171	**2,956,039**	**19,389,918**	**3,108,567**	**119,964**	**491,171**	**3,820,197**	**501,301**	**(17,092)**	**558,901**	**41,718**	**1,349,437**	**810,956**	**913,947**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2020

Estimated Transmission Enhancement Charges (Before True-Up) - 2020

Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (CWIP)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70) (CWIP)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81) (CWIP)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83) (CWIP)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) (CWIP)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (CWIP)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (CWIP)	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)
0	0	0	0	0	0	0	0	0	0	0	0

Actual Transmission Enhancement Charges - 2018

Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (CWIP)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70) (CWIP)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81) (CWIP)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83) (CWIP)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) (CWIP)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (CWIP)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (CWIP)	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)
917,013	**2,282,447**	**17,100**	**17,100**	**4,988**	**4,988**	**72,710**	**11,268**	**5,145**	**81**	**61**	**206,342**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2020

Reconciliation by Project (without interest)

Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (CWIP)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70) (CWIP)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81) (CWIP)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83) (CWIP)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) (CWIP)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (CWIP)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (CWIP)	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)
75,300	**954,055**	**9,054**	**9,362**	**4,988**	**4,988**	**(63,365)**	**(22,476)**	**(28,599)**	**(654)**	**(674)**	**46,180**

1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912

True Up by Project (with interest) -2018

Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (CWIP)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70) (CWIP)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81) (CWIP)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83) (CWIP)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) (CWIP)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (CWIP)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (CWIP)	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)
78,999	**1,000,919**	**9,499**	**9,822**	**5,233**	**5,233**	**(66,478)**	**(23,580)**	**(30,004)**	**(686)**	**(707)**	**48,448**

Estimated Transmission Enhancement Charges (After True-Up) - 2020

Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (CWIP)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70) (CWIP)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81) (CWIP)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83) (CWIP)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) (CWIP)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (CWIP)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (CWIP)	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)
78,999	**1,000,919**	**9,499**	**9,822**	**5,233**	**5,233**	**(66,478)**	**(23,580)**	**(30,004)**	**(686)**	**(707)**	**48,448**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2020

1 New Plant Carrying Charge

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

Line			Formula Line		
3		A	152	Net Plant Carrying Charge without Depreciation	9.63%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.23%
5		C		Line B less Line A	0.59%
6	**FCR if a CIAC**				
7		D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.29%

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.

Line		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		9.63%		9.63%	9.63%	9.63%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.63%		9.63%	9.63%	9.63%
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified - End of year	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	15,229,564	491,562	2,199,535	6,259,896	192,120	894,158	67,061,488	2,058,755	9,579,601	16,949,826	528,306	2,429,204
45	W Increased ROE	2017	15,229,564	491,562	2,199,535	6,259,896	192,120	894,158	67,061,488	2,058,755	9,579,601	16,949,826	528,306	2,429,204
46	W 11.68 % ROE	2018	14,738,003	491,562	1,953,369	6,067,776	192,120	793,960	65,002,733	2,058,755	8,506,133	16,421,520	528,306	2,157,095
47	W Increased ROE	2018	14,738,003	491,562	1,953,369	6,067,776	192,120	793,960	65,002,733	2,058,755	8,506,133	16,421,520	528,306	2,157,095
44	W 11.68 % ROE	2019	14,246,440	491,562	1,637,120	5,875,657	192,120	664,582	62,943,978	2,058,755	7,120,088	15,893,213	528,306	1,806,282
45	W Increased ROE	2019	14,246,440	491,562	1,637,120	5,875,657	192,120	664,582	62,943,978	2,058,755	7,120,088	15,893,213	528,306	1,806,282
44	W 11.68 % ROE	2020	13,754,878	491,562	1,816,716	5,683,537	192,120	739,676	60,885,223	2,058,755	7,924,480	15,364,907	528,306	2,008,572
45	W Increased ROE	2020	13,754,878	491,562	1,816,716	5,683,537	192,120	739,676	60,885,223	2,058,755	7,924,480	15,364,907	528,306	2,008,572

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	9.63%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.23%
5		C		Line B less Line A	0.59%
6	**FCR if a CIAC**				
7		D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.29%

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.

Line		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		9.63%			9.63%			9.63%			9.63%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.63%			9.63%			9.63%			9.63%		
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified - End of year	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	3,084,762	21,066,812	610,820	2,973,432	12,874,060	374,561	1,818,367	5,610,124	165,750	794,917
45		W Increased ROE	2017	21,772,741	642,982	3,084,762	21,066,812	610,820	2,973,432	12,874,060	374,561	1,818,367	5,610,124	165,750	794,917
46		W 11.68 % ROE	2018	21,129,759	642,982	2,738,764	20,455,991	610,820	2,639,774	12,499,499	374,561	1,614,339	5,444,374	165,750	705,757
47		W Increased ROE	2018	21,129,759	642,982	2,738,764	20,455,991	610,820	2,639,774	12,499,499	374,561	1,614,339	5,444,374	165,750	705,757
44		W 11.68 % ROE	2019	20,486,777	642,982	2,290,326	19,845,171	610,820	2,206,573	12,124,939	374,561	1,349,529	5,278,624	165,750	590,205
45		W Increased ROE	2019	20,486,777	642,982	2,290,326	19,845,171	610,820	2,206,573	12,124,939	374,561	1,349,529	5,278,624	165,750	590,205
44		W 11.68 % ROE	2020	19,843,795	642,982	2,554,747	19,234,351	610,820	2,463,871	11,750,378	374,561	1,506,600	5,112,874	165,750	658,328
45		W Increased ROE	2020	19,843,795	642,982	2,554,747	19,234,351	610,820	2,463,871	11,750,378	374,561	1,506,600	5,112,874	165,750	658,328

			Formula Line		
1	New Plant Carrying Charge				
2	**Fixed Charge Rate (FCR) if if not a CIAC**				
3		A	152	Net Plant Carrying Charge without Depreciation	9.63%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.23%
5		C		Line B less Line A	0.59%
6	**FCR if a CIAC**				
7		D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxe	1.29%

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		9.63%	9.63%	9.63%	9.63%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.63%	9.63%	9.63%	9.63%
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified - End of year	Investment		21,014,433	27,988	9,158,918	20,626,991
		Annual Depreciation or Amort Exp					
18	Line 17 divided by line 12			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

		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
21														
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	17,235,419	500,344	2,433,270	21,880	666	3,120	7,831,801	218,069	1,096,394	17,871,199	491,119	2,495,347
45	W Increased ROE	2017	17,235,419	500,344	2,433,270	21,880	666	3,120	7,831,801	218,069	1,096,394	17,871,199	491,119	2,495,347
46	W 11.68 % ROE	2018	16,735,075	500,344	2,160,233	21,214	666	2,770	7,613,732	218,069	973,247	17,380,080	491,119	2,214,984
47	W Increased ROE	2018	16,735,075	500,344	2,160,233	21,214	666	2,770	7,613,732	218,069	973,247	17,380,080	491,119	2,214,984
44	W 11.68 % ROE	2019	16,234,731	500,344	1,805,780	20,548	666	2,319	7,395,662	218,069	812,756	16,888,961	491,119	1,849,162
45	W Increased ROE	2019	16,234,731	500,344	1,805,780	20,548	666	2,319	7,395,662	218,069	812,756	16,888,961	491,119	1,849,162
44	W 11.68 % ROE	2020	15,734,388	500,344	2,016,205	19,881	666	2,582	7,177,593	218,069	909,564	16,397,842	491,119	2,070,898
45	W Increased ROE	2020	15,734,388	500,344	2,016,205	19,881	666	2,582	7,177,593	218,069	909,564	16,397,842	491,119	2,070,898

1 New Plant Carrying Charge

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

Line			Formula Line		
3		A	152	Net Plant Carrying Charge without Depreciation	9.63%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.23%
5		C		Line B less Line A	0.59%
6	**FCR if a CIAC**				
7		D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.29%

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.

Line		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
10		Details					
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	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		9.63%	9.63%	9.63%	9.63%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.63%	9.63%	9.63%	9.63%
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified - End of year	Investment		21,170,273	77,234,030	14,404,842	18,664,931
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		504,054	1,838,905	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

Line		Invest Yr	B1018 Ending	B1018 Depreciation or Amortization	B1018 Revenue	B0290 Ending	B0290 Depreciation or Amortization	B0290 Revenue	B0472 Ending	B0472 Depreciation or Amortization	B0472 Revenue	B0664 & B0665 Ending	B0664 & B0665 Depreciation or Amortization	B0664 & B0665 Revenue
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	2,591,411	68,524,248	1,841,734	9,526,626	12,822,540	342,972	1,781,001	16,570,216	444,403	2,302,728
45	W Increased ROE	2017	18,612,436	504,054	2,591,411	68,524,248	1,841,734	9,526,626	12,822,540	342,972	1,781,001	16,570,216	444,403	2,302,728
46	W 11.68 % ROE	2018	18,108,382	504,054	2,300,157	66,563,714	1,838,905	8,441,111	12,479,568	342,972	1,580,774	16,125,813	444,403	2,043,862
47	W Increased ROE	2018	18,108,382	504,054	2,300,157	66,563,714	1,838,905	8,441,111	12,479,568	342,972	1,580,774	16,125,813	444,403	2,043,862
44	W 11.68 % ROE	2019	17,604,328	504,054	1,919,620	64,840,780	1,841,734	7,055,589	12,136,595	342,972	1,318,877	15,681,410	444,403	1,705,347
45	W Increased ROE	2019	17,604,328	504,054	1,919,620	64,840,780	1,841,734	7,055,589	12,136,595	342,972	1,318,877	15,681,410	444,403	1,705,347
44	W 11.68 % ROE	2020	17,100,273	504,054	2,151,506	62,883,074	1,838,905	7,897,105	11,793,622	342,972	1,479,178	15,237,006	444,403	1,912,347
45	W Increased ROE	2020	17,100,273	504,054	2,151,506	62,883,074	1,838,905	7,897,105	11,793,622	342,972	1,479,178	15,237,006	444,403	1,912,347

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	9.63%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.23%
5		C		Line B less Line A	0.59%
6	**FCR if a CIAC**				
7		D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.29%

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.

Line		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		9.63%	9.63%	9.63%	9.63%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.63%	9.63%	9.63%	9.63%
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified - End of year	Investment		6,390,403	46,035,637	15,865,267	21,732,218
		Annual Depreciation or Amort Exp					
18	Line 17 divided by line 12			152,152	1,096,087	377,744	517,434
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

Line		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	794,193	41,541,291	1,096,087	5,754,880	14,509,330	377,744	2,004,944	19,921,276	517,546	2,751,687
45	W Increased ROE	2017	5,724,913	152,152	794,193	41,541,291	1,096,087	5,754,880	14,509,330	377,744	2,004,944	19,921,276	517,546	2,751,687
46	W 11.68 % ROE	2018	5,572,760	152,152	704,894	40,445,204	1,096,087	5,107,695	14,131,586	377,744	1,779,404	19,399,030	517,434	2,441,551
47	W Increased ROE	2018	5,572,760	152,152	704,894	40,445,204	1,096,087	5,107,695	14,131,586	377,744	1,779,404	19,399,030	517,434	2,441,551
44	W 11.68 % ROE	2019	5,420,608	152,152	588,024	39,349,118	1,096,087	4,260,154	13,753,841	377,744	1,483,693	18,886,184	517,546	2,036,186
45	W Increased ROE	2019	5,420,608	152,152	588,024	39,349,118	1,096,087	4,260,154	13,753,841	377,744	1,483,693	18,886,184	517,546	2,036,186
44	W 11.68 % ROE	2020	5,268,456	152,152	659,719	38,253,031	1,096,087	4,781,410	13,376,097	377,744	1,666,407	18,364,051	517,434	2,286,639
45	W Increased ROE	2020	5,268,456	152,152	659,719	38,253,031	1,096,087	4,781,410	13,376,097	377,744	1,666,407	18,364,051	517,434	2,286,639

1 New Plant Carrying Charge

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

Line		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	9.63%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.23%
5	C		Line B less Line A	0.59%

6 **FCR if a CIAC**

Line		Formula Line		
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.29%

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.

Line		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		9.63%	9.63%	9.63%	9.63%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.63%	9.63%	9.63%	10.38%
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified - End of year	Investment		62,938,142	72,376,948	11,276,183	5,857,687
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		1,498,527	1,723,261	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

Line		Invest Yr	B1155 Ending	B1155 Depreciation or Amortization	B1155 Revenue	B1399 Ending	B1399 Depreciation or Amortization	B1399 Revenue	B1590 Ending	B1590 Depreciation or Amortization	B1590 Revenue	b0489 Ending	b0489 Depreciation or Amortization	b0489 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	58,272,563	1,498,527	8,033,708	68,392,049	1,723,359	9,393,425	10,703,887	268,481	1,468,905	5,036,479	139,469	704,302
45	W Increased ROE	2017	58,272,563	1,498,527	8,033,708	68,392,049	1,723,359	9,393,425	10,703,887	268,481	1,468,905	5,036,479	139,469	747,840
46	W 11.68 % ROE	2018	62,148,121	1,626,482	7,790,721	66,664,575	1,723,261	8,335,470	10,435,407	268,481	1,303,530	4,897,011	139,469	625,185
47	W Increased ROE	2018	62,148,121	1,626,482	7,790,721	66,664,575	1,723,261	8,335,470	10,435,407	268,481	1,303,530	4,897,011	139,469	660,864
44	W 11.68 % ROE	2019	55,275,530	1,498,527	5,943,239	64,941,230	1,723,261	6,945,193	10,166,926	268,481	1,086,004	4,757,542	139,469	522,023
45	W Increased ROE	2019	55,275,530	1,498,527	5,943,239	64,941,230	1,723,261	6,945,193	10,166,926	268,481	1,086,004	4,757,542	139,469	556,175
44	W 11.68 % ROE	2020	53,649,027	1,498,527	6,667,112	63,218,053	1,723,261	7,813,732	9,898,446	268,481	1,222,104	4,618,073	139,469	584,377
45	W Increased ROE	2020	53,649,027	1,498,527	6,667,112	63,218,053	1,723,261	7,813,732	9,898,446	268,481	1,222,104	4,618,073	139,469	618,695

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	9.63%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.23%
5	C		Line B less Line A	0.59%

6 **FCR if a CIAC**

7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.29%

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.

Line		Details		Susquehanna Roseland < 500KV (B0489.4)	Susquehanna Roseland > 500KV (B0489)	Burlington - Camden 230kV Conversion (B1156)	Mickleton-Gloucester-Camden(B1398-B1398.7)
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		9.63%	9.63%	9.63%	9.63%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		10.38%	10.38%	9.63%	9.63%
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified - End of year	Investment		40,538,248	721,881,197	356,333,540	439,023,933
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		965,196	17,187,648	8,484,132	10,452,951
19	Months in service for depreciation expense from			13.00	13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)			2011	2012	2011	2013

Line		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				768,277,132								
24	W 11.68 % ROE	2007				770,174,683								
25	W Increased ROE	2007				(1,897,551)								
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	5,163,491	677,132,437	17,186,557	93,125,945	330,033,388	8,484,132	45,496,882	420,701,437	10,447,458	57,628,494
45	W Increased ROE	2017	37,435,134	965,196	5,487,093	677,132,437	17,186,557	98,979,324	330,033,388	8,484,132	45,496,882	420,701,437	10,447,458	57,628,494
46	W 11.68 % ROE	2018	36,469,937	965,196	4,582,513	659,838,953	17,184,011	82,630,967	321,549,256	8,484,132	40,377,399	410,411,336	10,451,205	51,158,369
47	W Increased ROE	2018	36,469,937	965,196	4,848,227	659,838,953	17,184,011	87,438,438	321,549,256	8,484,132	40,377,399	410,411,336	10,451,205	51,158,369
44	W 11.68 % ROE	2019	35,504,741	965,196	3,820,137	642,834,128	17,187,649	68,878,020	313,065,125	8,484,132	33,657,737	399,754,320	10,446,356	42,590,650
45	W Increased ROE	2019	35,504,741	965,196	4,075,005	642,834,128	17,187,649	73,492,563	313,065,125	8,484,132	33,657,737	399,754,320	10,446,356	42,590,650
44	W 11.68 % ROE	2020	34,539,544	965,196	4,292,760	625,620,033	17,187,648	77,460,316	304,580,993	8,484,132	37,827,676	389,587,112	10,452,951	47,986,044
45	W Increased ROE	2020	34,539,544	965,196	4,549,433	625,620,033	17,187,648	82,109,464	304,580,993	8,484,132	37,827,676	389,587,112	10,452,951	47,986,044

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2020

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	9.63%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.23%
5		C		Line B less Line A	0.59%
6	**FCR if a CIAC**				
7		D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.29%

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		9.63%	9.63%	9.63%	9.63%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.63%	9.78%	9.78%	9.63%
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified - End of year	Investment		370,007,352	625,166,511	350,966,539	179,379,994
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		8,809,699	14,884,917	8,356,346	4,270,952
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	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	338,516,483	8,809,699	46,773,815	602,065,287	14,885,514	82,406,233	342,609,998	8,356,943	46,780,141	176,296,656	4,203,493	23,733,009
45	W Increased ROE	2017	338,516,483	8,809,699	46,773,815	602,065,287	14,885,514	83,447,128	342,609,998	8,356,943	47,372,470	176,296,656	4,203,493	23,733,009
46	W 11.68 % ROE	2018	329,706,784	8,809,699	41,512,081	587,254,037	14,887,282	73,134,812	334,327,320	8,358,711	41,519,387	174,138,554	4,283,105	21,470,381
47	W Increased ROE	2018	329,706,784	8,809,699	41,512,081	587,254,037	14,887,282	73,990,538	334,327,320	8,358,711	42,006,557	174,138,554	4,283,105	21,470,381
44	W 11.68 % ROE	2019	320,897,093	8,809,699	34,613,073	572,224,877	14,883,974	60,896,647	334,253,055	8,356,943	35,234,272	169,419,235	4,291,004	17,914,025
45	W Increased ROE	2019	320,897,093	8,809,699	34,613,073	572,224,877	14,883,974	61,718,183	334,253,055	8,356,943	35,714,155	169,419,235	4,291,004	17,914,025
44	W 11.68 % ROE	2020	312,087,386	8,809,699	38,876,415	557,383,451	14,884,917	68,583,626	317,512,336	8,356,346	38,945,705	164,165,674	4,270,952	20,086,787
45	W Increased ROE	2020	312,087,386	8,809,699	38,876,415	557,383,451	14,884,917	69,412,039	317,512,336	8,356,346	39,417,609	164,165,674	4,270,952	20,086,787

Line			Formula Line	Description	Value
1	New Plant Carrying Charge				
2	**Fixed Charge Rate (FCR) if if not a CIAC**				
3		A	152	Net Plant Carrying Charge without Depreciation	9.63%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.23%
5		C		Line B less Line A	0.59%
6	**FCR if a CIAC**				
7		D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.29%

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.

Line		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		9.63%			9.63%			9.63%			9.63%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.63%			9.63%			9.63%			9.63%		
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified - End of year	Investment		66,233,353			48,848,837			158,323,120			126,346,267		
		Annual Depreciation or Amort Exp													
18	Line 17 divided by line 12			1,576,985			1,163,068			3,769,598			3,008,244		
19	Months in service for depreciation expense from			13.00			13.00			13.00			13.00		
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	42,938,400	916,068	5,198,758	24,558,823	583,272	3,294,965	14,747,154	214,966	1,226,916			
45		W Increased ROE	2017	42,938,400	916,068	5,198,758	24,558,823	583,272	3,294,965	14,747,154	214,966	1,226,916			
46		W 11.68 % ROE	2018	63,528,886	1,341,837	6,824,760	47,639,887	913,654	4,648,728	164,431,353	3,052,775	15,752,824	125,948,110	2,038,280	10,529,391
47		W Increased ROE	2018	63,528,886	1,341,837	6,824,760	47,639,887	913,654	4,648,728	164,431,353	3,052,775	15,752,824	125,948,110	2,038,280	10,529,391
44		W 11.68 % ROE	2019	61,564,011	1,530,357	6,480,727	45,509,601	1,128,954	4,788,386	161,066,436	3,918,488	16,869,860	122,507,954	2,965,269	12,816,149
45		W Increased ROE	2019	61,564,011	1,530,357	6,480,727	45,509,601	1,128,954	4,788,386	161,066,436	3,918,488	16,869,860	122,507,954	2,965,269	12,816,149
44		W 11.68 % ROE	2020	62,122,188	1,576,985	7,561,879	45,900,054	1,163,068	5,585,111	151,128,277	3,769,598	18,329,401	121,342,718	3,008,244	14,698,486
45		W Increased ROE	2020	62,122,188	1,576,985	7,561,879	45,900,054	1,163,068	5,585,111	151,128,277	3,769,598	18,329,401	121,342,718	3,008,244	14,698,486

1 New Plant Carrying Charge

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

Line		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	9.63%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.23%
5	C		Line B less Line A	0.59%

6 **FCR if a CIAC**

Line		Formula Line		
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.29%

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.

Line		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)
10							
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.63%	9.63%	9.63%	9.63%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.63%	9.63%	9.63%	9.63%
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified - End of year	Investment		65,664,032	42,471,432	81,535,606	54,818,781
		Annual Depreciation or Amort Exp					
18	Line 17 divided by line 12			1,563,429	1,011,225	1,941,324	1,305,209
19	Months in service for depreciation expense from			13.00	13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)			2018	2015	2015	2015

Line		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
21														
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				14,747,154	214,966	1,226,916	14,747,154	214,966	1,226,916	31,239,305	465,743	2,658,611
45	W Increased ROE	2017				14,747,154	214,966	1,226,916	14,747,154	214,966	1,226,916	31,239,305	465,743	2,658,611
46	W 11.68 % ROE	2018	65,344,588	975,261	5,038,025	48,375,637	892,291	4,592,318	87,724,589	1,428,689	7,365,226	48,346,394	1,116,292	5,721,000
47	W Increased ROE	2018	65,344,588	975,261	5,038,025	48,375,637	892,291	4,592,318	87,724,589	1,428,689	7,365,226	48,346,394	1,116,292	5,721,000
44	W 11.68 % ROE	2019	64,591,882	1,563,733	6,757,574	47,322,821	1,154,062	4,959,296	86,748,462	2,111,017	9,086,471	47,577,259	1,169,320	4,995,013
45	W Increased ROE	2019	64,591,882	1,563,733	6,757,574	47,322,821	1,154,062	4,959,296	86,748,462	2,111,017	9,086,471	47,577,259	1,169,320	4,995,013
44	W 11.68 % ROE	2020	63,125,038	1,563,429	7,644,939	40,201,498	1,011,225	4,884,265	77,772,319	1,941,324	9,433,963	52,054,741	1,305,209	6,320,199
45	W Increased ROE	2020	63,125,038	1,563,429	7,644,939	40,201,498	1,011,225	4,884,265	77,772,319	1,941,324	9,433,963	52,054,741	1,305,209	6,320,199

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2020

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	9.63%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.23%
5		C		Line B less Line A	0.59%
6	**FCR if a CIAC**				
7		D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.29%

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		9.63%			9.63%			9.63%			9.63%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.63%			9.63%			9.63%			9.63%		
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified - End of year	Investment		54,818,781			53,423,989			53,423,988			31,266,389		
		Annual Depreciation or Amort Exp													
18	Line 17 divided by line 12			1,305,209			1,272,000			1,272,000			744,438		
19	Months in service for depreciation expense from			13.00			13.00			13.00			13.00		
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	31,239,305	465,743	2,658,611	43,917,206	652,295	3,723,870	43,917,206	652,295	3,723,870	30,818,452	697,633	3,942,807
45		W Increased ROE	2017	31,239,305	465,743	2,658,611	43,917,206	652,295	3,723,870	43,917,206	652,295	3,723,870	30,818,452	697,633	3,942,807
46		W 11.68 % ROE	2018	48,346,394	1,116,292	5,721,000	46,812,614	1,092,190	5,578,331	46,812,613	1,092,190	5,578,331	30,173,644	743,679	3,734,130
47		W Increased ROE	2018	48,346,394	1,116,292	5,721,000	46,812,614	1,092,190	5,578,331	46,812,613	1,092,190	5,578,331	30,173,644	743,679	3,734,130
44		W 11.68 % ROE	2019	47,577,259	1,169,320	4,995,013	44,843,021	1,109,081	4,714,914	46,568,719	1,109,081	4,853,677	29,930,334	757,637	3,164,339
45		W Increased ROE	2019	47,577,259	1,169,320	4,995,013	44,843,021	1,109,081	4,714,914	46,568,719	1,109,081	4,853,677	29,930,334	757,637	3,164,339
44		W 11.68 % ROE	2020	52,054,741	1,305,209	6,320,199	50,557,738	1,272,000	6,142,767	50,557,737	1,272,000	6,142,767	28,679,547	744,438	3,507,445
45		W Increased ROE	2020	52,054,741	1,305,209	6,320,199	50,557,738	1,272,000	6,142,767	50,557,737	1,272,000	6,142,767	28,679,547	744,438	3,507,445

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	9.63%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.23%
5		C		Line B less Line A	0.59%
6	**FCR if a CIAC**				
7		D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.29%

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.

Line		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		9.63%			9.63%			9.63%			9.63%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.63%			9.63%			9.63%			9.63%		
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified - End of year	Investment		24,992,501			27,892,523			27,892,523			9,049,265		
		Annual Depreciation or Amort Exp													
18	Line 17 divided by line 12			595,060			664,108			664,108			215,459		
19	Months in service for depreciation expense from			13.00			13.00			13.00			13.00		
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	24,558,823	583,272	3,294,965	27,091,682	653,428	3,685,670	27,091,682	653,428	3,685,670	14,750,891	214,966	1,227,172
45		W Increased ROE	2017	24,558,823	583,272	3,294,965	27,091,682	653,428	3,685,670	27,091,682	653,428	3,685,670	14,750,891	214,966	1,227,172
46		W 11.68 % ROE	2018	24,088,516	593,745	2,977,510	27,083,985	659,568	3,303,681	27,083,985	659,568	3,303,681	15,430,944	370,082	1,890,122
47		W Increased ROE	2018	24,088,516	593,745	2,977,510	27,083,985	659,568	3,303,681	27,083,985	659,568	3,303,681	15,430,944	370,082	1,890,122
44		W 11.68 % ROE	2019	23,486,597	594,836	2,483,396	26,129,595	662,586	2,763,670	26,129,595	662,586	2,763,670	15,238,900	376,860	1,602,222
45		W Increased ROE	2019	23,486,597	594,836	2,483,396	26,129,595	662,586	2,763,670	26,129,595	662,586	2,763,670	15,238,900	376,860	1,602,222
44		W 11.68 % ROE	2020	22,897,745	595,060	2,801,044	25,509,907	664,108	3,121,750	25,509,907	664,108	3,121,750	8,082,480	215,459	994,130
45		W Increased ROE	2020	22,897,745	595,060	2,801,044	25,509,907	664,108	3,121,750	25,509,907	664,108	3,121,750	8,082,480	215,459	994,130

1	New Plant Carrying Charge				
2	**Fixed Charge Rate (FCR) if not a CIAC**				
			Formula Line		
3		A	152	Net Plant Carrying Charge without Depreciation	9.63%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.23%
5		C		Line B less Line A	0.59%
6	**FCR if a CIAC**				
7		D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.29%

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		9.63%			9.63%			9.63%			9.63%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.63%			9.63%			9.63%			9.63%		
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified - End of year	Investment		9,049,265			33,825,459			14,573,915			12,087,610		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		215,459			805,368			346,998			287,800		
19	Months in service for depreciation expense from			13.00			13.00			13.00			13.00		
20	Year placed in Service (0 if CWIP)			2015			2016			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	14,750,613	214,966	1,227,153	18,339,519	295,246	1,684,077				11,583,248	287,798	1,586,839
45		W Increased ROE	2017	14,750,613	214,966	1,227,153	18,339,519	295,246	1,684,077				11,583,248	287,798	1,586,839
46		W 11.68 % ROE	2018	15,430,666	370,082	1,890,095	21,049,155	471,208	2,404,813	14,368,655	223,345	1,153,763	11,289,046	287,646	1,407,364
47		W Increased ROE	2018	15,430,666	370,082	1,890,095	21,049,155	471,208	2,404,813	14,368,655	223,345	1,153,763	11,289,046	287,646	1,407,364
44		W 11.68 % ROE	2019	15,238,622	376,860	1,602,199	20,242,376	500,513	2,128,205	13,620,433	331,313	1,426,533	11,001,247	287,646	1,172,258
45		W Increased ROE	2019	15,238,622	376,860	1,602,199	20,242,376	500,513	2,128,205	13,620,433	331,313	1,426,533	11,001,247	287,646	1,172,258
44		W 11.68 % ROE	2020	8,082,201	215,459	994,104	32,534,065	805,368	3,939,723	14,019,257	346,998	1,697,623	10,720,232	287,800	1,320,595
45		W Increased ROE	2020	8,082,201	215,459	994,104	32,534,065	805,368	3,939,723	14,019,257	346,998	1,697,623	10,720,232	287,800	1,320,595

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	9.63%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.23%
5	C		Line B less Line A	0.59%

6 **FCR if a CIAC**

7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.29%

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.

Line		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		9.63%	9.63%	9.63%	9.63%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.63%	9.63%	9.63%	9.63%
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified - End of year	Investment		19,515,077	43,062,455	32,029,640	0
		Annual Depreciation or Amort Exp					
18	Line 17 divided by line 12			464,645	1,025,297	762,610	0
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

Line		Invest Yr	Mickleton-Gloucester Ending	Mickleton-Gloucester Depreciation or Amortization	Mickleton-Gloucester Revenue	Ridge Road Ending	Ridge Road Depreciation or Amortization	Ridge Road Revenue	Cox's Corner Ending	Cox's Corner Depreciation or Amortization	Cox's Corner Revenue	Sewaren Ending	Sewaren Depreciation or Amortization	Sewaren 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	18,586,669	458,892	2,542,906	39,858,124	277,639	1,582,248	31,074,276	763,146	4,250,525	0	0	0
45	W Increased ROE	2017	18,586,669	458,892	2,542,906	39,858,124	277,639	1,582,248	31,074,276	763,146	4,250,525	0	0	0
46	W 11.68 % ROE	2018	18,353,373	464,363	2,284,765	42,538,575	998,751	5,123,158	30,311,131	762,610	3,769,058	0	0	0
47	W Increased ROE	2018	18,353,373	464,363	2,284,765	42,538,575	998,751	5,123,158	30,311,131	762,610	3,769,058	0	0	0
44	W 11.68 % ROE	2019	17,670,135	459,021	1,879,878	41,581,532	1,018,617	4,362,193	29,548,579	762,610	3,138,615	0	0	0
45	W Increased ROE	2019	17,670,135	459,021	1,879,878	41,581,532	1,018,617	4,362,193	29,548,579	762,610	3,138,615	0	0	0
44	W 11.68 % ROE	2020	17,441,834	464,645	2,145,003	40,671,622	1,025,297	4,943,629	28,785,910	762,610	3,535,865	0	0	0
45	W Increased ROE	2020	17,441,834	464,645	2,145,003	40,671,622	1,025,297	4,943,629	28,785,910	762,610	3,535,865	0	0	0

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	9.63%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.23%
5		C		Line B less Line A	0.59%
6	**FCR if a CIAC**				
7		D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.29%

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.

				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)**		
10		Details													
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes			Yes			Yes			Yes		
12	Useful life of the project	Life		42			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		9.63%			9.63%			9.63%			9.63%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.63%			9.63%			9.63%			9.63%		
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified - End of year	Investment		1,108,058			22,106,940			157,394,496			22,217,516		
		Annual Depreciation or Amort Exp													
18	Line 17 divided by line 12			26,382			526,356			3,747,488			528,988		
19	Months in service for depreciation expense from			13.00			13.00			13.00			13.00		
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	1,081,675	26,382	147,691	2,060,962	3,775	21,554	75,384,047	433,473	2,475,231			
45		W Increased ROE	2017	1,081,675	26,382	147,691	2,060,962	3,775	21,554	75,384,047	433,473	2,475,231			
46		W 11.68 % ROE	2018	1,055,293	26,382	131,053	22,086,187	389,139	2,009,945	154,527,405	2,298,869	11,848,761	22,306,913	361,856	1,869,285
47		W Increased ROE	2018	1,055,293	26,382	131,053	22,086,187	389,139	2,009,945	154,527,405	2,298,869	11,848,761	22,306,913	361,856	1,869,285
44		W 11.68 % ROE	2019	1,028,911	26,382	109,117	21,887,850	529,005	2,289,010	146,538,027	3,550,621	15,333,762	22,030,024	531,017	2,302,454
45		W Increased ROE	2019	1,028,911	26,382	109,117	21,887,850	529,005	2,289,010	146,538,027	3,550,621	15,333,762	22,030,024	531,017	2,302,454
44		W 11.68 % ROE	2020	1,002,528	26,382	122,967	21,185,021	526,356	2,567,335	151,111,534	3,747,488	18,305,678	21,324,643	528,988	2,583,419
45		W Increased ROE	2020	1,002,528	26,382	122,967	21,185,021	526,356	2,567,335	151,111,534	3,747,488	18,305,678	21,324,643	528,988	2,583,419

Line					
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	9.63%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.23%
5		C		Line B less Line A	0.59%
6	**FCR if a CIAC**				
7		D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.29%

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.

Line		Details		New 500 kV bay at Hope Creek (Expansion of Hope Creek substation) (B2633.4)			New 500/230 kV autotransformer at Hope Creek and a new Hope Creek 230 kV substation (B2633.5)			Rebuild Aldene-Warinanco-Linden VFT 230kV Circuit (B2955)			Reconductor L-2238 Cedar Grove - Jackson Rd 230kV (B2956)		
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		9.63%			9.63%			9.63%			9.63%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.63%			9.63%			9.63%			9.63%		
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified - End of year	Investment		12,979,846			53,143,656			92,900,015			54,239,691		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		309,044			1,265,325			2,211,905			1,291,421		
19	Months in service for depreciation expense from			1.00			1.00			4.45			1.00		
20	Year placed in Service (0 if CWIP)			2020			2020			2020			2020		
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												
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												
44		W 11.68 % ROE	2019												
45		W Increased ROE	2019												
44		W 11.68 % ROE	2020	12,979,846	23,773	119,964	53,143,656	97,333	491,171	92,900,015	757,028	3,820,197	54,239,691	99,340	501,301
45		W Increased ROE	2020	12,979,846	23,773	119,964	53,143,656	97,333	491,171	92,900,015	757,028	3,820,197	54,239,691	99,340	501,301

1	New Plant Carrying Charge		
2	**Fixed Charge Rate (FCR) if if not a CIAC**		
			Formula Line
3		A	152
4		B	159
5		C	
6	**FCR if a CIAC**		
7		D	153
8			
9			

10		Details	
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)
12	Useful life of the project	Life	
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)
14	Input the allowed increase in ROE	Increased ROE (Basis Points)	
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE	
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project	
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified - End of year	Investment	
		Annual Depreciation or Amort Exp	
18	Line 17 divided by line 12		
19	Months in service for depreciation expense from		
20	Year placed in Service (0 if CWIP)		

21			**Invest Yr**	**Total**	**Incentive Charged**	**Revenue Credit**	
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				
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				
44		W 11.68 % ROE	2019				
45		W Increased ROE	2019				
44		W 11.68 % ROE	2020	$ 551,551,876		$ 551,551,876	
45		W Increased ROE	2020	$ 557,792,331	$ 557,792,331		$ 6,240,455

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, 2020

Required Transmission Enhancements

Upgrade ID	RTEP Baseline Project Description	Estimated/Actual Project Cost (thru 2020) *	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-07
b0498	Loop the 5021 circuit into New Freedom 500 kV substation	$ 27,005,248	May-08
b0161	Install 230-138kV transformer at Metuchen substation	$ 25,654,455	Nov-09
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-09
b0170	Reconductor the Flagtown-Somerville-Bridgewater 230 kV circuit with 1590 ACSS	$ 6,961,495	May-08
b0172.2	Replace wave trap at Branchburg 500kV substation	$ 27,988	Feb-08
b0274	Replace both 230/138 kV transformers at Roseland	$ 21,014,433	May-09
b0813	Reconductor Hudson - South Waterfront 230kV circuit	$ 9,158,918	May-10
b1017	Reconductor South Mahwah 345 kV J-3410 Circuit	$ 20,626,991	Dec-11
b1018	Reconductor South Mahwah 345 kV K-3411 Circuit	$ 21,170,273	May-11
b0290	Branchburg 400 MVAR Capacitor	$ 77,234,030	Nov-12
b0472	Saddle Brook - Athenia Upgrade Cable	$ 14,404,842	Nov-12
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-12
b1410-b1415	Replace Salem 500 kV breakers	$ 15,865,267	Oct-12
b1228	230kV Lawrence Switching Station Upgrade	$ 21,732,218	May-13
b1155	Branchburg-Middlesex Swich Rack	$ 62,938,142	Dec-13
b1399	Aldene-Springfield Rd. Conversion	$ 72,376,948	Dec-14
b1590	Upgrade Camden-Richmond 230kV Circuit	$ 11,276,183	Apr-14
b1588	Uprate EaglePoint-Gloucester 230kV Circuit	$ 12,087,610	May-15
b2139	Build Mickleton-Gloucester Corridor Ultimate Design	$ 19,515,077	Dec-15
b1255	Ridge Road 69kV Breaker Station	$ 43,062,455	Jun-16
b1787	New Cox's Corner-Lumberton 230kV Circuit	$ 32,029,640	Nov-15
b0376	Install Conemaugh 250MVAR Cap Bank	$ 1,108,058	Mar-16
b1589	Reconfigure Kearny- Loop in P2216 Ckt	$ 22,106,940	May-18
b2146	Reconfigure Brunswick Sw-New 69kVCkt-T	$ 157,394,496	Oct-17
b2702	350 MVAR Reactor Hopatcong 500kV	$ 22,217,516	Jun-18
b0489.5-b0489.15	Susquehanna Roseland Breakers	$ 5,857,687	Jun-10
b0489.4	Build new 500 kV transmission facilities from Pennsylvania - New Jersey border at Bushkill to Roseland (Below 500 kV elements of the project)	$ 40,538,248	Nov-11
b0489	Build new 500 kV transmission facilities from Pennsylvania - New Jersey border at Bushkill to Roseland (500kV and above elements of the project)	$ 721,881,197	Mar-12
b1156	Burlington - Camden 230kV Conversion	$ 356,333,540	Oct-11
b1398 - b1398.7	Mickleton-Gloucester-Camden	$ 439,023,933	Jun-13
b1154	North Central Reliability (West Orange Conversion)	$ 370,007,352	Jun-12
b1304.1-b1304.4	Northeast Grid Reliability Project	$ 625,166,511	Jun-13
b1304.5-b1304.21	Northeast Grid Reliability Project (In-Service)	$ 350,966,539	Dec-16
b2436.10	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades	$ 179,379,994	Jan-16
b2436.21	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades	$ 66,233,353	May-16
b2436.22	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades	$ 48,848,837	May-16

Upgrade ID	RTEP Baseline Project Description	Estimated/Actual Project Cost (thru 2020) *	Anticipated/Actual In-Service Date *
b2436.33	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades	$ 158,323,120	Dec-15
b2436.34	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34)	$ 126,346,267	Apr-18
b2436.50	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50)	$ 65,664,032	Apr-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)	$ 42,471,432	Dec-15
b2436.70	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70)	$ 81,535,606	Dec-15
b2436.81	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades	$ 54,818,781	Dec-15
b2436.83	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades	$ 54,818,781	Dec-15
b2436.84	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades	$ 53,423,989	Dec-15
b2436.85	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades	$ 53,423,988	Dec-15
b2436.90	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades	$ 31,266,389	May-16
b2436.91	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91)	$ 24,992,501	Jun-16
b2437.10	New Bergen 345/230 kV transformer and any associated substation upgrades	$ 27,892,523	May-16
b2437.11	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11)	$ 27,892,523	Jun-16
b2437.20	New Bayway 345/138 kV transformer #1 and any associated substation upgrades	$ 9,049,265	Dec-15
b2437.21	New Bayway 345/138 kV transformer #2 and any associated substation upgrades	$ 9,049,265	Dec-15
b2437.30	New Linden 345/230 kV transformer and any associated substation upgrades	$ 33,825,459	Jul-16
b2437.33	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33)	$ 14,573,915	Apr-18
b2633.4	New 500 kV bay at Hope Creek (Expansion of Hope Creek substation) (B2633.4)	$ 12,979,846	Dec-20
b2633.5	New 500/230 kV autotransformer at Hope Creek and a new Hope Creek 230 kV substation	$ 53,143,656	Dec-20
b2955	Rebuild Aldene-Warinanco-Linden VFT 230kV Circuit (B2955)	$ 92,900,015	Jun-20
b2956	Reconductor L-2238 Cedar Grove - Jackson Rd 230kV (B2956)	$ 54,239,691	Dec-20
	Total	**$ 5,228,031,190**	

Attachment 9

VEPCO Formula Rate for January 1, 2020 to December 31, 2020

Virginia Electric and Power Company
ATTACHMENT H-16A

Formula Rate -- Appendix A

Shaded cells are input cells

Line	Description	Notes	FERC Form 1 Page # or Instruction (Note H)		2020 (000's)
	Allocators				
	Wages & Salary Allocation Factor				
1	Transmission Wages Expense		p354.21b/ Attachment 5	$	45,121
2	Less Generator Step-ups		Attachment 5		22
3	Net Transmission Wage Expenses		(Line 1 - 2)		45,099
4	Total Wages Expense		p354.28b/Attachment 5		621,125
5	Less A&G Wages Expense		p354.27b/Attachment 5		98,841
6	Total		(Line 4 - 5)	$	522,284
7	**Wages & Salary Allocator**	(Note B)	(Line 3 / 6)		**8.6350%**
	Plant Allocation Factors				
8	Electric Plant in Service	(Notes A& Q)	p207.104.g/Attachment 5	$	45,348,157
9	Common Plant In Service - Electric		(Line 26)		0
10	Total Plant In Service		(Sum Lines 8 & 9)		45,348,157
11	Accumulated Depreciation (Total Electric Plant)	(Notes A & Q)	(Line 15 - 14 - 13 -12)		13,532,250
12	Accumulated Intangible Amortization	(Notes A & Q)	p200.21c/Attachment 5		155,846
13	Accumulated Common Amortization - Electric	(Notes A & Q)	p356/Attachment 5		0
14	Accumulated Common Plant Depreciation - Electric	(Notes A & Q)	p356/Attachment 5		0
15	Total Accumulated Depreciation		p219.29c/Attachment 5		13,688,097
16	Net Plant		(Line 10 - 15)		31,660,061
17	Transmission Gross Plant		(Line 31 - 30)		9,947,377
18	**Gross Plant Allocator**	(Note B)	(Line 17 / 10)		**21.9356%**
19	Transmission Net Plant		(Line 44 - 30)	$	8,136,653
20	**Net Plant Allocator**	(Note B)	(Line 19 / 16)		**25.7001%**
	Plant Calculations				
	Plant In Service				
21	Transmission Plant In Service	(Notes A & Q)	p207.58.g/Attachment 5	$	10,424,329
22	Less: Generator Step-ups	(Notes A & Q)	Attachment 5		408,461
23	Less: Interconnect Facilities Installed After March 15, 2000	(Notes A & Q)	Attachment 5		170,113
24	**Total Transmission Plant In Service**		(Lines 21 - 22 - 23)		**9,845,754**
25	General & Intangible	(Notes A & Q)	p205.5.g + p207.99.g/Attachment 5		1,176,876
26	Common Plant (Electric Only)		p356/Attachment 5		0
27	Total General & Common		(Line 25 + 26)		1,176,876
28	Wage & Salary Allocation Factor		(Line 7)		8.6350%
29	**General & Common Plant Allocated to Transmission**		(Line 27 * 28)	**$**	**101,623**
30	**Plant Held for Future Use (Including Land)**	(Notes C & Q)	p214.47.d/Attachment 5	**$**	**2,222**
31	**TOTAL Plant In Service**		**(Line 24 + 29 + 30)**	**$**	**9,949,599**
	Accumulated Depreciation				
32	Transmission Accumulated Depreciation	(Notes A & Q)	p219.25.c/Attachment 5	$	1,912,514
33	Less Accumulated Depreciation for Generator Step-ups	(Notes A & Q)	Attachment 5		121,188
34	Less Accumulated Depreciation for Interconnect Facilities Installed After March 15, 2000	(Notes A & Q)	Attachment 5		30,264
35	Total Accumulated Depreciation for Transmission		(Line 32 - 33 - 34)		1,761,062
36	Accumulated General Depreciation	(Notes A & Q)	p219.28.b/Attachment 5		419,284
37	Accumulated Intangible Amortization	(Notes A & Q)	(Line 12)		155,846
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)		575,130
41	Wage & Salary Allocation Factor		(Line 7)		8.6350%
42	**General & Common Allocated to Transmission**		(Line 40 * 41)		**49,662**
43	**TOTAL Accumulated Depreciation**		**(Line 35 + 42)**	**$**	**1,810,724**
44	**TOTAL Net Property, Plant & Equipment**		**(Line 31 - 43)**	**$**	**8,138,875**

Virginia Electric and Power Company
ATTACHMENT H-16A

Formula Rate -- Appendix A

Line		Notes	FERC Form 1 Page # or Instruction (Note H)		2020
	Adjustment To Rate Base				
	Accumulated Deferred Income Taxes				
45	Average Balance	(Note U)	Attachment 1	$	(1,642,593)
45A	Accumulated Deferred Income Taxes Attributable To Acquisition Adjustments		Attachment 5	$	(401)
46	**Accumulated Deferred Income Taxes Allocated To Transmission**		(Line 45 + 45A)	**$**	**(1,642,995)**
	Transmission O&M Reserves				
47	**Total Balance Transmission Related Account 242 Reserves**	Enter Negative	Attachment 5	**$**	**(19,081)**
	Unamortized Excess/Deficient Deferred Income Taxes				
47A	**Unamortized Exc/Def Deferral**		Attachment 5	**$**	**2,245**
	Prepayments				
48	Prepayments	(Notes A & R)	Attachment 5	$	2,125
49	**Total Prepayments Allocated to Transmission**		(Line 48)	**$**	**2,125**
	Materials and Supplies				
50	Undistributed Stores Exp	(Notes A & R)	Attachment 5	$	-
51	Wage & Salary Allocation Factor		(Line 7)		8.6350%
52	Total Transmission Allocated Materials and Supplies		(Line 50 * 51)		0
53	Transmission Materials & Supplies	(Note A)	Attachment 5		23,988
54	**Total Materials & Supplies Allocated to Transmission**		(Line 52 + 53)	**$**	**23,988**
	Cash Working Capital				
55	Transmission Operation & Maintenance Expense		(Line 85)	$	135,667
56	1/8th Rule		x 1/8		12.5%
57	**Total Cash Working Capital Allocated to Transmission**		(Line 55 * 56)	**$**	**16,958**
	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	$	8,804
60B	Acummulated Provision for Amortization of Line 60A Amount		Attachment 5		597
60C	Transmission Plant Unamortized Acquisition Adjustments Amount		(Line 60A - 60B)	**$**	**8,207**
61	**TOTAL Adjustment to Rate Base**		(Line 46 + 47 + 47A + 49 + 54 + 57 - 60 + 60C)	**$**	**(1,608,552)**
62	**Rate Base**		(Line 44 + 61)	**$**	**6,530,323**
	O&M				
	Transmission O&M				
63	Transmission O&M		p321.112.b/Attachment 5	$	79,413
64	Less GSU Maintenance		Attachment 5		29
65	Less Account 565 - Transmission by Others		p321.96.b/Attachment 5		(26,632)
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)	**$**	**106,016**
	Allocated General & Common Expenses				
68	Common Plant O&M	(Note A)	p356		0
69	Total A&G		Attachment 5		359,827
70	Less Property Insurance Account 924		p323.185b		10,667
71	Less Regulatory Commission Exp Account 928	(Note E)	p323.189b/Attachment 5		34,844
72	Less General Advertising Exp Account 930.1		p323.911b/Attachment 5		3,532
73	Less EPRI Dues	(Note D)	p352-353/Attachment 5		3,368
74	**General & Common Expenses**		(Lines 68 + 69) - Sum (70 to 73)	$	307,416
75	Wage & Salary Allocation Factor		(Line 7)		8.6350%
76	**General & Common Expenses Allocated to Transmission**		(Line 74 * 75)	**$**	**26,545**
	Directly Assigned A&G				
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b/Attachment 5	$	365
78	General Advertising Exp Account 930.1	(Note K)	p323.191b		0
79	Subtotal - Transmission Related		(Line 77 + 78)		**365**
80	Property Insurance Account 924		p323.185b		10,667
81	General Advertising Exp Account 930.1	(Note F)	Attachment 5		0
82	Total		(Line 80 + 81)		10,667
83	Net Plant Allocation Factor		(Line 20)		25.7001%
84	**A&G Directly Assigned to Transmission**		(Line 82 * 83)	**$**	**2,741**
85	**Total Transmission O&M**		**(Line 67 + 76 + 79 + 84)**	**$**	**135,667**

Virginia Electric and Power Company
ATTACHMENT H-16A

Formula Rate -- Appendix A

Line	Description		Notes	FERC Form 1 Page # or Instruction (Note H)		2020
	Depreciation & Amortization Expense					
	Depreciation Expense					
86	Transmission Depreciation Expense		(Notes A and S)	p336.7b&c/Attachment 5	$	261,253
87	Less: GSU Depreciation			Attachment 5		12,471
88	Less Interconnect Facilities Depreciation			Attachment 5		5,194
89	Extraordinary Property Loss			Attachment 5		0
90	Total Transmission Depreciation			(Line 86 - 87 - 88 + 89)		243,588
90A	Amortization of Acquisition Adjustments			Attachment 5		205
91	General Depreciation		(Note A)	p336.10b&c&d/Attachment 5		46,092
92	Intangible Amortization		(Note A)	p336.1d&e/Attachment 5		35,598
93	Total			(Line 91 + 92)		81,690
94	Wage & Salary Allocation Factor			(Line 7)		8.6350%
95	**General and Intangible Depreciation Allocated to Transmission**			(Line 93 * 94)		7,054
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)		8.6350%
100	**Common Depreciation - Electric Only Allocated to Transmission**			(Line 98 * 99)		0
101	**Total Transmission Depreciation & Amortization**			**(Line 90 + 90A + 95 + 100)**	**$**	**250,847**
	Taxes Other than Income					
102	**Taxes Other than Income**			Attachment 2	**$**	**69,098**
103	**Total Taxes Other than Income**			**(Line 102)**	**$**	**69,098**
	Return / Capitalization Calculations					
	Long Term Interest					
104	Long Term Interest		(Note T)	p117.62c through 67c/Attachment 5	$	503,802
105	Less LTD Interest on Securitization Bonds		(Note P)	Attachment 8		0
106	**Long Term Interest**			(Line 104 - 105)	$	503,802
107	**Preferred Dividends**		(Note T), enter positive	p118.29c	$	-
	Common Stock					
108	Proprietary Capital			p112.16c,d/2	$	12,634,978
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	$	(25,340)
111	**Common Stock**			(Sum Lines 108 to 110)	$	12,609,638
	Capitalization					
112	Long Term Debt			p112.24c,d/2	$	11,582,604
113	Less Loss on Reacquired Debt		(Note T), enter negative	p111.81c,d/2	$	(827)
114	Plus Gain on Reacquired Debt		(Note T), enter positive	p113.61c,d/2	$	3,177
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)		11,584,954
117	Preferred Stock		(Note T), enter positive	p112.3c,d/2		0
118	Common Stock			(Line 111)		12,609,638
119	**Total Capitalization**			(Sum Lines 116 to 118)	$	24,194,592
120	Debt %	Total Long Term Debt		(Line 116 / 119)		47.9%
121	Preferred %	Preferred Stock		(Line 117 / 119)		0.0%
122	Common %	Common Stock		(Line 118 / 119)		52.1%
123	Debt Cost	Total Long Term Debt		(Line 106 / 116)		0.0435
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)		0.0208
127	Weighted Cost of Preferred	Preferred Stock		(Line 121 * 124)		0.0000
128	Weighted Cost of Common	Common Stock		(Line 122 * 125)		0.0594
129	**Total Return (R)**			(Sum Lines 126 to 128)		**0.0802**
130	**Investment Return = Rate Base * Rate of Return**			**(Line 62 * 129)**		**523,973**

Virginia Electric and Power Company
ATTACHMENT H-16A

Formula Rate -- Appendix A

Line	Description	Notes	FERC Form 1 Page # or Instruction (Note H)		2020
Composite Income Taxes					
	Income Tax Rates				
131	FIT=Federal Income Tax Rate		Attachment 5		21.00%
132	SIT=State Income Tax Rate or Composite	(Note I)	Attachment 5		5.85%
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)} =			25.62%
135	T/ (1-T)				34.45%
	Transmission Related Income Tax Adjustments				
136	Amortized Investment Tax Credit (ITC)	(Note I) enter negative	Attachment 1	$	(128)
136A	Other Income Tax Adjustments		Attachment 5	$	(4,314)
137	T/(1-T)		(Line 135)		34.45%
138	**Transmission Income Taxes - Income Tax Adjustments**		((Line 136 + 136A) * (1 + Line 137))	**$**	**(5,973)**
139	**Transmission Income Taxes - Equity Return =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =	[Line 135 * 130 * (1-(126 / 129))]		**133,651**
140	**Total Transmission Income Taxes**		**(Line 138 + 139)**		**127,678**
REVENUE REQUIREMENT					
	Summary				
141	Net Property, Plant & Equipment		(Line 44)	$	8,138,875
142	Adjustment to Rate Base		(Line 61)		(1,608,552)
143	**Rate Base**		(Line 62)	**$**	**6,530,323**
144	O&M		(Line 85)		135,667
145	Depreciation & Amortization		(Line 101)		250,847
146	Taxes Other than Income		(Line 103)		69,098
147	Investment Return		(Line 130)		523,973
148	Income Taxes		(Line 140)		127,678
149					
150	**Revenue Requirement**		**(Sum Lines 144 to 149)**	**$**	**1,107,263**
	Acquisition Adjustments Revenue Requirement				
150A	Acquisition Adjustments Return		Line 129 * (60C + 45A)	$	626
150B	Acquisition Adjustments Income Taxes		[Line 135 * 150A * (1- (126 / 129))]		160
150C	Amortization of Acquisition Adjustments		(Line 90A)		205
150D	**Acquisition Adjustments Revenue Requirement**		(Line 150A + 150B + 150C)	**$**	**991**
	Net Plant Carrying Charge				
151	Revenue Requirement excluding Acquisition Adjustments Revenue Requirement		(Line 150 - 150D)	**$**	**1,106,273**
152	Net Transmission Plant		(Line 24 - 35)		**8,084,692**
153	Net Plant Carrying Charge without Acquisition Adjustments		(Line 151 / 152)		**13.6835%**
154	Net Plant Carrying Charge without Acquisition Adjustments and Depreciation		(Line 151 - 86) / 152		**10.4521%**
155	Net Plant Carrying Charge without Acquisition Adjustments, Depreciation, Return or Income Taxes		(Line 150 - 86 - 90A - 130 - 140) / 152		**2.4015%**
	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)	**$**	**455,408**
157	Increased Return and Taxes		Attachment 4		**696,568**
158	Net Revenue Requirement excluding Acquisition Adjustments Rev. Req. with 100 Basis Point increase in ROE		(Line 156 + 157)		**1,151,976**
159	Net Transmission Plant		(Line 152)		**8,084,692**
160	Net Plant Carrying Charge with 100 Basis Point increase in ROE without Acquisition Adjustments		(Line 158 / 159)		**14.2489%**
161	Net Plant Carrying Charge with 100 Basis Point increase in ROE without Acquisition Adjustments and Depreciation		(Line 158 - 86) / 159		**11.0174%**
162	**Revenue Requirement**		(Line 150)	**$**	**1,107,263**
163	True-up Adjustment		Attachment 6		**29,712**
164	Plus any increased ROE calculated on Attachment 7 other than PJM Schedule 12 projects.		Attachment 7		**2,054**
165	Facility Credits under Section 30.9 of the PJM OATT.		Attachment 5		**3,184**
166	Revenue Credits		Attachment 3		**(44,200)**
167	Interest on Network Credits		PJM data		0
168	**Annual Transmission Revenue Requirement (ATRR)**		(Line 162 + 163 +164 + 165 + 166 + 167)	**$**	**1,098,013**
	Rate for Network Integration Transmission Service				
169	1 CP Peak	(Note L)	PJM Data		**19,930.0**
170	Rate ($/MW-Year)		(Line 168 / 169)		**55,093.50**
171	**Rate for Network Integration Transmission Service ($/MW/Year)**		**(Line 170)**		**55,093.50**

Virginia Electric and Power Company ATTACHMENT H-16A Formula Rate -- Appendix A	Notes	FERC Form 1 Page # or Instruction (Note H)	2020

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: **2020**

Wage and Salary Allocator from Line 7 of Appendix A for the Current Year	8.6350%
Gross Plant Allocator from Line 18 of Appendix A for the Current Year	21.9356%

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
						Transmission		
						Allocation /	Allocation /	Transmission
Line		Account 190	Account 282	Account 283	Total	Assignment Method	Assignment %	Total
	ADIT - Liberalized Depreciation (Amounts Including Adjustments)							
1	Liberalized Depreciation - Transmission		$ (1,517,725)		(1,517,725)	Assigned	100.0000%	(1,517,725)
2	Liberalized Depreciation - General Plant		$ (54,747)		(54,747)	Wages & Salaries	8.6350%	(4,727)
3	Liberalized Depreciation - Computer Software (Reverse Book Depreciation)		$ (13,852)		(13,852)	Wages & Salaries	8.6350%	(1,196)
4	Liberalized Depreciation - Computer Software (Tax Depreciation)		$ -		-	Wages & Salaries	8.6350%	-
5	**Total Liberalized Depreciation Amounts including Adjustments (Sum of Lines 1 - 4)**	$ -	$ (1,586,324)		$ (1,586,324)			$ (1,523,649)
	ADIT - Plant Related Other than Liberalized Depreciation							
6	Transmission Plant (net of GSU/GI Proportion)	127,311	(257,072)	-	(129,761)	Assigned	100.0000%	(129,761)
7	General Plant	3,511	(31,116)	-	(27,605)	Wages & Salaries	8.6350%	(2,384)
8	Plant - Other	53,426	(6,940)	(50,331)	(3,845)	Gross Plant	21.9356%	(843)
9	**Total Plant Related Other than Liberalized Depreciation (Sum of Lines 6 - 8)**	$ 184,248	$ (295,128)	$ (50,331)	$ (161,211)			$ (132,988)
	ADIT - Not Plant Related							
10	Employee Benefits	219,541	-	(63,713)	155,829	Wages & Salaries	8.6350%	13,456
11	Other Operating	8,146	-	(373)	7,773	Wages & Salaries	8.6350%	671
12	**Total Not Plant Related (Sum of Lines 10 - 11)**	$ 227,687	$ -	$ (64,085)	$ 163,602			$ 14,127
13	**Total ADIT used for Assignment or Allocation to Transmission (Sum of Lines 5, 9 & 12)**	**$ 411,935**	**$ (1,881,452)**	**$ (114,416)**	**$ (1,583,933)**			**$ (1,642,510)**
	Reconciliation to FERC Form 1 Accounts:							
14	Liberalized Depreciation not Allocated or Assigned to Transmission		(4,095,115)					
15	Total Amount of Excluded ADIT in Line 5 due to Adjustments		(53,698)					
16	Excluded Amounts (see Explanations below)	2,718,241	1,665,458	(1,410,059)				
17	**Total ADIT Not Used for Assignment or Allocation to Transmission (Sum of Lines 14-16)**	2,718,241	(2,483,355)	(1,410,059)				
18	**Total FERC Form 1 Balance (Sum of Lines 13 & 17)**	$ 3,130,176	$ (4,364,807)	$ (1,524,475)				

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	$ (1,642,510)
20	Transmission Total ADIT from Attachment 1A, Line 13 (Note 1)	December 31 of the Previous Year	$ (1,642,676)
21	Average Balance for Entry on Line 45 of Appendix A		$ (1,642,593)

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	$ 128
23	Amortization, Other	$ (834)
24	Current Year Amortization (Line 22 + 23)	$ (706)
25	Current Year Amortization from Form 1 (Current Year Items from p266.8f-g)	$ (706)
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: **2019**

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	8.3570%
Gross Plant Allocator from Line 18 of Appendix A for the Previous Year	21.3775%

(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		$ (1,517,725)		(1,517,725)	Assigned	100.0000%	(1,517,725)
2	Liberalized Depreciation - General Plant		$ (54,747)		(54,747)	Wages & Salaries	8.3570%	(4,575)
3	Liberalized Depreciation - Computer Software (Reverse Book Depreciation)		$ (13,852)		(13,852)	Wages & Salaries	8.3570%	(1,158)
4	Liberalized Depreciation - Computer Software (Tax Depreciation)		$ -		-	Wages & Salaries	8.3570%	-
5	**Total Liberalized Depreciation Amounts including Adjustments (Sum of Lines 1 - 4)**	$ -	$ (1,586,324)		$ (1,586,324)			$ (1,523,458)
	ADIT - Plant Related Other than Liberalized Depreciation							
6	Transmission Plant (net of GSU/GI Proportion)	127,311	(257,072)	-	(129,761)	Assigned	100.0000%	(129,761)
7	General Plant	3,511	(31,116)	-	(27,605)	Wages & Salaries	8.3570%	(2,307)
8	Plant - Other	53,426	(6,940)	(50,331)	(3,845)	Gross Plant	21.3775%	(822)
9	**Total Plant Related Other than Liberalized Depreciation (Sum of Lines 6 - 8)**	$ 184,248	$ (295,128)	$ (50,331)	$ (161,211)			$ (132,890)
	ADIT - Not Plant Related							
10	Employee Benefits	219,541	-	(63,713)	155,829	Wages & Salaries	8.3570%	13,023
11	Other Operating	8,146	-	(373)	7,773	Wages & Salaries	8.3570%	650
12	**Total Not Plant Related (Sum of Lines 10 - 11)**	$ 227,687	$ -	$ (64,085)	$ 163,602			$ 13,672
13	**Total ADIT used for Assignment or Allocation to Transmission (Sum of Lines 5, 9 & 12)**	**$ 411,935**	**$ (1,881,452)**	**$ (114,416)**	**$ (1,583,933)**			**$ (1,642,676)**
	Reconciliation to FERC Form 1 Accounts:							
14	Liberalized Depreciation not Allocated or Assigned to Transmission		(4,095,115)					
15	Total Amount of Excluded ADIT in Line 5 due to Adjustments		(53,584)					
16	Excluded Amounts (see Explanations below)	2,720,834	1,665,477	(1,410,059)				
17	**Total ADIT Not Used for Assignment or Allocation to Transmission (Sum of Lines 14-16)**	2,720,834	(2,483,221)	(1,410,059)				
18	**Total FERC Form 1 Balance (Sum of Lines 13 & 17)**	$ 3,132,769	$ (4,364,674)	$ (1,524,475)				

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 2019 and Later and True-ups of 2019 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:	2020	
Line 2	Number of Days in Year:	366	(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	2019	Dec	(1,588,077,790)					(1,588,077,790)
4	2020	Jan	(1,591,473,651)	(3,395,861)	336	0.918033	(3,117,511)	(1,591,195,301)
5	2020	Feb	(1,594,869,511)	(3,395,861)	307	0.838798	(2,848,441)	(1,594,043,742)
6	2020	Mar	(1,598,265,372)	(3,395,861)	276	0.754098	(2,560,813)	(1,596,604,555)
7	2020	Apr	(1,601,661,233)	(3,395,861)	246	0.672131	(2,282,464)	(1,598,887,019)
8	2020	May	(1,605,057,093)	(3,395,861)	215	0.587432	(1,994,836)	(1,600,881,855)
9	2020	Jun	(1,608,452,954)	(3,395,861)	185	0.505464	(1,716,487)	(1,602,598,342)
10	2020	Jul	(1,611,848,815)	(3,395,861)	154	0.420765	(1,428,859)	(1,604,027,201)
11	2020	Aug	(1,615,244,675)	(3,395,861)	123	0.336066	(1,141,232)	(1,605,168,433)
12	2020	Sep	(1,618,640,536)	(3,395,861)	93	0.254098	(862,883)	(1,606,031,316)
13	2020	Oct	(1,622,036,397)	(3,395,861)	62	0.169399	(575,255)	(1,606,606,571)
14	2020	Nov	(1,625,432,257)	(3,395,861)	32	0.087432	(296,906)	(1,606,903,477)
15	2020	Dec	(1,628,828,118)	(3,395,861)	1	0.002732	(9,278)	(1,606,912,755)

16	Total Transmission Plant In Service Net of GSU and GI Plant as a Percentage of Total Transmission Plant In Service:	94.45%
17	Amount to be Entered (in thousands) in Column D of the Account 282 Section of Attachments 1 and 1A Only When the Formula Rate Population is to Calculate a Projected ATRR:	(1,517,725,385)

<u>Explanations</u>:

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 15 multiplied by line 16.

Attachment 1B (Continued)
2020
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	2019	Dec	(56,023,120)					(56,023,120)
2	2020	Jan	(55,793,059)	230,061	336	0.918033	211,204	(55,811,916)
3	2020	Feb	(55,562,998)	230,061	307	0.838798	192,975	(55,618,941)
4	2020	Mar	(55,332,937)	230,061	276	0.754098	173,489	(55,445,452)
5	2020	Apr	(55,102,875)	230,061	246	0.672131	154,631	(55,290,821)
6	2020	May	(54,872,814)	230,061	215	0.587432	135,145	(55,155,676)
7	2020	Jun	(54,642,753)	230,061	185	0.505464	116,288	(55,039,388)
8	2020	Jul	(54,412,692)	230,061	154	0.420765	96,802	(54,942,586)
9	2020	Aug	(54,182,631)	230,061	123	0.336066	77,316	(54,865,270)
10	2020	Sep	(53,952,570)	230,061	93	0.254098	58,458	(54,806,812)
11	2020	Oct	(53,722,508)	230,061	62	0.169399	38,972	(54,767,840)
12	2020	Nov	(53,492,447)	230,061	32	0.087432	20,115	(54,747,725)
13	2020	Dec	(53,262,386)	230,061	1	0.002732	629	(54,747,096)
14	Amount to be Entered (in thousands) in Column D of the Account 282 Section of Attachments and 1 1A Only When the Formula Rate Population is to Calculate a Projected ATRR:							(54,747,096)

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 13.

Attachment 1B (Continued)
2020
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	2019	Dec	(17,105,765)					(17,105,765)
2	2020	Jan	(16,519,122)	586,643	336	0.918033	538,557	(16,567,208)
3	2020	Feb	(15,932,480)	586,643	307	0.838798	492,075	(16,075,133)
4	2020	Mar	(15,345,837)	586,643	276	0.754098	442,386	(15,632,747)
5	2020	Apr	(14,759,194)	586,643	246	0.672131	394,301	(15,238,446)
6	2020	May	(14,172,551)	586,643	215	0.587432	344,613	(14,893,833)
7	2020	Jun	(13,585,909)	586,643	185	0.505464	296,527	(14,597,306)
8	2020	Jul	(12,999,266)	586,643	154	0.420765	246,839	(14,350,467)
9	2020	Aug	(12,412,623)	586,643	123	0.336066	197,150	(14,153,317)
10	2020	Sep	(11,825,980)	586,643	93	0.254098	149,065	(14,004,252)
11	2020	Oct	(11,239,338)	586,643	62	0.169399	99,377	(13,904,875)
12	2020	Nov	(10,652,695)	586,643	32	0.087432	51,291	(13,853,584)
13	2020	Dec	(10,066,052)	586,643	1	0.002732	1,603	(13,851,981)
14	Amount to be Entered (in thousands) in Column D of the Account 282 Section of Attachments 1 and 1A Only When the Formula Rate Population is to Calculate a Projected ATRR:							(13,851,981)

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	2019	Dec	0					0
2	2020	Jan	0	0	336	0.918033	0	0
3	2020	Feb	0	0	307	0.838798	0	0
4	2020	Mar	0	0	276	0.754098	0	0
5	2020	Apr	0	0	246	0.672131	0	0
6	2020	May	0	0	215	0.587432	0	0
7	2020	Jun	0	0	185	0.505464	0	0
8	2020	Jul	0	0	154	0.420765	0	0
9	2020	Aug	0	0	123	0.336066	0	0
10	2020	Sep	0	0	93	0.254098	0	0
11	2020	Oct	0	0	62	0.169399	0	0
12	2020	Nov	0	0	32	0.087432	0	0
13	2020	Dec	0	0	1	0.002732	0	0
14	Amount to be Entered (in thousands) in Column D of the Account 282 Section of Attachments 1 and 1A Only When the Formula Rate Population is to Calculate a Projected ATRR:							0

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 1C - 2018
True-up of Accumulated Deferred Federal Income Taxes Associated with Pro-rata Liberalized Depreciation

Applicable Only to the True-up of 2018

If the formula rate population is for determining the 2018 true-up ATRR for use on Line A of Attachment 6, populate this Attachment 1C - 2018 with the actual data associated with that year. Use the amounts from line 17 of Part 1, and line 14 of Parts 2, 3, and 4, in populating Attachment 1 and Attachment 1A as instructed in this Attachment 1C - 2018.

Sheet 1 of 4

Line 1	True-up Year:	2018
Line 2	Number of Days in Year:	365

Part 1: Account 282, Transmission Plant In Service

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

Line	(1) Year	(2) Month	(3) Actual Transmission Plant In Service ADIT	(4) Actual Activity	(5) Projected Activity from Column (4) of Attachment 1B	(6) Activity Difference	(7) Reversal of Projected Activity Not Realized	(8) Activity Not in Projection	(9) Reversal of Projected Activity Not Realized With Proration	(10) Projected Activity With Proration from Column (7) of Attachment 1B	(11) ADIT Activity for True-up	(12) ADIT Balances for True-up
3	2017	Dec										-
4	2018	Jan		-		-	-	-	-		-	-
5	2018	Feb		-		-	-	-	-		-	-
6	2018	Mar		-		-	-	-	-		-	-
7	2018	Apr		-		-	-	-	-		-	-
8	2018	May		-		-	-	-	-		-	-
9	2018	Jun		-		-	-	-	-		-	-
10	2018	Jul		-		-	-	-	-		-	-
11	2018	Aug		-		-	-	-	-		-	-
12	2018	Sep		-		-	-	-	-		-	-
13	2018	Oct		-		-	-	-	-		-	-
14	2018	Nov		-		-	-	-	-		-	-
15	2018	Dec		-		-	-	-	-		-	-

Line	Description	Amount
15a	Pre-change -- Average of Actual ADIT Balance from Col.12, December 31, 2017 and December 31, 2018	-
15b	177 DaysDivided by 365 Days	48.49%
15c	Component of Average ADIT Balance Attributable to January 1 Through June 26 (15a X 15b)	-
15d	Post-change -- ADIT Balance for True-up from Col. 12, December 31, 2018	-
15e	188 Days Divided by 365 Days	51.51%
15f	Component of ADIT Balance Attributable to June 27 Through December 31 (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:	94.45%
17	Amount to be Entered (in thousands) in Column D of the Account 282 Section of Attachments 1 and 1A Only When the Formula Rate Population is to Calculate the 2018 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 15b	Effective date of change is June 27, 2018.
Col. 12, Line 15d	December 31, 2018 balance minus the sum of the activity in col. 8 times a factor of 50%.
Col. 12, Line 16	Appendix A, Line 24 ÷ Appendix A, Line 21 (from the true-up population of the formula).
Col. 12, Line 17	Col. 12, Line 15g multiplied by line 16.

Attachment 1C - 2018 (Continued)
2018
Sheet 2 of 4

Part 2: Account 282, General Plant

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

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
Line	Year	Month	Actual General Plant ADIT	Actual Activity	Projected Activity from Column (4) of Attachment 1B	Activity Difference	Reversal of Projected Activity Not Realized	Activity Not in Projection	Reversal of Projected Activity Not Realized With Proration	Projected Activity With Proration from Column (7) of Attachment 1B	ADIT Activity for True-up	ADIT Balances for True-up
1	2017	Dec										-
2	2018	Jan		-		-	-	-	-		-	-
3	2018	Feb		-		-	-	-	-		-	-
4	2018	Mar		-		-	-	-	-		-	-
5	2018	Apr		-		-	-	-	-		-	-
6	2018	May		-		-	-	-	-		-	-
7	2018	Jun		-		-	-	-	-		-	-
8	2018	Jul		-		-	-	-	-		-	-
9	2018	Aug		-		-	-	-	-		-	-
10	2018	Sep		-		-	-	-	-		-	-
11	2018	Oct		-		-	-	-	-		-	-
12	2018	Nov		-		-	-	-	-		-	-
13	2018	Dec		-		-	-	-	-		-	-

13a	Pre-change -- Average of Actual ADIT Balance from Col. 12, December 31, 2017 and December 31, 2018	-
13b	177 Days Divided by 365 Days	48.49%
13c	Component of Average ADIT Balance Attributable to January 1 Through June 26 (13a X 13b)	-
13d	Post-change -- ADIT Balance for True-up from Col. 12, December 31, 2018	-
13e	188 Days Divided by 365 Days	51.51%
13f	Component of ADIT Balance Attributable to June 27 Through December 31 (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 Attachments 1 and 1A Only When the Formula Rate Population is to Calculate the 2018 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 13d	December 31, 2018 balance minus the sum of the activity in col. 8 times a factor of 50%.
Col. 12, Line 14	Amount from col. 12, line 13g.

Attachment 1C - 2018 (Continued)
2018
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	2017	Dec										-
2	2018	Jan		-		-	-	-	-		-	-
3	2018	Feb		-		-	-	-	-		-	-
4	2018	Mar		-		-	-	-	-		-	-
5	2018	Apr		-		-	-	-	-		-	-
6	2018	May		-		-	-	-	-		-	-
7	2018	Jun		-		-	-	-	-		-	-
8	2018	Jul		-		-	-	-	-		-	-
9	2018	Aug		-		-	-	-	-		-	-
10	2018	Sep		-		-	-	-	-		-	-
11	2018	Oct		-		-	-	-	-		-	-
12	2018	Nov		-		-	-	-	-		-	-
13	2018	Dec		-		-	-	-	-		-	-

13a	Pre-change -- Average of Actual ADIT Balance from Col. 12, December 31, 2017 and December 31, 2018	-
13b	177 Days Divided by 365 Days	48.49%
13c	Component of Average ADIT Balance Attributable to January 1 Through June 26 (13a X 13b)	-
13d	Post-change -- ADIT Balance for True-up from Col. 12, December 31, 2018	-
13e	188 Days Divided by 365 Days	51.51%
13f	Component of ADIT Balance Attributable to June 27 Through December 31 (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 Attachments 1 and 1A Only When the Formula Rate Population is to Calculate the 2018 True-up ATRR: -

Attachment 1C - 2018 (Continued)
2018
Sheet 4 of 4

Part 4: Account 282, Computer Software - Tax Amortization

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

Line	(1) Year	(2) Month	(3) Actual Computer Software Tax Amount ADIT	(4) Actual Activity	(5) Projected Activity from Column (4) of Attachment 1B	(6) Activity Difference	(7) Reversal of Projected Activity Not Realized	(8) Activity Not in Projection	(9) Reversal of Projected Activity Not Realized With Proration	(10) Projected Activity With Proration from Column (7) of Attachment 1B	(11) ADIT Activity for True-up	(12) ADIT Balances for True-up
1	2017	Dec										-
2	2018	Jan		-		-	-	-	-		-	-
3	2018	Feb		-		-	-	-	-		-	-
4	2018	Mar		-		-	-	-	-		-	-
5	2018	Apr		-		-	-	-	-		-	-
6	2018	May		-		-	-	-	-		-	-
7	2018	Jun		-		-	-	-	-		-	-
8	2018	Jul		-		-	-	-	-		-	-
9	2018	Aug		-		-	-	-	-		-	-
10	2018	Sep		-		-	-	-	-		-	-
11	2018	Oct		-		-	-	-	-		-	-
12	2018	Nov		-		-	-	-	-		-	-
13	2018	Dec		-		-	-	-	-		-	-

Line		
13a	Pre-change -- Average of Actual ADIT Balance from Col. 12, December 31, 2017 and December 31, 2018	-
13b	177 Days Divided by 365 Days	48.49%
13c	Component of Average ADIT Balance Attributable to January 1 Through June 26 (13a X 13b)	-
13d	Post-change -- ADIT Balance for True-up from Col. 12, December 31, 2018	-
13e	188 Days Divided by 365 Days	51.51%
13f	Component of ADIT Balance Attributable to June 27 Through December 31 (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 Attachments 1 and 1A Only When the Formula Rate Population is to Calculate the 2018 True-up ATRR: -

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 2019 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 line 17 of Part 1, and line 14 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 Attachments 1 and 1A 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 times a factor of 50%, 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 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 Attachments 1 and 1A 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 times a factor of 50%, 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 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 Attachments 1 and 1A 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 Attachments 1 and 1A Only When the Formula Rate Population is to Calculate a True-up ATRR: -

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 2 - Taxes Other Than Income Worksheet
2020 (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)	$ 65,137	100.0000%	$ 65,137
1a	Other Plant Related Taxes	0	21.9356%	-
2				-
3				-
4				-
5				-
				-
Total Plant Related		$ 65,137		$ 65,137
Labor Related			***Wages & Salary Allocator***	
6	Federal FICA & Unemployment & State Unemployment	$ 45,870		
Total Labor Related		$ 45,870	8.6350%	$ 3,961
Other Included			***Gross Plant Allocator***	
7	Sales and Use Tax	$ -		
Total Other Included		$ -	21.9356%	$ -
Total Included		$ 111,007		$ 69,098
	Currently Excluded			
8	Business and Occupation Tax - West Virginia	$ 21,343		
9	Gross Receipts Tax	0		
10	IFTA Fuel Tax	0		
11	Property Taxes - Other	201,017		
12	Property Taxes - Generator Step-Ups and Interconnects	2,947		
13	Sales and Use Tax - not allocated to Transmission	4,755		
14	Sales and Use Tax - Retail	0		
15	Other	15,981		
16		0		
17		0		
18		0		
19		0		
20		0		
21	Total "Other" Taxes (included on p. 263)	$ 246,042		
22	Total "Taxes Other Than Income Taxes" - acct 408.10 (p. 114.14)	$ 357,049		
23	Difference	$ (111,007)		

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
2020 (000's)

Directly Assigned Property Taxes	$	269,101
Production Property Tax		100,770
Transmission Property Tax		64,987
GSU/Interconnect Facilities		2,947
Distribution Property tax		98,658
General Property Tax		1,739
Total check		269,101

Allocation of General Property Tax to Transmission

General Property Tax	$	1,739
Wages & Salary Allocator		8.6350%
Trans General		150

Total Transmission Property Taxes		
Transmission	$	64,987
General		150
Total Transmission Property Taxes	$	65,137

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 3 - Revenue Credit Workpaper
2020 (000's)

Line			Transmission Related	Production/Other Related	Total
	Account 454 - Rent from Electric Property				
1	Rent from Electric Property - Transmission Related (Note 3)		13,818		13,818
2	Total Rent Revenues	(Sum Lines 1)	13,818	-	13,818
	Account 456 - Other Electric Revenues (Note 1)				
3	Schedule 1A				
4	Net revenues associated with Network Integration Transmission Service (NITS) and for the transmission component of the NCEMPA contract rate for which the load is not included in the divisor. (Note 4)		1,483		1,483
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)		2,032		2,032
9	Revenues from Directly Assigned Transmission Facility Charges (Note 2)		36,230		36,230
10	Rent or Attachment Fees associated with Transmission Facilities (Note 3)				-
11	Gross Revenue Credits (Accounts 454 and 456)	(Sum Lines 2-10)	53,563	-	53,563
12	Less line 14g		(9,363)	-	(9,363)
13	Total Revenue Credits		44,200	-	44,200
	Revenue Adjustment to Determine Revenue Credit				
14a	Revenues included in lines 1-11 which are subject to 50/50 sharing. (Lines 1 + 8 + 10)		15,850	-	15,850
14b	Costs associated with revenues in line 14a		2,876	-	2,876
14c	Net Revenues (14a - 14b)		12,974	-	12,974
14d	50% Share of Net Revenues (14c / 2)		6,487	-	6,487
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)		6,487	-	6,487
14g	Line 14f less line 14a		(9,363)	-	(9,363)

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. Notwithstanding the above, the revenue crediting of the UG Transmission Charge revenues shall be in accordance with section 6 of Attachment 10.

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
2020 (000's)

	Return and Taxes with Basis Point increase in ROE				
A		Basis Point increase in ROE and Income Taxes		(Line 130 + 140)	696,568
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)	6,522,517
	Long Term Interest				
104		**Long Term Interest**		p117.62c through 67c	503,802
105		Less LTD Interest on Securitizatic (Note P)		Attachment 8	0
106		Long Term Interest		(Line 104 - 105)	503,802
107	Preferred Dividends		enter positive	p118.29c	0
	Common Stock				
108		Proprietary Capital		p112.16c,d/2	12,634,978
109		Less Preferred Stock	enter negative	(Line 117)	0
110		Less Account 219 - Accumulated Other Comprehensive Income	enter negative	p112.15c,d/2	-25,340
111		Common Stock		(Sum Lines 108 to 110)	12,609,638
	Capitalization				
112		Long Term Debt		p112.24c,d/2	11,582,604
113		Less Loss on Reacquired Debt	enter negative	p111.81c,d/2	-827
114		Plus Gain on Reacquired Debt	enter positive	p113.61c,d/2	3,177
115		Less LTD on Securitization Bonds	enter negative	Attachment 8	0
116		Total Long Term Debt		(Sum Lines 112 to 115)	11,584,954
117		Preferred Stock		p112.3c,d/2	0
118		Common Stock		(Line 111)	12,609,638
119		Total Capitalization		(Sum Lines 116 to 118)	24,194,592
120		Debt %	Total Long Term Debt	(Line 116 / 119)	47.9%
121		Preferred %	Preferred Stock	(Line 117 / 119)	0.0%
122		Common %	Common Stock	(Line 118 / 119)	52.1%
123		Debt Cost	Total Long Term Debt	(Line 106 / 116)	0.0435
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)	0.0208
127		Weighted Cost of Preferred	Preferred Stock	(Line 121 * 124)	0.0000
128		Weighted Cost of Common	Common Stock	(Line 122 * 125)	0.0646
129	Total Return (R)			**(Sum Lines 126 to 128)**	**0.0854**
130	Investment Return = Rate Base * Rate of Return			**(Line 62 * 129)**	**557,341**

Composite Income Taxes

	Income Tax Rates				
131		FIT=Federal Income Tax Rate			0.2100
132		SIT=State Income Tax Rate or Composite			0.0585
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)} =		0.2562
135		T/ (1-T)			0.3445
	Transmission Related Income Tax Adjustments				
136	Amortized Investment Tax Credit (ITC)	(Note I) enter negative	Attachment 1		$ (128)
136A	Other Income Tax Adjustments		Attachment 5		$ (4,314)
137	T/(1-T)		(Line 135)		34.45%
138	**Transmission Income Taxes - Income Tax Adjustments**		((Line 136 + 136A) * (1 + Line 137))		**$ (5,973)**
139	**Transmission Income Taxes - Equity Return =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =	[Line 135 * 130 * (1-(126 / 129))]		**145,201**
140	**Total Transmission Income Taxes**		**(Line 138 + 139)**		**139,228**

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 5 - Cost Support
2020 (000's)

Electric / Non-electric Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Previous Year Form 1Dec	Current Year 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	44,117,049	44,220,710	44,388,939	44,561,176	44,698,762	45,053,284	45,485,725	45,618,468	45,796,444	45,882,852	45,986,315	46,114,044	47,602,275	45,348,157	0	
15	Accumulated Depreciation (Total Electric Plant)	(Notes A & Q)	p219.29c	13,189,450	13,272,731	13,355,667	13,435,110	13,518,162	13,602,070	13,684,064	13,768,883	13,853,652	13,936,480	14,022,594	14,109,801	14,196,591	13,688,097	0	
12	Accumulated Intangible Amortization	(Notes A & Q)	p200.21c	149,654	150,686	151,718	152,750	153,782	154,814	155,846	156,878	157,910	158,942	159,974	161,006	162,038	155,846	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	10,140,492	10,154,771	10,172,953	10,256,396	10,294,672	10,404,289	10,456,032	10,491,355	10,556,364	10,554,363	10,552,081	10,586,319	10,896,185	10,424,329	0	
15	Generator Step-Ups		Trans. Input Sht	408,461	408,461	408,461	408,461	408,461	408,461	408,461	408,461	408,461	408,461	408,461	408,461	408,461	408,461	0	
23	Generator Interconnect Facilities		Input Sht	170,113	170,113	170,113	170,113	170,113	170,113	170,113	170,113	170,113	170,113	170,113	170,113	170,113	170,113		
25	General & Intangible		p205.5.g & p207.99.g/G&I Wksht	1,149,307	1,153,902	1,158,497	1,163,092	1,167,686	1,172,281	1,176,876	1,181,471	1,186,066	1,190,661	1,195,256	1,199,851	1,204,446	1,176,876	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	1,800,918	1,819,144	1,837,405	1,855,773	1,874,271	1,892,926	1,911,751	1,930,668	1,949,693	1,968,784	1,987,872	2,006,995	2,026,480	1,912,514	0	
33	Transmission Accumulated Depreciation - Generator Step-Ups		GSU Input Sht	114,952	115,991	117,031	118,070	119,109	120,148	121,188	122,227	123,266	124,305	125,345	126,384	127,423	121,188	0	
34	Transmission Accumulated Depreciation - Interconnection Facilities		Input Sht	27,667	28,100	28,533	28,966	29,399	29,831	30,264	30,697	31,130	31,563	31,996	32,428	32,861	30,264		
36	Accumulated General Depreciation	(Notes A & Q)	p219.28.b	406,669	408,772	410,874	412,977	415,079	417,181	419,284	421,386	423,489	425,591	427,694	429,796	431,898	419,284	0	
	Materials and Supplies																		
50	Undistributed Stores Exp	(Notes A & R)	p227.16 b&c	-												-	-	0	Respondent is Electric Utility only.
	Materials & Supplies Assigned to Transmission Construction (Estimated)	(Note A)	M&S Input Sht	22,662												22,662	22,662	0	
	Materials & Supplies Assigned to Transmission O&M (Estimated)	(Note A)	p227.8 b&c	1,326												1,326	1,326	0	
53	Transmission Materials & Supplies																23,988	0	
	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														261,253	0	
91	Depreciation-General	(Note A)															46,092	0	
92	Depreciation-Intangible	(Note A)	p336.1d&e/Attachment 5														35,598	0	Respondent is Electric Utility only.
87	Depreciation - Generator Step-Ups																12,471	0	
88	Depreciation - Interconnection Facilities																5,194	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

Line #s	Descriptions	Notes	Page #'s & Instructions	Previous Year Form 1Dec	Current Year 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	-	6,018	6,536	7,014	5,696	6,596	7,000	6,748	6,555	6,916	7,489	6,307	6,538	79,413	(12,068)	
64	Generator Step-Ups		Input Sheet		-	-	-	-	-	-	-	-	-	-	-	-	29	0	
65	Transmission by Others		p321.96.b	-	(2,219)	(2,219)	(2,219)	(2,219)	(2,219)	(2,219)	(2,219)	(2,219)	(2,219)	(2,219)	(2,219)	(2,219)	(26,632)	0	

Wages & Salary

Line #s	Descriptions	Notes	Page #'s & Instructions	Previous Year Form 1Dec	Current Year 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														621,125	0	
5	Total A&G Wages Expense	(Note A)	p354.27b/Trans. Wksht														98,841	0	
1	Transmission Wages	(Note A)	p354.21b/Trans. Wksht														45,121	0	
2	Generator Step-Ups		Trans. Wksht														22	0	

based on plant records.

Transmission / Non-transmission Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Previous Year Form 1Dec	Current Year 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	13,268	13,268	13,268	13,268	13,268	13,268	13,268	13,268	13,268	13,268	13,268	13,268	13,268	13,268	11,046	Specific identification based on plant records. The following plant investments are included:
																Form 1 Amount	Transmission Related	Non-transmission Related	
																13,268	2,222	11,046	Enter Details

EPRI Dues Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1 Amount	EPRI Dues	Details
	Allocated General & Common Expenses					
73	Less EPRI Dues	(Note D)	p352-353/Attachment 5	$3,368	3,368	See Form 1

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 5 - Cost Support
2020 (000's)

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	$ 34,844	365	34,479	See FERC Form 1 pages 350-351.
	Directly Assigned A&G						
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b/Attachment 5		365		

Safety Related Advertising Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1 Amount	Safety Related	Non-safety Related	Details
	Directly Assigned A&G						
81	General Advertising Exp Account 930.1	(Note F)	Attachment 5	3,532	-	3,532	

MultiState Workpaper

Line #s	Descriptions	Notes	Page #'s & Instructions	State 1	State 2	State 3	State 4	State 5	Details
	Income Tax Rates								
				Va	NC	Wva			Enter Calculation
132	SIT=State Income Tax Rate or Composite	(Note I)		5.61%	0.09%	0.15%			5.85%

Education and Out Reach Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1 Amount	Education & Outreach	Other		Details
	Directly Assigned A&G							
78	General Advertising Exp Account 930.1	(Note K)	p323.191b	3,532	-	3,532	-	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

Instructions:

1 Remove all investment below 69 kV or generator step up transformers included in transmission plant in service that are not a result of the RTEP Process

2 If unable to determine the investment below 69kV in a substation with investment of 69 kV and higher as well as below 69 kV, the following formula will be used:

		Example
A	Total investment in substation	1,000,000
B	Identifiable investment in Transmission (provide workpapers)	500,000
C	Identifiable investment in Distribution (provide workpapers)	400,000
D	Amount to be excluded (A x (C / (B + C)))	444,444

Add more lines if necessary

Transmission Related Account 242 Reserves

Line #s	Descriptions	Notes	Page #'s & Instructions	Beginning Year Balance	End of Year Balance	Average Balance	Allocation	Transmission Related		Details
47	Transmission Related Account 242 Reserves (exclude current year environmental site related reserves)			Enter $	Enter $			Amount		
	Directly Assignable to Transmission			$ 14,934	$ 20,389	$ 17,661	100%	17,661		
	Labor Related, General plant related or Common Plant related			$ 956	$ 2,920	$ 1,938	8.635%	167		
	Plant Related			$ 5,404	$ 6,010	$ 5,707	21.94%	1,252		
	Other			$ 110,030	$ 301,393	$ 205,712	0.00%	-		
	Total Transmission Related Reserves			$ -	$ -	$ -		19,081	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								8.635%		
	Pension Liabilities, if any, in Account 242			$ 7	$ 12			$ 9	8.635%	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	$ 29,415	$ 27,745	$ 28,580	$ 3,980	$ 24,600	8.635%	2,124	
	Prepaid Pensions if not included in Prepayments							$ -	8.635%	-	

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

Outstanding Network Credits Cost Support

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

Extraordinary Property Loss

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

Interest on Outstanding Network Credits Cost Support

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

Facility Credits under Section 30.9 of the PJM OATT.

Line #s	Descriptions	Notes	Page #'s & Instructions	Amount	Description & PJM Documentation
	Revenue Requirement				
165	Facility Credits under Section 30.9 of the PJM OATT.			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	19,930.0	

A&G Expenses - Other Post Employment Benefits

Line #s	Descriptions	Notes	Page #'s & Instructions	Amount
	Total A&G Expenses		p323.197b	365,986
	Less OPEB Current Year			35,482
	Plus: Stated OPEB		Fixed (from FERC accepted § 205 Filing)	(41,641)
69	Current Year Total A&G Expenses			359,827

Interest on Long-Term Debt

Line #s	Descriptions	Notes	Page #'s & Instructions	Amount
	Interest on Long-Term Debt		p117.62c through 67c	509,120
	Less Interest on Short-Term Debt Included in Account 430			(5,318)
104	Total Interest on Long-Term Debt			503,802

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	$ 4,343	X	25.62%	=	$ 1,113			
	Amortization of Excess/Deficient Deferred Taxes -- Transmission Component										
	Amortized Excess Deferred Taxes	(Note C)	Inst. 1, 3, 4, below (Enter Negative)					$ (5,427)	$ 2,271	$ 2,219	$ 2,245
	Amortized Deficient Deferred Taxes	(Note C)	Inst. 1, 3, 4, below (Enter Positive)								$ -
136A	Total Other Income Tax Adjustments to Line 136A							$ (4,314)			
47A	Unamortized Exc/Def Deferral to Line 47A										$ 2,245

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	8,804	8,804	8,804	8,804	8,804	8,804	8,804	8,804	8,804	8,804	8,804	8,804	8,804	8,804	0	
60B	Accumulated Provision for Amortization of Line 60A Amount		Inst. 2	495	512	529	546	563	580	597	614	631	648	665	682	700	597	0	
90A	Amortization of Acquisition Adjustments Amount		Inst. 3														205		
45A	Accumulated Deferred Income Taxes Attributable to Acquisition Adjustments	Note 1	Inst. 4	(401)												(401)	(401)		

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.	937,928.95
B	ATRR based on projected costs included for the previous calendar year but excludes the true-up adjustment.	910,972.18
C	Difference (A-B)	26,957
D	Future Value Factor (1+i)^24	1.10221
E	True-up Adjustment (C*D)	29,712

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.

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

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

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

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

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

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

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

1 New Plant Carrying Charge

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

		Formula Line		
3	A	154	Net Plant Carrying Charge without Acquisition Adjustments and Depreciation	10.4521%
4	B	161	Net Plant Carrying Charge with 100 Basis Point increase in ROE without Acquisition Adjustments and Depreciation	11.0174%
5	C		Line B less Line A	0.5653%

6 **FCR if a CIAC**

7	D	155	Net Plant Carrying Charge without Acquisition Adjustments, Depreciation, Return or Income Taxes	2.4015%

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

8 **The FCR resulting from Formula is for the rate period only.**
9 **Therefore actual revenues collected or the lack of revenues collected in other years are not applicable. Depreciation will be calculated for each project using the applicable Life input in effect during the months of each calendar year the project was in service.**

10			10	Details			**Project A**				**Project A-1**		
11	Schedule 12	(Yes or No)	11	Schedule 12	(Yes or No)	Yes	b0217			Yes	b0217		
12	Life		12	Life		40	Upgrade Mt.Storm - Doubs 500 kV			40	Upgrade Mt.Storm - Doubs 500 kV		
13	FCR W/O incentive	Line 3	13	FCR W/O incentive	Line 3	10.4521%				10.4521%	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)		10.4521%				10.4521%			
16	Investment		16	Investment		1,039,321				911,807			
17	Annual Depreciation Exp		17	Annual Depreciation Exp		25,983				22,795			
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								
46	W / O incentive	2019	46	W / O incentive	2019	788,878	25,983	762,895		814,088	22,795	791,293	
47	W incentive	2019	47	W incentive	2019	788,878	25,983	762,895		814,088	22,795	791,293	
48	W / O incentive	2020	48	W / O incentive	2020	762,895	25,983	736,912	104,364	791,293	22,795	768,498	104,311
49	W incentive	2020	49	W incentive	2020	762,895	25,983	736,912	104,364	791,293	22,795	768,498	104,311

50
51

Lines continue as new rate years are added.

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*	120,315	120,131
B	Proj Rev Req w/ Incentive PCY*	Projected Revenue Requirement with Incentive for Previous Calendar Year*	120,315	120,131
C	Actual Rev Req w/o Incentive PCY*	Actual Revenue Requirement without Incentive for Previous Calendar Year *	110,781	110,091
D	Actual Rev Req w/ Incentive PCY*	Actual Revenue Requirement with Incentive for Previous Calendar Year *	110,781	110,091
E	TUA w/o Int w/o Incentive PCY (C-A)	True-Up Adjustment Before Interest without Incentive for Previous Calendar Year (C-A)	(9,533)	(10,041)
F	TUA w/o Int w/ Incentive PCY (B-D)	True-Up Adjustment Before Interest with Incentive for Previous Calendar Year (B-D)	(9,533)	(10,041)
G	Future Value Factor (1+i)^24 mo (ATT6)	Future Value Factor (1+i)^24 months from Attachment 6	1.10221	1.10221
H	True-Up Adjustment w/o Incentive (E*G)	True-Up Adjustment without Incentive (E*G)	(10,508)	(11,067)
I	True-Up Adjustment w/ Incentive (F*G)	True-Up Adjustment with Incentive (F*G)	(10,508)	(11,067)

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	93,856	93,244
W incentive	W incentive	93,856	93,244

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

Line	Item		Project B				Project B-1				Project E			
10														
11	Schedule 12 (Yes or No)		Yes	b0222			Yes	b0222			Yes	B0226		
12	Life		40	Install 150 MVAR capacitor			40	Install 150 MVAR capacitor			40	Install 500/230 kV transformer at		
13	FCR W/O incentive Line 3		10.4521%	at Loudoun			10.4521%	at Loudoun - Replacement of			10.4521%	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)		10.4521%				10.4521%				10.4521%			
16	Investment		1,070,848				591,996				7,557,110			
17	Annual Depreciation Exp		26,771				14,800				188,928			
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	1,070,848	6,124	1,064,724									
46	W / O incentive	2019	786,562	26,771	759,791		511,342	14,800	496,542		5,686,699	188,928	5,497,772	
47	W incentive	2019	786,562	26,771	759,791		511,342	14,800	496,542		5,686,699	188,928	5,497,772	
48	W / O incentive	2020	759,791	26,771	733,020	104,786	496,542	14,800	481,742	65,926	5,497,772	188,928	5,308,844	753,686
49	W incentive	2020	759,791	26,771	733,020	104,786	496,542	14,800	481,742	65,926	5,497,772	188,928	5,308,844	753,686
50														
51														
A	Proj Rev Req w/o Incentive PCY*					121,550				75,939				876,732
B	Proj Rev Req w/ Incentive PCY*					121,550				75,939				876,732
C	Actual Rev Req w/o Incentive PCY*					111,366				69,657				800,289
D	Actual Rev Req w/ Incentive PCY*					111,366				69,657				800,289
E	TUA w/o Int w/o Incentive PCY (C-A)					(10,184)				(6,282)				(76,443)
F	TUA w/o Int w/ Incentive PCY (B-D)					(10,184)				(6,282)				(76,443)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.10221				1.10221				1.10221
H	True-Up Adjustment w/o Incentive (E*G)					(11,225)				(6,924)				(84,257)
I	True-Up Adjustment w/ Incentive (F*G)					(11,225)				(6,924)				(84,257)
	W / O incentive					93,562				59,001				669,430
	W incentive					93,562				59,001				669,430

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)

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

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

10			**Project E-1**				**Project G-1**				**Project G-1A**			
11	Schedule 12 (Yes or No)		Yes	B0226			Yes	B0403			Yes	B0403		
12	Life		40	Install 500/230 kV transformer at			40	2nd Dooms 500/230 kV transformer			40	2nd Dooms 500/230 kV transformer		
13	FCR W/O incentive Line 3		10.4521%	Clifton and Clifton 500 KV 150 MVAR			10.4521%	addition			10.4521%	addition		
14	Incentive Factor (Basis Points /100)		0	capacitor			0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.4521%				10.4521%				10.4521%			
16	Investment		914,051				6,810,242				516,125			
17	Annual Depreciation Exp		22,851				170,256				12,903			
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												
46	W / O incentive	2019	863,920	22,851	841,069		5,158,067	170,256	4,987,811		481,817	12,903	468,914	
47	W incentive	2019	863,920	22,851	841,069		5,158,067	170,256	4,987,811		481,817	12,903	468,914	
48	W / O incentive	2020	841,069	22,851	818,217	109,566	4,987,811	170,256	4,817,555	682,689	468,914	12,903	456,010	61,240
49	W incentive	2020	841,069	22,851	818,217	109,566	4,987,811	170,256	4,817,555	682,689	468,914	12,903	456,010	61,240
50														
51														
A	Proj Rev Req w/o Incentive PCY*					125,144				787,042				70,510
B	Proj Rev Req w/ Incentive PCY*					125,144				787,042				70,510
C	Actual Rev Req w/o Incentive PCY*					115,420				724,727				64,538
D	Actual Rev Req w/ Incentive PCY*					115,420				724,727				64,538
E	TUA w/o Int w/o Incentive PCY (C-A)					(9,725)				(62,315)				(5,972)
F	TUA w/o Int w/ Incentive PCY (B-D)					(9,725)				(62,315)				(5,972)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.10221				1.10221				1.10221
H	True-Up Adjustment w/o Incentive (E*G)					(10,719)				(68,685)				(6,583)
I	True-Up Adjustment w/ Incentive (F*G)					(10,719)				(68,685)				(6,583)
	W / O incentive					98,847				614,004				54,658
	W incentive					98,847				614,004				54,658

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

Line	Item		**Project G-2**				**Project G-2A**				**Project H-1**			
11	Schedule 12 (Yes or No)		Yes	B0403			Yes	B0403			Yes	b0328.1		
12	Life		40	2nd Dooms 500/230 kV transformer			40	2nd Dooms 500/230 kV transformer			40	Build new Meadowbrook-Loudon 500kV circuit		
13	FCR W/O incentive Line 3		10.4521%	addition			10.4521%	addition			10.4521%	(30 of 50 miles)		
14	Incentive Factor (Basis Points /100)		0				0				1.5			
15	FCR W incentive L.13 +(L.14*L.5)		10.4521%	Spare Transformer Addition			10.4521%	Spare Transformer Addition			11.3001%	line 2101 v11		
16	Investment		2,245,293				257,907				21,850,320			
17	Annual Depreciation Exp		56,132				6,448				546,258			
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												
46	W / O incentive	2019	1,762,951	56,132	1,706,819		240,763	6,448	234,316		17,227,760	546,258	16,681,502	
47	W incentive	2019	1,762,951	56,132	1,706,819		240,763	6,448	234,316		17,227,760	546,258	16,681,502	
48	W / O incentive	2020	1,706,819	56,132	1,650,686	231,597	234,316	6,448	227,868	30,602	16,681,502	546,258	16,135,244	2,261,276
49	W incentive	2020	1,706,819	56,132	1,650,686	231,597	234,316	6,448	227,868	30,602	16,681,502	546,258	16,135,244	2,400,413
50														
51														
A	Proj Rev Req w/o Incentive PCY*					266,936				35,234				2,606,246
B	Proj Rev Req w/ Incentive PCY*					266,936				35,234				2,785,276
C	Actual Rev Req w/o Incentive PCY*					245,533				32,249				2,396,986
D	Actual Rev Req w/ Incentive PCY*					245,533				32,249				2,542,986
E	TUA w/o Int w/o Incentive PCY (C-A)					(21,402)				(2,984)				(209,260)
F	TUA w/o Int w/ Incentive PCY (B-D)					(21,402)				(2,984)				(242,290)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.10221				1.10221				1.10221
H	True-Up Adjustment w/o Incentive (E*G)					(23,590)				(3,289)				(230,648)
I	True-Up Adjustment w/ Incentive (F*G)					(23,590)				(3,289)				(267,054)
	W / O incentive					208,007				27,312				2,030,628
	W incentive					208,007				27,312				2,133,359

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

Line			Project H-2				Project H-3				Project H-4			
10														
11	Schedule 12 (Yes or No)		Yes	b0328.1			Yes	b0328.1			Yes	b0328.1		
12	Life		40	Build new Meadowbrook-Loudon 500kV circuit			40	Build new Meadowbrook-Loudon 500kV circuit			40	Build new Meadowbrook-Loudon 500kV circuit		
13	FCR W/O incentive Line 3		10.4521%	(30 of 50 miles)			10.4521%	(30 of 50 miles)			10.4521%	(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)		11.3001%	Line 2030 & 559 v12 & v13			11.3001%	Line 580 - Phase 1			11.3001%	Line 124		
16	Investment		45,089,209				13,581,000				11,224,282			
17	Annual Depreciation Exp		1,127,230				339,525				280,607			
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												
46	W / O incentive	2019	35,992,381	1,127,230	34,865,150		10,996,347	339,525	10,656,822		9,033,124	280,607	8,752,517	
47	W incentive	2019	35,992,381	1,127,230	34,865,150		10,996,347	339,525	10,656,822		9,033,124	280,607	8,752,517	
48	W / O incentive	2020	34,865,150	1,127,230	33,737,920	4,712,458	10,656,822	339,525	10,317,297	1,435,642	8,752,517	280,607	8,471,910	1,180,763
49	W incentive	2020	34,865,150	1,127,230	33,737,920	5,003,322	10,656,822	339,525	10,317,297	1,524,568	8,752,517	280,607	8,471,910	1,253,792
50														
51														
A	Proj Rev Req w/o Incentive PCY*					5,430,939				1,654,377				1,360,717
B	Proj Rev Req w/ Incentive PCY*					5,804,884				1,768,594				1,454,553
C	Actual Rev Req w/o Incentive PCY*					4,993,046				1,520,347				1,250,702
D	Actual Rev Req w/ Incentive PCY*					5,298,012				1,613,500				1,327,231
E	TUA w/o Int w/o Incentive PCY (C-A)					(437,893)				(134,030)				(110,015)
F	TUA w/o Int w/ Incentive PCY (B-D)					(506,872)				(155,094)				(127,322)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.10221				1.10221				1.10221
H	True-Up Adjustment w/o Incentive (E*G)					(482,651)				(147,729)				(121,260)
I	True-Up Adjustment w/ Incentive (F*G)					(558,680)				(170,947)				(140,336)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	H-2	H-3	H-4
W / O incentive	4,229,807	1,287,913	1,059,503
W incentive	4,444,643	1,353,622	1,113,456

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

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

			Project H-5				Project H-6				Project H-7			
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		40	Build new Meadowbrook-Loudon 500kV circuit			40	Build new Meadowbrook-Loudon 500kV circuit			40	Build new Meadowbrook-Loudon 500kV circuit		
13	FCR W/O incentive Line 3		10.4521%	(30 of 50 miles)			10.4521%	(30 of 50 miles)			10.4521%	(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)		11.3001%	Line 114			11.3001%	Clevenger DP/580			11.3001%	Line 580 - Phase 2		
16	Investment		14,655,559				16,900,800				11,362,770			
17	Annual Depreciation Exp		366,389				422,520				284,069			
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												
46	W / O incentive	2019	11,842,456	366,389	11,476,067		13,739,575	422,520	13,317,055		9,293,110	284,069	9,009,041	
47	W incentive	2019	11,842,456	366,389	11,476,067		13,739,575	422,520	13,317,055		9,293,110	284,069	9,009,041	
48	W / O incentive	2020	11,476,067	366,389	11,109,678	1,546,730	13,317,055	422,520	12,894,535	1,792,349	9,009,041	284,069	8,724,972	1,210,857
49	W incentive	2020	11,476,067	366,389	11,109,678	1,642,490	13,317,055	422,520	12,894,535	1,903,482	9,009,041	284,069	8,724,972	1,286,046
50														
51														

	Item	Project H-5	Project H-6	Project H-7
A	Proj Rev Req w/o Incentive PCY*	1,782,413	2,065,380	1,395,255
B	Proj Rev Req w/ Incentive PCY*	1,905,423	2,208,080	1,491,763
C	Actual Rev Req w/o Incentive PCY*	1,638,108	1,897,828	1,281,841
D	Actual Rev Req w/ Incentive PCY*	1,738,431	2,014,212	1,360,553
E	TUA w/o Int w/o Incentive PCY (C-A)	(144,305)	(167,552)	(113,414)
F	TUA w/o Int w/ Incentive PCY (B-D)	(166,992)	(193,868)	(131,210)
G	Future Value Factor (1+i)^24 mo (ATT6)	1.10221	1.10221	1.10221
H	True-Up Adjustment w/o Incentive (E*G)	(159,055)	(184,677)	(125,006)
I	True-Up Adjustment w/ Incentive (F*G)	(184,061)	(213,683)	(144,621)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	Project H-5	Project H-6	Project H-7
W / O incentive	1,387,675	1,607,672	1,085,850
W incentive	1,458,429	1,689,799	1,141,424

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

Line	Item	Year	Project H-8				Project H-9				Project H-9A			
10														
11	Schedule 12 (Yes or No)		Yes	b0328.1			Yes	b0328.3			Yes	b0328.3		
12	Life		40	Build new Meadowbrook-Loudon 500kV circuit			40	Upgrade Mt Storm 500 kV Substation			40	Upgrade Mt Storm 500 kV Substation		
13	FCR W/O incentive Line 3		10.4521%	(30 of 50 miles)			10.4521%				10.4521%	Replace Digital Fault Recorder		
14	Incentive Factor (Basis Points /100)		1.5				1.5				0			
15	FCR W incentive L.13 +(L.14*L.5)		11.3001%	Line 535			11.3001%				10.4521%			
16	Investment		95,055,273				13,601,204				223,827			
17	Annual Depreciation Exp		2,376,382				340,030				5,596			
18	In Service Month (1-12)		4				5				9			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
46	W / O incentive	2019	78,362,807	2,376,382	75,986,425		11,234,948	340,030	10,894,918		216,599	5,596	211,004	
47	W incentive	2019	78,362,807	2,376,382	75,986,425		11,234,948	340,030	10,894,918		216,599	5,596	211,004	
48	W / O incentive	2020	75,986,425	2,376,382	73,610,043	10,194,361	10,894,918	340,030	10,554,888	1,461,007	211,004	5,596	205,408	27,358
49	W incentive	2020	75,986,425	2,376,382	73,610,043	10,828,623	10,894,918	340,030	10,554,888	1,551,950	211,004	5,596	205,408	27,358
50														
51														

		Project H-8	Project H-9	Project H-9A
A	Proj Rev Req w/o Incentive PCY*	11,741,286	1,698,942	-
B	Proj Rev Req w/ Incentive PCY*	12,554,617	1,816,673	-
C	Actual Rev Req w/o Incentive PCY*	10,788,941	1,546,111	28,970
D	Actual Rev Req w/ Incentive PCY*	11,452,591	1,641,256	28,970
E	TUA w/o Int w/o Incentive PCY (C-A)	(952,345)	(152,832)	28,970
F	TUA w/o Int w/ Incentive PCY (B-D)	(1,102,026)	(175,417)	28,970
G	Future Value Factor (1+i)^24 mo (ATT6)	1.10221	1.10221	1.10221
H	True-Up Adjustment w/o Incentive (E*G)	(1,049,686)	(168,453)	31,931
I	True-Up Adjustment w/ Incentive (F*G)	(1,214,666)	(193,346)	31,931

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	Project H-8	Project H-9	Project H-9A
W / O incentive	9,144,675	1,292,554	59,288
W incentive	9,613,957	1,358,604	59,288

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 H-10

10				
11	Schedule 12	(Yes or No)	Yes	b0328.4
12	Life		40	Upgrade Loudoun 500 kV Substation
13	FCR W/O incentive	Line 3	10.4521%	
14	Incentive Factor (Basis Points /100)		1.5	
15	FCR W incentive L.13 +(L.14*L.5)		11.3001%	
16	Investment		3,123,926	
17	Annual Depreciation Exp		78,098	
18	In Service Month (1-12)		5	

Line		Year	Beginning	Depreciation	Ending	Rev Req
19						
20	W / O incentive	2006				
46	W / O incentive	2019	2,580,444	78,098	2,502,346	
47	W incentive	2019	2,580,444	78,098	2,502,346	
48	W / O incentive	2020	2,502,346	78,098	2,424,248	335,564
49	W incentive	2020	2,502,346	78,098	2,424,248	356,452
50						
51						

Project I-1

10				
11	Schedule 12	(Yes or No)	Yes	b0329
12	Life		40	Carson-Suffolk 500 kV line +
13	FCR W/O incentive	Line 3	10.4521%	Suffolk 500/230 # 2 transformer +
14	Incentive Factor (Basis Points /100)		1.5	Suffolk - Thrasher 230kV line
15	FCR W incentive L.13 +(L.14*L.5)		11.3001%	
16	Investment		2,434,850	Cost associated with below 500 kV elements.
17	Annual Depreciation Exp		60,871	
18	In Service Month (1-12)		12	

Line		Year	Beginning	Depreciation	Ending	Rev Req
19						
20	W / O incentive	2006				
46	W / O incentive	2019	1,943,615	60,871	1,882,743	
47	W incentive	2019	1,943,615	60,871	1,882,743	
48	W / O incentive	2020	1,882,743	60,871	1,821,872	254,476
49	W incentive	2020	1,882,743	60,871	1,821,872	270,183
50						
51						

Project I-2A

10				
11	Schedule 12	(Yes or No)	Yes	b0329
12	Life		40	Carson-Suffolk 500 kV line +
13	FCR W/O incentive	Line 3	10.4521%	Suffolk 500/230 # 2 transformer +
14	Incentive Factor (Basis Points /100)		1.5	Suffolk - Thrasher 230kV line
15	FCR W incentive L.13 +(L.14*L.5)		11.3001%	
16	Investment		38,923,714	Cost associated with below 500 kV elements.
17	Annual Depreciation Exp		973,093	
18	In Service Month (1-12)		6	

Line		Year	Beginning	Depreciation	Ending	Rev Req
19						
20	W / O incentive	2006				
46	W / O incentive	2019	32,215,600	973,093	31,242,507	
47	W incentive	2019	32,215,600	973,093	31,242,507	
48	W / O incentive	2020	31,242,507	973,093	30,269,415	4,187,734
49	W incentive	2020	31,242,507	973,093	30,269,415	4,448,533
50						
51						

		Project H-10	Project I-1	Project I-2A
A	Proj Rev Req w/o Incentive PCY*	386,642	293,275	4,825,428
B	Proj Rev Req w/ Incentive PCY*	413,435	313,468	5,159,934
C	Actual Rev Req w/o Incentive PCY*	355,111	269,628	4,431,362
D	Actual Rev Req w/ Incentive PCY*	376,964	286,096	4,704,178
E	TUA w/o Int w/o Incentive PCY (C-A)	(31,531)	(23,647)	(394,066)
F	TUA w/o Int w/ Incentive PCY (B-D)	(36,471)	(27,371)	(455,756)
G	Future Value Factor (1+i)^24 mo (ATT6)	1.10221	1.10221	1.10221
H	True-Up Adjustment w/o Incentive (E*G)	(34,754)	(26,063)	(434,344)
I	True-Up Adjustment w/ Incentive (F*G)	(40,199)	(30,169)	(502,340)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	Project H-10	Project I-1	Project I-2A
W / O incentive	300,810	228,413	3,753,390
W incentive	316,253	240,014	3,946,193

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

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Line			Project I-2B				Project I-3				Project J			
10														
11	Schedule 12	(Yes or No)	Yes	b0329			Yes	b0329			Yes	b0512		
12	Life		40	Carson-Suffolk 500 kV line +			40	Carson-Suffolk 500 kV line +			40	MAPP Project -- Dominion Portion		
13	FCR W/O incentive	Line 3	10.4521%	Suffolk 500/230 # 2 transformer +			10.4521%	Suffolk 500/230 # 2 transformer +			10.4521%			
14	Incentive Factor (Basis Points /100)		1.5	Suffolk - Thrasher 230kV line			0	Suffolk - Thrasher 230kV line			1.5			
15	FCR W incentive L.13 +(L.14*L.5)		11.3001%				10.4521%				11.3001%			
16	Investment		163,410,059	Cost associated with Regional Facilities			905,153	Cost associated with Regional Facilities						
17	Annual Depreciation Exp		4,085,251	and Necessary Lower Voltage Facilities.			22,629	and Necessary Lower Voltage Facilities.			-			
18	In Service Month (1-12)		5				3	Replaced transformer bank/bushings						
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
46	W / O incentive	2019	134,980,956	4,085,251	130,895,705		887,239	22,629	864,610		-	-	-	
47	W incentive	2019	134,980,956	4,085,251	130,895,705		887,239	22,629	864,610		-	-	-	
48	W / O incentive	2020	130,895,705	4,085,251	126,810,453	17,553,091	864,610	22,629	841,981	111,816	-	-	-	-
49	W incentive	2020	130,895,705	4,085,251	126,810,453	18,645,719	864,610	22,629	841,981	111,816	-	-	-	-
50														
51														
A	Proj Rev Req w/o Incentive PCY*					20,225,225				-				-
B	Proj Rev Req w/ Incentive PCY*					21,626,760				-				-
C	Actual Rev Req w/o Incentive PCY*					18,575,565				92,943				-
D	Actual Rev Req w/ Incentive PCY*					19,718,678				92,943				-
E	TUA w/o Int w/o Incentive PCY (C-A)					(1,649,659)								-
F	TUA w/o Int w/ Incentive PCY (B-D)					(1,908,082)								-
G	Future Value Factor (1+i)^24 mo (ATT6)					1.10221				1.10221				1.10221
H	True-Up Adjustment w/o Incentive (E*G)					(1,818,273)								-
I	True-Up Adjustment w/ Incentive (F*G)					(2,103,109)								-

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	15,734,818	111,816	-
W incentive	16,542,610	111,816	-

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

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10				Project K-1				Project K-2				Project L-1a		
11	Schedule 12 (Yes or No)		No				No				No			
12	Life		40	Loudoun Bank # 1 transformer replacement			40	Loudoun Bank # 2 transformer replacement			40	Ox Bank # 1 transformer replacement		
13	FCR W/O incentive Line 3		10.4521%				10.4521%				10.4521%			
14	Incentive Factor (Basis Points /100)		1.5				1.5				1.5			
15	FCR W incentive L.13 +(L.14*L.5)		11.3001%				11.3001%				11.3001%			
16	Investment		12,786,365				14,388,779				10,056,166			
17	Annual Depreciation Exp		319,659				359,719				251,404			
18	In Service Month (1-12)		12				5				7			
19			Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req
20	W / O incentive	2006												
46	W / O incentive	2019	10,206,693	319,659	9,887,034		11,603,373	359,719	11,243,653		7,945,158	251,404	7,693,754	
47	W incentive	2019	10,206,693	319,659	9,887,034		11,603,373	359,719	11,243,653		7,945,158	251,404	7,693,754	
48	W / O incentive	2020	9,887,034	319,659	9,567,375	1,336,355	11,243,653	359,719	10,883,934	1,516,117	7,693,754	251,404	7,442,350	1,042,424
49	W incentive	2020	9,887,034	319,659	9,567,375	1,418,838	11,243,653	359,719	10,883,934	1,609,934	7,693,754	251,404	7,442,350	1,106,598
50														
51														

		Project K-1	Project K-2	Project L-1a
A	Proj Rev Req w/o Incentive PCY*	1,540,102	1,747,158	1,201,435
B	Proj Rev Req w/ Incentive PCY*	1,646,145	1,867,689	1,283,998
C	Actual Rev Req w/o Incentive PCY*	1,415,924	1,605,802	1,104,902
D	Actual Rev Req w/ Incentive PCY*	1,502,406	1,704,103	1,172,233
E	TUA w/o Int w/o Incentive PCY (C-A)	(124,177)	(141,355)	(96,533)
F	TUA w/o Int w/ Incentive PCY (B-D)	(143,738)	(163,586)	(111,765)
G	Future Value Factor (1+i)^24 mo (ATT6)	1.10221	1.10221	1.10221
H	True-Up Adjustment w/o Incentive (E*G)	(136,870)	(155,803)	(106,400)
I	True-Up Adjustment w/ Incentive (F*G)	(158,430)	(180,306)	(123,189)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	Project K-1	Project K-2	Project L-1a
W / O incentive	1,199,485	1,360,314	936,024
W incentive	1,260,409	1,429,628	983,409

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 7 - Transmission Enhancement Annual Revenue Requirement Worksheet
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10				Project L-1b				Project L-2				Project M		
11	Schedule 12 (Yes or No)		No				No				No			
12	Life		40	Ox Bank # 1 transformer			40	Ox Bank # 2 transformer			40	Yadkin Bank # 2 transformer		
13	FCR W/O incentive Line 3		10.4521%	spare			10.4521%	replacement			10.4521%	replacement		
14	Incentive Factor (Basis Points /100)		1.5				1.5				1.5			
15	FCR W incentive L.13 +(L.14*L.5)		11.3001%				11.3001%				11.3001%			
16	Investment		2,857,132				11,501,538				16,350,882			
17	Annual Depreciation Exp		71,428				287,538				408,772			
18	In Service Month (1-12)		12				3				6			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
46	W / O incentive	2019	2,280,701	71,428	2,209,272		9,011,942	287,538	8,724,403		13,212,365	408,772	12,803,593	
47	W incentive	2019	2,280,701	71,428	2,209,272		9,011,942	287,538	8,724,403		13,212,365	408,772	12,803,593	
48	W / O incentive	2020	2,209,272	71,428	2,137,844	298,611	8,724,403	287,538	8,436,865	1,184,394	12,803,593	408,772	12,394,821	1,725,653
49	W incentive	2020	2,209,272	71,428	2,137,844	317,042	8,724,403	287,538	8,436,865	1,257,155	12,803,593	408,772	12,394,821	1,832,489
50														
51														
A	Proj Rev Req w/o Incentive PCY*					344,138				1,365,134				1,989,447
B	Proj Rev Req w/ Incentive PCY*					367,833				1,458,797				2,126,745
C	Actual Rev Req w/o Incentive PCY*					316,390				1,255,760				1,827,600
D	Actual Rev Req w/ Incentive PCY*					335,715				1,332,141				1,939,529
E	TUA w/o Int w/o Incentive PCY (C-A)					(27,748)				(109,375)				(161,847)
F	TUA w/o Int w/ Incentive PCY (B-D)					(32,119)				(126,657)				(187,216)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.10221				1.10221				1.10221
H	True-Up Adjustment w/o Incentive (E*G)					(30,584)				(120,554)				(178,389)
I	True-Up Adjustment w/ Incentive (F*G)					(35,401)				(139,602)				(206,352)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive		268,027	1,063,840	1,547,263
W incentive		281,640	1,117,553	1,626,137

Virginia Electric and Power Company
ATTACHMENT H-16A
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10				Project N					Project O					Project P			
11	Schedule 12 (Yes or No)		No					No					No				
12	Life		40	Carson Bank # 1 transformer				40	Lexington Bank # 1 transformer				40	Dooms Bank # 7 transformer			
13	FCR W/O incentive Line 3		10.4521%	replacement				10.4521%	replacement				10.4521%	replacement			
14	Incentive Factor (Basis Points /100)		1.5					1.5					1.5				
15	FCR W incentive L.13 +(L.14*L.5)		11.3001%					11.3001%					11.3001%				
16	Investment		18,431,682					9,761,643					18,889,751				
17	Annual Depreciation Exp		460,792					244,041					472,244				
18	In Service Month (1-12)		5					12					8				
19			Beginning	Depreciation	Ending	Rev Req		Beginning	Depreciation	Ending	Rev Req		Beginning	Depreciation	Ending	Rev Req	
20	W / O incentive	2006															
46	W / O incentive	2019	14,863,643	460,792	14,402,851			8,175,024	244,041	7,930,983			15,696,022	472,244	15,223,778		
47	W incentive	2019	14,863,643	460,792	14,402,851			8,175,024	244,041	7,930,983			15,696,022	472,244	15,223,778		
48	W / O incentive	2020	14,402,851	460,792	13,942,059	1,942,110		7,930,983	244,041	7,686,941	1,060,241		15,223,778	472,244	14,751,535	2,038,767	
49	W incentive	2020	14,402,851	460,792	13,942,059	2,062,287		7,930,983	244,041	7,686,941	1,126,458		15,223,778	472,244	14,751,535	2,165,857	
50																	
51																	

		Project N	Project O	Project P
A	Proj Rev Req w/o Incentive PCY*	2,341,876	1,221,521	2,349,995
B	Proj Rev Req w/ Incentive PCY*	2,503,435	1,306,382	2,513,019
C	Actual Rev Req w/o Incentive PCY*	2,056,994	1,121,458	2,157,076
D	Actual Rev Req w/ Incentive PCY*	2,182,916	1,190,675	2,289,989
E	TUA w/o Int w/o Incentive PCY (C-A)	(284,882)	(100,064)	(192,919)
F	TUA w/o Int w/ Incentive PCY (B-D)	(320,519)	(115,707)	(223,029)
G	Future Value Factor (1+i)^24 mo (ATT6)	1.10221	1.10221	1.10221
H	True-Up Adjustment w/o Incentive (E*G)	(314,000)	(110,291)	(212,637)
I	True-Up Adjustment w/ Incentive (F*G)	(353,280)	(127,534)	(245,826)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	Project N	Project O	Project P
W / O incentive	1,628,110	949,949	1,826,130
W incentive	1,709,007	998,924	1,920,032

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

Line	Item		Project Q		Project R-1		Project R-2	
10								
11	Schedule 12	(Yes or No)	No		No	s0124	No	s0124
12	Life		40	Valley Bank # 1 transformer	40	Garrisonville 230 kV UG line	40	Garrisonville 230 kV UG line
13	FCR W/O incentive	Line 3	10.4521%	replacement	10.4521%	Phase 1	10.4521%	Phase 2
14	Incentive Factor (Basis Points /100)		1.5		1.25		1.25	
15	FCR W incentive L.13 +(L.14*L.5)		11.3001%		11.1587%		11.1587%	
16	Investment		12,056,414		91,286,357		32,204,664	
17	Annual Depreciation Exp		301,410		2,282,159		805,117	
18	In Service Month (1-12)		12		6		6	

Line	Item	Year	Project Q Beginning	Project Q Depreciation	Project Q Ending	Project Q Rev Req	Project R-1 Beginning	Project R-1 Depreciation	Project R-1 Ending	Project R-1 Rev Req	Project R-2 Beginning	Project R-2 Depreciation	Project R-2 Ending	Project R-2 Rev Req
19														
20	W / O incentive	2006												
46	W / O incentive	2019	9,860,411	301,410	9,559,001		73,764,136	2,282,159	71,481,977		26,654,512	805,117	25,849,395	
47	W incentive	2019	9,860,411	301,410	9,559,001		73,764,136	2,282,159	71,481,977		26,654,512	805,117	25,849,395	
48	W / O incentive	2020	9,559,001	301,410	9,257,591	1,284,774	71,481,977	2,282,159	69,199,818	9,634,253	25,849,395	805,117	25,044,278	3,464,843
49	W incentive	2020	9,559,001	301,410	9,257,591	1,364,553	71,481,977	2,282,159	69,199,818	10,131,308	25,849,395	805,117	25,044,278	3,644,660
50														
51														

	Item	Project Q	Project R-1	Project R-2
A	Proj Rev Req w/o Incentive PCY*	1,480,429	11,102,313	3,992,197
B	Proj Rev Req w/ Incentive PCY*	1,582,828	11,740,818	4,222,818
C	Actual Rev Req w/o Incentive PCY*	1,360,091	10,203,424	3,666,416
D	Actual Rev Req w/ Incentive PCY*	1,443,608	10,724,168	3,854,517
E	TUA w/o Int w/o Incentive PCY (C-A)	(120,338)	(898,889)	(325,781)
F	TUA w/o Int w/ Incentive PCY (B-D)	(139,220)	(1,016,650)	(368,301)
G	Future Value Factor (1+i)^24 mo (ATT6)	1.10221	1.10221	1.10221
H	True-Up Adjustment w/o Incentive (E*G)	(132,637)	(990,765)	(359,079)
I	True-Up Adjustment w/ Incentive (F*G)	(153,450)	(1,120,563)	(405,945)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	Project Q	Project R-1	Project R-2
W / O incentive	1,152,136	8,643,488	3,105,763
W incentive	1,211,103	9,010,745	3,238,715

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 R-3				Project S-1				Project S-2			
10															
11	Schedule 12 (Yes or No)		No	s0124			No	s0133			No	s0133			
12	Life		40	Garrisonville 230 kV UG line			40	Pleasant View Hamilton 230kV			40	Pleasant View Hamilton 230kV			
13	FCR W/O incentive Line 3		10.4521%	Phase 3			10.4521%	transmission line			10.4521%	transmission line			
14	Incentive Factor (Basis Points /100)		1.25				1.25				1.25				
15	FCR W incentive L.13 +(L.14*L.5)		11.1587%				11.1587%				11.1587%				
16	Investment		13,426,813				84,131,836				1,301,988				
17	Annual Depreciation Exp		335,670				2,103,296				32,550				
18	In Service Month (1-12)		2				10				2				
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	
20	W / O incentive	2006													
46	W / O incentive	2019	11,288,350	335,670	10,952,679		68,532,791	2,103,296	66,429,495		1,069,094	32,550	1,036,544		
47	W incentive	2019	11,288,350	335,670	10,952,679		68,532,791	2,103,296	66,429,495		1,069,094	32,550	1,036,544		
48	W / O incentive	2020	10,952,679	335,670	10,617,009	1,462,912	66,429,495	2,103,296	64,326,199	8,936,647	1,036,544	32,550	1,003,994	139,189	
49	W incentive	2020	10,952,679	335,670	10,617,009	1,539,122	66,429,495	2,103,296	64,326,199	9,398,631	1,036,544	32,550	1,003,994	146,399	
50															
51															

		Project R-3	Project S-1	Project S-2
A	Proj Rev Req w/o Incentive PCY*	1,685,405	10,297,845	160,382
B	Proj Rev Req w/ Incentive PCY*	1,783,047	10,890,978	169,633
C	Actual Rev Req w/o Incentive PCY*	1,547,168	9,461,886	147,328
D	Actual Rev Req w/ Incentive PCY*	1,626,812	9,945,640	154,873
E	TUA w/o Int w/o Incentive PCY (C-A)	(138,237)	(835,959)	(13,054)
F	TUA w/o Int w/ Incentive PCY (B-D)	(156,236)	(945,338)	(14,760)
G	Future Value Factor (1+i)^24 mo (ATT6)	1.10221	1.10221	1.10221
H	True-Up Adjustment w/o Incentive (E*G)	(152,367)	(921,403)	(14,388)
I	True-Up Adjustment w/ Incentive (F*G)	(172,205)	(1,041,962)	(16,268)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	Project R-3	Project S-1	Project S-2
W / O incentive	1,310,545	8,015,244	124,801
W incentive	1,366,917	8,356,670	130,130

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

Line			Project T-1				Project T-2				Project U-1			
11	Schedule 12 (Yes or No)		Yes	b0768			Yes	b0768			Yes	b0453.1		
12	Life		40	Glen Carlyn Line 251 GIB substation project			40	Glen Carlyn Line 251 GIB substation project			40	Convert Remington - Sowego		
13	FCR W/O incentive Line 3		10.4521%				10.4521%				10.4521%	115kV to 230kV		
14	Incentive Factor (Basis Points /100)		1.25	Loop Line 251 Idylwood -- Arlington into			1.25	Loop Line 251 Idylwood -- Arlington into			1.25			
15	FCR W incentive L.13 +(L.14*L.5)		11.1587%	the GIS sub			11.1587%	the GIS sub			11.1587%			
16	Investment		205,578				23,483,583				1,472,605			
17	Annual Depreciation Exp		5,139				587,090				36,815			
18	In Service Month (1-12)		6				6				9			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
46	W / O incentive	2019	166,118	5,139	160,978		19,436,422	587,090	18,849,332		1,197,160	36,815	1,160,345	
47	W incentive	2019	166,118	5,139	160,978		19,436,422	587,090	18,849,332		1,197,160	36,815	1,160,345	
48	W / O incentive	2020	160,978	5,139	155,839	21,696	18,849,332	587,090	18,262,243	2,526,557	1,160,345	36,815	1,123,530	156,171
49	W incentive	2020	160,978	5,139	155,839	22,816	18,849,332	587,090	18,262,243	2,657,679	1,160,345	36,815	1,123,530	164,241
50														
51														

		Project T-1	Project T-2	Project U-1
A	Proj Rev Req w/o Incentive PCY*	25,002	2,911,103	179,961
B	Proj Rev Req w/ Incentive PCY*	26,440	3,079,271	190,323
C	Actual Rev Req w/o Incentive PCY*	22,978	2,673,544	165,362
D	Actual Rev Req w/ Incentive PCY*	24,151	2,810,707	173,813
E	TUA w/o Int w/o Incentive PCY (C-A)	(2,024)	(237,559)	(14,599)
F	TUA w/o Int w/ Incentive PCY (B-D)	(2,289)	(268,564)	(16,510)
G	Future Value Factor (1+i)^24 mo (ATT6)	1.10221	1.10221	1.10221
H	True-Up Adjustment w/o Incentive (E*G)	(2,231)	(261,840)	(16,091)
I	True-Up Adjustment w/ Incentive (F*G)	(2,523)	(296,014)	(18,197)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	Project T-1	Project T-2	Project U-1
W / O incentive	19,465	2,264,717	140,080
W incentive	20,292	2,361,665	146,043

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

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Line	Description	Year	Project U-2				Project V				Project W			
10														
11	Schedule 12 (Yes or No)		Yes	b0453.2			Yes	b0337			Yes	b0467.2		
12	Life		40	Add Sowego - Gainsville 230 kV			40	Build Lexington 230kV ring bus			40	Reconductor the Dickerson - Pleasant		
13	FCR W/O incentive Line 3		10.4521%				10.4521%				10.4521%	View 230 kV circuit		
14	Incentive Factor (Basis Points /100)		1.25				1.25				1.25			
15	FCR W incentive L.13 +(L.14*L.5)		11.1587%				11.1587%				11.1587%			
16	Investment		13,559,633				6,389,531				5,249,379			
17	Annual Depreciation Exp		338,991				159,738				131,234			
18	In Service Month (1-12)		5				3				6			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
46	W / O incentive	2019	11,466,484	338,991	11,127,494		5,006,468	159,738	4,846,730		4,344,701	131,234	4,213,466	
47	W incentive	2019	11,466,484	338,991	11,127,494		5,006,468	159,738	4,846,730		4,344,701	131,234	4,213,466	
48	W / O incentive	2020	11,127,494	338,991	10,788,503	1,484,331	4,846,730	159,738	4,686,991	657,975	4,213,466	131,234	4,082,232	564,771
49	W incentive	2020	11,127,494	338,991	10,788,503	1,561,764	4,846,730	159,738	4,686,991	691,659	4,213,466	131,234	4,082,232	594,082
50														
51														
A	Proj Rev Req w/o Incentive PCY*					1,625,526				758,383				650,730
B	Proj Rev Req w/ Incentive PCY*					1,719,798				801,744				688,322
C	Actual Rev Req w/o Incentive PCY*					1,569,502				697,621				597,628
D	Actual Rev Req w/ Incentive PCY*					1,650,395				732,981				628,289
E	TUA w/o Int w/o Incentive PCY (C-A)					(56,024)				(60,762)				(53,103)
F	TUA w/o Int w/ Incentive PCY (B-D)					(69,403)				(68,762)				(60,033)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.10221				1.10221				1.10221
H	True-Up Adjustment w/o Incentive (E*G)					(61,750)				(66,972)				(58,530)
I	True-Up Adjustment w/ Incentive (F*G)					(76,497)				(75,791)				(66,169)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive		1,422,580	591,003	506,241
W incentive		1,485,267	615,869	527,912

Virginia Electric and Power Company
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(dollars)

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10			Project X				Project AA - 1				Project AA - 1B			
11	Schedule 12 (Yes or No)		Yes	b0311			Yes	b0231			Yes	b0231		
12	Life		40	Reconductor Idylwood to Arlington			40	Install 500 kV breakers and			40	Install 500 kV breakers and		
13	FCR W/O incentive Line 3		10.4521%	230 kV			10.4521%	500 kV bus work at Suffolk			10.4521%	500 kV bus work at Suffolk - Replacement		
14	Incentive Factor (Basis Points /100)		1.25				0				0	of bushings		
15	FCR W incentive L.13 +(L.14*L.5)		11.1587%				10.4521%				10.4521%			
16	Investment		3,196,608				21,905,733				832,048			
17	Annual Depreciation Exp		79,915				547,643				20,801			
18	In Service Month (1-12)		8				11				11			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
46	W / O incentive	2019	2,530,794	79,915	2,450,879		17,450,419	547,643	16,902,775		808,647	20,801	787,845	
47	W incentive	2019	2,530,794	79,915	2,450,879		17,450,419	547,643	16,902,775		808,647	20,801	787,845	
48	W / O incentive	2020	2,450,879	79,915	2,370,963	331,907	16,902,775	547,643	16,355,132	2,285,717	787,845	20,801	767,044	102,060
49	W incentive	2020	2,450,879	79,915	2,370,963	348,943	16,902,775	547,643	16,355,132	2,285,717	787,845	20,801	767,044	102,060
50														
51														
A	Proj Rev Req w/o Incentive PCY*					382,531				2,635,030				-
B	Proj Rev Req w/ Incentive PCY*					404,446				2,635,030				-
C	Actual Rev Req w/o Incentive PCY*					351,773				2,421,991				107,691
D	Actual Rev Req w/ Incentive PCY*					369,645				2,421,991				107,691
E	TUA w/o Int w/o Incentive PCY (C-A)					(30,757)				(213,039)				107,691
F	TUA w/o Int w/ Incentive PCY (B-D)					(34,800)				(213,039)				107,691
G	Future Value Factor (1+i)^24 mo (ATT6)					1.10221				1.10221				1.10221
H	True-Up Adjustment w/o Incentive (E*G)					(33,901)				(234,814)				118,698
I	True-Up Adjustment w/ Incentive (F*G)					(38,357)				(234,814)				118,698

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive		298,006	2,050,903	220,758
W incentive		310,586	2,050,903	220,758

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

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Line	Description	Year	Project AB-2				Project AC				Project AG			
10														
11	Schedule 12 (Yes or No)		Yes	b0456			Yes	b0227			Yes	b0455		
12	Life		40	Re-Conductor 9.4 miles of Edinburg -			40	Install 500/230 kV transformer at Bristers;			40	Add 2nd Endless Caverns 230/115kV		
13	FCR W/O incentive Line 3		10.4521%	Mt. Jackson 115 kV			10.4521%	build new 230 kV Bristers- Gainesville circuit,			10.4521%	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)		10.4521%				10.4521%				10.4521%			
16	Investment		4,847,602				21,117,166				3,424,618			
17	Annual Depreciation Exp		121,190				527,929				85,615			
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												
46	W / O incentive	2019	3,861,669	121,190	3,740,479		16,649,709	527,929	16,121,780		2,694,525	85,615	2,608,909	
47	W incentive	2019	3,861,669	121,190	3,740,479		16,649,709	527,929	16,121,780		2,694,525	85,615	2,608,909	
48	W / O incentive	2020	3,740,479	121,190	3,619,289	505,815	16,121,780	527,929	15,593,851	2,185,402	2,608,909	85,615	2,523,294	353,827
49	W incentive	2020	3,740,479	121,190	3,619,289	505,815	16,121,780	527,929	15,593,851	2,185,402	2,608,909	85,615	2,523,294	353,827
50														
51														
A	Proj Rev Req w/o Incentive PCY*					582,025				2,518,797				407,810
B	Proj Rev Req w/ Incentive PCY*					582,025				2,518,797				407,810
C	Actual Rev Req w/o Incentive PCY*					535,971				2,316,559				375,090
D	Actual Rev Req w/ Incentive PCY*					535,971				2,316,559				375,090
E	TUA w/o Int w/o Incentive PCY (C-A)					(46,054)				(202,238)				(32,721)
F	TUA w/o Int w/ Incentive PCY (B-D)					(46,054)				(202,238)				(32,721)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.10221				1.10221				1.10221
H	True-Up Adjustment w/o Incentive (E*G)					(50,761)				(222,909)				(36,065)
I	True-Up Adjustment w/ Incentive (F*G)					(50,761)				(222,909)				(36,065)
	W / O incentive					455,054				1,962,493				317,762
	W incentive					455,054				1,962,493				317,762

TUA = True-Up Adjusment
PCY = Previous Calendar Year

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

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10			2009 Add-1				2009 Add-6				Project AJ				
11	Schedule 12 (Yes or No)		Yes	B0453.3			Yes	B0837			Yes	B0327			
12	Life		40	Add Sowego 230/115/ kV transformer			40	At Mt. Storm, replace the existing MOD on			40	Build 2nd Harrisonburg - Valley 230 kV			
13	FCR W/O incentive Line 3		10.4521%				10.4521%	the 500 kV side of the transformer with a			10.4521%				
14	Incentive Factor (Basis Points /100)		1.25				0	circuit breaker			0				
15	FCR W incentive L.13 +(L.14*L.5)		11.1587%				10.4521%				10.4521%				
16	Investment		3,355,513				779,172				6,211,387				
17	Annual Depreciation Exp		83,888				19,479				155,285				
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													
46	W / O incentive	2019	2,662,084	83,888	2,578,196		614,334	19,479	594,854		5,029,274	155,285	4,873,989		
47	W incentive	2019	2,662,084	83,888	2,578,196		614,334	19,479	594,854		5,029,274	155,285	4,873,989		
48	W / O incentive	2020	2,578,196	83,888	2,494,308	348,979	594,854	19,479	575,375	80,636	4,873,989	155,285	4,718,705	656,603	
49	W incentive	2020	2,578,196	83,888	2,494,308	366,901	594,854	19,479	575,375	80,636	4,873,989	155,285	4,718,705	656,603	
50															
51															

		2009 Add-1	2009 Add-6	Project AJ
A	Proj Rev Req w/o Incentive PCY*	402,202	92,937	756,643
B	Proj Rev Req w/ Incentive PCY*	425,253	92,937	756,643
C	Actual Rev Req w/o Incentive PCY*	369,840	85,475	695,344
D	Actual Rev Req w/ Incentive PCY*	388,639	85,475	695,344
E	TUA w/o Int w/o Incentive PCY (C-A)	(32,362)	(7,462)	(61,300)
F	TUA w/o Int w/ Incentive PCY (B-D)	(36,614)	(7,462)	(61,300)
G	Future Value Factor (1+i)^24 mo (ATT6)	1.10221	1.10221	1.10221
H	True-Up Adjustment w/o Incentive (E*G)	(35,669)	(8,225)	(67,565)
I	True-Up Adjustment w/ Incentive (F*G)	(40,356)	(8,225)	(67,565)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	2009 Add-1	2009 Add-6	Project AJ
W / O incentive	313,310	72,411	589,038
W incentive	326,545	72,411	589,038

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		40	Rebuild Mt Storm - Doubs 500 kV			40	Rebuild Mt Storm - Doubs 500 kV			40	Rebuild Mt. Storm-Doubs 500 kV		
13	FCR W/O incentive Line 3		10.4521%				10.4521%				10.4521%			
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.4521%				10.4521%				10.4521%			
16	Investment		23,947,642				21,791,010				120,381,556			
17	Annual Depreciation Exp		598,691				544,775				3,009,539			
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												
46	W / O incentive	2019	20,055,286	598,691	19,456,595		18,427,215	544,775	17,882,440		104,214,033	3,009,539	101,204,494	
47	W incentive	2019	20,055,286	598,691	19,456,595		18,427,215	544,775	17,882,440		104,214,033	3,009,539	101,204,494	
48	W / O incentive	2020	19,456,595	598,691	18,857,904	2,601,024	17,882,440	544,775	17,337,665	2,385,394	101,204,494	3,009,539	98,194,955	13,430,244
49	W incentive	2020	19,456,595	598,691	18,857,904	2,601,024	17,882,440	544,775	17,337,665	2,385,394	101,204,494	3,009,539	98,194,955	13,430,244
50														
51														
A	Proj Rev Req w/o Incentive PCY*					2,996,684				2,748,088				15,470,068
B	Proj Rev Req w/ Incentive PCY*					2,996,684				2,748,088				15,470,068
C	Actual Rev Req w/o Incentive PCY*					2,751,204				2,522,268				14,189,356
D	Actual Rev Req w/ Incentive PCY*					2,751,204				2,522,268				14,189,356
E	TUA w/o Int w/o Incentive PCY (C-A)					(245,480)				(225,820)				(1,280,711)
F	TUA w/o Int w/ Incentive PCY (B-D)					(245,480)				(225,820)				(1,280,711)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.10221				1.10221				1.10221
H	True-Up Adjustment w/o Incentive (E*G)					(270,571)				(248,902)				(1,411,614)
I	True-Up Adjustment w/ Incentive (F*G)					(270,571)				(248,902)				(1,411,614)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive		2,330,453	2,136,492	12,018,630
W incentive		2,330,453	2,136,492	12,018,630

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-4**				**Project AK-5**				**Project AK-6**		
11	Schedule 12 (Yes or No)		Yes	B1507			Yes	B1507			Yes	B1507		
12	Life		40	Rebuild Mt. Storm-Doubs 500 kV			40	Rebuild Mt. Storm-Doubs 500 kV			40	Rebuild Mt. Storm-Doubs 500 kV		
13	FCR W/O incentive Line 3		10.4521%				10.4521%				10.4521%			
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.4521%				10.4521%				10.4521%			
16	Investment		150,057,664				15,370,002				515,816			
17	Annual Depreciation Exp		3,751,442				384,250				12,895			
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												
46	W / O incentive	2019	133,394,284	3,751,442	129,642,842		14,020,659	384,250	13,636,409		483,528	12,895	470,632	
47	W incentive	2019	133,394,284	3,751,442	129,642,842		14,020,659	384,250	13,636,409		483,528	12,895	470,632	
48	W / O incentive	2020	129,642,842	3,751,442	125,891,401	17,105,776	13,636,409	384,250	13,252,159	1,789,459	470,632	12,895	457,737	61,412
49	W incentive	2020	129,642,842	3,751,442	125,891,401	17,105,776	13,636,409	384,250	13,252,159	1,789,459	470,632	12,895	457,737	61,412
50														
51														
A	Proj Rev Req w/o Incentive PCY*					19,700,702				1,969,727				70,707
B	Proj Rev Req w/ Incentive PCY*					19,700,702				1,969,727				70,707
C	Actual Rev Req w/o Incentive PCY*					18,056,314				1,887,259				64,711
D	Actual Rev Req w/ Incentive PCY*					18,056,314				1,887,259				64,711
E	TUA w/o Int w/o Incentive PCY (C-A)					(1,644,388)				(82,468)				(5,996)
F	TUA w/o Int w/ Incentive PCY (B-D)					(1,644,388)				(82,468)				(5,996)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.10221				1.10221				1.10221
H	True-Up Adjustment w/o Incentive (E*G)					(1,812,462)				(90,897)				(6,609)
I	True-Up Adjustment w/ Incentive (F*G)					(1,812,462)				(90,897)				(6,609)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive		15,293,314	1,698,562	54,804
W incentive		15,293,314	1,698,562	54,804

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

These Three Columns
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Line Number
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Line														
10			Project AL				Project AM				Project AO			
11	Schedule 12 (Yes or No)		Yes	B0457			Yes	B0784			Yes	B1224		
12	Life		40	Replace both wave traps on			40	Replace wave traps on North Anna to			40	Install 2nd Clover 500/230		
13	FCR W/O incentive Line 3		10.4521%	Dooms - Lexington 500 kV			10.4521%	Ladysmith 500 kV			10.4521%	kV transformer and a 150		
14	Incentive Factor (Basis Points /100)		0				0				0	MVAr capacitor		
15	FCR W incentive L.13 +(L.14*L.5)		10.4521%				10.4521%				10.4521%			
16	Investment		108,763				75,695				14,160,502			
17	Annual Depreciation Exp		2,719				1,892				354,013			
18	In Service Month (1-12)		12				10				4			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
46	W / O incentive	2019	91,085	2,719	88,366		63,144	1,892	61,252		12,231,271	354,013	11,877,258	
47	W incentive	2019	91,085	2,719	88,366		63,144	1,892	61,252		12,231,271	354,013	11,877,258	
48	W / O incentive	2020	88,366	2,719	85,647	11,813	61,252	1,892	59,360	8,196	11,877,258	354,013	11,523,246	1,576,933
49	W incentive	2020	88,366	2,719	85,647	11,813	61,252	1,892	59,360	8,196	11,877,258	354,013	11,523,246	1,576,933
50														
51														
A	Proj Rev Req w/o Incentive PCY*					13,610				9,443				1,816,467
B	Proj Rev Req w/ Incentive PCY*					13,610				9,443				1,816,467
C	Actual Rev Req w/o Incentive PCY*					12,495				8,670				1,666,194
D	Actual Rev Req w/ Incentive PCY*					12,495				8,670				1,666,194
E	TUA w/o Int w/o Incentive PCY (C-A)					(1,115)				(773)				(150,273)
F	TUA w/o Int w/ Incentive PCY (B-D)					(1,115)				(773)				(150,273)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.10221				1.10221				1.10221
H	True-Up Adjustment w/o Incentive (E*G)					(1,229)				(851)				(165,633)
I	True-Up Adjustment w/ Incentive (F*G)					(1,229)				(851)				(165,633)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive		10,584	7,344	1,411,301
W incentive		10,584	7,344	1,411,301

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

Line	These Three Columns are Repeated to Provide Line Number References on All Pages		Project AP-1				Project AP-2				Project AQ			
10														
11	Schedule 12	(Yes or No)	Yes	B1508.3			Yes	B1508.3			Yes	B1647		
12	Life		40	Upgrade a 115 kV shunt capacitor banks			40	Upgrade a 115 kV shunt capacitor banks			40	Upgrade the name plate		
13	FCR W/O incentive	Line 3	10.4521%	at Merck and Edinburg			10.4521%	at Merck and Edinburg			10.4521%	rating at Morrisville 500 kV		
14	Incentive Factor (Basis Points /100)		0				0				0	breaker 'H1T573' with		
15	FCR W incentive L.13 +(L.14*L.5)		10.4521%	Merck			10.4521%	Edinburg			10.4521%	50kA breaker		
16	Investment		511,009				734,802				16,278			
17	Annual Depreciation Exp		12,775				18,370				407			
18	In Service Month (1-12)		7				2				1			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
46	W / O incentive	2019	433,796	12,775	421,021		617,771	18,370	599,401		13,978	407	13,571	
47	W incentive	2019	433,796	12,775	421,021		617,771	18,370	599,401		13,978	407	13,571	
48	W / O incentive	2020	421,021	12,775	408,246	56,113	599,401	18,370	581,031	80,060	13,571	407	13,164	1,804
49	W incentive	2020	421,021	12,775	408,246	56,113	599,401	18,370	581,031	80,060	13,571	407	13,164	1,804
50														
51														
A	Proj Rev Req w/o Incentive PCY*					64,643				94,776				2,078
B	Proj Rev Req w/ Incentive PCY*					64,643				94,776				2,078
C	Actual Rev Req w/o Incentive PCY*					59,325				84,671				1,907
D	Actual Rev Req w/ Incentive PCY*					59,325				84,671				1,907
E	TUA w/o Int w/o Incentive PCY (C-A)					(5,319)				(10,105)				(172)
F	TUA w/o Int w/ Incentive PCY (B-D)					(5,319)				(10,105)				(172)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.10221				1.10221				1.10221
H	True-Up Adjustment w/o Incentive (E*G)					(5,862)				(11,138)				(189)
I	True-Up Adjustment w/ Incentive (F*G)					(5,862)				(11,138)				(189)
	W / O incentive					50,251				68,922				1,615
	W incentive					50,251				68,922				1,615

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

Line	Item		Project AR				Project AS				Project AT			
10														
11	Schedule 12 (Yes or No)		Yes	B1648			Yes	B1649			Yes	B1650		
12	Life		40	Upgrade the name plate rating			40	Replace Morrisville 500 kV			40	Replace Morrisville 500 kV		
13	FCR W/O incentive Line 3		10.4521%	at Morrisville 500 kV			10.4521%	breaker 'H1T580' with			10.4521%	breaker 'H2T569' with		
14	Incentive Factor (Basis Points /100)		0	breaker 'H2T545' with			0	50kA breaker			0	50kA breaker		
15	FCR W incentive L.13 +(L.14*L.5)		10.4521%	50kA breaker			10.4521%				10.4521%			
16	Investment		16,278				858,877				858,877			
17	Annual Depreciation Exp		407				21,472				21,472			
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												
46	W / O incentive	2019	13,978	407	13,571		737,523	21,472	716,051		737,523	21,472	716,051	
47	W incentive	2019	13,978	407	13,571		737,523	21,472	716,051		737,523	21,472	716,051	
48	W / O incentive	2020	13,571	407	13,164	1,804	716,051	21,472	694,579	95,192	716,051	21,472	694,579	95,192
49	W incentive	2020	13,571	407	13,164	1,804	716,051	21,472	694,579	95,192	716,051	21,472	694,579	95,192
50														
51														

		Project AR	Project AS	Project AT
A	Proj Rev Req w/o Incentive PCY*	2,078	109,656	109,656
B	Proj Rev Req w/ Incentive PCY*	2,078	109,656	109,656
C	Actual Rev Req w/o Incentive PCY*	1,907	100,601	100,601
D	Actual Rev Req w/ Incentive PCY*	1,907	100,601	100,601
E	TUA w/o Int w/o Incentive PCY (C-A)	(172)	(9,055)	(9,055)
F	TUA w/o Int w/ Incentive PCY (B-D)	(172)	(9,055)	(9,055)
G	Future Value Factor (1+i)^24 mo (ATT6)	1.10221	1.10221	1.10221
H	True-Up Adjustment w/o Incentive (E*G)	(189)	(9,980)	(9,980)
I	True-Up Adjustment w/ Incentive (F*G)	(189)	(9,980)	(9,980)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	Project AR	Project AS	Project AT
W / O incentive	1,615	85,212	85,212
W incentive	1,615	85,212	85,212

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 AU-1				Project AU-2				Project AV-1			
11	Schedule 12 (Yes or No)		Yes	B1188.6			Yes	B1188.6			Yes	B1188		
12	Life		40	Install one 500/230 kV			40	Install one 500/230 kV			40	Build new Brambleton 500 kV three		
13	FCR W/O incentive Line 3		10.4521%	transformer and two 230 kV breakers			10.4521%	transformer and two 230 kV breakers			10.4521%	ring bus connected to the Loudoun		
14	Incentive Factor (Basis Points /100)		0	at Brambleton			0	at Brambleton			0	to Pleasant View 500 kV line		
15	FCR W incentive L.13 +(L.14*L.5)		10.4521%				10.4521%				10.4521%			
16	Investment		235,892				16,717,801				-			
17	Annual Depreciation Exp		5,897				417,945				-			
18	In Service Month (1-12)		6				12							
19			Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req
20	W / O incentive	2006												
46	W / O incentive	2019	199,864	5,897	193,966		14,699,353	417,945	14,281,408		-	-	-	
47	W incentive	2019	199,864	5,897	193,966		14,699,353	417,945	14,281,408		-	-	-	
48	W / O incentive	2020	193,966	5,897	188,069	25,863	14,281,408	417,945	13,863,463	1,888,809	-	-	-	-
49	W incentive	2020	193,966	5,897	188,069	25,863	14,281,408	417,945	13,863,463	1,888,809	-	-	-	-
50														
51														
A	Proj Rev Req w/o Incentive PCY*					29,795				2,175,482				-
B	Proj Rev Req w/ Incentive PCY*					29,795				2,175,482				-
C	Actual Rev Req w/o Incentive PCY*					27,345				1,994,508				-
D	Actual Rev Req w/ Incentive PCY*					27,345				1,994,508				-
E	TUA w/o Int w/o Incentive PCY (C-A)					(2,450)				(180,974)				-
F	TUA w/o Int w/ Incentive PCY (B-D)					(2,450)				(180,974)				-
G	Future Value Factor (1+i)^24 mo (ATT6)					1.10221				1.10221				1.10221
H	True-Up Adjustment w/o Incentive (E*G)					(2,700)				(199,471)				-
I	True-Up Adjustment w/ Incentive (F*G)					(2,700)				(199,471)				-

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	23,162	1,689,337	-
W incentive	23,162	1,689,337	-

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

Line	Item		Project AV-2				Project AW				Project AX-1			
10														
11	Schedule 12 (Yes or No)		Yes	B1188			Yes	B1698.1			Yes	B1321		
12	Life		40	Build new Brambleton 500 kV three ring bus connected to the Loudoun to Pleasant View 500 kV line			40	Install a 500 kV breaker at Brambleton			40	Build a new 230 kV line North Anna -- Oak Green and install a 224 MVA 230/115 kV transformer at Oak Green		
13	FCR W/O incentive Line 3		10.4521%				10.4521%				10.4521%			
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.4521%				10.4521%				10.4521%			
16	Investment		1,595,794				-				31,931,622			
17	Annual Depreciation Exp		39,895				-				798,291			
18	In Service Month (1-12)		1								3			
19			Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req
20	W / O incentive	2006												
46	W / O incentive	2019	1,406,216	39,895	1,366,321		-	-	-		29,004,557	798,291	28,206,266	
47	W incentive	2019	1,406,216	39,895	1,366,321		-	-	-		29,004,557	798,291	28,206,266	
48	W / O incentive	2020	1,366,321	39,895	1,326,426	180,619	-	-	-	-	28,206,266	798,291	27,407,976	3,704,716
49	W incentive	2020	1,366,321	39,895	1,326,426	180,619	-	-	-	-	28,206,266	798,291	27,407,976	3,704,716
50														
51														

		Project AV-2	Project AW	Project AX-1
A	Proj Rev Req w/o Incentive PCY*	209,159	-	4,140,193
B	Proj Rev Req w/ Incentive PCY*	209,159	-	4,140,193
C	Actual Rev Req w/o Incentive PCY*	190,712	-	3,907,747
D	Actual Rev Req w/ Incentive PCY*	190,712	-	3,907,747
E	TUA w/o Int w/o Incentive PCY (C-A)	(18,446)	-	(232,445)
F	TUA w/o Int w/ Incentive PCY (B-D)	(18,446)	-	(232,445)
G	Future Value Factor (1+i)^24 mo (ATT6)	1.10221	1.10221	1.10221
H	True-Up Adjustment w/o Incentive (E*G)	(20,332)	-	(256,204)
I	True-Up Adjustment w/ Incentive (F*G)	(20,332)	-	(256,204)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	Project AV-2	Project AW	Project AX-1
W / O incentive	160,287	-	3,448,512
W incentive	160,287	-	3,448,512

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

Line	Item		Project AX-2				Project AY-1				Project AY-2			
10														
11	Schedule 12 (Yes or No)		Yes	B1321			Yes	B0756.1			Yes	B0756.1		
12	Life		40	Build a new 230 kV line North Anna -- Oak			40	Install two 500 kV breakers at			40	Install two 500 kV breakers at		
13	FCR W/O incentive Line 3		10.4521%	Green and install a 224 MVA 230/115			10.4521%	Chancellor 500 kV			10.4521%	Chancellor 500 kV		
14	Incentive Factor (Basis Points /100)		0	kV transformer at Oak Green			0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.4521%				10.4521%				10.4521%			
16	Investment		6,368,620				4,076,165				116,523			
17	Annual Depreciation Exp		159,216				101,904				2,913			
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												
46	W / O incentive	2019	5,821,857	159,216	5,662,641		3,528,727	101,904	3,426,822		105,164	2,913	102,251	
47	W incentive	2019	5,821,857	159,216	5,662,641		3,528,727	101,904	3,426,822		105,164	2,913	102,251	
48	W / O incentive	2020	5,662,641	159,216	5,503,426	742,759	3,426,822	101,904	3,324,918	454,753	102,251	2,913	99,338	13,448
49	W incentive	2020	5,662,641	159,216	5,503,426	742,759	3,426,822	101,904	3,324,918	454,753	102,251	2,913	99,338	13,448
50														
51														

		Project AX-2	Project AY-1	Project AY-2
A	Proj Rev Req w/o Incentive PCY*	855,511	523,822	15,487
B	Proj Rev Req w/ Incentive PCY*	855,511	523,822	15,487
C	Actual Rev Req w/o Incentive PCY*	783,298	480,457	14,188
D	Actual Rev Req w/ Incentive PCY*	783,298	480,457	14,188
E	TUA w/o Int w/o Incentive PCY (C-A)	(72,212)	(43,365)	(1,299)
F	TUA w/o Int w/ Incentive PCY (B-D)	(72,212)	(43,365)	(1,299)
G	Future Value Factor (1+i)^24 mo (ATT6)	1.10221	1.10221	1.10221
H	True-Up Adjustment w/o Incentive (E*G)	(79,593)	(47,798)	(1,431)
I	True-Up Adjustment w/ Incentive (F*G)	(79,593)	(47,798)	(1,431)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	Project AX-2	Project AY-1	Project AY-2
W / O incentive	663,166	406,955	12,017
W incentive	663,166	406,955	12,017

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

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			Project AZ				Project BA				Project BB-1			
10														
11	Schedule 12 (Yes or No)		Yes	B1797			Yes	B1799			Yes	B1798		
12	Life		40	Wreck and rebuild 7 miles of the			40	Build 150 MVAR Switched Shunt at Pleasant			40	Build a 450 MVAR SVC and 300 MVAR		
13	FCR W/O incentive Line 3		10.4521%	Dominion owned section of Cloverdale -			10.4521%	View 500 kV			10.4521%	switched shunt at Loudoun 500 kV		
14	Incentive Factor (Basis Points /100)		0	Lexington 500 kV			0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.4521%				10.4521%				10.4521%			
16	Investment		18,459,911				26,070,960				3,131,641			
17	Annual Depreciation Exp		461,498				651,774				78,291			
18	In Service Month (1-12)		10				11				12			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
46	W / O incentive	2019	16,159,577	461,498	15,698,079		23,479,022	651,774	22,827,248		2,753,538	78,291	2,675,247	
47	W incentive	2019	16,159,577	461,498	15,698,079		23,479,022	651,774	22,827,248		2,753,538	78,291	2,675,247	
48	W / O incentive	2020	15,698,079	461,498	15,236,582	2,078,157	22,827,248	651,774	22,175,474	3,003,636	2,675,247	78,291	2,596,956	353,819
49	W incentive	2020	15,698,079	461,498	15,236,582	2,078,157	22,827,248	651,774	22,175,474	3,003,636	2,675,247	78,291	2,596,956	353,819
50														
51														

		Project AZ	Project BA	Project BB-1
A	Proj Rev Req w/o Incentive PCY*	2,393,632	3,456,017	407,519
B	Proj Rev Req w/ Incentive PCY*	2,393,632	3,456,017	407,519
C	Actual Rev Req w/o Incentive PCY*	2,194,783	3,169,155	373,619
D	Actual Rev Req w/ Incentive PCY*	2,194,783	3,169,155	373,619
E	TUA w/o Int w/o Incentive PCY (C-A)	(198,849)	(286,862)	(33,901)
F	TUA w/o Int w/ Incentive PCY (B-D)	(198,849)	(286,862)	(33,901)
G	Future Value Factor (1+i)^24 mo (ATT6)	1.10221	1.10221	1.10221
H	True-Up Adjustment w/o Incentive (E*G)	(219,174)	(316,183)	(37,366)
I	True-Up Adjustment w/ Incentive (F*G)	(219,174)	(316,183)	(37,366)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	Project AZ	Project BA	Project BB-1
W / O incentive	1,858,983	2,687,454	316,453
W incentive	1,858,983	2,687,454	316,453

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

Line	Description		Project BB-2				Project BB-3				Project BB-4			
10														
11	Schedule 12 (Yes or No)		Yes	B1798			Yes	B1798			Yes	B1798		
12	Life		40	Build a 450 MVAR SVC and 300 MVAR			40	Build a 450 MVAR SVC and 300 MVAR			40	Build a 450 MVAR SVC and 300 MVAR		
13	FCR W/O incentive Line 3		10.4521%	switched shunt at Loudoun 500 kV			10.4521%	switched shunt at Loudoun 500 kV			10.4521%	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)		10.4521%				10.4521%				10.4521%			
16	Investment		35,293,503				18,023,576				38,035,625			
17	Annual Depreciation Exp		882,338				450,589				950,891			
18	In Service Month (1-12)		5				6				8			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
46	W / O incentive	2019	31,374,283	882,338	30,491,945		16,057,050	450,589	15,606,461		34,033,039	950,891	33,082,148	
47	W incentive	2019	31,374,283	882,338	30,491,945		16,057,050	450,589	15,606,461		34,033,039	950,891	33,082,148	
48	W / O incentive	2020	30,491,945	882,338	29,609,607	4,023,272	15,606,461	450,589	15,155,871	2,058,243	33,082,148	950,891	32,131,258	4,358,973
49	W incentive	2020	30,491,945	882,338	29,609,607	4,023,272	15,606,461	450,589	15,155,871	2,058,243	33,082,148	950,891	32,131,258	4,358,973
50														
51														

		Project BB-2	Project BB-3	Project BB-4
A	Proj Rev Req w/o Incentive PCY*	4,623,130	2,362,205	5,018,859
B	Proj Rev Req w/ Incentive PCY*	4,623,130	2,362,205	5,018,859
C	Actual Rev Req w/o Incentive PCY*	4,246,838	2,172,456	4,600,181
D	Actual Rev Req w/ Incentive PCY*	4,246,838	2,172,456	4,600,181
E	TUA w/o Int w/o Incentive PCY (C-A)	(376,292)	(189,749)	(418,678)
F	TUA w/o Int w/ Incentive PCY (B-D)	(376,292)	(189,749)	(418,678)
G	Future Value Factor (1+i)^24 mo (ATT6)	1.10221	1.10221	1.10221
H	True-Up Adjustment w/o Incentive (E*G)	(414,753)	(209,144)	(461,472)
I	True-Up Adjustment w/ Incentive (F*G)	(414,753)	(209,144)	(461,472)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	Project BB-2	Project BB-3	Project BB-4
W / O incentive	3,608,519	1,849,099	3,897,501
W incentive	3,608,519	1,849,099	3,897,501

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 BB-5**				**Project BB-6**				**Project BC**				
11	Schedule 12 (Yes or No)		Yes	B1798			Yes	B1798			Yes	B1805			
12	Life		40	Build a 450 MVAR SVC and 300 MVAR			40	Build a 450 MVAR SVC and 300 MVAR			40	Install a 250 MVAR SVC at the existing Mt.			
13	FCR W/O incentive Line 3		10.4521%	switched shunt at Loudoun 500 kV			10.4521%	switched shunt at Loudoun 500 kV			10.4521%	Storm 500 kV substation			
14	Incentive Factor (Basis Points /100)		0				0				0				
15	FCR W incentive L.13 +(L.14*L.5)		10.4521%				10.4521%				10.4521%				
16	Investment		12,313,490				4,574,038				37,153,276				
17	Annual Depreciation Exp		307,837				114,351				928,832				
18	In Service Month (1-12)		12				1				6				
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	
20	W / O incentive	2006													
46	W / O incentive	2019	11,113,163	307,837	10,805,326		4,137,022	114,351	4,022,671		33,099,537	928,832	32,170,705		
47	W incentive	2019	11,113,163	307,837	10,805,326		4,137,022	114,351	4,022,671		33,099,537	928,832	32,170,705		
48	W / O incentive	2020	10,805,326	307,837	10,497,489	1,421,132	4,022,671	114,351	3,908,320	528,828	32,170,705	928,832	31,241,873	4,242,802	
49	W incentive	2020	10,805,326	307,837	10,497,489	1,421,132	4,022,671	114,351	3,908,320	528,828	32,170,705	928,832	31,241,873	4,242,802	
50															
51															

		Project BB-5	Project BB-6	Project BC
A	Proj Rev Req w/o Incentive PCY*	1,631,126	608,988	4,886,367
B	Proj Rev Req w/ Incentive PCY*	1,631,126	608,988	4,886,367
C	Actual Rev Req w/o Incentive PCY*	1,499,337	557,890	4,478,237
D	Actual Rev Req w/ Incentive PCY*	1,499,337	557,890	4,478,237
E	TUA w/o Int w/o Incentive PCY (C-A)	(131,789)	(51,099)	(408,130)
F	TUA w/o Int w/ Incentive PCY (B-D)	(131,789)	(51,099)	(408,130)
G	Future Value Factor (1+i)^24 mo (ATT6)	1.10221	1.10221	1.10221
H	True-Up Adjustment w/o Incentive (E*G)	(145,259)	(56,322)	(449,846)
I	True-Up Adjustment w/ Incentive (F*G)	(145,259)	(56,322)	(449,846)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	Project BB-5	Project BB-6	Project BC
W / O incentive	1,275,873	472,506	3,792,956
W incentive	1,275,873	472,506	3,792,956

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

Line	Description		Project BD-1				Project BD-2				Project BD-3			
10														
11	Schedule 12 (Yes or No)		Yes	B1508.1			Yes	B1508.1			Yes	B1508.1		
12	Life		40	Build a 2nd 230kV line Harrisonburg to			40	Build a 2nd 230kV line Harrisonburg to			40	Build a 2nd 230kV line Harrisonburg to		
13	FCR W/O incentive Line 3		10.4521%	Endless Caverns			10.4521%	Endless Caverns			10.4521%	Endless Caverns		
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.4521%				10.4521%				10.4521%			
16	Investment		4,808,713				51,208,945				2,000,000			
17	Annual Depreciation Exp		120,218				1,280,224				50,000			
18	In Service Month (1-12)		10				9				12			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
46	W / O incentive	2019	4,209,488	120,218	4,089,270		45,919,339	1,280,224	44,639,115		1,805,039	50,000	1,755,039	
47	W incentive	2019	4,209,488	120,218	4,089,270		45,919,339	1,280,224	44,639,115		1,805,039	50,000	1,755,039	
48	W / O incentive	2020	4,089,270	120,218	3,969,052	541,349	44,639,115	1,280,224	43,358,892	5,879,039	1,755,039	50,000	1,705,039	230,825
49	W incentive	2020	4,089,270	120,218	3,969,052	541,349	44,639,115	1,280,224	43,358,892	5,879,039	1,755,039	50,000	1,705,039	230,825
50														
51														
A	Proj Rev Req w/o Incentive PCY*					626,288				6,770,534				265,817
B	Proj Rev Req w/ Incentive PCY*					626,288				6,770,534				265,817
C	Actual Rev Req w/o Incentive PCY*					571,730				6,203,909				243,528
D	Actual Rev Req w/ Incentive PCY*					571,730				6,203,909				243,528
E	TUA w/o Int w/o Incentive PCY (C-A)					(54,558)				(566,624)				(22,290)
F	TUA w/o Int w/ Incentive PCY (B-D)					(54,558)				(566,624)				(22,290)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.10221				1.10221				1.10221
H	True-Up Adjustment w/o Incentive (E*G)					(60,134)				(624,540)				(24,568)
I	True-Up Adjustment w/ Incentive (F*G)					(60,134)				(624,540)				(24,568)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	481,215	5,254,499	206,257
W incentive	481,215	5,254,499	206,257

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

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Line			Project BD-4				Project BD-5				Project BE			
10														
11	Schedule 12	(Yes or No)	Yes	B1508.1			Yes	B1508.1			Yes	B1508.2		
12	Life		40	Build a 2nd 230kV line Harrisonburg to			40	Build a 2nd 230kV line Harrisonburg to			40	Install a 3rd 230 - 115 kV Tx at		
13	FCR W/O incentive	Line 3	10.4521%	Endless Caverns			10.4521%	Endless Caverns			10.4521%	Endless Caverns		
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.4521%				10.4521%				10.4521%			
16	Investment		6,221,144				1,165,302				11,994,009			
17	Annual Depreciation Exp		155,529				29,133				299,850			
18	In Service Month (1-12)		6				7				9			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
46	W / O incentive	2019	5,687,042	155,529	5,531,513		1,094,616	29,133	1,065,483		10,755,093	299,850	10,455,243	
47	W incentive	2019	5,687,042	155,529	5,531,513		1,094,616	29,133	1,065,483		10,755,093	299,850	10,455,243	
48	W / O incentive	2020	5,531,513	155,529	5,375,985	725,559	1,065,483	29,133	1,036,351	138,975	10,455,243	299,850	10,155,393	1,376,971
49	W incentive	2020	5,531,513	155,529	5,375,985	725,559	1,065,483	29,133	1,036,351	138,975	10,455,243	299,850	10,155,393	1,376,971
50														
51														
A	Proj Rev Req w/o Incentive PCY*					831,629				159,857				1,585,775
B	Proj Rev Req w/ Incentive PCY*					831,629				159,857				1,585,775
C	Actual Rev Req w/o Incentive PCY*					765,160				146,429				1,453,061
D	Actual Rev Req w/ Incentive PCY*					765,160				146,429				1,453,061
E	TUA w/o Int w/o Incentive PCY (C-A)					(66,469)				(13,428)				(132,713)
F	TUA w/o Int w/ Incentive PCY (B-D)					(66,469)				(13,428)				(132,713)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.10221				1.10221				1.10221
H	True-Up Adjustment w/o Incentive (E*G)					(73,263)				(14,800)				(146,278)
I	True-Up Adjustment w/ Incentive (F*G)					(73,263)				(14,800)				(146,278)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	Project BD-4	Project BD-5	Project BE
W / O incentive	652,297	124,175	1,230,693
W incentive	652,297	124,175	1,230,693

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

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Line	Description		Project BF-1				Project BF-2				Project BF-3			
10														
11	Schedule 12 (Yes or No)		Yes	B2053			Yes	B2053			Yes	B2053		
12	Life		40	Rebuild 28 mile line			40	Rebuild 28 mile line			40	Rebuild 28 mile line		
13	FCR W/O incentive Line 3		10.4521%	(Altavista - Skimmer, 115kV)			10.4521%	(Altavista - Skimmer, 115kV)			10.4521%	(Altavista - Skimmer, 115kV)		
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.4521%				10.4521%				10.4521%			
16	Investment		6,782,738				23,185,930				12,489,226			
17	Annual Depreciation Exp		169,568				579,648				312,231			
18	In Service Month (1-12)		11				3				6			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
46	W / O incentive	2019	6,108,408	169,568	5,938,839		21,060,553	579,648	20,480,905		11,416,992	312,231	11,104,761	
47	W incentive	2019	6,108,408	169,568	5,938,839		21,060,553	579,648	20,480,905		11,416,992	312,231	11,104,761	
48	W / O incentive	2020	5,938,839	169,568	5,769,271	781,440	20,480,905	579,648	19,901,257	2,690,038	11,104,761	312,231	10,792,531	1,456,593
49	W incentive	2020	5,938,839	169,568	5,769,271	781,440	20,480,905	579,648	19,901,257	2,690,038	11,104,761	312,231	10,792,531	1,456,593
50														
51														

		Project BF-1	Project BF-2	Project BF-3
A	Proj Rev Req w/o Incentive PCY*	899,914	3,097,711	1,677,422
B	Proj Rev Req w/ Incentive PCY*	899,914	3,097,711	1,677,422
C	Actual Rev Req w/o Incentive PCY*	824,502	2,837,462	1,536,093
D	Actual Rev Req w/ Incentive PCY*	824,502	2,837,462	1,536,093
E	TUA w/o Int w/o Incentive PCY (C-A)	(75,412)	(260,249)	(141,329)
F	TUA w/o Int w/ Incentive PCY (B-D)	(75,412)	(260,249)	(141,329)
G	Future Value Factor (1+i)^24 mo (ATT6)	1.10221	1.10221	1.10221
H	True-Up Adjustment w/o Incentive (E*G)	(83,120)	(286,850)	(155,775)
I	True-Up Adjustment w/ Incentive (F*G)	(83,120)	(286,850)	(155,775)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	Project BF-1	Project BF-2	Project BF-3
W / O incentive	698,320	2,403,189	1,300,818
W incentive	698,320	2,403,189	1,300,818

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

Line	Description		Project BF-4				Project BG-1				Project BG-2			
10														
11	Schedule 12 (Yes or No)		Yes	B2053			Yes	B1906.1			Yes	B1906.1		
12	Life		40	Rebuild 28 mile line			40	At Yadkin 500 kV, install six 500 kV breakers			40	At Yadkin 500 kV, install six 500 kV breakers		
13	FCR W/O incentive Line 3		10.4521%	(Altavista - Skimmer, 115kV)			10.4521%				10.4521%			
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.4521%				10.4521%				10.4521%			
16	Investment		1,006,355				4,398,307				5,644,742			
17	Annual Depreciation Exp		25,159				109,958				141,119			
18	In Service Month (1-12)		12				5				11			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
46	W / O incentive	2019	931,658	25,159	906,500		4,012,177	109,958	3,902,219		5,214,823	141,119	5,073,704	
47	W incentive	2019	931,658	25,159	906,500		4,012,177	109,958	3,902,219		5,214,823	141,119	5,073,704	
48	W / O incentive	2020	906,500	25,159	881,341	118,592	3,902,219	109,958	3,792,261	512,075	5,073,704	141,119	4,932,586	664,052
49	W incentive	2020	906,500	25,159	881,341	118,592	3,902,219	109,958	3,792,261	512,075	5,073,704	141,119	4,932,586	664,052
50														
51														
A	Proj Rev Req w/o Incentive PCY*					136,550				589,666				764,614
B	Proj Rev Req w/ Incentive PCY*					136,550				589,666				764,614
C	Actual Rev Req w/o Incentive PCY*					125,013				540,061				700,050
D	Actual Rev Req w/ Incentive PCY*					125,013				540,061				700,050
E	TUA w/o Int w/o Incentive PCY (C-A)					(11,537)				(49,604)				(64,564)
F	TUA w/o Int w/ Incentive PCY (B-D)					(11,537)				(49,604)				(64,564)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.10221				1.10221				1.10221
H	True-Up Adjustment w/o Incentive (E*G)					(12,717)				(54,674)				(71,163)
I	True-Up Adjustment w/ Incentive (F*G)					(12,717)				(54,674)				(71,163)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive		105,876	457,400	592,889
W incentive		105,876	457,400	592,889

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

Line	Description		Project BH-1				Project BH-2				Project BH-3			
10														
11	Schedule 12 (Yes or No)		Yes	B1908			Yes	B1908			Yes	B1908		
12	Life		40	Rebuild Lexington-Dooms 500 kV			40	Rebuild Lexington-Dooms 500 kV			40	Rebuild Lexington-Dooms 500 kV		
13	FCR W/O incentive Line 3		10.4521%				10.4521%				10.4521%			
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.4521%				10.4521%				10.4521%			
16	Investment		74,619,245				30,169,103				20,758,952			
17	Annual Depreciation Exp		1,865,481				754,228				518,974			
18	In Service Month (1-12)		5				12				12			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
46	W / O incentive	2019	68,068,369	1,865,481	66,202,888		27,929,807	754,228	27,175,580		19,700,889	518,974	19,181,915	
47	W incentive	2019	68,068,369	1,865,481	66,202,888		27,929,807	754,228	27,175,580		19,700,889	518,974	19,181,915	
48	W / O incentive	2020	66,202,888	1,865,481	64,337,407	8,687,576	27,175,580	754,228	26,421,352	3,555,227	19,181,915	518,974	18,662,942	2,496,763
49	W incentive	2020	66,202,888	1,865,481	64,337,407	8,687,576	27,175,580	754,228	26,421,352	3,555,227	19,181,915	518,974	18,662,942	2,496,763
50														
51														

		Project BH-1	Project BH-2	Project BH-3
A	Proj Rev Req w/o Incentive PCY*	9,920,161	4,080,313	2,709,812
B	Proj Rev Req w/ Incentive PCY*	9,920,161	4,080,313	2,709,812
C	Actual Rev Req w/o Incentive PCY*	9,162,384	3,747,699	2,629,794
D	Actual Rev Req w/ Incentive PCY*	9,162,384	3,747,699	2,629,794
E	TUA w/o Int w/o Incentive PCY (C-A)	(757,778)	(332,614)	(80,018)
F	TUA w/o Int w/ Incentive PCY (B-D)	(757,778)	(332,614)	(80,018)
G	Future Value Factor (1+i)^24 mo (ATT6)	1.10221	1.10221	1.10221
H	True-Up Adjustment w/o Incentive (E*G)	(835,231)	(366,611)	(88,197)
I	True-Up Adjustment w/ Incentive (F*G)	(835,231)	(366,611)	(88,197)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	Project BH-1	Project BH-2	Project BH-3
W / O incentive	7,852,345	3,188,617	2,408,567
W incentive	7,852,345	3,188,617	2,408,567

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

Line	Item	Year	Project BI				Project BJ-1				Project BJ-2			
11	Schedule 12 (Yes or No)		Yes	B1698			Yes	B1905.1			Yes	B1905.1		
12	Life		40	Install a 2nd 500/230 kV transformer			40	Surry to Skiffes Creek 500 kV Line			40	Surry to Skiffes Creek 500 kV Line		
13	FCR W/O incentive Line 3		10.4521%	at Brambleton			10.4521%	(7 miles overhead)			10.4521%	(7 miles overhead)		
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.4521%				10.4521%				10.4521%			
16	Investment		21,908,705				8,292,150				230,602,671			
17	Annual Depreciation Exp		547,718				207,304				5,765,067			
18	In Service Month (1-12)		6				9				2			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
46	W / O incentive	2019	21,360,987	547,718	20,813,270		8,231,686	207,304	8,024,383		230,602,671	5,044,433	225,558,238	
47	W incentive	2019	21,360,987	547,718	20,813,270		8,231,686	207,304	8,024,383		230,602,671	5,044,433	225,558,238	
48	W / O incentive	2020	20,813,270	547,718	20,265,552	2,694,515	8,024,383	207,304	7,817,079	1,035,186	225,558,238	5,765,067	219,793,171	29,039,332
49	W incentive	2020	20,813,270	547,718	20,265,552	2,694,515	8,024,383	207,304	7,817,079	1,035,186	225,558,238	5,765,067	219,793,171	29,039,332
50														
51														
A	Proj Rev Req w/o Incentive PCY*					3,041,598				1,171,271				-
B	Proj Rev Req w/ Incentive PCY*					3,041,598				1,171,271				-
C	Actual Rev Req w/o Incentive PCY*					2,835,614				315,293				-
D	Actual Rev Req w/ Incentive PCY*					2,835,614				315,293				-
E	TUA w/o Int w/o Incentive PCY (C-A)					(205,985)				(855,977)				-
F	TUA w/o Int w/ Incentive PCY (B-D)					(205,985)				(855,977)				-
G	Future Value Factor (1+i)^24 mo (ATT6)					1.10221				1.10221				1.10221
H	True-Up Adjustment w/o Incentive (E*G)					(227,038)				(943,467)				-
I	True-Up Adjustment w/ Incentive (F*G)					(227,038)				(943,467)				-
	W / O incentive					2,467,477				91,718				29,039,332
	W incentive					2,467,477				91,718				29,039,332

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 BK				Project BL-1				Project BL-2			
11	Schedule 12 (Yes or No)		Yes	B1905.2			Yes	B1905.3			Yes	B1905.3		
12	Life		40	Surry 500 kV Station Work			40	Skiffes Creek 500-230 kV Tx and			40	Skiffes Creek 500-230 kV Tx and		
13	FCR W/O incentive Line 3		10.4521%				10.4521%	Switching Station			10.4521%	Switching Station		
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.4521%				10.4521%				10.4521%			
16	Investment		1,834,471				9,613,413				38,452,563			
17	Annual Depreciation Exp		45,862				240,335				961,314			
18	In Service Month (1-12)		5				9				10			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
46	W / O incentive	2019	1,630,759	45,862	1,584,898		9,543,315	240,335	9,302,980		38,252,289	961,314	37,290,975	
47	W incentive	2019	1,630,759	45,862	1,584,898		9,543,315	240,335	9,302,980		38,252,289	961,314	37,290,975	
48	W / O incentive	2020	1,584,898	45,862	1,539,036	209,120	9,302,980	240,335	9,062,645	1,200,131	37,290,975	961,314	36,329,661	4,808,762
49	W incentive	2020	1,584,898	45,862	1,539,036	209,120	9,302,980	240,335	9,062,645	1,200,131	37,290,975	961,314	36,329,661	4,808,762
50														
51														
A	Proj Rev Req w/o Incentive PCY*					240,843				356,732				-
B	Proj Rev Req w/ Incentive PCY*					240,843				356,732				-
C	Actual Rev Req w/o Incentive PCY*					220,740				365,532				1,045,230
D	Actual Rev Req w/ Incentive PCY*					220,740				365,532				1,045,230
E	TUA w/o Int w/o Incentive PCY (C-A)					(20,103)				8,800				1,045,230
F	TUA w/o Int w/ Incentive PCY (B-D)					(20,103)				8,800				1,045,230
G	Future Value Factor (1+i)^24 mo (ATT6)					1.10221				1.10221				1.10221
H	True-Up Adjustment w/o Incentive (E*G)					(22,158)				9,699				1,152,064
I	True-Up Adjustment w/ Incentive (F*G)					(22,158)				9,699				1,152,064
	TUA = True-Up Adjusment													
	PCY = Previous Calendar Year													
	W / O incentive					186,962				1,209,830				5,960,825
	W incentive					186,962				1,209,830				5,960,825

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

Line			BL-3				BL-4				BL-5			
10			**Project BL-3**				**Project BL-4**				**Project BL-5**			
11	Schedule 12 (Yes or No)		Yes	B1905.3			Yes	B1905.3			Yes	B1905.3		
12	Life		40	Skiffes Creek 500-230 kV Tx and			40	Skiffes Creek 500-230 kV Tx and			40	Skiffes Creek 500-230 kV Tx and		
13	FCR W/O incentive Line 3		10.4521%	Switching Station			10.4521%	Switching Station			10.4521%	Switching Station		
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.4521%				10.4521%				10.4521%			
16	Investment		38,308,019				13,621,175				6,356,020			
17	Annual Depreciation Exp		957,700				340,529				158,901			
18	In Service Month (1-12)		11				12				2			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
46	W / O incentive	2019	38,188,306	957,700	37,230,606		13,606,986	340,529	13,266,457		6,356,020	139,038	6,216,982	
47	W incentive	2019	38,188,306	957,700	37,230,606		13,606,986	340,529	13,266,457		6,356,020	139,038	6,216,982	
48	W / O incentive	2020	37,230,606	957,700	36,272,905	4,799,027	13,266,457	340,529	12,925,928	1,709,355	6,216,982	158,901	6,058,082	800,401
49	W incentive	2020	37,230,606	957,700	36,272,905	4,799,027	13,266,457	340,529	12,925,928	1,709,355	6,216,982	158,901	6,058,082	800,401
50														
51														
A	Proj Rev Req w/o Incentive PCY*					-				-				-
B	Proj Rev Req w/ Incentive PCY*					-				-				-
C	Actual Rev Req w/o Incentive PCY*					625,308				74,176				-
D	Actual Rev Req w/ Incentive PCY*					625,308				74,176				-
E	TUA w/o Int w/o Incentive PCY (C-A)					625,308				74,176				-
F	TUA w/o Int w/ Incentive PCY (B-D)					625,308				74,176				-
G	Future Value Factor (1+i)^24 mo (ATT6)					1.10221				1.10221				1.10221
H	True-Up Adjustment w/o Incentive (E*G)					689,221				81,758				-
I	True-Up Adjustment w/ Incentive (F*G)					689,221				81,758				-
	W / O incentive					5,488,248				1,791,113				800,401
	W incentive					5,488,248				1,791,113				800,401

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

Line	Description	Year	Project BM-1				Project BM-2				Project BM-3			
10														
11	Schedule 12 (Yes or No)		Yes	B1905.4			Yes	B1905.4			Yes	B1905.4		
12	Life		40	Skiffes Creek - Whealton 230 kV line			40	Skiffes Creek - Whealton 230 kV line			40	Skiffes Creek - Whealton 230 kV line		
13	FCR W/O incentive Line 3		10.4521%				10.4521%				10.4521%			
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.4521%				10.4521%				10.4521%			
16	Investment		7,585,377				14,074,806				9,383,204			
17	Annual Depreciation Exp		189,634				351,870				234,580			
18	In Service Month (1-12)		9				3				6			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
46	W / O incentive	2019	7,585,377	189,634	7,395,743		13,796,242	351,870	13,444,372		9,256,140	234,580	9,021,560	
47	W incentive	2019	7,585,377	189,634	7,395,743		13,796,242	351,870	13,444,372		9,256,140	234,580	9,021,560	
48	W / O incentive	2020	7,585,377	189,634	7,395,743	972,554	13,444,372	351,870	13,092,502	1,738,699	9,021,560	234,580	8,786,980	1,165,262
49	W incentive	2020	7,585,377	189,634	7,395,743	972,554	13,444,372	351,870	13,092,502	1,738,699	9,021,560	234,580	8,786,980	1,165,262
50														
51														
A	Proj Rev Req w/o Incentive PCY*					2,692,048				-				-
B	Proj Rev Req w/ Incentive PCY*					2,692,048				-				-
C	Actual Rev Req w/o Incentive PCY*					981,765				1,445,234				660,909
D	Actual Rev Req w/ Incentive PCY*					981,765				1,445,234				660,909
E	TUA w/o Int w/o Incentive PCY (C-A)					(1,710,283)				1,445,234				660,909
F	TUA w/o Int w/ Incentive PCY (B-D)					(1,710,283)				1,445,234				660,909
G	Future Value Factor (1+i)^24 mo (ATT6)					1.10221				1.10221				1.10221
H	True-Up Adjustment w/o Incentive (E*G)					(1,885,092)				1,592,953				728,461
I	True-Up Adjustment w/ Incentive (F*G)					(1,885,092)				1,592,953				728,461

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	(912,538)	3,331,652	1,893,724
W incentive	(912,538)	3,331,652	1,893,724

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

Line	Description		Year	Project BM-4				Project BM-5				Project BM-6			
11	Schedule 12	(Yes or No)		Yes	B1905.4			Yes	B1905.4			Yes	B1905.4		
12	Life			40	Skiffes Creek - Whealton 230 kV line			40	Skiffes Creek - Whealton 230 kV line			40	Skiffes Creek - Whealton 230 kV line		
13	FCR W/O incentive	Line 3		10.4521%				10.4521%				10.4521%			
14	Incentive Factor (Basis Points /100)			0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)			10.4521%				10.4521%				10.4521%			
16	Investment			586,450				802,990				40,425,150			
17	Annual Depreciation Exp			14,661				20,075				1,010,629			
18	In Service Month (1-12)			9				10				12			
19				**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive		2006												
46	W / O incentive		2019	582,174	14,661	567,513		798,808	20,075	778,733		40,383,040	1,010,629	39,372,412	
47	W incentive		2019	582,174	14,661	567,513		798,808	20,075	778,733		40,383,040	1,010,629	39,372,412	
48	W / O incentive		2020	567,513	14,661	552,851	73,212	778,733	20,075	758,658	100,420	39,372,412	1,010,629	38,361,783	5,073,053
49	W incentive		2020	567,513	14,661	552,851	73,212	778,733	20,075	758,658	100,420	39,372,412	1,010,629	38,361,783	5,073,053
50															
51															

	Description	Project BM-4	Project BM-5	Project BM-6
A	Proj Rev Req w/o Incentive PCY*	-	-	-
B	Proj Rev Req w/ Incentive PCY*	-	-	-
C	Actual Rev Req w/o Incentive PCY*	22,299	21,827	212,612
D	Actual Rev Req w/ Incentive PCY*	22,299	21,827	212,612
E	TUA w/o Int w/o Incentive PCY (C-A)	22,299	21,827	212,612
F	TUA w/o Int w/ Incentive PCY (B-D)	22,299	21,827	212,612
G	Future Value Factor (1+i)^24 mo (ATT6)	1.10221	1.10221	1.10221
H	True-Up Adjustment w/o Incentive (E*G)	24,578	24,058	234,343
I	True-Up Adjustment w/ Incentive (F*G)	24,578	24,058	234,343

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	Project BM-4	Project BM-5	Project BM-6
W / O incentive	97,790	124,478	5,307,395
W incentive	97,790	124,478	5,307,395

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

Line	Item		Year	Project BM-7				Project BN				Project BO			
10															
11	Schedule 12	(Yes or No)		Yes	B1905.4			Yes	B1905.5			Yes	B1905.6		
12	Life			40	Skiffes Creek - Whealton 230 kV line			40	Whealton 230 kV breakers			40	Yorktown 230 kV work		
13	FCR W/O incentive	Line 3		10.4521%				10.4521%				10.4521%			
14	Incentive Factor (Basis Points /100)			0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)			10.4521%				10.4521%				10.4521%			
16	Investment			9,306,646				5,301,638				1,363,422			
17	Annual Depreciation Exp			232,666				132,541				34,086			
18	In Service Month (1-12)			1				6				2			
19				**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive		2006												
46	W / O incentive		2019	9,306,646	222,972	9,083,674		4,969,772	132,541	4,837,231		1,363,422	29,825	1,333,597	
47	W incentive		2019	9,306,646	222,972	9,083,674		4,969,772	132,541	4,837,231		1,363,422	29,825	1,333,597	
48	W / O incentive		2020	9,083,674	232,666	8,851,008	1,169,941	4,837,231	132,541	4,704,690	631,206	1,333,597	34,086	1,299,512	171,693
49	W incentive		2020	9,083,674	232,666	8,851,008	1,169,941	4,837,231	132,541	4,704,690	631,206	1,333,597	34,086	1,299,512	171,693
50															
51															

	Item	Project BM-7	Project BN	Project BO
A	Proj Rev Req w/o Incentive PCY*	-	705,867	-
B	Proj Rev Req w/ Incentive PCY*	-	705,867	-
C	Actual Rev Req w/o Incentive PCY*	-	686,184	-
D	Actual Rev Req w/ Incentive PCY*	-	686,184	-
E	TUA w/o Int w/o Incentive PCY (C-A)	-	(19,683)	-
F	TUA w/o Int w/ Incentive PCY (B-D)	-	(19,683)	-
G	Future Value Factor (1+i)^24 mo (ATT6)	1.10221	1.10221	1.10221
H	True-Up Adjustment w/o Incentive (E*G)	-	(21,695)	-
I	True-Up Adjustment w/ Incentive (F*G)	-	(21,695)	-

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	Project BM-7	Project BN	Project BO
W / O incentive	1,169,941	609,511	171,693
W incentive	1,169,941	609,511	171,693

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

Line			Project BP				Project BR				Project BS			
10														
11	Schedule 12 (Yes or No)		Yes	B1905.7			Yes	B1905.9			Yes	B1907		
12	Life		40	Lanexa 115 kV work			40	Kings Mill, Peninmen, Toano, Waller,			40	Install a 3rd 500/230 kV TX at Clover		
13	FCR W/O incentive Line 3		10.4521%				10.4521%	Warkwick			10.4521%			
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.4521%				10.4521%				10.4521%			
16	Investment		79,622				84,761				19,042,583			
17	Annual Depreciation Exp		1,991				2,119				476,065			
18	In Service Month (1-12)		5				5				4			
19			Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req
20	W / O incentive	2006												
46	W / O incentive	2019	79,622	1,244	78,378		84,761	1,324	83,437		17,776,768	476,065	17,300,703	
47	W incentive	2019	79,622	1,244	78,378		84,761	1,324	83,437		17,776,768	476,065	17,300,703	
48	W / O incentive	2020	78,378	1,991	76,387	10,079	83,437	2,119	81,318	10,729	17,300,703	476,065	16,824,639	2,259,470
49	W incentive	2020	78,378	1,991	76,387	10,079	83,437	2,119	81,318	10,729	17,300,703	476,065	16,824,639	2,259,470
50														
51														

		Project BP	Project BR	Project BS
A	Proj Rev Req w/o Incentive PCY*	-	-	2,633,317
B	Proj Rev Req w/ Incentive PCY*	-	-	2,633,317
C	Actual Rev Req w/o Incentive PCY*	-	-	2,464,655
D	Actual Rev Req w/ Incentive PCY*	-	-	2,464,655
E	TUA w/o Int w/o Incentive PCY (C-A)	-	-	(168,661)
F	TUA w/o Int w/ Incentive PCY (B-D)	-	-	(168,661)
G	Future Value Factor (1+i)^24 mo (ATT6)	1.10221	1.10221	1.10221
H	True-Up Adjustment w/o Incentive (E*G)	-	-	(185,900)
I	True-Up Adjustment w/ Incentive (F*G)	-	-	(185,900)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	Project BP	Project BR	Project BS
W / O incentive	10,079	10,729	2,073,570
W incentive	10,079	10,729	2,073,570

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

Line			Project BT-1				Project BT-2				Project BT-3			
10														
11	Schedule 12 (Yes or No)		Yes	B1909			Yes	B1909			Yes	B1909		
12	Life		40	Uprate Bremo – Midlothian 230 kV to			40	Uprate Bremo – Midlothian 230 kV to			40	Uprate Bremo – Midlothian 230 kV to		
13	FCR W/O incentive Line 3		10.4521%	its maximum operating temperature			10.4521%	its maximum operating temperature			10.4521%	its maximum operating temperature		
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.4521%				10.4521%				10.4521%			
16	Investment		764,184				1,217,598				1,389,088			
17	Annual Depreciation Exp		19,105				30,440				34,727			
18	In Service Month (1-12)		6				6				5			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
46	W / O incentive	2019	698,577	19,105	679,472		1,141,380	30,440	1,110,940		1,332,656	34,727	1,297,929	
47	W incentive	2019	698,577	19,105	679,472		1,141,380	30,440	1,110,940		1,332,656	34,727	1,297,929	
48	W / O incentive	2020	679,472	19,105	660,368	89,125	1,110,940	30,440	1,080,500	144,966	1,297,929	34,727	1,263,202	168,573
49	W incentive	2020	679,472	19,105	660,368	89,125	1,110,940	30,440	1,080,500	144,966	1,297,929	34,727	1,263,202	168,573
50														
51														
A	Proj Rev Req w/o Incentive PCY*					102,628				167,113				-
B	Proj Rev Req w/ Incentive PCY*					102,628				167,113				-
C	Actual Rev Req w/o Incentive PCY*					93,990				157,592				179,788
D	Actual Rev Req w/ Incentive PCY*					93,990				157,592				179,788
E	TUA w/o Int w/o Incentive PCY (C-A)					(8,639)				(9,521)				179,788
F	TUA w/o Int w/ Incentive PCY (B-D)					(8,639)				(9,521)				179,788
G	Future Value Factor (1+i)^24 mo (ATT6)					1.10221				1.10221				1.10221
H	True-Up Adjustment w/o Incentive (E*G)					(9,522)				(10,495)				198,164
I	True-Up Adjustment w/ Incentive (F*G)					(9,522)				(10,495)				198,164

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	79,603	134,471	366,737
W incentive	79,603	134,471	366,737

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

Line	Item		Project BU				Project BV-1A				Project BV-1B			
11	Schedule 12 (Yes or No)		Yes	B1328			Yes	B1912			Yes	B1912		
12	Life		40	Uprate the 3.63 mile line section between			40	Install a 500 MVAR SVC at			40	Install a 500 MVAR SVC at		
13	FCR W/O incentive Line 3		10.4521%	Possum and Dumfries substations,			10.4521%	Landstown 230 kV			10.4521%	Landstown 230 kV		
14	Incentive Factor (Basis Points /100)		0	Replace 1600 amp wave trap at Possum Point			0	(Includes project modifications.)			0	(Includes project modifications.)		
15	FCR W incentive L.13 +(L.14*L.5)		10.4521%				10.4521%				10.4521%			
16	Investment		3,881,027				20,609,467				25,360,720			
17	Annual Depreciation Exp		97,026				515,237				634,018			
18	In Service Month (1-12)		12				4				6			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
46	W / O incentive	2019	3,592,959	97,026	3,495,933		19,239,497	515,237	18,724,260		23,773,218	634,018	23,139,200	
47	W incentive	2019	3,592,959	97,026	3,495,933		19,239,497	515,237	18,724,260		23,773,218	634,018	23,139,200	
48	W / O incentive	2020	3,495,933	97,026	3,398,907	457,353	18,724,260	515,237	18,209,023	2,445,387	23,139,200	634,018	22,505,182	3,019,414
49	W incentive	2020	3,495,933	97,026	3,398,907	457,353	18,724,260	515,237	18,209,023	2,445,387	23,139,200	634,018	22,505,182	3,019,414
50														
51														
A	Proj Rev Req w/o Incentive PCY*					526,418				2,764,895				3,474,771
B	Proj Rev Req w/ Incentive PCY*					526,418				2,764,895				3,474,771
C	Actual Rev Req w/o Incentive PCY*					482,113				2,667,455				3,282,403
D	Actual Rev Req w/ Incentive PCY*					482,113				2,667,455				3,282,403
E	TUA w/o Int w/o Incentive PCY (C-A)					(44,305)				(97,439)				(192,368)
F	TUA w/o Int w/ Incentive PCY (B-D)					(44,305)				(97,439)				(192,368)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.10221				1.10221				1.10221
H	True-Up Adjustment w/o Incentive (E*G)					(48,834)				(107,399)				(212,030)
I	True-Up Adjustment w/ Incentive (F*G)					(48,834)				(107,399)				(212,030)
	W / O incentive					408,519				2,337,988				2,807,384
	W incentive					408,519				2,337,988				2,807,384

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

Line	Description	Year	Project BV-1C				Project BV-2A				Project BV-2B			
11	Schedule 12 (Yes or No)		Yes	B1912			Yes	B1912			Yes	B1912		
12	Life		40	Install a 500 MVAR SVC at			40	125 MVAr STATCOM at Lynnhaven			40	125 MVAr STATCOM at Lynnhaven		
13	FCR W/O incentive Line 3		10.4521%	Landstown 230 kV			10.4521%				10.4521%			
14	Incentive Factor (Basis Points /100)		0	(Includes project modifications.)			0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.4521%				10.4521%				10.4521%			
16	Investment		24,992,898				27,334,610				94,777			
17	Annual Depreciation Exp		624,822				683,365				2,369			
18	In Service Month (1-12)		11				4				10			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
46	W / O incentive	2019	23,670,599	624,822	23,045,777		26,167,194	683,365	25,483,829		94,283	2,369	91,914	
47	W incentive	2019	23,670,599	624,822	23,045,777		26,167,194	683,365	25,483,829		94,283	2,369	91,914	
48	W / O incentive	2020	23,045,777	624,822	22,420,954	3,000,934	25,483,829	683,365	24,800,464	3,311,245	91,914	2,369	89,545	11,853
49	W incentive	2020	23,045,777	624,822	22,420,954	3,000,934	25,483,829	683,365	24,800,464	3,311,245	91,914	2,369	89,545	11,853
50														
51														
A	Proj Rev Req w/o Incentive PCY*					3,360,096				3,909,735				-
B	Proj Rev Req w/ Incentive PCY*					3,360,096				3,909,735				-
C	Actual Rev Req w/o Incentive PCY*					3,234,797				3,537,881				2,576
D	Actual Rev Req w/ Incentive PCY*					3,234,797				3,537,881				2,576
E	TUA w/o Int w/o Incentive PCY (C-A)					(125,300)				(371,854)				2,576
F	TUA w/o Int w/ Incentive PCY (B-D)					(125,300)				(371,854)				2,576
G	Future Value Factor (1+i)^24 mo (ATT6)					1.10221				1.10221				1.10221
H	True-Up Adjustment w/o Incentive (E*G)					(138,107)				(409,861)				2,840
I	True-Up Adjustment w/ Incentive (F*G)					(138,107)				(409,861)				2,840

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	Project BV-1C	Project BV-2A	Project BV-2B
W / O incentive	2,862,827	2,901,384	14,692
W incentive	2,862,827	2,901,384	14,692

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 BW				Project BX				Project BY-1			
11	Schedule 12 (Yes or No)		Yes	B1701			Yes	B1791			Yes	B1694		
12	Life		40	Reconductor line #2104			40	Wreck and rebuild 2.1 mile section of			40	Rebuild Loudoun - Brambleton 500 kV		
13	FCR W/O incentive Line 3		10.4521%	(Fredericksburg - Cranes Corner 230 kV)			10.4521%	Gordonsville and Somerset (Line #11)			10.4521%			
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.4521%				10.4521%				10.4521%			
16	Investment		3,178,496				3,441,461				27,912,088			
17	Annual Depreciation Exp		79,462				86,037				697,802			
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												
46	W / O incentive	2019	3,010,331	79,462	2,930,869		3,139,333	86,037	3,053,296		25,948,505	697,802	25,250,703	
47	W incentive	2019	3,010,331	79,462	2,930,869		3,139,333	86,037	3,053,296		25,948,505	697,802	25,250,703	
48	W / O incentive	2020	2,930,869	79,462	2,851,407	381,647	3,053,296	86,037	2,967,260	400,673	25,250,703	697,802	24,552,901	3,300,561
49	W incentive	2020	2,930,869	79,462	2,851,407	381,647	3,053,296	86,037	2,967,260	400,673	25,250,703	697,802	24,552,901	3,300,561
50														
51														
A	Proj Rev Req w/o Incentive PCY*					439,658				461,385				3,781,378
B	Proj Rev Req w/ Incentive PCY*					439,658				461,385				3,781,378
C	Actual Rev Req w/o Incentive PCY*					411,388				422,572				3,478,766
D	Actual Rev Req w/ Incentive PCY*					411,388				422,572				3,478,766
E	TUA w/o Int w/o Incentive PCY (C-A)					(28,270)				(38,813)				(302,612)
F	TUA w/o Int w/ Incentive PCY (B-D)					(28,270)				(38,813)				(302,612)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.10221				1.10221				1.10221
H	True-Up Adjustment w/o Incentive (E*G)					(31,159)				(42,780)				(333,542)
I	True-Up Adjustment w/ Incentive (F*G)					(31,159)				(42,780)				(333,542)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive		350,487	357,893	2,967,019
W incentive		350,487	357,893	2,967,019

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

Line	Description	Year	Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req
10			Project BY-2				Project BY-3				Project BY-4			
11	Schedule 12 (Yes or No)		Yes	B1694			Yes	B1694			Yes	B1694		
12	Life		40	Rebuild Loudoun - Brambleton 500 kV			40	Rebuild Loudoun - Brambleton 500 kV			40	Rebuild Loudoun - Brambleton 500 kV		
13	FCR W/O incentive Line 3		10.4521%				10.4521%				10.4521%			
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.4521%				10.4521%				10.4521%			
16	Investment		2,711,987				15,702,803				477,481			
17	Annual Depreciation Exp		67,800				392,570				11,937			
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												
46	W / O incentive	2019	2,536,969	67,800	2,469,170		14,719,856	392,570	14,327,286		448,518	11,937	436,580	
47	W incentive	2019	2,536,969	67,800	2,469,170		14,719,856	392,570	14,327,286		448,518	11,937	436,580	
48	W / O incentive	2020	2,469,170	67,800	2,401,370	322,336	14,327,286	392,570	13,934,716	1,869,555	436,580	11,937	424,643	56,945
49	W incentive	2020	2,469,170	67,800	2,401,370	322,336	14,327,286	392,570	13,934,716	1,869,555	436,580	11,937	424,643	56,945
50														
51														
A	Proj Rev Req w/o Incentive PCY*					362,964				2,143,665				64,502
B	Proj Rev Req w/ Incentive PCY*					362,964				2,143,665				64,502
C	Actual Rev Req w/o Incentive PCY*					339,670				1,969,960				59,999
D	Actual Rev Req w/ Incentive PCY*					339,670				1,969,960				59,999
E	TUA w/o Int w/o Incentive PCY (C-A)					(23,294)				(173,705)				(4,503)
F	TUA w/o Int w/ Incentive PCY (B-D)					(23,294)				(173,705)				(4,503)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.10221				1.10221				1.10221
H	True-Up Adjustment w/o Incentive (E*G)					(25,675)				(191,460)				(4,963)
I	True-Up Adjustment w/ Incentive (F*G)					(25,675)				(191,460)				(4,963)
	W / O incentive					296,661				1,678,095				51,982
	W incentive					296,661				1,678,095				51,982

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 BZ-1**				**Project BZ-2**				**Project CA-1**			
11	Schedule 12 (Yes or No)		Yes	B1696			Yes	B1696			Yes	B2373		
12	Life		40	Install a breaker and a half scheme with			40	Install a breaker and a half scheme with			40	Build 2nd Loudoun - Brambleton 500 kV		
13	FCR W/O incentive Line 3		10.4521%	a minimum of eight 230 kV breakers			10.4521%	a minimum of eight 230 kV breakers			10.4521%	within existing ROW. The Loudoun -		
14	Incentive Factor (Basis Points /100)		0	for five existing lines at Idylwood 230 kV			0	for five existing lines at Idylwood 230 kV			0	Brambleton 230 kV line relocated as an		
15	FCR W incentive L.13 +(L.14*L.5)		10.4521%				10.4521%				10.4521%	underbuild on the new 500 kV line.		
16	Investment		2,147,423				33,000,000				28,003,295			
17	Annual Depreciation Exp		53,686				825,000				700,082			
18	In Service Month (1-12)		1				5				12			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
46	W / O incentive	2019	1,992,192	53,686	1,938,507						25,924,756	700,082	25,224,673	
47	W incentive	2019	1,992,192	53,686	1,938,507						25,924,756	700,082	25,224,673	
48	W / O incentive	2020	1,938,507	53,686	1,884,821	253,494	33,000,000	515,625	32,484,375	2,654,527	25,224,673	700,082	24,524,591	3,300,001
49	W incentive	2020	1,938,507	53,686	1,884,821	253,494	33,000,000	515,625	32,484,375	2,654,527	25,224,673	700,082	24,524,591	3,300,001
50														
51														
A	Proj Rev Req w/o Incentive PCY*					291,422				-				3,907,042
B	Proj Rev Req w/ Incentive PCY*					291,422				-				3,907,042
C	Actual Rev Req w/o Incentive PCY*					267,200				-				3,478,656
D	Actual Rev Req w/ Incentive PCY*					267,200				-				3,478,656
E	TUA w/o Int w/o Incentive PCY (C-A)					(24,222)				-				(428,386)
F	TUA w/o Int w/ Incentive PCY (B-D)					(24,222)				-				(428,386)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.10221				1.10221				1.10221
H	True-Up Adjustment w/o Incentive (E*G)					(26,698)				-				(472,172)
I	True-Up Adjustment w/ Incentive (F*G)					(26,698)				-				(472,172)
	TUA = True-Up Adjusment													
	PCY = Previous Calendar Year													
	W / O incentive					226,796				2,654,527				2,827,829
	W incentive					226,796				2,654,527				2,827,829

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

Line	Item		Year	Project CA-2				Project CA-3				Project CB-1			
10															
11	Schedule 12	(Yes or No)		Yes	B2373			Yes	B2373			Yes	B2582		
12	Life			40	Build 2nd Loudoun - Brambleton 500 kV			40	Build 2nd Loudoun - Brambleton 500 kV			40	Rebuild the Elmont - Cunningham 500 kV line		
13	FCR W/O incentive	Line 3		10.4521%	within existing ROW. The Loudoun -			10.4521%	within existing ROW. The Loudoun -			10.4521%			
14	Incentive Factor (Basis Points /100)			0	Brambleton 230 kV line relocated as an			0	Brambleton 230 kV line relocated as an			0			
15	FCR W incentive L.13 +(L.14*L.5)			10.4521%	underbuild on the new 500 kV line.			10.4521%	underbuild on the new 500 kV line.			10.4521%			
16	Investment			14,818,770				1,620,339				70,601,238			
17	Annual Depreciation Exp			370,469				40,508				1,765,031			
18	In Service Month (1-12)			9				12				5			
19				**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive		2006												
46	W / O incentive		2019	13,977,317	370,469	13,606,847		1,537,752	40,508	1,497,243		67,733,063	1,765,031	65,968,032	
47	W incentive		2019	13,977,317	370,469	13,606,847		1,537,752	40,508	1,497,243		67,733,063	1,765,031	65,968,032	
48	W / O incentive		2020	13,606,847	370,469	13,236,378	1,773,308	1,497,243	40,508	1,456,735	194,885	65,968,032	1,765,031	64,203,001	8,567,828
49	W incentive		2020	13,606,847	370,469	13,236,378	1,773,308	1,497,243	40,508	1,456,735	194,885	65,968,032	1,765,031	64,203,001	8,567,828
50															
51															
A	Proj Rev Req w/o Incentive PCY*						1,919,973				224,068				-
B	Proj Rev Req w/ Incentive PCY*						1,919,973				224,068				-
C	Actual Rev Req w/o Incentive PCY*						1,868,166				205,268				9,137,822
D	Actual Rev Req w/ Incentive PCY*						1,868,166				205,268				9,137,822
E	TUA w/o Int w/o Incentive PCY (C-A)						(51,807)				(18,799)				9,137,822
F	TUA w/o Int w/ Incentive PCY (B-D)						(51,807)				(18,799)				9,137,822
G	Future Value Factor (1+i)^24 mo (ATT6)						1.10221				1.10221				1.10221
H	True-Up Adjustment w/o Incentive (E*G)						(57,102)				(20,721)				10,071,808
I	True-Up Adjustment w/ Incentive (F*G)						(57,102)				(20,721)				10,071,808

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive	1,716,206	174,164	18,639,636
W incentive	1,716,206	174,164	18,639,636

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

These Three Columns are Repeated to Provide Line Number References on All Pages														
10			Project CB-2				Project CC				Project CE			
11	Schedule 12 (Yes or No)		Yes	B2582			Yes	B1911			Yes	B2471		
12	Life		40	Rebuild the Elmont - Cunningham 500 kV			40	Add a second Valley 500/230 kV TX			40	R/P Midlothian 500 kV breaker and		
13	FCR W/O incentive Line 3		10.4521%	line			10.4521%				10.4521%	M.O. switches with 3 breaker 500 kV ring bus.		
14	Incentive Factor (Basis Points /100)		0				0				0	Terminate Lines #563 Carson - Midlothian,		
15	FCR W incentive L.13 +(L.14*L.5)		10.4521%				10.4521%				10.4521%	#576 Midlothian - North Anna,		
16	Investment		23,231,945				21,934,675				7,896,194	Transformer #2 in new ring		
17	Annual Depreciation Exp		580,799				548,367				197,405			
18	In Service Month (1-12)		1				6				11			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
46	W / O incentive	2019	22,675,346	580,799	22,094,548		20,561,632	548,367	20,013,265		7,294,798	197,405	7,097,393	
47	W incentive	2019	22,675,346	580,799	22,094,548		20,561,632	548,367	20,013,265		7,294,798	197,405	7,097,393	
48	W / O incentive	2020	22,094,548	580,799	21,513,749	2,859,788	20,013,265	548,367	19,464,899	2,611,513	7,097,393	197,405	6,899,988	928,914
49	W incentive	2020	22,094,548	580,799	21,513,749	2,859,788	20,013,265	548,367	19,464,899	2,611,513	7,097,393	197,405	6,899,988	928,914
50														
51														
A	Proj Rev Req w/o Incentive PCY*					-				2,998,946				1,069,408
B	Proj Rev Req w/ Incentive PCY*					-				2,998,946				1,069,408
C	Actual Rev Req w/o Incentive PCY*					2,882,818				2,751,765				979,271
D	Actual Rev Req w/ Incentive PCY*					2,882,818				2,751,765				979,271
E	TUA w/o Int w/o Incentive PCY (C-A)					2,882,818				(247,181)				(90,136)
F	TUA w/o Int w/ Incentive PCY (B-D)					2,882,818				(247,181)				(90,136)
G	Future Value Factor (1+i)^24 mo (ATT6)					1.10221				1.10221				1.10221
H	True-Up Adjustment w/o Incentive (E*G)					3,177,474				(272,446)				(99,349)
I	True-Up Adjustment w/ Incentive (F*G)					3,177,474				(272,446)				(99,349)

TUA = True-Up Adjusment
PCY = Previous Calendar Year

W / O incentive		6,037,262	2,339,068	829,565
W incentive		6,037,262	2,339,068	829,565

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 CJ-1				Project CJ-2				Project CJ-3			
10														
11	Schedule 12 (Yes or No)		Yes	B2744			Yes	B2744			Yes	B2744		
12	Life		40	Rebuild the Carson-Rogers rd 500 kV circuit			40	Rebuild the Carson-Rogers rd 500 kV circuit			40	Rebuild the Carson-Rogers rd 500 kV circuit		
13	FCR W/O incentive Line 3		10.4521%				10.4521%				10.4521%			
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.4521%				10.4521%				10.4521%			
16	Investment		27,730,674				26,960,491				1,258,593			
17	Annual Depreciation Exp		693,267				674,012				31,465			
18	In Service Month (1-12)		1				2				8			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
46	W / O incentive	2019	27,066,293	693,267	26,373,026		26,370,730	674,012	25,696,718		1,246,794	31,465	1,215,329	
47	W incentive	2019	27,066,293	693,267	26,373,026		26,370,730	674,012	25,696,718		1,246,794	31,465	1,215,329	
48	W / O incentive	2020	26,373,026	693,267	25,679,760	3,413,569	25,696,718	674,012	25,022,706	3,324,632	1,215,329	31,465	1,183,864	156,848
49	W incentive	2020	26,373,026	693,267	25,679,760	3,413,569	25,696,718	674,012	25,022,706	3,324,632	1,215,329	31,465	1,183,864	156,848
50														
51														

		Project CJ-1	Project CJ-2	Project CJ-3
A	Proj Rev Req w/o Incentive PCY*	3,531,137	846,029	-
B	Proj Rev Req w/ Incentive PCY*	3,531,137	846,029	-
C	Actual Rev Req w/o Incentive PCY*	3,441,059	3,057,175	61,477
D	Actual Rev Req w/ Incentive PCY*	3,441,059	3,057,175	61,477
E	TUA w/o Int w/o Incentive PCY (C-A)	(90,078)	2,211,146	61,477
F	TUA w/o Int w/ Incentive PCY (B-D)	(90,078)	2,211,146	61,477
G	Future Value Factor (1+i)^24 mo (ATT6)	1.10221	1.10221	1.10221
H	True-Up Adjustment w/o Incentive (E*G)	(99,285)	2,437,149	67,760
I	True-Up Adjustment w/ Incentive (F*G)	(99,285)	2,437,149	67,760

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	Project CJ-1	Project CJ-2	Project CJ-3
W / O incentive	3,314,284	5,761,781	224,608
W incentive	3,314,284	5,761,781	224,608

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 CD-1				Project CF-1				Project CF-2			
11	Schedule 12 (Yes or No)		Yes	B2443			Yes	B2665			Yes	B2665		
12	Life		40	Glebe to Station C 230 kV UG line			40	Rebuild the Cunningham - Dooms 500 kV line			40	Rebuild the Cunningham - Dooms 500 kV line		
13	FCR W/O incentive Line 3		10.4521%				10.4521%				10.4521%			
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		10.4521%				10.4521%				10.4521%			
16	Investment		-				23,021,251				44,645,740			
17	Annual Depreciation Exp		-				575,531				1,116,144			
18	In Service Month (1-12)		-				12				4			
19			Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req
20	W / O incentive	2006												
46	W / O incentive	2019	-	-	-		22,997,271	575,531	22,421,739		44,645,740	790,602	43,855,138	
47	W incentive	2019	-	-	-		22,997,271	575,531	22,421,739		44,645,740	790,602	43,855,138	
48	W / O incentive	2020	-	-	-	-	22,421,739	575,531	21,846,208	2,888,994	43,855,138	1,116,144	42,738,995	5,641,592
49	W incentive	2020	-	-	-	-	22,421,739	575,531	21,846,208	2,888,994	43,855,138	1,116,144	42,738,995	5,641,592
50														
51														

		Project CD-1	Project CF-1	Project CF-2
A	Proj Rev Req w/o Incentive PCY*	-	-	-
B	Proj Rev Req w/ Incentive PCY*	-	-	-
C	Actual Rev Req w/o Incentive PCY*	-	125,366	-
D	Actual Rev Req w/ Incentive PCY*	-	125,366	-
E	TUA w/o Int w/o Incentive PCY (C-A)	-	125,366	-
F	TUA w/o Int w/ Incentive PCY (B-D)	-	125,366	-
G	Future Value Factor (1+i)^24 mo (ATT6)	1.10221	1.10221	1.10221
H	True-Up Adjustment w/o Incentive (E*G)	-	138,179	-
I	True-Up Adjustment w/ Incentive (F*G)	-	138,179	-

TUA = True-Up Adjusment
PCY = Previous Calendar Year

	Project CD-1	Project CF-1	Project CF-2
W / O incentive	-	3,027,173	5,641,592
W incentive	-	3,027,173	5,641,592

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 CG-1**				**Project CG-2**				**Project CI**					
11	Schedule 12 (Yes or No)		Yes	B2758			Yes	B2758			Yes	B2729			If Yes for Schedule 12 Include in this Total.	If No for Schedule 1 this Sum.
12	Life		40	Rebuild Line #549 Dooms - Valley 500 kV line			40	Rebuild Line #549 Dooms - Valley 500 kV line			40	Optimal Capacitors Configuration:				
13	FCR W/O incentive Line 3		10.4521%				10.4521%				10.4521%	New 175 MVAR Capacitor at Brambleton,				
14	Incentive Factor (Basis Points /100)		0				0				0	new 175 MVAR capacitor at Ashburn,new				
15	FCR W incentive L.13 +(L.14*L.5)		10.4521%				10.4521%				10.4521%	300 MVAR capacitor at Shelhorm,				
16	Investment		25,000,000				34,000,000				9,365,755	new 150 MVAR capacitor at Liberty				Annual Revenue Requirement including Incentive if Applicable
17	Annual Depreciation Exp		625,000				850,000				234,144					
18	In Service Month (1-12)		11				7				12					
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Total**	**Sum**
20	W / O incentive	2006														
46	W / O incentive	2019	25,000,000	78,125	24,921,875						9,365,755	9,756	9,355,999			
47	W incentive	2019	25,000,000	78,125	24,921,875						9,365,755	9,756	9,355,999			
48	W / O incentive	2020	24,921,875	625,000	24,296,875	3,197,194	34,000,000	389,583	33,610,417	2,009,036	9,355,999	234,144	9,121,855	1,199,805	284,640,655	
49	W incentive	2020	24,921,875	625,000	24,296,875	3,197,194	34,000,000	389,583	33,610,417	2,009,036	9,355,999	234,144	9,121,855	1,199,805	287,945,618	39,121,330
50																
51																
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)					1.10221				1.10221				1.10221		
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

	Project CG-1	Project CG-2	Project CI
W / O incentive	3,197,194	2,009,036	1,199,805
W incentive	3,197,194	2,009,036	1,199,805

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

These Three Columns are Repeated to Provide Line Number References on All Pages			
10			
11	Schedule 12	(Yes or No)	2 include in
12	Life		
13	FCR W/O incentive	Line 3	
14	Incentive Factor (Basis Points /100)		
15	FCR W incentive L.13 +(L.14*L.5)		
16	Investment		Annual Revenue Requirement excluding Incentive
17	Annual Depreciation Exp		
18	In Service Month (1-12)		
19			**Sum**
20	W / O incentive	2006	
46	W / O incentive	2019	
47	W incentive	2019	
48	W / O incentive	2020	37,067,289
49	W incentive	2020	
50			
51			
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)		
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	
W incentive	

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%

[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 April 1, 2013 And Through December 31, 2016

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.

Virginia Electric and Power Company

ATTACHMENT H-16A

Attachment 9 - Depreciation Rates (Continued)[1]

Depreciation Rates Applicable On And After January 1, 2017

Plant Type	Applied Depreciation Rate
Transmission Plant	
Land	
Land Rights	1.31%
Structures and Improvements	1.59%
Station Equipment	3.05%
Station Equipment - Power Supply Computer Equipment	7.21%
Towers and Fixtures	2.30%
Poles and Fixtures	2.33%
Overhead conductors and Devices	2.18%
Underground Conduit	2.10%
Underground Conductors and Devices	2.03%
Roads and Trails	1.06%
General Plant	
Land	
Land Rights	1.49%
Structures and Improvements-Major	2.38%
Structures and Improvements-Other	2.24%
Office Furniture and Equipment - 2012 and Prior	8.97%
Office Furniture and Equipment - 2013 and Subsequent	6.67%
Office Furniture and Equipment-EDP Hardware - 2012 and Prior	65.49%
Office Furniture and Equipment-EDP Hardware - 2013 and Subsequent	20.00%
Office Furniture and Equipment-EDP Fixed Location - 2012 and Prior	10.83%
Office Furniture and Equipment-EDP Fixed Location - 2013 and Subsequent	20.00%
Transportation Equipment	5.75%
Stores Equipment - 2012 and Prior	4.25%
Stores Equipment - 2013 and Subsequent	4.00%
Tools, Shop, and Garage Equipment - 2012 and Prior	3.70%
Tools, Shop, and Garage Equipment - 2013 and Subsequent	4.00%
Tools, Shop, and Garage Equipment-Electric Vehicles	0.00%
Laboratory Equipment - 2012 and Prior	4.12%
Laboratory Equipment - 2013 and Subsequent	4.00%
Power Operated Equipment	6.49%
Communication Equipment - 2012 and Prior	3.70%
Communication Equipment - 2013 and Subsequent	4.00%
Communication Equpment-Clearing	0.00%
Communication Equipment-Massed - 2012 and Prior	8.61%
Communication Equipment-Massed - 2013 and Subsequent	6.67%
Communication Equpment-25 Years - 2012 and Prior	2.66%
Communication Equpment-25 Years - 2013 and Subsequent	4.00%
Miscellaneous Equipment - 2012 and Prior	7.15%
Miscellaneous Equipment - 2013 and Subsequent	6.67%

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

Attachment 10

Incremental Undergrounding Costs of the
Garrisonville, Pleasant View, and NIVO Underground Projects

Section 1 -- Purpose

This Attachment 10 determines the appropriate amount of undergrounding costs to be allocated to each Network Customer for their Virginia loads in the Dominion Zone in accordance with the March 20, 2014 order of the Federal Energy Regulatory Commission in Docket No. EL10-49-005 and in compliance with the Federal Energy Regulatory Commission's October 19, 2017 Order on Initial Decision issued in Opinion No. 555. To provide compensation for these costs, each Network Customer with Virginia loads in the Dominion Zone shall pay a monthly Demand Charge, which shall be known as the "UG Transmission Charge" as determined herein.

Section 2 -- Underground ("UG") Transmission Project Descriptions

The projects are generally described below. The projects may be modified resulting in changes to their costs.

Garrisonville	The Aquia Harbor Terminal Station, the Garrisonville Substation excluding the distribution assets and the 230 kV shunt reactor banks in Garrisonville Substation, two underground transmission lines with associated duct systems running from Aquia Harbor Terminal Station to Garrisonville Substation, and modifications to transmission line protection equipment at Fredericksburg and Possum Point substations to interface with equipment at Aquia Harbor Terminal Station.
Pleasant View	An overhead transmission line running from Pleasant View Substation to Dry Mill South Station, facilities in Pleasant View Substation to facilitate connection of such transmission line, Dry Mill South Station, an underground transmission line with associated duct systems running from Dry Mill South Station to Breezy Knoll Station, Breezy Knoll Station, an overhead transmission line running from Breezy Knoll Station to Hamilton Substation, and Hamilton Substation excluding the distribution assets and the 230 kV shunt reactor bank in Hamilton Substation.
NIVO	Two underground transmission lines with associated duct system running from Beaumeade Substation to NIVO Substation, the NIVO Substation excluding distribution assets in NIVO Substation, and the facilities in Beaumeade Substation to facilitate connection of the two new underground transmission lines.

Attachment 10 (Continued)

Section 3 -- Determination of the Total Incremental Undergrounding Costs Revenue Requirement

The Total Incremental Undergrounding Costs Revenue Requirement shall be determined as set forth in the formula

Instructions:

1. Calculate this formula using data for Year on line 1.
2. On line 1, enter the year.
3. Lines 2a, 2b and 2c are the applicable UG Project Revenue Requirements consistent with the note below from either Attachment 10A if the applicable year is prior to 2015 or from Attachment 10B if the applicable year is after 2014.

Line	Description	Year
1	Enter the Rate Year	2020

(In Dollars)

Line	(1) Project Name	(2) Requirement	(3) Adjustment Factors	(4) Undergrounding
2a	Garrisonville	$28,500,799	92.49%	$26,359,136
2b	Pleasant View	$19,579,010	23.37%	$4,574,816
2c	NIVO	$2,259,398	22.09%	$499,137
3	**Total Incremental Undergrounding Costs Revenue Requirement**			**$31,433,089**

NOTE: All column 2 amounts are for the year indicated on line 1 and include true-up adjustments for the calendar year that is two years prior to that year. However in the event that a one-time net refund settlement addresses the charges and credits for a calendar year, the true-up adjustment for that calendar year shall equal zero. The revenue requirements in column (2) and column (4) include depreciation, return on capital investment, income taxes, and accumulated deferred income taxes (ADIT) , and property taxes in accordance with Opinion No. 555 Order on Initial Decision in FERC Docket No. EL10-49-005 . The Adjustment Factors set forth in column (3) are the ratio of the Estimated Incremental Underground Capital Costs divided by the Total Capital Costs shown on page 8 of Opinion No. 555 Order on Initial Decision in FERC Docket No. EL10-49-005 and shall not be changed except pursuant to a filing under the appropriate of Section 205 or 206.

Attachment 10 (Continued)

Section 4 --Annual UG Transmission Rate

The Annual UG Transmission Rate shall be calculated as follows:

Instructions:

1. On line 6, enter the portion of the amount on line 5 attributable to load located in Virginia as determined by PJM state estimator load bus data at the time of annual peak of the Dominion Zone.

Line	Description	Amounts
4	Total Incremental Undergrounding Costs Revenue Requirement (from Line 3) (dollars per year)	$31,433,089
5	Dominion Zone NSPL 1 CP Peak from Appendix A, line 169 (in Megawatts)	19,930.0
6	Virginia Portion of the Dominion Zone NSPL (Analysis of PJM load bus data) (in Megawatts)	18,687.6
7	Annual UG Transmission Rate (dollars per MW-year) (line 4 ÷ line 6)	$1,682.03

Attachment 10 (Continued)

Section 5 -- Billing

The UG Transmission Charge shall be billed in accordance with the PJM billing procedure applied to billing the monthly Demand Charge for Zone Network Loads in Section 34.1 of the PJM Tariff, but for purposes of this calculation, the Zone Network Loads (including losses) at the time of the annual peak of the Zone in which the load is located shall include only Virginia loads in the Dominion Zone. If necessary, PJM state estimator load bus MWs at the time of the annual peak of the Dominion Zone shall be used to separate Virginia loads from other loads in the Dominion Zone. VEPCO shall provide to PJM the contribution of each Network Customer's Virginia Portion of the Dominion Zone NSPL. Also, for the purpose of calculating the UG Transmission Charge in accordance with this attachment, the Annual UG Transmission Rate calculated on line 7 above shall be used instead of the rate for Network Integration Transmission Service ("RTZ").

Section 6 -- Revenue Crediting

A. For calculating the Annual Transmission Revenue Requirement and rate for Network Integration Transmission Service used for billing, the Total UG Project Adjusted Revenue Requirement amount, shown on line 4 of Section 4, shall be included in line 9 of Attachment 3, provided that the Annual Transmission Revenue Requirement is not one of the Annual Transmission Revenue Requirements used to determine refunds to each Network Customer as part of a net refund or charge settlement process that is in addition to the normal formula rate cycle billing process.

B. For calculating the annual true-up, the UG Transmission Charge revenues received by the Company shall be included in line 9 of Attachment 3, provided that the UG Transmission Charge revenues for the applicable year are not distributed to each Network Customer as part of a net refund or charge settlement process that is in addition to the normal formula rate cycle billing process.

Virginia Electric and Power Company

Attachment 10A - UG Project Revenue Requirement for 2010 - 2014 Calendar Years

Year =

Inst. 1 For each month enter the amount included in Electric Plant in Service attributable to the UG Project for the applicable month.
Inst. 2 For each month enter the amount included in the Accumulated Provision for Depreciation of Electric Plant in Service attributable to the UG Project for the applicable month, and for each year enter the applicable depreciation expense.
Inst. 3 For each year enter the amount of Accumulated Deferred Income Tax ("ADIT") attributable to the UG Project for December 31 of each year.
Inst. 4 For each year enter the amount of Property Tax attributable to the UG Project.

Pleasant View UG Project Revenue Requirement

Line #s	Descriptions	Notes	Page #'s & Instructions	Previous Year Dec	Current Year Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Amount
1	Electric Plant in Service	Note 1	Inst. 1														-
2	Accumulated Depreciation	Note 1	Inst. 2														-
3	Accumulated Deferred Income Taxes	Note 2	Inst. 3														-
4	Applicable Rate Base		Line (1 + 2 + 3)														-
5	Return	Note 3	Line 4 * (Appendix A Line 129 + Incentive)														-
6	Income Taxes associated with Equity Return	Note 3	Line 5 * Appendix A Line 137 * (1-(126 / (129 + Incentive)))														-
7	Transmission Related Income Tax Adjustments		Line 6 * Appendix A Line (138 / 139)														-
8	Total Income Tax Provision		Line (6 + 7)														-
9	Depreciation-Transmission		Inst. 2														
10	Property Tax		Inst. 4														
11	UG Project Revenue Requirement		Line (5 + 8 + 9 + 10)														-
12	Projected UG Project Revenue Requirement for Previous Calendar Year	Note 4															
13	Actual UG Project Revenue Requirement for Previous Calendar Year	Note 4															
14	True-Up Adjustment Before Interest for Previous Calendar Year		Line (13 - 12)														0
15	Future Value Factor (1+i)^24 months		Attachment 6														1.10221
16	True-Up Adjustment		Line (14 * 15)														-
17	UG Project Revenue Requirement including True-up Adjustment, if applicable		Line (11 + 16)														-

Note 1 The value in the amount column is calculated using 13 month average balance.
Note 2 The value in the amount column is calculated using average of beginning and end of year balances.
Note 3 Per FERC order in Docket No. ER08-1207-002, 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. The Incentive for Pleasant View = 125 basis points Authorized Incentive Adder times the Common Equity % from Appendix A Line 122 = 0.0065
Note 4 These amounts do not include any True-Up Adjustments.

Garrisonville UG Project Revenue Requirement

Line #s	Descriptions	Notes	Page #'s & Instructions	Previous Year Dec	Current Year Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Amount
1	Electric Plant in Service	Note 1	Inst. 1														-
2	Accumulated Depreciation	Note 1	Inst. 2														-
3	Accumulated Deferred Income Taxes	Note 2	Inst. 3														-
4	Applicable Rate Base		Line (1 + 2 + 3)														-
5	Return	Note 3	Line 4 * (Appendix A Line 129 + Incentive)														-
6	Income Taxes associated with Equity Return	Note 3	Line 5 * Appendix A Line 137 * (1-(126 / (129 + Incentive)))														-
7	Transmission Related Income Tax Adjustments		Line 6 * Appendix A Line (138 / 139)														-
8	Total Income Tax Provision		Line (6 + 7)														-
9	Depreciation-Transmission		Inst. 2														
10	Property Tax		Inst. 4														
11	UG Project Revenue Requirement		Line (5 + 8 + 9 + 10)														-
12	Projected UG Project Revenue Requirement for Previous Calendar Year	Note 4															
13	Actual UG Project Revenue Requirement for Previous Calendar Year	Note 4															
14	True-Up Adjustment Before Interest for Previous Calendar Year		Line (13 - 12)														0
15	Future Value Factor (1+i)^24 months		Attachment 6														1.10221
16	True-Up Adjustment		Line (14 * 15)														-
17	UG Project Revenue Requirement including True-up Adjustment, if applicable		Line (11 + 16)														-

Note 1 The value in the amount column is calculated using 13 month average balance.
Note 2 The value in the amount column is calculated using average of beginning and end of year balances.
Note 3 Per FERC order in Docket No. ER08-1207-002, 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. The Incentive for Garrisonville = 125 basis points Authorized Incentive Adder times the Common Equity % from Appendix A Line 122 = 0.0065
Note 4 These amounts do not include any True-Up Adjustments.

Virginia Electric and Power Company

Attachment 10A - UG Project Revenue Requirement for 2010 - 2014 Calendar Years

Year =

NIVO UG Project Revenue Requirement

Line #s	Descriptions	Notes	Page #'s & Instructions	Previous Year	Current Year												Amount
				Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	
1	Electric Plant in Service	Note 1	Inst. 1														-
2	Accumulated Depreciation	Note 1	Inst. 2														-
3	Accumulated Deferred Income Taxes	Note 2	Inst. 3														-
4	Applicable Rate Base		Line (1 + 2 + 3)														-
5	Return		Line 4 * (Appendix A Line 129)														-
6	Income Taxes associated with Equity Return		Line 5 * Appendix A Line 137 * (1-(126 / 129))														-
7	Transmission Related Income Tax Adjustments		Line 6 * Appendix A Line (138 / 139)														-
8	Total Income Tax Provision		Line (6 + 7)														-
9	Depreciation-Transmission		Inst. 2														
10	Property Tax		Inst. 4														
11	UG Project Revenue Requirement		Line (5 + 8 + 9 + 10)														-
12	Projected UG Project Revenue Requirement for Previous Calendar Year	Note 3															
13	Actual UG Project Revenue Requirement for Previous Calendar Year	Note 3															
14	True-Up Adjustment Before Interest for Previous Calendar Year		Line (13 - 12)														0
15	Future Value Factor (1+i)^24 months		Attachment 6														1.10221
16	True-Up Adjustment		Line (14 * 15)														-
17	UG Project Revenue Requirement including True-up Adjustment, if applicable		Line (11 + 16)														-

Note 1 The value in the amount column is calculated using 13 month average balance.

Note 2 The value in the amount column is calculated using average of beginning and end of year balances.

Note 3 These amounts do not include any True-Up Adjustments.

Virginia Electric and Power Company

Attachment 10B - UG Project Revenue Requirement for Calendar Years after 2014

Year = 2020

Inst. 1 For each month enter the amount included in the Accumulated Provision for Depreciation of Electric Plant in Service attributable to the UG Project for the applicable month, and for each year enter the applicable depreciation expense.
Inst. 2 For each year enter the amount of Accumulated Deferred Income Tax ("ADIT") attributable to the UG Project for December 31 of each year.
Inst. 3 For each year enter the amount of Property Tax attributable to the UG Project.

Pleasant View UG Project Revenue Requirement

				Previous Year	Current Year													
Line #s	Descriptions	Notes	Page #'s & Instructions	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Amount
1	Electric Plant in Service	Note 1		86,031,713	86,031,713	86,031,713	86,031,713	86,031,713	86,031,713	86,031,713	86,031,713	86,031,713	86,031,713	86,031,713	86,031,713	86,031,713	86,031,713
2	Accumulated Depreciation	4	Inst. 1	(16,303,241)	(16,459,532)	(16,615,823)	(16,772,114)	(16,928,405)	(17,084,696)	(17,240,987)	(17,397,278)	(17,553,569)	(17,709,860)	(17,866,151)	(18,022,442)	(18,178,733)	(17,240,987)
3	Accumulated Deferred Income Taxes	Note 2	Inst. 2	(3,893,504)												(3,893,504)	(3,893,504)
4	Applicable Rate Base		Line (1 + 2 + 3)														64,897,222
5	Return	Note 3	Line 4 * (Appendix A Line 129 + Incentive)														5,629,942
6	Income Taxes associated with Equity Return	Note 3	Line 5 * Appendix A Line 137 * (1-(126 / (129 + Incentive)))														1,473,836
7	Transmission Related Income Tax Adjustments		Line 6 * Appendix A Line (138 / 139)														(65,872)
8	Total Income Tax Provision		Line (6 + 7)														1,407,964
9	Depreciation-Transmission		Inst. 1														1,875,491
10	Property Tax		Inst. 3														181,037
11	UG Project Revenue Requirement		Line (5 + 8 + 9 + 10)														9,094,434
12	Projected UG Project Revenue Requirement for Previous Calendar Year	Note 4															-
13	Actual UG Project Revenue Requirement for Previous Calendar Year	Note 4															9,512,312
14	True-Up Adjustment Before Interest for Previous Calendar Year		Line (13 - 12)														9,512,312
15	Future Value Factor (1+i)^24 months		Attachment 6														1.10221
16	True-Up Adjustment		Line (14 * 15)														10,484,575
17	UG Project Revenue Requirement including True-up Adjustment, if applicable		Line (11 + 16)														19,579,010

Note 1 The value in the amount column is calculated using 13 month average balance.
Note 2 The value in the amount column is calculated using average of beginning and end of year balances.
Note 3 Per FERC order in Docket No. ER08-1207-002, 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. The Incentive for Pleasant View = 125 basis points Authorized Incentive Adder times the Common Equity % from Appendix A Line 122 = 0.0065
Note 4 These amounts do not include any True-Up Adjustments.

Garrisonville UG Project Revenue Requirement

				Previous Year	Current Year													
Line #s	Descriptions	Notes	Page #'s & Instructions	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Amount
1	Electric Plant in Service	Note 1		136,918,173	136,918,173	136,918,173	136,918,173	136,918,173	136,918,173	136,918,173	136,918,173	136,918,173	136,918,173	136,918,173	136,918,173	136,918,173	136,918,173
2	Accumulated Depreciation	Note 1	Inst. 1	(35,147,296)	(35,495,296)	(35,843,296)	(36,191,297)	(36,539,297)	(36,887,298)	(37,235,298)	(37,583,298)	(37,931,299)	(38,279,299)	(38,627,299)	(38,975,300)	(39,323,300)	(37,235,298)
3	Accumulated Deferred Income Taxes	Note 2	Inst. 2	(27,514,856)												(27,514,856)	(27,514,856)
4	Applicable Rate Base		Line (1 + 2 + 3)														72,168,019
5	Return	Note 3	Line 4 * (Appendix A Line 129 + Incentive)														6,260,696
6	Income Taxes associated with Equity Return	Note 3	Line 5 * Appendix A Line 137 * (1-(126 / (129 + Incentive)))														1,638,958
7	Transmission Related Income Tax Adjustments		Line 6 * Appendix A Line (138 / 139)														(73,252)
8	Total Income Tax Provision		Line (6 + 7)														1,565,706
9	Depreciation-Transmission		Inst. 1														4,176,004
10	Property Tax		Inst. 3														980,510
11	UG Project Revenue Requirement		Line (5 + 8 + 9 + 10)														12,982,916
12	Projected UG Project Revenue Requirement for Previous Calendar Year	Note 4															-
13	Actual UG Project Revenue Requirement for Previous Calendar Year	Note 4															14,078,867
14	True-Up Adjustment Before Interest for Previous Calendar Year		Line (13 - 12)														14,078,867
15	Future Value Factor (1+i)^24 months		Attachment 6														1.10221
16	True-Up Adjustment		Line (14 * 15)														15,517,883
17	UG Project Revenue Requirement including True-up Adjustment, if applicable		Line (11 + 16)														28,500,799

Note 1 The value in the amount column is calculated using 13 month average balance.
Note 2 The value in the amount column is calculated using average of beginning and end of year balances.
Note 3 Per FERC order in Docket No. ER08-1207-002, 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. The Incentive for Garrisonville = 125 basis points Authorized Incentive Adder times the Common Equity % from Appendix A Line 122 = 0.0065
Note 4 These amounts do not include any True-Up Adjustments.

Virginia Electric and Power Company

Attachment 10B - UG Project Revenue Requirement for Calendar Years after 2014

Year = 2020

NIVO UG Project Revenue Requirement

				Previous Year	Current Year													
Line #s	Descriptions	Notes	Page #'s & Instructions	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Amount
1	Electric Plant in Service	Note 1		10,113,838	10,113,838	10,113,838	10,113,838	10,113,838	10,113,838	10,113,838	10,113,838	10,113,838	10,113,838	10,113,838	10,113,838	10,113,838	10,113,838
2	Accumulated Depreciation	Note 1	Inst. 1	(2,371,982)	(2,397,688)	(2,423,394)	(2,449,100)	(2,474,806)	(2,500,512)	(2,526,218)	(2,551,924)	(2,577,630)	(2,603,336)	(2,629,042)	(2,654,748)	(2,680,454)	(2,526,218)
3	Accumulated Deferred Income Taxes	Note 2	Inst. 2	(439,374)												(439,374)	(439,374)
4	Applicable Rate Base		Line (1 + 2 + 3)														7,148,246
5	Return		Line 4 * (Appendix A Line 129)														573,554
6	Income Taxes associated with Equity Return		Line 5 * Appendix A Line 137 * (1-(126 / 129))														146,297
7	Transmission Related Income Tax Adjustments		Line 6 * Appendix A Line (138 / 139)														(6,539)
8	Total Income Tax Provision		Line (6 + 7)														139,759
9	Depreciation-Transmission		Inst. 1														308,472
10	Property Tax		Inst. 3														19,342
11	UG Project Revenue Requirement		Line (5 + 8 + 9 + 10)														1,041,127
12	Projected UG Project Revenue Requirement for Previous Calendar Year	Note 3															-
13	Actual UG Project Revenue Requirement for Previous Calendar Year	Note 3															1,105,298
14	True-Up Adjustment Before Interest for Previous Calendar Year		Line (13 - 12)														1,105,298
15	Future Value Factor (1+i)^24 months		Attachment 6														1.10221
16	True-Up Adjustment		Line (14 * 15)														1,218,271
17	UG Project Revenue Requirement including True-up Adjustment, if applicable		Line (11 + 16)														2,259,398

Note 1 The value in the amount column is calculated using 13 month average balance.

Note 2 The value in the amount column is calculated using average of beginning and end of year balances.

Note 3 These amounts do not include any True-Up Adjustments.

Attachment 10

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

For the 12 months ended 12/31/2020

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	$741,921	(A)	$370,823	(B)	$1,112,744
2	PJM Project No.					
3	b0490 & b0491	$741,921	(C)			$741,921
4	b0492 & b0560			$370,823	(D)	$370,823
5	Order 554 True-up	-$1,182,194	(E)	-$622,410	(E)	-$1,804,604
6	Total (Sum lines 3 to 5)	-$440,273		-$251,587		-$691,860

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)	Order 554 refund related to January 17, 2019 FERC Order

Formula Rate - Non-Levelized

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2020

PATH West Virginia Transmission Company, LLC

Line No.			(1)		(2)		(3) Allocated Amount
1	GROSS REVENUE REQUIREMENT	(line 86)			12 months	$	751,420
	REVENUE CREDITS		Total	Allocator			
2	Total Revenue Credits	Attachment 1, line 12	0	TP	1.00000	$	-
3	True-up Adjustment with Interest	Protocols	-9,499	DA	1.00000	$	(9,499)
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)				$	741,921

Formula Rate - Non-Levelized

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

PATH West Virginia Transmission Company, LLC

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	RATE BASE:					
	GROSS PLANT IN SERVICE					
6	Production	(Attachment 4)	-	NA	0.00000	-
7	Transmission	(Attachment 4)	-	TP	1.00000	-
8	Distribution	(Attachment 4)	-	NA	0.00000	-
9	General & Intangible	(Attachment 4)	-	W/S	1.00000	-
10	Common	(Attachment 4)	-	CE	1.00000	-
11	TOTAL GROSS PLANT (sum lines 6-10)	(GP=1 if plant =0)	-	GP=	1.00000	-
12	ACCUMULATED DEPRECIATION					
13	Production	(Attachment 4)	-	NA	0.00000	-
14	Transmission	(Attachment 4)	-	TP	1.00000	-
15	Distribution	(Attachment 4)	-	NA	0.00000	-
16	General & Intangible	(Attachment 4)	-	W/S	1.00000	-
17	Common	(Attachment 4)	-	CE	1.00000	-
18	TOTAL ACCUM. DEPRECIATION (sum lines 13-17)		-			-
19	NET PLANT IN SERVICE					
20	Production	(line 6- line 13)	-			-
21	Transmission	(line 7- line 14)	-			-
22	Distribution	(line 8- line 15)	-			-
23	General & Intangible	(line 9- line 16)	-			-
24	Common	(line 10- line 17)	-			-
25	TOTAL NET PLANT (sum lines 20-24)	(NP=1 if plant =0)	-	NP=	1.0000	-
26	ADJUSTMENTS TO RATE BASE (Note A)					
27	Account No. 281 (enter negative)	(Attachment 4)	-	NA	0.00000	-
28	Account No. 282 (enter negative)	(Attachment 4)	-	NP	1.00000	-
29	Account No. 283 (enter negative)	(Attachment 4)	1,579,968	NP	1.00000	1,579,968
30	Account No. 190	(Attachment 4)	3,602,062	NP	1.00000	3,602,062
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)		5,182,030			5,182,030
36	LAND HELD FOR FUTURE USE	(Attachment 4)	-	TP	1.00000	-
37	WORKING CAPITAL (Note C)					
38	CWC	calculated	42,749			42,749
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)		42,749			42,749
42	RATE BASE (sum lines 25, 35, 36, & 41)		5,224,779			5,224,779

Formula Rate - Non-Levelized

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

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	338,000	W/S	1.00000	338,000
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)	3,995			3,995
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)		341,995			341,995
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)} =		26.09%			
76	CIT=(T/1-T) * (1-(WCLTD/R)) =		22.35%			
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)		1.3530			
80	Amortized Investment Tax Credit (266.8f) (enter negative)		0			
81	Income Tax Calculation = line 76 * line 85		74,778	NA		74,778
82	ITC adjustment (line 79 * line 80)		0	NP	1.00000	-
83	Total Income Taxes	(line 81 plus line 82)	74,778			74,778
84	RETURN					
85	[Rate Base (line 42) * Rate of Return (line 121)]		334,647	NA		334,647
86	REV. REQUIREMENT (sum lines 57, 63, 73, 83, 85)		751,420			751,420

Formula Rate - Non-Levelized

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

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

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 =	21.00%	
		SIT=	6.44%	(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 12/31/2020

PATH Allegheny Transmission Company, LLC

Line No.			(1) Total	(2) Allocator		(3) Allocated Amount
1	GROSS REVENUE REQUIREMENT	(line 86)		12 months		$ 168,055
	REVENUE CREDITS					
2	Total Revenue Credits	Attachment 1, line 12	0	TP	1.00000	-
3	True-up Adjustment with Interest	Protocols	202,768	DA	1.00000	$ 202,768
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)				$ 370,823

Formula Rate - Non-Levelized

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2020

PATH Allegheny 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)	-	NP	1.00000	-
29	Account No. 283 (enter negative)	(Attachment 4)	-	NP	1.00000	-
30	Account No. 190	(Attachment 4)	485,140	NP	1.00000	485,140
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)		485,140			485,140
36	LAND HELD FOR FUTURE USE	(Attachment 4)	-	TP	1.00000	-
37	WORKING CAPITAL (Note C)					
38	CWC	calculated	16,208			16,208
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)		16,208			16,208
42	RATE BASE (sum lines 25, 35, 36, & 41)		501,348			501,348

Formula Rate - Non-Levelized

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2020

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	37,710	TE	1.00000	37,710
45	Less Account 565	321.96.b	-	TE	1.00000	-
46	Less Account 566	Line 56	37,710	DA	1.00000	37,710
47	A&G	323.197.b	91,955	W/S	1.00000	91,955
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	37,710	DA	1.00000	37,710
56	Total Account 566		37,710			37,710
57	TOTAL O&M (sum lines 44, 47, 49, 50, 51, 52, 56 less lines 45,46, 48)		129,665			129,665
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)} =		23.60%			
76	CIT=(T/1-T) * (1-(WCLTD/R)) =		19.55%			
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)		1.3088			
80	Amortized Investment Tax Credit	(266.8f) (enter negative)	0			
81	Income Tax Calculation = line 76 * line 85		6,278	NA		6,278
82	ITC adjustment (line 79 * line 80)		0	NP	1.00000	-
83	Total Income Taxes	(line 81 plus line 82)	6,278			6,278
84	RETURN					
85	[Rate Base (line 42) * Rate of Return (line 121)]		32,111	NA		32,111
86	REV. REQUIREMENT (sum lines 57, 63, 73, 83, 85)		168,055			168,055

Formula Rate - Non-Levelized

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2020

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)						37,710		
96	Less transmission expenses included in OATT Ancillary Services (Note G)						0		
97	Included transmission expenses (line 95 less line 96)						37,710		
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

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

Formula Rate - Non-Levelized

For the 12 months ended 12/31/2020

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 =	21.00%	
	SIT=	3.29%	(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	2019	-
3	January	company records	2020	-
4	February	company records	2020	-
5	March	company records	2020	-
6	April	company records	2020	-
7	May	company records	2020	-
8	June	company records	2020	-
9	July	company records	2020	-
10	August	company records	2020	-
11	September	company records	2020	-
12	October	company records	2020	-
13	November	company records	2020	-
14	December	p207.58.g	2020	-
15	**Transmission Plant In Service**	(sum lines 2-14) /13		-
16	**Calculation of Distribution Plant In Service**	Source		
17	December	p206.75.b	2019	-
18	January	company records	2020	-
19	February	company records	2020	-
20	March	company records	2020	-
21	April	company records	2020	-
22	May	company records	2020	-
23	June	company records	2020	-
24	July	company records	2020	-
25	August	company records	2020	-
26	September	company records	2020	-
27	October	company records	2020	-
28	November	company records	2020	-
29	December	p207.75.g	2020	-
30	**Distribution Plant In Service**	(sum lines 17-29) /13		-
31	**Calculation of Intangible Plant In Service**	Source		
32	December	p204.5.b	2019	-
33	December	p205.5.g	2020	-
34	**Intangible Plant In Service**	(sum lines 32 & 33) /2		-
35	**Calculation of General Plant In Service**	Source		
36	December	p206.99.b	2019	-
37	December	p207.99.g	2020	-
38	**General Plant In Service**	(sum lines 36 & 37) /2		-
39	**Calculation of Production Plant In Service**	Source		
40	December	p204.46b	2019	-
41	January	company records	2020	-
42	February	company records	2020	-
43	March	company records	2020	-
44	April	company records	2020	-
45	May	company records	2020	-
46	March	Attachment 6	2020	-
47	April	company records	2020	-
48	August	company records	2020	-
49	September	company records	2020	-
50	October	company records	2020	-
51	November	company records	2020	-
52	December	p205.46.g	2020	-
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	2019	-
56	December (Electric Portion)	p356	2020	-
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	2019	-	
61	January	company records	2020	-	
62	February	company records	2020	-	
63	March	company records	2020	-	
64	April	company records	2020	-	
65	May	company records	2020	-	
66	June	company records	2020	-	
67	July	company records	2020	-	
68	August	company records	2020	-	
69	September	company records	2020	-	
70	October	company records	2020	-	
71	November	company records	2020	-	
72	December	p219.25	2020	-	
73	**Transmission Accumulated Depreciation**	(sum lines 60-72) /13		-	
74	**Calculation of Distribution Accumulated Depreciation**	Source			
75	December	Prior year p219.26	2019	-	
76	January	company records	2020	-	
77	February	company records	2020	-	
78	March	company records	2020	-	
79	April	company records	2020	-	
80	May	company records	2020	-	
81	June	company records	2020	-	
82	July	company records	2020	-	
83	August	company records	2020	-	
84	September	company records	2020	-	
85	October	company records	2020	-	
86	November	company records	2020	-	
87	December	p219.26	2020	-	
88	**Distribution Accumulated Depreciation**	(sum lines 75-87) /13		-	
89	**Calculation of Intangible Accumulated Depreciation**	Source			
90	December	Prior year p200.21.c	2019	-	
91	December	p200.21c	2020	-	
92	**Accumulated Intangible Depreciation**	(sum lines 90 & 91) /2		-	
93	**Calculation of General Accumulated Depreciation**	Source			
94	December	Prior year p219.28	2019	-	
95	December	p219.28	2020	-	
96	**Accumulated General Depreciation**	(sum lines 94 & 95) /2		-	

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

		Source	Year	Balance
97	**Calculation of Production Accumulated Depreciation**	Source	Year	Balance
98	December	Prior year p219	2019	-
99	January	company records	2020	-
100	February	company records	2020	-
101	March	company records	2020	-
102	April	company records	2020	-
103	May	company records	2020	-
104	June	company records	2020	-
105	July	company records	2020	-
106	August	company records	2020	-
107	September	company records	2020	-
108	October	company records	2020	-
109	November	company records	2020	-
110	December	p219.20 thru 219.24	2020	-
111	**Production Accumulated Depreciation**	(sum lines 98-110) /13		-
112	**Calculation of Common Accumulated Depreciation**	Source		
113	December (Electric Portion)	p356	2019	-
114	December (Electric Portion)	p356	2020	-
115	**Common Plant Accumulated Depreciation (Electric Only)**	(sum lines 113 & 114) /2		-
116	**Total Accumulated Depreciation**	(sum lines 73, 88, 92, 96, 111, & 115)		-

ADJUSTMENTS TO RATE BASE (Note A)

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Beginning of Year	End of Year	Average Balance	Details
117	Account No. 281 (enter negative)	273.8.k	-	-	0	
118	Account No. 282 (enter negative)	275.2.k	-	-	0	
119	Account No. 283 (enter negative)	277.9.k	1,582,774	1,577,161	1,579,968	
120	Account No. 190	234.8.c	3,644,652	3,559,472	3,602,062	
121	Account No. 255 (enter negative)	267.8.h	-	-	0	

			Months Remaining In Amortization Period	Beginning Balance	Amortization Expense (p114.10.c)	Additions (Deductions)	Ending Balance
122	**Unamortized Abandoned Plant**	Per FERC Order					
123	**Monthly Balance**	Source					
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 Appendix A Line 62	-	$0.00 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

					Amos Substation Upgrade	Amos to Welton Spring Line	Welton Spring Substation and SVC	Welton Spring to Interconnection with PATH Allegheny	Total
139	**Calculation of Transmission CWIP**	Source							
140	December	216.b	2019	$ -	-	-	-	-	-
141	January	company records	2020	-	-	-	-	-	-
142	February	company records	2020	-	-	-	-	-	-
143	March	company records	2020	-	-	-	-	-	-
144	April	company records	2020	-	-	-	-	-	-
145	May	company records	2020	-	-	-	-	-	-
146	June	company records	2020	-	-	-	-	-	-
147	July	company records	2020	-	-	-	-	-	-
148	August	company records	2020	-	-	-	-	-	-
149	September	company records	2020	-	-	-	-	-	-
150	October	company records	2020	-	-	-	-	-	-
151	November	company records	2020	-	-	-	-	-	-
152	December	216.b	2020	-	-	-	-	-	-
153	**Transmission CWIP**	(sum lines 140-152) /13		-	-	-	-	-	-

LAND HELD FOR FUTURE USE

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

EPRI Dues Cost Support

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

Regulatory Expense Related to Transmission Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Form 1 Amount	Transmission Related	Non-transmission Related	Details
	Directly Assigned A&G					
156	Regulatory Commission Exp Account 928	p323.189.b	-	-	-	

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

Safety Related Advertising, Education and Out Reach Cost Support

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

Multi-state Workpaper

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	State 1	State 2	State 3	State 4	State 5	Weighed Average
	Income Tax Rates						
			WV				
158	SIT=State Income Tax Rate or Composite		6.490%				6.49%

Excluded Plant Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Excluded Transmission Facilities	Description of the Facilities
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
159	Excluded Transmission Facilities		-	**General Description of the Facilities**
	Instructions:		**Enter $**	**None**
1	Remove all investment below 69 kV facilities, including the investment allocated to distribution of a dual function substation, generator, interconnection and local and direct assigned facilities for which separate costs are charged and step-up generation substation included in transmission plant in service.		-	
2	If unable to determine the investment below 69kV in a substation with investment of 69 kV and higher as well as below 69 kV, the following formula will be used:	**Example**	**Or Enter $**	
A	Total investment in substation	1,000,000	-	
B	Identifiable investment in Transmission (provide workpapers)	500,000	-	
C	Identifiable investment in Distribution (provide workpapers)	400,000	-	
D	Amount to be excluded (A x (C / (B + C)))	444,444	-	
				Add more lines if necessary

Materials & Supplies

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

Regulatory Asset

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			
				Reference FERC Form 1 page 232 for details.
164	Beginning Balance of Regulatory Asset	p111.72.d (and notes)	-	Uncapitalized costs as of date the rates become effective
165	Months Remaining in Amortization Period		-	As approved by FERC
166	Monthly Amortization	(line 164 - line 168) / 167	-	
167	Months in Year to be amortized		-	Number of months rates are in effect during the calendar year
168	Ending Balance of Regulatory Asset	p111.72.c	-	
169	Average Balance of Regulatory Asset	(line 164 + line 168)/2	-	

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

Capital Structure

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

		Year	Debt	Preferred Stock	Common Stock
170	Monthly Balances for Capital Structure				
171		Year	Debt	Preferred Stock	Common Stock
172	January	2020	0	-	0
173	February	2020	-	-	-
174	March	2020	-	-	-
175	April	2020	-	-	-
176	May	2020	-	-	-
177	June	2020	-	-	-
178	July	2020	-	-	-
179	August	2020	-	-	-
180	September	2020	-	-	-
181	October	2020	-	-	-
182	November	2020	-	-	-
183	December	2020	-	-	-
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		29,834
196	PATH WV PBOP Expense for current year		$3,037
197	PATH WV PBOP Expense in Account 926 for current year		-$958
198	PBOP Adjustment for Appendix A, Line 50		$3,995
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)	$3,995

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	2019	-
3	January	company records	2020	-
4	February	company records	2020	-
5	March	company records	2020	-
6	April	company records	2020	-
7	May	company records	2020	-
8	June	company records	2020	-
9	July	company records	2020	-
10	August	company records	2020	-
11	September	company records	2020	-
12	October	company records	2020	-
13	November	company records	2020	-
14	December	p207.58.g	2020	-
15	**Transmission Plant In Service**	(sum lines 2-14) /13		-
16	**Calculation of Distribution Plant In Service**	Source		
17	December	p206.75.b	2019	-
18	January	company records	2020	-
19	February	company records	2020	-
20	March	company records	2020	-
21	April	company records	2020	-
22	May	company records	2020	-
23	June	company records	2020	-
24	July	company records	2020	-
25	August	company records	2020	-
26	September	company records	2020	-
27	October	company records	2020	-
28	November	company records	2020	-
29	December	p207.75.g	2020	-
30	**Distribution Plant In Service**	(sum lines 17-29) /13		-
31	**Calculation of Intangible Plant In Service**	Source		
32	December	p204.5b	2019	-
33	December	p205.5.g	2020	-
34	**Intangible Plant In Service**	(sum lines 32 & 33) /2		-
35	**Calculation of General Plant In Service**	Source		
36	December	p206.99.b	2019	-
37	December	p207.99.g	2020	-
38	**General Plant In Service**	(sum lines 36 & 37) /2		-
39	**Calculation of Production Plant In Service**	Source		
40	December	p204.46b	2019	-
41	January	company records	2020	-
42	February	company records	2020	-
43	March	company records	2020	-
44	April	company records	2020	-
45	May	company records	2020	-
46	March	Attachment 6	2020	-
47	April	company records	2020	-
48	August	company records	2020	-
49	September	company records	2020	-
50	October	company records	2020	-
51	November	company records	2020	-
52	December	p205.46.g	2020	-
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	2019	-
56	December (Electric Portion)	p356	2020	-
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	2019	-	
61	January	company records	2020	-	
62	February	company records	2020	-	
63	March	company records	2020	-	
64	April	company records	2020	-	
65	May	company records	2020	-	
66	June	company records	2020	-	
67	July	company records	2020	-	
68	August	company records	2020	-	
69	September	company records	2020	-	
70	October	company records	2020	-	
71	November	company records	2020	-	
72	December	p219.25	2020	-	
73	**Transmission Accumulated Depreciation**	(sum lines 60-72) /13		-	
74	**Calculation of Distribution Accumulated Depreciation**	Source			
75	December	Prior year p219.26	2019	-	
76	January	company records	2020	-	
77	February	company records	2020	-	
78	March	company records	2020	-	
79	April	company records	2020	-	
80	May	company records	2020	-	
81	June	company records	2020	-	
82	July	company records	2020	-	
83	August	company records	2020	-	
84	September	company records	2020	-	
85	October	company records	2020	-	
86	November	company records	2020	-	
87	December	p219.26	2020	-	
88	**Distribution Accumulated Depreciation**	(sum lines 75-87) /13		-	
89	**Calculation of Intangible Accumulated Depreciation**	Source			
90	December	Prior year p200.21.c	2019	-	
91	December	p200.21c	2020	-	
92	**Accumulated Intangible Depreciation**	(sum lines 90 & 91) /2		-	
93	**Calculation of General Accumulated Depreciation**	Source			
94	December	Prior year p219.28	2019	-	
95	December	p219.28	2020	-	
96	**Accumulated General Depreciation**	(sum lines 94 & 95) /2		-	

Attachment 4 - Cost Support
PATH Allegheny Transmission Company, LLC

		Source	Year	Balance
97	**Calculation of Production Accumulated Depreciation**	Source	Year	Balance
98	December	Prior year p219	2019	-
99	January	company records	2020	-
100	February	company records	2020	-
101	March	company records	2020	-
102	April	company records	2020	-
103	May	company records	2020	-
104	June	company records	2020	-
105	July	company records	2020	-
106	August	company records	2020	-
107	September	company records	2020	-
108	October	company records	2020	-
109	November	company records	2020	-
110	December	p219.20 thru 219.24	2020	-
111	**Production Accumulated Depreciation**	(sum lines 98-110) /13		-
112	**Calculation of Common Accumulated Depreciation**	Source		
113	December (Electric Portion)	p356	2019	-
114	December (Electric Portion)	p356	2020	-
115	**Common Plant Accumulated Depreciation (Electric Only)**	(sum lines 113 & 114) /2		-
116	**Total Accumulated Depreciation**	(sum lines 73, 88, 92, 96, 111, & 115)		-

ADJUSTMENTS TO RATE BASE (Note A)

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Beginning of Year	End of Year	Average Balance	Details
117	Account No. 281 (enter negative)	273.8.k	-	-	-	
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	485,140	485,140	485,140	
121	Account No. 255 (enter negative)	267.8.h	-	-	-	

			Months Remaining In Amortization Period	Beginning Balance	Amortization Expense (p114.10.c)	Additions (Deductions)	Ending Balance
122	**Unamortized Abandoned Plant**	Per FERC Order					
123	**Monthly Balance**	Source					
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.

			Beginning of Year	End of Year	Average Balance
138	Prepayments (Account 165)	111.57.c	-	-	-

Attachment 4 - Cost Support
PATH Allegheny Transmission Company, LLC

139	**Calculation of Transmission CWIP**	Source			Kemptown Substation	Kemptown to Interconnection with PATH West Virginia	Welton Spring Substation and SVC	Total
140	December	216.b	2019	$ -				
141	January	company records	2020	-				
142	February	company records	2020	-				
143	March	company records	2020	-				
144	April	company records	2020	-				
145	May	company records	2020	-				
146	June	company records	2020	-				
147	July	company records	2020	-				
148	August	company records	2020	-				
149	September	company records	2020	-				
150	October	company records	2020	-				
151	November	company records	2020	-				
152	December	216.b	2020	-				
153	**Transmission CWIP**	(sum lines 140-152) /13		-	-	-	-	-

LAND HELD FOR FUTURE USE

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

EPRI Dues Cost Support

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

Regulatory Expense Related to Transmission Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Form 1 Amount	Transmission Related	Non-transmission Related	Details
	Directly Assigned A&G					
156	Regulatory Commission Exp Account 928	p323.189.b	-	-	-	

Attachment 4 - Cost Support
PATH Allegheny Transmission Company, LLC

Safety Related Advertising, Education and Out Reach Cost Support

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

Multi-state Workpaper

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	State 1	State 2	State 3	State 4	State 5	Weighed Average
	Income Tax Rates						
		MD	WV	VA			
158	SIT=State Income Tax Rate or Composite	8.250%	6.500%	6.000%			3.286%

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	2020	0	-	0
173	February	2020	-	-	-
174	March	2020	-	-	-
175	April	2020	-	-	-
176	May	2020	-	-	-
177	June	2020	-	-	-
178	July	2020	-	-	-
179	August	2020	-	-	-
180	September	2020	-	-	-
181	October	2020	-	-	-
182	November	2020	-	-	-
183	December	2020	-	-	-
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		37,710
187	Total Account 566	Footnote Data: Schedule Page 320 b. 97	37,710

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

Line	Formula Line	Item	
2	Formula Line	Item	
3	5	NET REVENUE REQUIREMENT	741,921
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**

Line		Details		(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		-	-	-	-	-	-	741,921

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

1 New Plant Carrying Charge

Line	Formula Line	Item	
2	Formula Line	Item	
3	5	NET REVENUE REQUIREMENT	370,823
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**

Line		Details		(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		-	-	-	-	-	370,822.78

Attachment 6 has been removed and intentionally left blank.

Attachment 6 has been removed and intentionally left blank.

Attachment 7

Potomac-Appalachian Transmission Highline, LLC

PATH West Virginia Transmission Company, LLC

CALCULATION OF COST OF DEBT AFTER CONSTRUCTION PHASE

YEAR ENDED **12/31/2014**

(HYPOTHETICAL EXAMPLE)

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

Development of Effective Cost Rates:

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

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

Attachment 7

Potomac-Appalachian Transmission Highline, LLC **PATH Allegheny Transmission Company, LLC**

CALCULATION OF COST OF DEBT AFTER CONSTRUCTION PHASE

YEAR ENDED 12/31/2014

(HYPOTHETICAL EXAMPLE)

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

Development of Effective Cost Rates:

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

[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 2018 Available June 1, 2019		2018 Revenue Requirement Forecast by Sept 1, 2017		True-up Adjustment - Over (Under) Recovery
$638,392	-	$646,981	=	$8,589

		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			0.4095%				

An over or under collection will be recovered prorata over 2018, held for 2019 and returned prorate over 2020

		Over (Under) Recovery Plus Interest	Average Monthly Interest Rate	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
Calculation of Interest					Monthly		
January	Year 2018	716	0.4095%	12	(35)		(751)
February	Year 2018	716	0.4095%	11	(32)		(748)
March	Year 2018	716	0.4095%	10	(29)		(745)
April	Year 2018	716	0.4095%	9	(26)		(742)
May	Year 2018	716	0.4095%	8	(23)		(739)
June	Year 2018	716	0.4095%	7	(21)		(736)
July	Year 2018	716	0.4095%	6	(18)		(733)
August	Year 2018	716	0.4095%	5	(15)		(730)
September	Year 2018	716	0.4095%	4	(12)		(727)
October	Year 2018	716	0.4095%	3	(9)		(725)
November	Year 2018	716	0.4095%	2	(6)		(722)
December	Year 2018	716	0.4095%	1	(3)		(719)
					(229)		(8,818)
					Annual		
January through December	Year 2019	(8,818)	0.4095%	12	(433)		(9,251)
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					Monthly		
January	Year 2020	9,251	0.4095%		(38)	792	(8,497)
February	Year 2020	8,497	0.4095%		(35)	792	(7,740)
March	Year 2020	7,740	0.4095%		(32)	792	(6,981)
April	Year 2020	6,981	0.4095%		(29)	792	(6,218)
May	Year 2020	6,218	0.4095%		(25)	792	(5,451)
June	Year 2020	5,451	0.4095%		(22)	792	(4,682)
July	Year 2020	4,682	0.4095%		(19)	792	(3,910)
August	Year 2020	3,910	0.4095%		(16)	792	(3,134)
September	Year 2020	3,134	0.4095%		(13)	792	(2,355)
October	Year 2020	2,355	0.4095%		(10)	792	(1,573)
November	Year 2020	1,573	0.4095%		(6)	792	(788)
December	Year 2020	788	0.4095%		(3)	792	(0)
					(248)		

True-Up Adjustment with Interest*	(9,499)
Less Over (Under) Recovery	8,589
Total Interest	(910)

*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

Revised Reconciliation Revenue Requirement For Year 2018 Available July 12, 2019		2018 Revenue Requirement Forecast by Sept 1, 2017		True-up Adjustment - Over (Under) Recovery
$467,639	-	$284,296	=	($183,343)

Interest Rate on Amount of Refunds or Surcharges from 35.19a		Over (Under) Recovery Plus Interest	Average Monthly Interest Rate	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
			0.4095%				

An over or under collection will be recovered prorata over 2018, held for 2019 and returned prorate over 2020

Calculation of Interest					Monthly		
January	Year 2018	(15,279)	0.4095%	12	751		16,029
February	Year 2018	(15,279)	0.4095%	11	688		15,967
March	Year 2018	(15,279)	0.4095%	10	626		15,904
April	Year 2018	(15,279)	0.4095%	9	563		15,842
May	Year 2018	(15,279)	0.4095%	8	501		15,779
June	Year 2018	(15,279)	0.4095%	7	438		15,717
July	Year 2018	(15,279)	0.4095%	6	375		15,654
August	Year 2018	(15,279)	0.4095%	5	313		15,591
September	Year 2018	(15,279)	0.4095%	4	250		15,529
October	Year 2018	(15,279)	0.4095%	3	188		15,466
November	Year 2018	(15,279)	0.4095%	2	125		15,404
December	Year 2018	(15,279)	0.4095%	1	63		15,341
					4,880		188,223
					Annual		
January through December	Year 2019	188,223	0.4095%	12	9,249		197,472
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					Monthly		
January	Year 2020	(197,472)	0.4095%		809	(16,897)	181,384
February	Year 2020	(181,384)	0.4095%		743	(16,897)	165,229
March	Year 2020	(165,229)	0.4095%		677	(16,897)	149,008
April	Year 2020	(149,008)	0.4095%		610	(16,897)	132,721
May	Year 2020	(132,721)	0.4095%		543	(16,897)	116,367
June	Year 2020	(116,367)	0.4095%		477	(16,897)	99,947
July	Year 2020	(99,947)	0.4095%		409	(16,897)	83,459
August	Year 2020	(83,459)	0.4095%		342	(16,897)	66,903
September	Year 2020	(66,903)	0.4095%		274	(16,897)	50,280
October	Year 2020	(50,280)	0.4095%		206	(16,897)	33,588
November	Year 2020	(33,588)	0.4095%		138	(16,897)	16,828
December	Year 2020	(16,828)	0.4095%		69	(16,897)	0
					5,296		

True-Up Adjustment with Interest	$	202,768
Less Over (Under) Recovery	$	(183,343)
Total Interest	$	19,425

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)	

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

Applicable to PATH West Virginia Transmission Company, LLC

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

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

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

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

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

Applicable to PATH Allegheny Transmission Company, LLC

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

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

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

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

Attachment 11
MAIT Formula Rate for January 1, 2020 to December 31, 2020

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/2020

Mid-Atlantic Interstate Transmission, LLC

Line No.	(1)	(2)	(3)		(4)	(5)
						Allocated Amount
1	GROSS REVENUE REQUIREMENT [page 3, line 43, col 5]					$ 257,681,663
	REVENUE CREDITS	(Note T)	Total	Allocator		
2	Account No. 451	(page 4, line 29)	-	TP	1.00000	-
3	Account No. 454	(page 4, line 30)	3,761,088	TP	1.00000	3,761,088
4	Account No. 456	(page 4, line 31)	910,157	TP	1.00000	910,157
5	Revenues from Grandfathered Interzonal Transactions		-	TP	1.00000	-
6	Revenues from service provided by the ISO at a discount		-	TP	1.00000	-
7	TEC Revenue	Attachment 11, Page 2, Line 3, Col. 12	15,935,929	TP	1.00000	15,935,929
8	TOTAL REVENUE CREDITS (sum lines 2-7)		20,607,175			20,607,175
9	True-up Adjustment with Interest	Attachment 13, Line 28				(14,793,106)
10	NET REVENUE REQUIREMENT	(Line 1 - Line 8 + Line 9)				$ 222,281,382

Line No.				
	DIVISOR			Total
11	1 Coincident Peak (CP) (MW)		(Note A)	5,994.1
12	Average 12 CPs (MW)		(Note CC)	5,262.3

Line No.			Total
13	Annual Rate ($/MW/Yr)	(line 10 / line 11)	37,083.18

Line No.			Peak Rate Total	Off-Peak Rate Total
14	Point-to-Point Rate ($/MW/Year)	(line 10 / line 12)	42,240.11	42,240.11
15	Point-to-Point Rate ($/MW/Month)	(line 14/12)	3,520.01	3,520.01
16	Point-to-Point Rate ($/MW/Week)	(line 14/52)	812.31	812.31
17	Point-to-Point Rate ($/MW/Day)	(line 16/5; line 16/7)	162.46	116.04
18	Point-to-Point Rate ($/MWh)	(line 14/4,160; line 14/8,760)	10.15	4.82

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/2020

Mid-Atlantic Interstate Transmission, LLC

Line No.	(1)	(2) Source	(3) Company Total		(4) Allocator	(5) Transmission (Col 3 times Col 4)
	RATE BASE:					
	GROSS PLANT IN SERVICE					
1	Production	Attachment 3, Line 14, Col. 1 (Notes U & X)	-	NA		
2	Transmission	Attachment 3, Line 14, Col. 2 (Notes U & X)	1,906,484,203	TP	1.00000	1,906,484,203
3	Distribution	Attachment 3, Line 14, Col. 3 (Notes U & X)	-	NA		
4	General & Intangible	Attachment 3, Line 14, Col. 4 & 5 (Notes U & X)	77,949,383	W/S	1.00000	77,949,383
5	Common	Attachment 3, Line 14, Col. 6 (Notes U & X)	-	CE	1.00000	-
6	TOTAL GROSS PLANT (sum lines 1-5)		1,984,433,586	GP=	100.000%	1,984,433,586
	ACCUMULATED DEPRECIATION					
7	Production	Attachment 4, Line 14, Col. 1 (Notes U & X)	-	NA		
8	Transmission	Attachment 4, Line 14, Col. 2 (Notes U & X)	351,881,732	TP	1.00000	351,881,732
9	Distribution	Attachment 4, Line 14, Col. 3 (Notes U & X)	-	NA		
10	General & Intangible	Attachment 4, Line 14, Col. 4 & 5 (Notes U & X)	12,102,725	W/S	1.00000	12,102,725
11	Common	Attachment 4, Line 14, Col. 6 (Notes U & X)	-	CE	1.00000	-
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		363,984,457			363,984,457
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)	-			
14	Transmission	(line 2- line 8)	1,554,602,471			1,554,602,471
15	Distribution	(line 3 - line 9)	-			
16	General & Intangible	(line 4 - line 10)	65,846,658			65,846,658
17	Common	(line 5 - line 11)	-			-
18	TOTAL NET PLANT (sum lines 13-17)		1,620,449,129	NP=	100.000%	1,620,449,129
	ADJUSTMENTS TO RATE BASE					
19	Account No. 281 (enter negative)	Attachment 5, Line 3, Col. 1 (Notes F & Y & DD)	-	NA		
20	Account No. 282 (enter negative)	Attachment 5, Line 3, Col. 2 (Notes F & Y & DD)	(316,827,382)	NP	1.00000	(316,827,382)
21	Account No. 283 (enter negative)	Attachment 5, Line 3, Col. 3 (Notes F & Y & DD)	(3,562,930)	NP	1.00000	(3,562,930)
22	Account No. 190	Attachment 5, Line 3, Col. 4 (Notes F & Y & DD)	8,005,046	NP	1.00000	8,005,046
23	Account No. 255 (enter negative)	Attachment 5, Line 3, Col. 5 (Notes F & Y & DD)	-	NP	1.00000	-
24	Unfunded Reserve Plant-related (enter negative)	Attachment 14, Line 9, Col. G (Note Y)	-	DA	1.00000	-
25	Unfunded Reserve Labor-related (enter negative	Attachment 14, Line 10, Col. G (Note Y)	-	DA	1.00000	-
26	CWIP	216.b (Notes X & Z)	-	DA	1.00000	-
27	Unamortized Regulatory Asset	Attachment 16a, 16b, 16c, line 15, Col. 7 (Notes X)	2,819,191	DA	1.00000	2,819,191
28	Unamortized Abandoned Plant	Attachment 17, Line 15, Col. 7 (Notes X & BB)	-	DA	1.00000	-
29	TOTAL ADJUSTMENTS (sum lines 19-28)		(309,566,075)			(309,566,075)
30	LAND HELD FOR FUTURE USE	214.x.d (Attachment 14, Line 1, Col. D) (Notes G & Y)	-	TP	1.00000	-
31	WORKING CAPITAL (Note H)					
32	CWC	1/8*(Page 3, Line 15 minus Page 3, Lines 11 & 12)	9,510,158			9,276,322
33	Materials & Supplies (Note G)	227.8.c & .16.c (Attachment 14, Line 2, Col. D) (Note Y)	-	TE	0.97620	-
34	Prepayments (Account 165)	111.57.c (Attachment 14, Line 3, Col. D) (Notes B & Y)	673,477	GP	1.00000	673,477
35	TOTAL WORKING CAPITAL (sum lines 32 - 34)		10,183,634			9,949,798
36	RATE BASE (sum lines 18, 29, 30, & 35)		1,321,066,688			1,320,832,852

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Mid-Atlantic Interstate Transmission, LLC

Line No.	(1)	(2) Source	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	321.112.b (Attachment 20, page 1, line 112)	78,603,308	TE	0.97620	76,732,621
2	Less LSE Expenses Included in Transmission O&M Accounts (Note W)		228,660	DA	1.00000	228,660
3	Less Account 565	321.96.b	-	DA	1.00000	-
4	Less Account 566	321.97.b	6,973,026	DA	1.00000	6,973,026
5	A&G	323.197.b (Attachment 20, page 2, line 197)	(1,203,979)	W/S	1.00000	(1,203,979)
6	Less FERC Annual Fees		-	W/S	1.00000	-
7	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)		243,238	W/S	1.00000	243,238
8	Plus Transmission Related Reg. Comm. Exp. (Note I)		-	TE	0.97620	-
9	PBOP Expense Adjustment in Year	Attachment 6, Line 9	(846,168)	DA	1.00000	(846,168)
10	Common	356.1	-	CE	1.00000	-
11	Account 407.3 Amortization of Regulatory Assets	Attachment 16a, 16b, 16c, Line 15, Col. 5	860,406	DA	1.00000	860,406
12	Account 566 Amortization of Regulatory Assets	321.97.b (notes)	-	DA	1.00000	-
13	Acct. 566 Miscellaneous Transmission Expense (less amortization of regulatory asset)	321.97.b - line 12	6,973,026	DA	1.00000	6,973,026
14	Total Account 566 (sum lines 12 & 13, ties to 321.97.b)		6,973,026			6,973,026
15	TOTAL O&M (sum lines 1, 5,8, 9, 10, 11, 14 less 2, 3, 4, 6, 7)		76,941,667			75,070,980
	DEPRECIATION AND AMORTIZATION EXPENSE					
16	Transmission	336.7.b (Note U)	41,996,782	TP	1.00000	41,996,782
17	General & Intangible	336.1.f & 336.10.f (Note U)	4,741,303	W/S	1.00000	4,741,303
18	Common	336.11.b (Note U)	-	CE	1.00000	-
19	Amortization of Abandoned Plant	Attachment 17, Line 15, Col. 5 (Note BB)	-	DA	1.00000	-
20	TOTAL DEPRECIATION (sum lines 16 -19)		46,738,085			46,738,085
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
21	Payroll	263.i (Attachment 7, line 1z)	468,257	W/S	1.00000	468,257
22	Highway and vehicle	263.i (Attachment 7, line 2z)	-	W/S	1.00000	-
23	PLANT RELATED					
24	Property	263.i (Attachment 7, line 3z)	77,040	GP	1.00000	77,040
25	Gross Receipts	263.i (Attachment 7, line 4z)	-	NA		-
26	Other	263.i (Attachment 7, line 5z)	-	GP	1.00000	-
27	Payments in lieu of taxes	Attachment 7, line 6z	-	GP	1.00000	-
28	TOTAL OTHER TAXES (sum lines 21 - 27)		545,297			545,297
	INCOME TAXES	(Note K)				
29	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		28.89%			
30	CIT=(T/1-T) * (1-(WCLTD/R)) =		32.08%			
	where WCLTD=(page 4, line 22) and R= (page 4, line 25)					
	and FIT, SIT & p are as given in footnote K.					
31	1 / (1 - T) = (from line 29)		1.4063			
32	Amortized Investment Tax Credit (266.8.f) (enter negative)		(140,188)			
33	Tax Effect of Permanent Differences and AFUDC Equity (Attachment 15, Line 1, Col. 3) [Notes D & Y]		946,688			
34	(Excess)/Deficient Deferred Income Taxes (Attachment 15, Lines 2 & 3, Col. 3) [Notes E & Y]		(1,210,716)			
35	Income Tax Calculation = line 30 * line 40		33,010,967	NA		33,005,124
36	ITC adjustment (line 31 * line 32)		(197,148)	NP	1.00000	(197,148)
37	Permanent Differences and AFUDC Equity Tax Adjustment (line 31 * line 33)		1,331,340	DA	1.00000	1,331,340
38	(Excess)/Deficient Deferred Income Tax Adjustment (line 31 * line 34)		(1,702,646)	DA	1.00000	(1,702,646)
39	Total Income Taxes	sum lines 35 through 38	32,442,513			32,436,670
40	RETURN	[Rate Base (page 2, line 36) * Rate of Return (page 4, line 25)]	102,908,846.89	NA		102,890,631
41	GROSS REV. REQUIREMENT (WITHOUT INCENTIVE)	(sum lines 15, 20, 28, 39, 40)	259,576,408			257,681,663
42	ADDITIONAL INCENTIVE REVENUE	Attachment 11, page 2, line 4, col 11 (Note AA)	0			0
43	GROSS REV. REQUIREMENT	(line 41 + line 42)	259,576,408			257,681,663

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Mid-Atlantic Interstate Transmission, LLC

SUPPORTING CALCULATIONS AND NOTES

Line No.	(1)	(2)	(3)	(4)	(5)		(6)	
	TRANSMISSION PLANT INCLUDED IN ISO RATES							
1	Total transmission plant (page 2, line 2, column 3)						1,906,484,203	
2	Less transmission plant excluded from ISO rates (Note M)						-	
3	Less transmission plant included in OATT Ancillary Services (Note N)						-	
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)						1,906,484,203	
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)					TP=	1.00000	
	TRANSMISSION EXPENSES							
6	Total transmission expenses (page 3, line 1, column 3)						78,603,308	
7	Less transmission expenses included in OATT Ancillary Services (Note L)						1,870,687	
8	Included transmission expenses (line 6 less line 7)						76,732,621	
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)						0.97620	
10	Percentage of transmission plant included in ISO Rates (line 5)					TP	1.00000	
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)					TE=	0.97620	
	WAGES & SALARY ALLOCATOR (W&S)							
		Form 1 Reference	$	TP	Allocation			
12	Production	354.20.b	-	0.00	-			
13	Transmission	354.21.b	-	1.00	-			
14	Distribution	354.23.b	-	0.00	-		W&S Allocator	
15	Other	354.24,25,26.b	-	0.00	-		($ / Allocation)	
16	Total (sum lines 12-15)		-		-	=	1.00000	= WS
	COMMON PLANT ALLOCATOR (CE) (Note O)							
			$		% Electric (line 17 / line 20)		W&S Allocator (line 16)	CE
17	Electric	200.3.c	-					
18	Gas	201.3.d	-		1.00000	*	1.00000	= 1.00000
19	Water	201.3.e	-					
20	Total (sum lines 17 - 19)		-					
	RETURN (R)						$	
21		Preferred Dividends (118.29c) (positive number)					-	
			$	(Note C) %	Cost (Note P)		Weighted	
22	Long Term Debt (112.24.c) (Attachment 8, Line 14, Col. 7) (Note X)		676,834,634	40%	0.0407		0.0164	=WCLTD
23	Preferred Stock (112.3d) (Attachment 8, Line 14, Col. 2) (Note X)		-	0%	0.0000		0.0000	
24	Common Stock (Attachment 8, Line 14, Col. 6) (Note X)		1,003,003,578	60%	0.1030		0.0615	
25	Total (sum lines 22-24)		1,679,838,212				0.0779	=R
	REVENUE CREDITS							
	ACCOUNT 447 (SALES FOR RESALE)		(310-311)	(Note Q)				
26	a. Bundled Non-RQ Sales for Resale (311.x.h)						-	
27	b. Bundled Sales for Resale included in Divisor on page 1						-	
28	Total of (a)-(b)						-	
29	ACCOUNT 451 (MISCELLANEOUS SERVICE REVENUE) (Note S)			(300.17.b) (Attachment 21, line 1z)			-	
30	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)			(300.19.b) (Attachment 21, line 2z)			3,761,088	
31	ACCOUNT 456 (OTHER ELECTRIC REVENUE) (Note V)			(330.x.n) (Attachment 21, line 3z)			910,157	

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Mid-Atlantic Interstate Transmission, 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	As provided by PJM and in effect at the time of the annual rate calculations pursuant to Section 34.1 of the PJM OATT. Includes combined CPs for Met-Ed and Penelec zones.
B	Prepayments shall exclude prepayments of income taxes.
C	In its order approving the transfer of Penelec's and Met-Ed's transmission assets to MAIT, the Commission approved MAIT's commitment to apply a 50 percent equity/50 percent debt capital structure for ratemaking purposes for a two-year transition period. Pennsylvania Electric, 154 FERC ¶ 61,109 at P 51. Consequently, for the first two years (i.e., calendar years 2017 and 2018) the hypothetical capital structure will be used instead of the actual calculation. Per the Settlement Agreement in docket number ER17-211-000, beginning in calendar year 2019, the equity component of MAIT's capital structure to be used in calculating charges under the formula rate shall be the lower of (i) MAIT's actual equity component as calculated in accordance with Attachment 8 or (ii) 60%.
D	Includes the annual income tax cost or benefits due to permanent differences or differences between the amounts of expenses or revenues recognized in one period for ratemaking purposes and the amounts recognized for income tax purposes which do not reverse in one or more other periods, including the cost of income taxes on the Allowance for Other Funds Used During Construction.
E	Upon enactment of changes in tax law, income tax rates (including changes in apportionment) and other actions taken by a taxing authority, 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 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. Amounts to be included will be January 1, 2017 and thereafter.
F	The balances in Accounts 190, 281, 282 and 283, should exclude all FASB 106 or 109 related amounts. For example, any and all amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109 should be excluded. The 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 K. Account 281 is not allocated.
G	Identified in Form 1 as being only transmission related.
H	Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 15, column 5 minus amortization of regulatory assets (page 3, lines 11 & 12, col. 5). Prepayments are the electric related prepayments booked to Account No. 165 and reported on Page 111, line 57 in the Form 1.
I	Line 7 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 8 - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.
J	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.
K	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 3, line 31).

Inputs Required:			
	FIT =	21.00%	
	SIT=	9.99%	(State Income Tax Rate or Composite SIT)
	p =		(percent of federal income tax deductible for state purposes)

L	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1 - 561.3, and 561.BA., and related to generation step-up facilities, which are deemed included in OATT ancillary servic 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.
M	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).
N	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed 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.
O	Enter dollar amounts
P	Debt cost rate will be set at 4.5% until such time as debt is issued by MAIT. Once debt is issued, the long-term debt cost rate will be the weighted average of the rates for all outstanding debt instruments, calculated within Attachment 10, col. j. Consistent with Note C, there will be no preferred stock cost, consistent with MAIT's commitment to use a hypothetical 50%/50% capital structure until calendar year 2019. Thereafter, Preferred cost rate = preferred dividends (line 21) / preferred outstanding (line 23). No change in ROE may be made absent a filing with FERC under Section 205 or Section 206 of the Federal Power Act. Per the Settlement Agreement in Docket No. ER17-211-000, MAIT's stated ROE is set to 10.30% (9.8 base ROE plus 50 basis point adder for RTO participation).
Q	Line 28 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.
R	Includes income related only to transmission facilities, such as pole attachments, rentals and special use.
S	Excludes revenues unrelated to transmission services.
T	The revenues credited on page 1, lines 2-6 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, or facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template. The revenue on line 7 is supported by it own reference.
U	Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC.
V	On Page 4, Line 31, enter revenues from RTO settlements that are associated with NITS and firm Point-to-Point Service for which the load is not included in the divisor to derive Met-Ed's and Penelec's zonal rates. Exclude non-firm Point-to-Point revenues and revenues related to RTEP projects.
W	Account Nos. 561.4, 561.8, and 575.7 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.
X	Calculate using a 13 month average balance.
Y	Calculate using average of beginning and end of year balance.
Z	Includes only CWIP authorized by the Commission for inclusion in rate base.
AA	Any actual ROE incentive must be approved by the Commission; therefore, line will remain zero until a project(s) is granted an ROE incentive adder.
BB	Unamortized Abandoned Plant and Amortization of Abandoned Plant will be zero until the Commission accepts or approves recovery of the cost of abandoned plant. Utility must submit a Section 205 filing to recover the cost of abandoned plant.
CC	Peak as would be reported on page 401, column d of Form 1 at the time of Met-Ed's and Penelec's zonal peak for the twelve month period ending October 31 of the calendar year used to calculate rates. The projection year will utilize the most recent preceding 12-month period at the time of the filing.
DD	Includes transmission-related balance only.

Schedule 1A Rate Calculation

1	$ 1,870,687	Attachment H-28A, Page 4, Line 7
2	105,237	Revenue Credits for Sched 1A - Note A
3	$ 1,765,450	Net Schedule 1A Expenses (Line 1 - Line 2
4	32,084,029	Annual MWh in Met-Ed and Penelec Zones - Note B
5	$ 0.0550	Schedule 1A rate $/MWh (Line 3/ Line 4)

Note:

A Revenues received pursuant to PJM Schedule 1A revenue allocation procedures for transmission service outside of Met-Ed's and Penelec's zones during the year used to calculate rates under Attachment H-28A.

B Load expressed in MWh consistent with load used for billing under Schedule 1A for the Met-Ed and Penelec zones. Data from RTO settlement systems for the calendar year prior to the rate year.

Incentive ROE Calculation

			Source Reference	
Return Calculation				
1	Rate Base		Attachment H-28A, page 2, Line 36, Col. 5	1,320,832,852
2	Preferred Dividends	enter positive	Attachment H-28A, page 4, Line 21, Col. 6	0
	Common Stock			
3	Proprietary Capital		Attachment 8, Line 14, Col. 1	1,226,595,548
4	Less Preferred Stock		Attachment 8, Line 14, Col. 2	0
5	Less Accumulated Other Comprehensive Income Account 219		Attachment 8, Line 14, Col. 4	0
6	Less Account 216.1 & Goodwill		Attachment 8, Line 14, Col. 3 & 5	223,591,970
7	Common Stock		Attachment 8, Line 14, Col. 6	1,003,003,578
	Capitalization			
8	Long Term Debt		Attachment H-28A, page 4, Line 22, Col. 3	676,834,634
9	Preferred Stock		Attachment H-28A, page 4, Line 23, Col. 3	0
10	Common Stock		Attachment H-28A, page 4, Line 24, Col. 3	1,003,003,578
11	Total Capitalization		Attachment H-28A, page 4, Line 25, Col. 3	1,679,838,212
12	Debt %	Total Long Term Debt	Attachment H-28A, page 4, Line 22, Col. 4	40.2917%
13	Preferred %	Preferred Stock	Attachment H-28A, page 4, Line 23, Col. 4	0.0000%
14	Common %	Common Stock	Attachment H-28A, page 4, Line 24, Col. 4	59.7083%
15	Debt Cost	Total Long Term Debt	Attachment H-28A, page 4, Line 22, Col. 5	0.0407
16	Preferred Cost	Preferred Stock	Attachment H-28A, page 4, Line 23, Col. 5	0.0000
17	Common Cost	Common Stock	10.30%	0.1030
18	Weighted Cost of Debt	Total Long Term Debt (WCLTD)	(Line 12 * Line 15)	0.0164
19	Weighted Cost of Preferred	Preferred Stock	(Line 13 * Line 16)	0.0000
20	Weighted Cost of Common	Common Stock	(Line 14 * Line 17)	0.0615
21	Rate of Return on Rate Base (ROR)		(Sum Lines 18 to 20)	**0.0779**
22	Investment Return = Rate Base * Rate of Return		**(Line 1 * Line 21)**	**102,890,631**
Income Taxes				
	Income Tax Rates			
23	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		Attachment H-28A, page 3, Line 29, Col. 3	28.89%
24	CIT=(T/1-T) * (1-(WCLTD/R)) =		Calculated	32.08%
25	1 / (1 - T) = (from line 23)		Attachment H-28A, page 3, Line 31, Col.3	1.4063
26	Amortized Investment Tax Credit (266.8.f) (enter negative)		Attachment H-28A, page 3, Line 32, Col. 3	(140,188.00)
27	Tax Effect of Permanent Differences and AFUDC Equity		Attachment H-28A, page 3, Line 33, Col. 3	946,688.00
28	(Excess)/Deficient Deferred Income Taxes		Attachment H-28A, page 3, Line 34, Col. 3	(1,210,716.00)
29	Income Tax Calculation		(line 22 * line 24)	33,005,124.04
30	ITC adjustment		(line 25 * line 26)	(197,148.28)
31	Permanent Differences and AFUDC Equity Tax Adjustment		Attachment H-28A, page 3, Line 37, Col. 3	1,331,340.12
32	(Excess)/Deficient Deferred Income Tax Adjustment		Attachment H-28A, page 3, Line 38, Col. 3	(1,702,646.26)
33	Total Income Taxes		Sum lines 29 to 32	32,436,669.62
Increased Return and Taxes				
34	Return and Income taxes with increase in ROE		(Line 22 + Line 33)	135,327,301.10
35	Return without incentive adder		Attachment H-28A, Page 3, Line 40, Col. 5	102,890,631.48
36	Income Tax without incentive adder		Attachment H-28A, Page 3, Line 39, Col. 5	32,436,669.62
37	Return and Income taxes without increase in ROE		Line 35 + Line 36	135,327,301.10
38	Return and Income taxes with increase in ROE		Line 34	135,327,301.10
39	Incremental Return and incomes taxes for increase in ROE		Line 38 - Line 37	-
40	Rate Base		Line 1	1,320,832,851.73
41	Incremental Return and incomes taxes for increase in ROE divided by rate base		Line 39 / Line 40	-

Notes:

Line 17 to include an incentive ROE that is used only to determine the increase in return and incomes taxes associated with a specific increase in ROE. Any actual ROE incentive must be approved by the Commission. Until an ROE incentive is approved, line 17 will reflect the current ROE.

Gross Plant Calculation

For the 12 months ended 12/31/2020

			[1]	[2]	[3]	[4]	[5]	[6]	[7]
			Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**	**Total**
1	December	2019	-	1,788,041,456	-	18,290,526	51,222,280	-	1,857,554,263
2	January	2020	-	1,795,860,107	-	18,290,526	54,084,974	-	1,868,235,608
3	February	2020	-	1,808,416,736	-	18,290,526	54,657,430	-	1,881,364,692
4	March	2020	-	1,823,136,274	-	18,290,526	54,950,438	-	1,896,377,238
5	April	2020	-	1,841,369,120	-	18,290,526	55,100,111	-	1,914,759,758
6	May	2020	-	1,872,088,837	-	18,290,526	55,106,272	-	1,945,485,636
7	June	2020	-	1,894,706,805	-	18,290,526	55,110,527	-	1,968,107,859
8	July	2020	-	1,897,864,909	-	18,290,526	57,763,410	-	1,973,918,845
9	August	2020	-	1,922,112,646	-	18,290,526	57,982,261	-	1,998,385,433
10	September	2020	-	1,981,237,637	-	18,290,526	69,474,530	-	2,069,002,693
11	October	2020	-	2,004,678,704	-	18,290,526	69,476,019	-	2,092,445,250
12	November	2020	-	2,027,162,158	-	18,290,526	69,477,467	-	2,114,930,151
13	December	2020	-	2,127,619,250	-	18,290,526	71,159,418	-	2,217,069,194
14	**13-month Average**	**[A] [C]**	**-**	**1,906,484,203**	**-**	**18,290,526**	**59,658,857**	**-**	**1,984,433,586**

			Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**	**Total**
		[B]	205.46.g	207.58.g	207.75.g	205.5.g	207.99.g	356.1	
15	December	2019		1,788,053,111		18,290,526	51,222,280		1,857,565,918
16	January	2020		1,795,871,762		18,290,526	54,084,974		1,868,247,262
17	February	2020		1,808,428,391		18,290,526	54,657,430		1,881,376,347
18	March	2020		1,823,147,928		18,290,526	54,950,438		1,896,388,893
19	April	2020		1,841,380,775		18,290,526	55,100,111		1,914,771,412
20	May	2020		1,872,100,491		18,290,526	55,106,272		1,945,497,290
21	June	2020		1,894,718,460		18,290,526	55,110,527		1,968,119,513
22	July	2020		1,897,876,563		18,290,526	57,763,410		1,973,930,500
23	August	2020		1,922,124,300		18,290,526	57,982,261		1,998,397,088
24	September	2020		1,981,249,291		18,290,526	69,474,530		2,069,014,347
25	October	2020		2,004,690,358		18,290,526	69,476,019		2,092,456,904
26	November	2020		2,027,173,812		18,290,526	69,477,467		2,114,941,806
27	December	2020		2,127,630,904		18,290,526	71,159,418		2,217,080,848
28	13-month Average		-	1,906,495,857	-	18,290,526	59,658,857	-	1,984,445,241

Asset Retirement Costs

			Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**
		[B]	205.44.g	207.57.g	207.74.g	company records	207.98.g	company records
29	December	2019		11,654				
30	January	2020		11,654				
31	February	2020		11,654				
32	March	2020		11,654				
33	April	2020		11,654				
34	May	2020		11,654				
35	June	2020		11,654				
36	July	2020		11,654				
37	August	2020		11,654				
38	September	2020		11,654				
39	October	2020		11,654				
40	November	2020		11,654				
41	December	2020		11,654				
42	13-month Average			11,654	-	-	-	-

Notes:

[A] Included on Attachment H-28A, page 2, lines 1-6, Col. 3

[B] Reference for December balances as would be reported in FERC Form 1.

[C] Balance excludes Asset Retirements Costs

[D] Met-Ed retained 34.5kV lines

Accumulated Depreciation Calculation

For the 12 months ended 12/31/2020

			[1]	[2]	[3]	[4]	[5]	[6]	[7]
			Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**	**Total**
1	December	2019	-	346,139,163	-	2,482,084	7,891,288	-	356,512,535
2	January	2020	-	347,857,759	-	2,699,894	7,846,433	-	358,404,086
3	February	2020	-	349,297,945	-	2,917,704	7,955,927	-	360,171,575
4	March	2020	-	350,485,558	-	3,135,513	8,086,864	-	361,707,935
5	April	2020	-	351,357,773	-	3,353,323	8,227,323	-	362,938,418
6	May	2020	-	351,606,636	-	3,571,133	8,377,106	-	363,554,875
7	June	2020	-	352,918,344	-	3,788,942	8,527,066	-	365,234,352
8	July	2020	-	355,593,477	-	4,006,752	8,528,774	-	368,129,003
9	August	2020	-	356,472,507	-	4,224,562	8,706,887	-	369,403,955
10	September	2020	-	354,318,975	-	4,442,371	8,179,494	-	366,940,840
11	October	2020	-	354,159,176	-	4,660,181	8,399,379	-	367,218,736
12	November	2020	-	354,401,885	-	4,877,991	8,619,271	-	367,899,146
13	December	2020	-	349,853,324	-	5,095,801	8,733,365	-	363,682,489
14	**13-month Average**	**[A] [C]**	**-**	**351,881,732**	**-**	**3,788,942**	**8,313,783**	**-**	**363,984,457.50**

			Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**	**Total**
		[B]	219.20-24.c	219.25.c	219.26.c	200.21.c	219.28.c	356.1	
15	December	2019		346,147,377		2,482,084	7,891,288		356,520,749
16	January	2020		347,865,992		2,699,894	7,846,433		358,412,319
17	February	2020		349,306,197		2,917,704	7,955,927		360,179,827
18	March	2020		350,493,829		3,135,513	8,086,864		361,716,206
19	April	2020		351,366,063		3,353,323	8,227,323		362,946,708
20	May	2020		351,614,945		3,571,133	8,377,106		363,563,184
21	June	2020		352,926,671		3,788,942	8,527,066		365,242,680
22	July	2020		355,601,824		4,006,752	8,528,774		368,137,350
23	August	2020		356,480,873		4,224,562	8,706,887		369,412,321
24	September	2020		354,327,360		4,442,371	8,179,494		366,949,225
25	October	2020		354,167,580		4,660,181	8,399,379		367,227,140
26	November	2020		354,410,308		4,877,991	8,619,271		367,907,569
27	December	2020		349,861,765		5,095,801	8,733,365		363,690,931
28	13-month Average		-	351,890,060	-	3,788,942	8,313,783	-	363,992,785

Reserve for Depreciation of Asset Retirement Costs

			Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**
		[B]		Company Records				
29	December	2019		8,214				
30	January	2020		8,233				
31	February	2020		8,252				
32	March	2020		8,271				
33	April	2020		8,290				
34	May	2020		8,309				
35	June	2020		8,328				
36	July	2020		8,347				
37	August	2020		8,366				
38	September	2020		8,385				
39	October	2020		8,404				
40	November	2020		8,423				
41	December	2020		8,442				
42	13-month Average			8,328	-	-	-	-

Notes:

[A] Included on Attachment H-28A, page 2, lines 7-11, Col. 3

[B] Reference for December balances as would be reported in FERC Form 1.

[C] Balance excludes reserve for depreciation of asset retirement costs

Attachment 11

ADIT Calculation

				[1]	[2]	[3]	[4]	[5]	[6]
				ADIT Transmission Total (including Plant & Labor Related Transmission ADITs and applicable transmission adjustments from notes below					
				Acct. No. 281	**Acct. No. 282**	**Acct. No. 283**	**Acct. No. 190**	**Acct. No. 255**	**Total**
				(enter negative)	**(enter negative)**	**(enter negative)**		**(enter negative)**	
					[C]	[D]	[E]	[F]	
1	December 31	2019		-	(312,263,916)	(3,609,374)	8,403,921	-	(307,469,369)
2	December 31	2020		-	(321,390,848)	(3,516,487)	7,606,171	-	(317,301,164)
3	**Begin/End Average**		**[A]**	**-**	**(316,827,382)**	**(3,562,930)**	**8,005,046**	**-**	**(312,385,266)**

				Acct. No. 281	**Acct. No. 282**	**Acct. No. 283**	**Acct. No. 190**	**Acct. No. 255**	**Total**
				ADIT Total Transmission-related only, including Plant & Labor Related Transmission ADITs (prior to adjustments from notes below)					
			[B]	273.8.k	275.2.k	277.9.k	234.8.c	267.h	
4	December 31	2019			244,280,262	(19,881,356)	15,740,021	2,216,284	242,355,212
5	December 31	2020			273,962,566	(18,200,889)	16,103,938	2,076,096	273,941,711
6	Begin/End Average			-	259,121,414	(19,041,122)	15,921,980	2,146,190	258,148,462

Notes:

[A] Beginning/Ending Average with adjustments for FAS143, FAS106, FAS109, CIACs and normalization to populate Appendix H-28A, page 2, lines 19-23, col. 3 for accounts 281, 282, 283, 190, and 255, respectively

[B] Reference for December balances as would be reported in FERC Form 1.

[C] FERC Account No. 282 is adjusted for the following items.

	FAS 143 - ARO	FAS 106	FAS 109	CIAC	Other: [H]	Other: [H]	Normalization [G]
2019	-	(7,593,654)	(60,390,000)		-	-	-
2020	-	(7,414,495)	(55,312,689)		-	-	15,298,902

[D] FERC Account No. 283 is adjusted for the following items.

	FAS 143 - ARO	FAS 106	FAS 109	CIAC	Other: [H]	Other: [H]	Normalization [G]
2019	-	-	(23,490,730)		-	-	-
2020	-	-	(21,561,674)	-	-	-	(155,702)

[E] FERC Account No. 190 is adjusted for the following items:

	FAS 143 - ARO	FAS 106	FAS 109	CIAC	Other: [H]	Other: [H]	Normalization [G]
2019	-	-	(2,575,701)	9,911,801	-	-	-
2020	-	-	(2,246,096)	12,081,081	-	-	(1,337,218)

[F] See Attachment H-28A, page 5, note K; 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).

[G] Taken from Attachment 5a, page 2, col. 4.

[H] Include any additional adjustments to ADIT items as may be recognized in the future to be proper for PTRR/ATRR calculation purposes.

ADIT Normalization Calculation

[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
	2020 Quarterly Activity and Balances							
Beginning 190 (including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
8,403,921	(522,002)	7,881,919	(526,842)	7,355,078	(527,764)	6,827,313	(558,360)	6,268,954
Beginning 190 (including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
8,403,921	**(394,719)**		**(267,029)**		**(134,471)**		**(1,530)**	
Beginning 282 (including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
312,263,916	5,972,145	318,236,061	6,027,513	324,263,574	6,038,068	330,301,642	6,388,108	336,689,750
Beginning 282 (including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
312,263,916	**4,515,923**		**3,055,041**		**1,538,467**		**17,502**	
Beginning 283 (including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
3,609,374	(60,780)	3,548,594	(61,344)	3,487,250	(61,451)	3,425,799	(65,014)	3,360,785
Beginning 283 (including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
3,609,374	**(45,960)**		**(31,092)**		**(15,657)**		**(178)**	

ADIT Normalization Calculation

2020 Activity		[1] **FERC Form 1 - Year-End (sourced from Attachment 5, page 1, line 5)**	[2] **Prorated year-end less FERC Form 1 Year-end**	[3] **Sum of FAS143, FAS106, FAS109, CIAC and Other from Attachment 5, page 1, notes**	[4] **Total Normalization to Attachment 5 (col. 2 - col. 3)**	[5] **Ending Balance for formula rate (col. 1 - col. 3. - col. 4)**
Pro-rated Total	**Pro-rated Ending 190**					
(797,750)	**7,606,171**	16,103,938	8,497,767	9,834,985	**(1,337,218)**	7,606,171
Pro-rated Total	**Pro-rated Ending 282**					
9,126,932	**321,390,848**	273,962,566	(47,428,283)	(62,727,184)	**15,298,902**	321,390,848
Pro-rated Total	**Pro-rated Ending 283**					
(92,888)	**3,516,487**	(18,200,889)	(21,717,375)	(21,561,674)	**(155,702)**	3,516,487

ADIT Detail

For the 12 months ended 12/31/2020

	COLUMN A	COLUMN B	COLUMN C	COLUMN D
		BALANCE AS OF 12-31-19	BALANCE AS OF 12-31-20	AVERAGE BALANCE
	ACCOUNT 255:			
	Investment Tax Credit	2,216,284	2,076,096	2,146,190
1	TOTAL ACCOUNT 255	2,216,284	2,076,096	
	ACCOUNT 282:			
	263A Capitalized Overheads	21,981,810	21,288,359	21,635,085
	Accelarated Depreciation	237,574,192	258,308,435	247,941,313
	AFUDC	3,351,179	3,355,865	3,353,522
	AFUDC Equity	9,348,077	14,500,996	11,924,536
	Capitalized Benefits	5,315,776	5,190,423	5,253,100
	Capitalized Tree Trimming	6,983,159	7,528,426	7,255,792
	Casualty Loss	991,493	167,248	579,371
	OPEBs	(7,593,654)	(7,414,495)	(7,504,074)
	Other	(3,720,372)	(3,798,428)	(3,759,400)
	Repairs	39,786,679	44,649,421	42,218,050
	FAS109 Related to Property	(69,738,077)	(69,813,685)	(69,775,881)
2	TOTAL ACCOUNT 282	244,280,262	273,962,566	

ADIT Detail

For the 12 months ended 12/31/2020

	COLUMN A	COLUMN B	COLUMN C	COLUMN D
		BALANCE AS OF 12-31-19	BALANCE AS OF 12-31-20	AVERAGE BALANCE
	ACCOUNT 283:			
	PJM Receivable	2,670,556	2,670,556	2,670,556
	Storm Damage	76,032	0	38,016
	Vegetation Management	862,786	690,229	776,507
	AFUDC Equity Flow Thru (Gross up)	3,798,250	5,891,950	4,845,100
	Property FAS109	(27,288,980)	(27,453,624)	(27,371,302)
3	TOTAL ACCOUNT 283	(19,881,356)	(18,200,889)	

ADIT Detail

For the 12 months ended 12/31/2020

COLUMN A	COLUMN B	COLUMN C	COLUMN D
	BALANCE AS OF 12-31-19	BALANCE AS OF 12-31-20	AVERAGE BALANCE
ACCOUNT 190:			
Federal Long Term	1,722,581	1,722,581	1,722,581
Investment Tax Credit	905,992	865,488	885,740
PJM Payable	2,523,947	0	1,261,973
Capitalized Interest	3,251,402	3,680,885	3,466,143
Contribution in Aid of Construction	9,911,801	12,081,081	10,996,441
FAS109 Related to Property	(2,575,701)	(2,246,096)	(2,410,898)
4 TOTAL ACCOUNT 190	15,740,021	16,103,938	15,921,980

1	**Calculation of PBOP Expenses**		
2	**MAIT**	**Amount**	**Source**
3	Total FirstEnergy PBOP expenses	(108,686,300)	FirstEnergy 2015 Actuarial Study
4	Labor dollars (FirstEnergy)	2,024,261,894	FirstEnergy 2015 Actual: Company Records
5	cost per labor dollar (line 3 / line 4)	-$0.0537	
6	labor (labor not capitalized) current year	21,785,239	MAIT Labor: Company Records
7	PBOP Expense for current year (line 5 * line 6)	-$1,169,689	
8	PBOP expense in Account 926 for current year	(323,521)	MAIT Account 926: Company Records
9	PBOP Adjustment for Attachment H-28A, page 3, line 9 (line 7 - line 8)	(846,168)	

10 Lines 3-4 cannot change absent a Section 205 or 206 filing approved or accepted by FERC in a separate proceeding

For the 12 months ended 12/31/2020

Taxes Other than Income Calculation

		[A]	Dec 31, 2020
1	**Payroll Taxes**		
1a	Federal - Other	263.i	468,257
1b		263.i	-
1c		263.i	-
1z	**Payroll Taxes Total**		468,257
2	**Highway and Vehicle Taxes**		
2a		263.i	-
2z	**Highway and Vehicle Taxes**		-
3	**Property Taxes**		
3a	Property Tax	263.i	77,040
3b			-
3c			-
3z	**Property Taxes**		77,040
4	**Gross Receipts Tax**		
4a		263.i	-
4z	**Gross Receipts Tax**		-
5	**Other Taxes**		
5a		263.i	-
5b		263.i	-
5c			-
5z	**Other Taxes**		-
6z	**Payments in lieu of taxes**		
7	Total other than income taxes (sum lines 1z, 2z, 3z, 4z, 5z, 6z) [tie to 114.14c]		$545,297

Notes:

[A] Reference for December balances as would be reported in FERC Form 1.

Capital Structure Calculation

For the 12 months ended 12/31/2020

			[1]	[2]	[3]	[4]	[5]	[6]	[7]
			Proprietary Capital	**Preferred Stock**	**Account 216.1**	**Account 219**	**Goodwill**	**Common Stock**	**Long Term Debt**
		[A]	112.16.c	112.3.d	112.12.c	112.15.c	233.5.f	(1) - (2) - (3) - (4) - (5)	112.24.c
1	December	2019	1,025,305,425				223,591,970	801,713,455	599,905,942
2	January	2020	1,207,572,914				223,591,970	983,980,944	599,906,878
3	February	2020	1,215,153,945				223,591,970	991,561,975	599,907,814
4	March	2020	1,222,846,816				223,591,970	999,254,846	699,908,750
5	April	2020	1,230,675,322				223,591,970	1,007,083,352	699,909,686
6	May	2020	1,238,872,565				223,591,970	1,015,280,595	699,910,622
7	June	2020	1,246,984,325				223,591,970	1,023,392,355	699,911,558
8	July	2020	1,254,797,640				223,591,970	1,031,205,670	699,912,493
9	August	2020	1,263,024,674				223,591,970	1,039,432,704	699,913,429
10	September	2020	1,272,033,948				223,591,970	1,048,441,978	699,914,365
11	October	2020	1,280,097,944				223,591,970	1,056,505,974	699,915,301
12	November	2020	1,288,076,358				223,591,970	1,064,484,388	699,916,237
13	December	2020	1,200,300,247	-	-	-	223,591,970	976,708,277	699,917,173
14	13-month Average		1,226,595,548	-	-	-	223,591,970	1,003,003,578	676,834,634

Notes:

[A] Reference for December balances as would be reported in FERC Form 1.

Stated Value Inputs For the 12 months ended 12/31/2020

Formula Rate Protocols
Section VIII.A

1. Rate of Return on Common Equity ("ROE")

MAIT's stated ROE is set to: 10.3%

2. Postretirement Benefits Other Than Pension ("PBOP")
**sometimes referred to as Other Post Employment Benefits, or "OPEB"*

Total FirstEnergy PBOP expenses	(108,686,300)
Labor dollars (FirstEnergy)	2,024,261,894

3. Depreciation Rates

FERC Account	Depr %
352	1.28%
353	2.05%
354	1.39%
355	2.32%
356	2.68%
356.1	1.27%
358	2.52%
359	0.87%
390.1	2.90%
390.2	1.24%
391.1	0.63%
391.2	18.82%
392	4.84%
393	0.01%
394	4.62%
395	0.00%
396	0.47%
397	1.80%
398	0.32%
303	14.29%

4. Net Plant Allocator
If the Net Plant (NP) allocator becomes anything other than 1.000 (or 100%), MAIT must make a Section 205 filing to seek approval of any new depreciation or amortization rates applicable to production and/or distribution plant accounts.

5. Land Rights
If Land Rights (Account 350) are acquired by MAIT, it must make a Section 205 filing to establish the appropriate depreciation rate.

Debt Cost Calculation

TABLE 1: Summary Cost of Long Term Debt

CALCULATION OF COST OF DEBT

YEAR ENDED 12/31/2020

t=N	(a) Issue Date	(b) Maturity Date	(c) ORIGINAL ISSUANCE (table 2, col. cc)	(d) Net Proceeds At Issuance (table 2, col. hh)	(e) Net Amount Outstanding at t=N	(f) Months Outstanding at t=N	(g) Average Net Outstanding in Year* z* ((col e. * col. F)/12)	(h) Weighted Outstanding Ratios (col. g/col. g total)	(i) Effective Cost Rate (Table 2, Col. ll)	(j) Weighted Debt Cost at t = N (h) * (i)	
Long Term Debt 12/31/2020											
First Mortgage Bonds:											
(1) 4.10%, Senior Unsecured Notes	5/10/2018	5/15/2028	$ 450,000,000	$ 445,907,666	$ 446,875,832	12	$ 446,875,832	66.30%	4.21%	2.79%	
(2) 3.75%, Senior Unsecured Notes - Planned	11/15/2019	11/15/2029	$ 150,000,000	$ 148,500,000	$ 148,668,727	12	$ 148,668,727	22.06%	3.87%	0.85%	
(3) 3.50%, Senior Unsecured Notes - Planned	3/15/2020	3/15/2030	$ 100,000,000	$ 99,000,000	$ 99,179,263	9.5	$ 78,516,917	11.65%	3.62%	0.42%	
Total			$ 700,000,000		$ 694,723,822		$ 674,061,476	100.000%		4.07%	**

t = time
The current portion of long term debt is included in the Net Amount Outstanding at t = N in these calculations.
The outstanding amount (column (e)) for debt retired during the year is the outstanding amount at the last month it was outstanding.
* z = Average of monthly balances for months outstanding during the year (averge of the balances for the 12 months of the year, with zero in months that the issuance is not outstanding in a month.).
Interim (individual debenture) debt cost calculations shall be taken to four decimals in percentages (7.2300%, 5.2582%); Final Total Weighted Average Debt Cost for the Formula Rate shall be rounded to two decimals of a percent (7.03%).
** This Total Weighted Average Debt Cost will be shown on page 4, line 22, column 5 of formula rate Attachment H-28A.

TABLE 2: Effective Cost Rates For Traditional Front-Loaded Debt Issuances:

YEAR ENDED 12/31/2020

Long Term Debt I: Affiliate	(aa) Issue Date	(bb) Maturity Date	(cc) Amount Issued	(dd) (Discount) Premium at Issuance	(ee) Issuance Expense	(ff) Loss/Gain on Reacquired Debt	(gg) Less Related ADIT	(hh) Net Proceeds (col. cc + col. dd + col. ee + col. ff)	(ii) Net Proceeds Ratio ((col. cc / col. hh)*100)	(jj) Coupon Rate	(kk) Annual Interest (col. cc * col. jj)	(ll) Effective Cost Rate* (Yield to Maturity at Issuance, t = 0)
(1) 4.10%, Senior Unsecured Notes	5/10/2018	5/15/2028	$ 450,000,000	$ (112,500)	$ 3,979,834	-	xxx	$ 445,907,666	99.0906	0.04100	$ 18,450,000	4.21%
(2) 3.75%, Senior Unsecured Notes - Planned	11/15/2019	11/15/2029	$ 150,000,000	$ -	$ 1,500,000	-	xxx	$ 148,500,000	99.0000	0.03750	$ 5,625,000	3.87%
(3) 3.50%, Senior Unsecured Notes - Planned	3/15/2020	3/15/2030	$ 100,000,000	$ -	$ 1,000,000	-	xxx	$ 99,000,000	99.0000	0.03500	$ 3,500,000	3.62%
TOTALS			$ 700,000,000	(112,500)	$ 6,479,834	-	xxx	$ 693,407,666			$ 27,575,000	

* YTM at issuance calculated from an acceptable bond table or from YTM = Internal Rate of Return (IRR) calculation
Effective Cost Rate of Individual Debenture (YTM at issuance): the t=0 Cashflow Çequals Net Proceeds column (gg); Semi-annual (or other) interest cashflows (C, $C_{t=2}$, etc.).

Transmission Enhancement Charge (TEC) Worksheet
To be completed in conjunction with Attachment H-28A

	(1)	(2)	(3)	(4)
Line No.		**Reference**	**Transmission**	**Allocator**
1	Gross Transmission Plant - Total	Attach. H-28A, p. 2, line 2, col. 5 (Note A)	$ 1,906,484,203	
2	Net Transmission Plant - Total	Attach. H-28A, p. 2, line 14, col. 5 (Note B)	$ 1,554,602,471	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Attach. H-28A, p. 3, line 15, col. 5	$ 75,070,980	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1, col. 3)	3.937666%	3.937666%
	GENERAL, INTANGIBLE, AND COMMON (G,I, & C) DEPRECIATION EXPENSE			
5	Total G, I, & C depreciation expense	Attach. H-28A, p. 3, lines 17 & 18, col. 5	$ 4,741,303	
6	Annual allocation factor for G, I, & C depreciation expense	(line 5 divided by line 1, col. 3)	0.248694%	0.248694%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Attach. H-28A, p. 3, line 28, col. 5	$ 545,297	
8	Annual Allocation Factor for Other Taxes	(line 7 divided by line 1, col. 3)	0.028602%	0.028602%
9	**Annual Allocation Factor for Expense**	**Sum of line 4, 6, & 8**		**4.214962%**
	INCOME TAXES			
10	Total Income Taxes	Attach. H-28A, p. 3, line 39, col. 5	$ 32,436,670	
11	Annual Allocation Factor for Income Taxes	(line 10 divided by line 2, col. 3)	2.086493%	2.086493%
	RETURN			
12	Return on Rate Base	Attach. H-28A, p. 3, line 40, col. 5	$ 102,890,631	
13	Annual Allocation Factor for Return on Rate Base	(line 12 divided by line 2, col. 3)	6.618453%	6.618453%
14	**Annual Allocation Factor for Return**	**Sum of line 11 and 13**		**8.704946%**

Columns 5-9 (page 1) only applies with incentive ROE project(s) (Note F)

(5)	(6)	(7)	(8)	(9)
Line No.		**Reference**	**Transmission**	**Allocator**
	INCOME TAXES			
10b	Total Income Taxes	Attachment 2, line 33	$ 32,436,670	
11b	Annual Allocation Factor for Income Taxes	(line 10b divided by line 2, col. 3)	2.086493%	2.086493%
	RETURN			
12b	Return on Rate Base	Attachment 2, line 22	$ 102,890,631	
13b	Annual Allocation Factor for Return on Rate Base	(line 12b divided by line 2, col. 3)	6.618453%	6.618453%
14b	**Annual Allocation Factor for Return**	**Sum of line 11b and 13b**		**8.704946%**
15	**Additional Annual Allocation Factor for Return**	**Line 14 b, col. 9 less line 14, col. 4**		**0.00000%**

Attachment 11

Transmission Enhancement Charge (TEC) Worksheet
To be completed in conjunction with Attachment H-28A

Line No.	(1) Project Name	(2) RTEP Project Number	(3) Project Gross Plant	(4) Annual Allocation Factor for Expense	(5) Annual Expense Charge	(6) Project Net Plant	(7) Annual Allocation Factor for Return	(8) Annual Return Charge	(9) Project Depreciation Expense	(10) Annual Revenue Requirement	(11) Additional Incentive Annual Allocation Factor for Return (Note F)	(12) Total Annual Revenue Requirement	(13) True-up Adjustment	(14) Net Revenue Requirement with True-up
			(Note C & H)	(Page 1, line 9)	(Col. 3 * Col. 4)	(Note D & H)	Page 1, line 14	(Col. 6 * Col. 7)	(Note E)	(Sum Col. 5, 8, & 9)	(Col. 6 * Page 1, line 15, Col. 9)	(Sum Col. 10 & 11)	(Note G)	(Sum Col. 12 & 13)
2a	Install 230Kv series reactor and 2- 100MVAR PLC switched capacitors at Hunterstown	b0215	$ 12,637,437	4.214962%	$532,663	$ 10,033,021	8.704946%	$873,369	$ 193,353	$1,599,385	-	$1,599,385	(248,938)	$1,350,447
2b	Install 250 MVAR capacitor at Keystone 500 kV	b0549	$ 3,207,134	4.214962%	$135,179	$ 2,789,057	8.704946%	$242,786	$ 44,258	$422,224	-	$422,224	(72,074)	$350,150
2c	Install 25 MVAR capacitor at Saxton 115 kV substation	b0551	$ 1,380,393	4.214962%	$58,183	$ 1,094,795	8.704946%	$95,301	$ 18,940	$172,424	-	$172,424	(29,047)	$143,377
2d	Install 50 MVAR capacitor at Altoona 230 kV substation	b0552	$ 1,038,335	4.214962%	$43,765	$ 929,389	8.704946%	$80,903	$ 14,329	$138,997	-	$138,997	(23,783)	$115,214
2e	Install 50 MVAR capacitor at Raystown 230 kV substation	b0553	$ 927,947	4.214962%	$39,113	$ 806,639	8.704946%	$70,217	$ 12,806	$122,136	-	$122,136	(20,848)	$101,288
2f	Install 75 MVAR capacitor at East Towanda 230 kV substation	b0557	$ 2,177,814	4.214962%	$91,794	$ 1,893,650	8.704946%	$164,841	$ 29,867	$286,502	-	$286,502	(48,666)	$237,837
2g	Relocate the Erie South 345 kV line terminal	b1993	$ 10,675,225	4.214962%	$449,957	$ 9,877,011	8.704946%	$859,788	$ 147,089	$1,456,834	-	$1,456,834	(251,326)	$1,205,508
2h	Convert Lewis Run-Farmers Valley to 230 kV using 1033.5 ACSR conductor. Project to b completed in conjunction with new Farmers Valley 345/230 kV transformation	b1994	$ 61,645,506	4.214962%	$2,598,335	$ 59,793,468	8.704946%	$5,204,989	$ 886,860	$8,690,183	-	$8,690,183	5,266,091	$13,956,274
2i	Portland-Kittatinny 230kv Terminal Upgrade	b0132.3	$ 130,995	4.214962%	$5,521	$ 108,673	8.704946%	$9,460	$ 2,685	$17,667	-	$17,667	18,798	$36,465
2j	South Lebanon 230/69 kv Bank 1 - Upgrade 69 kv Terminal Facilities	b1364	$ 87,275	4.214962%	$3,679	$ 73,639	8.704946%	$6,410	$ 1,789	$11,878	-	$11,878	12,621	$24,499
2k	Middletown Sub - 69 kv Capacitor Bank	b1362	$ 52,365	4.214962%	$2,207	$ 46,465	8.704946%	$4,045	$ 670	$6,922	-	$6,922	7,242	$14,164
2l	Germantown - 138kv Reactor Removal	b1816.4	$ 5,837	4.214962%	$246	$ (5,139)	8.704946%	-$447	$ 120	-$82	-	-$82	9,337	$9,255
2m	Germantown r p 138 115kV #1 Bk Xfmr + Upgrade 138kV 999L & 115kV 998L components RTEP b2688, b2688.1, b2688.2	b2688.1	$ 5,923,777	4.214962%	$249,685	$ 5,653,390	8.704946%	$492,125	$ 121,437	$863,247	-	$863,247	639,440	$1,502,687
2n	Loop the 2026 (TMI - Hosensack 500 kV) line in to the Lauschtown substation and upgrade relay at TMI 500 kV	b2006.1.1_DFAX_Allocation	$ 2,215,749	4.214962%	$93,393	$ 2,046,702	8.704946%	$178,164	$ 54,507	$326,065	-	$326,065	3,584	$329,649
2o	Loop the 2026 (TMI - Hosensack 500 kV) line in to the Lauschtown substation and upgrade relay at TMI 500 kV	b2006.1.1_Load_Ratio_Share_Allocation	$ 2,215,749	4.214962%	$93,393	$ 2,046,702	8.704946%	$178,164	$ 54,507	$326,065	-	$326,065	51,769	$377,834
2p	Tie in new Rice substation to Conemaugh-Hunterstown 500 kV	b2743.2	$ 1,291,021	4.214962%	$54,416	$ 1,288,729	8.704946%	$112,183	$ 22,343	$188,942	-	$188,942	-	$188,942
2q	Upgrade terminal equipment at Conemaugh 500 kV: on the Conemaugh - Hunterstown 5(kV circuit	b2743.3	$ 178,147	4.214962%	$7,509	$ 176,929	8.704946%	$15,402	$ 3,709	$26,619	-	$26,619	-	$26,619
2r	Upgrade terminal equipment at Hunterstown 500 kV: on the Conemaugh - Hunterstown 500 kV circuit	b2743.4	$ 59,988	4.214962%	$2,528	$ 59,834	8.704946%	$5,209	$ 1,110	$8,847	-	$8,847	-	$8,847
2s	Install 2nd Hunterstown 230/115 kV transformer	b2452	$ 6,023,169	4.214962%	$253,874	$ 5,619,890	8.704946%	$489,208	$ 132,510	$875,592	-	$875,592	(109,206)	$766,387
2t	Reconductor Hunterstown - Oxford 115 kV line	b2452.1	$ 2,721,723	4.214962%	$114,720	$ 2,537,448	8.704946%	$220,884	$ 59,878	$395,481	-	$395,481	(73,203)	$322,278
3	Transmission Enhancement Credit taken to Attachment H-28A Page 1, Line 7											15,935,929.30		
4	Additional Incentive Revenue taken to Attachment H-28A Page 3, Line 42										$0.00			

Notes
- A Gross Transmission Plant is that identified on page 2 line 2 of Attachment H-28A.
- B Net Transmission Plant is that identified on page 2 line 14 of Attachment H-28A.
- C Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 above. This value includes subsequent capital investments required to maintain the project in-service.
- D Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation.
- E Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H-28A, page 3, line 16.
- F Any actual ROE incentive must be approved by the Commission
- G True-up adjustment is calculated on the project true-up schedule, attachment 12, column j
- H Based on a 13-month average

TEC Worksheet Support
Net Plant Detail

Line No.	Project Name	RTEP Project Number	Project Gross Plant (Note A)	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
2a	Install 230Kv series reactor and 2- 100MVAR PLC switched capacitors at Hunterstown	b0215	$ 12,637,437	$ 12,637,431	$ 12,637,432	$ 12,637,433	$ 12,637,434	$ 12,637,435	$ 12,637,436	$ 12,637,437	$ 12,637,438	$ 12,637,439	$ 12,637,440	$ 12,637,441	$ 12,637,442	$ 12,637,443
2b	Install 250 MVAR capacitor at Keystone 500 kV	b0549	$ 3,207,134	$3,207,134	$3,207,134	$3,207,134	$3,207,134	$3,207,134	$3,207,134	$3,207,134	$3,207,134	$3,207,134	$3,207,134	$3,207,134	$3,207,134	$3,207,134
2c	Install 25 MVAR capacitor at Saxton 115 kV substatio	b0551	$ 1,380,393	$1,380,393	$1,380,393	$1,380,393	$1,380,393	$1,380,393	$1,380,393	$1,380,393	$1,380,393	$1,380,393	$1,380,393	$1,380,393	$1,380,393	$1,380,393
2d	Install 50 MVAR capacitor at Altoona 230 kV substatio	b0552	$ 1,038,335	$1,038,335	$1,038,335	$1,038,335	$1,038,335	$1,038,335	$1,038,335	$1,038,335	$1,038,335	$1,038,335	$1,038,335	$1,038,335	$1,038,335	$1,038,335
2e	Install 50 MVAR capacitor at Raystown 230 kV substatio	b0553	$ 927,947	$927,947	$927,947	$927,947	$927,947	$927,947	$927,947	$927,947	$927,947	$927,947	$927,947	$927,947	$927,947	$927,947
2f	Install 75 MVAR capacitor at East Towanda 230 kV substatio	b0557	$ 2,177,814	$2,177,814	$2,177,814	$2,177,814	$2,177,814	$2,177,814	$2,177,814	$2,177,814	$2,177,814	$2,177,814	$2,177,814	$2,177,814	$2,177,814	$2,177,814
2g	Relocate the Erie South 345 kV line termina	b1993	$ 10,675,225	$10,675,225	$10,675,225	$10,675,225	$10,675,225	$10,675,225	$10,675,225	$10,675,225	$10,675,225	$10,675,225	$10,675,225	$10,675,225	$10,675,225	$10,675,225
2h	Convert Lewis Run-Farmers Valley to 230 kV using 1033.5 ACSR conductor. Project to be completed in conjunction with new Farmers Valley 345/230 kV transformation	b1994	$ 61,645,506	$61,645,506	$61,645,506	$61,645,506	$61,645,506	$61,645,506	$61,645,506	$61,645,506	$61,645,506	$61,645,506	$61,645,506	$61,645,506	$61,645,506	$61,645,506
2i	Portland-Kittatinny 230kv Terminal Upgrade	b0132.3	$ 130,995	$130,995	$130,995	$130,995	$130,995	$130,995	$130,995	$130,995	$130,995	$130,995	$130,995	$130,995	$130,995	$130,995
2j	South Lebanon 230/69 kv Bank 1 - Upgrade 69 kv Terminal Facilities	b1364	$ 87,275	$87,275	$87,275	$87,275	$87,275	$87,275	$87,275	$87,275	$87,275	$87,275	$87,275	$87,275	$87,275	$87,275
2k	Middletown Sub - 69 kv Capacitor Banl	b1362	$ 52,365	$52,365	$52,365	$52,365	$52,365	$52,365	$52,365	$52,365	$52,365	$52,365	$52,365	$52,365	$52,365	$52,365
2l	Germantown - 138kv Reactor Removal	b1816.4	$ 5,837	$5,837	$5,837	$5,837	$5,837	$5,837	$5,837	$5,837	$5,837	$5,837	$5,837	$5,837	$5,837	$5,837
2m	Germantown r p 138 115kV #1 Bk Xfmr + Upgrade 138kV 999L & 115kV 998L components RTEP b2688, b2688.1, b2688.2	b2688.1 & b2888.2	$ 5,923,777	$5,923,777	$5,923,777	$5,923,777	$5,923,777	$5,923,777	$5,923,777	$5,923,777	$5,923,777	$5,923,777	$5,923,777	$5,923,777	$5,923,777	$5,923,777
2n	Loop the 2026 (TMI - Hosensack 500 kV) line in to the Lauschtown substation and upgrade relay at TMI 500 kV	b2006.1.1_DFAX_Allocation	$ 2,215,749	$2,215,749	$2,215,749	$2,215,749	$2,215,749	$2,215,749	$2,215,749	$2,215,749	$2,215,749	$2,215,749	$2,215,749	$2,215,749	$2,215,749	$2,215,749
2o	Loop the 2026 (TMI - Hosensack 500 kV) line in to the Lauschtown substation and upgrade relay at TMI 500 kV	b2006.1.1_Load_Ratio_Share_Allocation	$ 2,215,749	$2,215,749	$2,215,749	$2,215,749	$2,215,749	$2,215,749	$2,215,749	$2,215,749	$2,215,749	$2,215,749	$2,215,749	$2,215,749	$2,215,749	$2,215,749
2p	Tie in new Rice substation to Conemaugh-Hunterstown 500 kV	b2743.2	$ 1,291,021	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$8,391,634	$8,391,634
2q	Upgrade terminal equipment at Conemaugh 500 kV: on the Conemaugh - Hunterstown 500 kV circuit	b2743.3	$ 178,147	$0	$0	$0	$0	$0	$289,488	$289,488	$289,488	$289,488	$289,488	$289,488	$289,488	$289,488
2r	Upgrade terminal equipment at Hunterstown 500 kV: on the Conemaugh - Hunterstown 500 kV circuit	b2743.4	$ 59,988	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$259,947	$259,947	$259,947
2s	Install 2nd Hunterstown 230/115 kV transforme	b2452	$ 6,023,169	$6,023,169	$6,023,169	$6,023,169	$6,023,169	$6,023,169	$6,023,169	$6,023,169	$6,023,169	$6,023,169	$6,023,169	$6,023,169	$6,023,169	$6,023,169
2t	Reconductor Hunterstown - Oxford 115 kV lin	b2452.1	$ 2,721,723	$2,721,723	$2,721,723	$2,721,723	$2,721,723	$2,721,723	$2,721,723	$2,721,723	$2,721,723	$2,721,723	$2,721,723	$2,721,723	$2,721,723	$2,721,723

[redacted]

NOTE
[A] Project Gross Plant is the total capital investment for the project, including subsequent capital investments required to maintain the project in-service. Utilizing a 13-month average.

TEC Worksheet Support
Net Plant Detail

Accumulated Depreciation (Note B)	Dec-19 (Note D)	Jan-20 (Note D)	Feb-20 (Note D)	Mar-20 (Note D)	Apr-20 (Note D)	May-20 (Note D)	Jun-20 (Note D)	Jul-20 (Note D)	Aug-20 (Note D)	Sep-20 (Note D)	Oct-20 (Note D)	Nov-20 (Note D)	Dec-20 (Note D)	[redacted]	Project Net Plant (Note B & C)
$2,604,416	$ 2,507,740	$ 2,523,853	$ 2,539,965	$ 2,556,078	$ 2,572,191	$ 2,588,304	$ 2,604,416	$ 2,620,529	$ 2,636,642	$ 2,652,754	$ 2,668,867	$ 2,684,980	$ 2,701,093		$10,033,021
$418,078	$395,948	$399,637	$403,325	$407,013	$410,701	$414,389	$418,078	$421,766	$425,454	$429,142	$432,830	$436,519	$440,207		$2,789,057
$285,598	$276,128	$277,706	$279,285	$280,863	$282,441	$284,020	$285,598	$287,176	$288,755	$290,333	$291,911	$293,490	$295,068		$1,094,795
$108,946	$101,781	$102,975	$104,169	$105,363	$106,557	$107,752	$108,946	$110,140	$111,334	$112,528	$113,722	$114,916	$116,110		$929,389
$121,308	$114,905	$115,973	$117,040	$118,107	$119,174	$120,241	$121,308	$122,375	$123,443	$124,510	$125,577	$126,644	$127,711		$806,639
$284,164	$269,231	$271,720	$274,208	$276,697	$279,186	$281,675	$284,164	$286,653	$289,142	$291,631	$294,120	$296,609	$299,098		$1,893,650
$798,214	$724,669	$736,927	$749,184	$761,442	$773,699	$785,956	$798,214	$810,471	$822,729	$834,986	$847,244	$859,501	$871,758		$9,877,011
$1,852,039	$1,408,609	$1,482,514	$1,556,419	$1,630,324	$1,704,229	$1,778,134	$1,852,039	$1,925,944	$1,999,849	$2,073,754	$2,147,659	$2,221,564	$2,295,469		$59,793,468
$22,322	$20,979	$21,203	$21,427	$21,650	$21,874	$22,098	$22,322	$22,546	$22,769	$22,993	$23,217	$23,441	$23,664		$108,673
$13,636	$12,741	$12,890	$13,039	$13,188	$13,337	$13,487	$13,636	$13,785	$13,934	$14,083	$14,232	$14,381	$14,530		$73,639
$5,900	$5,565	$5,620	$5,676	$5,732	$5,788	$5,844	$5,900	$5,956	$6,011	$6,067	$6,123	$6,179	$6,235		$46,465
$10,975	$10,915	$10,925	$10,935	$10,945	$10,955	$10,965	$10,975	$10,985	$10,995	$11,005	$11,015	$11,025	$11,035		-$5,139
$270,388	$209,669	$219,789	$229,908	$240,028	$250,148	$260,268	$270,388	$280,507	$290,627	$300,747	$310,867	$320,987	$331,106		$5,653,390
$169,046	$141,792	$146,335	$150,877	$155,419	$159,962	$164,504	$169,046	$173,588	$178,131	$182,673	$187,215	$191,758	$196,300		$2,046,702
$169,046	$141,792	$146,335	$150,877	$155,419	$159,962	$164,504	$169,046	$173,588	$178,131	$182,673	$187,215	$191,758	$196,300		$2,046,702
$2,292	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,448	$22,343		$1,288,729
$1,217	$0	$0	$0	$0	$0	$247	$742	$1,236	$1,731	$2,225	$2,720	$3,215	$3,709		$176,929
$154	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$222	$666	$1,110		$59,834
$403,279	$337,024	$348,066	$359,109	$370,151	$381,194	$392,236	$403,279	$414,321	$425,364	$436,406	$447,449	$458,491	$469,534		$5,619,890
$184,274	$154,335	$159,325	$164,315	$169,305	$174,295	$179,284	$184,274	$189,264	$194,254	$199,244	$204,234	$209,223	$214,213		$2,537,448

NOTE
[B] Utilizing a 13-month average. [C] Taken to Attachment 11, Page 2, Col. 6 [D] Company records

TEC - True-up
To be completed after Attachment 11 for the True-up Year is updated using actual data

Line No.		(a) Project Name	(b) RTEP Project Number	(c) Actual Revenues for Appendix D	(d) Projected Annual Revenue Requirement	(e) % of Total Revenue Requirement	(f) Revenue Received	(g) Actual Annual Revenue Requirement	(h) True-up Adjustment Principal Over/(Under)	(i) Applicable Interest Rate on Over/(Under)	(j) Total True-up Adjustment with Interest Over(Under)
					Projected Attachment 11 p 2 of 2, col. 14	Col d, line 2 / Col. d, line 3	Col c, line 1 * Col e	Actual Attachment 11 p 2 of 2, col. 14	Col. f - Col. G	Col. H line 2x / Col. H line 3 * Col. J line 4	Col. h + Col. i
1	[A]	Actual RTEP Credit Revenues for true-up year		6,591,186							
2a		b0215			$1,722,473	0.27	1,757,987.88	$1,532,898	225,090	23,848	248,938
2b		b0549			$456,461	0.07	465,872.77	$400,703	65,170	6,905	72,074
2c		b0551			$187,275	0.03	191,136.25	$164,872	26,264	2,783	29,047
2d		b0552			$150,010	0.02	153,102.92	$131,598	21,505	2,278	23,783
2e		b0553			$132,043	0.02	134,765.37	$115,915	18,851	1,997	20,848
2f		b0557			$309,489	0.05	315,870.51	$271,867	44,004	4,662	48,666
2g		b1993			$1,570,347	0.24	1,602,725.30	$1,375,476	227,249	24,077	251,326
2h		b1994			$15,407	0.00	15,724.55	$4,777,328	(4,761,604)	(504,487)	(5,266,091)
2i		b0132.3			$0	-	-	$16,998	(16,998)	(1,801)	(18,798)
2j		b1364			$0	-	-	$11,412	(11,412)	(1,209)	(12,621)
2k		b1362			$0	-	-	$6,548	(6,548)	(694)	(7,242)
2l		b1816.4			$0	-	-	$8,442	(8,442)	(894)	(9,337)
2m		b2688.1			$0	-	-	$578,182	(578,182)	(61,258)	(639,440)
2n		b2006.1.1_DFAX_Allocation			$302,983	0.05	309,230.31	$312,471	(3,241)	(343)	(3,584)
2o		b2006.1.1_Load_Ratio_Share_Allocation			$260,294	0.04	265,661.04	$312,471	(46,810)	(4,959)	(51,769)
2p		b2452			$915,736	0.14	934,617.20	$835,873	98,744	10,462	109,206
2q		b2452.1			$435,512	0.07	444,491.48	$378,301	66,191	7,013	73,203
3		Subtotal			6,458,031			11,231,355	(4,640,170)		(5,131,791)
4		Total Interest (Sourced from Attachment 13a, line 30)									(491,622)

NOTE
[A] Amount included in revenues reported on pages 328-330 of FERC Form 1.

Net Revenue Requirement True-up with Interest

	Reconciliation Revenue Requirement For Year 2018 Available June 3, 2019		2018 Revenue Requirement Collected by PJM Based on Forecast filed on Oct 13, 2017		True-up Adjustment - Over (Under) Recovery
1	$134,749,156	-	$148,125,094	=	$13,375,938

			Over (Under) Recovery Plus Interest	Average Monthly Interest Rate	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
2	Interest Rate on Amount of Refunds or Surcharges [A]			0.4095%				
	An over or under collection will be recovered prorata over 2018, held for 2019 and returned prorate over 2020							
	Calculation of Interest					Monthly		
3	January	Year 2018	1,114,662	0.4095%	12	(54,774)		(1,169,436)
4	February	Year 2018	1,114,662	0.4095%	11	(50,210)		(1,164,871)
5	March	Year 2018	1,114,662	0.4095%	10	(45,645)		(1,160,307)
6	April	Year 2018	1,114,662	0.4095%	9	(41,081)		(1,155,742)
7	May	Year 2018	1,114,662	0.4095%	8	(36,516)		(1,151,178)
8	June	Year 2018	1,114,662	0.4095%	7	(31,952)		(1,146,613)
9	July	Year 2018	1,114,662	0.4095%	6	(27,387)		(1,142,049)
10	August	Year 2018	1,114,662	0.4095%	5	(22,823)		(1,137,484)
11	September	Year 2018	1,114,662	0.4095%	4	(18,258)		(1,132,920)
12	October	Year 2018	1,114,662	0.4095%	3	(13,694)		(1,128,355)
13	November	Year 2018	1,114,662	0.4095%	2	(9,129)		(1,123,791)
14	December	Year 2018	1,114,662	0.4095%	1	(4,565)		(1,119,226)
						(356,034)		(13,731,972)
						Annual		
15	January through December	Year 2019	(13,731,972)	0.4095%	12	(674,789)		(14,406,761)
	Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					Monthly		
16	January	Year 2020	14,406,761	0.4095%		(58,996)	1,232,759	(13,232,998)
17	February	Year 2020	13,232,998	0.4095%		(54,189)	1,232,759	(12,054,428)
18	March	Year 2020	12,054,428	0.4095%		(49,363)	1,232,759	(10,871,032)
19	April	Year 2020	10,871,032	0.4095%		(44,517)	1,232,759	(9,682,790)
20	May	Year 2020	9,682,790	0.4095%		(39,651)	1,232,759	(8,489,683)
21	June	Year 2020	8,489,683	0.4095%		(34,765)	1,232,759	(7,291,689)
22	July	Year 2020	7,291,689	0.4095%		(29,859)	1,232,759	(6,088,790)
23	August	Year 2020	6,088,790	0.4095%		(24,934)	1,232,759	(4,880,964)
24	September	Year 2020	4,880,964	0.4095%		(19,988)	1,232,759	(3,668,193)
25	October	Year 2020	3,668,193	0.4095%		(15,021)	1,232,759	(2,450,456)
26	November	Year 2020	2,450,456	0.4095%		(10,035)	1,232,759	(1,227,731)
27	December	Year 2020	1,227,731	0.4095%		(5,028)	1,232,759	0
						(386,345)		
28	True-Up with Interest						$ 14,793,106	
29	Less Over (Under) Recovery						$ 13,375,938	
30	Total Interest						$ 1,417,168	

[A] Interest rate equal to: (i) MAIT's actual short-term debt costs capped at the interest rate determined by 18 C.F.R. 35.19a; or (ii) the interest rate determined by 18 C.F.R. 35.19, if MAIT does not have short term debt

TEC Revenue Requirement True-up with Interest

	TEC Reconciliation Revenue Requirement For Year 2018 Available June 3, 2019		TEC 2018 Revenue Requirement Collected by PJM Based on Forecast filed on Oct 13, 2017		True-up Adjustment - Over (Under) Recovery
1	$11,231,355	-	$6,591,186	=	($4,640,170)

			Over (Under) Recovery Plus Interest	Average Monthly Interest Rate	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
2	Interest Rate on Amount of Refunds or Surcharges [A]			0.4095%				
	An over or under collection will be recovered prorata over 2018, held for 2019 and returned prorate over 2020							
	Calculation of Interest					Monthly		
3	January	Year 2018	(386,681)	0.4095%	12	19,001		405,682
4	February	Year 2018	(386,681)	0.4095%	11	17,418		404,099
5	March	Year 2018	(386,681)	0.4095%	10	15,835		402,515
6	April	Year 2018	(386,681)	0.4095%	9	14,251		400,932
7	May	Year 2018	(386,681)	0.4095%	8	12,668		399,348
8	June	Year 2018	(386,681)	0.4095%	7	11,084		397,765
9	July	Year 2018	(386,681)	0.4095%	6	9,501		396,182
10	August	Year 2018	(386,681)	0.4095%	5	7,917		394,598
11	September	Year 2018	(386,681)	0.4095%	4	6,334		393,015
12	October	Year 2018	(386,681)	0.4095%	3	4,750		391,431
13	November	Year 2018	(386,681)	0.4095%	2	3,167		389,848
14	December	Year 2018	(386,681)	0.4095%	1	1,583		388,264
						123,510		4,763,679
						Annual		
15	January through December	Year 2019	4,763,679	0.4095%	12	234,087		4,997,766
	Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					Monthly		
16	January	Year 2020	(4,997,766)	0.4095%		20,466	(427,649)	4,590,583
17	February	Year 2020	(4,590,583)	0.4095%		18,798	(427,649)	4,181,732
18	March	Year 2020	(4,181,732)	0.4095%		17,124	(427,649)	3,771,207
19	April	Year 2020	(3,771,207)	0.4095%		15,443	(427,649)	3,359,001
20	May	Year 2020	(3,359,001)	0.4095%		13,755	(427,649)	2,945,107
21	June	Year 2020	(2,945,107)	0.4095%		12,060	(427,649)	2,529,518
22	July	Year 2020	(2,529,518)	0.4095%		10,358	(427,649)	2,112,227
23	August	Year 2020	(2,112,227)	0.4095%		8,650	(427,649)	1,693,227
24	September	Year 2020	(1,693,227)	0.4095%		6,934	(427,649)	1,272,512
25	October	Year 2020	(1,272,512)	0.4095%		5,211	(427,649)	850,073
26	November	Year 2020	(850,073)	0.4095%		3,481	(427,649)	425,905
27	December	Year 2020	(425,905)	0.4095%		1,744	(427,649)	0
						134,025		
28	True-Up with Interest					$	(5,131,791)	
29	Less Over (Under) Recovery					$	(4,640,170)	
30	Total Interest					$	(491,622)	

[A] Interest rate equal to: (i) MAIT's actual short-term debt costs capped at the interest rate determined by 18 C.F.R. 35.19a; or (ii) the interest rate determined by 18 C.F.R. 35.19, if MAIT does not have short term debt

Other Rate Base Items

	COLUMN A	COLUMN B	COLUMN C	COLUMN D	COLUMN E	COLUMN F	COLUMN G
Line No.	Description	BALANCE AS OF 12-31-19	BALANCE AS OF 12-31-20	AVERAGE BALANCE			
1	Land Held for Future Use (214.x.d)	0	0	-	[redacted]		
2	Materials & Supplies (227.8.c & .16.c)	0	0	-			
3	Prepayments: Account 165 (111.57.c) - Note [A]	673,477	673,477	673,477			

Unfunded Reserves

Line No.	Description	BALANCE AS OF 12-31-19	BALANCE AS OF 12-31-20	AVERAGE BALANCE	ALLOCATION FACTOR		TRANSMISSION TOTAL (Col D times Col F)
	Account 228.1						
4a	Property Insurance (Self insurance not covered by property insurance)	0	0	0	GP	1.00	0
4b	[Insert Item Included in Account 228.1 that are not allocated to transmission]	0	0	0	Other	0	0
4c	[Insert Item Included in Account 228.1 that are not allocated to transmission]	0	0	0	Other	0	0
4z	Total Account 228.1 (112.27.c)	0	0				0
	Account 228.2						
5a	Workman's Compensation	0	0	0	W/S	1.00	0
5b	Probable liabilities not covered by insurance for death or injuries to employees and others	0	0	0	W/S	1.00	0
5c	Probable liabilities not covered by insurance for damages to property neither owned nor held under lease by the utility	0	0	0	GP	1.00	0
5d	[Insert Item Included in Account 228.2 that are not allocated to transmission]	0	0	0	Other	0	0
5e	[Insert Item Included in Account 228.2 that are not allocated to transmission]	0	0	0	Other	0	0
5z	Total Account 228.2 (112.28.c)	0	0				0
	Account 228.3						
6a	Year-End Vacation Pay Accrual	0	0	0	W/S	1.00	0
6b	Year-End Deferred Compensation Accrual	0	0	0	W/S	1.00	0
6c	Year-End Sick Pay Accrual	0	0	0	W/S	1.00	0
6d	Year-End Incentive Compensation Accrual	0	0	0	W/S	1.00	0
6e	Year-End Severance Pay Accrual	0	0	0	W/S	1.00	0
6f	Year-End PBOP/OPEB Accrual not included in established trusts	0	0	0	W/S	1.00	0
6g	[Insert Item Included in Account 228.3 that are not allocated to transmission]	0	0	0	Other	0	0
6h	[Insert Item Included in Account 228.3 that are not allocated to transmission]	0	0	0	Other	0	0
6z	Total Account 228.3 (112.29.c)	0	0				0
	Account 228.4						
7a	Year-End Vacation Pay Accrual	0	0	0	W/S	1.00	0
7b	Year-End Deferred Compensation Accrual	0	0	0	W/S	1.00	0
7c	Year-End Sick Pay Accrual	0	0	0	W/S	1.00	0
7d	Year-End Incentive Compensation Accrual	0	0	0	W/S	1.00	0
7e	Year-End Severance Pay Accrual	0	0	0	W/S	1.00	0
7f	Year-End PBOP/OPEB Accrual not included in established trusts	0	0	0	W/S	1.00	0
7g	[Insert Item Included in Account 228.4 that are not allocated to transmission]	0	0	0	Other	0	0
7h	[Insert Item Included in Account 228.4 that are not allocated to transmission]	0	0	0	Other	0	0
7z	Total Account 228.4 (112.30.c)	0	0				0
	Account 242						
8a	Year-End Vacation Pay Accrual	0	0	-	W/S	1.00	-
8b	Year-End Deferred Compensation Accrual	0	0	0	W/S	1.00	-
8c	Year-End Sick Pay Accrual	0	0	0	W/S	1.00	-
8d	Year-End Incentive Compensation Accrual	0	0	0	W/S	1.00	-
8e	Year-End Severance Pay Accrual	0	0	0	W/S	1.00	-
8f	Year-End PBOP/OPEB Accrual not included in established trusts	0	0	0	W/S	1.00	-
8g	[Insert Item Included in Account 242 that are not allocated to transmission]	0	-	-	Other	0	-
8h	[Insert Item Included in Account 242 that are not allocated to transmission]	0	0	0	Other	0	-
8z	Total Account 242 (113.48.c)	0	-				-
9	Total Unfunded Reserves Plant-related (items with GP allocator) - Note [B]	0	0	0	GP	1.00	-
10	Total Unfunded Reserves Labor-related (items with W/S allocator) - Note [C]	0	-	-	W/S	1.00	-

Notes:
[A] Prepayments shall exclude prepayments of income taxes.
[B] Column G balance taken to Attachment H-28A, page 2, line 24, col. 3
[C] Column G balance taken to Attachment H-28A, page 2, line 25, col. 3

Income Tax Adjustments

	[1]	[2]	[3]	[4]	[5]	[6]
				Dec 31,	Dec 31,	
			Beg/End Average [C]	2020	2020	Reference
1	Tax adjustment for Permanent Differences & AFUDC Equity	[A]	$946,688	$946,688	$946,688	MAIT Company Records
2	Amortized Excess Deferred Taxes (enter negative)	[B]	(1,210,716)	(1,210,716)	(1,210,716)	MAIT Company Records
3	Amortized Deficient Deferred Taxes	[B]	-	-	$0	MAIT Company Records

Notes:

[A] AFUDC equity component is the gross cumulative annual amount based upon tax records of capitalized AFUDC equity embedded in the gross plant attributable to the transmission function.

[B] Upon enactment of changes in tax law, income tax rates (including changes in apportionment) and other actions taken by a taxing authority, 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 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. Amounts to be included will be January 1, 2017 and thereafter.

[C] (Column 4 + Column 5)/2; Beg/End Average for line 1 included on Attachment H-28A, page 3, line 33; Beg/End Average for lines 2-3 taken to Attachment H-28A, page 3, line 34

Regulatory Asset - Deferred Storms

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
1	**Monthly Balance**	Source	Months Remaining In Amortization Period	BegInning Balance	Amortization Expense (Company Records)	Additions (Deductions)	Ending Balance
2	December 2019	p232 (and Notes)	13				263,159
3	January	FERC Account 182.3	12	263,159	21,930	-	241,229
4	February	FERC Account 182.3	11	241,229	21,930	-	219,299
5	March	FERC Account 182.3	10	219,299	21,930	-	197,369
6	April	FERC Account 182.3	9	197,369	21,930	-	175,439
7	May	FERC Account 182.3	8	175,439	21,930	-	153,509
8	June	FERC Account 182.3	7	153,509	21,930	-	131,579
9	July	FERC Account 182.3	6	131,579	21,930	-	109,649
10	August	FERC Account 182.3	5	109,649	21,930	-	87,720
11	September	FERC Account 182.3	4	87,720	21,930	-	65,790
12	October	FERC Account 182.3	3	65,790	21,930	-	43,860
13	November	FERC Account 182.3	2	43,860	21,930	-	21,930
14	December 2020	p232 (and Notes)	1	21,930	21,930	-	-
15	**Ending Balance 13-Month Average**	(sum lines 2-14) /13			263,159		131,579
					Attachment H-28A, page 3, line 11		Attachment H-28A, page 2, Line 27

Regulatory Asset - Vegetation Management

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
1	**Monthly Balance**	Source	Months Remaining In Amortization Period	BegInning Balance	Amortization Expense (Company Records)	Additions (Deductions)	Ending Balance
2	December 2019	p232 (and Notes)	61				2,986,235
3	January	FERC Account 182.3	60	2,986,235	49,771	-	2,936,465
4	February	FERC Account 182.3	59	2,936,465	49,771	-	2,886,694
5	March	FERC Account 182.3	58	2,886,694	49,771	-	2,836,923
6	April	FERC Account 182.3	57	2,836,923	49,771	-	2,787,153
7	May	FERC Account 182.3	56	2,787,153	49,771	-	2,737,382
8	June	FERC Account 182.3	55	2,737,382	49,771	-	2,687,612
9	July	FERC Account 182.3	54	2,687,612	49,771	-	2,637,841
10	August	FERC Account 182.3	53	2,637,841	49,771	-	2,588,070
11	September	FERC Account 182.3	52	2,588,070	49,771	-	2,538,300
12	October	FERC Account 182.3	51	2,538,300	49,771	-	2,488,529
13	November	FERC Account 182.3	50	2,488,529	49,771	-	2,438,759
14	December 2020	p232 (and Notes)	49	2,438,759	49,771	-	2,388,988
15	**Ending Balance 13-Month Average**	(sum lines 2-14) /13			$597,247		2,687,612
					Attachment H-28A, page 3, line 11		Attachment H-28A, page 2, Line 27

For the 12 months ended 12/31/2020

Regulatory Asset - Start-up Costs

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
1	**Monthly Balance**	Source	Months Remaining In Amortization Period	BegInning Balance	Amortization Expense (Company Records)	Additions (Deductions)	Ending Balance
2	December 2019	p232 (and Notes)	13				-
3	January	FERC Account 182.3	12	-	-	-	-
4	February	FERC Account 182.3	11	-	-	-	-
5	March	FERC Account 182.3	10	-	-	-	-
6	April	FERC Account 182.3	9	-	-	-	-
7	May	FERC Account 182.3	8	-	-	-	-
8	June	FERC Account 182.3	7	-	-	-	-
9	July	FERC Account 182.3	6	-	-	-	-
10	August	FERC Account 182.3	5	-	-	-	-
11	September	FERC Account 182.3	4	-	-	-	-
12	October	FERC Account 182.3	3	-	-	-	-
13	November	FERC Account 182.3	2	-	-	-	-
14	December 2020	p232 (and Notes)	1	-	-	-	-
15	**Ending Balance 13-Month Average**	(sum lines 2-14) /13			$0.00		-
					Attachment H-28A, page 3, line 11		Attachment H-28A, page 2, Line 27

Abandoned Plant

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
1	**Monthly Balance**	Source	Months Remaining In Amortization Period	BegInning Balance	Amortization Expense (p114.10.c)	Additions (Deductions)	Ending Balance
2	December 2019	p111.71.d (and Notes)	13				-
3	January	FERC Account 182.2	12	-	-	-	-
4	February	FERC Account 182.2	11	-	-	-	-
5	March	FERC Account 182.2	10	-	-	-	-
6	April	FERC Account 182.2	9	-	-	-	-
7	May	FERC Account 182.2	8	-	-	-	-
8	June	FERC Account 182.2	7	-	-	-	-
9	July	FERC Account 182.2	6	-	-	-	-
10	August	FERC Account 182.2	5	-	-	-	-
11	September	FERC Account 182.2	4	-	-	-	-
12	October	FERC Account 182.2	3	-	-	-	-
13	November	FERC Account 182.2	2	-	-	-	-
14	December 2020	p111.71.c (and Notes) Detail on p230b	1	-	-	-	-
15	**Ending Balance 13-Month Average**	(sum lines 2-14) /13			$0.00		$0.00
					Attachment H-28A, page 3, Line 19		Attachment H-28A, page 2, Line 28

Note:

Recovery of abandoned plant is limited to any abandoned plant recovery authorized by FERC and will be zero until the Commission accepts or approves recovery of the cost of abandoned plant

			CWIP
			[A]
			216.b
1	December	2019	
2	January	2020	
3	February	2020	
4	March	2020	
5	April	2020	
6	May	2020	
7	June	2020	
8	July	2020	
9	August	2020	
10	September	2020	
11	October	2020	
12	November	2020	
13	December	2020	
14	13-month Average		-

Notes:
[A] Includes only CWIP authorized by the Commission for inclusion in rate base.

Federal Income Tax Rate

Nominal Federal Income Tax Rat (entered on Attachment H-28A, page 5 of 5, Note K)	21.00%

State Income Tax Rate

	Pennsylvania	Combined Rate (entered on Attachment H-28A, page 5 of 5, Note K)
Nominal State Income Tax Rate	9.99%	
Times Apportionment Percentage	100.00%	
Combined State Income Tax Rat	9.990%	9.990%

For the 12 months ended 12/31/2020

Operation and Maintenance Expenses

Line No. [a]	Account Reference	Description	Account Balance [b]
82		***Operation***	
83	560	Operation Supervision and Engineering	$287,841
84			
85	561.1	Load Dispatch-Reliability	$1,061,431
86	561.2	Load Dispatch-Monitor and Operate Transmission System	$809,255
87	561.3	Load-Dispatch-Transmission Service and Scheduling	
88	561.4	Scheduling, System Control and Dispatch Services	$228,660
89	561.5	Reliability, Planning and Standards Development	$193,003
90	561.6	Transmission Service Studies	
91	561.7	Generation Interconnection Studies	
92	561.8	Reliability, Planning and Standards Development Services	
93	562	Station Expenses	$733,346
94	563	Overhead Lines Expense	$14,711
95	564	Underground Lines Expense	
96	565	Transmission of Electricity by Others	
97	566	Miscellaneous Transmission Expense	$6,973,026
98	567	Rents	$7,054,468
99		TOTAL Operation (Enter Total of Lines 83 thru 98)	$17,355,742
100		***Maintenance***	
101	568	Maintenance Supervision and Engineering	$3,748,423
102	569	Maintenance of Structures	
103	569.1	Maintenance of Computer Hardware	$1,612
104	569.2	Maintenance of Computer Software	$28,642
105	569.3	Maintenance of Communication Equipment	
106	569.4	Maintenance of Miscellaneous Regional Transmission Plant	
107	570	Maintenance of Station Equipment	$5,755,494
108	571	Maintenance of Overhead Lines	$51,508,732
109	572	Maintenance of Underground Lines	
110	573	Maintenance of Miscellaneous Transmission Plant	$204,661
111		TOTAL Maintenance (Total of lines 101 thru 110)	$61,247,566
112		**TOTAL Transmission Expenses (Total of lines 99 and 111) [c]**	**$78,603,308**

Notes:
[a] Line No. as would be reported in FERC Form 1, page 321
[b] December balances as would be reported in FERC Form 1
[c] Ties to Attachment H-28A, page 3, line 1, column 3
Above expenses do not include amounts for Met-Ed's 34.5 kV transmission lines

For the 12 months ended 12/31/2020

Administrative and General (A&G) Expenses

Line No. [d]	Account Reference	Description	Account Balance [e]
180		***Operation***	
181	920	Administrative and General Salaries	
182	921	Office Supplies and Expenses	$273,500
183	Less 922	Administrative Expenses Transferred - Credit	
184	923	Outside Services Employed	$3,012,108
185	924	Property Insurance	$100,173
186	925	Injuries and Damages	$692,155
187	926	Employee Pensions and Benefits	-$6,463,934
188	927	Franchise Requirements	
189	928	Regulatory Commission Expense	
190	Less 929	(Less) Duplicate Charges-Cr.	
191	930.1	General Advertising Expenses	$243,238
192	930.2	Miscellaneous General Expenses	$32,000
193	931	Rents	
194		**Total Operation (Enter Total of lines 181 thru 193)**	-$2,110,759
195		***Maintenance***	
196	935	Maintenance of General Plant	$906,779
197		**TOTAL A&G Expenses (Total of lines 194 and 196) [f]**	**-$1,203,979**

Notes:

[d] Line No. as would be reported in FERC Form 1, page 323

[e] December balances as would be reported in FERC Form 1

[f] Ties to Attachment H-28A, page 3, line 5, column 3

Above expenses do not include amounts for Met-Ed's 34.5 kV transmission lines

Revenue Credit Worksheet
(See Footnote T on Attachment H-28A, page 5)

				December 31, 2019	
1	Account 451 -- Miscellaneous Service Revenues		FERC Form 1 , page 300 and footnote data	Amount	Note S, page 5
1a				$ -	
1z		Account 451 Total		$0	
2	Account 454 -- Rent from Electric Property		FERC Form 1, pages 300 and 429		Note R, page 5
2a		Transmission Charge - TMI Unit 1		$ 1,998,563	
2b		Transmission Investment - Power Pool Agreement		$ 1,762,525	
2z		Account 454 Total		$3,761,088	
3	Account 456 -- Other Electric Revenues		FERC Form 1, page 330 and footnote data		Note V, page 5
3a		Point-to-point Revenues		$ 644,157	
3b		Facility Maintenance Charges		$ 266,000	
3z		Account 456 Total		$910,157	

Attachment 12

AEP Formula Rate for January 1, 2020 to December 31, 2020

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, 2020
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, 2020 through December 31, 2020. 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, 2020 from $31,173.04 per MW per year to $41,579.82 per MW per year with the AEP annual revenue requirement increasing from $708,843,770 to $935,533,420.

The AEP Transmission Companies' Schedule 1A rate will be $.0371 per MWh.

An annual revenue requirement of $141,408,818 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 $(192,339)
2. b1465.2 (Rockport Jefferson-MVAR Bank) $1,821,345
3. b2048 (Tanners Creek 345/138 kV transformer) $700,107
4. b1818 (Expand the Allen station) $8,156,593
5. b1819 (Rebuild Robinson Park) $12,575,610
6. b1659 (Sorenson Add 765/345 kV transformer) $7,952,328
7. b1659.13 (Sorenson Exp. Work 765kV) $6,429,876
8. b1659.14 (Sorenson 14miles 765 line) $4,361,585
9. b1465.1 (Add a 3rd 2250 MVA 765/345kV transformer Sullivan) $4,271,272
10. b1465.5 (Sullivan Inst Baker 765kV tsfr) $2,123,520
11. b0570 (Lima-Sterling) $1,634,748
12. b1231 (Wapakoneta-West Moulton) $531,801
13. b1034.1 (South Canton-Wagenhals-Wayview 138 kV) $1,342,727
14. b1034.8 (South Canton Wagenhals Station) $694,109
15. b1864.2 (West Bellaire-Brues 138 kV Circuit) $172,818
16. b1870 (Ohio Central Transformer) $1,104,600
17. b1032.2 (Two 138kV outlets to Delano/Camp Sherman) $308,399

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, 2020
Docket No ER17-405

18. b1034.2 (Loop existing South Canton-Wayview 138kV) $1,050,659
19. b1034.3 (345/138kV 450 MVA transformer Canton Central) $2,228,348
20. b1970 (Reconductor Kammer-West Bellaire) $(2,260,708)
21. b2018 (Loop Conesville-Bixby 345 kV) $2,215,998
22. b2021 (OHTCo - Add 345/138kV trans. Sporn, Kanawha & Muskingum River stations) $3,482,259
23. b2032 (Rebuild 138kV Elliott Tap Poston line) $621,279
24. b1032.1 (Construct new 345/138kV station Marquis-Bixby) $4,463,056
25. b1032.4 (Install 138/69kV transformer Ross Highland) $1,040,064
26. b1666 (Build 8 breaker 138kV station Fostoria-East Lima) $5,203,476
27. b1957 (Terminate Transformer #2 SW Lima) $1,243,660
28. b2019 (Establish Burger 345/138kV station) $8,563,738
29. b2017 (OHTCo Rebuild Sporn-Waterford-Muskingum River) $8,750,217
30. b1818 (Allen Station Expansion) $500,518
31. b2833 (Reconductor Maddox Creed-East Lima 345kV circuit) $269,768
32. b1661 (765kV circuit breaker Wyoming station) $(2,562)
33. b1864.1 (Add 2 345/138kV transformers at Kammer) $10,025,778
34. b2021 (WVTCo - Add 345/138kV trans. Sporn, Kanawha & Muskingum River stations) $2,322,999
35. b1948 (New 765/345 interconnection Sporn) $6,787,360
36. b1962 (Add four 765kV breakers Kammer) $2,632,404
37. b2017 (WVTCo Rebuild Sporn-Waterford-Muskingum River) $175,747
38. b2020 (Rebuild Amos-Kanawha River 138 kV corridor) $18,487,717
39. b2022 (Tristate-Kyger Creek 345kV line at Sporn) $521,854
40. b1875 (138 kV Bradley to McClung upgrades) $232,326
41. b2230 (Replace 3 765kV reactors Amos-Hanging Rock) $1,542,044
42. b2423 (Install 300 MVAR shunt reactor Wyoming 765kV station) $2,550,006
43. b1495 (Add 765/345 kV transf. Baker Station) $4,771,714

Projected Formula Rate for AEP East subsidiaries in PJM

To be Effective January 1, 2020 through December 31, 2020
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, 2020 through December 31, 2020. 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, 2020 from $34,750.39 per MW per year to $38,726.59 per MW per year with the AEP annual revenue requirement increasing from $790,189,172 to $871,336,638.

The AEP Schedule 1A rate will be $.0302 per MWh.

An annual revenue requirement of $33,003,121 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) $766,995
2. b0318 (Amos 765/138 kV Transformer) $1,340,039
3. b0504 (Hanging Rock) $757,221
4. b0570 (East Side Lima) $141,524
5. b1034.1 (Torrey-West Canton) $869,293
6. b1034.6 (138kV circuit South Canton Station) $318,865
7. b1231 (West Moulton Station) $972,185
8. b1465.2 (Rockport Jefferson 300 MVAR bank) $59,359
9. b1465.3 (Rockport Jefferson 765 kV line) $2,215,823
10. b1712.2 (Altavista-Leesville 138kV line) $263,583
11. b1864.1 (OPCo Kammer 345/138 kV transformers) $1,914,182
12. b1864.2 (West Bellaire-Brues 138 kV circuit) of $110,426
13. b2020 (Rebuild Amos-Kanawha River) $2,880,682
14. b2021 (APCo Kanawha River Gen Retirement Upgrades) $265,319
15. b2017 (APCo Rebuild Sporn-Waterford Muskingum River 345kV line) $1,674,715
16. b1659.14 (Ft. Wayne Relocate) $256,415
17. b2048 (Tanners Creek-Transformer Replacement) $83,806
18. b1818 (Expand the Allen Station) $1,048,661
19. b1819 (Rebuild Robinson Park 138kV line corridor) $433,455
20. b1465.4 (Switching imp at Sullivan Jefferson 765kV station) $(85,413)
21. b2021 (OPCo 345/138kV Transformer) $613,989
22. b2032 (Rebuild 138kV Elliott Tap-Poston) $17,688
23. b1034.2 (Loop South Canton-Wayview) $543,050

Projected Formula Rate for AEP East subsidiaries in PJM

To be Effective January 1, 2020 through December 31, 2020
Docket No ER17-405

24. b1034.7 (Replace circuit breakers Torrey/Wagenhals) $737,297
25. b1970 (Reconductor Kammer-West Bellaire) $(152,364)
26. b2018 (Loop Conesville-Bixby 345kV) $1,123,373
27. b1032.4 (Loop the existing South Canton-Wayview 138kV circuit) $191,706
28. b1666 (Build an 8 breaker 138kV station Fosteria-East Lima) $488,118
29. b1957 (Terminate transformer #2 SW Lima) $381,631
30. b1962 (Add four 765kV breakers Kammer) $212,611
31. b2019 (Burger 345/138kV Station) $1,093,456
32. b2017 (OPCo Reconductor Sporn-Waterford-Muskingum River) $939,763
33. b1660 (Install 765/500 kV transformer Cloverdale) $(1,176,607)
34. b1660.1 (Cloverdale Establish 500 kV station) $2,992,258
35. b1663.2 (Jacksons-Ferry 765kV breakers) $612,138
36. b1875 (138 kV Bradley to McClung upgrades) $118,728
37. b1797.1 (Reconductor Cloverdale-Lexington 500 kV line) $5,797,458
38. b1712.1 (Altavista-Leesville 138kV line) $28,912
39. b1032.2 (Two 138kV outlets to Delano&Camp) $198,016
40. b1818 (Expand Allen w/345/138kV xfmr) $39,035
41. b2687.1 (Install a 450 MVAR SVC Jacksons Ferry 765kV Substation) $(756,038)
42. b2687.2 (Reactor Replacement at Broadford) $1,074,837
43. b1870 (Replace Ohio Central Tfmr) $2,833
44. b1465.5 (Switching Imp at Sullivan Jefferson 765kV stations) $153,354
45. b2831.1 (Upgrade Tanners Creek Miami Fort 345kV circuit) $138,048
46. b2833 (Reconductor Maddox Creek East Lima 345kV circuit) $1,123,919
47. b2230 (Amos Station retire 3 765kV reactors Amos-Hanging Rock) $178,779

Attachment 13

PJM Complince Filing for EL05-121

PJM Interconnection, L.L.C.
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July 30, 2018

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

Re: PJM Interconnection, L.L.C., Docket No. EL05-121-009 and ER18-2102-001
eTariff Compliance Filing for Schedule 12 and Schedule 12-Appendices

Dear Secretary Bose:

On June 15, 2016, the Settling Parties[1] filed Settlement Agreement and Offer of Settlement ("Settlement")[2] in the captioned matter for rates to become effective January 1, 2016. In the Order on Contested Settlement,[3] the Federal Energy Regulatory Commission ("Commission") approved the Settlement and directed PJM Interconnection, L.L.C. ("PJM") to

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[1] The "Settling Parties" are: American Electric Power Service Corporation, on behalf of its operating companies; Baltimore Gas and Electric Company, an Exelon Company; Blue Ridge Power Agency, Inc.; The Dayton Power and Light Company; Delaware Municipal Electric Corporation, Inc.; Duke Energy Business Services, LLC on behalf of Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc.; Duquesne Light Company; East Kentucky Power Cooperative, Inc.; Exelon Corporation as agent for Commonwealth Edison Company and PECO Energy Company; FirstEnergy Utilities On behalf of affiliates American Transmission Systems, Incorporated, The Cleveland Electric Illuminating Company, Jersey Central Power & Light Company, Metropolitan Edison Company, Ohio Edison Company, Monongahela Power Company, Pennsylvania Electric Company, Pennsylvania Power Company, The Potomac Edison Company, Toledo Edison Company, and West Penn Power Company; Illinois Commerce Commission; Indiana Utility Regulatory Commission; Michigan Public Service Commission; Pennsylvania Public Utility Commission; Pepco Holdings, LLC, an Exelon Company, and Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City Electric Company; PJM Interconnection, L.L.C.; PPL Electric Utilities Corporation; Public Service Commission of West Virginia; Public Utilities Commission of Ohio; and UGI Utilities, Inc. Additionally, the following parties have agreed to be listed in the Settlement as "NonOpposing Parties": Consolidated Edison Company of New York, Inc.; Delaware Public Service Commission; Maryland Public Service Commission; New Jersey Board of Public Utilities; Old Dominion Electric Cooperative; PSEG Energy Resources & Trade LLC; Public Power Association of New Jersey; Public Service Electric and Gas Company; Public Service Commission of the District of Columbia; Rockland Electric Company; Virginia Electric and Power Company, DBA Dominion Virginia Power; and the Virginia State Corporation Commission.

[2] *PJM Interconnection, L.L.C.*, Offer of Settlement, Docket No. EL05-121-009 (June 15, 2016) ("Settlement").

[3] *PJM Interconnection, L.L.C.*, 163 FERC ¶ 61,168 (May 31, 2018) ("May 31 Order").

submit the associated Tariff amendments by way of compliance eTariff records consistent with the *pro forma* tariff records included with the Settlement.[4]

Accordingly, in compliance with the May 31 Order, and pursuant to section 205 of the Federal Power Act[5] and Part 35 of the Commission's rules and regulations,[6] PJM submits amendments to the PJM Open Access Transmission Tariff ("Tariff") to add in eTariff format the *pro forma* tariff records to include a new Schedule 12-C, including Appendices A through C, as approved under the Settlement.[7] In addition, consistent with section 2.2(c) of the Settlement, PJM submits amendments to Tariff, Schedule 12-Appendix to amend cost responsibility assignments for Covered Transmission Enhancements as described in detail below. PJM requests that these proposed amendments become effective January 1, 2016, as directed by the Commission in its May 31 Order.

I. DESCRIPTION OF FILING

A. Background

This filing follows years of litigation before the Commission under multiple dockets,[8] two 7th Circuit Remand Orders[9] and an established FERC hearing and settlement judge

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[4] In the May 31 Order, the Commission directed PJM to submit a compliance filing within 30 days of the Order or June 30, 2018. Pursuant to a motion for extension of time filed by PJM, the Commission extended the date to comply an additional 30 days to July 30, 2018. *See PJM Interconnection, L.L.C.*, Notice Granting Request for Extension of Time, Docket No. EL05-121-009 (June 13, 2018).

[5] 16 U.S.C. § 824d.

[6] 18 C.F.R. Part 35 (2018).

[7] Due to e-Tariff restrictions, the proposed revisions to the PJM Tariff for Schedule 12-C Appendix B and Schedule 12-C Appendix C will be filed under separate cover using the same transmittal letter with the specified attachments corresponding to each filing because the version effective January 1, 2018 could not be submitted in the same filing in which the tariff record was initial created.

[8] May 31 Order, PP 3 - 7.

[9] *See Illinois Commerce Comm'n, et al. v. FERC*, 756 F.3d 556 (7th Cir. 2014); *see also Illinois Commerce Comm'n, et al. v. FERC*, 576 F.3d 470 (7th Cir. 2009), *reh'g and reh'g en banc denied* (Oct. 20, 2009).

proceeding[10] to determine the appropriate cost allocation for new transmission facilities that operate at or above 500 kV ("Regional Facilities")[11] and Necessary Lower Voltage Facilities[12] that PJM planned and approved before February 1, 2013, whose costs were allocated in accordance with the 100 percent load-ratio share method established in Opinion No. 494.[13] Following seven settlement conferences convened by settlement judge Steven L. Sterner and attended by interested parties both in person and via teleconference, the Settling Parties submitted the Settlement on June 15, 2016 in Docket No. EL05-121-009 to take effect on the date the Commission approved the Settlement, i.e., May 31, 2018.

B. Description of New Schedule 12-C and Appendices to Implement the Settlement

The May 31 Order approved the *pro forma* tariff records included in the Settlement to add a new Schedule 12-C and three (3) appendices: (i) Appendix A (List of Covered Transmission Enhancements), (ii) Appendix B (Allocations for Canceled Projects) and (iii) Appendix C (Transmission Enhancement Charge (TEC) Adjustments – Monthly). Schedule 12-C sets forth the assignment of cost responsibility for Required Transmission Enhancements[14] listed in Schedule 12-C Appendix A, as of January 1, 2016. Each Required Transmission Enhancement listed in Schedule 12-C Appendix A, is referred to as a "Covered Transmission

[10] *PJM Interconnection, L.L.C.*, 149 FERC ¶ 61,233 (2014).

[11] Prior to 2013, Regional Facilities were defined to mean new transmission enhancements and expansions that will operate at or above 500 kV and are included in the upgrade to the RTEP approved by the PJM Board of Managers ("PJM Board"). PJM Tariff, Schedule 12 § (b)(i) (2010).

[12] Necessary Lower Voltage Facilities are defined as Required Transmission Enhancements included in the Regional Transmission Expansion Plan ("RTEP") that are lower voltage facilities that must be constructed or reinforced to support new Regional Facilities.

[13] *PJM Interconnection, L.L.C.*, Opinion No. 494, 119 FERC ¶ 61,063 (2007), *order on reh'g*, Opinion No. 494-A, 122 FERC ¶61,082 (2008).

[14] "Required Transmission Enhancements" is defined in the Tariff in pertinent part to mean "enhancements and expansions of the transmission system that an [RTEP] developed pursuant to Schedule 6 of the Operating Agreement . . . . " *See* PJM Tariff, OATT Definitions – R-S.

Enhancement." Covered Transmission Enhancements included in this Settlement that were canceled or abandoned before entering service are identified in Schedule 12-C Appendix A as a "Canceled Project."[15] Schedule 12-C contains different methods for recovery of costs incurred for Covered Transmission Enhancements.

1. Description of Proposed Amendments to Schedule 12-Appendix for the Going Forward Period Commencing January 1, 2016

In the May 31 Order, the Commission accepted under Schedule 12-C for the going-forward period (the period commencing January 1, 2016 onward) modifications to the cost allocation methodology for Covered Transmission Enhancements included in Tariff, Schedule 12-Appendix. Therefore, pursuant to the Settlement, section 2.2(c) (Current Recovery Charge), PJM is required to modify Schedule 12-Appendix to assign cost responsibility to Responsible Customers[16] for each Covered Transmission Enhancement listed in Schedule 12-C Appendix A, based on the agreed-upon hybrid methodology in which: (i) 50 percent of the cost responsibility shall be assigned to Responsible Customers using the annual load-ratio share method;[17] and (ii) 50 percent of the cost responsibility shall be assigned to Responsible Customers using: (A) for MAPP and PATH projects identified as Canceled Projects Schedule 12-C Appendix A, the cost assignments are set forth in Schedule 12-C Appendix B;[18]

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[15] The Allocations for those Canceled Projects are detailed in Schedule 12-C Appendix B. In addition, Schedule 12-Appendix contains allocations for Regional Facilities that are not listed in Schedule 12-C Appendix A and not revised in this filing as revenues were not collected for those canceled projects and those baseline upgrades will be removed from Schedule 12-Appendix in a subsequent clean-up filing.

[16] "Responsible Customers" are defined to mean "customers using Point-to-Point Transmission Service and/or Network Integration Transmission Service and Merchant Transmission Facility owners that will be subject to each such Transmission Enhancement Charge. *See* Tariff, Schedule 12, § (b)(viii).

[17] Tariff, Schedule 12 § (b)(i)(A)(1).

[18] The Branchburg to Roseland to Hudson ("BRH") project was not included in Schedule 12-C Appendix B because there were no abandonment costs after January 1, 2016.

or (B) for all other Covered Transmission Enhancements listed in Schedule 12-C Appendix A, the current effective solution-based DFAX method.[19]

In addition, the Tariff sheets reflect additional changes to address: (i) the 2017 and 2018 annual updates provided for under the Tariff for load-ratio share[20] and solution-based DFAX, where applicable;[21] (ii) changes in cost allocations to Responsible Customers in 2017 due to the integration of MAIT,[22] effective February 1, 2017; (iii) the elimination of cost responsibility to Consolidated Edison Company of New York, Inc. ("Con Edison") due to termination of its long-term firm point-to-point transmission service agreements, effective May 1, 2017;[23] and (iv) changes in cost allocations to remaining Responsible Customers in 2018 due to termination of allocations to two Merchant Transmission Facilities, Linden VFT, LLC ("Linden") and Hudson Transmission Partners, LLC ("HTP"), as a result of relinquishment of their Firm Transmission Withdrawal Rights, effective January 1, 2018.[24]

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[19] Tariff, Schedule 12 § (b)(i)(A)(a).

[20] Tariff, Schedule 12 § (b)(i)(A).

[21] Tariff, Schedule 12 § (b)(iii)(H)(2).

[22] *PJM Interconnection, L.L.C.*, Amendments to PJM agreements and tariffs for integration of MAIT, Docket No. ER17-214-000 (Oct. 28, 2016) (this filing affected the Metropolitan Edison Company's and Pennsylvania Electric Company's eTariff records only).

[23] *PJM Interconnection, L.L.C.,* 159 FERC ¶ 62,310 (June 20, 2017).

[24] *PJM Interconnection, L.L.C.,* 162 FERC ¶ 61,197 (Mar. 5, 2018) (accepting annual updates including elimination of cost allocations to Linden and HTP, effective January 1, 2018); *see also PJM Interconnection, L.L.C.*, Compliance Filing, Docket No. ER18-680-000 (Jan. 19, 2018) (filing in compliance with the December 15, 2017 orders issued in Docket Nos. EL17-84-000 and EL17-90-000 to eliminate cost responsibility to Linden and HTP as a result of relinquishing their Firm Transmission Withdrawal Rights effective January 1, 2018). Based on requests for rehearing granted by the Commission in Docket Nos. ER18-579-000 and the outstanding issues in Docket No. ER18-680, the Commission issued an order on July 19, 2018 setting for settlement proceedings all Commission dockets specific to eliminating cost allocations to Hudson and Linden effective January 1, 2018 as a result of their relinquishment of their Firm Transmission Withdrawal Rights. *See Linden VFT, LLC v. PJM Interconnection, L.L.C.*, 164 FERC ¶ 61,034 (July 19, 2018).

2. Description of Covered Transmission Enhancement Charge Adjustments for the Historical Period Prior to January 1, 2016

For the historical period (the period prior to January 1, 2016) during which the costs of the Covered Transmission Enhancements were recovered using the 100 percent load-ratio share method approved in Opinion No. 494,[25] Schedule 12-C Appendix C provides for Covered Transmission Enhancement Charge Adjustments to the billing for Covered Transmission Enhancements through a schedule of credits or payments from Responsible Customers based on a negotiated schedule. Specifically, effective as of January 1, 2016 and continuing through December 31, 2025, in addition to the Current Recovery Charge detailed in B(1) above, PJM shall collect from or credit to Responsible Customers the Transmission Enhancement Charge Adjustments set forth in Appendix 12-C for each Zone and each Merchant Transmission Facility.

C. Adjustments to Transmission Enhancement Charge Adjustments

The Settlement provides that the Transmission Enhancement Charge Adjustments set forth in Schedule 12-C Appendix C may be adjusted only under two circumstances as detailed in section 2.2(e) of the Settlement. Consistent with that provision, PJM proposes to make the following adjustments to the Transmission Enhancement Charge Adjustments.

1. Consistent with Section 2.2(e)(2) of the Settlement, PJM has Adjusted the Transmission Enhancement Charge Adjustments in Schedule 12-C Appendix C as a Result of Linden's and HTP's Relinquishment of their Firm Transmission Withdrawal Rights, Effective January 1, 2018.

Section 2.2(e)(2) of the Settlement provides, *inter alia*, that if a Merchant Transmission Facility is no longer subject to Transmission Enhancements Charges under the Tariff during the period in which Transmission Enhancement Charge Adjustments are collected, the Responsible Customer shall not be subject to such Transmission Enhancement Charges during the portion of

[25] *See supra*, at 3, n. 12.

that period and payment from or credits to such Responsible Customer(s) shall cease. Section 2.2(e)(2) of the Settlement further provides that PJM shall adjust the Transmission Enhancement Charge Adjustments payable by and credited to other Responsible Customers on a *pro rata* basis so that if, for example, the Responsible Customers were required to make payments, then the payment obligation associated with such Responsible Customers will be allocated *pro rata* among all remaining Zones and Merchant Transmission Facilities in which Responsible Customers remain subject to Transmission Enhancement Charges and have payment obligations under this Schedule 12-C Appendix C.

Merchant Transmission Facilities, Linden (identified as East Coast Power) and HTP, were assigned cost responsibility for Transmission Enhancement Charge Adjustments under Schedule 12-C Appendix C. Given that Linden and HTP relinquished their Firm Transmission Withdrawal Rights, effective January 1, 2018, PJM adjusted, on a *pro rata* basis, allocations, commencing January 1, 2018, to all remaining Zones and Merchant Transmission having payment obligations under Schedule 12-C Appendix C.

2. No Adjustments to Transmission Enhancement Charge Adjustments are Required at this time for the Canceled PATH Project.

PJM has determined that no adjustment to the Transmission Enhancement Charge Adjustments is required under section 2.2(e)(1) of the Settlement, as implemented by section 4(c)(i)(1) of Schedule 12-C. That provision provides that if the Commission issues a final decision in Docket No. ER12-2708-003 "that is no longer subject to judicial review," relating to the recovery of costs by the owners of the canceled Potomac Appalachian Transmission Highline ("PATH") project, PJM must make the necessary adjustments to the Transmission Enhancement Charge Adjustments to ensure that the amounts recovered by Transmission Enhancement Charge

Adjustments with respect to that project "reflect only the amounts the Commission authorizes the owner(s) to recover prior to January 1, 2016." On January 19, 2017, the Commission issued Opinion No. 554 in Docket No. ER12-2708-003, addressing the PATH project owners' cost recovery.[26] Opinion No. 554 is pending on rehearing. Moreover, under Opinion No. 554, the Commission did not require the owners of the PATH project to adjust their collections for the period prior to January 1, 2016, but instead directed them to issue refunds with interest associated with the decision in Opinion No. 554 as prospective credits against charges recovered after the decision pursuant to the annual update process described in the project owners' formula rate protocols.[27] The PATH project owners began providing those credits through the annual update mechanism in 2018.[28] Because Opinion No. 554 is not final and because the issuance of refunds as credits against future charges, in accordance that decision by the owners of the PATH project ensures that the Transmission Enhancement Adjustments reflect only the amounts the Commission authorizes them to recover prior to January 1, 2016, no adjustments are required under the Settlement, section 2.2(e)(1).

II. DOCUMENTS ENCLOSED

1. This transmittal letter;

2. Attachment A – Redlines of Schedule 12-C and Appendices and Schedule 12-Appendix, effective January 1, 2016 and forward; and

3. Attachment B – Clean Versions of Schedule 12-C and Appendices and Schedule 12-Appendix, effective January 1, 2016 and forward.

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[26] *Potomac-Appalachian Transmission Highline, LLC*, Opinion No. 554, 158 FERC ¶ 61,050 (2017).

[27] *Id.* at PP 85-86.

[28] *See* Compliance Filing, Docket Nos. ER12-2708-005, *et al.* (filed March 20, 2017).

III. COMMUNICATIONS

The following individuals are designated for receipt of any communications regarding this filing:

Craig Glazer
Vice President – Federal Government Policy
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IV. SERVICE

PJM has served a copy of this filing on all PJM Members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically. In accordance with the Commission's regulations,[29] PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: http://www.pjm.com/documents/ferc-manuals/ferc-filings.aspx with a specific link to the newly-filed document, and will send an e-mail on the same date as this filing to all PJM Members and all state utility regulatory commissions in the PJM Region[30] alerting them that this filing has been made by PJM and is available by following such link. If the document is not immediately available by using the referenced link, the document will be available through the referenced link within 24 hours of the filing. Also, a copy of this filing will be available on the FERC's eLibrary website located at the

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[29] *See* 18C.F.R §§ 35.2(e) and 385.2010(f)(3) (2018).

[30] PJM already maintains, updates and regularly uses e-mail lists for all PJM Members and affected state commissions.

following link: http://www.ferc.gov/docs-filing/elibrary.asp in accordance with the Commission's regulations and Order No. 714.

Respectfully submitted,

By: ______________________

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On behalf of PJM Interconnection, L.L.C.

Dated: July 30, 2018

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day caused to be served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Audubon, PA, this 30th day of July, 2018.

By: ______________________

Pauline Foley
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On behalf of PJM Interconnection, L.L.C.

Attachment A

Revisions to Schedule 12-C Appendices B and C
of the PJM Open Access Transmission Tariff

(Marked / Redline Format)

SCHEDULE 12-C APPENDIX B

Allocations for Canceled Projects

	PATH	MAPP
AEC	~~4.99~~5.01%	3.94%
AEP	~~4.37~~4.39%	0.00%
APS	~~9.22~~9.26%	0.33%
ATSI	0.00%	0.00%
BGE	~~4.41~~4.43%	~~34.52~~34.54%
ComEd	0.00%	0.00%
Coned	0.00%	0.00%
Dayton	0.00%	0.00%
DEOK	0.00%	0.00%
DL	0.02%	0.00%
DPL	~~6.88~~6.91%	~~14.68~~14.69%
Dominion	~~10.77~~10.82%	0.30%
EKPC	0.00%	0.00%
HTP	0.00%	0.00%
JCPL	~~11.59~~11.64%	9.43%
ME	~~2.93~~2.94%	2.16%
Neptune	~~1.11~~1.12%	0.90%
PECO	~~14.45~~14.51%	~~10.51~~10.52%
PENELEC	0.00%	0.00%
PEPCO	~~6.08~~6.11%	2.44%
PPL	~~6.36~~6.39%	5.50%
PSEG	~~15.79~~15.86%	~~14.37~~14.71%
RE	0.59%	0.54%
UGI	0.00%	0.00%
ECP	~~0.44~~0.00%	~~0.38~~0.00%
TOTAL	100.00%	100.00%

Note: The above percentages apply to 50% of the responsibility to pay the Transmission Enhancement Charges for the identified Canceled Projects in accordance with section 3.b.ii.(2) of Schedule 12-C.

SCHEDULE 12-C APPENDIX C

TRANSMISSION ENHANCEMENT CHARGE ADJUSTMENTS

(Effective January 1, ~~2016~~2018)

Zone or MTF	TEC Adjustment Years 1-4 Without PATH	TEC Adjustment Years 1-4 PATH Only	**Total TEC Adjustment Years 1 through 4**	TEC Adjustment Years 5-10 Without PATH	TEC Adjustment Years 5-10 PATH Only	**Total TEC Adjustment Years 5 through 10**
AE	~~-$24,860.09~~ -$25,237.09	~~$47,899.66~~ $48,626.05	~~$23,039.57~~ $23,388.96	~~-$10,418.79~~ -$10,576.79	~~$20,074.61~~ $20,379.04	~~$9,655.82~~ $9,802.25
AEP	-$2,444,812.18	-$174,489.11	-$2,619,301.30	-$1,024,614.00	-$73,127.90	-$1,097,741.90
APS	~~$954,922.88~~ $969,404.16	~~$52,440.01~~ $53,235.26	~~$1,007,362.89~~ $1,022,639.42	~~$400,205.53~~ $406,274.59	~~$21,977.46~~ $22,310.75	~~$422,182.99~~ $428,585.34
ATSI	-$1,093,902.38	-$72,438.56	-$1,166,340.94	-$458,451.45	-$30,358.80	-$488,810.25
BGE	~~$1,281,971.91~~ $1,301,412.84	~~-$2,640.98~~ -$2,681.03	~~$1,279,330.93~~ $1,298,731.81	~~$537,270.87~~ $545,418.51	~~-$1,106.83~~ -$1,123.61	~~$536,164.04~~ $544,294.90
ComEd	-$2,608,103.66	-$221,693.57	-$2,829,797.23	-$1,093,049.01	-$92,911.16	-$1,185,960.17
ConEd	-$70,904.37	-$4,688.81	-$75,593.18	-$29,715.83	-$1,965.07	-$31,680.89
Dayton	-$375,384.08	-$34,767.87	-$410,151.95	-$157,322.42	-$14,571.12	-$171,893.54
Duke OH/KY	-$302,715.79	-$20,247.63	-$322,963.42	-$126,867.35	-$8,485.73	-$135,353.07
Duquesne	-$318,588.72	-$28,822.02	-$347,410.74	-$133,519.65	-$12,079.23	-$145,598.88
Delmarva DE	-$157,754.97	$37,622.55	-$120,132.43	-$66,114.67	$15,767.50	-$50,347.17
Delmarva MD	-$97,639.85	$22,956.13	-$74,683.72	-$40,920.59	$9,620.85	-$31,299.74
Delmarva VA	-$13,369.07	$3,188.35	-$10,180.71	-$5,602.94	$1,336.23	-$4,266.71
Dominion	~~$2,548,417.01~~ $2,587,063.40	~~-$29,708.12~~ -$30,158.64	~~$2,518,708.88~~ $2,556,904.76	~~$1,068,034.50~~ $1,084,231.09	~~-$12,450.59~~ -$12,639.40	~~$1,055,583.90~~ $1,071,591.69
EKPC	-$88,156.35	-$3,920.00	-$92,076.35	-$36,946.08	-$1,642.86	-$38,588.94
HTP	~~$67,459.71~~ $0.00	~~-$392.30~~ $0.00	~~$67,067.41~~ $0.00	~~$28,272.18~~ $0.00	~~-$164.41~~ $0.00	~~$28,107.76~~ $0.00
JCPL	~~$684,836.11~~ $695,221.56	~~$113,570.16~~ $115,292.43	~~$798,406.27~~ $810,513.99	~~$287,012.91~~ $291,365.43	~~$47,596.94~~ $48,318.74	~~$334,609.85~~ $339,684.16
MedEd	-$290,626.73	$14,498.19	-$276,128.54	-$121,800.86	$6,076.15	-$115,724.70
Neptune	~~$63,553.63~~ $64,517.41	~~$10,067.97~~ $10,220.65	~~$73,621.60~~ $74,738.06	~~$26,635.15~~ $27,039.07	~~$4,219.46~~ $4,283.45	~~$30,854.61~~ $31,322.51
PECO	-$766,990.16	$132,927.71	-$634,062.44	-$321,443.45	$55,709.64	-$265,733.81
Penelec	-$224,425.28	-$30,009.25	-$254,434.53	-$94,056.01	-$12,576.79	-$106,632.80
PEPCO DC	~~$787,856.55~~ $799,804.28	~~$9,072.91~~ $9,210.50	~~$796,929.46~~ $809,014.78	~~$330,188.49~~ $335,195.76	~~$3,802.43~~ $3,860.10	~~$333,990.92~~ $339,055.85
PEPCO MD	~~$1,145,526.02~~ $1,162,897.77	~~$13,215.00~~ $13,415.41	~~$1,158,741.03~~ $1,176,313.18	~~$480,086.78~~ $487,367.23	~~$5,538.37~~ $5,622.36	~~$485,625.15~~ $492,989.59
PEPCO SMECO	~~$273,479.45~~ $277,626.73	~~$3,154.91~~ $3,202.75	~~$276,634.36~~ $280,829.48	~~$114,614.48~~ $116,352.59	~~$1,322.21~~ $1,342.27	~~$115,936.69~~ $117,694.86
PPL EU	-$786,877.08	$20,174.85	-$766,702.23	-$329,778.00	$8,455.23	-$321,322.78
PPL UGI	-$40.31	$0.00	-$40.31	-$16.89	$0.00	-$16.89
PSEG	~~$1,713,725.35~~ $1,739,713.76	~~$135,477.48~~ $137,531.98	~~$1,849,202.83~~ $1,877,245.74	~~$718,217.54~~ $729,109.21	~~$56,778.24~~ $57,639.27	~~$774,995.77~~ $786,748.48
Rockland	~~$63,940.65~~ $64,910.31	~~$4,698.27~~ $4,769.52	~~$68,638.92~~ $69,679.82	~~$26,797.35~~ $27,203.73	~~$1,969.03~~ $1,998.89	~~$28,766.38~~ $29,202.62
East Coast Power	~~$79,461.78~~ $0.00	~~$2,854.08~~ $0.00	~~$82,315.86~~ $0.00	~~$33,302.21~~ $0.00	~~$1,196.14~~ $0.00	~~$34,498.35~~ $0.00

Attachment B

Revisions to Schedule 12-C Appendices B and C
of the PJM Open Access Transmission Tariff

(Clean Format)

SCHEDULE 12-C APPENDIX B

Allocations for Canceled Projects

	PATH	*MAPP*
AEC	*5.01%*	*3.94%*
AEP	4.39%	*0.00%*
APS	*9.26%*	*0.33%*
ATSI	*0.00%*	*0.00%*
BGE	4.43%	34.54%
ComEd	*0.00%*	*0.00%*
Coned	*0.00%*	*0.00%*
Dayton	*0.00%*	*0.00%*
DEOK	*0.00%*	*0.00%*
DL	*0.02%*	*0.00%*
DPL	6.91%	14.69%
Dominion	10.82%	*0.30%*
EKPC	*0.00%*	*0.00%*
HTP	*0.00%*	*0.00%*
JCPL	11.64%	*9.43%*
ME	2.94%	*2.16%*
Neptune	1.12%	*0.90%*
PECO	14.51%	10.52%
PENELEC	*0.00%*	*0.00%*
PEPCO	6.11%	*2.44%*
PPL	6.39%	*5.50%*
PSEG	15.86%	14.71%
RE	*0.59%*	*0.54%*
UGI	*0.00%*	*0.00%*
ECP	0.00%	0.00%
TOTAL	*100.00%*	*100.00%*

Note: The above percentages apply to 50% of the responsibility to pay the Transmission Enhancement Charges for the identified Canceled Projects in accordance with section 3.b.ii.(2) of Schedule 12-C.

SCHEDULE 12-C APPENDIX C

TRANSMISSION ENHANCEMENT CHARGE ADJUSTMENTS

(Effective January 1, 2018)

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AE	-$25,237.09	$48,626.05	$23,388.96	-$10,576.79	$20,379.04	$9,802.25
AEP	-$2,444,812.18	-$174,489.11	-$2,619,301.30	-$1,024,614.00	-$73,127.90	-$1,097,741.90
APS	$969,404.16	$53,235.26	$1,022,639.42	$406,274.59	$22,310.75	$428,585.34
ATSI	-$1,093,902.38	-$72,438.56	-$1,166,340.94	-$458,451.45	-$30,358.80	-$488,810.25
BGE	$1,301,412.84	-$2,681.03	$1,298,731.81	$545,418.51	-$1,123.61	$544,294.90
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ConEd	-$70,904.37	-$4,688.81	-$75,593.18	-$29,715.83	-$1,965.07	-$31,680.89
Dayton	-$375,384.08	-$34,767.87	-$410,151.95	-$157,322.42	-$14,571.12	-$171,893.54
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Delmarva DE	-$157,754.97	$37,622.55	-$120,132.43	-$66,114.67	$15,767.50	-$50,347.17
Delmarva MD	-$97,639.85	$22,956.13	-$74,683.72	-$40,920.59	$9,620.85	-$31,299.74
Delmarva VA	-$13,369.07	$3,188.35	-$10,180.71	-$5,602.94	$1,336.23	-$4,266.71
Dominion	$2,587,063.40	-$30,158.64	$2,556,904.76	$1,084,231.09	-$12,639.40	$1,071,591.69
EKPC	-$88,156.35	-$3,920.00	-$92,076.35	-$36,946.08	-$1,642.86	-$38,588.94
HTP	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
JCPL	$695,221.56	$115,292.43	$810,513.99	$291,365.43	$48,318.74	$339,684.16
MedEd	-$290,626.73	$14,498.19	-$276,128.54	-$121,800.86	$6,076.15	-$115,724.70
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Penelec	-$224,425.28	-$30,009.25	-$254,434.53	-$94,056.01	-$12,576.79	-$106,632.80
PEPCO DC	$799,804.28	$9,210.50	$809,014.78	$335,195.76	$3,860.10	$339,055.85
PEPCO MD	$1,162,897.77	$13,415.41	$1,176,313.18	$487,367.23	$5,622.36	$492,989.59
PEPCO SMECO	$277,626.73	$3,202.75	$280,829.48	$116,352.59	$1,342.27	$117,694.86
PPL EU	-$786,877.08	$20,174.85	-$766,702.23	-$329,778.00	$8,455.23	-$321,322.78
PPL UGI	-$40.31	$0.00	-$40.31	-$16.89	$0.00	-$16.89
PSEG	$1,739,713.76	$137,531.98	$1,877,245.74	$729,109.21	$57,639.27	$786,748.48
Rockland	$64,910.31	$4,769.52	$69,679.82	$27,203.73	$1,998.89	$29,202.62
East Coast Power	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00