Alexander C. Stern
Associate General Regulatory Counsel

Law Department
PSEG Services Corporation
80 Park Plaza – T5, Newark, New Jersey 07102-4194
973-430-5754 fax: 973-430-5983
email: alexander.stern@pseg.com

PSEG
Services Corporation

VIA ELECTRONIC MAIL & OVERNIGHT MAIL

December 17, 2015

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, 2013
-and-
In the Matter of the Provision of
Basic Generation Service for the Period Beginning June 1, 2014
-and-
In the Matter of the Provision of
Basic Generation Service for the Period Beginning June 1, 2015

Docket Nos. EO03050394, ER12060485, ER13050378, ER14040370
++
Compliance Tariff Filing Reflecting Changes to Schedule 12 Charges in PJM Open Access
Transmission Tariff Docket No. _______________

Irene Kim Asbury, Esquire
Secretary of the Board
Board of Public Utilities
44 South Clinton Ave., 9th Floor
Trenton, New Jersey 08625-0350

Dear Secretary Asbury:

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

("FERC") Docket No. ER08-386-000, Virginia Electric and Power Company ("VEPCo") in Docket No. ER-08-92-000 and by PSE&G in Docket No. ER09-1257-000.

Background

In its Orders dated October 22, 2003 (BPU Docket No. EO03050394) and October 22, 2004 (BPU Docket No. EO04040288), the Board authorized the EDCs to recover FERC-approved changes in firm transmission service-related charges. The Board has also authorized recovery of FERC-approved changes in firm transmission service-related charges in subsequent orders approving the Basic Generation Service ("BGS") supply procurement process and the associated Supplier Master Agreement ("SMA"). In the most recent Board Order (BPU Docket No. ER15070764), the Board once 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, 2015, and specifically reflect changes to BGS rates applicable to Basic Generation Service – Residential Small Commercial Pricing ("BGS-RSCP"), and Commercial and Industrial Energy Pricing ("BGS-CIEP") customers resulting from the PATH, PSE&G, and VEPCo annual formula rate updates filed with FERC on or about September 1, 2015, October 19, 2015, and October 29, 2015, respectively. The specific additional PJM transmission charges related to the PATH, PSE&G, and VEPCo filings are found in Schedule 12 of the PJM OATT. On June 25, 2015, 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 2016, 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, 2016. In support of this request, the EDCs have included pro-forma tariff sheets as noted above. The BGS rates have been modified in accordance with the Board-approved methodology contained in each EDC's Company-Specific Addendum in the above-referenced BGS proceedings and in conformance with each EDC's Board-approved BGS tariff sheets.

The determinants for calculation of the PJM charges are set forth in Schedule 12 of the PJM OATT and on the Formula Rates page of the PJM website. Copies of all formula rate updates are attached, but can also be found on the PJM website at: http://www.pjm.com/markets-and-operations/billing-settlements-and-credit/formula-rates.aspx.

Attachment 1 shows the derivation of the PSE&G Network Integration Transmission Service Charge. The translation of the transmission zone rate impact to the BGS rates of each of the EDCs, assuming implementation on January 1, 2016, 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 2016 period for each of the EDCs. These costs were allocated to the various transmission zones using the cost information from the formula rates for the PATH, PSE&G, and VEPCo projects posted on the PJM website. Attachment 7 provides excerpts of the Schedule 12 OATT indicating responsible share of projects. Attachments 8, 9, and 10 provide the formula rate updates for PATH, PSE&G, and VEPCo, respectively.

The EDCs also request that BGS Suppliers be compensated for the changes to the OATT resulting from the implementation of the PSE&G, PATH, and VEPCo project annual formula updates effective on January 1, 2016. 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 EDC file for and obtain Board approval of an increase in retail rates commensurate with the FERC-implemented rate increase.

We thank the Board for all courtesies extended.

Respectfully submitted,

Alexander C. Stern

Attachments

cc: Jerry May, NJBPU
Alice Bator, NJBPU
Frank Perrotti, NJBPU
Stacy Peterson, NJBPU
Stefanie Brand, Division of Rate Counsel
Service List (via Electronic Mail Server)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
BGS TRANSMISSION ENHANCEMENT CHARGE
BPU Docket Nos. EO03050394, ER12060485, ER13050378, ER14040370

<table>
<tr><th colspan="3">BOARD OF PUBLIC UTILITIES</th></tr>
<tr><td>Jerome May
NJBPU
44 S. Clinton Avenue, 9th Fl.
P.O. Box 350
Trenton, NJ 08625-0350</td><td>Alice Bator
NJBPU
44 S. Clinton Avenue, 9th Fl.
P.O. Box 350
Trenton, NJ 08625-0350</td><td>Stacy Peterson
NJBPU
44 S. Clinton Avenue, 9th Fl.
P.O. Box 350
Trenton, NJ 08625-0350</td></tr>
<tr><td>Irene Kim Asbury, Secretary
NJBPU
44 S. Clinton Avenue, 9th Fl.
P.O. Box 350
Trenton, NJ 08625-0350</td><td>Frank Perrotti
NJBPU
44 S. Clinton Avenue, 9th Fl.
P.O. Box 350
Trenton, NJ 08625-0350</td><td></td></tr>
<tr><th colspan="3">DIVISION OF RATE COUNSEL</th></tr>
<tr><td>Stefanie A. Brand, Esq.
Division of Rate Counsel
140 East Front St., 4th Fl.
Trenton, NJ 08608-2014</td><td>Diane Schulze, Esq.
Division of Rate Counsel
140 East Front St., 4th Fl.
Trenton, NJ 08608-2014</td><td>Ami Morita, Esq.
Division of Rate Counsel
140 East Front St., 4th Fl.
Trenton, NJ 08608-2014</td></tr>
<tr><th colspan="3">DEPARTMENT OF LAW & PUBLIC SAFETY</th></tr>
<tr><td>Caroline Vachier, DAG
Division of Law
124 Halsey Street, 5th Fl.
P.O. Box 45029
Newark, NJ 07101</td><td>Babette Tenzer, DAG
Division of Law
124 Halsey Street, 5th Fl.
P.O. Box 45029
Newark, NJ 07101</td><td>Alex Moreau, DAG
Division of Law
124 Halsey Street, 5th Fl.
P.O. Box 45029
Newark, NJ 07101</td></tr>
<tr><th colspan="3">EDCs</th></tr>
<tr><td>Joseph Janocha
ACE – 63ML38
5100 Harding Highway
Atlantic Regional Office
Mays Landing, NJ 08330</td><td>Greg Marquis
PEPCO Holdings, Inc.
7801 Ninth Street NW
Washington, DC 20068-0001</td><td>Philip Passanante, Esq.
ACE – 89KS
800 King Street, 5th Floor
P.O. Box 231
Wilmington, DE 19899</td></tr>
<tr><td>Sally J. Cheong, Manager
Tariff Activity, Rates, NJ
JCP&L
300 Madison Avenue
Morristown, NJ 07962</td><td>Kevin Connelly
First Energy
300 Madison Avenue
Morristown, NJ 07960</td><td>Gregory Eisenstark, Esq.
Windels Marx Lane &
Mittendorf, LLP
120 Albany Street Plaza
New Brunswick, NJ 08901</td></tr>
<tr><td>John L. Carley, Esq.
Consolidated Edison of NY
Law Dept., Room 1815-S
4 Irving Place
New York, NY 10003</td><td>Margaret Comes, Esq.
Senior Staff Attorney
Consolidated Edison of NY
Law Dept., Room 1815-S
4 Irving Place
New York, NY 10003</td><td>Alexander Stern, Esq.
Assoc. Gen. Reg. Counsel
PSEG Services Corporation
P.O. Box 570
80 Park Plaza, T-5
Newark, NJ 07101</td></tr>
<tr><td>Eugene Meehan
NERA
1255 23rd Street
Suite 600
Washington, DC 20037</td><td>Chantale LaCasse
NERA
1166 Avenue of the Americas,
29th Floor
New York, NY 10036</td><td>Myron Filewicz
Manager - BGS
PSE&G
80 Park Plaza, T-8
P.O. Box 570
Newark, NJ 07101</td></tr>
</table>

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
BGS TRANSMISSION ENHANCEMENT CHARGE
BPU Docket Nos. EO03050394, ER12060485, ER13050378, ER14040370

OTHER		
Steven Gabel Gabel Associates 417 Denison Street Highland Park, NJ 08904	Shawn P. Leyden, Esq. PSEG Services Corporation 80 Park Plaza, T-19 P.O. Box 570 Newark, NJ 07101	Lisa A. Balder NRG Power Marketing Inc. 211 Carnegie Center Contract Administration Princeton, NJ 08540
Frank Cernosek Reliant Energy 1000 Main Street REP 11-235 Houston, TX 77002	Elizabeth Sager VP – Asst. General Counsel J.P. Morgan Chase Bank, N.A. 270 Park Avenue, Floor 41 New York, NY 10017-2014	Commodity Confirmations J.P. Morgan Ventures Energy 1 Chase Manhattan Plaza 14th Floor New York, NY 10005
Manager - Contracts Admin. Sempra Energy Trading Corp. 58 Commerce Road Stamford, CT 06902	Raymond DePillo PSEG ER&T 80 Park Plaza, T-19 P.O. Box 570 Newark, NJ 07101	Sylvia Dooley Consolidated Edison of NY 4 Irving Place Room 1810-S New York, NY 10003
Kate Trischitta – Director of Trading & Asset Optimization Consolidated Edison Energy 701 Westchester Avenue Suite 201 West White Plains, NY 10604	Gary Ferenz Conectiv Energy Supply, Inc. 500 North Wakefield Drive P.O. Box 6066 Newark, DE 19714-6066	Daniel Freeman Contract Services – Power BP Energy Company 501 W Lark Park Blvd WL1-100B Houston, TX 77079
Michael S. Freeman Exelon Generation Company 300 Exelon Way Kennett Square, PA 19348	Marjorie Garbini Conectiv Energy Supply, Inc. 500 North Wakefield Drive P.O. Box 6066 Newark, DE 19714-6066	Arland H. Gifford DTE Energy Trading 414 South Main Street Suite 200 Ann Arbor, MI 48104
Deborah Hart, Vice President Morgan Stanley Capital Group 2000 Westchester Avenue Trading Floor Purchase, NY 10577	Marcia Hissong, Director DTE Energy Trading 414 South Main Street Suite 200 Ann Arbor, MI 48104	Dir – Contracts & Legal Svcs Talen Energy Marketing, LLC 835 Hamilton Street Allentown, PA 18101
Fred Jacobsen NextEra Energy Power Mktg. 700 Universe Boulevard CTR/JB Juno Beach, FL 33408-2683	Gary A. Jeffries, Sr Counsel Dominion Retail, Inc. 1201 Pitt Street Pittsburgh, PA 15221	Shiran Kochavi NRG Energy 211 Carnegie Center Princeton, NJ 08540
Robert Mannella Consolidated Edison Energy 701 Westchester Avenue Suite 201 West White Plains, NY 10604	Randall D. Osteen, Esq. Constellation Energy 111 Market Place, Suite 500 Baltimore, MD 21202	Ken Salamone Sempra Energy Trading Corp. 58 Commerce Road Stamford, CT 06902

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
BGS TRANSMISSION ENHANCEMENT CHARGE
BPU Docket Nos. EO03050394, ER12060485, ER13050378, ER14040370

OTHER		
Steve Sheppard DTE Energy Trading 414 South Main Street Suite 200 Ann Arbor, MI 48104	Edward Zabrocki Morgan Stanley Capital Group 1585 Boardway, 4th Floor Attn: Chief Legal Officer New York, NY 10036	Paul Weiss Edison Mission Marketing & Trading 160 Federal Street, 4th Floor Boston, MA 02110
Matt Webb BP Energy Company 501 West Lark Park Blvd. Houston, TX 77079	Noel H. Trask Exelon Generation Company 300 Exelon Way Kennett Square, PA 19348	Jessica Wang FPL Energy Power Marketing 700 Universe Boulevard Building E, 4th Floor Juno Beach, FL 33408
Robert Fagan Synapse Energy Economics 485 Massachusetts Avenue Suite 2 Cambridge, MA 02139	Ryan Belgram Macquarie Energy LLC 500 Dallas Street, Level 31 Houston, TX 77002	Morgan Tarves TransCanada Power Marketing 110 Turnpike Road, Suite 300 Westborough, MA 01581
Graham Fisher ConocoPhillips 600 N Dairy Ashford, CH1081 Houston, TX 77079	Danielle Fazio Noble Americas Gas & Power Four Stamford Plaza, 7th Fl. Stamford, CT 06902	Jan Nulle Energy America, LLC 12 Greenway Plaza, Suite 250 Houston, TX 77046
Kim M. Durham Citigroup Energy Inc. 2800 Post Oak Boulevard Suite 500 Houston, TX 77056		

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, 2016 through December 31, 2016

Line #	Description		Rate		Source
(1)	Transmission Service Annual Revenue Requirement	$	1,064,228,951.56		Page 326 in Attachment 10 -Line 164
(2)	Total Schedule 12 TEC Included in above	$	(520,436,728.38)		Page 53 in Attachment 10 - Row 6[1]
(3)	PSE&G Customer Share of Schedule 12 TEC	$	247,944,752.83		Page 53 in Attachment 6a - Column (n)
(4)	Total Transmission Costs Borne by PSE&G customers	$	791,736,976.01		=(1) +(2) +(3)
(5)	2016 PSE&G Network Service Peak		9,594.9	MW	Page 326 in Attachment 10 - -Line 165
(6)	2016 Derived Network Integration Transmission Service Rate	$	82,516.44	per MW-year	
	Resulting 2016 BGS Firm Transmission Service Supplier Rate	$	225.45	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 2a
Pro-forma PSE&G Tariff Sheets

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

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

BGS ENERGY CHARGES:

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

Charges per kilowatthour:

	For usage in each of the months of October through May		For usage in each of the months of June through September	
Rate Schedule	Charges	Charges Including SUT	Charges	Charges Including SUT
RS – first 600 kWh	0.112055	0.119899	$0.114461	$0.122473
RS – in excess of 600 kWh	0.112055	0.119899	0.123443	0.132084
RHS – first 600 kWh	0.088283	0.094463	0.085791	0.091796
RHS – in excess of 600 kWh	0.088283	0.094463	0.097802	0.104648
RLM On-Peak	0.175502	0.187787	0.188015	0.201176
RLM Off-Peak	0.056868	0.060849	0.054557	0.058376
WH	0.058283	0.062363	0.057569	0.061599
WHS	0.058754	0.062867	0.058870	0.062991
HS	0.106332	0.113775	0.110991	0.118760
BPL	0.054147	0.057937	0.051661	0.055277
BPL-POF	0.054147	0.057937	0.051661	0.055277
PSAL	0.054147	0.057937	0.051661	0.055277

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

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

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

BGS CAPACITY CHARGES:

Applicable to Rate Schedules GLP and LPL-Sec.

Charges per kilowatt of Generation Obligation:

Charge applicable in the months of June through September	$5.2621
Charge including New Jersey Sales and Use Tax (SUT)	$5.6304
Charge applicable in the months of October through May	$5.2621
Charge including New Jersey Sales and Use Tax (SUT)	$5.6304

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	$ 82,516.44 per MW per year
PJM Seams Elimination Cost Assignment Charges	$ 0.00 per MW per month
PJM Reliability Must Run Charge	$ 0.00 per MW per month
PJM Transmission Enhancements	
Trans-Allegheny Interstate Line Company	$ 107.25 per MW per month
Virginia Electric and Power Company	$ 84.86 per MW per month
Potomac-Appalachian Transmission Highline L.L.C.	$ 15.15 per MW per month
PPL Electric Utilities Corporation	$ 56.28 per MW per month
American Electric Power Service Corporation	$ 10.54 per MW per month
Atlantic City Electric Company.	$ 11.77 per MW per month
Delmarva Power and Light Company	$ 6.75 per MW per month
Potomac Electric Power Company.	$ 11.37 per MW per month

Above rates converted to a charge per kW of Transmission Obligation, applicable in all months	$ 7.1806
Charge including New Jersey Sales and Use Tax (SUT)	$ 7.6832

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

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

(Continued)

BGS TRANSMISSION CHARGES

Charges per kilowatt of Transmission Obligation:

Currently effective Annual Transmission Rate for Network Integration Transmission Service for the Public Service Transmission Zone as derived from the FERC Electric Tariff of the PJM Interconnection, LLC	$ 82,516.44 per MW per year
PJM Seams Elimination Cost Assignment Charges	$ 0.00 per MW per month
PJM Reliability Must Run Charge	$ 0.00 per MW per month
PJM Transmission Enhancements	
Trans-Allegheny Interstate Line Company	$ 107.25 per MW per month
Virginia Electric and Power Company	$ 84.86 per MW per month
Potomac-Appalachian Transmission Highline L.L.C.	$ 15.15 per MW per month
PPL Electric Utilities Corporation	$ 56.28 per MW per month
American Electric Power Service Corporation	$ 10.54 per MW per month
Atlantic City Electric Company.	$ 11.77 per MW per month
Delmarva Power and Light Company	$ 6.75 per MW per month
Potomac Electric Power Company.	$ 11.37 per MW per month

Above rates converted to a charge per kW of Transmission Obligation, applicable in all months	$ 7.1806
Charge including New Jersey Sales and Use Tax (SUT)	$ 7.6832

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

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

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

Network Integration Service Calculation - BGS-RSCP
NITS Charges for January 2016 - December 2016

		Effective 1/1/16 - 12/31/16	
PSE&G Annual Transmission Service Revenue Req	$ 1,064,228,951.56		
Total Schedule 12 TEC Included in above	$ (520,436,728.38)		
PSE&G Customer Share of Schedule 12 NITS	$ 247,944,752.83		
NITS Charges for Jan 2016 - Dec 2016	$ 791,736,976.01		
PSE&G Zonal Transmission Load for Effective Yr. (MW) (1/1/16)	9,594.90		
Term (Months)	12		
OATT rate	$ 6,876.37	/MW/month	all values show w/o NJ SUT
converted to $/MW/yr =	$ 82,516.44	/MW/yr	**Jan 16 - Dec 16 NITS Charge**
	$ 57,084.59	/MW/yr	**Jan 16 - May 16 Weighted Average of 42,285.83, 55,722.38 and 72,688.29**
	$ 70,337.03	/MW/yr	**Jun 16 - Dec 16 Weighted Average of 55,722.38, 72,688.29, 82,516.44**
	$ 64,815.18	/MW/yr	**Jan 16 - Dec 16 Weighted Average**
Resulting Increase in Transmission Rate	$ 17,701.26	/MW/yr	
Resulting Increase in Transmission Rate	$ 1,475.10	/MW/month	

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	3,579.2	25.7	62.8	0.0	0.0	4.4	0.0	0.0
Total Annual Energy - MWh	12,129,950	161,550	216,336	1,579	33	17,189	152,549	208,076
Change in energy charge								
in $/MWh	$ 5.2231	$ 2.8160	$ 5.1385	$ -	$ -	$ 4.5312	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.005223**	**$ 0.002816**	**$ 0.005138**	**$ -**	**$ -**	**$ 0.004531**	**$ -**	**$ -**

Line #					
1	Total BGS-RSCP Trans Obl	6,392.2	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust	23,723,046	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes	25,441,259	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 113,149,985		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl adjusted for migration
5	Change in Average Supplier Payment Rate	$ 4.4475	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ 4.45	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ 113,213,602		unrounded	= (6) * (3)
8	Difference due to rounding	$ 63,617		unrounded	= (7) - (4)

Attachment 2c

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

Transmission Charge Adjustment - BGS-RSCP
Attachment 6c - PJM Schedule 12 - Transmission Enhancement Charges for January 2016 - December 2016
Calculation of costs and monthly PJM charges for VEPCO Projects

TEC Charges for Jan 2016 - Dec 2016	$	9,770,443.79		
PSE&G Zonal Transmission Load for Effective Yr. (MW) (1/1/16)		9,594.90		
Term (Months)		12		
OATT rate	$	84.86	/MW/month	all values show w/o NJ SUT
Resulting Increase in Transmission Rate	$	1,018.32	/MW/yr	

	RS	**RHS**	**RLM**	**WH**	**WHS**	**HS**	**PSAL**	**BPL**
Trans Obl - MW	3,579.2	25.7	62.8	0.0	0.0	4.4	0.0	0.0
Total Annual Energy - MWh	12,129,950	161,550	216,336	1,579	33	17,189	152,549	208,076
Change in energy charge								
in $/MWh	$ 0.3005	$ 0.1620	$ 0.2956	$ -	$ -	$ 0.2607	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000300**	**$ 0.000162**	**$ 0.000296**	**$ -**	**$ -**	**$ 0.000261**	**$ -**	**$ -**

Line #						
1	Total BGS-RSCP Trans Obl		6,392.2	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust		23,723,046	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes		25,441,259	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	6,509,305		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.2559	/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	$	6,614,727		unrounded	= (6) * (3)
8	Difference due to rounding	$	105,422		unrounded	= (7) - (4)

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

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges for January 2016 - December 2016
Calculation of costs and monthly PJM charges for PATH Project

TEC Charges for Jan 2016 - Dec 2016	$	1,744,305.54		
PSE&G Zonal Transmission Load for Effective Yr. (MW) (1/1/16)		9,594.90		
Term (Months)		12		
OATT rate	$	15.15	/MW/month	all values show w/o NJ SUT
Resulting Increase in Transmission Rate	$	181.80	/MW/yr	

	RS	**RHS**	**RLM**	**WH**	**WHS**	**HS**	**PSAL**	**BPL**
Trans Obl - MW	3,579.2	25.7	62.8	0.0	0.0	4.4	0.0	0.0
Total Annual Energy - MWh	12,129,950	161,550	216,336	1,579	33	17,189	152,549	208,076
Change in energy charge								
in $/MWh	$ 0.0536	$ 0.0289	$ 0.0528	$ -	$ -	$ 0.0465	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000054**	**$ 0.000029**	**$ 0.000053**	**$ -**	**$ -**	**$ 0.000047**	**$ -**	**$ -**

Line #						
1	Total BGS-RSCP Trans Obl		6,392.2	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust		23,723,046	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes		25,441,259	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	1,162,102		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.0457	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	0.05	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	1,272,063		unrounded	= (6) * (3)
8	Difference due to rounding	$	109,961		unrounded	= (7) - (4)

Attachment 3 – JCP&L Tariffs and Rate Translation

Attachment 3a
Pro-forma JCP&L Tariff Sheets

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

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

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

Attachment 3a
Pro-forma JCP&L Tariff Sheets

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

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

Effective September 1, 2015, a TRAILCO4-TEC surcharge of **$0.000444** per KWH (includes Sales and Use Tax as provided in Rider SUT), a PEPCO2-TEC surcharge of **$0.000044** per KWH (includes Sales and Use Tax as provided in Rider SUT), an ACE2-TEC surcharge of **$0.000088** per KWH (includes Sales and Use Tax as provided in Rider SUT), a Delmarva2-TEC surcharge of **$0.000026** per KWH (includes Sales and Use Tax as provided in Rider SUT), an AEP-East2-TEC surcharge of **$0.000040** per KWH (includes Sales and Use Tax as provided in Rider SUT), and a PPL2-TEC surcharge of **$0.000209** per KWH (includes Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage except lighting under Service Classifications OL, SVL, MVL and ISL.

Effective January 1, 2016, a PATH3-TEC surcharge of **$0.000058** per KWH (includes Sales and Use Tax as provided in Rider SUT), a VEPCO3-TEC surcharge of **$0.000323** per KWH (includes Sales and Use Tax as provided in Rider SUT), and a PSEG2-TEC surcharge of **$0.001998** per KWH (includes Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage except lighting under Service Classifications OL, SVL, MVL and ISL.

3) BGS Reconciliation Charge per KWH: ($0.002150) (includes Sales and Use Tax as provided in Rider SUT)

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

Issued: **Effective: January 1, 2016**

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

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, 2015, the following TEC surcharges will be added to the BGS Transmission Charge applicable to all KWH usage, as follows (includes Sales and Use Tax as provided in Rider SUT):

	TRAILCO4-TEC	PEPCO2-TEC	ACE2-TEC
GT – High Tension Service	**$0.000058**	**$0.000005**	**$0.000012**
GT	**$0.000261**	**$0.000026**	**$0.000051**
GP	**$0.000295**	**$0.000029**	**$0.000059**
GS and GST	**$0.000444**	**$0.000044**	**$0.000088**

	Delmarva2-TEC	AEP-East2-TEC	PPL2-TEC
GT – High Tension Service	**$0.000003**	**$0.000005**	**$0.000027**
GT	**$0.000015**	**$0.000024**	**$0.000122**
GP	**$0.000017**	**$0.000027**	**$0.000139**
GS and GST	**$0.000026**	**$0.000040**	**$0.000209**

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

	PATH3-TEC	VEPCO3-TEC	PSEG2-TEC
GT – High Tension Service	**$0.000022**	**$0.000125**	**$0.000774**
GT	**$0.000036**	**$0.000202**	**$0.001249**
GP	**$0.000040**	**$0.000224**	**$0.001381**
GS and GST	**$0.000058**	**$0.000323**	**$0.001998**

4) BGS Reconciliation Charge per KWH: ($0.000928) (includes Sales and Use Tax as provided in Rider SUT)

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

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

Attachment 3b

Jersey Central Power & Light Company
Proposed PSEG Project Transmission Enhancement Charge (PSEG-TEC Surcharge) effective January 1, 2016
To reflect FERC-approved PSEG Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 2016

2016 Average Monthly PSEG-TEC Costs Allocated to JCP&L Zone	$	2,984,097.56	(1)
2016 JCP&L Zone Transmission Peak Load (MW)		5818.1	
PSEG-Transmission Enhancement Rate ($/MW-month)	$	512.90	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	**Effective January 1, 2016:** PSEG-TEC Surcharge ($/kWh)	PSEG-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5079.4	31,262,629	16,747,305,504	$ 0.001867	$ 0.001998
Primary	376.7	2,318,509	1,796,093,554	$ 0.001291	$ 0.001381
Transmission @ 34.5 kV	323.3	1,989,843	1,704,936,059	$ 0.001167	$ 0.001249
Transmission @ 230 kV	38.7	238,190	329,300,188	$ 0.000723	$ 0.000774
Total	5818.1	35,809,171	20,577,635,305		

(1) Cost Allocation of PSEG Project Schedule 12 Charges to JCP&L Zone for 2016
(2) Based on 12 months PSEG Project costs from January through December 2016
(3) January through December 2016

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales January through December @ Customer		15,750,010	MWH
2	BGS-FP Eligible Sales January through December @ Transmission Node		17,459,674	MWH
3	BGS-FP Eligible Transmission Obligation		4,340	MW
4	PSEG-Transmission Enhancement Costs to FP Suppliers	$	26,711,779	= Line 3 x $512.90 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	1.53	= Line 4 / Line 2

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

Attachment 3c

Jersey Central Power & Light Company

Proposed VEPCO Project Transmission Enhancement Charge (VEPCO-TEC Surcharge) effective January 1, 2016

To reflect FERC-approved VEPCO Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 2016

2016 Average Monthly VEPCO-TEC Costs Allocated to JCP&L Zone	$	483,240.91	(1)
2016 JCP&L Zone Transmission Peak Load (MW)		5818.1	
VEPCO-Transmission Enhancement Rate ($/MW-month)	$	83.06	

				Effective January 1, 2016:	
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)	5079.4	5,062,630	16,747,305,504	$ 0.000302	$ 0.000323
Primary	376.7	375,456	1,796,093,554	$ 0.000209	$ 0.000224
Transmission @ 34.5 kV	323.3	322,233	1,704,936,059	$ 0.000189	$ 0.000202
Transmission @ 230 kV	38.7	38,572	329,300,188	$ 0.000117	$ 0.000125
Total	5818.1	5,798,891	20,577,635,305		

(1) Cost Allocation of VEPCO Project Schedule 12 Charges to JCP&L Zone for 2016

(2) Based on 12 months VEPCO Project costs from January through December 2016

(3) January through December 2016

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales January through December @ Customer		15,750,010	MWH
2	BGS-FP Eligible Sales January through December @ Transmission Node		17,459,674	MWH
3	BGS-FP Eligible Transmission Obligation		4,340	MW
4	VEPCO-Transmission Enhancement Costs to FP Suppliers	$	4,325,671	= Line 3 x $83.06 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.25	= Line 4 / Line 2

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

Attachment 3d

Jersey Central Power & Light Company
Proposed PATH Project Transmission Enhancement Charge (PATH-TEC Surcharge) effective January 1, 2016
To reflect FERC-approved PATH Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 2016

2016 Average Monthly PATH-TEC Costs Allocated to JCP&L Zone	$	86,192.65	(1)
2016 JCP&L Zone Transmission Peak Load (MW)		5818.1	
PATH-Transmission Enhancement Rate ($/MW-month)	$	14.81	

				Effective January 1, 2016:	
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	PATH-TEC Surcharge ($/kWh)	PATH-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5079.4	902,990	16,747,305,504	$ 0.000054	$ 0.000058
Primary	376.7	66,968	1,796,093,554	$ 0.000037	$ 0.000040
Transmission @ 34.5 kV	323.3	57,475	1,704,936,059	$ 0.000034	$ 0.000036
Transmission @ 230 kV	38.7	6,880	329,300,188	$ 0.000021	$ 0.000022
Total	5818.1	1,034,312	20,577,635,305		

(1) Cost Allocation of PATH Project Schedule 12 Charges to JCP&L Zone for 2016
(2) Based on 12 months PATH Project costs from January through December 2016
(3) January through December 2016

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

Line No.				
1	BGS-FP Eligible Sales January through December @ Customer		15,750,010	MWH
2	BGS-FP Eligible Sales January through December @ Transmission Node		17,459,674	MWH
3	BGS-FP Eligible Transmission Obligation		4,340	MW
4	PATH-Transmission Enhancement Costs to FP Suppliers	$	771,543	= Line 3 x $14.81 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.04	= Line 4 / Line 2

Attachment 4 – ACE Tariffs and Rate Translation

Attachment 4a
Pro-forma ACE Tariff Sheets

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

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

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

Attachment 4a
Pro-forma ACE Tariff Sheets

RIDER (BGS) continued
Basic Generation Service (BGS)

CIEP Standby Fee $0.000161 per kWh
This charge recovers the costs associated with the winning BGS-CIEP bidders maintaining the availability of the hourly priced default electric supply service plus administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT. This charge is assessed on all kWhs delivered to all CIEP- eligible customers on Rate Schedules MGS Secondary, MGS Primary, AGS Secondary, AGS Primary or TGS.

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

	Rate Class							
	RS	MGS Secondary	MGS Primary	AGS Secondary	AGS Primary	TGS	SPL/CSL	DDC
VEPCo	0.000355	0.000303	0.000131	0.000179	0.000067	0.000151	-	0.000146
TrAILCo	0.000536	0.000461	0.000407	0.000335	0.000277	0.000233	-	0.000224
PSE&G	0.000583	0.000496	0.000214	0.000294	0.000110	0.000249	-	0.000240
PATH	0.000062	0.000052	0.000022	0.000031	0.000012	0.000027	-	0.000026
PPL	0.000220	0.000189	0.000167	0.000138	0.000113	0.000095	-	0.000092
Pepco	0.000055	0.000047	0.000041	0.000034	0.000028	0.000024	-	0.000022
Delmarva	0.000028	0.000024	0.000021	0.000017	0.000014	0.000012	-	0.000012
AEP - East	0.000032	0.000028	0.000024	0.000020	0.000016	0.000014	-	0.000013
Total	0.001871	0.001600	0.001027	0.001048	0.000637	0.000805	-	0.000775

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

Atlantic City Electric Company

Proposed PSE&G Projects Transmission Enhancement Charge (PSE&G-TEC Surcharge) effective January 1, 2016
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 1, 2016

Transmission Enhancement Costs Allocated to ACE Zone (2016)	$ 349,161
	$ 349,161
2016 ACE Zone Transmission Peak Load (MW)	2,553
Transmission Enhancement Rate ($/MW)	$ 136.78

Rate Class	Col. 1 Transmission Obligation (MW)	Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2015 - May 2016 (kWh)	Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)	Col. 5 = Col. 4 x 1/(1-.005) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)	Col. 6 = Col. 5 x 1.07 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,377.1	$ 2,260,264	4,153,440,930	$ 0.000544	$ 0.000545	$ 0.000583
MGS Secondary	327.3	$ 537,244	1,159,405,523	$ 0.000463	$ 0.000464	$ 0.000496
MGS Primary	2.4	$ 3,937	19,649,973	$ 0.000200	$ 0.000200	$ 0.000214
AGS Secondary	320.6	$ 526,147	1,920,506,563	$ 0.000274	$ 0.000275	$ 0.000294
AGS Primary	36.5	$ 59,827	578,947,070	$ 0.000103	$ 0.000103	$ 0.000110
TGS	157.4	$ 258,307	1,115,063,185	$ 0.000232	$ 0.000233	$ 0.000249
SPL/CSL	0.0	$ -	74,668,520	$ -	$ -	$ -
DDC	1.7	$ 2,740	12,290,157	$ 0.000223	$ 0.000224	$ 0.000240
	2,222.9	$ 3,648,467	9,033,971,921			

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

Atlantic City Electric Company

Proposed VEPCO Projects Transmission Enhancement Charge (VEPCO-TEC Surcharge) effective January 1, 2016

To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 1, 2016

Transmission Enhancement Costs Allocated to ACE Zone (2016)	$ 212,229
	$ 212,229
2016 ACE Zone Transmission Peak Load (MW)	2,553
Transmission Enhancement Rate ($/MW)	$ 83.14

Rate Class	Col. 1 Transmission Obligation (MW)	Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2015 - May 2016 (kWh)	Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)	Col. 5 = Col. 4 x 1/(1-.005) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)	Col. 6 = Col. 5 x 1.07 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,377.1	$ 1,373,847	4,153,440,930	$ 0.000331	$ 0.000332	$ 0.000355
MGS Secondary	327.3	$ 326,551	1,159,405,523	$ 0.000282	$ 0.000283	$ 0.000303
MGS Primary	2.4	$ 2,393	19,649,973	$ 0.000122	$ 0.000122	$ 0.000131
AGS Secondary	320.6	$ 319,806	1,920,506,563	$ 0.000167	$ 0.000167	$ 0.000179
AGS Primary	36.5	$ 36,364	578,947,070	$ 0.000063	$ 0.000063	$ 0.000067
TGS	157.4	$ 157,006	1,115,063,185	$ 0.000141	$ 0.000141	$ 0.000151
SPL/CSL	0.0	$ -	74,668,520	$ -	$ -	$ -
DDC	1.7	$ 1,666	12,290,157	$ 0.000136	$ 0.000136	$ 0.000146
	2,222.9	$ 2,217,633	9,033,971,921			

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

Atlantic City Electric Company

Proposed PATH Projects Transmission Enhancement Charge (PATH-TEC Surcharge) effective January 1, 2016
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 1, 2016

Transmission Enhancement Costs Allocated to ACE Zone (2016)	$	37,253
	$	37,253
2016 ACE Zone Transmission Peak Load (MW)		2,553
Transmission Enhancement Rate ($/MW)	$	14.59

	Col. 1	Col. 2	Col. 3	Col. 4 = Col. 2/Col. 3	Col. 5 = Col. 4 x 1/(1-.005)	Col. 6 = Col. 5 x 1.07
Rate Class	Transmission Obligation (MW)	Allocated Cost Recovery	BGS Eligible Sales June 2015 - May 2016 (kWh)	Transmission Enhancement Charge ($/kWh)	Transmission Enhancement Charge w/ BPU Assessment ($/kWh)	Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,377.1	$ 241,153	4,153,440,930	$ 0.000058	$ 0.000058	$ 0.000062
MGS Secondary	327.3	$ 57,320	1,159,405,523	$ 0.000049	$ 0.000049	$ 0.000052
MGS Primary	2.4	$ 420	19,649,973	$ 0.000021	$ 0.000021	$ 0.000022
AGS Secondary	320.6	$ 56,136	1,920,506,563	$ 0.000029	$ 0.000029	$ 0.000031
AGS Primary	36.5	$ 6,383	578,947,070	$ 0.000011	$ 0.000011	$ 0.000012
TGS	157.4	$ 27,559	1,115,063,185	$ 0.000025	$ 0.000025	$ 0.000027
SPL/CSL	0.0	$ -	74,668,520	$ -	$ -	$ -
DDC	1.7	$ 292	12,290,157	$ 0.000024	$ 0.000024	$ 0.000026
	2,222.9	$ 389,263	9,033,971,921			

Attachment 5 – RECO Tariffs and Rate Translation

Attachment 5a
Pro-forma RECO Tariff Sheets

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

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

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

Attachment 5a

Pro-forma RECO Tariff Sheets

Rockland Electric Company
Calculation of Transmission Surcharges reflecting proposed changes effective January 1, 2016
To reflect: RMR Costs
FERC-approved ACE Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved AEP-East Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved Delmarva Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved PATH Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved PEPCO Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved PPL Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved PSE&G Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved TrailCo Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved VEPCo Project Schedule 12 Charges (Schedule 12 PJM OATT)

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

Transmission Project	Note	SC1	SC2 Sec	SC2 Pri	SC3	SC4	SC5	SC6	SC7
Reliability Must Run	(1)	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
ACE - TEC	(2)	0.00004	0.00002	0.00002	0.00002	0.00000	0.00002	0.00000	0.00001
AEP-East - TEC	(3)	0.00004	0.00003	0.00002	0.00003	0.00000	0.00003	0.00000	0.00002
Delmarva - TEC	(4)	0.00003	0.00002	0.00001	0.00002	0.00000	0.00002	0.00000	0.00001
PATH - TEC	(5)	0.00006	0.00004	0.00003	0.00004	0.00000	0.00004	0.00000	0.00002
PEPCO - TEC	(6)	0.00004	0.00002	0.00002	0.00003	0.00000	0.00003	0.00000	0.00002
PPL - TEC	(7)	0.00022	0.00013	0.00012	0.00014	0.00000	0.00015	0.00000	0.00009
PSE&G - TEC	(8)	0.00827	0.00493	0.00424	0.00493	0.00000	0.00552	0.00000	0.00333
TrAILCo - TEC	(9)	0.00042	0.00025	0.00023	0.00026	0.00000	0.00028	0.00000	0.00017
VEPCo - TEC	(10)	0.00034	0.00020	0.00017	0.00020	0.00000	0.00023	0.00000	0.00014
Total ($/kWh and excl SUT)		$0.00946	$0.00564	$0.00486	$0.00567	$0.00000	$0.00632	$0.00000	$0.00381
Total (¢/kWh and excl SUT)		0.946 ¢	0.564 ¢	0.486 ¢	0.567 ¢	0.000 ¢	0.632 ¢	0.000 ¢	0.381 ¢

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

Transmission Project	Note	SC1	SC2 Sec	SC2 Pri	SC3	SC4	SC5	SC6	SC7
Reliability Must Run	(1)	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
ACE - TEC	(2)	0.00004	0.00002	0.00002	0.00002	0.00000	0.00002	0.00000	0.00001
AEP-East - TEC	(3)	0.00004	0.00003	0.00002	0.00003	0.00000	0.00003	0.00000	0.00002
Delmarva - TEC	(4)	0.00003	0.00002	0.00001	0.00002	0.00000	0.00002	0.00000	0.00001
PATH - TEC	(5)	0.00006	0.00004	0.00003	0.00004	0.00000	0.00004	0.00000	0.00002
PEPCO - TEC	(6)	0.00004	0.00002	0.00002	0.00003	0.00000	0.00003	0.00000	0.00002
PPL - TEC	(7)	0.00024	0.00014	0.00013	0.00015	0.00000	0.00016	0.00000	0.00010
PSE&G - TEC	(8)	0.00885	0.00528	0.00454	0.00528	0.00000	0.00591	0.00000	0.00356
TrAILCo - TEC	(9)	0.00045	0.00027	0.00025	0.00028	0.00000	0.00030	0.00000	0.00018
VEPCo - TEC	(10)	0.00036	0.00021	0.00018	0.00021	0.00000	0.00025	0.00000	0.00015
Total ($/kWh and incl SUT)		$0.01011	$0.00603	$0.00520	$0.00606	$0.00000	$0.00676	$0.00000	$0.00407
Total (¢/kWh and incl SUT)		1.011 ¢	0.603 ¢	0.520 ¢	0.606 ¢	0.000 ¢	0.676 ¢	0.000 ¢	0.407 ¢

Notes:

(1) RMR rates based on allocations by transmission zone. For RECO, the estimated allocation is zero percent for calendar year 2016.
(2) ACE-TEC rates pursuant to the Board’s Order dated August 19, 2015 in Docket No. ER15070764.
(3) AEP-East-TEC rates pursuant to the Board’s Order dated August 19, 2015 in Docket No. ER15070764.
(4) Delmarva-TEC rates pursuant to the Board’s Order dated August 19, 2015 in Docket No. ER15070764.
(5) PATH-TEC rates calculated in Attachment 5 of the joint filing.
(6) PEPCO-TEC rates pursuant to the Board’s Order dated August 19, 2015 in Docket No. ER15070764.
(7) PPL-TEC rates pursuant to the Board’s Order dated August 19, 2015 in Docket No. ER15070764.
(8) PSE&G-TEC rates calculated in Attachment 5 of the joint filing.
(9) TrAILCo-TEC rates pursuant to the Board’s Order dated August 19, 2015 in Docket No. ER15070764.
(10) VEPCo-TEC rates calculated in Attachment 5 of the joint filing.

SERVICE CLASSIFICATION NO. 1
RESIDENTIAL SERVICE (Continued)

RATE – MONTHLY (Continued)

(3) Transmission Charge

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

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

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

All kWh	1.011 ¢ per kWh	1.011 ¢ per kWh

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

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

* Definition of Summer Billing Months - June through September

(Continued)

SERVICE CLASSIFICATION NO. 2
GENERAL SERVICE (Continued)

RATE – MONTHLY (Continued)

(3) Transmission Charges (Continued)

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

	Summer Months*	Other Months
Secondary Voltage Service Only		
All kWh ....@	0.603 ¢ per kWh	0.603 ¢ per kWh
Primary Voltage Service Only		
All kWh ....@	0.520 ¢ per kWh	0.520 ¢ per kWh

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

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

* Definition of Summer Billing Months - June through September

(Continued)

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

RATE – MONTHLY (Continued)

(3) Transmission Charge

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

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

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

All kWh .....@	0.606 ¢ per kWh	0.606 ¢ per kWh

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

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

* Definition of Summer Billing Months - June through September

(Continued)

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

RATE - MONTHLY (Continued)

(3) Transmission Charge

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

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

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

All kWh ... @	0.676 ¢ per kWh	0.676 ¢ per kWh

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

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

* Definition of Summer Billing Months - June through September

(Continued)

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

RATE– MONTHLY (Continued)

(3) Transmission Charges (Continued)

(a) (Continued)

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

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

		Primary	High Voltage Distribution
All Periods	All kWh @	0.407 ¢ per kWh	0.407 ¢ per kWh

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

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

(Continued)

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

SPECIAL PROVISIONS

(A) Space Heating

Customers who take service under this classification for 10 kW or more of permanently installed space heating equipment may elect to have the electricity for this service billed separately. All monthly use shall be billed at a Distribution Charge of 3.159 ¢ per kWh during the billing months of October through May and 5.106 ¢ per kWh during the summer billing months and a Transmission Charge of 0.552 ¢ per kWh and a Transmission Surcharge of 0.407 ¢ per kWh during all billing months.

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

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

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

(B) Budget Billing Plan

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

(Continued)

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

Rockland Electric Company

Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (PSE&G Project) effective January 1, 2016
To reflect FERC-approved PSE&G Project Schedule 12 Charges (Schedule 12 PJM OATT) for 2016

2016 Average Monthly PSE&G-TEC Costs Allocated to RECO	$	827,939	(1)
2016 RECO Zone Transmission Peak Load (MW)		424.4	(2)
Transmission Enhancement Rate ($/MW-month)	$	1,951.07	

	Col. 1	Col. 2	Col.3=Col.2 x $827,939 x 12	Col. 4	Col. 5 = Col. 3/Col. 4	Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)	Allocated Cost Recovery (1)	BGS Eligible Sales Jan 2016 - Dec 2016 (kWh)	Transmission Enhancement Charge ($/kWh)	Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	251.5	59.27%	$ 5,888,696	712,254,000	$ 0.00827	$ 0.00885
SC2 Secondary	116.8	27.52%	$ 2,733,866	554,531,000	$ 0.00493	$ 0.00528
SC2 Primary	15.6	3.67%	$ 364,433	86,032,000	$ 0.00424	$ 0.00454
SC3	0.1	0.01%	$ 1,386	281,000	$ 0.00493	$ 0.00528
SC4	0.0	0.00%	$ -	6,481,000	$ -	$ -
SC5	3.9	0.91%	$ 90,500	16,404,000	$ 0.00552	$ 0.00591
SC6	0.0	0.00%	$ -	5,690,000	$ -	$ -
SC7	36.6	8.62%	$ 856,386	257,514,000	$ 0.00333	$ 0.00356
Total	424.4 (2)	100.00%	$ 9,935,267	1,639,187,000		

(1) Attachment 4 - Cost Allocation of PSE&G Project Schedule 12 Charges to RECO Zone for 2016
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales Jan - Dec @ cust (RECO Eastern Division)		1,327,160	MWH
2	BGS-FP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)		1,234,839	MWH
3	BGS-FP Eligible Transmission Obligation		388	MW
4	Transmission Enhancement Costs to FP Suppliers	$	9,078,871.89	= Line 3 x $1951.07 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	7.35	= Line 4/Line 2

Attachment 5c

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

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (VEPCo) effective January 1, 2016
To reflect FERC-approved VEPCo Project Schedule 12 Charges (Schedule 12 PJM OATT) for 2016

2016 Average Monthly VEPCo-TEC Costs Allocated to RECO	$	34,096	(1)
2016 RECO Zone Transmission Peak Load (MW)		424.4	(2)
Transmission Enhancement Rate ($/MW-month)	$	80.35	

	Col. 1		Col. 2	Col.3=Col.2 x $34,096 x 12		Col. 4	Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07	
Rate Class	BGS-Eligible Transmission Obligation (MW)		Transmission Obligation (Pct)	Allocated Cost Recovery (1)		BGS Eligible Sales Jan 2016 - Dec 2016(kWh)	Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)	
SC1	251.5		59.27%	$	242,504	712,254,000	$	0.00034	$	0.00036
SC2 Secondary	116.8		27.52%	$	112,584	554,531,000	$	0.00020	$	0.00021
SC2 Primary	15.6		3.67%	$	15,008	86,032,000	$	0.00017	$	0.00018
SC3	0.1		0.01%	$	57	281,000	$	0.00020	$	0.00021
SC4	0.0		0.00%	$	-	6,481,000	$	-	$	-
SC5	3.9		0.91%	$	3,727	16,404,000	$	0.00023	$	0.00025
SC6	0.0		0.00%	$	-	5,690,000	$	-	$	-
SC7	36.6		8.62%	$	35,267	257,514,000	$	0.00014	$	0.00015
Total	424.4	(2)	100.00%	$	409,147	1,639,187,000				

(1) Attachment 4 - Cost Allocation of VEPCo Schedule 12 Charges to RECO Zone for 2016
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales Jan - Dec @ cust (RECO Eastern Division)		1,327,160	MWH
2	BGS-FP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)		1,234,839	MWH
3	BGS-FP Eligible Transmission Obligation		388	MW
4	Transmission Enhancement Costs to FP Suppliers	$	373,890.92	= Line 3 x $80.35 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.30	= Line 4/Line 2

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

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (PATH) effective January 1, 2016
To reflect FERC-approved PATH Project Schedule 12 Charges (Schedule 12 PJM OATT) for 2016

2016 Average Monthly PATH-TEC Costs Allocated to RECO	$	6,087	(1)
2016 RECO Zone Transmission Peak Load (MW)		424.4	(2)
Transmission Enhancement Rate ($/MW-month)	$	14.34	

Rate Class	Col. 1 BGS-Eligible Transmission Obligation (MW)	Col. 2 Transmission Obligation (Pct)	Col.3=Col.2 x $6,087 x 12 Allocated Cost Recovery (1)	Col. 4 BGS Eligible Sales Jan 2016 - Dec 2016 (kWh)	Col. 5 = Col. 3/Col. 4 Transmission Enhancement Charge ($/kWh)	Col. 6 = Col. 5 x 1.07 Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	251.5	59.27%	$ 43,294	712,254,000	$ 0.00006	$ 0.00006
SC2 Secondary	116.8	27.52%	$ 20,100	554,531,000	$ 0.00004	$ 0.00004
SC2 Primary	15.6	3.67%	$ 2,679	86,032,000	$ 0.00003	$ 0.00003
SC3	0.1	0.01%	$ 10	281,000	$ 0.00004	$ 0.00004
SC4	0.0	0.00%	$ -	6,481,000	$ -	$ -
SC5	3.9	0.91%	$ 665	16,404,000	$ 0.00004	$ 0.00004
SC6	0.0	0.00%	$ -	5,690,000	$ -	$ -
SC7	36.6	8.62%	$ 6,296	257,514,000	$ 0.00002	$ 0.00002
Total	424.4 (2)	100.00%	$ 73,044	1,639,187,000		

(1) Attachment 4 - Cost Allocation of PATH Project Schedule 12 Charges to RECO Zone for 2016
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-FP Eligible Sales Jan - Dec @ cust (RECO Eastern Division)		1,327,160	MWH
2	BGS-FP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)		1,234,839	MWH
3	BGS-FP Eligible Transmission Obligation		388	MW
4	Transmission Enhancement Costs to FP Suppliers	$	66,728.01	= Line 3 x $14.34 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.05	= Line 4/Line 2

Attachment 6 – PJM Schedule 12 (Transmission Enhancement) Charges

Attachment 6a
PSE&G Project Charges

Attachment 6b
Potomac-Appalachian Transmission Highline Project Charges

Attachment 6c
Virginia Electric Power Company Project Charges

Attachment 6a
PSE&G Project Charges

Attachment 6a -PJM Schedule 12 - Transmission Enhancement Charges for January 2016 - December 2016
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 2016 Annual Revenue Requirement**	**ACE Zone Share**	**JCP&L Zone Share**	**PSE&G Zone Share1,2**	**RE Zone Share**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
per PJM website	*per PJM spreadsheet*	*per PJM website*	*per PJM Open Access Transmission Tariff*								
Replace all derated Branchburg 500/230 kava transformers	b0130	$ 3,071,297.20	1.36%	47.63%	50.75%	0.00%	$41,770	$1,462,859	$1,558,683	$0	$3,063,312
Reconductor Kittatinny - Newtown 230 kV with 1590 ACSS	b0134	$ 1,240,095.29	0.00%	51.11%	45.96%	2.93%	$0	$633,813	$569,948	$36,335	$1,240,095
Build new Essex - Aldene 230 kV cable connected through phase angle regulator at Essex	b0145	$ 13,394,967.82	0.00%	73.45%	21.78%	4.77%	$0	$9,838,604	$2,917,424	$638,940	$13,394,968
Install 4th 500/230 kV transformer at New Freedom	b0411	$ 3,385,900.51	47.01%	7.04%	22.31%	0.00%	$1,591,712	$238,367	$755,394	$0	$2,585,474
Replace wave trap at Branchburg 500kV substation	b0172.2	$ 2,285.29	1.53%	3.54%	5.97%	0.25%	$35	$81	$136	$6	$258
Reconductor the Flagtown-Somerville-Bridgewater 230 kV circuit with 1590 ACSS	b0170	$ 1,114,815.03	0.00%	42.95%	38.36%	0.79%	$0	$478,813	$427,643	$8,807	$915,263
Loop the 5021 circuit into New Freedom 500 kV substation	b0498	$ 2,982,831.59	1.53%	3.54%	5.97%	0.25%	$45,637	$105,592	$178,075	$7,457	$336,762
Install 230-138kV transformer at Metuchen substation	b0161	$ 4,249,279.62	0.00%	0.00%	99.80%	0.20%	$0	$0	$4,240,781	$8,499	$4,249,280
Build a new 230 kV section from Branchburg - Flagtown and move the Flagtown - Somerville 230 kV circuit to the new section	b0169	$ 976,747.43	1.70%	25.66%	58.96%	0.00%	$16,605	$250,633	$575,890	$0	$843,128
Replace both 230/138 kV transformers at Roseland	b0274	$ 3,067,264.47	0.00%	0.00%	88.56%	0.00%	$0	$0	$2,716,369	$0	$2,716,369
Reconductor Hudson - South Waterfront 230kV circuit	b0813	$ 1,203,471.24	0.00%	9.92%	83.73%	3.12%	$0	$119,384	$1,007,666	$37,548	$1,164,599
Reconductor South Mahwah 345 kV J-3410 Circuit	b1017	$ 3,454,222.48	0.00%	14.69%	32.84%	1.28%	$0	$507,425	$1,134,367	$44,214	$1,686,006
Reconductor South Mahwah 345 kV K-3411 Circuit	b1018	$ 2,877,378.88	0.00%	14.77%	32.74%	1.28%	$0	$424,989	$942,054	$36,830	$1,403,873
Replace Salem 500 kV breakers	b1410-b1415	$ 3,750,334.87	1.53%	3.54%	5.97%	0.25%	$57,380	$132,762	$223,895	$9,376	$423,413
Branchburg 400 MVAR Capacitor	b0290	$ 17,144,700.59	1.53%	3.54%	5.97%	0.25%	$262,314	$606,922	$1,023,539	$42,862	$1,935,637
Saddle Brook - Athenia Upgrade Cable	b0472	$ 2,940,449.14	0.00%	0.00%	92.86%	3.47%	$0	$0	$2,730,501	$102,034	$2,832,535
Branchburg-Somerville-Flagtown Reconductor	b0664-b0665	$ 5,138,662.23	0.00%	36.35%	43.24%	1.61%	$0	$1,867,904	$2,221,958	$82,732	$4,172,594
Somerville -Bridgewater Reconductor	b0668	$ 1,396,346.28	0.00%	39.41%	38.76%	1.45%	$0	$550,300	$541,224	$20,247	$1,111,771
New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie	b0814	$ 14,219,398.91	0.00%	23.49%	67.03%	2.50%	$0	$3,340,137	$9,531,263	$355,485	$13,226,885
230kV Lawrence Switching Station Upgrade	b1228	$ 3,260,909.34	0.00%	0.00%	95.83%	3.81%	$0	$0	$3,124,929	$124,241	$3,249,170
Ridge Rd 69kV Breaker Station	b1255	$ 2,807,870.91	0.00%	0.00%	96.18%	3.82%	$0	$0	$2,700,610	$107,261	$2,807,871
New Cox's Corner-Lumberton 230kV Circuit	b1787	$ 4,125,793.09	4.96%	44.20%	48.08%	1.92%	$204,639	$1,823,601	$1,983,681	$79,215	$4,091,136
Sewaren Switch 230kV Convers.	b2276	$ 9,480,938.08	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Bergen Substation Transformer	b1082	$ (1,822,685.13)	0.00%	0.00%	80.29%	3.19%	$0	$0	-$1,463,434	-$58,144	-$1,521,578

Attachment 6a -PJM Schedule 12 - Transmission Enhancement Charges for January 2016 - December 2016
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 2016 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**
Upgrade Camden Richmon 230kV	b1590	$ 1,767,770.54	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Uprate Eagle Point-Gloucester 230 kV Circuit	b1588	$ 1,654,204.43	0.00%	10.31%	54.17%	2.16%	$0	$170,548	$896,083	$35,731	$1,102,362
Build Mickleton-Gloucester Corridor Ultimate Design	b2139	$ 2,525,192.28	0.00%	0.00%	61.11%	2.44%	$0	$0	$1,543,145	$61,615	$1,604,760
Branchburg-Middlesex Sw Rack	b1155	$ 13,935,900.56	0.00%	4.61%	91.75%	3.64%	$0	$642,445	$12,786,189	$507,267	$13,935,901
Aldene-Springfield Rd. Conv	b1399	$ 9,579,949.84	0.00%	0.00%	96.18%	3.82%	$0	$0	$9,213,996	$365,954	$9,579,950
Susquehanna Roseland Breakers (In-Service)	b0489.5-.15	$ 283,758.12	1.53%	3.54%	5.97%	0.25%	$4,341	$10,045	$16,940	$709	$32,036
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	$ 6,316,485.41	5.07%	32.57%	40.51%	1.51%	$320,246	$2,057,279	$2,558,808	$95,379	$5,031,712
Susquehanna Roseland <500kV (CWIP)	b0489.4	$ (5,604,287.23)	5.07%	32.57%	40.51%	1.51%	-$284,137	-$1,825,316	-$2,270,297	-$84,625	-$4,464,375
Build new 500 kV transmission facilities from Pennsylvania - New Jersey border at Bushkill to Roseland (500kV and above elements of the project)	b0489	$ 127,132,901.55	1.53%	3.54%	5.97%	0.25%	$1,945,133	$4,500,505	$7,589,834	$317,832	$14,353,305
Susquehanna Roseland >500kV CWIP	b0489	$ (20,263,143.38)	1.53%	3.54%	5.97%	0.25%	-$310,026	-$717,315	-$1,209,710	-$50,658	-$2,287,709
Burlington - Camden 230kV Conversion	b1156	$ 42,580,414.02	0.00%	0.00%	96.18%	3.82%	$0	$0	$40,953,842	$1,626,572	$42,580,414
Burlington - Camden 230kV Conversion (CWIP)	b1156	$ 9,513,868.01	0.00%	0.00%	96.18%	3.82%	$0	$0	$9,150,438	$363,430	$9,513,868
West Orange Conversion (North Central Reliability)	b1154	$ 48,245,193.71	0.00%	0.00%	96.18%	3.82%	$0	$0	$46,402,227	$1,842,966	$48,245,194
West Orange Conversion (North Central Reliability) (CWIP)	b1154	$ (2,347,819.55)	0.00%	0.00%	96.18%	3.82%	$0	$0	-$2,258,133	-$89,687	-$2,347,820
Mickleton-Gloucester-Camden	b1398-b1398.7	$ 64,428,974.94	0.00%	12.82%	31.46%	1.25%	$0	$8,259,795	$20,269,356	$805,362	$29,334,512
Mickleton-Gloucester-Camden (CWIP)	b1398-b1398.7	$ (7,214,890.91)	0.00%	12.82%	31.46%	1.25%	$0	-$924,949	-$2,269,805	-$90,186	-$3,284,940
Northeast Grid Reliability Project	b1304.1-b1304.4	$ 119,666,665.77	0.21%	1.06%	63.81%	2.53%	$251,300	$1,268,467	$76,359,299	$3,027,567	$80,906,633
Northeast Grid Reliability Project (CWIP)	b1304.1-b1304.4	$ (19,851,347.56)	0.21%	1.06%	63.81%	2.53%	-$41,688	-$210,424	-$12,667,145	-$502,239	-$13,421,496
Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.21	$ 1,480,229.77	0.77%	1.77%	2.99%	0.13%	$11,324	$26,200	$44,185	$1,850	$83,559
Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (CWIP)	b2436.21	$ 1,492,254.38	0.77%	1.77%	2.99%	0.13%	$11,416	$26,413	$44,544	$1,865	$84,238

Attachment 6a -PJM Schedule 12 - Transmission Enhancement Charges for January 2016 - December 2016
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 2016 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**
Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.22	$ 1,480,229.77	0.77%	1.77%	2.99%	0.13%	$11,324	$26,200	$44,185	$1,850	$83,559
Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (CWIP)	b2436.22	$ 1,127,508.97	0.77%	1.77%	2.99%	0.13%	$8,625	$19,957	$33,656	$1,409	$63,648
Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (CWIP)	b2436.50	$ 1,594,351.75	0.00%	0.00%	0.00%	0.00%					
Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (CWIP)	b2436.60	$ 1,030,613.90	0.00%	0.00%	0.00%	0.00%					
Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (CWIP)	b2436.70	$ 1,853,412.12	0.00%	0.00%	0.00%	0.00%					
Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (CWIP)	b2436.81	$ 1,145,297.49	0.77%	1.77%	37.57%	0.13%	$8,762	$20,272	$430,288	$1,432	$460,753
Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (CWIP)	b2436.83	$ 1,145,297.49	0.77%	1.77%	37.57%	0.13%	$8,762	$20,272	$430,288	$1,432	$460,753
Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades	b2436.90	$ 2,047,239.69	0.77%	1.77%	2.99%	0.13%	$15,661	$36,236	$61,110	$2,559	$115,567
Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (CWIP)	b2436.90	$ 1,150,052.66	0.77%	1.77%	2.99%	0.13%	$8,798	$20,356	$34,329	$1,438	$64,920
New Bergen 345/230 kV transformer and any associated substation upgrades	b2437.10	$ 1,898,793.54	0.00%	0.00%	3.31%	0.13%	$0	$0	$62,825	$2,468	$65,294
New Bergen 345/230 kV transformer and any associated substation upgrades (CWIP)	b2437.10	$ 1,561,800.55	0.00%	0.00%	3.31%	0.13%	$0	$0	$51,675	$2,030	$53,706
New Bergen 345/138 kV transformer #1 and any associated substation upgrades	b2437.11	$ 1,898,793.54	0.00%	0.00%	0.00%	0.00%					
New Bergen 345/138 kV transformer #1 and any associated substation upgrades (CWIP)	b2437.11	$ 1,561,986.10	0.00%	0.00%	0.00%	0.00%					

Attachment 6a -PJM Schedule 12 - Transmission Enhancement Charges for January 2016 - December 2016
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 2016 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*								
New Bayway 345/138 kV transformer #1 and any associated substation upgrades (CWIP)	b2437.20	$ 644,576.28	0.00%	0.00%	0.00%	0.00%					
New Bayway 345/138 kV transformer #2 and any associated substation upgrades (CWIP)	b2437.21	$ 644,666.17	0.00%	0.00%	0.00%	0.00%					
New Linden 345/230 kV transformer and any associated substation upgrades (CWIP)	b2437.30	$ 866,558.50	0.00%	0.00%	0.00%	0.00%					
Totals		**$ 520,436,728.38**					**$4,189,932**	**$35,809,171**	**$247,944,753**	**$9,935,268**	**$297,879,123**
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 2016**	**2016 Trans. Peak Load ^{2}**	**Rate in $/MW-mo. ^{1}**	**2016 Impact (12 months)**	
PSE&G	$ 20,662,062.74	9,594.9	$ 2,153.44	$ 247,944,753	
JCP&L	$ 2,984,097.56	5,818.1	$ 512.90	$ 35,809,171	
ACE	$ 349,161.03	2,552.8	$ 136.78	$ 4,189,932	
RE	$ 827,938.97	397.7	$ 2,081.82	$ 9,935,268	
Total Impact on NJ Zones	**$ 24,823,260.29**	**18,363.5**		**$ 297,879,123**	
Notes on calculations >>>			= (k) / (l)	= (k) *12	

Notes:

1) Uncompressed rate - assumes implementation on January 1, 2016

2) Data on PJM website

Attachment 6b
Potomac-Appalachian Transmission Highline Project Charges

Attachment 6b Potomac-Allegheny Transmission Highline (PATH)
PJM Schedule 12 - Transmission Enhancement Charges for January 2016 - December 2016
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 2016 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	$	14,648,480.37	1.53%	3.54%	5.97%	0.25%	$224,122	$518,556	$874,514	$36,621	$1,653,813
Amos-Bedington 765 kV Circuit (APS)	b0491	Included above		1.53%	3.54%	5.97%	0.25%	$0	$0	$0	$0	$0
Bedington-Kemptown 500 kV Circuit	b0492 & b560	$	14,569,367.93	1.53%	3.54%	5.97%	0.25%	$222,911	$515,756	$869,791	$36,423	$1,644,882
Totals		**$**	**29,217,848.30**					**$447,033**	**$1,034,312**	**$1,744,306**	**$73,045**	**$3,298,695**
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 2016**	**2016 Trans. Peak Load**[2]	**Rate in $/MW-mo.**[1]		**2016 Impact (12 months)**
PSE&G	$	145,358.80	9,594.9	$15.15	$	1,744,306
JCP&L	$	86,192.65	5,818.1	$14.81	$	1,034,312
ACE	$	37,252.76	2,552.8	$14.59	$	447,033
RE	$	6,087.05	397.7	$15.31	$	73,045
Total Impact on NJ Zones	**$**	**274,891.26**	**18,363.5**		**$**	**3,298,695**
Notes on calculations >>>				= (k) / (l)		= (k) *12

Notes:
1) Uncompressed rate - assumes implementation on January 1, 2016
2) Data on PJM website

Attachment 6c
Virginia Electric Power Company Project Charges

Attachment 6c - PJM Schedule 12 - Transmission Enhancement Charges for January 2016 - December 2016
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 2016 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	$249,935.00	1.53%	3.54%	5.97%	0.25%	$3,824	$8,848	$14,921	$625	$28,218
Loudoun 150 MVA capacitor @ 500 kV	b0222	$228,296.00	1.53%	3.54%	5.97%	0.25%	$3,493	$8,082	$13,629	$571	$25,775
500 kV breakers and bus work at Suffolk	b0231	$2,923,307.00	1.53%	3.54%	5.97%	0.25%	$44,727	$103,485	$174,521	$7,308	$330,041
Meadowbrook-Loudon 500kV circuit	b0328.1	$32,848,646.00	1.53%	3.54%	5.97%	0.25%	$502,584	$1,162,842	$1,961,064	$82,122	$3,708,612
Upgrade Mt. Storm 500 KV Substation	b0328.3	$1,993,985.00	1.53%	3.54%	5.97%	0.25%	$30,508	$70,587	$119,041	$4,985	$225,121
Upgrade Loudoun 500 KV Substation	b0328.4	$453,787.00	1.53%	3.54%	5.97%	0.25%	$6,943	$16,064	$27,091	$1,134	$51,233
Carson – Suffolk 500 kV, Suffolk 500/230 kV transformer & build Suffolk – Trascher 230 kV circuit	B0329.2B	$23,751,985.00	1.53%	3.54%	5.97%	0.25%	$363,405	$840,820	$1,417,994	$59,380	$2,681,599
500/230 KV transformer at Bristers, new 230 Bristers - Gainsville circuit	b0227	$2,810,247.00	0.71%	0.00%	0.00%	0.00%	$19,953	$0	$0	$0	$19,953
Rebuild Mt Storm-Doubs 500 KV circuit	b1507	$48,941,258.00	1.53%	3.54%	5.97%	0.25%	$748,801	$1,732,521	$2,921,793	$122,353	$5,525,468
Replace wave traps on Dooms-Lexington 500KV circuit	b0457	$14,939.00	1.53%	3.54%	5.97%	0.25%	$229	$529	$892	$37	$1,687
Morrisville H1T573	b1647	$4,627.00	1.53%	3.54%	5.97%	0.25%	$71	$164	$276	$12	$522
Morrisville H2T545	b1648	$4,627.00	1.53%	3.54%	5.97%	0.25%	$71	$164	$276	$12	$522
Morrisville H1T580	b1649	$117,878.00	1.53%	3.54%	5.97%	0.25%	$1,804	$4,173	$7,037	$295	$13,308
Morrisville H2T569	b1650	$117,878.00	1.53%	3.54%	5.97%	0.25%	$1,804	$4,173	$7,037	$295	$13,308
Replace wave traps on North Anna-Ladysmith 500KV circuit	b0784	$10,367.00	1.53%	3.54%	5.97%	0.25%	$159	$367	$619	$26	$1,170
Reconductor the Dickerson-Pleasant View 230 KV circuit	b0467.2	$755,135.00	1.75%	0.71%	0.00%	0.00%	$13,215	$5,361	$0	$0	$18,576
Install 500/230 kV transformer and two 230 kV breakers at Brambleton	b1188.6	$2,636,464.00	0.22%	0.00%	0.00%	0.00%	$5,800	$0	$0	$0	$5,800
New Brambleton 500 kV line, 3 ring bus, to Loudon to Pleasant View 500 kV	b1188	$1,968,983.00	1.53%	3.54%	5.97%	0.25%	$30,125	$69,702	$117,548	$4,922	$222,298
500 kV breaker at Brambleton	b1698.1	($76,836.00)	1.53%	3.54%	5.97%	0.25%	-$1,176	-$2,720	-$4,587	-$192	-$8,675
Install 2 500kV breakers at Chancellor 500 kV	b0756.1	$702,538.00	1.53%	3.54%	5.97%	0.25%	$10,749	$24,870	$41,942	$1,756	$79,317
Wreck and Rebuild 7 miles of Cloverdale - Lexington 500 kV Line	b1797	$3,516,298.00	1.53%	3.54%	5.97%	0.25%	$53,799	$124,477	$209,923	$8,791	$396,990
Build 450 MVAR SVC and 300 MVAR switched shunt at Loudoun 500 kV	b1798	$17,866,527.00	1.53%	3.54%	5.97%	0.25%	$273,358	$632,475	$1,066,632	$44,666	$2,017,131
Build 150 MVAR Switched Shunt at Pleasant View 500 kV Line	b1799	$3,170,226.00	1.53%	3.54%	5.97%	0.25%	$48,504	$112,226	$189,262	$7,926	$357,919
Install 250 MVAR SVC at Mt. Storm 500 kV Substation	b1805	$5,770,625.00	1.53%	3.54%	5.97%	0.25%	$88,291	$204,280	$344,506	$14,427	$651,504
At Yadkin 500 kV, install six 500 kV Breakers	b1906.1	$1,406,102.00	1.53%	3.54%	5.97%	0.25%	$21,513	$49,776	$83,944	$3,515	$158,749

Attachment 6c - PJM Schedule 12 - Transmission Enhancement Charges for January 2016 - December 2016
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 2016 Annual Revenue Requirement *per PJM website*	ACE Zone Share *per PJM Open Access Transmission Tariff*	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
Rebuild Lexington-Dooms 500 kV Line	b1908	$13,906,041.00	1.53%	3.54%	5.97%	0.25%	$212,762	$492,274	$830,191	$34,765	$1,569,992
Surry 500 kV Station Work	b1905.2	$452,711.00	1.53%	3.54%	5.97%	0.25%	$6,926	$16,026	$27,027	$1,132	$51,111
Mt Storm - Replace MOD with breaker on 500kV side of Transformer	b0837	$102,303.00	1.53%	3.54%	5.97%	0.25%	$1,565	$3,622	$6,107	$256	$11,550
Uprate Section between Possum and Dumfries Substation	b1328	$575,562.00	0.66%	0.00%	0.00%	0.00%	$3,799	$0	$0	$0	$3,799
Rebuild Loudoun - Brambleto 500kV	b1694	$2,682,860.00	1.53%	3.54%	5.97%	0.25%	$41,048	$94,973	$160,167	$6,707	$302,895
R/P Midlothian 500kV 3 breaker Ring Bus	b2471	$1,058,264.00	0.77%	1.77%	2.99%	0.13%	$8,096	$18,731	$31,589	$1,323	$59,739
Totals		**$ 170,965,565.00**					**$2,546,750**	**$5,798,891**	**$9,770,444**	**$409,148**	**$18,525,232**
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 2016**	**2016 Trans. Peak Load [2]**	**Rate in $/MW-mo. [1]**	**2016 Impact (12 months)**
PSE&G	$ 814,203.65	9,594.9	$ 84.86	$ 9,770,444
JCP&L	$ 483,240.91	5,818.1	$ 83.06	$ 5,798,891
ACE	$ 212,229.14	2,552.8	$ 83.14	$ 2,546,750
RE	$ 34,095.63	397.7	$ 85.73	$ 409,148
Total Impact on NJ Zones	**$ 1,543,769.33**	**18,363.5**		**$ 18,525,232**
Notes on calculations >>>			= (k) / (l)	= (k) *12

Attachment 7 – Cost Allocations

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

NOTE: The “Responsible Share” percentages (annual cost allocation) for regional facilities were amended by PJM after the issues of the PJM OATT tariff pages. PJM has not yet issued an updated tariff to reflect its modifications of the Responsible Share percentages. For these regional projects, PJM’s modifications allocate the new updated responsible percentages to New Jersey’s EDCs as follow: 1.53% for ACE; 3.54% for JCP&L; 0.25% for RE; and 5.97% for PSE&G

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

Source – PJM OATT

SCHEDULE 12 – APPENDIX

(12) Public Service Electric and Gas Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0025	Convert the Bergen-Leonia 138 Kv circuit to 230 kV circuit.		PSEG (100%)
b0090	Add 150 MVAR capacitor at Camden 230 kV		PSEG (100%)
b0121	Add 150 MVAR capacitor at Aldene 230 kV		PSEG (100%)
b0122	Bypass the Essex 138 kV series reactors		PSEG (100%)
b0125	Add Special Protection Scheme at Bridgewater to automatically open 230 kV breaker for outage of Branchburg – Deans 500 kV and Deans 500/230 kV #1 transformer		PSEG (100%)
b0126	Replace wavetrap on Branchburg – Flagtown 230 kV		PSEG (100%)
b0127	Replace terminal equipment to increase Brunswick – Adams – Bennetts Lane 230 kV to conductor rating		PSEG (100%)
b0129	Replace wavetrap on Flagtown – Somerville 230 kV		PSEG (100%)
b0130	Replace all derated Branchburg 500/230 kV transformers		AEC (1.36%) / ConEd (0.26%) / JCPL (47.63%) / PSEG (50.75%)
b0134	Upgrade or Retension PSEG portion of Kittatinny – Newton 230 kVcircuit		JCPL (51.11%) / PSEG (45.96%) / RE (2.93%)

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0145	Build new Essex – Aldene 230 kV cable connected through a phase angle regulator at Essex		PSEG (21.78%) / JCPL (73.45%) /RE (4.77%)
b0157	Add 100MVAR capacitor at West Orange 138kV substation		PSEG (100%)
b0158	Close the Sunnymeade "C" and "F" bus tie		PSEG (100%)
b0159	Make the Bayonne reactor permanent installation		PSEG (100%)
b0160	Relocate the X-2250 circuit from Hudson 1-6 bus to Hudson 7-12 bus		PSEG (100%)
b0161	Install 230/138kV transformer at Metuchen substation		PSEG (99.80%) / RE (0.20%)
b0162	Upgrade the Edison – Meadow Rd 138kV "Q" circuit		PSEG (100%)
b0163	Upgrade the Edison – Meadow Rd 138kV "R" circuit		PSEG (100%)
b0169	Build a new 230 kV section from Branchburg – Flagtown and move the Flagtown – Somerville 230 kV circuit to the new section		AEC (1.70%) / ConEd (1.06%) / JCPL (25.66%) / Neptune* (10.51%) / PSEG (58.96%) / ECP** (2.11%)
b0170	Reconductor the Flagtown-Somerville-Bridgewater 230 kV circuit with 1590 ACSS		JCLP (42.95%) / Neptune* (17.90%) / PSEG (38.36%) RE (0.79%)

* Neptune Regional Transmission System, LLC

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0172.2	Replace wave trap at Branchburg 500kV substation		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0184	Replace Hudson 230kV circuit breakers #1-2		PSEG (100%)
b0185	Replace Deans 230kV circuit breakers #9-10		PSEG (100%)
b0186	Replace Essex 230kV circuit breaker #5-6		PSEG (100%)
b1082	Install 230/138 kV transformer at Bergen substation		PENELEC (16.52%) / PSEG (80.29%) / RE (3.19%)

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0201	Branchburg substation: replace wave trap on Branchburg – Readington 230 kV circuit		PSEG (100%)
b0213.1	Replace New Freedom 230 kV breaker BS2-6		PSEG (100%)
b0213.3	Replace New Freedom 230 kV breaker BS2-8		PSEG (100%)
b0274	Replace both 230/138 kV transformers at Roseland		ConEd (8.48%) / PSEG (88.56%) / ECP** (2.96%)
b0275	Upgrade the two 138 kV circuits between Roseland and West Orange		PSEG (100%)
b0278	Install 228 MVAR capacitor at Roseland 230 kV substation		PSEG (100%)
b0290	Install 400 MVAR capacitor in the Branchburg 500 kV vicinity		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0358	Reconductor the PSEG portion of Buckingham – Pleasant Valley 230 kV, replace wave trap and metering transformer		PSEG (100%)

* Neptune Regional Transmission System, LLC

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

Public Service Electric and Gas Company (cont.)

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

Public Service Electric and Gas Company (cont.)

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

Public Service Electric and Gas Company (cont.)

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0472	Increase the emergency rating of Saddle Brook – Athenia 230 kV by 25% by adding forced cooling		ConEd (1.64%) / ECP (2.03%) / PSEG (92.86%) / RE (3.47%)
b0473	Move the 150 MVAR mobile capacitor from Aldene 230 kV to Lawrence 230 kV substation		PSEG (100%)
b0489	Build new 500 kV transmission facilities from Pennsylvania – New Jersey border at Bushkill to Roseland		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)†
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. 07%) / ComEd (0.29%) / ConEd (0.48%) / Dayton (0.03%) / DPL (1.75%) / JCPL (32.57%) / Neptune* (6.29%) / PECO (9.99%) / PENELEC (0.56%) / ECP** (0.95%) / PSEG (40.51%) / RE (1.51%) ††

* Neptune Regional Transmission System, LLC
** East Coast Power, L.L.C.
†Cost allocations associated with Regional Facilities and Necessary Lower Voltage Facilities associated with the project
††Cost allocations associated with below 500 kV elements of the project

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0489.5	Replace Roseland 230 kV breaker '42H' with 80 kA		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0489.6	Replace Roseland 230 kV breaker '51H' with 80 kA		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0489.7	Replace Roseland 230 kV breaker '71H' with 80 kA		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0489.8	Replace Roseland 230 kV breaker '31H' with 80 kA		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)

* Neptune Regional Transmission System, LLC

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0489.9	Replace Roseland 230 kV breaker '11H' with 80 kA		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0489.10	Replace Roseland 230 kV breaker '21H'		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0489.11	Replace Roseland 230 kV breaker '32H'		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0489.12	Replace Roseland 230 kV breaker '12H'		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0489.13	Replace Roseland 230 kV breaker '52H'		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0489.14	Replace Roseland 230 kV breaker '41H'		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0489.15	Replace Roseland 230 kV breaker '72H'		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0498	Loop the 5021 circuit into New Freedom 500 kV substation		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0498.1	Upgrade the 20H circuit breaker		PSEG (100%)
b0498.2	Upgrade the 22H circuit breaker		PSEG (100%)
b0498.3	Upgrade the 30H circuit breaker		PSEG (100%)
b0498.4	Upgrade the 32H circuit breaker		PSEG (100%)
b0498.5	Upgrade the 40H circuit breaker		PSEG (100%)
b0498.6	Upgrade the 42H circuit breaker		PSEG (100%)

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512	MAPP Project – install new 500 kV transmission from Possum Point to Calvert Cliffs and install a DC line from Calvert Cliffs to Vienna and a DC line from Calvert Cliffs to Indian River		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0565	Install 100 MVAR capacitor at Cox's Corner 230 kV substation		PSEG (100%)
b0578	Replace Essex 138 kV breaker 4LM (C1355 line to ECRRF)		PSEG (100%)
b0579	Replace Essex 138 kV breaker 1LM (220-1 TX)		PSEG (100%)
b0580	Replace Essex 138 kV breaker 1BM (BS1-3 tie)		PSEG (100%)
b0581	Replace Essex 138 kV breaker 2BM (BS3-4 tie)		PSEG (100%)
b0582	Replace Linden 138 kV breaker 3 (132-7 TX)		PSEG (100%)
b0592	Replace Metuchen 138 kV breaker '2-2 Transfer'		PSEG (100%)
b0664	Reconductor with 2x1033 ACSS conductor		JCPL (36.35%) / NEPTUNE* (18.80%) / PSEG (43.24%) / RE (1.61%)

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

Public Service Electric and Gas Company (cont.)

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

*Neptune Regional Transmission System, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0814.9	Replace Essex 138 kV breaker '2LM' with 63 kA breaker and 2.5 cycle contact parting time		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.10	Replace Essex 138 kV breaker '1BT' with 63 kA breaker and 2.5 cycle contact parting time		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.11	Replace Essex 138 kV breaker '2PM' with 63 kA breaker and 2.5 cycle contact parting time		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.12	Replace Marion 138 kV breaker '2HM' with 63 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.13	Replace Marion 138 kV breaker '2LM' with 63 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.14	Replace Marion 138 kV breaker '1LM' with 63 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.15	Replace Marion 138 kV breaker '6PM' with 63 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.16	Replace Marion 138 kV breaker '3PM' with 63 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.17	Replace Marion 138 kV breaker '4LM' with 63 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)

*Neptune Regional Transmission System, LLC

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 (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0829.6	Replace Branchburg 500 kV breaker 91X		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0829.9	Replace Branchburg 230 kV breaker 102H		PSEG (100%)

*Neptune Regional Transmission System, LLC

**East Coast Power, L.L.C

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0829.11	Replace Branchburg 230 kV breaker 32H		PSEG (100%)
b0829.12	Replace Branchburg 230 kV breaker 52H		PSEG (100%)

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0830	Build Roseland - Hudson 500 kV circuit as part of Branchburg – Hudson 500 kV project		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
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%)

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0830.3	Replace Roseland 230 kV breaker '22H' with 80 kA		PSEG (100%)
b0831	Replace 138/13 kV transformers with 230/13 kV units as part of Branchburg – Hudson 500 kV project		ComEd (2.51%) / Dayton (0.09%) / PENELEC (2.75%) / ECP** (2.45%) / PSEG (88.74%) / RE (3.46%)
b0832	Build Hudson 500 kV switching station as part of Branchburg – Hudson 500 kV project		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) /PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0833	Build Roseland 500 kV switching station as part of Branchburg – Hudson 500 kV project		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) /PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)

*Neptune Regional Transmission System, LLC

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0834	Convert the E-1305/F-1306 to one 230 kV circuit as part of Branchburg – Hudson 500 kV project		ComEd (2.51%) / Dayton (0.09%) / PENELEC (2.75%) / ECP** (2.45%) / PSEG (88.74%) / RE (3.46%)
b0835	Build Hudson 230 kV transmission lines as part of Roseland – Hudson 500 kV project as part of Branchburg – Hudson 500 kV project		ComEd (2.51%) / Dayton (0.09%) / PENELEC (2.75%) / ECP** (2.45%) / PSEG (88.74%) / RE (3.46%)
b0836	Install transformation at new Hudson 500 kV switching station and perform Hudson 230 kV and 345 kV station work as part of Branchburg – Hudson 500 kV project		ComEd (2.51%) / Dayton (0.09%) / PENELEC (2.75%) / ECP** (2.45%) / PSEG (88.74%) / RE (3.46%)
b0882	Replace Hudson 230 kV breaker 1HA with 80 kA		PSEG (100%)
b0883	Replace Hudson 230 kV breaker 2HA with 80 kA		PSEG (100%)
b0884	Replace Hudson 230 kV breaker 3HB with 80 kA		PSEG (100%)
b0885	Replace Hudson 230 kV breaker 4HA with 80 kA		PSEG (100%)
b0886	Replace Hudson 230 kV breaker 4HB with 80 kA		PSEG (100%)
b0889	Replace Bergen 230 kV breaker '21H'		PSEG (100%)
b0890	Upgrade New Freedom 230 kV breaker '21H'		PSEG (100%)
b0891	Upgrade New Freedom 230 kV breaker '31H'		PSEG (100%)
b0899	Replace ECRR 138 kV breaker 901		PSEG (100%)
b0900	Replace ECRR 138 kV breaker 902		PSEG (100%)

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1013	Replace Linden 138 kV breaker '7PB'		PSEG (100%)
b1017	Reconductor South Mahwah - Waldwick 345 kV J-3410 circuit		ConEd (49.36%) / JCPL (14.69%) / NEPTUNE* (1.39%) / PSEG (32.84%) / RE (1.28%) / ECP** (0.44%)
b1018	Reconductor South Mahwah - Waldwick 345 kV K-3411 circuit		ConEd (49.38%) / JCPL (14.77%) / NEPTUNE* (1.39%) / PSEG (32.74%) / RE (1.28%) / ECP** (0.44%)
b1019.1	Replace wave trap, line disconnect and ground switch at Roseland on the F-2206 circuit		PSEG (100%)
b1019.2	Replace wave trap, line disconnect and ground switch at Roseland on the B-2258 circuit		PSEG (100%)
b1019.3	Replace 1-2 and 2-3 section disconnect and ground switches at Cedar Grove on the F-2206 circuit		PSEG (100%)
b1019.4	Replace 1-2 and 2-3 section disconnect and ground switches at Cedar Grove on the B-2258 circuit		PSEG (100%)
b1019.5	Replace wave trap, line disconnect and ground switch at Cedar Grove on the F-2206 circuit		PSEG (100%)
b1019.6	Replace line disconnect and ground switch at Cedar Grove on the K-2263 circuit		PSEG (100%)
b1019.7	Replace 2-4 and 4-5 section disconnect and ground switches at Clifton on the B-2258 circuit		PSEG (100%)
b1019.8	Replace 1-2 and 2-3 section disconnect and ground switches at Clifton on the K-2263 circuit		PSEG (100%)
b1019.9	Replace line, ground, 230 kV main bus disconnects at Athenia on the B-2258 circuit		PSEG (100%)

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1019.10	Replace wave trap, line, ground 230 kV breaker disconnect and 230 kV main bus disconnects at Athenia on the K-2263 circuit		PSEG (100%)
b1082.1	Replace Bergen 138 kV breaker '30P' with 80 kA		PSEG (100%)
b1082.2	Replace Bergen 138 kV breaker '80P' with 80 kA		PSEG (100%)
b1082.3	Replace Bergen 138 kV breaker '70P' with 80 kA		PSEG (100%)
b1082.4	Replace Bergen 138 kV breaker '90P' with 63 kA		PSEG (100%)
b1082.5	Replace Bergen 138 kV breaker '50P' with 63 kA		PSEG (100%)
b1082.6	Replace Bergen 230 kV breaker '12H' with 80 kA		PSEG (100%)
b1082.7	Replace Bergen 230 kV breaker '21H' with 80 kA		PSEG (100%)
b1082.8	Replace Bergen 230 kV breaker '11H' with 80 kA		PSEG (100%)
b1082.9	Replace Bergen 230 kV breaker '20H' with 80 kA		PSEG (100%)
b1098	Re-configure the Bayway 138 kV substation and install three new 138 kV breakers		PSEG (100%)
b1099	Build a new 230 kV substation by tapping the Aldene – Essex circuit and install three 230/26 kV transformers, and serve some of the Newark area load from the new station		PSEG (100%)
b1100	Build a new 138 kV circuit from Bayonne to Marion		PSEG (100%)
b1101	Re-configure the Cedar Grove substation with breaker and half scheme and build a new 69 kV circuit from Cedar Grove to Hinchman		PSEG (100%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1154	Convert the West Orange 138 kV substation, the two Roseland – West Orange 138 kV circuits, and the Roseland – Sewaren 138 kV circuit from 138 kV to 230 kV		PSEG (96.18%) / RE (3.82%)
b1155	Build a new 230 kV circuit from Branchburg to Middlesex Sw. Rack. Build a new 230 kV substation at Middlesex		JCPL (4.61%) / PSEG (91.75%) / RE (3.64%)
b1155.3	Replace Branchburg 230 kV breaker '81H' with 63 kA		PSEG (100%)
b1155.4	Replace Branchburg 230 kV breaker '72H' with 63 kA		PSEG (100%)
b1155.5	Replace Branchburg 230 kV breaker '61H' with 63 kA		PSEG (100%)
b1155.6	Replace Branchburg 230 kV breaker '41H' with 63 kA		PSEG (100%)
b1156	Convert the Burlington, Camden, and Cuthbert Blvd 138 kV substations, the 138 kV circuits from Burlington to Camden, and the 138 kV circuit from Camden to Cuthbert Blvd. from 138 kV to 230 kV		PSEG (96.18%) / RE (3.82%)
b1156.13	Replace Camden 230 kV breaker '22H' with 80 kA		PSEG (100%)
b1156.14	Replace Camden 230 kV breaker '32H' with 80 kA		PSEG (100%)
b1156.15	Replace Camden 230 kV breaker '21H' with 80 kA		PSEG (100%)
b1156.16	Replace New Freedom 230 kV breaker '50H' with 63 kA		PSEG (100%)
b1156.17	Replace New Freedom 230 kV breaker '41H' with 63 kA		PSEG (100%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1156.18	Replace New Freedom 230 kV breaker '51H' with 63 kA		PSEG (100%)
b1156.19	Rebuild Camden 230 kV to 80 kA		PSEG (100%)
b1156.20	Rebuild Burlington 230 kV to 80 kA		PSEG (100%)
b1197.1	Reconductor the PSEG portion of the Burlington – Croydon circuit with 1590 ACSS		PSEG (100%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1228	Re-configure the Lawrence 230 kV substation to breaker and half		HTP (0.14%) / ECP (0.22%) / PSEG (95.83%) / RE (3.81%)
b1255	Build a new 69 kV substation (Ridge Road) and build new 69 kV circuits from Montgomery – Ridge Road – Penns Neck/Dow Jones		PSEG (96.18%) / RE (3.82%)
b1304.1	Convert the existing 'D1304' and 'G1307' 138 kV circuits between Roseland – Kearny – Hudson to 230 kV operation		AEC (0.21%) / BGE (0.88%) / ComEd (2.11%) / ConEd (9.05%) / Dayton (0.12%) / JCPL (1.06%) / Neptune (0.06%) / HTP (14.60%) / PENELEC (2.70%) / PEPCO (0.95%) / ECP (1.92%) / PSEG (63.81%) / RE (2.53%)
b1304.2	Expand existing Bergen 230 kV substation and reconfigure the Athenia 230 kV substation to breaker and a half scheme		AEC (0.21%) / BGE (0.88%) / ComEd (2.11%) / ConEd (9.05%) / Dayton (0.12%) / JCPL (1.06%) / Neptune (0.06%) / HTP (14.60%) / PENELEC (2.70%) / PEPCO (0.95%) / ECP (1.92%) / PSEG (63.81%) / RE (2.53%)
b1304.3	Build second 230 kV underground cable from Bergen to Athenia		AEC (0.21%) / BGE (0.88%) / ComEd (2.11%) / ConEd (9.05%) / Dayton (0.12%) / JCPL (1.06%) / Neptune (0.06%) / HTP (14.60%) / PENELEC (2.70%) / PEPCO (0.95%) / ECP (1.92%) / PSEG (63.81%) / RE (2.53%)
b1304.4	Build second 230 kV underground cable from Hudson to South Waterfront		AEC (0.21%) / BGE (0.88%) / ComEd (2.11%) / ConEd (9.05%) / Dayton (0.12%) / JCPL (1.06%) / Neptune (0.06%) / HTP (14.60%) / PENELEC (2.70%) / PEPCO (0.95%) / ECP (1.92%) / PSEG (63.81%) / RE (2.53%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1304.5	Replace Athenia 230 kV breaker '21H' with 80 kA		PSEG (100%)
b1304.6	Replace Athenia 230 kV breaker '41H' with 80 kA		PSEG (100%)
b1304.7	Replace South Waterfront 230 kV breaker '12H' with 80 kA		PSEG (100%)
b1304.8	Replace South Waterfront 230 kV breaker '22H' with 80 kA		PSEG (100%)
b1304.9	Replace South Waterfront 230 kV breaker '32H' with 80 kA		PSEG (100%)
b1304.10	Replace South Waterfront 230 kV breaker '52H' with 80 kA		PSEG (100%)
b1304.11	Replace South Waterfront 230 kV breaker '62H' with 80 kA		PSEG (100%)
b1304.12	Replace South Waterfront 230 kV breaker '72H' with 80 kA		PSEG (100%)
b1304.13	Replace South Waterfront 230 kV breaker '82H' with 80 kA		PSEG (100%)
b1304.14	Replace Essex 230 kV breaker '20H' with 80 kA		PSEG (100%)
b1304.15	Replace Essex 230 kV breaker '21H' with 80 kA		PSEG (100%)
b1304.16	Replace Essex 230 kV breaker '10H' with 80 kA		PSEG (100%)
b1304.17	Replace Essex 230 kV breaker '11H' with 80 kA		PSEG (100%)
b1304.18	Replace Essex 230 kV breaker '11HL' with 80 kA		PSEG (100%)
b1304.19	Replace Newport R 230 kV breaker '23H' with 63 kA		PSEG (100%)
b1304.20	Rebuild Athenia 230 kV substation to 80 kA		PSEG (100%)
b1304.21	Rebuild Bergen 230 kV substation to 80 kA		PSEG (100%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1398	Build two new parallel underground circuits from Gloucester to Camden		JCPL (12.82%) / NEPTUNE (1.18%) / HTP (0.79%) / PECO (51.08%) / PEPCO (0.57%) / ECP** (0.85%) / PSEG (31.46%) / RE (1.25%)
b1398.1	Install shunt reactor at Gloucester to offset cable charging		JCPL (12.82%) / NEPTUNE (1.18%) / HTP (0.79%) / PECO (51.08%) / PEPCO (0.57%) / ECP** (0.85%) / PSEG (31.46%) / RE (1.25%)
b1398.2	Reconfigure the Cuthbert station to breaker and a half scheme		JCPL (12.82%) / NEPTUNE (1.18%) / HTP (0.79%) / PECO (51.08%) / PEPCO (0.57%) / ECP** (0.85%) / PSEG (31.46%) / RE (1.25%)
b1398.3	Build a second 230 kV parallel overhead circuit from Mickelton – Gloucester		JCPL (12.82%) / NEPTUNE (1.18%) / HTP (0.79%) / PECO (51.08%) / PEPCO (0.57%) / ECP** (0.85%) / PSEG (31.46%) / RE (1.25%)
b1398.4	Reconductor the existing Mickleton – Gloucester 230 kV circuit (PSEG portion)		JCPL (12.82%) / NEPTUNE (1.18%) / HTP (0.79%) / PECO (51.08%) / PEPCO (0.57%) / ECP** (0.85%) / PSEG (31.46%) / RE (1.25%)
b1398.7	Reconductor the Camden – Richmond 230 kV circuit (PSEG portion) and upgrade terminal equipments at Camden substations		JCPL (12.82%) / NEPTUNE (1.18%) / HTP (0.79%) / PECO (51.08%) / PEPCO (0.57%) / ECP** (0.85%) / PSEG (31.46%) / RE (1.25%)

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1398.15	Replace Gloucester 230 kV breaker '21H' with 63 kA		PSEG (100%)
b1398.16	Replace Gloucester 230 kV breaker '51H' with 63 kA		PSEG (100%)
b1398.17	Replace Gloucester 230 kV breaker '56H' with 63 kA		PSEG (100%)
b1398.18	Replace Gloucester 230 kV breaker '26H' with 63 kA		PSEG (100%)
b1398.19	Replace Gloucester 230 kV breaker '71H' with 63 kA		PSEG (100%)
b1399	Convert the 138 kV path from Aldene – Springfield Rd. – West Orange to 230 kV		PSEG (96.18%) / RE (3.82%)
b1400	Install 230 kV circuit breakers at Bennetts Ln. "F" and "X" buses		PSEG (100%)

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1410	Replace Salem 500 kV breaker ‘11X’		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b1411	Replace Salem 500 kV breaker ‘12X’		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b1412	Replace Salem 500 kV breaker ‘20X’		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1413	Replace Salem 500 kV breaker '21X'		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b1414	Replace Salem 500 kV breaker '31X'		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b1415	Replace Salem 500 kV breaker '32X'		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)

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

Public Service Electric and Gas Company (cont.)

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

*Neptune Regional Transmission System, LLC

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements   Annual Revenue Requirement   Responsible Customer(s)

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

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

Public Service Electric and Gas Company (cont.)

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

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

SCHEDULE 12 – APPENDIX A

(12) Public Service Electric and Gas Company

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

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

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2276	Eliminate the Sewaren 138 kV bus by installing a new 230 kV bay at Sewaren 230 kV		ConEd (*50.82%*) / ECP** (*49.18%*)
b2276.1	Convert the two 138 kV circuits from Sewaren – Metuchen to 230 kV circuits including Lafayette and Woodbridge substation		ConEd (*50.82%*) / ECP** (*49.18%*)
b2276.2	Reconfigure the Metuchen 230 kV station to accommodate the two converted circuits		ConEd (*50.82%*) / ECP** (*49.18%*)
b2290	Replace disconnect switches at Kilmer, Lake Nilson and Greenbrook 230 kV substations on the Raritian River - Middlesex (I-1023) circuit		PSEG (100%)
b2291	Replace circuit switcher at Lake Nelson 230 kV substation on the Raritian River - Middlesex (W-1037) circuit		PSEG (100%)
b2295	Replace the Salem 500 kV breaker 10X with 63kA breaker		PSEG (100%)
b2421	*Install all 69kV lines to interconnect Plainfield, Greenbrook, and Bridgewater stations and establish the 69kV network*		*PSEG (100%)*
b2421.1	*Install two 18MVAR capacitors at Plainfield and S. Second St substation*		*PSEG (100%)*

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		*Annual Revenue Requirement*	*Responsible Customer(s)*
b2421.2	*Install a second four (4) breaker 69kV ring bus at Bridgewater Switching Station*		*PSEG (100%)*
b2436.11	*Convert the Bergen - Homestead "F" 138 kV circuit to 345 kV and any associated substation upgrades*		***Load-Ratio Share Allocation:*** *AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP*** (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)*
			DFAX Allocation: *ConEd (94.04%) / HTP*** (0.51%) / ECP** (5.45%)*
b2436.12	*Convert the Bergen - North Bergen "E" 138 kV circuit to 345 kV and any associated substation upgrades*		***Load-Ratio Share Allocation:*** *AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP*** (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)*
			DFAX Allocation: *ConEd (94.32%) / HTP*** (0.22%) / ECP** (5.46%)*

**Neptune Regional Transmission System, LLC*

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

****Hudson Transmission Partners, LLC*

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		*Annual Revenue Requirement*	*Responsible Customer(s)*
b2436.13	*Convert the North Bergen - Homestead "E" 138 kV circuit to 345 kV and any associated substation upgrades*		***Load-Ratio Share Allocation:*** *AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP*** (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)*
			DFAX Allocation: *ConEd (93.88%) / HTP*** (0.68%) / ECP** (5.44%)*
b2436.14	*Convert the Homestead - Marion "E" 138 kV circuit to 345 kV and any associated substation upgrades*		***Load-Ratio Share Allocation:*** *AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP*** (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)*
			DFAX Allocation: *ConEd (92.09%) / HTP*** (0.44%) / ECP** (5.33%) / PSEG (2.06%) / RE (0.08%)*

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		*Annual Revenue Requirement*	*Responsible Customer(s)*
b2436.15	*Convert the Homestead - Marion "F" 138 kV circuit to 345 kV and any associated substation upgrades*		***Load-Ratio Share Allocation:*** *AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP*** (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)* ***DFAX Allocation:*** *ConEd (92.45%) / HTP*** (0.39%) / ECP** (5.35%) / PSEG (1.74%) / RE (0.07%)*
b2436.21	*Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades*		***Load-Ratio Share Allocation:*** *AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP*** (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)* ***DFAX Allocation:*** *ConEd (85.83%) / HTP*** (13.21%) / ECP** (0.96%)*

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		*Annual Revenue Requirement*	*Responsible Customer(s)*
b2436.22	*Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades*		***Load-Ratio Share Allocation:*** *AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP*** (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)*
			DFAX Allocation: *ConEd (85.83%) / HTP*** (13.21%) / ECP** (0.96%)*
b2436.31	*Convert the Bayonne - PVSC "I" 138 kV circuit to 345 kV and any associated substation upgrades*		***Load-Ratio Share Allocation:*** *AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP*** (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)*
			DFAX Allocation: *ConEd (86.70%) / HTP*** (12.33%) / ECP** (0.97%)*

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		*Annual Revenue Requirement*	*Responsible Customer(s)*
b2436.32	*Construct a new Bayonne - PVSC 345 kV circuit and any associated substation upgrades*		***Load-Ratio Share Allocation:*** *AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP*** (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)*
			DFAX Allocation: *ConEd (86.67%) / HTP*** (12.32%) / ECP** (1.01%)*
b2436.41	*Convert the PVSC - North Ave "E" 138 kV circuit to 345 kV and any associated substation upgrades*		***Load-Ratio Share Allocation:*** *AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP*** (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)*
			DFAX Allocation: *ConEd (86.92%) / HTP*** (12.36%) / ECP** (0.72%)*

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		*Annual Revenue Requirement*	*Responsible Customer(s)*
b2436.42	*Construct a new PVSC - North Ave 345 kV circuit and any associated substation upgrades*		***Load-Ratio Share Allocation:*** *AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP*** (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)*
			DFAX Allocation: *ConEd (86.93%) / HTP*** (12.36%) / ECP** (0.71%)*
b2436.50	*Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades*		*ConEd (86.59%) / HTP*** (12.31%) / ECP** (1.10%)*
b2436.60	*Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades*		*ConEd (87.35%) / HTP*** (12.42%) / ECP** (0.23%)*
b2436.70	*Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades*		*ConEd (87.43%) / HTP*** (12.43%) / ECP** (0.14%)*

**Neptune Regional Transmission System, LLC*

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

****Hudson Transmission Partners, LLC*

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		*Annual Revenue Requirement*	*Responsible Customer(s)*
b2436.81	*Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades*		***Load-Ratio Share Allocation:*** *AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP*** (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)*
			DFAX Allocation: *ConEd (22.94%) / HTP*** (5.10%) / ECP** (0.08%) / PSEG (69.17%) / RE (2.71%)*
b2436.82	*Convert the Bayway - Linden "X" 138 kV circuit to 345 kV and any associated substation upgrades*		***Load-Ratio Share Allocation:*** *AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP*** (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)*
			DFAX Allocation: *ConEd (22.94%) / HTP*** (5.10%) / ECP** (0.08%) / PSEG (69.17%) / RE (2.71%)*

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		*Annual Revenue Requirement*	*Responsible Customer(s)*
b2436.83	*Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades*		***Load-Ratio Share Allocation:*** *AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP*** (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)*
			DFAX Allocation: *ConEd (22.94%) / HTP*** (5.10%) / ECP** (0.08%) / PSEG (69.17%) / RE (2.71%)*
b2436.90	*Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades*		***Load-Ratio Share Allocation:*** *AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP*** (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)*
			DFAX Allocation: *ConEd (100.00%)*

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		*Annual Revenue Requirement*	*Responsible Customer(s)*
b2436.91	*Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades*		*PSEG (100.00%)*
b2437.10	*New Bergen 345/230 kV transformer and any associated substation upgrades*		*ConEd (91.84%) / HTP*** (1.16%) / ECP** (3.56%) / PSEG (3.31%) / RE (0.13%)*
b2437.11	*New Bergen 345/138 kV transformer #1 and any associated substation upgrades*		*ConEd (100.00%)*
b2437.12	*New Bergen 345/138 kV transformer #2 and any associated substation upgrades*		*ConEd (81.64%) / HTP*** (18.36%)*
b2437.20	*New Bayway 345/138 kV transformer #1 and any associated substation upgrades*		*ConEd (100.00%)*
b2437.21	*New Bayway 345/138 kV transformer #2 and any associated substation upgrades*		*ConEd (100.00%)*
b2437.30	*New Linden 345/230 kV transformer and any associated substation upgrades*		*ConEd (86.94%) / HTP*** (11.36%) / ECP** (1.70%)*
b2437.31	*New Linden 230/138 kV transformer and any associated substation upgrades*		*ConEd (15.49%) / HTP*** (3.67%) / ECP** (15.51%) / PSEG (62.86%) / RE (2.47%)*
b2438	*Install two reactors at Tosco 230 kV*		*PSEG (100.00%)*
b2439	*Replace the Tosco 138kV breaker 'CB1/2 (CBT)' with 63kA*		*PSEG (100.00%)*
b2474	Rebuild Athenia 138 kV to 80kA		PSEG (100%)

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

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

SCHEDULE 12 – APPENDIX

(20) Virginia Electric and Power Company

Required Transmission Enhancements		Annual Revenue Requirement***	Responsible Customer(s)
b0217	Upgrade Mt. Storm - Doubs 500kV		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0222	Install 150 MVAR capacitor at Loudoun 500 kV		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)

* Neptune Regional Transmission System, LLC

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

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

Virginia Electric and Power Company (cont.)

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0231	Install 500 kV breakers & 500 kV bus work at Suffolk		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0231.2	Install 500/230 kV Transformer, 230 kV breakers, & 230 kV bus work at Suffolk		Dominion (100%)
b0232	Install 150 MVAR capacitor at Lynnhaven 230 kV		Dominion (100%)
b0233	Install 150 MVAR capacitor at Landstown 230 kV		Dominion (100%)
b0234	Install 150 MVAR capacitor at Greenwich 230 kV		Dominion (100%)
b0235	Install 150 MVAR capacitor at Fentress 230 kV		Dominion (100%)

* Neptune Regional Transmission System, LLC

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0307	Reconductor Endless Caverns – Mt. Jackson 115 kV		Dominion (100%)
b0308	Replace L breaker and switches at Endless Caverns 115 kV		Dominion (100%)
b0309	Install SPS at Earleys 115 kV		Dominion (100%)
b0310	Reconductor Club House – South Hill and Chase City – South Hill 115 kV		Dominion (100%)
b0311	Reconductor Idylwood to Arlington 230 kV		Dominion (100%)
b0312	Reconductor Gallows to Ox 230 kV		Dominion (100%)
b0325	Install a 2nd Everetts 230/115 kV transformer		Dominion (100%)
b0326	Uprate/resag Remington-Brandywine-Culppr 115 kV		Dominion (100%)
b0327	Build 2nd Harrisonburg – Valley 230 kV		APS (19.79%) / Dominion (76.18%) / PEPCO (4.03%)
b0328.1	Build new Meadow Brook – Loudoun 500 kV circuit (30 of 50 miles)		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)

* Neptune Regional Transmission System, LLC

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0328.3	Upgrade Mt. Storm 500 kV substation		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0328.4	Upgrade Loudoun 500 kV substation		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0329	Build Carson – Suffolk 500 kV, install 2nd Suffolk 500/230 kV transformer & build Suffolk – Fentress 230 kV circuit		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0329	Build Carson – Suffolk 500 kV, install 2nd Suffolk 500/230 kV transformer & build Suffolk – Fentress 230 kV circuit		Dominion (100%)††
b0329.1	Replace Thole Street 115 kV breaker '48T196'		Dominion (100%)
b0329.2	Replace Chesapeake 115 kV breaker 'T242'		Dominion (100%)
b0329.3	Replace Chesapeake 115 kV breaker '8722'		Dominion (100%)
b0329.4	Replace Chesapeake 115 kV breaker '16422'		Dominion (100%)
b0330	Install Crewe 115 kV breaker and shift load from line 158 to 98		Dominion (100%)
b0331	Upgrade/resag Shell Bank – Whealton 115 kV (Line 165)		Dominion (100%)

* Neptune Regional Transmission System, LLC

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

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

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

Virginia Electric and Power Company (cont.)

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0412	Retension Pruntytown – Mt. Storm 500 kV to a 3502 MVA rating		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
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%)
b0455	Add 2nd Endless Caverns 230/115 kV transformer		APS (32.70%) / BGE (7.01%) / DPL (1.80%) / Dominion (50.82%) / PEPCO (7.67%)
b0456	Reconductor 9.4 miles of Edinburg – Mt. Jackson 115 kV		APS (33.69%) / BGE (12.18%) / Dominion (40.08%) / PEPCO (14.05%)
b0457	Replace both wave traps on Dooms – Lexington 500 kV		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)

* Neptune Regional Transmission System, LLC

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0467.2	Reconductor the Dickerson – Pleasant View 230 kV circuit		AEC (1.75%) / APS (19.66%) / BGE (22.09%) / ConEd (0.18%) / DPL (3.69%) / JCPL (0.71%) / ME (2.48%) / Neptune* (0.06%) / PECO (5.53%) / PEPCO (41.78%) / PPL (2.07%)
b0492.6	Replace Mount Storm 500 kV breaker 55072		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0492.7	Replace Mount Storm 500 kV breaker 55172		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0492.8	Replace Mount Storm 500 kV breaker H1172-2		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0492.9	Replace Mount Storm 500 kV breaker G2T550		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0492.10	Replace Mount Storm 500 kV breaker G2T554		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0492.11	Replace Mount Storm 500 kV breaker G1T551		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0492.12	Upgrade nameplate rating of Mount Storm 500 kV breakers 55472, 57272, SX172, G3TSX1, G1TH11, G3T572, and SX22		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)

* Neptune Regional Transmission System, LLC

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
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 (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0512.5	Advance n0716 (Ox - Replace 230kV breaker L242)		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0512.6	Advance n0717 (Possum Point - Replace 230kV breaker SC192)		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
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%)

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0756	Install a second 500/115 kV autotransformer at Chancellor 500 kV		Dominion (100%)
b0756.1	Install two 500 kV breakers at Chancellor 500 kV		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0757	Reconductor one mile of Chesapeake – Reeves Avenue 115 kV line		Dominion (100%)
b0758	Install a second Fredericksburg 230/115 kV autotransformer		Dominion (100%)
b0759	Build a second Dooms – Dupont – Waynesboro 115 kV line		Dominion (100%)

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

Virginia Electric and Power Company (cont.)

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0774	Install a 33 MVAR capacitor at Bremo 115 kV		Dominion (100%)
b0775	Reconductor the Greenwich – Virginia Beach line to bring it up to a summer rating of 261 MVA; Reconductor the Greenwich – Amphibious Base line to bring it up to 291 MVA		Dominion (100%)
b0776	Re-build Trowbridge – Winfall 115 kV		Dominion (100%)
b0777	Terminate the Thelma – Carolina 230 kV circuit into Lakeview 230 kV		Dominion (100%)
b0778	Install 29.7 MVAR capacitor at Lebanon 115 kV		Dominion (100%)
b0779	Build a new 230 kV line from Yorktown to Hayes but operate at 115 kV initially		Dominion (100%)
b0780	Reconductor Chesapeake – Yadkin 115 kV line		Dominion (100%)
b0781	Reconductor and replace terminal equipment on line 17 and replace the wave trap on line 88		Dominion (100%)
b0782	Install a new 115 kV capacitor at Dupont Waynesboro substation		Dominion (100%)
b0784	Replace wave traps on North Anna to Ladysmith 500 kV		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0785	Rebuild the Chase City – Crewe 115 kV line		Dominion (100%)
b0786	Reconductor the Moran DP – Crewe 115 kV segment		Dominion (100%)
b0787	Upgrade the Chase City – Twitty's Creek 115 kV segment		Dominion (100%)
b0788	Reconductor the line from Farmville – Pamplin 115 kV		Dominion (100%)
b0793	Close switch 145T183 to network the lines. Rebuild the section of the line #145 between Possum Point – Minnieville DP 115 kV		Dominion (100%)
b0815	Replace Elmont 230 kV breaker '22192'		Dominion (100%)
b0816	Replace Elmont 230 kV breaker '21692'		Dominion (100%)
b0817	Replace Elmont 230 kV breaker '200992'		Dominion (100%)
b0818	Replace Elmont 230 kV breaker '2009T2032'		Dominion (100%)
b0837	At Mt. Storm, replace the existing MOD on the 500 kV side of the transformer with a circuit breaker		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)

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

Virginia Electric and Power Company (cont.)

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

* Neptune Regional Transmission System, LLC

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

Virginia Electric and Power Company (cont.)

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

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%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1188	Build new Brambleton 500 kV three breaker ring bus connected to the Loudoun to Pleasant View 500 kV line		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b1188.1	Replace Loudoun 230 kV breaker '200852' with a 63 kA breaker		Dominion (100%)
b1188.2	Replace Loudoun 230 kV breaker '2008T2094' with a 63 kA breaker		Dominion (100%)
b1188.3	Replace Loudoun 230 kV breaker '204552' with a 63 kA breaker		Dominion (100%)
b1188.4	Replace Loudoun 230 kV breaker '209452' with a 63 kA breaker		Dominion (100%)
b1188.5	Replace Loudoun 230 kV breaker 'WT2045' with a 63 kA breaker		Dominion (100%)
b1188.6	Install one 500/230 kV transformer and two 230 kV breakers at Brambleton		AEC (0.22%) / BGE (7.90%) / DPL (0.59%) / Dominion (75.58%) / ME (0.22%) / PECO (0.73%) /PEPCO (14.76%)
b1224	Install 2nd Clover 500/230 kV transformer and a 150 MVAr capacitor		BGE (7.56%) / DPL (1.03%) / Dominion (78.21%) / ME (0.77%) / PECO (1.39%) / PEPCO (11.04%)
b1225	Replace Yorktown 115 kV breaker 'L982-1'		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1226	Replace Yorktown 115 kV breaker 'L982-2'		Dominion (100%)
b1279	Line #69 Uprate – Increase rating on Locks – Purdy 115 kV to serve additional load at the Reams delivery point		Dominion (100%)
b1306	Reconfigure 115 kV bus at Endless Caverns substation such that the existing two 230/115 kV transformers at Endless Caverns operate in		Dominion (100%)
b1307	Install a 2nd 230/115 kV transformer at Northern Neck Substation		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1308	Improve LSE's power factor factor in zone to .973 PF, adjust LTC's at Gordonsville and Remington, move existing shunt capacitor banks		Dominion (100%)
b1309	Install a 230 kV line from Lakeside to Northwest utilizing the idle line and 60 line ROW's and reconductor the existing 221 line between Elmont and Northwest		Dominion (100%)
b1310	Install a 115 kV breaker at Broadnax substation on the South Hill side of Broadnax		Dominion (100%)
b1311	Install a 230 kV 3000 amp breaker at Cranes Corner substation to sectionalize the 2104 line into two lines		Dominion (100%)
b1312	Loop the 2054 line in and out of Hollymeade and place a 230 kV breaker at Hollymeade. This creates two lines: Charlottesville - Hollymeade		Dominion (100%)
b1313	Resag wire to 125C from Chesterfield – Shockoe and replace line switch 1799 with 1200 amp switch. The new rating would be 231 MVA.		Dominion (100%)
b1314	Rebuild the 6.8 mile line #100 from Chesterfield to Harrowgate 115 kV for a minimum 300 MBA rating		Dominion (100%)
b1315	Convert line #64 Trowbridge to Winfall to 230 kV and install a 230 kV capacitor bank at Winfall		Dominion (100%)
b1316	Rebuild 10.7 miles of 115 kV line #80, Battleboro – Heartsease DP		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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%)
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%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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%)
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%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1337	Advance n1751 (Replace Ox 230 kV breaker 248T2013 with a 63 kA breaker)		Dominion (100%)
b1503.1	Loop Line #2095 in and out of Waxpool approximately 1.5 miles		Dominion (100%)
b1503.2	Construct a new 230kV line from Brambleton to BECO Substation of approximately 11 miles with approximately 10 miles utilizing the vacant side of existing Line #2095 structures		Dominion (100%)
b1503.3	Install a one 230 kV breaker, Future 230 kV ring-bus at Waxpool Substation		Dominion (100%)
b1503.4	The new Brambleton - BECO line will feed Shellhorn Substation load and Greenway TX's #2&3 load		Dominion (100%)
b1506.1	At Gainesville Substation, create two 115 kV straight-buses with a normally open tie-breaker		Dominion (100%)
b1506.2	Upgrade Line 124 (radial from Loudoun) to a minimum continuous rating of 500 MVA and network it into the 115 kV bus feeding NOVEC's DP at Gainesville		Dominion (100%)
b1506.3	Install two additional 230 kV breakers in the ring at Gainesville (may require substation expansion) to accommodate conversion of NOVEC's Gainesville to Wheeler line		Dominion (100%)
b1506.4	Convert NOVEC's Gainesville-Wheeler line from 115 kV to 230 kV (will require Gainsville DP Upgrade replacement of three transformers total at Atlantic and Wheeler Substations)		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1507	Rebuild Mt Storm – Doubs 500 kV		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
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%)
b1538	Replace Loudoun 230 kV breaker '29552'		Dominion (100%)
b1571	Replace Acca 115 kV breaker '6072' with 40 kA		Dominion (100%)

* Neptune Regional Transmission System, LLC

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

Virginia Electric and Power Company (cont.)
Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1647	Upgrade the name plate rating at Morrisville 500kV breaker 'H1T573' with 50kA breaker		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b1648	Upgrade name plate rating at Morrisville 500kV breaker 'H2T545' with 50kA breaker		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b1649	Replace Morrisville 500kV breaker 'H1T580' with 50kA breaker		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1650	Replace Morrisville 500kV breaker 'H2T569' with 50kA breaker		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b1651	Replace Loudoun 230kV breaker '295T2030' with 63kA breaker		Dominion (100%)
b1652	Replace Ox 230kV breaker '209742' with 63kA breaker		Dominion (100%)
b1653	Replace Clifton 230kV breaker '26582' with 63kA breaker		Dominion (100%)
b1654	Replace Clifton 230kV breaker '26682' with 63kA breaker		Dominion (100%)
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%)

* Neptune Regional Transmission System, LLC

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

Virginia Electric and Power Company (cont.)
Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1694	Rebuild Loudoun - Brambleton 500 kV Rebuild Loudoun - Brambleton 500 kV		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b1696	Install a breaker and a half scheme with a minimum of eight 230 kV breakers for five existing lines at Idylwood 230 kV		AEC (0.46%) / APS (4.18%) / BGE (2.02%) / DPL (0.80%) / Dominion (88.45%) / JCPL (0.64%) / ME (0.50%) / NEPTUNE* (0.06%) / PECO (1.55%) / PEPCO (1.34%)
b1697	Build a 2nd Clark - Idylwood 230 kV line and install 230 kV gas-hybrid breakers at Clark		AEC (1.35%) / APS (15.65%) / BGE (10.53%) / DPL (2.59%) / Dominion (46.97%) / JCPL (2.36%) / ME (1.91%) / NEPTUNE* (0.23%) / PECO (4.48%) / PEPCO (11.23%) / PSEG (2.59%) / RE (0.11%)
b1698	Install a 2nd 500/230 kV transformer at Brambleton		APS (4.21%) / BGE (13.28%) / DPL (1.09%) / Dominion (59.38%) / PEPCO (22.04%)

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1698.1	Install a 500 kV breaker at Brambleton		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
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%)

* Neptune Regional Transmission System, LLC

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

Virginia Electric and Power Company (cont.)
Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1795	Reconductor segment of Line #54 (Carolina to Woodland 115 kV) to a minimum of 300 MVA		Dominion (100%)
b1796	Install 115 kV 25 MVAR capacitor bank at Kitty Hawk Substation		Dominion (100%)
b1797	Wreck and rebuild 7 miles of the Dominion owned section of Cloverdale - Lexington 500 kV		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b1798	Build a 450 MVAR SVC and 300 MVAR switched shunt at Loudoun 500 kV		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)

* Neptune Regional Transmission System, LLC

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1799	Build 150 MVAR Switched Shunt at Pleasant View 500 kV		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b1805	Install a 250 MVAR SVC at the existing Mt. Storm 500kV substation		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b1809	Replace Brambleton 230 kV Breaker '22702'		Dominion (100%)
b1810	Replace Brambleton 230 kV Breaker '227T2094'		Dominion (100%)
b1905.1	Surry to Skiffes Creek 500 kV Line (7 miles overhead)		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)

* Neptune Regional Transmission System, LLC

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1905.2	Surry 500 kV Station Work		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b1905.3	Skiffes Creek 500-230 kV Tx and Switching Station		Dominion (99.84%) / PEPCO (0.16%)
b1905.4	New Skiffes Creek - Whealton 230 kV line		Dominion (99.84%) / PEPCO (0.16%)
b1905.5	Whealton 230 kV breakers		Dominion (99.84%) / PEPCO (0.16%)
b1905.6	Yorktown 230 kV work		Dominion (99.84%) / PEPCO (0.16%)
b1905.7	Lanexa 115 kV work		Dominion (99.84%) / PEPCO (0.16%)
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%)

* Neptune Regional Transmission System, LLC

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1906.1	At Yadkin 500 kV, install six 500 kV breakers		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
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%)
b1908	Rebuild Lexington – Dooms 500 kV		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b1909	Uprate Bremo – Midlothian 230 kV to its maximum operating temperature		APS (6.31%) / BGE (3.81%) / Dominion (81. 90%) / PEPCO (7.98%)

* Neptune Regional Transmission System, LLC

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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%)
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%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements   Annual Revenue Requirement   Responsible Customer(s)

b2186	Install a 2nd 230-115kV transformer at Earleys connected to the existing 115kV and 230kV ring busses. Add a 115 kV breaker and 230kV breaker to the ring busses		Dominion (100%)
b2187	Install 4 - 230kV breakers at Shellhorn 230 kV to isolate load		Dominion (100%)

* Neptune Regional Transmission System, LLC

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

SCHEDULE 12 – APPENDIX A

(20) Virginia Electric and Power Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
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 achieive a summer emergency rating of 906 amps or greater		Dominion (100%)
b2358	Install a 230 kV 54 MVAR capacitor bank on the 2016 line at Harmony Village Substation		Dominion (100%)
b2359	Wreck and rebuild approximately 1.3 miles of existing 230 kV line between Cochran Mill - X4-039 Switching Station		Dominion (100%)
b2360	Build a new 39 mile 230 kV transmission line from Dooms - Lexington on existing right-of-way		Dominion (100%)
b2361	Construct 230 kV OH line along existing Line #2035 corridor, approx. 2.4 miles from Idylwood - Dulles Toll Road (DTR) and 2.1 miles on new right-of-way along DTR to new Scott's Run Substation		Dominion (100%)
b2368	*Replace the Brambleton 230 kV breaker '209502' with 63kA breaker*		*Dominion (100%)*
b2369	*Replace the Brambleton 230 kV breaker '213702' with 63kA breaker*		*Dominion (100%)*
b2370	*Replace the Brambleton 230 kV breaker 'H302' with 63kA breaker*		*Dominion (100%)*

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		*Annual Revenue Requirement*	*Responsible Customer(s)*
b2373	*Build a 2nd Loudoun - Brambleton 500 kV line within the existing ROW. The Loudoun - Brambleton 230 kV line will be relocated as an underbuild on the new 500 kV line*		***Load-Ratio Share Allocation:*** *AEC (1.70%) / AEP (14.22%) / APS (5.40%) / ATSI (8.17%) / BGE (4.25%) / ComEd (13.85%) / ConEd (0.56%) / Dayton (2.11%) / DEOK (3.20%) / DL (1.84%) / DPL (2.50%) / Dominion (11.67%) / EKPC (1.37%) / HTP*** (0.01%) / JCPL (3.97%) / ME (1.87%) / NEPTUNE* (0.42%) / PECO (5.36%) / PENELEC (1.92%) / PEPCO (4.06%) / PPL (4.60%) / PSEG (6.48%) / RE (0.27%) / ECP** (0.20%)*
			DFAX Allocation: *APS (35.59%) / BGE (17.80%) / Dominion (46.61%)*
b2397	*Replace the Beaumeade 230 kV breaker '2079T2116' with 63kA*		*Dominion (100%)*
b2398	*Replace the Beaumeade 230 kV breaker '2079T2130' with 63kA*		*Dominion (100%)*
b2399	*Replace the Beaumeade 230 kV breaker '208192' with 63kA*		*Dominion (100%)*
b2400	*Replace the Beaumeade 230 kV breaker '209592' with 63kA*		*Dominion (100%)*
b2401	*Replace the Beaumeade 230 kV breaker '211692' with 63kA*		*Dominion (100%)*
b2402	*Replace the Beaumeade 230 kV breaker '227T2130' with 63kA*		*Dominion (100%)*
b2403	*Replace the Beaumeade 230 kV breaker '274T2130' with 63kA*		*Dominion (100%)*

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

Virginia Electric and Power Company (cont.)

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

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

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-Ration Share Allocation:** AEC (1.73 %)/ AEP (14.41%)/ APS (5.47%)/ ATSI (8.29%)/ BGE (4.31%)/ ComEd (14.04%)/ ConEd (0.57%)/ Dayton (2.15%)/ DEOK (3.25%)/ DL (1.86%)/ Dominion (11.83%)/ DPL (2.53%)/ ECP (0.20%)/ HTP (0.01%)/ JCPL (4.02%)/ ME (1.90%)/ NEPTUNE (0.42%)/ PECO (5.43%)/ PENELEC (1.95%)/ PEPCO (4.12%)/ PPL (4.66%)/ PSEG (6.57%)/ RE (0.28%)
			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%)
b2565	Replace 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%)

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

SCHEDULE 12 – APPENDIX

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0216	Install -100/+525 MVAR dynamic reactive device at Black Oak	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0218	Install third Wylie Ridge 500/345kV transformer	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (11.62%) / ConEd (1.79%) / DPL (19.05%) / Dominion (13.56%) / JCPL (15.28%) / PECO (38.70%)
b0220	Upgrade coolers on Wylie Ridge 500/345 kV #7		AEC (11.62%) / ConEd (1.79%) / DPL (19.05%) / Dominion (13.56%) / JCPL (15.28%) / PECO (38.70%)
b0229	Install fourth Bedington 500/138 kV		APS (50.98%) / BGE (13.42%) / DPL (2.03%) / Dominion (14.50%) / ME (1.43%) / PEPCO (17.64%)
b0230	Install fourth Meadowbrook 500/138 kV	As specified under the procedures detailed in Attachment H-18B, Section 1.b	APS (79.16%) / BGE (3.61%) / DPL (0.86%) / Dominion (11.75%) / ME (0.67%) / PEPCO (3.95%)

* Neptune Regional Transmission System, LLC

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

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

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

* Neptune Regional Transmission System, LLC

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

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

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0322	Convert Lime Kiln substation to 230 kV operation		APS (100%)
b0323	Replace the North Shenandoah 138/115 kV transformer	As specified under the procedures detailed in Attachment H-18B, Section 1.b	APS (100%)
b0328.2	Build new Meadow Brook – Loudoun 500 kV circuit (20 of 50 miles)	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) /PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0343	Replace Doubs 500/230 kV transformer #2	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.85%) / BGE (21.49%) / DPL (3.91%) / Dominion (28.86%) / ME (2.97%) / PECO (5.73%) / PEPCO (35.19%)
b0344	Replace Doubs 500/230 kV transformer #3	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.86%) / BGE (21.50%) / DPL (3.91%) / Dominion (28.82%) / ME (2.97%) / PECO (5.74%) / PEPCO (35.20%)
b0345	Replace Doubs 500/230 kV transformer #4	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.85%) / BGE (21.49%) / DPL (3.90%) / Dominion (28.83%) / ME (2.98%) / PECO (5.75%) / PEPCO (35.20%)

* Neptune Regional Transmission System, LLC

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.1	Build new Mt. Storm – 502 Junction 500 kV circuit	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0347.2	Build new Mt. Storm – Meadow Brook 500 kV circuit	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)

* Neptune Regional Transmission System, LLC

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.3	Build new 502 Junction 500 kV substation	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0347.4	Upgrade Meadow Brook 500 kV substation	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0347.5	Replace Harrison 500 kV breaker HL-3		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.6	Upgrade (per ABB inspection) breaker HL-6		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0347.7	Upgrade (per ABB inspection) breaker HL-7		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0347.8	Upgrade (per ABB inspection) breaker HL-8		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0347.9	Upgrade (per ABB inspection) breaker HL-10		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.10	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-1		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0347.11	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-3		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0347.12	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-4		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0347.13	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-6		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.14	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-7		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0347.15	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-9		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0347.16	Upgrade (per ABB inspection) Harrison 500 kV breaker 'HL-3'		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.17	Replace Meadow Brook 138 kV breaker 'MD-10'		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0347.18	Replace Meadow Brook 138 kV breaker 'MD-11'		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0347.19	Replace Meadow Brook 138 kV breaker 'MD-12'		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0347.20	Replace Meadow Brook 138 kV breaker 'MD-13'		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)

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

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0347.21	Replace Meadow Brook 138 kV breaker 'MD-14'		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0347.22	Replace Meadow Brook 138 kV breaker 'MD-15'		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0347.23	Replace Meadow Brook 138 kV breaker 'MD-16'		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0347.24	Replace Meadow Brook 138 kV breaker 'MD-17'		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)

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

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0347.25	Replace Meadow Brook 138 kV breaker 'MD-18'		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0347.26	Replace Meadow Brook 138 kV breaker 'MD-22#1 CAP'		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0347.27	Replace Meadow Brook 138 kV breaker 'MD-4'		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0347.28	Replace Meadow Brook 138 kV breaker 'MD-5'		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.29	Replace Meadowbrook 138 kV breaker 'MD-6'		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0347.30	Replace Meadowbrook 138 kV breaker 'MD-7'		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0347.31	Replace Meadowbrook 138 kV breaker 'MD-8'		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0347.32	Replace Meadowbrook 138 kV breaker 'MD-9'		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.33	Replace Meadow Brook 138kV breaker 'MD-1'		APS (100%)
b0347.34	Replace Meadow Brook 138kV breaker 'MD-2'		APS (100%)
b0348	Upgrade Stonewall – Inwood 138 kV with 954 ACSR conductor		APS (100%)
b0373	Convert Doubs – Monocacy 138 kV facilities to 230 kV operation		AEC (1.82%) / APS (76.84%) / DPL (2.64%) / JCPL (4.53%) / ME (9.15%) / Neptune* (0.42%) / PPL (4.60%)
b0393	Replace terminal equipment at Harrison 500 kV and Belmont 500 kV		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0406.1	Replace Mitchell 138 kV breaker "#4 bank"		APS (100%)
b0406.2	Replace Mitchell 138 kV breaker "#5 bank"		APS (100%)
b0406.3	Replace Mitchell 138 kV breaker "#2 transf"		APS (100%)
b0406.4	Replace Mitchell 138 kV breaker "#3 bank"		APS (100%)
b0406.5	Replace Mitchell 138 kV breaker "Charlerio #2"		APS (100%)

* Neptune Regional Transmission System, LLC

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0406.6	Replace Mitchell 138 kV breaker “Charlerio #1”		APS (100%)
b0406.7	Replace Mitchell 138 kV breaker “Shepler Hill Jct”		APS (100%)
b0406.8	Replace Mitchell 138 kV breaker “Union Jct”		APS (100%)
b0406.9	Replace Mitchell 138 kV breaker “#1-2 138 kV bus tie”		APS (100%)
b0407.1	Replace Marlowe 138 kV breaker “#1 transf”		APS (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0407.2	Replace Marlowe 138 kV breaker "MBO"		APS (100%)
b0407.3	Replace Marlowe 138 kV breaker "BMA"		APS (100%)
b0407.4	Replace Marlowe 138 kV breaker "BMR"		APS (100%)
b0407.5	Replace Marlowe 138 kV breaker "WC-1"		APS (100%)
b0407.6	Replace Marlowe 138 kV breaker "R11"		APS (100%)
b0407.7	Replace Marlowe 138 kV breaker "W"		APS (100%)
b0407.8	Replace Marlowe 138 kV breaker "138 kV bus tie"		APS (100%)
b0408.1	Replace Trissler 138 kV breaker "Belmont 604"		APS (100%)
b0408.2	Replace Trissler 138 kV breaker "Edgelawn 90"		APS (100%)
b0409.1	Replace Weirton 138 kV breaker "Wylie Ridge 210"		APS (100%)
b0409.2	Replace Weirton 138 kV breaker "Wylie Ridge 216"		APS (100%)
b0410	Replace Glen Falls 138 kV breaker "McAlpin 30"		APS (100%)
b0417	Reconductor Mitchell – Shepler Hill Junction 138kV with 954 ACSR		APS (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0418	Install a breaker failure auto-restoration scheme at Cabot 500 kV for the failure of the #6 breaker		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0419	Install a breaker failure auto-restoration scheme at Bedington 500 kV for the failure of the #1 and #2 breakers		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0420	Operating Procedure to open the Black Oak 500/138 kV transformer #3 for the loss of Hatfield – Ronco 500 kV and the Hatfield #3 Generation		APS (100%)
b0445	Upgrade substation equipment and reconductor the Tidd – Mahans Lane – Weirton 138kV circuit with 954 ACSR		APS (100%)

* Neptune Regional Transmission System, LLC

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0460	Raise limiting structures on Albright – Bethelboro 138 kV to raise the rating to 175 MVA normal 214 MVA emergency		APS (100%)
b0491	Construct an Amos to Welton Spring to WV state line 765 kV circuit (APS equipment)	As specified under the procedures detailed in Attachment H-19B	AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0492	Construct a Welton Spring to Kemptown 765 kV line (APS equipment)	As specified under the procedures detailed in Attachment H-19B	AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0492.3	Replace Eastalco 230 kV breaker D-26		APS (100%)
b0492.4	Replace Eastalco 230 kV breaker D-28		APS (100%)

*Neptune Regional Transmission System, LLC

**East Coast Power, L.L.C

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0492.5	Replace Eastalco 230 kV breaker D-31		APS (100%)
b0495	Replace existing Kammer 765/500 kV transformer with a new larger transformer		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0533	Reconductor the Powell Mountain – Sutton 138 kV line		APS (100%)
b0534	Install a 28.61 MVAR capacitor on Sutton 138 kV		APS (100%)
b0535	Install a 44 MVAR capacitor on Dutch Fork 138 kV		APS (100%)
b0536	Replace Doubs circuit breaker DJ1		APS (100%)
b0537	Replace Doubs circuit breaker DJ7		APS (100%)
b0538	Replace Doubs circuit breaker DJ10		APS (100%)

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

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)
b0572.1	Reconductor Albright – Mettiki – Williams – Parsons – Loughs Lane 138 kV with 954 ACSR		APS (100%)
b0572.2	Reconductor Albright – Mettiki – Williams – Parsons – Loughs Lane 138 kV with 954 ACSR		APS (100%)
b0573	Reconfigure circuits in Butler – Cabot 138 kV area		APS (100%)
b0577	Replace Fort Martin 500 kV breaker FL-1		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0584	Install 33 MVAR 138 kV capacitor at Necessity 138 kV		APS (100%)
b0585	Increase Cecil 138 kV capacitor size to 44 MVAR, replace five 138 kV breakers at Cecil due to increased short circuit fault duty as a result of the addition of the Prexy substation		APS (100%)
b0586	Increase Whiteley 138 kV capacitor size to 44 MVAR		APS (100%)
b0587	Reconductor AP portion of Tidd – Carnegie 138 kV and Carnegie – Weirton 138 kV with 954 ACSR		APS (100%)
b0588	Install a 40.8 MVAR 138 kV capacitor at Grassy Falls		APS (100%)
b0589	Replace five 138 kV breakers at Cecil		APS (100%)

*Neptune Regional Transmission System, LLC

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

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

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

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

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

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

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

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

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

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

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0704	Install a third Cabot 500/138 kV transformer		APS (74.36%) / DL (2.73%) PENELEC (22.91%)
b0797	Advance n0321 (Replace Doubs Circuit Breaker DJ2)		APS(100%)
b0798	Advance n0322 (Replace Doubs Circuit Breaker DJ3)		APS(100%)
b0799	Advance n0323 (Replace Doubs Circuit Breaker DJ6)		APS(100%)
b0800	Advance n0327 (Replace Doubs Circuit Breaker DJ16)		APS(100%)
b0941	Replace Opequon 138 kV breaker 'BUSTIE'		APS(100%)
b0942	Replace Butler 138 kV breaker '#1 BANK'		APS(100%)
b0943	Replace Butler 138 kV breaker '#2 BANK'		APS(100%)
b0944	Replace Yukon 138 kV breaker 'Y-8'		APS(100%)
b0945	Replace Yukon 138 kV breaker 'Y-3'		APS(100%)
b0946	Replace Yukon 138 kV breaker 'Y-1'		APS(100%)
b0947	Replace Yukon 138 kV breaker 'Y-5'		APS(100%)
b0948	Replace Yukon 138 kV breaker 'Y-2'		APS(100%)
b0949	Replace Yukon 138 kV breaker 'Y-19'		APS(100%)

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

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

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

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

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

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0989	Replace Edgelawn 138 kV breaker 'GOFF RUN #632'		APS(100%)
b0990	Change reclosing on Cabot 138 kV breaker 'C-9'		APS(100%)
b0991	Change reclosing on Belmont 138 kV breaker 'B-7'		APS(100%)
b0992	Change reclosing on Belmont 138 kV breaker 'B-12'		APS(100%)
b0993	Change reclosing on Belmont 138 kV breaker 'B-9'		APS(100%)
b0994	Change reclosing on Belmont 138 kV breaker 'B-19'		APS(100%)
b0995	Change reclosing on Belmont 138 kV breaker 'B-21'		APS(100%)
b0996	Change reclosing on Willow Island 138 kV breaker 'FAIRVIEW #84'		APS(100%)
b0997	Change reclosing on Cabot 138 kV breaker 'C-4'		APS(100%)
b0998	Change reclosing on Cabot 138 kV breaker 'C-1'		APS(100%)
b0999	Replace Redbud 138 kV breaker 'BUS TIE'		APS(100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1022.1	Reconfigure the Peters to Bethel Park 138 kV line and Elrama to Woodville 138 kV line to create a 138 kV path from Woodville to Peters and a 138 kV path from Elrama to Bethel Park		APS (96.98%) / DL (3.02%)
b1022.3	Add static capacitors at Smith 138 kV		APS (96.98%) / DL (3.02%)
b1022.4	Add static capacitors at North Fayette 138 kV		APS (96.98%) / DL (3.02%)
b1022.5	Add static capacitors at South Fayette 138 kV		APS (96.98%) / DL (3.02%)
b1022.6	Add static capacitors at Manifold 138 kV		APS (96.98%) / DL (3.02%)
b1022.7	Add static capacitors at Houston 138 kV		APS (96.98%) / DL (3.02%)
b1023.1	Install a 500/138 kV transformer at 502 Junction		APS (100%)
b1023.2	Construct a new Franklin - 502 Junction 138 kV line including a rebuild of the Whiteley - Franklin 138 kV line to double circuit		APS (100%)
b1023.3	Construct a new 502 Junction - Osage 138 kV line		APS (100%)
b1023.4	Construct Braddock 138 kV breaker station that connects the Charleroi - Gordon 138 kV line, Washington - Franklin 138 kV line and the Washington - Vanceville 138 kV line including a 66 MVAR capacitor		APS (100%)
b1027	Increase the size of the shunt capacitors at Enon 138 kV		APS (100%)
b1028	Raise three structures on the Osage - Collins Ferry 138 kV line to increase the line rating		APS (100%)

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)
b1128	Reconductor the Edgewater – Vasco Tap; Edgewater – Loyalhanna 138 kV lines with 954 ACSR		APS (100%)
b1129	Reconductor the East Waynesboro – Ringgold 138 kV line with 954 ACSR		APS (100%)
b1131	Upgrade Double Tollgate – Meadowbrook MDT Terminal Equipment		APS (100%)
b1132	Upgrade Double Tollgate-Meadowbrook MBG terminal equipment		APS (100%)
b1133	Upgrade terminal equipment at Springdale		APS (100%)
b1135	Reconductor the Bartonville – Meadowbrook 138 kV line with high temperature conductor		APS (100%)
b1137	Reconductor the Eastgate – Luxor 138 kV; Eastgate – Sony 138 kV line with 954 ACSR		APS (78.59%) / PENELEC (14.08%) / ECP ** (0.23%) / PSEG (6.83%) / RE (0.27%)
b1138	Reconductor the King Farm – Sony 138 kV line with 954 ACSR		APS (100%)
b1139	Reconductor the Yukon – Waltz Mills 138 kV line with high temperature conductor		APS (100%)
b1140	Reconductor the Bracken Junction – Luxor 138 kV line with 954 ACSR		APS (100%)
b1141	Reconductor the Sewickley – Waltz Mills Tap 138 kV line with high temperature conductor		APS (100%)
b1142	Reconductor the Bartonsville – Stephenson 138 kV; Stonewall – Stephenson 138 kV line with 954 ACSR		APS (100%)
b1143	Reconductor the Youngwood – Yukon 138 kV line with high temperature conductor		APS (89.92%) / PENELEC (10.08%)

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1144	Reconductor the Bull Creek Junction – Cabot 138 kV line with high temperature conductor		APS (100%)
b1145	Reconductor the Lawson Junction – Cabot 138 kV line with high temperature conductor		APS (100%)
b1146	Replace Layton - Smithton #61 138 kV line structures to increase line rating		APS (100%)
b1147	Replace Smith – Yukon 138 kV line structures to increase line rating		APS (100%)
b1148	Reconductor the Loyalhanna – Luxor 138 kV line with 954 ACSR		APS (100%)
b1149	Reconductor the Luxor – Stony Springs Junction 138 kV line with 954 ACSR		APS (100%)
b1150	Upgrade terminal equipment at Social Hall		APS (100%)
b1151	Reconductor the Greenwood – Redbud 138 kV line with 954 ACSR		APS (100%)
b1152	Reconductor Grand Point – South Chambersburg		APS (100%)
b1159	Replace Peters 138 kV breaker 'Bethel P OCB'		APS (100%)
b1160	Replace Peters 138 kV breaker 'Cecil OCB'		APS (100%)
b1161	Replace Peters 138 kV breaker 'Union JctOCB'		APS (100%)
b1162	Replace Double Toll Gate 138 kV breaker 'DRB-2'		APS (100%)
b1163	Replace Double Toll Gate 138 kV breaker 'DT 138 kV OCB'		APS (100%)
b1164	Replace Cecil 138 kV breaker 'Enlow OCB'		APS (100%)
b1165	Replace Cecil 138 kV breaker 'South Fayette'		APS (100%)
b1166	Replace Wylie Ridge 138 kV breaker 'W-9'		APS (100%)
b1167	Replace Reid 138 kV breaker 'RI-2'		APS (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1171.1	Install the second Black Oak 500/138 kV transformer, two 138 kV breaker, and related substation work		BGE (20.76%) / DPL (3.14%) / Dominion (39.55%) / ME (2.71%) / PECO (3.36%) / PEPCO (30.48%)
b1171.3	Install six 500 kV breakers and remove BOL1 500 kV breaker at Black Oak		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b1200	Reconductor Double Toll Gate – Greenwood 138 kV with 954 ACSR conductor		APS (100%)
b1221.1	Convert Carbon Center from 138 kV to a 230 kV ring bus		APS (100%)
b1221.2	Construct Bear Run 230 kV substation with 230/138 kV transformer		APS (100%)
b1221.3	Loop Carbon Center Junction – Williamette line into Bear Run		APS (100%)
b1221.4	Carbon Center – Carbon Center Junction & Carbon Center Junction – Bear Run conversion from 138 kV to 230 kV		APS (100%)
b1230	Reconductor Willow-Eureka & Eurkea-St Mary 138 kV lines		APS (100%)
b1232	Reconductor Nipetown – Reid 138 kV with 1033 ACCR		AEC (1.40%) / APS (75.74%) / DPL (1.92%) / JCPL (2.92%) / ME (6.10%) / Neptune (0.27%) / PECO (4.40%) / PENELEC (3.26%) / PPL (3.99%)
b1233.1	Upgrade terminal equipment at Washington		APS (100%)
b1234	Replace structures between Ridgeway and Paper city		APS (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1235	Reconductor the Albright – Black Oak AFA 138 kV line with 795 ACSS/TW		APS (30.25%) / BGE (16.10%) / Dominion (30.51%) / PEPCO (23.14%)
b1237	Upgrade terminal equipment at Albright, replace bus and line side breaker disconnects and leads, replace breaker risers, upgrade RTU and line		APS (100%)
b1238	Install a 138 kV 44 MVAR capacitor at Edgelawn substation		APS (100%)
b1239	Install a 138 kV 44 MVAR capacitor at Ridgeway substation		APS (100%)
b1240	Install a 138 kV 44 MVAR capacitor at Elko Substation		APS (100%)
b1241	Upgrade terminal equipment at Washington substation on the GE Plastics/DuPont terminal		APS (100%)
b1242	Replace structures between Collins Ferry and West Run		APS (100%)
b1243	Install a 138 kV capacitor at Potter Substation		APS (100%)
b1261	Replace Butler 138 kV breaker '1-2 BUS 138'		APS (100%)
b1383	Install 2nd 500/138 kV transformer at 502 Junction		APS (93.27%) / DL (5.39%) / PENELEC (1.34%)
b1384	Reconductor approximately 2.17 miles of Bedington – Shepherdstown 138 kV with 954 ACSR		APS (100%)
b1385	Reconductor Halfway – Paramount 138 kV with 1033 ACCR		APS (100%)
b1386	Reconductor Double Tollgate – Meadow Brook 138 kV ckt 2 with 1033 ACCR		APS (93.33%) / BGE (3.39%) / PEPCO (3.28%)
b1387	Reconductor Double Tollgate – Meadow Brook 138 kV		APS (93.33%) / BGE (3.39%) / PEPCO (3.28%)
b1388	Reconductor Feagans Mill – Millville 138 kV with 954 ACSR		APS (100%)

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1389	Reconductor Bens Run – St. Mary's 138 kV with 954 ACSR		AEP (12.40%) / APS (17.80%) / DL (69.80%)
b1390	Replace Bus Tie Breaker at Opequon		APS (100%)
b1391	Replace Line Trap at Gore		APS (100%)
b1392	Replace structure on Belmont – Trissler 138 kV line		APS (100%)
b1393	Replace structures Kingwood – Pruntytown 138 kV line		APS (100%)
b1395	Upgrade Terminal Equipment at Kittanning		APS (100%)
b1401	Change reclosing on Pruntytown 138 kV breaker 'P-16' to 1 shot at 15 seconds		APS (100%)
b1402	Change reclosing on Rivesville 138 kV breaker 'Pruntytown #34' to 1 shot at 15 seconds		APS (100%)
b1403	Change reclosing on Yukon 138 kV breaker 'Y21 Shepler' to 1 shot at 15 seconds		APS (100%)
b1404	Replace the Kiski Valley 138 kV breaker 'Vandergrift' with a 40 kA breaker		APS (100%)
b1405	Change reclosing on Armstrong 138 kV breaker 'GARETTRJCT' at 1 shot at 15 seconds		APS (100%)
b1406	Change reclosing on Armstrong 138 kV breaker 'KITTANNING' to 1 shot at 15 seconds		APS (100%)
b1407	Change reclosing on Armstrong 138 kV breaker 'BURMA' to 1 shot at 15 seconds		APS (100%)
b1408	Replace the Weirton 138 kV breaker 'Tidd 224' with a 40 kA breaker		APS (100%)
b1409	Replace the Cabot 138 kV breaker 'C9 Kiski Valley' with a 40 kA breaker		APS (100%)

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1507.2	Terminal Equipment upgrade at Doubs substation		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b1507.3	Mt. Storm – Doubs transmission line rebuild in Maryland – Total line mileage for APS is 2.71 miles		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b1510	Install 59.4 MVAR capacitor at Waverly		APS (100%)
b1672	Install a 230 kV breaker at Carbon Center		APS (100%)

* Neptune Regional Transmission System, LLC

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0539	Replace Doubs circuit breaker DJ11		APS (100%)
b0540	Replace Doubs circuit breaker DJ12		APS (100%)
b0541	Replace Doubs circuit breaker DJ13		APS (100%)
b0542	Replace Doubs circuit breaker DJ20		APS (100%)
b0543	Replace Doubs circuit breaker DJ21		APS (100%)
b0544	Remove instantaneous reclose from Eastalco circuit breaker D-26		APS (100%)
b0545	Remove instantaneous reclose from Eastalco circuit breaker D-28		APS (100%)
b0559	Install 200 MVAR capacitor at Meadow Brook 500 kV substation		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b0560	Install 250 MVAR capacitor at Kemptown 500 kV substation		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)

* Neptune Regional Transmission System, LLC

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1803	Build a 300 MVAR Switched Shunt at Doubs 500 kV and increase (~50 MVAR) in size the existing Switched Shunt at Doubs 500 kV		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b1804	Install a new 600 MVAR SVC at Meadowbrook 500kV		AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)
b1816.1	Replace relaying at the Mt. Airy substation on the Carroll - Mt. Airy 230 kV line		APS (100%)
b1816.2	Adjust the control settings of all existing capacitors at Mt Airy 34.5kV, Monocacy 138kV, Ringgold 138kV served by Potomac Edison's Eastern 230 kV network to ensure that all units will be on during the identified N-1-1 contingencies		APS (100%)

* Neptune Regional Transmission System, LLC

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

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

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

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

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

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

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

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

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

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

* Neptune Regional Transmission System, LLC

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2095	Replace Weirt 138 kV breaker 'S-TORONTO226' with 63kA rated breaker		APS (100%)
b2096	Revise the reclosing of Weirt 138 kV breaker '2&5 XFMR'		APS (100%)
b2097	Replace Ridgeley 138 kV breaker '#2 XFMR OCB'		APS (100%)
b2098	Revise the reclosing of Ridgeley 138 kV breaker 'AR3' with 40kA rated breaker		APS (100%)
b2099	Revise the reclosing of Ridgeley 138 kV breaker 'RC1'		APS (100%)
b2100	Replace Ridgeley 138 kV breaker 'WC4' with 40kA rated breaker		APS (100%)
b2101	Replace Ridgeley 138 kV breaker '1 XFMR OCB' with 40kA rated breaker		APS (100%)
b2102	Replace Armstrong 138 kV breaker 'GARETTRJCT' with 40kA rated breaker		APS (100%)
b2103	Replace Armstrong 138 kV breaker 'BURMA' with 40kA rated breaker		APS (100%)
b2104	Replace Armstrong 138 kV breaker 'KITTANNING' with 40kA rated breaker		APS (100%)
b2105	Replace Armstrong 138 kV breaker 'KISSINGERJCT' with 40kA rated breaker		APS (100%)
b2106	Replace Wylie Ridge 345 kV breaker 'WK-1' with 63kA rated breaker		APS (100%)
b2107	Replace Wylie Ridge 345 kV breaker 'WK-2' with 63kA rated breaker		APS (100%)
b2108	Replace Wylie Ridge 345 kV breaker 'WK-3' with 63kA rated breaker		APS (100%)
b2109	Replace Wylie Ridge 345 kV breaker 'WK-4' with 63kA rated breaker		APS (100%)
b2110	Replace Wylie Ridge 345 kV breaker 'WK-6' with 63kA rated breaker		APS (100%)

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

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

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

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

SCHEDULE 12 – APPENDIX

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0318	Install a 765/138 kV transformer at Amos		AEP (99.00%) / PEPCO (1.00%)
b0324	Replace entrance conductors, wave traps, and risers at the Tidd 345 kV station on the Tidd – Canton Central 345 kV circuit		AEP (100%)
b0447	Replace Cook 345 kV breaker M2		AEP (100%)
b0448	Replace Cook 345 kV breaker N2		AEP (100%)
b0490	Construct an Amos – Bedington 765 kV circuit (AEP equipment)	As specified under the procedures detailed in Attachment H-19B	AEC (1.53%) / AEP (15.32%) / APS (5.87%) / ATSI (7.76%) / BGE (4.18%) / ComEd (12.38%) / ConEd (0.57%) / Dayton (2.01%) / DEOK (3.21%) / DL (1.69%) / DPL (2.43%) / Dominion (12.42%) / EKPC (2.15%) / HTP (0.20%) / JCPL (3.54%) / ME (1.77%) / NEPTUNE* (0.42%) / PECO (5.18%) / PENELEC (1.92%) / PEPCO (3.98%) / PPL (5.05%) / PSEG (5.97%) / RE (0.25%) / ECP** (0.20%)

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

Attachment 8

PATH Formula Rate for January 1, 2016 to December 31, 2016

September 1, 2015

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

Re: Potomac-Appalachian Transmission Highline, LLC
PJM Open Access Transmission Tariff, Attachment H-19
Projected Transmission Revenue Requirement for Rate Year 2016

Pursuant to section IV of the Formula Rate Implementation Protocols ("Protocols") set forth in Attachment H-19B of the PJM Open Access Transmission Tariff ("PJM OATT"),[1] Potomac-Appalachian Transmission Highline, LLC ("PATH"), on behalf of its operating companies PATH West Virginia Transmission Company, LLC and PATH Allegheny Transmission Company, LLC, is submitting a Projected Transmission Revenue Requirement for Rate Year 2016 ("2016 PTRR") to PJM for posting.

The 2016 PTRR was developed pursuant to the PATH formula rate as set forth in Attachment H-19 of the PJM OATT. PATH has asked PJM to post a copy of the 2016 PTRR to the formula rates section of its internet site, located at:

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

A copy of the 2016 PTRR is attached. Pursuant to section IV.C of the Protocols, within two business days of this submission to PJM, PATH will provide notice on PJM's website of the time, date and location of an open meeting among Interested Parties.

---

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

For the 12 months ended 12/31/2016

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	$14,648,480	(A)	$14,569,368	(B)	$29,217,848
2	PJM Project No.					
3	b0490 & b0491	$14,648,480	(C)			$14,648,480
4	b0492 & b0560			$14,569,368	(D)	$14,569,368
5						
6	Total (Sum lines 3 to 5)	$14,648,480		$14,569,368		$29,217,848

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

Formula Rate - Non-Levelized

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2016

PATH West Virginia Transmission Company, LLC

Line No.			(1)		(2)	(3) Allocated Amount
1	GROSS REVENUE REQUIREMENT	(line 86)			12 months	$ 14,372,077
	REVENUE CREDITS		Total	Allocator		
2	Total Revenue Credits	Attachment 1, line 12	0	TP	1.00000	$ -
3	True-up Adjustment with Interest	Protocols	276,404	DA	1.00000	$ 276,404
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)				$ 14,648,480

Attachment A

Formula Rate - Non-Levelized

Rate Formula Template

Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2016

PATH West Virginia Transmission Company, LLC

Line No.	(1)	(2) Form No. 1 Page, Line, Col.	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	RATE BASE:					
	GROSS PLANT IN SERVICE					
6	Production	(Attachment 4)	-	NA	0.00000	-
7	Transmission	(Attachment 4)	-	TP	1.00000	-
8	Distribution	(Attachment 4)	-	NA	0.00000	-
9	General & Intangible	(Attachment 4)	-	W/S	1.00000	-
10	Common	(Attachment 4)	-	CE	1.00000	-
11	TOTAL GROSS PLANT (sum lines 6-10)	(GP=1 if plant =0)	-	GP=	1.00000	-
12	ACCUMULATED DEPRECIATION					
13	Production	(Attachment 4)	-	NA	0.00000	-
14	Transmission	(Attachment 4)	-	TP	1.00000	-
15	Distribution	(Attachment 4)	-	NA	0.00000	-
16	General & Intangible	(Attachment 4)	-	W/S	1.00000	-
17	Common	(Attachment 4)	-	CE	1.00000	-
18	TOTAL ACCUM. DEPRECIATION (sum lines 13-17)		-			-
19	NET PLANT IN SERVICE					
20	Production	(line 6- line 13)	-			-
21	Transmission	(line 7- line 14)	-			-
22	Distribution	(line 8- line 15)	-			-
23	General & Intangible	(line 9- line 16)	-			-
24	Common	(line 10- line 17)	-			-
25	TOTAL NET PLANT (sum lines 20-24)	(NP=1 if plant =0)	-	NP=	1.0000	-
26	ADJUSTMENTS TO RATE BASE (Note A)					
27	Account No. 281 (enter negative)	(Attachment 4)	-	NA	0.00000	-
28	Account No. 282 (enter negative)	(Attachment 4)	(364)	NP	1.00000	(364)
29	Account No. 283 (enter negative)	(Attachment 4)	(2,814,490)	NP	1.00000	(2,814,490)
30	Account No. 190	(Attachment 4)	3,689,072	NP	1.00000	3,689,072
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)	13,380,446	DA	1.00000	13,380,446
35	TOTAL ADJUSTMENTS (sum lines 27-34)		14,254,664			14,254,664
36	LAND HELD FOR FUTURE USE	(Attachment 4)	-	TP	1.00000	-
37	WORKING CAPITAL (Note C)					
38	CWC	calculated	147,585			147,585
39	Materials & Supplies (Note B)	(Attachment 4)	-	TE	1.00000	-
40	Prepayments (Account 165 - Note C)	(Attachment 4)	195	GP	1.00000	195
41	TOTAL WORKING CAPITAL (sum lines 38-40)		147,779			147,779
42	RATE BASE (sum lines 25, 35, 36, & 41)		14,402,444			14,402,444

Formula Rate - Non-Levelized

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2016

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	1,158,539	W/S	1.00000	1,158,539
48	Less EPRI & Reg. Comm. Exp. & Other Ad	(Note D & Attach 4)	-	DA	1.00000	-
49	Plus Transmission Related Reg. Comm. E	(Note D & Attach 4)	-	TE	1.00000	-
50	PBOP Expense adjustment	(Attachment 4)	22,139			22,139
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)		1,180,678			1,180,678
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)	11,468,954	DA	1.00000	11,468,954
63	TOTAL DEPRECIATION (Sum lines 59-62)		11,468,954			11,468,954
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	11,650	GP	1.00000	11,650
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)		11,650			11,650
74	INCOME TAXES	(Note F)				
75	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		39.23%			
76	CIT=(T/1-T) * (1-(WCLTD/R)) =		39.38%			
77	where WCLTD=(line 118) and R= (line 121)					
78	and FIT, SIT & p are as given in footnote F.					
79	1 / (1 - T) = (T from line 75)		1.6454			
80	Amortized Investment Tax Credit (266.8f) (enter negative)		0			
81	Income Tax Calculation = line 76 * line 85		483,368	NA		483,368
82	ITC adjustment (line 79 * line 80)		0	NP	1.00000	-
83	Total Income Taxes	(line 81 plus line 82)	483,368			483,368
84	RETURN					
85	[Rate Base (line 42) * Rate of Return (line 121)]		1,227,427	NA		1,227,427
86	REV. REQUIREMENT (sum lines 57, 63, 73, 83, 85)		14,372,077			14,372,077

Formula Rate - Non-Levelized

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2016

PATH West Virginia Transmission Company, LLC
SUPPORTING CALCULATIONS AND NOTES

87	TRANSMISSION PLANT INCLUDED IN ISO RATES								
88	Total transmission plant (line 7, column 3)						0		
89	Less transmission plant excluded from ISO rates (Note H)						0		
90	Less transmission plant included in OATT Ancillary Services (Note H)						0		
91	Transmission plant included in ISO rates (line 88 less lines 89 & 90)						0		
92	Percentage of transmission plant included in ISO Rates (line 91 divided by line 88) [If line 88 equal zero, enter 1]					TP=	1.0000		
93	TRANSMISSION EXPENSES								
94									
95	Total transmission expenses (line 44, column 3)						0		
96	Less transmission expenses included in OATT Ancillary Services (Note G)						0		
97	Included transmission expenses (line 95 less line 96)						0		
98	Percentage of transmission expenses after adjustment (line 97 divided by line 95) [If line 95 equal zero, enter 1)						1.00000		
99	Percentage of transmission plant included in ISO Rates (line 92)					TP	1.00000		
100	Percentage of transmission expenses included in ISO Rates (line 98 times line 99)					TE=	1.00000		
101	WAGES & SALARY ALLOCATOR (W&S)								
102		Form 1 Reference	$	TP	Allocation				
103	Production	354.20.b	0						
104	Transmission	354.21.b	0	1.00	0				
105	Distribution	354.23.b	0				W&S Allocator		
106	Other	354.24,25,26.b	0				($ / Allocation)		
107	Total (sum lines 103-106) [TP equals 1 if there are no wages & salaries		0		0	=	1.00000	=	WS
108	COMMON PLANT ALLOCATOR (CE) (Note I)								
109			**$**		% Electric		W&S Allocator		
110	Electric	200.3.c	0		(line 110 / line 113)		(line 107)		CE
111	Gas	201.3.d	0		1.00000	x	1.00000	=	1.00000
112	Water	201.3.e	0						
113	Total (sum lines 110 - 112)		0						
114	RETURN (R)						$		
115									
116									
117			$	%	Cost		Weighted		
118	Long Term Debt (Note K)	(Attachment 4)	0	50%	6.64%		0.0332	=WCLTD	
119	Preferred Stock	(Attachment 4)	0	0%	0.00%		0.0000		
120	Common Stock (Note J)	(Attachment 4)	0	50%	10.40%		0.0520		
121	Total (sum lines 118-120)		0				0.0852	=R	

SUPPORTING CALCULATIONS AND NOTES
Attachment A
Formula Rate - Non-Levelized
Rate Formula Template
Utilizing FERC Form 1 Data
For the 12 months ended 12/31/2016

PATH West Virginia Transmission Company, LLC

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

Note Letter

A The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note F. Account 281 is not allocated.

B Identified in Form 1 as being only transmission related.

C Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission
Prepayments are the electric related prepayments booked to Account No. 165 and reported on Pages 110-111 line 57 in the Form 1.

D EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, except safety, education and out-reach related advertising included in Account 930.1. Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.

E Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year.
Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.

F The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 4, line 79).

Inputs Required:	FIT =	35.00%	
	SIT=	6.50%	(State Income Tax Rate or Composite SIT from Attachment 4)
	p =	0.00%	(percent of federal income tax deductible for state purposes)

G Removes dollar amount of transmission expenses included in the OATT ancillary services rates, if any.

H Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

I Enter dollar amounts

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

K The percentage shown for Long Term Debt is subject to the Annual Update and Attachment 6 and Attachment 9.

Formula Rate - Non-Levelized

Attachment A
Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2016

PATH Allegheny Transmission Company, LLC

Line No.			(1)		(2)	(3) Allocated Amount
1	GROSS REVENUE REQUIREMENT	(line 86)			12 months	$ 14,270,441
	REVENUE CREDITS		Total	Allocator		
2	Total Revenue Credits	Attachment 1, line 12	0	TP	1.00000	-
3	True-up Adjustment with Interest	Protocols	298,927	DA	1.00000	$ 298,927
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)				$ 14,569,368

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

For the 12 months ended 12/31/2016

PATH Allegheny Transmission Company, LLC

Line No.	(1)	(2) **Form No. 1 Page, Line, Col.**	(3) **Company Total**	(4) **Allocator**		(5) **Transmission** (Col 3 times Col 4)
	RATE BASE:					
	GROSS PLANT IN SERVICE					
6	Production	(Attachment 4)	-	NA	0.00000	-
7	Transmission	(Attachment 4)	-	TP	1.00000	-
8	Distribution	(Attachment 4)	-	NA	0.00000	-
9	General & Intangible	(Attachment 4)	-	W/S	1.00000	-
10	Common	(Attachment 4)	-	CE	1.00000	-
11	TOTAL GROSS PLANT (sum lines 6-10)	(GP=1 if plant =0)	-	GP=	1.00000	-
12	ACCUMULATED DEPRECIATION					
13	Production	(Attachment 4)	-	NA	0.00000	-
14	Transmission	(Attachment 4)	-	TP	1.00000	-
15	Distribution	(Attachment 4)	-	NA	0.00000	-
16	General & Intangible	(Attachment 4)	-	W/S	1.00000	-
17	Common	(Attachment 4)	-	CE	1.00000	-
18	TOTAL ACCUM. DEPRECIATION (sum lines 13-17)		-			-
19	NET PLANT IN SERVICE					
20	Production	(line 6- line 13)	-			-
21	Transmission	(line 7- line 14)	-			-
22	Distribution	(line 8- line 15)	-			-
23	General & Intangible	(line 9- line 16)	-			-
24	Common	(line 10- line 17)	-			-
25	TOTAL NET PLANT (sum lines 20-24)	(NP=1 if plant =0)	-	NP=	1.0000	-
26	ADJUSTMENTS TO RATE BASE (Note A)					
27	Account No. 281 (enter negative)	(Attachment 4)	-	NA	0.00000	-
28	Account No. 282 (enter negative)	(Attachment 4)	128,816	NP	1.00000	128,816
29	Account No. 283 (enter negative)	(Attachment 4)	(751,211)	NP	1.00000	(751,211)
30	Account No. 190	(Attachment 4)	4,897,692	NP	1.00000	4,897,692
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)	13,710,595	DA	1.00000	13,710,595
35	TOTAL ADJUSTMENTS (sum lines 27-34)		17,985,892			17,985,892
36	LAND HELD FOR FUTURE USE	(Attachment 4)	-	TP	1.00000	-
37	WORKING CAPITAL (Note C)					
38	CWC	calculated	38,652			38,652
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)		38,652			38,652
42	RATE BASE (sum lines 25, 35, 36, & 41)		18,024,544			18,024,544

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

For the 12 months ended 12/31/2016

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	38,850	TE	1.00000	38,850
45	Less Account 565	321.96.b	-	TE	1.00000	-
46	Less Account 566	Line 56	-	DA	1.00000	-
47	A&G	323.197.b	270,367	W/S	1.00000	270,367
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	-	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)		309,217			309,217
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)	11,751,939	DA	1.00000	11,751,939
63	TOTAL DEPRECIATION (Sum lines 59-62)		11,751,939			11,751,939
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	95,647	GP	1.00000	95,647
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)		95,647			95,647
74	INCOME TAXES	(Note F)				
75	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		37.71%			
76	CIT=(T/1-T) * (1-(WCLTD/R)) =		36.70%			
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)		1.6054			
80	Amortized Investment Tax Credit	(266.8f) (enter negative)	0			
81	Income Tax Calculation = line 76 * line 85		567,418	NA		567,418
82	ITC adjustment (line 79 * line 80)		0	NP	1.00000	-
83	Total Income Taxes	(line 81 plus line 82)	567,418			567,418
84	RETURN					
85	[Rate Base (line 42) * Rate of Return (line 121)]		1,546,220	NA		1,546,220
86	REV. REQUIREMENT (sum lines 57, 63, 73, 83, 85)		14,270,441			14,270,441

Attachment A

Formula Rate - Non-Levelized

Rate Formula Template

Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2016

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)						38,850		
96	Less transmission expenses included in OATT Ancillary Services (Note G)						0		
97	Included transmission expenses (line 95 less line 96)						38,850		
98	Percentage of transmission expenses after adjustment (line 97 divided by line 95) [If line 95 equal zero, enter 1)						1.00000		
99	Percentage of transmission plant included in ISO Rates (line 92)					TP	1.00000		
100	Percentage of transmission expenses included in ISO Rates (line 98 times line 99)					TE=	1.00000		
101	WAGES & SALARY ALLOCATOR (W&S)								
102		Form 1 Reference	$	TP	Allocation				
103	Production	354.20.b	0						
104	Transmission	354.21.b	0	1.00	0				
105	Distribution	354.23.b	0				W&S Allocator		
106	Other	354.24,25,26.b	0	1.00	0		($ / Allocation)		
107	Total (sum lines 103-106) [TP equals 1 if there are no wages & salaries]		0		0	=	1.00000	=	WS
108	COMMON PLANT ALLOCATOR (CE) (Note I)								
109			**$**		% Electric		W&S Allocator		
110	Electric	200.3.c	0		(line 110 / line 113)		(line 107)		CE
111	Gas	201.3.d	0		1.00000	x	1.00000	=	1.00000
112	Water	201.3.e	0						
113	Total (sum lines 110 - 112)		0						
114	RETURN (R)						$		
115									
116									
117			$	%	Cost		Weighted		
118	Long Term Debt (Note K)	(Attachment 4)	0	50%	6.76%		0.0338	=WCLTD	
119	Preferred Stock	(Attachment 4)	0	0%	0.00%		0.0000		
120	Common Stock (Note J)	(Attachment 4)	0	50%	10.40%		0.0520		
121	Total (sum lines 118-120)		0				0.0858	=R	

SUPPORTING CALCULATIONS AND NOTES

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

For the 12 months ended 12/31/2016

PATH Allegheny Transmission Company, LLC

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

Note Letter

A The balances in Accounts 190, 281, 282 and 283, as adjusted by any amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109. Balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note F. Account 281 is not allocated.

B Identified in Form 1 as being only transmission related.

C Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission
Prepayments are the electric related prepayments booked to Account No. 165 and reported on Pages 110-111 line 57 in the Form 1.

D EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, except safety, education, siting and out-reach related advertising included in Account 930.1. Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.

E Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year.
Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.

F The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 9, line 79).

Inputs Required:	FIT =	35.00%	
	SIT=	4.17%	(State Income Tax Rate or Composite SIT from Attachment 4)
	p =	0.00%	(percent of federal income tax deductible for state purposes)

G Removes dollar amount of transmission expenses included in the OATT ancillary services rates, if any.

H Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed to included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.

I Enter dollar amounts

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

K The percentage shown for Long Term Debt is subject to the Annual Update and Attachment 6 and Attachment 9.

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

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

Note 1 All revenues related to transmission that are received as a transmission owner (i.e., not received as a LSE), for which the cost of the service is recovered under this formula, except as specifically provided for elsewhere in this attachment or elsewhere in the formula will be included as a revenue credit or included in the peak on page 2, line 2 of Rate Formula Template.

Note 2 If the costs associated with the Directly Assigned Transmission Facility Charges are included in the Rates, the associated revenues are included in the Rates. If the costs associated with the Directly Assigned Transmission Facility Charges are not included in the Rates, the associated revenues are not included in the Rates.

Note 3 Ratemaking treatment for the following specified secondary uses of transmission assets: (1) right-of-way leases and leases for space on transmission facilities for telecommunications; (2) transmission tower licenses for wireless antennas; (3) right-of-way property leases for farming, grazing or nurseries; (4) licenses of intellectual property (including a portable oil degasification process and scheduling software); and (5) transmission maintenance and consulting services (including energized circuit maintenance, high-voltage substation maintenance, safety training, transformer oil testing, and circuit breaker testing) to other utilities and large customers (collectively, products). DLC will retain 50% of net revenues consistent with *Pacific Gas and Electric Company* , 90 FERC ¶ 61,314. Note: in order to use lines 15 - 20, the utility must track in separate subaccounts the revenues and costs associated with each secondary use (except for the cost of the associated income taxes).

Note 4 If the facilities associated with the revenues are not included in the formula, the revenue is shown here, but not included in the total above and explained in the Cost Support. For example revenues associated with distribution facilities. In addition Revenues from Schedule 12 are not included in the total above to the extent they are credited under Schedule 12.

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

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

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

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

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

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

Note 1 All revenues related to transmission that are received as a transmission owner (i.e., not received as a LSE), for which the cost of the service is recovered under this formula, except as specifically provided for elsewhere in this attachment or elsewhere in the formula will be included as a revenue credit or included in the peak on page 7, line 2 of Rate Formula Template.

Note 2 If the costs associated with the Directly Assigned Transmission Facility Charges are included in the Rates, the associated revenues are included in the Rates. If the costs associated with the Directly Assigned Transmission Facility Charges are not included in the Rates, the associated revenues are not included in the Rates.

Note 3 Ratemaking treatment for the following specified secondary uses of transmission assets: (1) right-of-way leases and leases for space on transmission facilities for telecommunications; (2) transmission tower licenses for wireless antennas; (3) right-of-way property leases for farming, grazing or nurseries; (4) licenses of intellectual property (including a portable oil degasification process and scheduling software); and (5) transmission maintenance and consulting services (including energized circuit maintenance, high-voltage substation maintenance, safety training, transformer oil testing, and circuit breaker testing) to other utilities and large customers (collectively, products). DLC will retain 50% of net revenues consistent with *Pacific Gas and Electric Company* , 90 FERC ¶ 61,314. Note: in order to use lines 15 - 20, the utility must track in separate subaccounts the revenues and costs associated with each secondary use (except for the cost of the associated income taxes).

Note 4 If the facilities associated with the revenues are not included in the formula, the revenue is shown here, but not included in the total above and explained in the Cost Support. For example revenues associated with distribution facilities. In addition Revenues from Schedule 12 are not included in the total above to the extent they are credited under Schedule 12.

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

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

Note 6	All Account 454 and 456 Revenues must be itemized below		
	Account 454	Include	$
	Joint pole attachments - telephone	Include	-
	Joint pole attachments - cable	Include	-
	Underground rentals	Include	-
	Transmission tower wireless rentals	Include	-
	Other rentals	Include	-
	Corporate headquarters sublease	Include	-
	Misc non-transmission rentals	Include	-
	Customer commitment services	Include	-
	xxxx		
	xxxx		
	Total		-
	Account 456	Include	-
	Other electric revenues	Include	-
	Transmission Revenue - Firm	Include	-
	Transmission Revenue - Non-Firm	Include	-
	xxxx		-
	xxxx		-
	xxxx		-
	xxxx		-
	xxxx		-
	xxxx		-
	xxxx		-
	Total		-
	Total Account 454 and 456 included		-
	Payments by PJM of the revenue requirement calculated on Rate Formula Template	Exclude	-
	Total Account 454 and 456 included and excluded		-

Attachment 3 - Calculation of Carrying Charges

PATH West Virginia Transmission Company, LLC

1 Calculation of Composite Depreciation Rate

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

Attachment 3 - Calculation of Carrying Charges

PATH Allegheny Transmission Company, LLC

1 Calculation of Composite Depreciation Rate

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

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

Plant in Service Worksheet

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

1	**Calculation of Transmission Plant In Service**	Source	Year	Balance
2	December	p206.58.b	2015	-
3	January	company records	2016	-
4	February	company records	2016	-
5	March	company records	2016	-
6	April	company records	2016	-
7	May	company records	2016	-
8	June	company records	2016	-
9	July	company records	2016	-
10	August	company records	2016	-
11	September	company records	2016	-
12	October	company records	2016	-
13	November	company records	2016	-
14	December	p207.58.g	2016	-
15	**Transmission Plant In Service**	(sum lines 2-14) /13		-
16	**Calculation of Distribution Plant In Service**	Source		
17	December	p206.75.b	2015	-
18	January	company records	2016	-
19	February	company records	2016	-
20	March	company records	2016	-
21	April	company records	2016	-
22	May	company records	2016	-
23	June	company records	2016	-
24	July	company records	2016	-
25	August	company records	2016	-
26	September	company records	2016	-
27	October	company records	2016	-
28	November	company records	2016	-
29	December	p207.75.g	2016	-
30	**Distribution Plant In Service**	(sum lines 17-29) /13		-
31	**Calculation of Intangible Plant In Service**	Source		
32	December	p204.5.b	2015	-
33	December	p205.5.g	2016	-
34	**Intangible Plant In Service**	(sum lines 32 & 33) /2		-
35	**Calculation of General Plant In Service**	Source		
36	December	p206.99.b	2015	-
37	December	p207.99.g	2016	-
38	**General Plant In Service**	(sum lines 36 & 37) /2		-
39	**Calculation of Production Plant In Service**	Source		
40	December	p204.46b	2015	-
41	January	company records	2016	-
42	February	company records	2016	-
43	March	company records	2016	-
44	April	company records	2016	-
45	May	company records	2016	-
46	March	Attachment 6	2016	-
47	April	company records	2016	-
48	August	company records	2016	-
49	September	company records	2016	-
50	October	company records	2016	-
51	November	company records	2016	-
52	December	p205.46.g	2016	-
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	2015	-
56	December (Electric Portion)	p356	2016	-
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	2015	-	
61	January	company records	2016	-	
62	February	company records	2016	-	
63	March	company records	2016	-	
64	April	company records	2016	-	
65	May	company records	2016	-	
66	June	company records	2016	-	
67	July	company records	2016	-	
68	August	company records	2016	-	
69	September	company records	2016	-	
70	October	company records	2016	-	
71	November	company records	2016	-	
72	December	p219.25	2016	-	
73	**Transmission Accumulated Depreciation**	(sum lines 60-72) /13		-	
74	**Calculation of Distribution Accumulated Depreciation**	Source			
75	December	Prior year p219.26	2015	-	
76	January	company records	2016	-	
77	February	company records	2016	-	
78	March	company records	2016	-	
79	April	company records	2016	-	
80	May	company records	2016	-	
81	June	company records	2016	-	
82	July	company records	2016	-	
83	August	company records	2016	-	
84	September	company records	2016	-	
85	October	company records	2016	-	
86	November	company records	2016	-	
87	December	p219.26	2016	-	
88	**Distribution Accumulated Depreciation**	(sum lines 75-87) /13		-	
89	**Calculation of Intangible Accumulated Depreciation**	Source			
90	December	Prior year p200.21.c	2015	-	
91	December	p200.21c	2016	-	
92	**Accumulated Intangible Depreciation**	(sum lines 90 & 91) /2		-	
93	**Calculation of General Accumulated Depreciation**	Source			
94	December	Prior year p219.28	2015	-	
95	December	p219.28	2016	-	
96	**Accumulated General Depreciation**	(sum lines 94 & 95) /2		-	

		Source	Year	Balance
97	**Calculation of Production Accumulated Depreciation**	Source	Year	Balance
98	December	Prior year p219	2015	-
99	January	company records	2016	-
100	February	company records	2016	-
101	March	company records	2016	-
102	April	company records	2016	-
103	May	company records	2016	-
104	June	company records	2016	-
105	July	company records	2016	-
106	August	company records	2016	-
107	September	company records	2016	-
108	October	company records	2016	-
109	November	company records	2016	-
110	December	p219.20 thru 219.24	2016	-
111	**Production Accumulated Depreciation**	(sum lines 98-110) /13		-
112	**Calculation of Common Accumulated Depreciation**	Source		
113	December (Electric Portion)	p356	2015	-
114	December (Electric Portion)	p356	2016	-
115	**Common Plant Accumulated Depreciation (Electric Only)**	(sum lines 113 & 114) /2		-
116	**Total Accumulated Depreciation**	(sum lines 73, 88, 92, 96, 111, & 115)		-

ADJUSTMENTS TO RATE BASE (Note A)

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions						Details
			Beginning of Year	End of Year	Average Balance	
117	Account No. 281 (enter negative)	273.8.k	-	-	0	
118	Account No. 282 (enter negative)	275.2.k	(364)	(364)	-364	
119	Account No. 283 (enter negative)	277.9.k	(5,450,980)	(178,000)	-2,814,490	
120	Account No. 190	234.8.c	3,146,144	4,232,000	3,689,072	
121	Account No. 255 (enter negative)	267.8.h	-	-	0	

122 Unamortized Abandoned Plant Per FERC Order

		Source	Months Remaining In Amortization Period	Beginning Balance	Amortization Expense (p114.10.c)	Additions (Deductions)	Ending Balance
123	**Monthly Balance**						
124	December	p111.71.d (and Notes)	21				19,114,923.35
125	January	company records	20	19,114,923	955,746.17	-	18,159,177.18
126	February	company records	19	18,159,177	955,746.17	-	17,203,431.02
127	March	company records	18	17,203,431	955,746.17	-	16,247,684.85
128	April	company records	17	16,247,685	955,746.17	-	15,291,938.68
129	May	company records	16	15,291,939	955,746.17	-	14,336,192.51
130	June	company records	15	14,336,193	955,746.17	-	13,380,446.35
131	July	company records	14	13,380,446	955,746.17	-	12,424,700.18
132	August	company records	13	12,424,700	955,746.17	-	11,468,954.01
133	September	company records	12	11,468,954	955,746.17	-	10,513,207.84
134	October	company records	11	10,513,208	955,746.17	-	9,557,461.68
135	November	company records	10	9,557,462	955,746.17	-	8,601,715.51
136	December	p111.71.c (and Notes) Detail on p230b	9	8,601,716	955,746.17	-	7,645,969.34
137	**Ending Balance is a 13-Month Average**	(sum lines 124-136) /13			$11,468,954.01	-	$13,380,446.35
					Appendix A Line 62		Appendix A Line 34

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

138	Prepayments (Account 165)	111.57.c	195	195	195

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	2015	$	-	-	-	-	-	-
141	January	company records	2016		-	-	-	-	-	-
142	February	company records	2016		-	-	-	-	-	-
143	March	company records	2016		-	-	-	-	-	-
144	April	company records	2016		-	-	-	-	-	-
145	May	company records	2016		-	-	-	-	-	-
146	June	company records	2016		-	-	-	-	-	-
147	July	company records	2016		-	-	-	-	-	-
148	August	company records	2016		-	-	-	-	-	-
149	September	company records	2016		-	-	-	-	-	-
150	October	company records	2016		-	-	-	-	-	-
151	November	company records	2016		-	-	-	-	-	-
152	December	216.b	2016		-	-	-	-	-	-
153	**Transmission CWIP**	(sum lines 140-152) /13			-	-	-	-	-	-

LAND HELD FOR FUTURE USE

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

EPRI Dues Cost Support

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

Regulatory Expense Related to Transmission Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Form 1 Amount	Transmission Related	Non-transmission Related	Details
	Directly Assigned A&G					
156	Regulatory Commission Exp Account 928	p323.189.b	-	-	-	

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

Safety Related Advertising, Education and Out Reach Cost Support

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

Multi-state Workpaper

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	State 1	State 2	State 3	State 4	State 5	Weighed Average
	Income Tax Rates						
			WV				
158	SIT=State Income Tax Rate or Composite		6.500%				6.50%

Excluded Plant Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Excluded Transmission Facilities	Description of the Facilities
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
159	Excluded Transmission Facilities		-	**General Description of the Facilities**
	Instructions:		**Enter $**	**None**
1	Remove all investment below 69 kV facilities, including the investment allocated to distribution of a dual function substation, generator, interconnection and local and direct assigned facilities for which separate costs are charged and step-up generation substation included in transmission plant in service.		-	
2	If unable to determine the investment below 69kV in a substation with investment of 69 kV and higher as well as below 69 kV, the following formula will be used:	**Example**	**Or** **Enter $**	
A	Total investment in substation	1,000,000	-	
B	Identifiable investment in Transmission (provide workpapers)	500,000	-	
C	Identifiable investment in Distribution (provide workpapers)	400,000	-	
D	Amount to be excluded (A x (C / (B + C)))	444,444	-	
				Add more lines if necessary

Materials & Supplies

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

Regulatory Asset

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			
				Reference FERC Form 1 page 232 for details.
164	Beginning Balance of Regulatory Asset	p111.72.d (and notes)	-	Uncapitalized costs as of date the rates become effective
165	Months Remaining in Amortization Period		-	As approved by FERC
166	Monthly Amortization	(line 164 - line 168) / 167	-	
167	Months in Year to be amortized		-	Number of months rates are in effect during the calendar year
168	Ending Balance of Regulatory Asset	p111.72.c	-	
169	Average Balance of Regulatory Asset	(line 164 + line 168)/2	-	

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

Capital Structure

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions					
170	Monthly Balances for Capital Structure				
171		Year	Debt	Preferred Stock	Common Stock
172	January	2016	0	-	0
173	February	2016	-	-	-
174	March	2016	-	-	-
175	April	2016	-	-	-
176	May	2016	-	-	-
177	June	2016	-	-	-
178	July	2016	-	-	-
179	August	2016	-	-	-
180	September	2016	-	-	-
181	October	2016	-	-	-
182	November	2016	-	-	-
183	December	2016	-	-	-
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		159,908	
196	PATH WV PBOP Expense for current year		$16,277	
197	PATH WV PBOP Expense in Account 926 for current year		-$5,862	
198	PBOP Adjustment for Appendix A, Line 50		$22,139	
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)	$22,139	

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	2015	-
3	January	company records	2016	-
4	February	company records	2016	-
5	March	company records	2016	-
6	April	company records	2016	-
7	May	company records	2016	-
8	June	company records	2016	-
9	July	company records	2016	-
10	August	company records	2016	-
11	September	company records	2016	-
12	October	company records	2016	-
13	November	company records	2016	-
14	December	p207.58.g	2016	-
15	**Transmission Plant In Service**	(sum lines 2-14) /13		-
16	**Calculation of Distribution Plant In Service**	Source		
17	December	p206.75.b	2015	-
18	January	company records	2016	-
19	February	company records	2016	-
20	March	company records	2016	-
21	April	company records	2016	-
22	May	company records	2016	-
23	June	company records	2016	-
24	July	company records	2016	-
25	August	company records	2016	-
26	September	company records	2016	-
27	October	company records	2016	-
28	November	company records	2016	-
29	December	p207.75.g	2016	-
30	**Distribution Plant In Service**	(sum lines 17-29) /13		-
31	**Calculation of Intangible Plant In Service**	Source		
32	December	p204.5b	2015	-
33	December	p205.5.g	2016	-
34	**Intangible Plant In Service**	(sum lines 32 & 33) /2		-
35	**Calculation of General Plant In Service**	Source		
36	December	p206.99.b	2015	-
37	December	p207.99.g	2016	-
38	**General Plant In Service**	(sum lines 36 & 37) /2		-
39	**Calculation of Production Plant In Service**	Source		
40	December	p204.46b	2015	-
41	January	company records	2016	-
42	February	company records	2016	-
43	March	company records	2016	-
44	April	company records	2016	-
45	May	company records	2016	-
46	March	Attachment 6	2016	-
47	April	company records	2016	-
48	August	company records	2016	-
49	September	company records	2016	-
50	October	company records	2016	-
51	November	company records	2016	-
52	December	p205.46.g	2016	-
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	2015	-
56	December (Electric Portion)	p356	2016	-
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	2015	-	
61	January	company records	2016	-	
62	February	company records	2016	-	
63	March	company records	2016	-	
64	April	company records	2016	-	
65	May	company records	2016	-	
66	June	company records	2016	-	
67	July	company records	2016	-	
68	August	company records	2016	-	
69	September	company records	2016	-	
70	October	company records	2016	-	
71	November	company records	2016	-	
72	December	p219.25	2016	-	
73	**Transmission Accumulated Depreciation**	(sum lines 60-72) /13		-	
74	**Calculation of Distribution Accumulated Depreciation**	Source			
75	December	Prior year p219.26	2015	-	
76	January	company records	2016	-	
77	February	company records	2016	-	
78	March	company records	2016	-	
79	April	company records	2016	-	
80	May	company records	2016	-	
81	June	company records	2016	-	
82	July	company records	2016	-	
83	August	company records	2016	-	
84	September	company records	2016	-	
85	October	company records	2016	-	
86	November	company records	2016	-	
87	December	p219.26	2016	-	
88	**Distribution Accumulated Depreciation**	(sum lines 75-87) /13		-	
89	**Calculation of Intangible Accumulated Depreciation**	Source			
90	December	Prior year p200.21.c	2015	-	
91	December	p200.21c	2016	-	
92	**Accumulated Intangible Depreciation**	(sum lines 90 & 91) /2		-	
93	**Calculation of General Accumulated Depreciation**	Source			
94	December	Prior year p219.28	2015	-	
95	December	p219.28	2016	-	
96	**Accumulated General Depreciation**	(sum lines 94 & 95) /2		-	

97	**Calculation of Production Accumulated Depreciation**	Source	Year	Balance
98	December	Prior year p219	2015	-
99	January	company records	2016	-
100	February	company records	2016	-
101	March	company records	2016	-
102	April	company records	2016	-
103	May	company records	2016	-
104	June	company records	2016	-
105	July	company records	2016	-
106	August	company records	2016	-
107	September	company records	2016	-
108	October	company records	2016	-
109	November	company records	2016	-
110	December	p219.20 thru 219.24	2016	-
111	**Production Accumulated Depreciation**	(sum lines 98-110) /13		-
112	**Calculation of Common Accumulated Depreciation**	Source		
113	December (Electric Portion)	p356	2015	-
114	December (Electric Portion)	p356	2016	-
115	**Common Plant Accumulated Depreciation (Electric Only)**	(sum lines 113 & 114) /2		-
116	**Total Accumulated Depreciation**	(sum lines 73, 88, 92, 96, 111, & 115)		-

ADJUSTMENTS TO RATE BASE (Note A)

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions					**Details**
			Beginning of Year	End of Year	Average Balance
117	Account No. 281 (enter negative)	273.8.k	-	-	0
118	Account No. 282 (enter negative)	275.2.k	96,733	160,899	128,816
119	Account No. 283 (enter negative)	277.9.k	(1,131,536)	(370,886)	(751,211)
120	Account No. 190	234.8.c	3,114,643	6,680,741	4,897,692
121	Account No. 255 (enter negative)	267.8.h	-	-	0
122	**Unamortized Abandoned Plant**	Per FERC Order			

123	**Monthly Balance**	Source	Months Remaining In Amortization Period	Beginning Balance	Amortization Expense (p114.10.c)	Additions (Deductions)	Ending Balance
124	December	p111.71.d (and Notes)	21				$ 19,586,565
125	January	company records	20	19,586,565	979,328	-	18,607,236
126	February	company records	19	18,607,236	979,328	-	17,627,908
127	March	company records	18	17,627,908	979,328	-	16,648,580
128	April	company records	17	16,648,580	979,328	-	15,669,252
129	May	company records	16	15,669,252	979,328	-	14,689,924
130	June	company records	15	14,689,924	979,328	-	13,710,595
131	July	company records	14	13,710,595	979,328	-	12,731,267
132	August	company records	13	12,731,267	979,328	-	11,751,939
133	September	company records	12	11,751,939	979,328	-	10,772,611
134	October	company records	11	10,772,611	979,328	-	9,793,282
135	November	company records	10	9,793,282	979,328	-	8,813,954
136	December	p111.71.c (and Notes) Detail on p230b	9	8,813,954	979,328	-	7,834,626
137	**Ending Balance is a 13-Month Average**	(sum lines 124-136) /13			11,751,939	-	13,710,595
					Appendix A Line 62		Appendix A Line 34

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

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

Attachment 4 - Cost Support
PATH 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	2015	$	-				
141	January	company records	2016		-				
142	February	company records	2016		-				
143	March	company records	2016		-				
144	April	company records	2016		-				
145	May	company records	2016		-				
146	June	company records	2016		-				
147	July	company records	2016		-				
148	August	company records	2016		-				
149	September	company records	2016		-				
150	October	company records	2016		-				
151	November	company records	2016		-				
152	December	216.b	2016		-				
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%			4.169%

Excluded Plant Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Excluded Transmission Facilities	Description of the Facilities
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
159	Excluded Transmission Facilities		-	**General Description of the Facilities**
	Instructions:		**Enter $**	**None**
1	Remove all investment below 69 kV facilities, including the investment allocated to distribution of a dual function substation, generator, interconnection and local and direct assigned facilities for which separate costs are charged and step-up generation substation included in transmission plant in service.		-	
2	If unable to determine the investment below 69kV in a substation with investment of 69 kV and higher as well as below 69 kV, the following formula will be used:	**Example**	**Or** **Enter $**	
A	Total investment in substation	1,000,000	-	
B	Identifiable investment in Transmission (provide workpapers)	500,000	-	
C	Identifiable investment in Distribution (provide workpapers)	400,000	-	
D	Amount to be excluded (A x (C / (B + C)))	444,444	-	
				Add more lines if necessary

Materials & Supplies

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

Regulatory Asset

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			
				Reference FERC Form 1 page 232 for details.
164	Beginning Balance of Regulatory Asset	p111.72.d (and notes)	-	Uncapitalized costs as of date the rates become effective
165	Months Remaining in Amortization Period		-	As approved by FERC
166	Monthly Amortization	(line 164 - line 168) / 167	-	
167	Months in Year to be Amortized		-	Number of months rates are in effect during the calendar year
168	Ending Balance of Regulatory Asset	p111.72.c	-	
169	Average Balance of Regulatory Asset	(line 164 + line 168)/2	-	

Attachment 4 - Cost Support
Ba

Capital Structure

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				
170	Monthly Balances for Capital Structure				
171		Year	Debt	Preferred Stock	Common Stock
172	January	2016	0	-	0
173	February	2016	-	-	-
174	March	2016	-	-	-
175	April	2016	-	-	-
176	May	2016	-	-	-
177	June	2016	-	-	-
178	July	2016	-	-	-
179	August	2016	-	-	-
180	September	2016	-	-	-
181	October	2016	-	-	-
182	November	2016	-	-	-
183	December	2016	-	-	-
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 - 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

2	Formula Line	Item	
3	5	NET REVENUE REQUIREMENT	14,648,480
4	21	NET TRANSMISSION PLANT IN SERVICE	-
5	32	CWIP	-
6	34	Unamortized Abandoned Plant	13,380,446
7		**Carrying charge (line 3/sum of lines 4, 5 and 6)**	**1.09477**

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

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

				(1)	(2)	(3)	(4)	(5)	(6)	(7)
				PJM Upgrade ID: b0490 & b0491						
10		Details		**Amos Substation Upgrade - CWIP**	**Amos to Midpoint Line - CWIP**	**Midpoint Substation and SVC - CWIP**	**Midpoint to Interconnection with PATH Allegheny - CWIP**	**Transmission Plant In Service**	**Unamortized Abandoned Plant**	**Totals**
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes		Yes	Yes	
12		FCR for This Project		109.5%	109.5%	109.5%	109.5%	109.5%	109.5%	
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	-	-	-	-	13,380,446.35	**13,380,446.35**
		Revenue Requirement		-	-	-	-	-	14,648,480.37	**14,648,480.37**

Attachment 5 - Transmission Enhancement Charge Worksheet

PATH Allegheny Transmission Company, LLC

1 New Plant Carrying Charge

	Formula Line	Item	
2	Formula Line	Item	
3	5	NET REVENUE REQUIREMENT	14,569,368
4	21	NET TRANSMISSION PLANT IN SERVICE	-
5	32	CWIP	-
6	34	Unamortized Abandoned Plant	13,710,595
7		**Carrying charge (line 3/sum of lines 4, 5and 6)**	**1.06264**

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

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

				(1)	(2)	(3)	(4)	(5)	(6)
				PJM Upgrade ID: b0492 & b0560					
10		Details		**Kemptown Substation - CWIP**	**Kemptown to Interconnection with PATH West Virginia - CWIP**	**Welton Spring Substation and SVC - CWIP**	**Transmission Plant In Service**	**Unamortized Abandoned Plant**	**Totals**
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes	Yes	
12		FCR for This Project		106.3%	106.3%	106.3%	106.3%	106.3%	
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		-	-	-	-	13,710,595.27	**13,710,595.27**
		Revenue Requirement		-	-	-	-	14,569,367.93	**14,569,367.93**

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

HYPOTHETICAL EXAMPLE

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

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

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

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

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

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

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

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

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

---

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

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

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

HYPOTHETICAL EXAMPLE

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

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

Internal Rate of Return[1]	**6.76%**
Based on following Financial Formula[2]:	

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

Origination Fees	
Underwriting Discount	-
Arrangement Fee	1,000,000
Upfront Fee	2,200,000
Rating Agency Fee	200,000
Legal Fees	750,000
Total Issuance Expense	**4,150,000**
Annual Rating Agency Fee	200,000
Annual Bank Agency Fee	75,000
Revolving Credit Commitment Fee	0.375%

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

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

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

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

Attachment 7

PATH West Virginia Transmission Company, LLC

Potomac-Appalachian Transmission Highline, LLC

CALCULATION OF COST OF DEBT AFTER CONSTRUCTION PHASE

YEAR ENDED **12/31/2014**

(HYPOTHETICAL EXAMPLE)

	Amount Outstanding	Unamortized Debt Issue Expense	Unamortized Debt Premium/ (Discount)	Unamortized Losses on Reacquired Debt	Net Amount Outstanding	Effective Cost Rate[1]	Annualized Cost
Debt:							
First Mortgage Bonds:							
	$ 300,000,000	$2,900,000	($2,320,000)	$0	$294,780,000	#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

PATH Allegheny Transmission Company, LLC

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

(HYPOTHETICAL EXAMPLE)

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

Development of Effective Cost Rates:

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

---

[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 2014 Available June 1, 2015		2014 Revenue Requirement Forecast by Sept 3, 2013		True-up Adjustment - Over (Under) Recovery
$18,161,530	-	$17,880,626	=	($280,903)

Interest Rate on Amount of Refunds or Surcharges		**Over (Under) Recovery Plus Interest**	**Average Monthly Interest Rate**	**Months**	**Calculated Interest**	**Amortization**	**Surcharge (Refund) Owed**
from 35.19a			0.2740%				
An over or under collection will be recovered prorata over 2014, held for 20145and returned prorate over 2016							
Calculation of Interest					**Monthly**		
January	Year 2014	(23,409)	0.2740%	12	770		24,178
February	Year 2014	(23,409)	0.2740%	11	706		24,114
March	Year 2014	(23,409)	0.2740%	10	641		24,050
April	Year 2014	(23,409)	0.2740%	9	577		23,986
May	Year 2014	(23,409)	0.2740%	8	513		23,922
June	Year 2014	(23,409)	0.2740%	7	449		23,858
July	Year 2014	(23,409)	0.2740%	6	385		23,793
August	Year 2014	(23,409)	0.2740%	5	321		23,729
September	Year 2014	(23,409)	0.2740%	4	257		23,665
October	Year 2014	(23,409)	0.2740%	3	192		23,601
November	Year 2014	(23,409)	0.2740%	2	128		23,537
December	Year 2014	(23,409)	0.2740%	1	64		23,473
					5,003		**285,906**
					Annual		
January through December	Year 2015	285,906	0.2740%	12	9,401		**295,307**
Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
January	Year 2016	**(295,307)**	0.2740%		809	(25,049)	271,066
February	Year 2016	(271,066)	0.2740%		743	(25,049)	246,760
March	Year 2016	(246,760)	0.2740%		676	(25,049)	222,387
April	Year 2016	(222,387)	0.2740%		609	(25,049)	197,947
May	Year 2016	(197,947)	0.2740%		542	(25,049)	173,440
June	Year 2016	(173,440)	0.2740%		475	(25,049)	148,865
July	Year 2016	(148,865)	0.2740%		408	(25,049)	124,224
August	Year 2016	(124,224)	0.2740%		340	(25,049)	99,515
September	Year 2016	(99,515)	0.2740%		273	(25,049)	74,738
October	Year 2016	(74,738)	0.2740%		205	(25,049)	49,894
November	Year 2016	(49,894)	0.2740%		137	(25,049)	24,981
December	Year 2016	(24,981)	0.2740%		68	(25,049)	(0)
					5,286		

True-Up Adjustment with Interest*	300,592
Less Over (Under) Recovery	(280,903)
Total Interest	19,689

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

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

Reconciliation Revenue Requirement For Year 2014 Available June 1, 2015		2014 Revenue Requirement Forecast by Sept 3, 2013		True-up Adjustment - Over (Under) Recovery
$16,838,878	-	$16,559,531	=	($279,347)

Interest Rate on Amount of Refunds or Surcharges		Over (Under) Recovery Plus Interest	Average Monthly Interest Rate	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
from 35.19a			0.2740%				
An over or under collection will be recovered prorata over 2014, held for 20145and returned prorate over 2016							
<u>Calculation of Interest</u>					**Monthly**		
January	Year 2014	(23,279)	0.2740%	12	765		24,044
February	Year 2014	(23,279)	0.2740%	11	702		23,981
March	Year 2014	(23,279)	0.2740%	10	638		23,917
April	Year 2014	(23,279)	0.2740%	9	574		23,853
May	Year 2014	(23,279)	0.2740%	8	510		23,789
June	Year 2014	(23,279)	0.2740%	7	446		23,725
July	Year 2014	(23,279)	0.2740%	6	383		23,662
August	Year 2014	(23,279)	0.2740%	5	319		23,598
September	Year 2014	(23,279)	0.2740%	4	255		23,534
October	Year 2014	(23,279)	0.2740%	3	191		23,470
November	Year 2014	(23,279)	0.2740%	2	128		23,406
December	Year 2014	(23,279)	0.2740%	1	64		23,343
					4,975		**284,322**
					Annual		
January through December	Year 2015	284,322	0.2740%	12	9,349		**293,671**
<u>Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months</u>					**Monthly**		
January	Year 2016	**(293,671)**	0.2740%		805	(24,911)	269,565
February	Year 2016	(269,565)	0.2740%		739	(24,911)	245,393
March	Year 2016	(245,393)	0.2740%		672	(24,911)	221,154
April	Year 2016	(221,154)	0.2740%		606	(24,911)	196,850
May	Year 2016	(196,850)	0.2740%		539	(24,911)	172,479
June	Year 2016	(172,479)	0.2740%		473	(24,911)	148,041
July	Year 2016	(148,041)	0.2740%		406	(24,911)	123,536
August	Year 2016	(123,536)	0.2740%		338	(24,911)	98,964
September	Year 2016	(98,964)	0.2740%		271	(24,911)	74,324
October	Year 2016	(74,324)	0.2740%		204	(24,911)	49,617
November	Year 2016	(49,617)	0.2740%		136	(24,911)	24,843
December	Year 2016	(24,843)	0.2740%		68	(24,911)	(0)
					5,257		

True-Up Adjustment with Interest	$	298,927
Less Over (Under) Recovery	$	(279,347)
Total Interest	$	19,580

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

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

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

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

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

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

Applicable to PATH Allegheny Transmission Company, LLC

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

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

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

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

Workpaper 1: PATH-WV FORMULA RATE ANNUAL PTRR UPDATE

Account 190 correction - PATH-WV, relating to a federal NOL carryforward

Original Calculation: Rev Requirement	Recalculation: Amount That Should Have Been Rev requirement	Over-collection Amount
18,242,460.49	18,220,894.96	(21,565.53)

	No. of Months	Beginning Balance	Credit of Over-collection with Interest	Interest Rate	Calculated Interest Quarterly	Ending Balance
Calculation of Interest						
Month of December 2012	1	-		0.0028	-	(21,565.53)
Jan 2013 through Mar 2013	3	(21,565.53)		0.0027	(174.68)	(21,740.21)
Apr 2013 through Jun 2013	3	(21,740.21)		0.0027	(176.10)	(21,916.31)
Jul 2013 through Sep 2013	3	(21,916.31)		0.0028	(184.10)	(22,100.40)
Oct 2013 through Dec 2013	3	(22,100.40)		0.0028	(185.64)	(22,286.05)
Jan 2014 through Mar 2014	3	(22,286.05)		0.0027	(180.52)	(22,466.56)
Apr 2014 through Jun 2014	3	(22,466.56)		0.0027	(181.98)	(22,648.54)
Jul 2014 through Sep 2014	3	(22,648.54)		0.0028	(190.25)	(22,838.79)
Oct 2014 through Dec 2014	3	(22,838.79)		0.0028	(191.85)	(23,030.64)
Jan 2015 through Mar 2015	3	(23,030.64)		0.0027	(186.55)	(23,217.18)
Apr 2015 through Jun 2015	3	(23,217.18)		0.0027	(188.06)	(23,405.24)
Jul 2015 through Sep 2015	3	(23,405.24)		0.0028	(196.60)	(23,601.85)
Oct 2015 through Dec 2015	3	(23,601.85)		0.0028	(198.26)	(23,800.10)
REVERSES						
Month of January 2016	1	(23,800.10)	2,015.73	0.0027	(61.54)	(21,845.92)
Feb 2016 through Apr 2016	3	(21,845.92)	6,047.18	0.0027	(152.46)	(15,951.20)
May 2016 through Jul 2016	3	(15,951.20)	6,047.18	0.0027	(104.71)	(10,008.73)
Aug 2016 through Oct 2016	3	(10,008.73)	6,047.18	0.0028	(58.68)	(4,020.23)
Nov 2016 through Dec 2016	2	(4,020.23)	4,031.45	0.0028	(11.23)	(0.00)

Total Interest	(2,623.19)
Over-collected Amount	(21,565.53)
Over-collected amount (including interest) to be entered in PATH-WV 2016 PTRR Formula Rate*	(24,188.72)

*This amount plus true-up adjustment with interest (see Attachment 8, PATH-WV) corresponds to PATH-WV Attachment A, Line 3

Attachment 9

VEPCO Formula Rate for January 1, 2016 to December 31, 2016

Virginia Electric and Power Company
ATTACHMENT H-16A

Formula Rate -- Appendix A

Shaded cells are input cells

		Notes	FERC Form 1 Page # or Instruction (Note H)		2016 Projection (000's)
	Allocators				
	Wages & Salary Allocation Factor				
1	Transmission Wages Expense		p354.21b/ Attachment 5	$	35,758
2	Less Generator Step-ups		Attachment 5		3
3	Net Transmission Wage Expenses		(Line 1 - 2)		35,755
4	Total Wages Expense		p354.28b/Attachment 5		611,279
5	Less A&G Wages Expense		p354.27b/Attachment 5		89,584
6	Total		(Line 4 - 5)	$	521,695
7	**Wages & Salary Allocator**	(Note B)	(Line 3 / 6)		**6.8537%**
	Plant Allocation Factors				
8	Electric Plant in Service	(Notes A& Q)	p207.104.g/Attachment 5	$	35,218,856
9	Common Plant In Service - Electric		(Line 26)		0
10	Total Plant In Service		(Sum Lines 8 & 9)		35,218,856
11	Accumulated Depreciation (Total Electric Plant)	(Notes A & Q)	(Line 15 - 14 - 13 -12)		12,387,057
12	Accumulated Intangible Amortization	(Notes A & Q)	p200.21c/Attachment 5		98,489
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		12,485,546
16	Net Plant		(Line 10 - 15)		22,733,311
17	Transmission Gross Plant		(Line 31 - 30)		6,758,726
18	**Gross Plant Allocator**	(Note B)	(Line 17 / 10)		**19.1906%**
19	Transmission Net Plant		(Line 44 - 30)	$	5,601,323
20	**Net Plant Allocator**	(Note B)	(Line 19 / 16)		**24.6393%**
	Plant Calculations				
	Plant In Service				
21	Transmission Plant In Service	(Notes A & Q)	p207.58.g/Attachment 5	$	7,048,951
22	Less: Generator Step-ups	(Notes A & Q)	Attachment 5		304,755
23	Less: Interconnect Facilities Installed After March 15, 2000	(Notes A & Q)	Attachment 5		49,413
24	**Total Transmission Plant In Service**		(Lines 21 - 22 - 23)		**6,694,782**
25	General & Intangible	(Notes A & Q)	p205.5.g + p207.99.g/Attachment 5		932,993
26	Common Plant (Electric Only)		p356/Attachment 5		0
27	Total General & Common		(Line 25 + 26)		932,993
28	Wage & Salary Allocation Factor		(Line 7)		6.8537%
29	**General & Common Plant Allocated to Transmission**		(Line 27 * 28)	**$**	**63,944**
30	**Plant Held for Future Use (Including Land)**	(Notes C & Q)	p214.47.d/Attachment 5	**$**	**7,183**
31	**TOTAL Plant In Service**		**(Line 24 + 29 + 30)**	**$**	**6,765,909**
	Accumulated Depreciation				
32	Transmission Accumulated Depreciation	(Notes A & Q)	p219.25.c/Attachment 5	$	1,199,386
33	Less Accumulated Depreciation for Generator Step-ups	(Notes A & Q)	Attachment 5		63,244
34	Less Accumulated Depreciation for Interconnect Facilities Installed After March 15, 2000	(Notes A & Q)	Attachment 5		8,507
35	Total Accumulated Depreciation for Transmission		(Line 32 - 33 - 34)		1,127,635
36	Accumulated General Depreciation	(Notes A & Q)	p219.28.b/Attachment 5		335,855
37	Accumulated Intangible Amortization	(Notes A & Q)	(Line 12)		98,489
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)		434,344
41	Wage & Salary Allocation Factor		(Line 7)		6.8537%
42	**General & Common Allocated to Transmission**		(Line 40 * 41)		**29,769**
43	**TOTAL Accumulated Depreciation**		**(Line 35 + 42)**	**$**	**1,157,403**
44	**TOTAL Net Property, Plant & Equipment**		**(Line 31 - 43)**	**$**	**5,608,506**

Virginia Electric and Power Company
ATTACHMENT H-16A

Formula Rate -- Appendix A

		Notes	FERC Form 1 Page # or Instruction (Note H)		2016 Projection
	Adjustment To Rate Base				
	Accumulated Deferred Income Taxes				
45	ADIT net of FASB 106 and 109		Attachment 1	$	(999,491)
46	**Accumulated Deferred Income Taxes Allocated To Transmission**		(Line 45)	**$**	**(999,491)**
	Transmission O&M Reserves				
47	**Total Balance Transmission Related Account 242 Reserves**	Enter Negative	Attachment 5	**$**	**(8,255)**
	Prepayments				
48	Prepayments	(Notes A & R)	Attachment 5	$	2,362
49	**Total Prepayments Allocated to Transmission**		(Line 48)	**$**	**2,362**
	Materials and Supplies				
50	Undistributed Stores Exp	(Notes A & R)	p227.6c & 16.c	$	-
51	Wage & Salary Allocation Factor		(Line 7)		6.8537%
52	Total Transmission Allocated Materials and Supplies		(Line 50 * 51)		0
53	Transmission Materials & Supplies		p227.8c/2		39,961
54	**Total Materials & Supplies Allocated to Transmission**		(Line 52 + 53)	**$**	**39,961**
	Cash Working Capital				
55	Transmission Operation & Maintenance Expense		(Line 85)	$	104,353
56	1/8th Rule		x 1/8		12.5%
57	**Total Cash Working Capital Allocated to Transmission**		(Line 55 * 56)	**$**	**13,044**
	Network Credits				
58	Outstanding Network Credits	(Note N)	Attachment 5 / From PJM		0
59	Less Accumulated Depreciation Associated with Facilities with Outstanding Network Credits	(Note N)	Attachment 5 / From PJM		0
60	Net Outstanding Credits		(Line 58 - 59)		**0**
61	**TOTAL Adjustment to Rate Base**		(Line 46 + 47 + 49 + 54 + 57 - 60)	**$**	**(952,379)**
62	**Rate Base**		(Line 44 + 61)	**$**	**4,656,127**
	O&M				
	Transmission O&M				
63	Transmission O&M		p321.112.b/Attachment 5	$	11,045
64	Less GSU Maintenance		Attachment 5		61
65	Less Account 565 - Transmission by Others		p321.96.b/Attachment 5		(68,414)
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)	**$**	**79,397**
	Allocated General & Common Expenses				
68	Common Plant O&M	(Note A)	p356		0
69	Total A&G		Attachment 5		367,809
70	Less Property Insurance Account 924		p323.185b		12,269
71	Less Regulatory Commission Exp Account 928	(Note E)	p323.189b/Attachment 5		28,622
72	Less General Advertising Exp Account 930.1		p323.911b/Attachment 5		3,817
73	Less EPRI Dues	(Note D)	p352-353/Attachment 5		3,088
74	**General & Common Expenses**		(Lines 68 + 69) - Sum (70 to 73)	$	320,013
75	Wage & Salary Allocation Factor		(Line 7)		6.8537%
76	**General & Common Expenses Allocated to Transmission**		(Line 74 * 75)	**$**	**21,933**
	Directly Assigned A&G				
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b/Attachment 5	$	-
78	General Advertising Exp Account 930.1	(Note K)	p323.191b		0
79	Subtotal - Transmission Related		(Line 77 + 78)		**0**
80	Property Insurance Account 924		p323.185b		12,269
81	General Advertising Exp Account 930.1	(Note F)	Attachment 5		0
82	Total		(Line 80 + 81)		12,269
83	Net Plant Allocation Factor		(Line 20)		24.6393%
84	**A&G Directly Assigned to Transmission**		(Line 82 * 83)	**$**	**3,023**
85	**Total Transmission O&M**		**(Line 67 + 76 + 79 + 84)**	**$**	**104,353**
	Depreciation & Amortization Expense				
	Depreciation Expense				
86	Transmission Depreciation Expense	(Notes A and S)	p336.7b&c/Attachment 5	**$**	**162,949**
87	Less: GSU Depreciation		Attachment 5		**8,813**
88	Less Interconnect Facilities Depreciation		Attachment 5		**1,429**
89	Extraordinary Property Loss		Attachment 5		**0**
90	Total Transmission Depreciation		(Line 86 - 87 - 88 + 89)		**152,707**
91	General Depreciation	(Note A)	p336.10b&c&d/Attachment 5		24,447
92	Intangible Amortization	(Note A)	p336.1d&e/Attachment 5		22,032
93	Total		(Line 91 + 92)		**46,479**
94	Wage & Salary Allocation Factor		(Line 7)		6.8537%
95	**General and Intangible Depreciation Allocated to Transmission**		(Line 93 * 94)		**3,186**
96	Common Depreciation - Electric Only	(Note A)	p336.11.b		0
97	Common Amortization - Electric Only	(Note A)	p356 or p336.11d		0
98	Total		(Line 96 + 97)		0
99	Wage & Salary Allocation Factor		(Line 7)		6.8537%
100	**Common Depreciation - Electric Only Allocated to Transmission**		(Line 98 * 99)		**0**
101	**Total Transmission Depreciation & Amortization**		**(Line 90 + 95 + 100)**	**$**	**155,893**

Virginia Electric and Power Company
ATTACHMENT H-16A

Formula Rate -- Appendix A

			Notes	FERC Form 1 Page # or Instruction (Note H)		2016 Projection
	Taxes Other than Income					
102	**Taxes Other than Income**			Attachment 2	**$**	**44,115**
103	**Total Taxes Other than Income**			**(Line 102)**	**$**	**44,115**
	Return / Capitalization Calculations					
	Long Term Interest					
104	Long Term Interest		(Note T)	p117.62c through 67c/Attachment 5	$	423,948
105	Less LTD Interest on Securitization Bonds		(Note P)	Attachment 8		0
106	**Long Term Interest**			(Line 104 - 105)	$	423,948
107	**Preferred Dividends**		(Note T), enter positive	p118.29c	$	10,867
	Common Stock					
108	Proprietary Capital			p112.16c,d/2	$	10,055,447
109	Less Preferred Stock		(Note T), enter negative	(Line 117)		(129,507)
110	Less Account 219 - Accumulated Other Comprehensive Income		(Note T), enter negative	p112.15c,d/2		(49,044)
111	**Common Stock**			(Sum Lines 108 to 110)	$	9,876,896
	Capitalization					
112	Long Term Debt			p112.24c,d/2	$	8,484,459
113	Less Loss on Reacquired Debt		(Note T), enter negative	p111.81c,d/2		(6,305)
114	Plus Gain on Reacquired Debt		(Note T), enter positive	p113.61c,d/2		4,032
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)		8,482,187
117	Preferred Stock		(Note T), enter positive	p112.3c,d/2		129,507
118	Common Stock			(Line 111)		9,876,896
119	**Total Capitalization**			(Sum Lines 116 to 118)	$	18,488,589
120	Debt %	Total Long Term Debt		(Line 116 / 119)		45.9%
121	Preferred %	Preferred Stock		(Line 117 / 119)		0.7%
122	Common %	Common Stock		(Line 118 / 119)		53.4%
123	Debt Cost	Total Long Term Debt		(Line 106 / 116)		0.0500
124	Preferred Cost	Preferred Stock		(Line 107 / 117)		0.0839
125	Common Cost	Common Stock	(Note J)	Fixed		0.1140
126	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Line 120 * 123)		0.0229
127	Weighted Cost of Preferred	Preferred Stock		(Line 121 * 124)		0.0006
128	Weighted Cost of Common	Common Stock		(Line 122 * 125)		0.0609
129	**Total Return (R)**			(Sum Lines 126 to 128)		**0.0844**
130	**Investment Return = Rate Base * Rate of Return**			**(Line 62 * 129)**		**393,064**
	Composite Income Taxes					
	Income Tax Rates					
131	FIT=Federal Income Tax Rate			Attachment 5		35.00%
132	SIT=State Income Tax Rate or Composite		(Note I)	Attachment 5		6.09%
133	p	(percent of federal income tax deductible for state purposes)		Per State Tax Code		0.00%
134	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =				38.96%
135	T/ (1-T)					63.83%
	ITC Adjustment		(Note I)			
136	Amortized Investment Tax Credit		enter negative	Attachment 1	$	(137)
137	T/(1-T)			(Line 135)		63.83%
138	**ITC Adjustment Allocated to Transmission**			(Line 136 * (1 + 137))	**$**	**(225)**
139	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		[Line 135 * 130 * (1-(126 / 129))]		**182,744**
140	**Total Income Taxes**			**(Line 138 + 139)**		**182,519**

Virginia Electric and Power Company
ATTACHMENT H-16A

Formula Rate -- Appendix A

REVENUE REQUIREMENT

		Notes	FERC Form 1 Page # or Instruction (Note H)		2016 Projection
	Summary				
141	Net Property, Plant & Equipment		(Line 44)	$	5,608,506
142	Adjustment to Rate Base		(Line 61)		(952,379)
143	**Rate Base**		(Line 62)	**$**	**4,656,127**
144	O&M		(Line 85)		104,353
145	Depreciation & Amortization		(Line 101)		155,893
146	Taxes Other than Income		(Line 103)		44,115
147	Investment Return		(Line 130)		393,064
148	Income Taxes		(Line 140)		182,519
149					-
150	**Revenue Requirement**		**(Sum Lines 144 to 149)**	**$**	**879,944**
	Net Plant Carrying Charge				
151	Revenue Requirement		(Line 150)	**$**	**879,944**
152	Net Transmission Plant		(Line 24 - 35)		**5,567,147**
153	Net Plant Carrying Charge		(Line 151 / 152)		**15.8060%**
154	Net Plant Carrying Charge without Depreciation		(Line 151 - 86) / 152		**12.8790%**
155	Net Plant Carrying Charge without Depreciation, Return or Income Taxes		(Line 151 - 86 - 130 - 140) / 152		**2.5401%**
	Net Plant Carrying Charge Calculation with 100 Basis Point increase in ROE				
156	Gross Revenue Requirement Less Return and Taxes		(Line 150 - 147 - 148)	**$**	**304,361**
157	Increased Return and Taxes		Attachment 4		**616,334**
158	Net Revenue Requirement with 100 Basis Point increase in ROE		(Line 156 + 157)		**920,695**
159	Net Transmission Plant		(Line 152)		**5,567,147**
160	Net Plant Carrying Charge with 100 Basis Point increase in ROE		(Line 158 / 159)		**16.5380%**
161	Net Plant Carrying Charge with 100 Basis Point increase in ROE without Depreciation		(Line 158 - 86) / 159		**13.6110%**
162	**Revenue Requirement**		(Line 150)	**$**	**879,944**
163	True-up Adjustment		Attachment 6		**18,192**
164	Plus any increased ROE calculated on Attachment 7 other than PJM Schedule 12 projects.		Attachment 7		**3,037**
165	Facility Credits under Section 30.9 of the PJM OATT.		Attachment 5		**2,479**
166	Revenue Credits		Attachment 3		**(9,605)**
167	Interest on Network Credits		PJM data		0
168	**Annual Transmission Revenue Requirement (ATRR)**		(Line 162 + 163 +164 + 165 + 166 + 167)	**$**	**894,047**
	Rate for Network Integration Transmission Service				
169	1 CP Peak	(Note L)	PJM Data		**21,651.0**
170	Rate ($/MW-Year)		(Line 168 / 169)		**41,293.56**
171	**Rate for Network Integration Transmission Service ($/MW/Year)**		**(Line 170)**		**41,293.56**

Notes

A Electric portion only - VEPCO does not have Common Plant.

B Excludes amounts for Generator Step-ups and Interconnection Facilities, when appropriate.

C Includes Transmission portion only.

D Excludes all EPRI Annual Membership Dues.

E Includes all regulatory commission expenses.

F Includes all safety related advertising included in Account 930.1.

G Includes all regulatory commission expenses directly related to transmission service, RTO filings, or transmission siting itemized in Form 1 at 351.h.

H The Form 1 reference indicates only the end-of-year balance used to derive the amount beside the reference. Each plant balance with a Form 1 reference will include the Form 1 balance in an average of the 13 month balances for the year. Each non-plant balance included in rate base with a Form 1 reference will include Form 1 balances in the calculation of the average of the beginning and end of year balances for the year. See notes Q and R below.

I The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = the percentage of federal income tax deductible for state income taxes. If the utility includes taxes in more than one state, it must explain in Attachment 5 the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to use amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T). A utility must not include tax credits as a reduction to rate base and as an amortization against taxable income.

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

K Education and outreach expenses relating to transmission, for example siting or billing.

L As provided for in Section 34.1 of the PJM OATT.

M Amount of transmission plant excluded from rates per Attachment 5.

N Outstanding Network Credits is the balance of Network Facilities Upgrades Credits due Transmission Customers who have made lump-sum payments (net of accumulated depreciation) toward the construction of Network Transmission Facilities consistent with Paragraph 657 of Order 2003-A. Interest on the Network Credits as booked each year is added to the revenue requirement on Line 167.

O Payments made under Schedule 12 of the PJM OATT that are not directly assessed to load in the Zone under Schedule 12 are included in Transmission O&M. If they are booked to Acct 565, they are included on Line 66.

P Securitization bonds may be included in the capital structure.

Q Calculated using 13 month average balance. Only beginning and end of year balances are from Form 1.

R Calculated using average of beginning and end of year balances. Beginning and end of year balances are from Form 1.

S The depreciation rates are included in Attachment 9.

T For the initial formula rate calculation, the projected capital structure shall reflect the capital structure from the 2006 FERC Form No. 1 data. For all other formula rate calculations, the projected capital structure and actual capital structure shall reflect the capital structure from the most recent FERC Form No. 1 data available.

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - 2016 Projection

	Only Transmission Related	*Plant Related*	*Labor Related*	*Total ADIT*
ADIT- 282	(1,044,861)	(43,466)	(82,031)	
ADIT-283	0	(4,094)	(1,700)	
ADIT-190	13,529	228,060	143,013	
Subtotal	(1,031,332)	180,501	59,282	
Wages & Salary Allocator			6.8537%	
Gross Plant Allocator		19.1906%		
End of Year ADIT	(1,031,332)	34,639	4,063	(992,629)
End of Previous Year ADIT (from Sheet 1A-ADIT (3))	(1,034,351)	24,938	3,061	(1,006,353)
Average Beginning and End of Year ADIT	(1,032,841)	29,788	3,562	(999,491)

End of Year ADIT	(992,629)
End of Previous Year ADIT	(1,006,353)
Average Beginning and End of Year ADIT (See Note 1)	(999,491)

NOTE: This Attachment 1 is effective Subject to Refund. See FERC Docket No. ER14-1831.

Note 1: For this amount and certain of its components above, portions from Account 282 may reflect 13-month average balances as provided for in the instructions for Account 282 in Attachments 1 and 1A.

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

End of Year Balances :

A ***ADIT-190***	**B** ***Total***	**C** ***Production Or Other Related***	**D** ***Only Transmission Related***	**E** ***Plant Related***	**F** ***Labor Related***	**G** ***Justification***
ADFIT - OTHER COMPREHENSIVE INCOME	(29,990)	(29,990)				Not applicable to Transmission Cost of Service calculation.
BAD DEBTS	24,274	24,274				For tax purposes bad debts are deductible when they are deemed to be uncollectible / worthless.
CAPITAL LEASE	(638)	(638)				Not applicable to Transmission Cost of Service calculation.
CAPITALIZED BROKERS FEES	-					Not applicable to Transmission Cost of Service calculation.
CAPITALIZED INTEREST - NONOP CWIP	-					Not applicable to Transmission Cost of Service calculation.
CAPITALIZED INTEREST NONOP IN SERVICE	-					Not applicable to Transmission Cost of Service calculation.
CAPITALIZED INTEREST OPERATING CWIP	108,186	108,186				Represents tax capitalized interest on projects in CWIP - increase in taxable income.
CAPITALIZED INTEREST OPERATING IN SERVICE	224,925			224,925		Represents tax "In Service" capitalized Interest placed in service net of tax amortization.
CAPITALIZED O&M EXP - DISTRIBUTION	8,212	8,212				Not applicable to Transmission Cost of Service calculation.
CHARITABLE CONTRIBUTION CFWD	3,902	3,902				Not applicable to Transmission Cost of Service calculation.
CIAC DC - NONOP CWIP	630	630				Not applicable to Transmission Cost of Service calculation.
CIAC DC - NONOP IN SERVICE	1,672	1,672				Not applicable to Transmission Cost of Service calculation.
CIAC NC - NONOP CWIP	114	114				Not applicable to Transmission Cost of Service calculation.
CIAC NC - NONOP IN SERVICE	1,640	1,640				Not applicable to Transmission Cost of Service calculation.
CIAC VA - NONOP CWIP	41,402	41,402				Not applicable to Transmission Cost of Service calculation.
CIAC VA - NONOP IN SERVICE	72,263	72,263				Not applicable to Transmission Cost of Service calculation.
CONTINGENT CLAIMS CURRENT	(727)	(727)				Not applicable to Transmission Cost of Service calculation.
CONTINGENT CLAIMS NONCURRENT	1,203	1,203				Not applicable to Transmission Cost of Service calculation.
COST OF REMOVAL	40,522	29,099	13,440		(2,017)	Represents the actual cost of removal allowable for tax over the accrued amount.
CUSTOMER ACCOUNTS-RESERVE & REFUND	-	-				Not applicable to Transmission Cost of Service calculation.
CUSTOMER ACCOUNTS INTEREST-RESERVE & REFUND	-	-				Not applicable to Transmission Cost of Service calculation.
CWIP ABANDONMENT NON CURRENT	980	980				Not applicable to Transmission Cost of Service calculation.
CWIP ABANDONMENT NON CURRENT - NA3	85,662	85,662				Not applicable to Transmission Cost of Service calculation.
CWIP ABANDONMENT NON CURRENT - WIND	1,159	1,159				Not applicable to Transmission Cost of Service calculation.
DECOMMISSIONING & DECONTAMINATION	-					Book expensed as billed over 15 yr assessment period; tax deduct in year of assessment because all events test met as liability is based on prior facility use.
DEDESIGNATED DEBT NOT ISSUED	(425)	(425)				Not applicable to Transmission Cost of Service calculation.
DEFERRED GAIN/LOSS NONOPERATING	(53)	(53)				Not applicable to Transmission Cost of Service calculation.
DEFERRED GAIN/LOSS OPERATING - DISTRIBUTION	127	127				Not applicable to Transmission Cost of Service calculation.
DEFERRED GAIN/LOSS OPERATING - GENERAL	33	33				Not applicable to Transmission Cost of Service calculation.
DEFERRED GAIN/LOSS OPERATING - PRODUCTION	(604)	(604)				Not applicable to Transmission Cost of Service calculation.
DEFERRED GAIN/LOSS OPERATING - PRODUCTION NA	(10)	(10)				Not applicable to Transmission Cost of Service calculation.
DEFERRED GAIN/LOSS OPERATING - TRANSMISSION	-	-				Not applicable to Transmission Cost of Service calculation.
DEFERRED GAIN/LOSS OPERATING	-					Represents the ADIT on Book Gain/Loss as accrued.
DEFERRED GAIN/LOSS-FUTURE USE	(736)	(736)				Not applicable to Transmission Cost of Service calculation.
DEFERRED GAIN/LOSS-FUTURE USE NONOP	1,917	1,917				Not applicable to Transmission Cost of Service calculation.
DEFERRED N.C. SIT NONOP - OCI	491	491				Not applicable to Transmission Cost of Service calculation.
DEFERRED REVENUE CURRENT	3,829	3,829				Not applicable to Transmission Cost of Service calculation.
DEFERRED SIT NONOP - OCI	(5,665)	(5,665)				Not applicable to Transmission Cost of Service calculation.
DFIT 190 OPERATING NONCURRENT ASSET	-					Not applicable to Transmission Cost of Service calculation.
DFIT 282 NONOPERATING PLANT NONCURR LIAB	-					Not applicable to Transmission Cost of Service calculation.
DFIT 282 OPERATING PLANT NONCURR LIAB	-					Not applicable to Transmission Cost of Service calculation.
DFIT 283 NONOPERATING CURRENT LIAB	-	-				Not applicable to Transmission Cost of Service calculation.
DFIT 283 NONOPERATING NONCURRENT LIAB	-					Not applicable to Transmission Cost of Service calculation.
DFIT 283 OPERATING CURRENT LIABILITY	-					Not applicable to Transmission Cost of Service calculation.
DFIT 283 OPERATING NONCURRENT CURRENT LIAB	-					Not applicable to Transmission Cost of Service calculation.
DFIT 283 OPERATING NONCURRENT LIAB	-					Not applicable to Transmission Cost of Service calculation.
DFIT 283 OPERATING OTHER NONCURRENT LIABILITY	-					Not applicable to Transmission Cost of Service calculation.
DFIT EFFECT ON SIT NONOP - OCI	1,812	1,812				Not applicable to Transmission Cost of Service calculation.
DIRECTOR CHARITABLE DONATION	158	158				Not applicable to Transmission Cost of Service calculation.
DISQUALIFIED DEBT NOT ISSUED	-	-				Not applicable to Transmission Cost of Service calculation.
DOE SETTLEMENT - ASSET BASIS REDUCTION	-	-				Not applicable to Transmission Cost of Service calculation.
DOE SETTLEMENT - INVENTORY BASIS REDUCTION	2,987	2,987				Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP CURRENT ASSET D.C.	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP CURRENT ASSET N.C.	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP CURRENT ASSET VA	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP CURRENT ASSET W.V.	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP NONCURRENT ASSET D.C.	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP NONCURRENT ASSET D.C.	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP NONCURRENT ASSET VA	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP NONCURRENT ASSET W.V.	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP PLANT NONCURR ASSET D.C.	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP PLANT NONCURR ASSET N.C.	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP PLANT NONCURR ASSET VA	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP PLANT NONCURR ASSET W.V.	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING CURRENT ASSET D.C.	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING CURRENT ASSET N.C.	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING CURRENT ASSET VA	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING CURRENT ASSET W.V.	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING NONCURR ASSEST D.C.	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING NONCURR ASSEST N.C.	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING NONCURR ASSEST VA	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING NONCURR ASSEST VA MIN	289	289				Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING NONCURR ASSEST W.V. NOL	-	-				Not applicable to Transmission Cost of Service calculation.
DSIT NONOPERATING DC	25	25				Not applicable to Transmission Cost of Service calculation.
DSIT NONOPERATING NC	5,648	5,648				Not applicable to Transmission Cost of Service calculation.
DSIT NONOPERATING VA	114,636	114,636				Not applicable to Transmission Cost of Service calculation.
DSIT NONOPERATING WV	3,154	3,154				Not applicable to Transmission Cost of Service calculation.
DSIT OPERATING DC	27	27				Not applicable to Transmission Cost of Service calculation.
DSIT OPERATING NC	6,258	6,258				Not applicable to Transmission Cost of Service calculation.
DSIT OPERATING NC ITC	104	104				Not applicable to Transmission Cost of Service calculation.
DSIT OPERATING VA	122,932	122,932				Not applicable to Transmission Cost of Service calculation.
DSIT OPERATING WV	3,650	3,650				Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING PLANT NONCURR ASSET D.C.	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING PLANT NONCURR ASSET N.C.	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING PLANT NONCURR ASSET VA	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING PLANT NONCURR ASSET W.V.	-					Not applicable to Transmission Cost of Service calculation.
DSIT 283 OP OTHER NONCURR LIAB N.C.	-					Not applicable to Transmission Cost of Service calculation.
DSIT 283 OP OTHER NONCURR LIAB VA	-					Not applicable to Transmission Cost of Service calculation.
DSIT 283 OP OTHER NONCURR LIAB W.V.	-					Not applicable to Transmission Cost of Service calculation.
DSM	-					Not applicable to Transmission Cost of Service calculation.
EARNEST MONEY	-					Not applicable to Transmission Cost of Service calculation.
EMISSIONS ALLOWANCES	-					Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DFIT DEFICIENCY (190)	4,159	4,159				Not applicable to Transmission Cost of Service calculation.

ATTACHMENT H-16A

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - 2016 Projection

FAS 109 ITC DFIT DEFICIENCY (190) - FED EFFECT OF STATE	29	29				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DFIT DEFICIENCY (190) - FED EFFECT OF STATE - SO	(52)	(52)				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DFIT DEFICIENCY (190) SOLAR	865	865				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT DEFICIENCY D.C. (190)	0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT DEFICIENCY D.C. (190) - SOLAR	0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT DEFICIENCY N.C. (190)	36	36				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT DEFICIENCY N.C. (190) - SOLAR	7	7				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT DEFICIENCY VA (190)	711	711				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT DEFICIENCY VA (190) - SOLAR	138	138				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT DEFICIENCY W.V.(190)	21	21				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT DEFICIENCY WV (190) - SOLAR	4	4				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT GROSSUP D.C.	0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT GROSSUP D.C. - SOLAR	0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT GROSSUP N.C.	23	23				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT GROSSUP N.C. - SOLAR	4	4				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT GROSSUP VA	453	453				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT GROSSUP VA - SOLAR	88	88				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT GROSSUP W.V.	13	13				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT GROSSUP WV - SOLAR	3	3				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC GROSSUP (190)	2,651	2,651				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC GROSSUP (190) - FED EFFECT OF STATE	19	19				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC GROSSUP (190) - FED EFFECT OF STATE - SOLAR	(33)	(33)				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC GROSSUP (190) - SOLAR	551	551				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC REG LIAB	-					Not applicable to Transmission Cost of Service calculation.
FAS 133	0	0				Not applicable to Transmission Cost of Service calculation.
FAS 133 - CAPACITY HEDGE CURRENT ASSET	-	-				Not applicable to Transmission Cost of Service calculation.
FASS 133 - DEBT HEDGE CURRENT ASSET	1,311	1,311				Not applicable to Transmission Cost of Service calculation.
FAS 133 - DEBT VALUATION - MTM HEDGE NON CURRENT AS	50,867	50,867				Not applicable to Transmission Cost of Service calculation.
FAS133 - DEFERRED GAIN/LOSS CAPAC HEDGE NON CURRE	-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133 REG FTR CURRENT	-					Not applicable to Transmission Cost of Service calculation.
FAS 133 - FTR HEDGE CURRENT ASSET	-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133 POWER HEDGE CURRENT ASSET	-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133 REG HEDGE DEBT CURRENT	-					Not applicable to Transmission Cost of Service calculation.
FAS 143 ASSET OBLIGATION	-					Represents ARO accruals not deductible for tax.
FAS 143 ASSET OBLIGATION - DISTRIBUTION	1,119	1,119				Represents ARO accruals not deductible for tax.
FAS 143 ASSET OBLIGATION - GENERAL	48	48				Represents ARO accruals not deductible for tax.
FAS 143 ASSET OBLIGATION - NA	442	442				Represents ARO accruals not deductible for tax.
FAS 143 ASSET OBLIGATION - OTHER	89,092	89,092				Represents ARO accruals not deductible for tax.
FAS 143 ASSET OBLIGATION - TRANSMISSION	89		89			Represents ARO accruals not deductible for tax.
FAS143 DECOMMISSIONING - NA	145,161	145,161				Represents ARO accruals not deductible for tax.
FAS143 DECOMMISSIONING - OTHER	197,617	197,617				Represents ARO accruals not deductible for tax.
FEDERAL EFFECT OF STATE NONOPERATING	19,734	19,734				Not applicable to Transmission Cost of Service calculation.
FEDERAL EFFECT OF STATE OPERATING	171,029	171,029				Not applicable to Transmission Cost of Service calculation.
FEDERAL NOL CARRYFORWARD CURRENT	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FEDERAL TAX INTEREST EXPENSE NON CURRENT	-					Not applicable to Transmission Cost of Service calculation.
FIXED ASSETS FED EFFECT CURRENT CURRENT	668	668				Not applicable to Transmission Cost of Service calculation.
FIXED ASSETS FED EFFECT NON CURRENT CURRENT	1.523	1.523				Not applicable to Transmission Cost of Service calculation.
FIXED ASSETS FED EFFECT OF STATE	246	246				Not applicable to Transmission Cost of Service calculation.
FIXED ASSETS NON CURRENT CURRENT	-					Not applicable to Transmission Cost of Service calculation.
FLEET LEASE CREDIT - CURRENT	0			0		Books amortize the fleet lease extension credit over the new lease; tax takes the deduction when incurred.
FLEET LEASE CREDIT - NONCURRENT	-			-		Books amortizes the fleet lease extension credit over the new lease; tax takes the deduction when incurred.
FUEL DEF CURRENT LIAB	25	25				Not applicable to Transmission Cost of Service calculation.
FUEL DEF NON CUR LIAB	13,287	13,287				Not applicable to Transmission Cost of Service calculation.
FUEL DEF OTHER CURRENT LIAB	5,785	5,785				Not applicable to Transmission Cost of Service calculation.
FUEL DEF OTHER NON CUR LIAB	401	401				Not applicable to Transmission Cost of Service calculation.
GAIN SALE/LEASEBACK - SYSTEM OFFICE	-					Not applicable to Transmission Cost of Service calculation.
GENERAL BUSINESS CREDIT	2.712	2.712				Not applicable to Transmission Cost of Service calculation.
GROSS REC-UNBILLED REV-NC	-	-				Books include income when meter is read; taxed when service is provided.
HEADWATER BENEFITS	1,259	1,259				Not applicable to Transmission Cost of Service calculation.
INT STOR NORTH ANNA	-	-				Books recognizes the expense as incurred. For tax the deduction is recognized when the casks are filled.
INT STOR SURRY	-	-				Books recognizes the expense as incurred. For tax the deduction is recognized when the casks are filled.
LONG TERM DISABILITY RESERVE	7,534				7,534	Book estimate accrued and expensed; tax deduction when paid.
METERS	306	306				Books pre-capitalize when purchased; tax purposes when installed.
NC MICROGRID ITC	148	148				Books pre-capitalize when purchased; tax purposes when installed.
NOL	48,328	48,328				Not applicable to Transmission Cost of Service calculation.
NUCLEAR FUEL - PERMANENT DISPOSAL	-					Books estimate expense, tax deduction taken when paid.
NUCLEAR FUEL - PERMANENT DISPOSAL NORTH ANNA	0	0				Books estimate expense, tax deduction taken when paid.
NUCLEAR FUEL - PERMANENT DISPOSAL SURRY	0	0				Books estimate expense, tax deduction taken when paid.
OBSOLETE INVENTORY	-					Not applicable to Transmission Cost of Service calculation.
OBSOLETE INVENTORY RESERVE	1,901	1,901				Not applicable to Transmission Cost of Service calculation.
OPEB	(24,771)				(24,771)	Represents the difference between the book accrual expense and the actual funded amount.
PERFORMANCE ACHIEVEMENT PLAN	-					Not applicable to Transmission Cost of Service calculation.
POWER PURCHASE BUYOUT	-	-				Represents the difference between the book accrual expense and the actual funded amount.
PREMIUM, DEBT, DISCOUNT AND EXPENSE	3,135			3,135		Books record the yield to maturity method; taxes amortize staight line.
PRODUCTION TAX CREDIT	14,480	14,480				Not applicable to Transmission Cost of Service calculation.
P'SHIP INCOME - NC ENTERPRISE	-	-				Not applicable to Transmission Cost of Service calculation.
P'SHIP INCOME - VIRGINIA CAPITAL	172	172				Not applicable to Transmission Cost of Service calculation.
QUALIFIED SETTLEMENT FUND	-					Not applicable to Transmission Cost of Service calculation.
REACTOR DECOMMISSIONING LIABILITY	-					Represents the difference between the accrual and payments.
REG FUEL HEDGE	(4,672)	(4,672)				Not applicable to Transmission Cost of Service calculation.
REG FUEL HEDGE NONOP	4,662	4,662				Not applicable to Transmission Cost of Service calculation.
REG HEDGES CAPACITY	-					Not applicable to Transmission Cost of Service calculation.
REG HEDGES CAPACITY NC	-					Not applicable to Transmission Cost of Service calculation.
REG HEDGES DEBT	-					Not applicable to Transmission Cost of Service calculation.
REG LIAB - ATRR CURRENT	-	-				Not applicable to Transmission Cost of Service calculation.
REG LIAB - DEBT VALUATION - MTM - CURRENT	133	133				Not applicable to Transmission Cost of Service calculation.
REG LIAB - DEFERRED DISQUALIFIED DEBT NOT ISSUED	-					Not applicable to Transmission Cost of Service calculation.
REG LIAB - DEFERRED G/L CAPACITY HEDGE - CURRENT	55	55				Not applicable to Transmission Cost of Service calculation.
REG LIAB - DEFERRED G/L CAPACITY HEDGE NON CUR	0	0				Not applicable to Transmission Cost of Service calculation.
REG LIAB - DEFERRED G/L POWER HEDGE - CURRENT	-	-				Not applicable to Transmission Cost of Service calculation.
REG LIAB - DEFERRED NC REPS REC COST - NC	658	658				Not applicable to Transmission Cost of Service calculation.
REG LIAB - DEFERRED VALUATION - MTM - NON CURRENT	-	-				Not applicable to Transmission Cost of Service calculation.
REG LIAB - FTR CURRENT	6,960	6,960				Not applicable to Transmission Cost of Service calculation.
REG LIAB A5 REC COSTS - VA NON CURRENT	1,396	1,396				Not applicable to Transmission Cost of Service calculation.
REG LIAB ATRR VA NON CURRENT	2,159	2,159				Not applicable to Transmission Cost of Service calculation.
REG LIAB - CURRENT RIDER A6 BEAR GARDEN AFUDC DEBT	3	3				Not applicable to Transmission Cost of Service calculation.
REG LIAB CURRENT RIDER A6 BEAR GARDEN COST RESERVE	(173)	(173)				Not applicable to Transmission Cost of Service calculation.
REG LIAB CURRENT DSM A5	2,354	2,354				Not applicable to Transmission Cost of Service calculation.
REG LIAB OTHER NCUC CURRENT	297	297				Not applicable to Transmission Cost of Service calculation.
REG LIAB OTHER NCUC NON CURR	297	297				Not applicable to Transmission Cost of Service calculation.
REG LIAB OTHER NON CURR DOE SETTLEMENT	-					Not applicable to Transmission Cost of Service calculation.
REG LIAB PLANT CONTRA VASLSTX	21,452	21,452				Not applicable to Transmission Cost of Service calculation.
REG LIAB VA OTHER CURRENT	5	5				Not applicable to Transmission Cost of Service calculation.
REG LIABILITY DECOMMISSIONING	284,550	284,550				Not applicable to Transmission Cost of Service calculation.
REG LIABILITY HEDGES DEBT	-					Not applicable to Transmission Cost of Service calculation.
REG RATE REFUND - CURRENT	525	525				Not applicable to Transmission Cost of Service calculation.
REG RATE REFUND - NONCURRENT	-	-				Not applicable to Transmission Cost of Service calculation.
REG RATE REFUND INTEREST - CURRENT	-	-				Not applicable to Transmission Cost of Service calculation.
REGULATORY ASSET - D & D	-					Not applicable to Transmission Cost of Service calculation.
REGULATORY ASSET - VA SLS TAX	-					Not applicable to Transmission Cost of Service calculation.
RENEWABLE ENERGY RESOURCE CREDIT	5	5				Not applicable to Transmission Cost of Service calculation.
RESTRICTED STOCK AWARD	(390)	(390)				Not applicable to Transmission Cost of Service calculation.
RETENTION BONUS	(28)	(28)				Not applicable to Transmission Cost of Service calculation.
RETIREMENT - (FASB 87)	121,617				121,617	Book estimate accrued and expensed; tax deduction when paid.
RETIREMENT - EXEC SUPP RET (ESRP) - NONOP	(63)	(63)				Not applicable to Transmission Cost of Service calculation.
RETIREMENT - SUPPLEMENTAL RETIREMENT	64	64				Not applicable to Transmission Cost of Service calculation.
SALES TAX RECOVERY CWIP	7.611	7.611				Not applicable to Transmission Cost of Service calculation.
SALES TAX RECOVERY IN SERVICE	14,078	14,078				Not applicable to Transmission Cost of Service calculation.
SEPARATION/ERT	860				860	Book amount accrued and expensed; tax deduction when paid. These amounts will be paid in the next 12 months.
SEPARATION/ERT - NON CURRENT	-					Book amount accrued and expensed; tax deduction when paid. These amounts will not be paid in the next 12 months.
SOLAR COMMUNITY ITC	3,324	3,324				Book amount accrued as its earned; tax deduction is actual payout.

ATTACHMENT H-16A

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - 2016 Projection

SUCCESS SHARE PLAN	9,958				9,958	Book amount accrued as its earned; tax deduction is actual payout.
VA PROPERTY TAX	-	-				Not applicable to Transmission Cost of Service calculation.
VA SALES & USE TAX AUDIT (INCL. INT)	-					Not applicable to Transmission Cost of Service calculation.
VACATION ACCRUAL	5,486	5,486				Not applicable to Transmission Cost of Service calculation.
W.VA. STATE NOL CFWD	1	1				Federal effect of state deductions.
W.VA. STATE POLLUTION CONTROL - FEDERAL EFFECT	1,433	1,433				Federal effect of state deductions.
WEST VA PROPERTY TAX	3,169	3,169				Property tax expense is accrued for accounting purposes using the prior year's rates on the balance of the property located in the state at December 31 of the previous year. Tax takes a deduction when paid.
WORKERS COMPENSATION - FAS 112	5,062				5,062	Books accrues the costs of the bonus; tax takes the deduction when actually paid.
ADFIT - OTHER COMPREHENSIVE INCOME	30,194	30,194				Not applicable to Transmission Cost of Service calculation.
DEFERRED SIT NONOP - OCI	5,700	5,700				Not applicable to Transmission Cost of Service calculation.
DFIT EFFECT ON SIT NONOP - OCI	12	12				Not applicable to Transmission Cost of Service calculation.
CONTINGENT CLAIMS CURRENT	727	727				Not applicable to Transmission Cost of Service calculation.
DEDESIGNATED DEBT NOT ISSUED	425	425				Not applicable to Transmission Cost of Service calculation.
FLEET LEASE CREDIT - CURRENT	-			-		Books amortize the fleet lease extension credit over the new lease; tax takes the deduction when incurred.
REG LIAB - ATRR CURRENT	-	-				Not applicable to Transmission Cost of Service calculation.
DEFERRED REVENUE CURRENT	-	-				Not applicable to Transmission Cost of Service calculation.
REG LIAB CURRENT RIDER A6 BEAR GARDEN COST RESERVE	173	173				Not applicable to Transmission Cost of Service calculation.
RETENTION BONUS	28	28				Not applicable to Transmission Cost of Service calculation.
OPEB	24,771				24,771	Represents the difference between the book accrual expense and the actual funded amount.
REG FUEL HEDGE	4,662	4,662				Not applicable to Transmission Cost of Service calculation.
CONTINGENT CLAIMS NONCURRENT	-	-				Not applicable to Transmission Cost of Service calculation.
REG LIAB A5 REC COSTS - VA NON CURRENT	-	-				Not applicable to Transmission Cost of Service calculation.
Reg Rate Refund	-	-				Not applicable to Transmission Cost of Service calculation.
Fixed Assets Effect Non Current Current	-	-				Not applicable to Transmission Cost of Service calculation.
RESTRICTED STOCK AWARD	390	390				Not applicable to Transmission Cost of Service calculation.
RETIREMENT EXEC SUPP RET (ESRP) - NONOP	63	63				Not applicable to Transmission Cost of Service calculation.
CAPITAL LEASE	638	638				Not applicable to Transmission Cost of Service calculation.
FIXED ASSETS FED EFFECT OF STATE	-	-				Not applicable to Transmission Cost of Service calculation.
COST OF REMOVAL	-	-	-		-	Represents the actual cost of removal allowable for tax over the accrued amount.
CAPITALIZED O&M EXP	-	-				Not applicable to Transmission Cost of Service calculation.
DOE SETTLEMENT - ASSET BASIS REDUCTION	-	-				Not applicable to Transmission Cost of Service calculation.
NUCLEAR FUEL - PERMANENT DISPOSAL	-	-				Book estimate accrued and expensed; tax deduction when paid.
Fixed Assets	-			-		Represents IRS audit adjustments to plant-related differences.
GAIN/(LOSS) INTERCO SALES - BOOK/TAX	31	31				Not applicable to Transmission Cost of Service calculation.
DOE SETTLEMENT CURRENT	-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133	-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133 Deferred G/L Power Hedge Non Current Liab	-	-				Not applicable to Transmission Cost of Service calculation.
Federal Tax Interest Expense NC	70	70				Not applicable to Transmission Cost of Service calculation.
Reg Asset - Hedge Debt De-Designated Debt Not Issued	1,034	1,034				Not applicable to Transmission Cost of Service calculation.
Reg Asset - Noncur Rider A6 ALTAVISTA Cost Reserve	518	518				Not applicable to Transmission Cost of Service calculation.
Reg Asset - NonCur Rider A6 BRUNSWICK AFUDC Debt	267	267				Not applicable to Transmission Cost of Service calculation.
Reg Asset - NonCur Rider A6 BRUNSWICK Cost Reserve	664	664				Not applicable to Transmission Cost of Service calculation.
Reg Asset - NonCur Rider A6 HOPEWELL AFUDC Debt	1	1				Not applicable to Transmission Cost of Service calculation.
Reg Asset - NonCur Rider A6 HOPEWELL Cost Reserve	479	479				Not applicable to Transmission Cost of Service calculation.
Reg Asset - NonCur Rider A6 Southampton AFUDC Debt	29	29				Not applicable to Transmission Cost of Service calculation.
Reg Asset - NonCur Rider A6 Southampton Cost Reserve	461	461				Not applicable to Transmission Cost of Service calculation.
Reg Asset - NonCur Rider A6 Halifax AFUDC Debt	-	-				Not applicable to Transmission Cost of Service calculation.
Reg Non Current DSM A5 Rider	-	-				Not applicable to Transmission Cost of Service calculation.
Fixed Assets	-	-				Represents IRS audit adjustments to plant-related differences.
Fixed Assets-DC	-	-				Represents the state impact of IRS Audit adjustments to plant related differences.
Fixed Assets-NC	-	-				Represents the state impact of IRS Audit adjustments to plant related differences.
Fixed Assets-VA	-	-				Represents the state impact of IRS Audit adjustments to plant related differences.
Fixed Assets-WV	-	-				Represents the state impact of IRS Audit adjustments to plant related differences.
Charitable Contributions CFWD	-	-				Not applicable to Transmission Cost of Service calculation.
Fuel Def Current Liab	-	-				Not applicable to Transmission Cost of Service calculation.
Reg Liab - Debt Valuation - MTM - CURRENT	-	-				Not applicable to Transmission Cost of Service calculation.
VA Property Tax	-	-				Not applicable to Transmission Cost of Service calculation.
Retirement - (FASB87)	-	-				Not applicable to Transmission Cost of Service calculation.
FAS133 - DEBT VALUATION - MTM - CURRENT LIAB	-	-				Not applicable to Transmission Cost of Service calculation.
REG ASSET - A5 REC COST VA	-	-				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A5 DSM	-	-				Not applicable to Transmission Cost of Service calculation.
EMISSIONS ALLOWANCES	-	-				Not applicable to Transmission Cost of Service calculation.
REG ASSET - PLANT	-	-				Not applicable to Transmission Cost of Service calculation.
REG ATRR NON CURRENT	-	-				Not applicable to Transmission Cost of Service calculation.
BOOK CAPITALIZED INTEREST CWIP	-	-				Not applicable to Transmission Cost of Service calculation.
ROUND	0	0				Not applicable to Transmission Cost of Service calculation.
Subtotal - p234	2,173,496	1,788,893	13,529	228,060	143,013	
Less FASB 109 Above if not separately removed	6,505	6,505	0	0	0	
Less FASB 106 Above if not separately removed	0	0	0	0	0	
Total	2,166,991	1,782,388	13,529	228,060	143,013	

Instructions for Account 190:

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

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

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

A ***ADIT- 282***	**B** ***Total***	**C** ***Production Or Other Related***	**D** ***Only Transmission Related***	**E** ***Plant Related***	**F** ***Labor Related***	**G** ***Justification***
AFC DEFERRED TAX - FUEL CWIP	(27)	(27)				Represents the amount of amortization of AFC in service not allowable for tax.
AFC DEFERRED TAX - FUEL IN SERVICE	(2)	(2)				Represents the amount of amortization of AFC in service not allowable for tax.
AFC DEFERRED TAX - FUEL IN SERVICE NA	4	4				Represents the amount of amortization of AFC in service not allowable for tax.
AFC DEFERRED TAX - PLANT CWIP	(18,472)	(18,472)				Represents the amount of amortization of AFC in service not allowable for tax.
AFC DEFERRED TAX - PLANT IN SERVICE	(32,556)	(11,046)	(21,510)			Represents the amount of amortization of AFC in service not allowable for tax.
AFUDC - DEBT - GENERATION RIDER	-					Not applicable to Transmission Cost of Service calculation.
BOOK CAPITALIZED INTEREST CWIP	(515)			(515)		Represents the unallowable amount of book interest.
CAP EXPENSE	32,699	11,497	21,202			Capitalized for books and current deduction for tax as repairs.
CAPITAL EXPENSE 481A - DISTRIBUTION	(6,622)	(6,622)				Capitalized for books and current deduction for tax as repairs.
CAPITAL EXPENSE 481A - PRODUCTION	41,192	41,192				Capitalized for books and current deduction for tax as repairs.
CAPITALIZED RESTORATION 481A	51,160	51,160				Capitalized for books and current deduction for tax as repairs.
CAPITAL LEASE	-					Not applicable to Transmission Cost of Service calculation.
CASUALTY LOSS	(67,513)			(67,513)		Book varies in treatment; tax sec. 165 casualty loss for the decline in value (up to the adj. basis) and Sec 162 deduction for repairs to restore to pre-casualty condition.
CASUALTY LOSS AMORTIZATION	28,642			28,642		Represents a decrease to tax depreciation (Sec 162) as a result of casualty loss (Sec 165) reduction to tax basis.
COMPUTER SOFTWARE-BOOK AMORT	47,670				47,670	Represents total Book Computer Software Amortization Schedule M addition.
COMPUTER SOFTWARE-CWIP	(9,447)	(9,447)				Represents the allowable "In house" deduction for tax.
COMPUTER SOFTWARE-TAX AMORT	(70,722)				(70,722)	Total tax amortization shown as a schedule M deduction and add back total book amortization.
COST OF REMOVAL	-	-	-		-	Represents the actual cost of removal allowable for tax over the accrued amount.
DECOMMISSIONING	-					Tax deduction for funding decomm trust and tax deferral of book income generated by trust.
DECOMMISSIONING TRUST BOOK INCOME	-					Not applicable to Transmission Cost of Service calculation.
DSIT NONOPERATING DC	0	0				Not applicable to Transmission Cost of Service calculation.
DSIT NONOPERATING NC	(56)	(56)				Not applicable to Transmission Cost of Service calculation.
DSIT NONOPERATING VA	(4,527)	(4,527)				Not applicable to Transmission Cost of Service calculation.
DSIT NONOPERATING WV	(1)	(1)				Not applicable to Transmission Cost of Service calculation.
DSIT OPERATING DC	(98)	(98)				Not applicable to Transmission Cost of Service calculation.
DSIT OPERATING NC	(30,112)	(30,112)				Not applicable to Transmission Cost of Service calculation.
DSIT OPERATING VA	(325,050)	(325,050)				Not applicable to Transmission Cost of Service calculation.
DSIT OPERATING WV	(22,296)	(22,296)				Not applicable to Transmission Cost of Service calculation.
DFIT 190 NONOPERATING NONCURR ASSET	-					Not applicable to Transmission Cost of Service calculation.
DFIT 190 OPERATING NONCURR ASSET	-					Not applicable to Transmission Cost of Service calculation.
DFIT 190 OPERATING PLANT NONCURRENT ASSET	-					Not applicable to Transmission Cost of Service calculation.
DSIT 282 NONOP NONCURR PLAN LIABLITY - D.C.	-					Not applicable to Transmission Cost of Service calculation.
DSIT 282 NONOP NONCURR PLAN LIABLITY - N.C.	-					Not applicable to Transmission Cost of Service calculation.

ATTACHMENT H-16A

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - 2016 Projection

DSIT 282 NONOP NONCURR PLAN LIABLITY - VA.		-					Not applicable to Transmission Cost of Service calculation.
DSIT 282 NONOP NONCURR PLAN LIABLITY - W.V.		-					Not applicable to Transmission Cost of Service calculation.
DSIT 282 NONOP PLANT NONCURR LIAB D.C.		-					Not applicable to Transmission Cost of Service calculation.
DSIT 282 NONOP PLANT NONCURR LIAB N.C.		-					Not applicable to Transmission Cost of Service calculation.
DSIT 282 NONOP PLANT NONCURR LIAB VA		-					Not applicable to Transmission Cost of Service calculation.
DSIT 282 NONOP PLANT NONCURR LIAB W.V.		-					Not applicable to Transmission Cost of Service calculation.
DSIT 282 OPERATING PLANT NONCURR LIAB D.C.		-					Not applicable to Transmission Cost of Service calculation.
DSIT 282 OPERATING PLANT NONCURR LIAB N.C.		-					Not applicable to Transmission Cost of Service calculation.
DSIT 282 OPERATING PLANT NONCURR LIAB VA		-					Not applicable to Transmission Cost of Service calculation.
DSIT 282 OPERATING PLANT NONCURR LIAB W.V.		-					Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT DEFICIENCY (282)		(47.285)	(47.285)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT DEFICIENCY (282) - FED EFFECT OF STATE		817	817				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282)		3.130	3.130				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - ALTAVISTA RIDER		(69)	(69)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - ALTAVISTA RIDER - FED EFFECT OF STATE		(6)	(6)				Not applicable to Transmission Cost of Service calculation.
FAS109 PLANT DFIT DEFICIENCY (282) - BEAR GARDEN		37	37				Not applicable to Transmission Cost of Service calculation.
FAS109 PLANT DFIT DEFICIENCY (282) - BEAR GARDEN - FED EFFECT OF STATE		(10)	(10)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - BREMO RIDER		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - BRUNSWICK RI		273	273				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - BRUNSWICK RIDER - FED EFFECT OF STATE		10	10				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - HALIFAX RIDE		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - HOPEWELL RID		(5)	(5)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - HOPEWELL RID		(2)	(2)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - NAIII RIDER		(15.338)	(15.338)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - NAIII RIDER		(460)	(460)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - PP7 RIDER		(82)	(82)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - PP7 RIDER - FED EFFECT OF STATE		4	4				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - REMINGTON SOLAR RIDER		(5)	(5)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - REMINGTON SOLAR RIDER - FED EFFECT OF STATE		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - SOUTHAMPTON RIDER		71	71				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - SOUTHAMPTON RIDER - FED EFFECT OF STATE		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - VCHEC RIDER		(479)	(479)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - VCHEC RIDER - FED EFFECT OF STATE		(83)	(83)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - WARREN RIDER		(2,214)	(2,214)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - WARREN RIDER FED EFFECT OF STATE		(9)	(9)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY D.C. (282)		(1)	(1)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY D.C. (282) - ALTAVIS		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY D.C. (282) - BEAR GARDEN		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY D.C. (282) - BRUNSWI		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY D.C. (282) - GREENSVILLE		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY D.C. (282) - HALIFAX		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY D.C. (282) - HOPEWEL		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY D.C. (282) - GENERAT		-					Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY D.C. (282) - NAIII R		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY D.C. (282) - PP7 RID		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY D.C. (282) - SOUTHAM		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY D.C. (282) - VCHEC R		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY D.C. (282) - WARREN		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282)		(205)	(205)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282) - ALTAVISTA		(1)	(1)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282) - BEAR GA		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282)-BRUNSWICK		3	3				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282) - GREENSVILLE		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282)-HALIFAX		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282)-HOPEWELL		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282)-NAIII R		(141)	(141)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282)-PP7 RID		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282)-REMINGTON SOLAR		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282)-SOUTHAMPTON		1	1				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282)-VCHEC R		(5)	(5)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282)-WARREN		(19)	(19)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282)		(4,088)	(4,088)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282) - ALTAVISTA		(13)	(13)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282)-BEAR GARD		5	5				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282) - BRUNSWICK		48	48				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282)-GREENSVILLE		(9)	(9)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282) - HALIFAX R		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282) - HOPEWELL		(1)	(1)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282) - NAIII RID		(2,682)	(2,682)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282) - PP7 RIDER		(4)	(4)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282) - REMINGTON SOLAR		(1)	(1)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282) - SOUTHAMPT		12	12				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282) - VCHEC RID		(95)	(95)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282) - WARREN		(378)	(378)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282)		(122)	(122)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282) ALTAVIS		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282)-BEAR GA		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282) - BRUNSWICK		1	1				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282)-GREENSVILLE		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282) - HALIFAX		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282) - HOPEWELL		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282) - NAIII R		(79)	(79)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282) - PP7 RID		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282) - REMINGTON SOLAR		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282) - SOUTHAM		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282) - VCHEC R		(3)	(3)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282) - WARREN		(11)	(11)				Not applicable to Transmission Cost of Service calculation.
FEDERAL EFFECT OF STATE NONOPERATING		(8,470)	(8,470)				Not applicable to Transmission Cost of Service calculation.
FEDERAL EFFECT OF STATE OPERATING		(49,516)	(49,516)				Not applicable to Transmission Cost of Service calculation.
FIXED ASSETS		(4,079)			(4,079)		Represents IRS audit adjustments to plant-related differences.
FIXED ASSETS - D.C.		-					Represents the state impact of IRS Audit adjustments to plant related differences.
FIXED ASSETS - NC							Represents the state impact of IRS Audit adjustments to plant related differences.
FIXED ASSETS - VA		-					Represents the state impact of IRS Audit adjustments to plant related differences.
FIXED ASSETS - W.V.		-					Represents the state impact of IRS Audit adjustments to plant related differences.
GAIN(LOSS) INTERCO SALES - BOOK/TAX		31	31				Tax recognizes the intercompany gain/loss over the tax life of the assets.
GOODWILL AMORTIZATION		-	-				Not applicable to Transmission Cost of Service calculation.
INVOLUNTARY CONVERSION - TELECOMMUNICATIONS		-					Represents the difference between book and tax related to the disposal of telecommunication equipment. Recognized for tax purposes when utilized.
LIBERALIZED DEPRECIATION - FUEL		-					Represents difference between book burn of nuclear fuel based on usage vs. tax depreciation.
LIBERALIZED DEPRECIATION - FUEL CWIP		(0)	(0)				Represents the difference between book CWIP and Tax CWIP.
LIBERALIZED DEPRECIATION - PLANT ACUFILE		(4,537,216)	(3,433,683)	(1,044,553)		(58,979)	Difference between book and tax depreciation taking in consideration flow-through and ARAM.
LIBERALIZED DEPRECIATION - PLANT LAND FUTURE USE		-					Not applicable to Transmission Cost of Service calculation.
LIBERALIZED DEPRECIATION - PLANT LAND NON UTILITY		-					Not applicable to Transmission Cost of Service calculation.
LIBERALIZED DEPRECIATION - PLANT OPER LAND		749	749				Not applicable to Transmission Cost of Service calculation.
LIBERALIZED DEPRECIATION - PLANT OTHER		(167,380)	(167,380)				Not applicable to Transmission Cost of Service calculation.
LIBERALIZED DEPRECIATION - PLANT FUTURE USE		201	201				Not applicable to Transmission Cost of Service calculation.
LIBERALIZED DEPRECIATION - PLANT NON UTILITY		(480)	(480)				Not applicable to Transmission Cost of Service calculation.
REG ASSET PLANT ABANDONMENT		-	-				Not applicable to Transmission Cost of Service calculation.
RESEARCH AND DEVELOPMENT		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
LIBERALIZED DEPRECIATON - PLANT ACUFILE		-	-				Not applicable to Transmission Cost of Service calculation.
SUCCESS SHARE PLAN		-					Not applicable to Transmission Cost of Service calculation.
YORKTOWN IMPLOSION - TAX DEP.-LIB - NON OP		-					Not applicable to Transmission Cost of Service calculation.
FERC 281		192,027	192,027				Difference between book and tax depreciation taking in consideration flow-through and ARAM.
CAPITAL LEASE		(638)	(638)				Not applicable to Transmission Cost of Service calculation.
NUCLEAR FUEL - PERMANENT DISPOSAL		-					Not applicable to Transmission Cost of Service calculation.
Capital O&M Exp		-					Not applicable to Transmission Cost of Service calculation.
Book Capitalized Interest (To Zero Balance from PY Top Side Entry)		-					Not applicable to Transmission Cost of Service calculation.
DOE Settlement -Asset Basis Reduction		-					Not applicable to Transmission Cost of Service calculation.
Fixed Assets Fed Effect of State		-					Not applicable to Transmission Cost of Service calculation.
Gain Loss Interco		(31)	(31)				Represents the actual cost of removal allowable for tax over the accrued amount.

ATTACHMENT H-16A

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - 2016 Projection

COST OF REMOVAL	-					Represents the actual cost of removal allowable for tax over the accrued amount.
Fixed Assets	-					Represents IRS audit adjustments to plant-related differences.
Fixed Assets-DC	-					Represents the state impact of IRS Audit adjustments to plant related differences.
Fixed Assets-NC	-					Represents the state impact of IRS Audit adjustments to plant related differences.
Fixed Assets-VA	-					Represents the state impact of IRS Audit adjustments to plant related differences.
Fixed Assets-WV	-					Represents the state impact of IRS Audit adjustments to plant related differences.
ROUND	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
Subtotal - p275 (Form 1-F filer: see note 6 below)	(5,030,946)	(3,860,588)	(1,044,861)	(43,466)	(82,031)	
Less FASB 109 Above if not separately removed	(69,402)	(69,402)	0	0	0	
Less FASB 106 Above if not separately removed	0					
Total	(4,961,544)	(3,791,187)	(1,044,861)	(43,466)	(82,031)	

Instructions for Account 282:

1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded
6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c
7. For true-ups beginning with the true-up of 2014, and for projections beginning with the projection of 2015:

7.a. For transmission plant liberalized depreciation, do not enter year-end balances in Column D. Instead, enter the ADIT amount from Attachment 1B, Part 1, column 9, line 16; however, for the 2014 true-up enter the ADIT amount from Attachment 1B-2014, Part 1, column 9, line 23. (The same entry is to be made in Attachment 1A.)

7.b. For general plant liberalized depreciation, computer software book amortization, and computer software tax amortization, do not enter year-end balances in Column F. Instead, enter the ADIT amounts from column 9, line 14, from the appropriate of Parts 2, 3, and 4 of Attachment 1B; however, for the 2014 true-up enter the ADIT amounts from column 9, line 20, from the appropriate of Parts 2, 3, and 4 of Attachment 1B-2014. (The same entry is to be made in Attachment 1A.)

A *ADIT-283*	B *Total*	C *Production Or Other Related*	D *Only Transmission Related*	E *Plant Related*	F *Labor Related*	G *Justification*
A5 ENVIRONMENTAL NC RECEIVABLE	(65)	(65)				Not applicable to Transmission Cost of Service calculation.
A6 RECEIVABLE CURRENT	(989)	(989)				Not applicable to Transmission Cost of Service calculation.
A6 RECEIVABLE NONCURRENT	(3,263)	(3,263)				Not applicable to Transmission Cost of Service calculation.
ADFIT - OTHER COMPREHENSIVE INCOME Total	-					Not applicable to Transmission Cost of Service calculation.
AFUDC - DEBT - VCHEC RIDER CURRENT Total	-					Not applicable to Transmission Cost of Service calculation.
AMORT EXP - SEC 197 INTANGIBLES Total	-	-				Not applicable to Transmission Cost of Service calculation.
CURRENT CAPITALIZED RESTORATION COSTS 481A - DISTR	(14,914)	(14,914)				Not applicable to Transmission Cost of Service calculation.
DECOMM POUR OVER Total	(50,820)	(50,820)				Not applicable to Transmission Cost of Service calculation.
DECOMMISSIONING	(17,899)	(17,899)				Not applicable to Transmission Cost of Service calculation.
DECOMMISSIONING TRUST - UNREALIZED GAIN/LOSS - NC Total	(173,771)	(173,771)				Not applicable to Transmission Cost of Service calculation.
DECOMMISSIONING TRUST BOOK INCOME Total	(409,317)	(409,317)				Not applicable to Transmission Cost of Service calculation.
DEFERRED FUEL EXPENSE Total	55,420	55,420				Not applicable to Transmission Cost of Service calculation.
DEFERRED FUEL EXPENSE - OTHER Total	-	-				Not applicable to Transmission Cost of Service calculation.
DEFERRED FUEL EXPENSE - OTHER CURRENT Total	(2,741)	(2,741)				Not applicable to Transmission Cost of Service calculation.
DEFERRED FUEL EXPENSE CURRENT Total	(40,205)	(40,205)				Not applicable to Transmission Cost of Service calculation.
DEFERRED SIT NONOP - OCI Total	-					Not applicable to Transmission Cost of Service calculation.
DFIT 190 NONOPERATING CURRENT ASSET Total	-					Not applicable to Transmission Cost of Service calculation.
DFIT 190 NONOPERATING NONCURR ASSET Total	-					Not applicable to Transmission Cost of Service calculation.
DFIT 190 OPERATING CURRENT ASSET Total	-					Not applicable to Transmission Cost of Service calculation.
DFIT 190 OPERATING NONCURR ASSET Total	-					Not applicable to Transmission Cost of Service calculation.
DFIT 190 OPERATING NONCURRENT ASSET Total	-					Not applicable to Transmission Cost of Service calculation.
DFIT 283 NONOPERATING NONCURRENT LIAB Total	-					Not applicable to Transmission Cost of Service calculation.
DFIT 283 OPERATING NONCURRENT LIAB Total	-					Not applicable to Transmission Cost of Service calculation.
DFIT EFFECT ON SIT NONOP - OCI Total	-					Not applicable to Transmission Cost of Service calculation.
DOE SETTLEMENT Total	(9,289)	(9,289)				Not applicable to Transmission Cost of Service calculation.
DOE SETTLEMENT CURRENT	-	-				Not applicable to Transmission Cost of Service calculation.
DSIT 283 NONOP CURRENT LIABILITY D.C. Total	-	-				Not applicable to Transmission Cost of Service calculation.
DSIT 283 NONOP CURRENT LIABILITY N.C. Total	-					Not applicable to Transmission Cost of Service calculation.
DSIT 283 NONOP CURRENT LIABILITY VA Total	-					Not applicable to Transmission Cost of Service calculation.
DSIT 283 NONOP CURRENT LIABILITY W.V. Total	-					Not applicable to Transmission Cost of Service calculation.
DSIT 283 NONOP NONCURRENT LIABILITY D.C. Total	-					Not applicable to Transmission Cost of Service calculation.
DSIT 283 NONOP NONCURRENT LIABILITY N.C. Total	-					Not applicable to Transmission Cost of Service calculation.
DSIT 283 NONOP NONCURRENT LIABILITY VA Total	-					Not applicable to Transmission Cost of Service calculation.
DSIT 283 NONOP NONCURRENT LIABILITY W.V. Total	-					Not applicable to Transmission Cost of Service calculation.
DSIT 283 OP OTHER NONCURR ASSET VA MIN Total	-					Not applicable to Transmission Cost of Service calculation.
DSIT 283 OP OTHER NONCURR LIAB D.C. Total	0	0				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OP OTHER NONCURR LIAB N.C. Total	90	90				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OP OTHER NONCURR LIAB VA Total	1,773	1,773				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OP OTHER NONCURR LIAB VA MIN Total	-					Not applicable to Transmission Cost of Service calculation.
DSIT 283 OP OTHER NONCURR LIAB W.V. Total	53	53				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OPERATING CURRENT LIABILITY D.C. Total	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OPERATING CURRENT LIABILITY N.C. Total	(90)	(90)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OPERATING CURRENT LIABILITY VA Total	(1,773)	(1,773)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OPERATING CURRENT LIABILITY W.V. Total	(53)	(53)				Not applicable to Transmission Cost of Service calculation.
DSIT NONOPERATING DC	(10)	(10)				Not applicable to Transmission Cost of Service calculation.
DSIT NONOPERATING NC	(2,440)	(2,440)				Not applicable to Transmission Cost of Service calculation.
DSIT NONOPERATING VA	(47,924)	(47,924)				Not applicable to Transmission Cost of Service calculation.
DSIT NONOPERATING WV	(1,423)	(1,423)				Not applicable to Transmission Cost of Service calculation.
DSIT OPERATING DC	(23)	(23)				Not applicable to Transmission Cost of Service calculation.
DSIT OPERATING NC	(5,292)	(5,292)				Not applicable to Transmission Cost of Service calculation.
DSIT OPERATING VA	(105,938)	(105,938)				Not applicable to Transmission Cost of Service calculation.
DSIT OPERATING WV	(3,032)	(3,032)				Not applicable to Transmission Cost of Service calculation.
EMISSIONS ALLOWANCES Total	-	-				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) Total	(25,885)	(25,885)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - ALTAVISTA RIDER	(44)	(44)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - ALTAVISTA RIDER - FED	(4)	(4)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - BEAR GARDEN RID Total	23	23				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - BEAR GARDEN RID - FED	(6)	(6)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - BREMO RIDER Total	-	-				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - BRUNSWICK RIDER	174	174				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - BRUNSWICK RIDER - FED	6	6				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - FED EFFECT OF STATE	171	171				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - GREENSVILLE RIDER	(38)	(38)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - GREENSVILLE RIDER - FED	2	2				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - HALIFAX RIDER Total	0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - HOPEWELL RIDER	(3)	(3)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - HOPEWELL RIDER - FED	(1)	(1)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - NAIII RIDER Total	(9,776)	(9,776)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - NAIII RIDER - FED EFFECT	(293)	(293)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - PP7 RIDER Total	(14)	(14)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - REMINGTON SOLAR RIDER	(3)	(3)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - REMINGTON SOLAR RIDER - FED	0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - SOUTHAMPTON RID	45	45				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - SOUTHAMPTON RIDER - FED	0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - VCHEC RIDER Total	(305)	(305)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - VCHEC RIDER - FED EFFECT	(53)	(53)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - WARREN RIDER Total	(1,411)	(1,411)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - WARREN RIDER - FED EFFECT	(6)	(6)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP DC Total	(1)	(1)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP DC - ALTAVISTA RIDER	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP DC - BEAR GARDEN RIDER Total	0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP DC - BRUNSWICK RIDER	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP DC - GREENSVILLE RIDER	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP DC - HALIFAX RIDER	-	-				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP DC - HOPEWELL RIDER		-				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP DC - NAIII RIDER Total	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP DC - PP7 RIDER	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP DC - SOUTHAMPTON RIDER	0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP DC - VCHEC RIDER Total	0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP DC - VCHEC RIDER CURR Total	-					Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP DC - WARREN RIDER Total	(0)	(0)				Not applicable to Transmission Cost of Service calculation.

ATTACHMENT H-16A

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - 2016 Projection

FAS 109 OTHER DSIT GROSSUP NC Total		(222)	(222)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - ALTAVISTA RIDER		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - BEAR GARDEN RIDER Total		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - BRUNSWICK RIDER Total		2	2				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - GREENSVILLE RIDER		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - HALIFAX RIDER Total		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - HOPEWELL RIDER		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - NAIII RIDER Total		(90)	(90)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - PP7 RIDER Total		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - REMINGTON SOLAR RIDER		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - SOUTHAMPTON RIDER		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - VCHEC RIDER Total		(3)	(3)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - VCHEC RIDER CURR Total		-					Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - VCHEC RIDER NONCUR Total		-					Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - WARREN RIDER Total		(12)	(12)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA Total		(4,369)	(4,369)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - ALTAVISTA RIDER		(8)	(8)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - BEAR GARDEN RIDER Total		3	3				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - BREMO RIDER Total		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - BRUNSWICK RIDER		31	31				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - GREENSVILLE RIDER Total		(6)	(6)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - HALIFAX RIDER Total		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - HOPEWELL RIDER		(1)	(1)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - NAIII RIDER Total		(1,710)	(1,710)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - PP7 RIDER Total		(2)	(2)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - REMINGTON SOLAR RIDER		(1)	(1)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - SOUTHAMPTON RIDER		8	8				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - VCHEC RIDER Total		(61)	(61)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - VCHEC RIDER CURR Total		-					Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - VCHEC RIDER NONCUR Total		-					Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - WARREN RIDER Total		(241)	(241)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV Total		(130)	(130)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - ALTAVISTA RIDER		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - BEAR GARDEN RIDER Total		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - BREMO RIDER Total		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - BRUNSWICK RIDER Total		1	1				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - GREENSVILLE RIDER Total		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - HOPEWELL RIDER		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - NAIII RIDER Total		(50)	(50)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - PP7 RIDER Total		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - REMINGTON SOLAR RIDER		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - SOUTHAMPTON RIDER		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - VCHEC RIDER Total		(2)	(2)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - VCHEC RIDER CURR Total		-					Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - VCHEC RIDER NONCUR Total		-					Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - WARREN RIDER Total		(7)	(7)				Not applicable to Transmission Cost of Service calculation.
FAS 133 Total		11	11				Not applicable to Transmission Cost of Service calculation.
FAS 133 - FTR HEDGE CURRENT ASSET Total		-					Not applicable to Transmission Cost of Service calculation.
FAS 133 REG FUEL HEDGE NONCURRENT Total		-					Not applicable to Transmission Cost of Service calculation.
FAS 133-DEBT VALUATION - MTM - CURRENT LIAB Total		(133)	(133)				Not applicable to Transmission Cost of Service calculation.
FAS 133-DEFERRED G/L CAPACITY HEDGE - NON CURRENT Total		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 133-DEFERRED G/L CAPACITY HEDGE CURRENT LIAB Total		(55)	(55)				Not applicable to Transmission Cost of Service calculation.
FAS 133-DEFERRED G/L POWER HEDGE - CURRENT LIAB Total		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 133-DEFERRED VALUATION- MTM NON CURRENT LIAB Total		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133-FTR CURRENT LIAB Total		(6,960)	(6,960)				Not applicable to Transmission Cost of Service calculation.
FEDERAL EFFECT OF STATE NONOPERATING		(34,742)	(34,742)				Not applicable to Transmission Cost of Service calculation.
FEDERAL EFFECT OF STATE OPERATING		2,912	2,912				Not applicable to Transmission Cost of Service calculation.
FEDERAL EFFECT OF STATE OPERATING NC MICROGRID ITC		(36)	(36)				Not applicable to Transmission Cost of Service calculation.
FEDERAL TAX INTEREST EXPENSE Total		(712)	(712)				Not applicable to Transmission Cost of Service calculation.
FEDERAL TAX INTEREST EXPENSE NON CURRENT Total		70	70				Not applicable to Transmission Cost of Service calculation.
FIXED ASSETS FED EFFECT OF STATE		-	-				Not applicable to Transmission Cost of Service calculation.
FUEL HANDLING COSTS Total		(187)	(187)				Not applicable to Transmission Cost of Service calculation.
GOODWILL AMORTIZATION Total		-					Not applicable to Transmission Cost of Service calculation.
NON CURRENT CAPITALIZED RESTORATION COSTS 481A - D		(22,371)	(22,371)				Not applicable to Transmission Cost of Service calculation.
NON CURRENT REC A4 ELEC TRAN Total		(6,511)	(6,511)				Not applicable to Transmission Cost of Service calculation.
POWERTREE CARBON CO, LLC. Total		(34)	(34)				Not applicable to Transmission Cost of Service calculation.
REACQUIRED DEBT GAIN(LOSS) Total		(103)	(103)				Not applicable to Transmission Cost of Service calculation.
REG ASSET FTR		-					Not applicable to Transmission Cost of Service calculation.
REG ASSET - A4 RAC COSTS CURRENT		(5,484)	(5,484)				Not applicable to Transmission Cost of Service calculation.
REG ASSET - A4 RAC COSTS NONCURRENT		(25,338)	(25,338)				Not applicable to Transmission Cost of Service calculation.
REG ASSET - A5 REC COST VA		-	-				Not applicable to Transmission Cost of Service calculation.
REG ASSSET - ATRR CURRENT		(8,869)	(8,869)				Not applicable to Transmission Cost of Service calculation.
REG ASSSET - CUR - NUG		(436)	(436)				Not applicable to Transmission Cost of Service calculation.
REG ASSET - FTR CURRENT		-					Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A4 NON VA OTHER		-					Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A5 DSM		-					Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 BEAR GARDEN AFUDC DEBT		-					Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 BEAR GARDEN COST RESERV		-					Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 HALIFAX AFUDC DEBT		-					Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 VCHEC AFUDC DEBT		-					Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 VCHEC COST RESERVE		-					Not applicable to Transmission Cost of Service calculation.
REG ASSET - DEBT VALUATION - MTM - NON CURRENT		(1,311)	(1,311)				Not applicable to Transmission Cost of Service calculation.
REG ASSET - DEFERRED G/L CAPACITY HEDGE CURRENT		-	-				Not applicable to Transmission Cost of Service calculation.
REG ASSET - DEFERRED GAIN/LOSS CAPAC HEDGE NONCUR		-	-				Not applicable to Transmission Cost of Service calculation.
REG ASSET - FTR - CURRENT		-	-				Not applicable to Transmission Cost of Service calculation.
REG ASSET - NRC REQUIREMENT - NORTH ANNA		(6,005)	(6,005)				Not applicable to Transmission Cost of Service calculation.
REG ASSET - NRC REQUIREMENT - SURRY		(2,780)	(2,780)				Not applicable to Transmission Cost of Service calculation.
REG ASSET - PLANT		0	0				Not applicable to Transmission Cost of Service calculation.
REG ASSET - PLANT CURRENT		-	-				Not applicable to Transmission Cost of Service calculation.
REG ASSET ABANDONED PLANT NCUC CURRENT		(406)	(406)				Not applicable to Transmission Cost of Service calculation.
REG ASSET ABANDONED PLANT NCUC NON CURR		(2,318)	(2,318)				Not applicable to Transmission Cost of Service calculation.
REG ASSET ASSET IMPAIRMENT NCUC CURRENT		(86)	(86)				Not applicable to Transmission Cost of Service calculation.
REG ASSET ASSET IMPAIRMENT NCUC NONCURR		(355)	(355)				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A4 NON VA OTHER Total		(1,012)	(1,012)				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A5 DSM Total		-	-				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 ALTAVISTA AFUDC DEBT Total		(1)	(1)				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 ALTAVISTA COST RESERVE		518	518				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 BEAR GARDEN AFUDC DEBT Total		(826)	(826)				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 BEAR GARDEN COST RESERV Total		(2,093)	(2,093)				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 BRUNSWICK AFUDC DEBT		(86)	(86)				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 BRUNSWICK COST RESERVE		68	68				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 HOPEWELL AFUDC DEBT Total		1	1				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 HOPEWELL COST RESERVE		479	479				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 SOUTHAMPTON AFUDC DEBT Total		29	29				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 SOUTHAMPTON COST RESERV		461	461				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 HALIFAX AFUDC DEBT Total		-					Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 VCHEC AFUDC DEBT Total		(653)	(653)				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 VCHEC COST RESERVE Total		(4,291)	(4,291)				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 WARREN AFUDC DEBT Total		(644)	(644)				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 WARREN COST RESERVE		140	140				Not applicable to Transmission Cost of Service calculation.
REG ASSET- DEBT VALUATION - MTM - NON CURRENT Total		(50,867)	(50,867)				Not applicable to Transmission Cost of Service calculation.
REG ASSET DEF A5 COST ENVIRONMENTAL COST RESERVE		(464)	(464)				Not applicable to Transmission Cost of Service calculation.
REG ASSET- DEFERRED GAIN/LOSS CAPAC HEDGE NONCUR Total		-	-				Not applicable to Transmission Cost of Service calculation.
REG ASSET DEFERRED NC RECPS REC COST CURRENT		(260)	(260)				Not applicable to Transmission Cost of Service calculation.
REG ASSET- HEDGE DEBT DE-DESIGNATED DEBT NOT ISSUE		1,034	1,034				Not applicable to Transmission Cost of Service calculation.
REG ASSET NATURAL DISASTER NCUC CURRENT		(476)	(476)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NATURAL DISASTER NCUC NONCURR		(79)	(79)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 ALTAVISTA AFUDC DEBT Total		(19)	(19)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 ALTAVISTA COST RESERVE		(4,113)	(4,113)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 BEAR GARDEN AFUDC DEBT Total		245	245				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 BEAR GARDEN COST RESERVE Total		(4,463)	(4,463)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 BRUNSWICK AFUDC DEBT Total		267	267				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 BRUNSWICK COST RESERVE		664	664				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 DISTRIBUTION UG		(178)	(178)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 GREENSVILLE AFUDC DEBT		(25)	(25)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 HALIFAX AFUDC DEBT Total		(0)	(0)				Not applicable to Transmission Cost of Service calculation.

ATTACHMENT H-16A

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - 2016 Projection

REG ASSET NONCUR RIDER A6 HOPEWELL AFUDC DEBT Total	(9)	(9)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 HOPEWELL COST RESERVE	(2,344)	(2,344)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 NAIII AFUDC DEBT Total	(6,154)	(6,154)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 NAIII COST RESERVE Total	5,342	5,342				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 PP7 AFUDC DEBT Total	(10)	(10)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 REMINGTON SOLAR AFUDC DEBT Total	(2)	(2)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 SOUTHAMPTON AFUDC DEBT Total	(9)	(9)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 SOUTHAMPTON COST RESERVE	(2,443)	(2,443)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 VCHEC AFUDC DEBT Total	(849)	(849)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 VCHEC COST RESERVE Total	(14,002)	(14,002)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 WARREN AFUDC DEBT Total	(146)	(146)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 WARREN COST RESERVE Total	(482)	(482)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NUCLEAR OUTAGE DEFERRAL - CURRENT	(26,472)	(26,472)				Not applicable to Transmission Cost of Service calculation.
REG ASSET RETIREMENT NCUC CURRENT	(40)	(40)				Not applicable to Transmission Cost of Service calculation.
REG ASSET RETIREMENT NCUC NONCURR	(307)	(307)				Not applicable to Transmission Cost of Service calculation.
REG ASSET RIDER PLANTS NCUC CURRENT	(208)	(208)				Not applicable to Transmission Cost of Service calculation.
REG ASSET RIDER PLANTS NCUC NONCURR	(277)	(277)				Not applicable to Transmission Cost of Service calculation.
REG ATRR NON CURRENT	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
REG NON CURRENT DSM A5 RIDER	(5,697)	(5,697)				Not applicable to Transmission Cost of Service calculation.
REG HEDGE DEBT - CURRENT	-					Not applicable to Transmission Cost of Service calculation.
REG POWER HEDGE - CURRENT	-					Not applicable to Transmission Cost of Service calculation.
REG POWER HEDGE	-					Not applicable to Transmission Cost of Service calculation.
REGULATORY ASSET - D & D	-					Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
REGULATORY ASSET - FAS 112	(1,700)				(1,700)	Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
REGULATORY ASSET - ISABEL	-					Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
REGULATORY ASSET - NUG	(1,141)	(1,141)				Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
REGULATORY ASSET - PJM CURRENT	-					Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
REGULATORY ASSET - VA SLS TAX	(2,131)	(2,131)				Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
REGULATORY ASSET - VA SLS TAX CURRENT	(16,320)	(16,320)				Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
RETIREMENT - EXEC SUPP RET (ESRP) - NONOP	(402)	(402)				Not applicable to Transmission Cost of Service calculation.
SO2 ALLOWANCES - NONCURRENT	-					Book expense for emissions allowances based on moving-average-cost, tax expense based on specific identification.
W.VA. STATE NOL CFWD	(0)	(0)				Represents the deferred state tax impact related to WV NOL. This deferral will turn around when the pollution control projects are placed in service.
W.VA. STATE POLLUTION CONTROL	(4,094)			(4,094)		Represents the deferred state tax impact related to WV Pollution control projects. This deferral will turn around once placed in service.
ADFIT - OTHER COMPREHENSIVE INCOME Total	(30,194)	(30,194)				Not applicable to Transmission Cost of Service calculation.
DEFERRED SIT NONOP - OCI Total	(5,700)	(5,700)				Not applicable to Transmission Cost of Service calculation.
DFIT EFFECT ON SIT NONOP - OCI Total	(12)	(12)				Not applicable to Transmission Cost of Service calculation.
CONTINGENT CLAIMS CURRENT	(727)	(727)				Not applicable to Transmission Cost of Service calculation.
DEDESIGNATED DEBT NOT ISSUED	(425)	(425)				Not applicable to Transmission Cost of Service calculation.
Fleet Lease Credit Current	-			-		Not applicable to Transmission Cost of Service calculation.
Reg Liab ATRR Current	-	-				Not applicable to Transmission Cost of Service calculation.
Deferred Revenue Current	-	-				Not applicable to Transmission Cost of Service calculation.
Fuel Def Current Liab	-	-				Not applicable to Transmission Cost of Service calculation.
REG LIAB - DEBT VALUATION - MTM - CURRENT	-	-				Not applicable to Transmission Cost of Service calculation.
REG LIAB CURRENT RIDER A6 BEAR GARDEN COST RESERVE	-	-				Not applicable to Transmission Cost of Service calculation.
RETENTION BONUS	(28)	(28)				Not applicable to Transmission Cost of Service calculation.
OPEB	(24,771)				(24,771)	Represents the difference between the book accrual expense and the actual funded amount.
Contingent Claims Non Current	-	-				Not applicable to Transmission Cost of Service calculation.
Reg Fuel Hedge	(4,662)	(4,662)				Not applicable to Transmission Cost of Service calculation.
Reg Liab A5 Rec Costs VA Non Current	-	-				Not applicable to Transmission Cost of Service calculation.
Reg Rate Refund Non Current	-	-				Not applicable to Transmission Cost of Service calculation.
Fixed Assets Effect Non Current Current	-	-				Not applicable to Transmission Cost of Service calculation.
VA PROPERTY TAX	-	-				Not applicable to Transmission Cost of Service calculation.
Retirement - (FASB 87)	-	-				Not applicable to Transmission Cost of Service calculation.
RESTRICTED STOCK AWARDS	(390)	(390)				Not applicable to Transmission Cost of Service calculation.
Retirement Exex Supp Ret ESRP Nonop	(63)	(63)				Not applicable to Transmission Cost of Service calculation.
DOE Settlement Current	-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133	-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133 Deferred G/L Power Hedge Non Current Liab	-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133 - Debt Valuation - MTM - Current Liab	-	-				Not applicable to Transmission Cost of Service calculation.
Reg Asset - A5 Rec Cost VA	-	-				Not applicable to Transmission Cost of Service calculation.
Reg Asset Current Rider A5 DSM	-	-				Not applicable to Transmission Cost of Service calculation.
Reg Asset Current Rider A6 Bear Garden Cost Reserve	(173)	(173)				Not applicable to Transmission Cost of Service calculation.
Emissions Allowances	-	-				Not applicable to Transmission Cost of Service calculation.
Federal Tax Interest Expense NC	(70)	(70)				Not applicable to Transmission Cost of Service calculation.
Reg Asset - Plant	-	-				Not applicable to Transmission Cost of Service calculation.
Reg Asset - Hedge Debt De-Designated Debt Not Issued	(1,034)	(1,034)				Not applicable to Transmission Cost of Service calculation.
Reg Asset - Noncur Rider A6 ALTAVISTA Cost Reserve	(518)	(518)				Not applicable to Transmission Cost of Service calculation.
Reg Asset - NonCur Rider A6 BRUNSWICK AFUDC Debt	(267)	(267)				Not applicable to Transmission Cost of Service calculation.
Reg Asset - NonCur Rider A6 BRUNSWICK Cost Reserve	(664)	(664)				Not applicable to Transmission Cost of Service calculation.
Reg Asset - NonCur Rider A6 HOPEWELL AFUDC Debt	(1)	(1)				Not applicable to Transmission Cost of Service calculation.
Reg Asset - NonCur Rider A6 HOPEWELL Cost Reserve	(479)	(479)				Not applicable to Transmission Cost of Service calculation.
Reg Asset - NonCur Rider A6 Southampton AFUDC Debt	(29)	(29)				Not applicable to Transmission Cost of Service calculation.
Reg Asset - NonCur Rider A6 Southampton Cost Reserve	(461)	(461)				Not applicable to Transmission Cost of Service calculation.
Reg ATRR Non Current	-	-				Not applicable to Transmission Cost of Service calculation.
Reg Asset - NonCur Rider A6 Halifax AFUDC Debt	-	-				Not applicable to Transmission Cost of Service calculation.
Reg Non Current DSM A5 Rider	-	-				Not applicable to Transmission Cost of Service calculation.
FIXED ASSETS NONCURRENT CURRENT	-					Not applicable to Transmission Cost of Service calculation.
Charitable Contributions CFWD	-	-				Not applicable to Transmission Cost of Service calculation.
ROUND	(0)	(0)				Not applicable to Transmission Cost of Service calculation.
Subtotal - p277 (Form 1-F filer: see note 6, below)	(1,217,676)	(1,187,111)	-	(4,094)	(26,471)	
Less FASB 109 Above if not separately removed	(44,282)	(44,282)	-	-	-	
Less FASB 106 Above if not separately removed	(24,771)	-	-	-	(24,771)	
Total	(1,148,623)	(1,142,829)	-	(4,094)	(1,700)	

Instructions for Account 283:

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

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

		Item	Balance	Amortization
1 Amortization				(12,325)
2 Amortization to line 136 of Appendix A		Total		137
3 Total			-	(12,188)
4 Total Form No. 1 (p 266 & 267)		Form No. 1 balance (p.266) for amortization		(12,188)
5 Difference /1			-	-

/1 Difference must be zero

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

	Only Transmission Related	*Plant Related*	*Labor Related*	*Total ADIT*
ADIT- 282	(1,044,861)	(59,822)	(82,031)	
ADIT-283	0	(4,094)	(1,700)	
ADIT-190	10,510	228,060	127,726	
Subtotal	(1,034,351)	164,145	43,995	
Wages & Salary Allocator			6.9575%	
Gross Plant Allocator		15.1925%		
End of Year ADIT (See Note 1)	(1,034,351)	24,938	3,061	(1,006,353)

NOTE: This Attachment 1A is effective Subject to Refund. See FERC Docket No. ER14-1831.

Note 1: For this amount and certain of its components above, portions from Account 282 may reflect 13-month average balances as provided for in the instructions for Account 282 in Attachments 1 and 1A.

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

End of Year Balances :

A ADIT-190	B Total	C Production Or Other Related	D Only Transmission Related	E Plant Related	F Labor Related	G Justification
ADFIT - OTHER COMPREHENSIVE INCOME	(29,990)	(29,990)				Not applicable to Transmission Cost of Service calculation.
BAD DEBTS	24,274	24,274				For tax purposes bad debts are deductible when they are deemed to be uncollectible / worthless.
CAPITAL LEASE	(638)	(638)				Not applicable to Transmission Cost of Service calculation.
CAPITALIZED BROKERS FEES	-					Not applicable to Transmission Cost of Service calculation.
CAPITALIZED INTEREST - NONOP CWIP	-					Not applicable to Transmission Cost of Service calculation.
CAPITALIZED INTEREST NONOP IN SERVICE	-					Not applicable to Transmission Cost of Service calculation.
CAPITALIZED INTEREST OPERATING CWIP	77,515	77,515				Represents tax capitalized interest on projects in CWIP - increase in taxable income.
CAPITALIZED INTEREST OPERATING IN SERVICE	224,925			224,925		Represents tax "In Service" capitalized Interest placed in service net of tax amortization.
CAPITALIZED O&M EXP - DISTRIBUTION	8,212	8,212				Not applicable to Transmission Cost of Service calculation.
CHARITABLE CONTRIBUTION CFWD	3,902	3,902				Not applicable to Transmission Cost of Service calculation.
CIAC DC - NONOP CWIP	630	630				Not applicable to Transmission Cost of Service calculation.
CIAC DC - NONOP IN SERVICE	1,672	1,672				Not applicable to Transmission Cost of Service calculation.
CIAC NC - NONOP CWIP	114	114				Not applicable to Transmission Cost of Service calculation.
CIAC NC - NONOP IN SERVICE	1,640	1,640				Not applicable to Transmission Cost of Service calculation.
CIAC VA - NONOP CWIP	22,257	22,257				Not applicable to Transmission Cost of Service calculation.
CIAC VA - NONOP IN SERVICE	72,263	72,263				Not applicable to Transmission Cost of Service calculation.
CONTINGENT CLAIMS CURRENT	(727)	(727)				Not applicable to Transmission Cost of Service calculation.
CONTINGENT CLAIMS NONCURRENT	1,203	1,203				Not applicable to Transmission Cost of Service calculation.
COST OF REMOVAL	51,308	42,904	10,421		(2,017)	Represents the actual cost of removal allowable for tax over the accrued amount.
CUSTOMER ACCOUNTS-RESERVE & REFUND	-	-				Not applicable to Transmission Cost of Service calculation.
CUSTOMER ACCOUNTS INTEREST-RESERVE & REFUND	-	-				Not applicable to Transmission Cost of Service calculation.
CWIP ABANDONMENT NON CURRENT	980	980				Not applicable to Transmission Cost of Service calculation.
CWIP ABANDONMENT NON CURRENT - NA3	85,662	85,662				Not applicable to Transmission Cost of Service calculation.
CWIP ABANDONMENT NON CURRENT - WIND	1,159	1,159				Not applicable to Transmission Cost of Service calculation.
DECOMMISSIONING & DECONTAMINATION	-					Book expensed as billed over 15 yr assessment period; tax deduct in year of assessment because all
DEDESIGNATED DEBT NOT ISSUED	(425)	(425)				Not applicable to Transmission Cost of Service calculation.
DEFERRED GAIN/LOSS NONOPERATING	(53)	(53)				Not applicable to Transmission Cost of Service calculation.
DEFERRED GAIN/LOSS OPERATING - DISTRIBUTION	127	127				Not applicable to Transmission Cost of Service calculation.
DEFERRED GAIN/LOSS OPERATING - GENERAL	33	33				Not applicable to Transmission Cost of Service calculation.
DEFERRED GAIN/LOSS OPERATING - PRODUCTION	(604)	(604)				Not applicable to Transmission Cost of Service calculation.
DEFERRED GAIN/LOSS OPERATING - PRODUCTION NA	(10)	(10)				Not applicable to Transmission Cost of Service calculation.
DEFERRED GAIN/LOSS OPERATING - TRANSMISSION	-	-				Not applicable to Transmission Cost of Service calculation.
DEFERRED GAIN/LOSS OPERATING	-					Represents the ADIT on Book Gain/Loss as accrued.
DEFERRED GAIN/LOSS-FUTURE USE	(736)	(736)				Not applicable to Transmission Cost of Service calculation.
DEFERRED GAIN/LOSS-FUTURE USE NONOP	1,917	1,917				Not applicable to Transmission Cost of Service calculation.
DEFERRED N.C. SIT NONOP - OCI	491	491				Not applicable to Transmission Cost of Service calculation.
DEFERRED REVENUE CURRENT	3,829	3,829				Not applicable to Transmission Cost of Service calculation.
DEFERRED SIT NONOP - OCI	(5,665)	(5,665)				Not applicable to Transmission Cost of Service calculation.
DFIT 190 OPERATING NONCURRENT ASSET	-					Not applicable to Transmission Cost of Service calculation.
DFIT 282 NONOPERATING PLANT NONCURR LIAB	-					Not applicable to Transmission Cost of Service calculation.
DFIT 282 OPERATING PLANT NONCURR LIAB	-					Not applicable to Transmission Cost of Service calculation.
DFIT 283 NONOPERATING CURRENT LIAB	-	-				Not applicable to Transmission Cost of Service calculation.
DFIT 283 NONOPERATING NONCURRENT LIAB	-					Not applicable to Transmission Cost of Service calculation.
DFIT 283 OPERATING CURRENT LIABILITY	-					Not applicable to Transmission Cost of Service calculation.
DFIT 283 OPERATING NONCURRENT CURRENT LIAB	-					Not applicable to Transmission Cost of Service calculation.
DFIT 283 OPERATING NONCURRENT LIAB	-					Not applicable to Transmission Cost of Service calculation.
DFIT 283 OPERATING OTHER NONCURRENT LIABILITY	-					Not applicable to Transmission Cost of Service calculation.
DFIT EFFECT ON SIT NONOP - OCI	1,812	1,812				Not applicable to Transmission Cost of Service calculation.
DIRECTOR CHARITABLE DONATION	158	158				Not applicable to Transmission Cost of Service calculation.
DISQUALIFIED DEBT NOT ISSUED	-	-				Not applicable to Transmission Cost of Service calculation.
DOE SETTLEMENT - ASSET BASIS REDUCTION	-	-				Not applicable to Transmission Cost of Service calculation.
DOE SETTLEMENT - INVENTORY BASIS REDUCTION	2,987	2,987				Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP CURRENT ASSET D.C.	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP CURRENT ASSET N.C.	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP CURRENT ASSET VA	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP CURRENT ASSET W.V.	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP NONCURRENT ASSET D.C.	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP NONCURRENT ASSET D.C.	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP NONCURRENT ASSET VA	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP NONCURRENT ASSET W.V.	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP PLANT NONCURR ASSET D.C.	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP PLANT NONCURR ASSET N.C.	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP PLANT NONCURR ASSET VA	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 NONOP PLANT NONCURR ASSET W.V.	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING CURRENT ASSET D.C.	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING CURRENT ASSET N.C.	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING CURRENT ASSET VA	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING CURRENT ASSET W.V.	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING NONCURR ASSEST D.C.	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING NONCURR ASSEST N.C.	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING NONCURR ASSEST VA	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING NONCURR ASSEST VA MIN	289	289				Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING NONCURR ASSEST W.V. NOL	-	-				Not applicable to Transmission Cost of Service calculation.
DSIT NONOPERATING DC	25	25				Not applicable to Transmission Cost of Service calculation.
DSIT NONOPERATING NC	5,648	5,648				Not applicable to Transmission Cost of Service calculation.
DSIT NONOPERATING VA	114,636	114,636				Not applicable to Transmission Cost of Service calculation.
DSIT NONOPERATING WV	3,154	3,154				Not applicable to Transmission Cost of Service calculation.
DSIT OPERATING DC	27	27				Not applicable to Transmission Cost of Service calculation.
DSIT OPERATING NC	6,258	6,258				Not applicable to Transmission Cost of Service calculation.
DSIT OPERATING NC ITC	104	104				Not applicable to Transmission Cost of Service calculation.
DSIT OPERATING VA	122,932	122,932				Not applicable to Transmission Cost of Service calculation.
DSIT OPERATING WV	3,650	3,650				Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING PLANT NONCURR ASSET D.C.	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING PLANT NONCURR ASSET N.C.	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING PLANT NONCURR ASSET VA	-					Not applicable to Transmission Cost of Service calculation.
DSIT 190 OPERATING PLANT NONCURR ASSET W.V.	-					Not applicable to Transmission Cost of Service calculation.
DSIT 283 OP OTHER NONCURR LIAB N.C.	-					Not applicable to Transmission Cost of Service calculation.
DSIT 283 OP OTHER NONCURR LIAB VA	-					Not applicable to Transmission Cost of Service calculation.
DSIT 283 OP OTHER NONCURR LIAB W.V.	-					Not applicable to Transmission Cost of Service calculation.
DSM	-					Not applicable to Transmission Cost of Service calculation.
EARNEST MONEY	-					Not applicable to Transmission Cost of Service calculation.
EMISSIONS ALLOWANCES	-					Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DFIT DEFICIENCY (190)	4,159	4,159				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DFIT DEFICIENCY (190) - FED EFFECT OF STATE	29	29				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DFIT DEFICIENCY (190) - FED EFFECT OF STATE - SO	(52)	(52)				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DFIT DEFICIENCY (190) SOLAR	865	865				Not applicable to Transmission Cost of Service calculation.

FAS 109 ITC DSIT DEFICIENCY D.C. (190)		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT DEFICIENCY D.C. (190) - SOLAR		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT DEFICIENCY N.C. (190)		36	36				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT DEFICIENCY N.C. (190) - SOLAR		7	7				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT DEFICIENCY VA (190)		711	711				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT DEFICIENCY VA (190) - SOLAR		138	138				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT DEFICIENCY W.V.(190)		21	21				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT DEFICIENCY WV (190) - SOLAR		4	4				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT GROSSUP D.C.		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT GROSSUP D.C. - SOLAR		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT GROSSUP N.C.		23	23				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT GROSSUP N.C. - SOLAR		4	4				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT GROSSUP VA		453	453				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT GROSSUP VA - SOLAR		88	88				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT GROSSUP W.V.		13	13				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC DSIT GROSSUP WV - SOLAR		3	3				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC GROSSUP (190)		2,651	2,651				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC GROSSUP (190) - FED EFFECT OF STATE		19	19				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC GROSSUP (190) - FED EFFECT OF STATE - SOLAR		(33)	(33)				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC GROSSUP (190) - SOLAR		551	551				Not applicable to Transmission Cost of Service calculation.
FAS 109 ITC REG LIAB		-					Not applicable to Transmission Cost of Service calculation.
FAS 133		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 133 - CAPACITY HEDGE CURRENT ASSET		-	-				Not applicable to Transmission Cost of Service calculation.
FASS 133 - DEBT HEDGE CURRENT ASSET		1,311	1,311				Not applicable to Transmission Cost of Service calculation.
FAS 133 - DEBT VALUATION - MTM HEDGE NON CURRENT AS		50,867	50,867				Not applicable to Transmission Cost of Service calculation.
FAS133 - DEFERRED GAIN/LOSS CAPAC HEDGE NON CURRE		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133 REG FTR CURRENT		-					Not applicable to Transmission Cost of Service calculation.
FAS 133 - FTR HEDGE CURRENT ASSET		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133 POWER HEDGE CURRENT ASSET		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133 REG HEDGE DEBT CURRENT		-					Not applicable to Transmission Cost of Service calculation.
FAS 143 ASSET OBLIGATION		-					Represents ARO accruals not deductible for tax.
FAS 143 ASSET OBLIGATION - DISTRIBUTION		1,119	1,119				Represents ARO accruals not deductible for tax.
FAS 143 ASSET OBLIGATION - GENERAL		48	48				Represents ARO accruals not deductible for tax.
FAS 143 ASSET OBLIGATION - NA		442	442				Represents ARO accruals not deductible for tax.
FAS 143 ASSET OBLIGATION - OTHER		79,645	79,645				Represents ARO accruals not deductible for tax.
FAS 143 ASSET OBLIGATION - TRANSMISSION		89		89			Represents ARO accruals not deductible for tax.
FAS143 DECOMMISSIONING - NA		145,161	145,161				Represents ARO accruals not deductible for tax.
FAS143 DECOMMISSIONING - OTHER		197,617	197,617				Represents ARO accruals not deductible for tax.
FEDERAL EFFECT OF STATE NONOPERATING		19,734	19,734				Not applicable to Transmission Cost of Service calculation.
FEDERAL EFFECT OF STATE OPERATING		171,029	171,029				Not applicable to Transmission Cost of Service calculation.
FEDERAL NOL CARRYFORWARD CURRENT		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FEDERAL TAX INTEREST EXPENSE NON CURRENT		-					Not applicable to Transmission Cost of Service calculation.
FIXED ASSETS FED EFFECT CURRENT CURRENT		668	668				Not applicable to Transmission Cost of Service calculation.
FIXED ASSETS FED EFFECT NON CURRENT CURRENT		1,523	1,523				Not applicable to Transmission Cost of Service calculation.
FIXED ASSETS FED EFFECT OF STATE		246	246				Not applicable to Transmission Cost of Service calculation.
FIXED ASSETS NON CURRENT CURRENT		-					Not applicable to Transmission Cost of Service calculation.
FLEET LEASE CREDIT - CURRENT		0			0		Books amortize the fleet lease extension credit over the new lease; tax takes the deduction when incurred.
FLEET LEASE CREDIT - NONCURRENT		-			-		Books amortizes the fleet lease extension credit over the new lease; tax takes the deduction when incurred.
FUEL DEF CURRENT LIAB		25	25				Not applicable to Transmission Cost of Service calculation.
FUEL DEF NON CUR LIAB		13,287	13,287				Not applicable to Transmission Cost of Service calculation.
FUEL DEF OTHER CURRENT LIAB		5,785	5,785				Not applicable to Transmission Cost of Service calculation.
FUEL DEF OTHER NON CUR LIAB		401	401				Not applicable to Transmission Cost of Service calculation.
GAIN SALE/LEASEBACK - SYSTEM OFFICE		-					Not applicable to Transmission Cost of Service calculation.
GENERAL BUSINESS CREDIT		2,712	2,712				Not applicable to Transmission Cost of Service calculation.
GROSS REC-UNBILLED REV-NC		-	-				Books include income when meter is read; taxed when service is provided.
HEADWATER BENEFITS		1,259	1,259				Not applicable to Transmission Cost of Service calculation.
INT STOR NORTH ANNA		-	-				Books recognizes the expense as incurred. For tax the deduction is recognized when the casks are filled.
INT STOR SURRY		-	-				Books recognizes the expense as incurred. For tax the deduction is recognized when the casks are filled.
LONG TERM DISABILITY RESERVE		7,534				7,534	Book estimate accrued and expensed; tax deduction when paid.
METERS		306	306				Books pre-capitalize when purchased; tax purposes when installed.
NC MICROGRID ITC		148	148				Books pre-capitalize when purchased; tax purposes when installed.
NOL		48,328	48,328				Not applicable to Transmission Cost of Service calculation.
NUCLEAR FUEL - PERMANENT DISPOSAL		-					Books estimate expense, tax deduction taken when paid.
NUCLEAR FUEL - PERMANENT DISPOSAL NORTH ANNA		0	0				Books estimate expense, tax deduction taken when paid.
NUCLEAR FUEL - PERMANENT DISPOSAL SURRY		0	0				Books estimate expense, tax deduction taken when paid.
OBSOLETE INVENTORY		-					Not applicable to Transmission Cost of Service calculation.
OBSOLETE INVENTORY RESERVE		1,901	1,901				Not applicable to Transmission Cost of Service calculation.
OPEB		(24,771)				(24,771)	Represents the difference between the book accrual expense and the actual funded amount.
PERFORMANCE ACHIEVEMENT PLAN		-					Not applicable to Transmission Cost of Service calculation.
POWER PURCHASE BUYOUT		-	-				Represents the difference between the book accrual expense and the actual funded amount.
PREMIUM, DEBT, DISCOUNT AND EXPENSE		3,135			3,135		Books record the yield to maturity method; taxes amortize staight line.
PRODUCTION TAX CREDIT		14,480	14,480				Not applicable to Transmission Cost of Service calculation.
P'SHIP INCOME - NC ENTERPRISE		-	-				Not applicable to Transmission Cost of Service calculation.
P'SHIP INCOME - VIRGINIA CAPITAL		172	172				Not applicable to Transmission Cost of Service calculation.
QUALIFIED SETTLEMENT FUND		-					Not applicable to Transmission Cost of Service calculation.
REACTOR DECOMMISSIONING LIABILITY		-					Represents the difference between the accrual and payments.
REG FUEL HEDGE		(4,672)	(4,672)				Not applicable to Transmission Cost of Service calculation.
REG FUEL HEDGE NONOP		4,662	4,662				Not applicable to Transmission Cost of Service calculation.
REG HEDGES CAPACITY		-					Not applicable to Transmission Cost of Service calculation.
REG HEDGES CAPACITY NC		-					Not applicable to Transmission Cost of Service calculation.
REG HEDGES DEBT		-					Not applicable to Transmission Cost of Service calculation.
REG LIAB - ATRR CURRENT		-	-				Not applicable to Transmission Cost of Service calculation.
REG LIAB - DEBT VALUATION - MTM - CURRENT		133	133				Not applicable to Transmission Cost of Service calculation.
REG LIAB - DEFERRED DISQUALIFIED DEBT NOT ISSUED		-					Not applicable to Transmission Cost of Service calculation.
REG LIAB - DEFERRED G/L CAPACITY HEDGE - CURRENT		55	55				Not applicable to Transmission Cost of Service calculation.
REG LIAB - DEFERRED G/L CAPACITY HEDGE NON CUR		0	0				Not applicable to Transmission Cost of Service calculation.
REG LIAB - DEFERRED G/L POWER HEDGE - CURRENT		-	-				Not applicable to Transmission Cost of Service calculation.
REG LIAB - DEFERRED NC REPS REC COST - NC		658	658				Not applicable to Transmission Cost of Service calculation.
REG LIAB - DEFERRED VALUATION - MTM - NON CURRENT		-	-				Not applicable to Transmission Cost of Service calculation.
REG LIAB - FTR CURRENT		6,960	6,960				Not applicable to Transmission Cost of Service calculation.
REG LIAB A5 REC COSTS - VA NON CURRENT		1,396	1,396				Not applicable to Transmission Cost of Service calculation.
REG LIAB ATRR VA NON CURRENT		2,159	2,159				Not applicable to Transmission Cost of Service calculation.
REG LIAB - CURRENT RIDER A6 BEAR GARDEN AFUDC DEBT		3	3				Not applicable to Transmission Cost of Service calculation.
REG LIAB CURRENT RIDER A6 BEAR GARDEN COST RESERVE		(173)	(173)				Not applicable to Transmission Cost of Service calculation.
REG LIAB CURRENT DSM A5		2,354	2,354				Not applicable to Transmission Cost of Service calculation.
REG LIAB OTHER NCUC CURRENT		297	297				Not applicable to Transmission Cost of Service calculation.
REG LIAB OTHER NCUC NON CURR		297	297				Not applicable to Transmission Cost of Service calculation.
REG LIAB OTHER NON CURR DOE SETTLEMENT		-					Not applicable to Transmission Cost of Service calculation.
REG LIAB PLANT CONTRA VASLSTX		21,452	21,452				Not applicable to Transmission Cost of Service calculation.
REG LIAB VA OTHER CURRENT		5	5				Not applicable to Transmission Cost of Service calculation.
REG LIABILITY DECOMMISSIONING		284,550	284,550				Not applicable to Transmission Cost of Service calculation.
REG LIABILITY HEDGES DEBT		-					Not applicable to Transmission Cost of Service calculation.
REG RATE REFUND - CURRENT		525	525				Not applicable to Transmission Cost of Service calculation.
REG RATE REFUND - NONCURRENT		-	-				Not applicable to Transmission Cost of Service calculation.
REG RATE REFUND INTEREST - CURRENT		-	-				Not applicable to Transmission Cost of Service calculation.
REGULATORY ASSET - D & D		-					Not applicable to Transmission Cost of Service calculation.
REGULATORY ASSET - VA SLS TAX		-					Not applicable to Transmission Cost of Service calculation.
RENEWABLE ENERGY RESOURCE CREDIT		5	5				Not applicable to Transmission Cost of Service calculation.
RESTRICTED STOCK AWARD		(390)	(390)				Not applicable to Transmission Cost of Service calculation.
RETENTION BONUS		(28)	(28)				Not applicable to Transmission Cost of Service calculation.
RETIREMENT - (FASB 87)		106,329				106,329	Book estimate accrued and expensed; tax deduction when paid.
RETIREMENT - EXEC SUPP RET (ESRP) - NONOP		(63)	(63)				Not applicable to Transmission Cost of Service calculation.
RETIREMENT - SUPPLEMENTAL RETIREMENT		64	64				Not applicable to Transmission Cost of Service calculation.
SALES TAX RECOVERY CWIP		7,611	7,611				Not applicable to Transmission Cost of Service calculation.
SALES TAX RECOVERY IN SERVICE		14,078	14,078				Not applicable to Transmission Cost of Service calculation.
SEPARATION/ERT		860				860	Book amount accrued and expensed; tax deduction when paid. These amounts will be paid in the next 12 months.
SEPARATION/ERT - NON CURRENT		-					Book amount accrued and expensed; tax deduction when paid. These amounts will not be paid in the next 12 months.
SOLAR COMMUNITY ITC		3,324	3,324				Book amount accrued as its earned; tax deduction is actual payout.
SUCCESS SHARE PLAN		9,958				9,958	Book amount accrued as its earned; tax deduction is actual payout.
VA PROPERTY TAX		-	-				Not applicable to Transmission Cost of Service calculation.

VA SALES & USE TAX AUDIT (INCL. INT)		-					Not applicable to Transmission Cost of Service calculation.
VACATION ACCRUAL		5,486	5,486				Not applicable to Transmission Cost of Service calculation.
W.VA. STATE NOL CFWD		1	1				Federal effect of state deductions.
W.VA. STATE POLLUTION CONTROL - FEDERAL EFFECT		1,433	1,433				Federal effect of state deductions.
WEST VA PROPERTY TAX		3,169	3,169				Property tax expense is accrued for accounting purposes using the prior year's rates on the balance of the property located in the state at December 31 of the previous year. Tax takes a deduction when paid.
WORKERS COMPENSATION - FAS 112		5,062				5,062	Not applicable to Transmission Cost of Service calculation.
ADFIT - OTHER COMPREHENSIVE INCOME		30,194	30,194				Not applicable to Transmission Cost of Service calculation.
DEFERRED SIT NONOP - OCI		5,700	5,700				Not applicable to Transmission Cost of Service calculation.
DFIT EFFECT ON SIT NONOP - OCI		12	12				Not applicable to Transmission Cost of Service calculation.
CONTINGENT CLAIMS CURRENT		727	727				Not applicable to Transmission Cost of Service calculation.
DEDESIGNATED DEBT NOT ISSUED		425	425				Not applicable to Transmission Cost of Service calculation.
FLEET LEASE CREDIT - CURRENT		0			0		Books amortize the fleet lease extension credit over the new lease; tax takes the deduction when incurred.
REG LIAB - ATRR CURRENT		-	-				Not applicable to Transmission Cost of Service calculation.
DEFERRED REVENUE CURRENT		-	-				Not applicable to Transmission Cost of Service calculation.
REG LIAB CURRENT RIDER A6 BEAR GARDEN COST RESERVE		173	173				Not applicable to Transmission Cost of Service calculation.
RETENTION BONUS		28	28				Not applicable to Transmission Cost of Service calculation.
OPEB		24,771				24,771	Represents the difference between the book accrual expense and the actual funded amount.
REG FUEL HEDGE		4,662	4,662				Not applicable to Transmission Cost of Service calculation.
CONTINGENT CLAIMS NONCURRENT		-	-				Not applicable to Transmission Cost of Service calculation.
REG LIAB A5 REC COSTS - VA NON CURRENT		-	-				Not applicable to Transmission Cost of Service calculation.
Reg Rate Refund		-	-				Not applicable to Transmission Cost of Service calculation.
Fixed Assets Effect Non Current Current		-	-				Not applicable to Transmission Cost of Service calculation.
RESTRICTED STOCK AWARD		390	390				Not applicable to Transmission Cost of Service calculation.
RETIREMENT EXEC SUPP RET (ESRP) - NONOP		63	63				Not applicable to Transmission Cost of Service calculation.
CAPITAL LEASE		638	638				Not applicable to Transmission Cost of Service calculation.
FIXED ASSETS FED EFFECT OF STATE		-	-				Not applicable to Transmission Cost of Service calculation.
COST OF REMOVAL		-	-	-		-	Represents the actual cost of removal allowable for tax over the accrued amount.
CAPITALIZED O&M EXP		-	-				Not applicable to Transmission Cost of Service calculation.
DOE SETTLEMENT - ASSET BASIS REDUCTION		-	-				Not applicable to Transmission Cost of Service calculation.
NUCLEAR FUEL - PERMANENT DISPOSAL		-	-				Book estimate accrued and expensed; tax deduction when paid.
Fixed Assets		-			-		Represents IRS audit adjustments to plant-related differences.
GAIN/(LOSS) INTERCO SALES - BOOK/TAX		31	31				Not applicable to Transmission Cost of Service calculation.
DOE SETTLEMENT CURRENT		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133 Deferred G/L Power Hedge Non Current Liab		-	-				Not applicable to Transmission Cost of Service calculation.
Federal Tax Interest Expense NC		70	70				Not applicable to Transmission Cost of Service calculation.
Reg Asset - Hedge Debt De-Designated Debt Not Issued		1,034	1,034				Not applicable to Transmission Cost of Service calculation.
Reg Asset - Noncur Rider A6 ALTAVISTA Cost Reserve		518	518				Not applicable to Transmission Cost of Service calculation.
Reg Asset - NonCur Rider A6 BRUNSWICK AFUDC Debt		267	267				Not applicable to Transmission Cost of Service calculation.
Reg Asset - NonCur Rider A6 BRUNSWICK Cost Reserve		664	664				Not applicable to Transmission Cost of Service calculation.
Reg Asset - NonCur Rider A6 HOPEWELL AFUDC Debt		1	1				Not applicable to Transmission Cost of Service calculation.
Reg Asset - NonCur Rider A6 HOPEWELL Cost Reserve		479	479				Not applicable to Transmission Cost of Service calculation.
Reg Asset - NonCur Rider A6 Southampton AFUDC Debt		29	29				Not applicable to Transmission Cost of Service calculation.
Reg Asset - NonCur Rider A6 Southampton Cost Reserve		461	461				Not applicable to Transmission Cost of Service calculation.
Reg Asset - NonCur Rider A6 Halifax AFUDC Debt		-	-				Not applicable to Transmission Cost of Service calculation.
Reg Non Current DSM A5 Rider		-	-				Not applicable to Transmission Cost of Service calculation.
Fixed Assets		-	-				Represents IRS audit adjustments to plant-related differences.
Fixed Assets-DC		-	-				Represents the state impact of IRS Audit adjustments to plant related differences.
Fixed Assets-NC		-	-				Represents the state impact of IRS Audit adjustments to plant related differences.
Fixed Assets-VA		-	-				Represents the state impact of IRS Audit adjustments to plant related differences.
Fixed Assets-WV		-	-				Represents the state impact of IRS Audit adjustments to plant related differences.
Charitable Contributions CFWD		-	-				Not applicable to Transmission Cost of Service calculation.
Fuel Def Current Liab		-	-				Not applicable to Transmission Cost of Service calculation.
Reg Liab - Debt Valuation - MTM - CURRENT		-	-				Not applicable to Transmission Cost of Service calculation.
VA Property Tax		-	-				Not applicable to Transmission Cost of Service calculation.
Retirement - (FASB87)		-	-				Not applicable to Transmission Cost of Service calculation.
FAS133 - DEBT VALUATION - MTM - CURRENT LIAB		-	-				Not applicable to Transmission Cost of Service calculation.
REG ASSET - A5 REC COST VA		-	-				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A5 DSM		-	-				Not applicable to Transmission Cost of Service calculation.
EMISSIONS ALLOWANCES		-	-				Not applicable to Transmission Cost of Service calculation.
REG ASSET - PLANT		-	-				Not applicable to Transmission Cost of Service calculation.
REG ATRR NON CURRENT		-	-				Not applicable to Transmission Cost of Service calculation.
BOOK CAPITALIZED INTEREST CWIP		-	-				Not applicable to Transmission Cost of Service calculation.
ROUND		0	0				Not applicable to Transmission Cost of Service calculation.
Subtotal - p234		2,109,732	1,743,436	10,510	228,060	127,726	
Less FASB 109 Above if not separately removed		9,692	9,692	-	-	-	
Less FASB 106 Above if not separately removed		-	0	0	0	0	
Total		2,100,039	1,733,743	10,510	228,060	127,726	

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

A ADIT- 282		B Total	C Production Or Other Related	D Only Transmission Related	E Plant Related	F Labor Related	G Justification
AFC DEFERRED TAX - FUEL CWIP		(27)	(27)				Represents the amount of amortization of AFC in service not allowable for tax.
AFC DEFERRED TAX - FUEL IN SERVICE		(2)	(2)				Represents the amount of amortization of AFC in service not allowable for tax.
AFC DEFERRED TAX - FUEL IN SERVICE NA		4	4				Represents the amount of amortization of AFC in service not allowable for tax.
AFC DEFERRED TAX - PLANT CWIP		(9,612)	(9,612)				Represents the amount of amortization of AFC in service not allowable for tax.
AFC DEFERRED TAX - PLANT IN SERVICE		(32,556)	(11,046)	(21,510)			Represents the amount of amortization of AFC in service not allowable for tax.
AFUDC - DEBT - GENERATION RIDER		-					Not applicable to Transmission Cost of Service calculation.
BOOK CAPITALIZED INTEREST CWIP		(515)			(515)		Represents the unallowable amount of book interest.
CAP EXPENSE		(1,871)	(23,073)	21,202			Capitalized for books and current deduction for tax as repairs.
CAPITAL EXPENSE 481A - DISTRIBUTION		(6,622)	(6,622)				Capitalized for books and current deduction for tax as repairs.
CAPITAL EXPENSE 481A - PRODUCTION		41,192	41,192				Capitalized for books and current deduction for tax as repairs.
CAPITALIZED RESTORATION 481A		51,160	51,160				Capitalized for books and current deduction for tax as repairs.
CAPITAL LEASE		-					Not applicable to Transmission Cost of Service calculation.
CASUALTY LOSS		(83,869)			(83,869)		Book varies in treatment; tax sec. 165 casualty loss for the decline in value (up to the adj. basis) and Sec 162 deduction for repairs to restore to pre-casualty condition.
CASUALTY LOSS AMORTIZATION		28,642			28,642		Represents a decrease to tax depreciation (Sec 162) as a result of casualty loss (Sec 165) reduction to tax basis.
COMPUTER SOFTWARE-BOOK AMORT		47,670				47,670	Represents total Book Computer Software Amortization Schedule M addition.
COMPUTER SOFTWARE-CWIP		(9,447)	(9,447)				Represents the allowable "In house" deduction for tax.
COMPUTER SOFTWARE-TAX AMORT		(70,722)				(70,722)	Total tax amortization shown as a schedule M deduction and add back total book amortization.
COST OF REMOVAL		-	-	-		-	Represents the actual cost of removal allowable for tax over the accrued amount.
DECOMMISSIONING		-					Tax deduction for funding decomm trust and tax deferral of book income generated by trust.
DECOMMISSIONING TRUST BOOK INCOME		-					Not applicable to Transmission Cost of Service calculation.
DSIT NONOPERATING DC		0	0				Not applicable to Transmission Cost of Service calculation.
DSIT NONOPERATING NC		(56)	(56)				Not applicable to Transmission Cost of Service calculation.
DSIT NONOPERATING VA		(4,527)	(4,527)				Not applicable to Transmission Cost of Service calculation.
DSIT NONOPERATING WV		(1)	(1)				Not applicable to Transmission Cost of Service calculation.
DSIT OPERATING DC		(98)	(98)				Not applicable to Transmission Cost of Service calculation.
DSIT OPERATING NC		(30,112)	(30,112)				Not applicable to Transmission Cost of Service calculation.
DSIT OPERATING VA		(325,050)	(325,050)				Not applicable to Transmission Cost of Service calculation.
DSIT OPERATING WV		(22,296)	(22,296)				Not applicable to Transmission Cost of Service calculation.
DFIT 190 NONOPERATING NONCURR ASSET		-					Not applicable to Transmission Cost of Service calculation.
DFIT 190 OPERATING NONCURR ASSET		-					Not applicable to Transmission Cost of Service calculation.
DFIT 190 OPERATING PLANT NONCURRENT ASSET		-					Not applicable to Transmission Cost of Service calculation.
DSIT 282 NONOP NONCURR PLAN LIABLITY - D.C.		-					Not applicable to Transmission Cost of Service calculation.
DSIT 282 NONOP NONCURR PLAN LIABLITY - N.C.		-					Not applicable to Transmission Cost of Service calculation.
DSIT 282 NONOP NONCURR PLAN LIABLITY - VA.		-					Not applicable to Transmission Cost of Service calculation.
DSIT 282 NONOP NONCURR PLAN LIABLITY - W.V.		-					Not applicable to Transmission Cost of Service calculation.

DSIT 282 NONOP PLANT NONCURR LIAB D.C.		-					Not applicable to Transmission Cost of Service calculation.
DSIT 282 NONOP PLANT NONCURR LIAB N.C.		-					Not applicable to Transmission Cost of Service calculation.
DSIT 282 NONOP PLANT NONCURR LIAB VA		-					Not applicable to Transmission Cost of Service calculation.
DSIT 282 NONOP PLANT NONCURR LIAB W.V.		-					Not applicable to Transmission Cost of Service calculation.
DSIT 282 OPERATING PLANT NONCURR LIAB D.C.		-					Not applicable to Transmission Cost of Service calculation.
DSIT 282 OPERATING PLANT NONCURR LIAB N.C.		-					Not applicable to Transmission Cost of Service calculation.
DSIT 282 OPERATING PLANT NONCURR LIAB VA		-					Not applicable to Transmission Cost of Service calculation.
DSIT 282 OPERATING PLANT NONCURR LIAB W.V.		-					Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT DEFICIENCY (282)		(47,285)	(47,285)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT DEFICIENCY (282) - FED EFFECT OF STATE		817	817				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282)		3,130	3,130				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - ALTAVISTA RIDER		(69)	(69)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - ALTAVISTA RIDER - FED EFFECT OF STATE		(6)	(6)				Not applicable to Transmission Cost of Service calculation.
FAS109 PLANT DFIT DEFICIENCY (282) - BEAR GARDEN		37	37				Not applicable to Transmission Cost of Service calculation.
FAS109 PLANT DFIT DEFICIENCY (282) - BEAR GARDEN - FED EFFECT OF STATE		(10)	(10)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - BREMO RIDER		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - BRUNSWICK RI		273	273				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - BRUNSWICK RIDER - FED EFFECT OF STATE		10	10				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - HALIFAX RIDE		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - HOPEWELL RID		(5)	(5)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - HOPEWELL RID		(2)	(2)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - NAIII RIDER		(15,338)	(15,338)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - NAIII RIDER		(460)	(460)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - PP7 RIDER		(82)	(82)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - PP7 RIDER - FED EFFECT OF STATE		4	4				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - REMINGTON SOLAR RIDER		(5)	(5)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - REMINGTON SOLAR RIDER - FED EFFECT OF STATE		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - SOUTHAMPTON RIDER		71	71				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - SOUTHAMPTON RIDER - FED EFFECT OF STATE		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - VCHEC RIDER		(479)	(479)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - VCHEC RIDER - FED EFFECT OF STATE		(83)	(83)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - WARREN RIDER		(2,214)	(2,214)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DFIT DEFICIENCY (282) - WARREN RIDER FED EFFECT OF STATE		(9)	(9)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY D.C. (282)		(1)	(1)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY D.C. (282) - ALTAVIS		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY D.C. (282) - BEAR GARDEN		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY D.C. (282) - BRUNSWI		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY D.C. (282) - GREENSVILLE		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY D.C. (282) - HALIFAX		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY D.C. (282) - HOPEWEL		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY D.C. (282) - GENERAT		-					Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY D.C. (282) - NAIII R		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY D.C. (282) - PP7 RID		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY D.C. (282) - SOUTHAM		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY D.C. (282) - VCHEC R		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY D.C. (282) - WARREN		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282)		(205)	(205)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282) - ALTAVISTA		(1)	(1)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282) - BEAR GA		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282)-BRUNSWICK		3	3				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282) - GREENSVILLE		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282)-HALIFAX		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282)-HOPEWELL		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282)-NAIII R		(141)	(141)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282)-PP7 RID		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282)-REMINGTON SOLAR		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282)-SOUTHAMPTON		1	1				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282)-VCHEC R		(5)	(5)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY N.C. (282)-WARREN		(19)	(19)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282)		(4,088)	(4,088)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282) - ALTAVISTA		(13)	(13)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282)-BEAR GARD		5	5				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282) - BRUNSWICK		48	48				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282)-GREENSVILLE		(9)	(9)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282) - HALIFAX R		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282) - HOPEWELL		(1)	(1)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282) - NAIII RID		(2,682)	(2,682)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282) - PP7 RIDER		(4)	(4)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282) - REMINGTON SOLAR		(1)	(1)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282) - SOUTHAMPT		12	12				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282) - VCHEC RID		(95)	(95)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY VA (282) - WARREN		(378)	(378)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282)		(122)	(122)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282) ALTAVIS		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282)-BEAR GA		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282) - BRUNSWICK		1	1				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282)-GREENSVILLE		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282) - HALIFAX		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282) - HOPEWELL		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282) - NAIII R		(79)	(79)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282) - PP7 RID		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282) - REMINGTON SOLAR		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282) - SOUTHAM		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282) - VCHEC R		(3)	(3)				Not applicable to Transmission Cost of Service calculation.
FAS 109 PLANT DSIT DEFICIENCY W.V. (282) - WARREN		(11)	(11)				Not applicable to Transmission Cost of Service calculation.
FEDERAL EFFECT OF STATE NONOPERATING		(8,470)	(8,470)				Not applicable to Transmission Cost of Service calculation.
FEDERAL EFFECT OF STATE OPERATING		(49,516)	(49,516)				Not applicable to Transmission Cost of Service calculation.
FIXED ASSETS		(4,079)			(4,079)		Represents IRS audit adjustments to plant-related differences.
FIXED ASSETS - D.C.		-					Represents the state impact of IRS Audit adjustments to plant related differences.
FIXED ASSETS - NC							Represents the state impact of IRS Audit adjustments to plant related differences.
FIXED ASSETS - VA		-					Represents the state impact of IRS Audit adjustments to plant related differences.
FIXED ASSETS - W.V.		-					Represents the state impact of IRS Audit adjustments to plant related differences.
GAIN(LOSS) INTERCO SALES - BOOK/TAX		31	31				Tax recognizes the intercompany gain/loss over the tax life of the assets.
GOODWILL AMORTIZATION		-	-				Not applicable to Transmission Cost of Service calculation.
INVOLUNTARY CONVERSION - TELECOMMUNICATIONS		-					Represents the difference between book and tax related to the disposal of telecommunication equipment. Recognized for tax purposes when utilized.
LIBERALIZED DEPRECIATION - FUEL		-					Represents difference between book burn of nuclear fuel based on usage vs. tax depreciation.
LIBERALIZED DEPRECIATION - FUEL CWIP		(0)	(0)				Represents the difference between book CWIP and Tax CWIP.
LIBERALIZED DEPRECIATION - PLANT ACUFILE		(4,543,183)	(3,439,650)	(1,044,553)		(58,979)	Difference between book and tax depreciation taking in consideration flow-through and ARAM.
LIBERALIZED DEPRECIATION - PLANT LAND FUTURE USE		-					Not applicable to Transmission Cost of Service calculation.
LIBERALIZED DEPRECIATION - PLANT LAND NON UTILITY		-					Not applicable to Transmission Cost of Service calculation.
LIBERALIZED DEPRECIATION - PLANT OPER LAND		749	749				Not applicable to Transmission Cost of Service calculation.
LIBERALIZED DEPRECIATION - PLANT OTHER		(167,380)	(167,380)				Not applicable to Transmission Cost of Service calculation.
LIBERALIZED DEPRECIATION - PLANT FUTURE USE		201	201				Not applicable to Transmission Cost of Service calculation.
LIBERALIZED DEPRECIATION - PLANT NON UTILITY		(480)	(480)				Not applicable to Transmission Cost of Service calculation.
REG ASSET PLANT ABANDONMENT		-	-				Not applicable to Transmission Cost of Service calculation.
RESEARCH AND DEVELOPMENT		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
LIBERALIZED DEPRECIATON - PLANT ACUFILE		-	-				Not applicable to Transmission Cost of Service calculation.
SUCCESS SHARE PLAN		-					Not applicable to Transmission Cost of Service calculation.
YORKTOWN IMPLOSION - TAX DEP.-LIB - NON OP		-					Not applicable to Transmission Cost of Service calculation.
FERC 281		184,641	184,641				Difference between book and tax depreciation taking in consideration flow-through and ARAM.
CAPITAL LEASE		(638)	(638)				Not applicable to Transmission Cost of Service calculation.
NUCLEAR FUEL - PERMANENT DISPOSAL		-	-				Not applicable to Transmission Cost of Service calculation.
Capital O&M Exp		-	-				Not applicable to Transmission Cost of Service calculation.
Book Capitalized Interest (To Zero Balance from PY Top Side Entry)		-	-				Not applicable to Transmission Cost of Service calculation.
DOE Settlement -Asset Basis Reduction		-	-				Not applicable to Transmission Cost of Service calculation.
Fixed Assets Fed Effect of State		-	-				Not applicable to Transmission Cost of Service calculation.

Gain Loss Interco		(31)	(31)	-		-	Represents the actual cost of removal allowable for tax over the accrued amount.
COST OF REMOVAL		-	-	-		-	Represents the actual cost of removal allowable for tax over the accrued amount.
Fixed Assets		-			-		Represents IRS audit adjustments to plant-related differences.
Fixed Assets-DC		-			-		Represents the state impact of IRS Audit adjustments to plant related differences.
Fixed Assets-NC		-			-		Represents the state impact of IRS Audit adjustments to plant related differences.
Fixed Assets-VA		-			-		Represents the state impact of IRS Audit adjustments to plant related differences.
Fixed Assets-WV		-			-		Represents the state impact of IRS Audit adjustments to plant related differences.
ROUND		(0)	(0)		-		Not applicable to Transmission Cost of Service calculation.
Subtotal - p275 (Form 1-F filer: see note 6 below)		(5,086,365)	(3,899,651)	(1,044,861)	(59,822)	(82,031)	
Less FASB 109 Above if not separately removed		(69,493)	(69,493)	0	0	0	
Less FASB 106 Above if not separately removed		0					
Total		(5,016,871)	(3,830,158)	(1,044,861)	(59,822)	(82,031)	

Instructions for Account 282:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving
6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c
7. For true-ups beginning with the true-up of 2014, and for projections beginning with the projection of 2015:
7.a. For transmission plant liberalized depreciation, do not enter year-end balances in Column D. Instead, enter the ADIT amount from Attachment 1B, Part 1, column 9, line 16; however, for the 2014 true-up enter the ADIT amount from Attachment 1B-2014, Part 1, column 9, line 23. (The same entry is to be made in Attachment 1.)
7.b. For general plant liberalized depreciation, computer software book amortization, and computer software tax amortization, do not enter year-end balances in Column F. Instead, enter the ADIT amounts from column 9, line 14, from the appropriate of Parts 2, 3, and 4 of Attachment 1B; however, for the 2014 true-up enter the ADIT amounts from column 9, line 20, from the appropriate of Parts 2, 3, and 4 of Attachment 1B-2014. (The same entry is to be made in Attachment 1.)

A ADIT-283		B Total	C Production Or Other Related	D Only Transmission Related	E Plant Related	F Labor Related	G Justification
A5 ENVIRONMENTAL NC RECEIVABLE		(65)	(65)				Not applicable to Transmission Cost of Service calculation.
A6 RECEIVABLE CURRENT		(989)	(989)				Not applicable to Transmission Cost of Service calculation.
A6 RECEIVABLE NONCURRENT		(3,263)	(3,263)				Not applicable to Transmission Cost of Service calculation.
ADFIT - OTHER COMPREHENSIVE INCOME Total		-					Not applicable to Transmission Cost of Service calculation.
AFUDC - DEBT - VCHEC RIDER CURRENT Total		-					Not applicable to Transmission Cost of Service calculation.
AMORT EXP - SEC 197 INTANGIBLES Total		-	-				Not applicable to Transmission Cost of Service calculation.
CURRENT CAPITALIZED RESTORATION COSTS 481A - DISTR		(14,914)	(14,914)				Not applicable to Transmission Cost of Service calculation.
DECOMM POUR OVER Total		(49,431)	(49,431)				Not applicable to Transmission Cost of Service calculation.
DECOMMISSIONING		(6,139)	(6,139)				Not applicable to Transmission Cost of Service calculation.
DECOMMISSIONING TRUST - UNREALIZED GAIN/LOSS - NC Total		(173,771)	(173,771)				Not applicable to Transmission Cost of Service calculation.
DECOMMISSIONING TRUST BOOK INCOME Total		(409,317)	(409,317)				Not applicable to Transmission Cost of Service calculation.
DEFERRED FUEL EXPENSE Total		25,521	25,521				Not applicable to Transmission Cost of Service calculation.
DEFERRED FUEL EXPENSE - OTHER Total		-	-				Not applicable to Transmission Cost of Service calculation.
DEFERRED FUEL EXPENSE - OTHER CURRENT Total		(2,741)	(2,741)				Not applicable to Transmission Cost of Service calculation.
DEFERRED FUEL EXPENSE CURRENT Total		(40,205)	(40,205)				Not applicable to Transmission Cost of Service calculation.
DEFERRED SIT NONOP - OCI Total		-					Not applicable to Transmission Cost of Service calculation.
DFIT 190 NONOPERATING CURRENT ASSET Total		-					Not applicable to Transmission Cost of Service calculation.
DFIT 190 NONOPERATING NONCURR ASSET Total		-					Not applicable to Transmission Cost of Service calculation.
DFIT 190 OPERATING CURRENT ASSET Total		-					Not applicable to Transmission Cost of Service calculation.
DFIT 190 OPERATING NONCURR ASSET Total		-					Not applicable to Transmission Cost of Service calculation.
DFIT 190 OPERATING NONCURRENT ASSET Total		-					Not applicable to Transmission Cost of Service calculation.
DFIT 283 NONOPERATING NONCURRENT LIAB Total		-					Not applicable to Transmission Cost of Service calculation.
DFIT 283 OPERATING NONCURRENT LIAB Total		-					Not applicable to Transmission Cost of Service calculation.
DFIT EFFECT ON SIT NONOP - OCI Total		-					Not applicable to Transmission Cost of Service calculation.
DOE SETTLEMENT Total		(9,289)	(9,289)				Not applicable to Transmission Cost of Service calculation.
DOE SETTLEMENT CURRENT		-	-				Not applicable to Transmission Cost of Service calculation.
DSIT 283 NONOP CURRENT LIABILITY D.C. Total		-	-				Not applicable to Transmission Cost of Service calculation.
DSIT 283 NONOP CURRENT LIABILITY N.C. Total		-					Not applicable to Transmission Cost of Service calculation.
DSIT 283 NONOP CURRENT LIABILITY VA Total		-					Not applicable to Transmission Cost of Service calculation.
DSIT 283 NONOP CURRENT LIABILITY W.V. Total		-					Not applicable to Transmission Cost of Service calculation.
DSIT 283 NONOP NONCURRENT LIABILITY D.C. Total		-					Not applicable to Transmission Cost of Service calculation.
DSIT 283 NONOP NONCURRENT LIABILITY N.C. Total		-					Not applicable to Transmission Cost of Service calculation.
DSIT 283 NONOP NONCURRENT LIABILITY VA Total		-					Not applicable to Transmission Cost of Service calculation.
DSIT 283 NONOP NONCURRENT LIABILITY W.V. Total		-					Not applicable to Transmission Cost of Service calculation.
DSIT 283 OP OTHER NONCURR ASSET VA MIN Total		-					Not applicable to Transmission Cost of Service calculation.
DSIT 283 OP OTHER NONCURR LIAB D.C. Total		0	0				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OP OTHER NONCURR LIAB N.C. Total		90	90				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OP OTHER NONCURR LIAB VA Total		1,773	1,773				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OP OTHER NONCURR LIAB VA MIN Total		-					Not applicable to Transmission Cost of Service calculation.
DSIT 283 OP OTHER NONCURR LIAB W.V. Total		53	53				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OPERATING CURRENT LIABILITY D.C. Total		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OPERATING CURRENT LIABILITY N.C. Total		(90)	(90)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OPERATING CURRENT LIABILITY VA Total		(1,773)	(1,773)				Not applicable to Transmission Cost of Service calculation.
DSIT 283 OPERATING CURRENT LIABILITY W.V. Total		(53)	(53)				Not applicable to Transmission Cost of Service calculation.
DSIT NONOPERATING DC		(10)	(10)				Not applicable to Transmission Cost of Service calculation.
DSIT NONOPERATING NC		(2,440)	(2,440)				Not applicable to Transmission Cost of Service calculation.
DSIT NONOPERATING VA		(47,924)	(47,924)				Not applicable to Transmission Cost of Service calculation.
DSIT NONOPERATING WV		(1,423)	(1,423)				Not applicable to Transmission Cost of Service calculation.
DSIT OPERATING DC		(23)	(23)				Not applicable to Transmission Cost of Service calculation.
DSIT OPERATING NC		(5,292)	(5,292)				Not applicable to Transmission Cost of Service calculation.
DSIT OPERATING VA		(105,938)	(105,938)				Not applicable to Transmission Cost of Service calculation.
DSIT OPERATING WV		(3,032)	(3,032)				Not applicable to Transmission Cost of Service calculation.
EMISSIONS ALLOWANCES Total		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) Total		(25,885)	(25,885)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - ALTAVISTA RIDER		(44)	(44)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - ALTAVISTA RIDER - FED		(4)	(4)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - BEAR GARDEN RID Total		23	23				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - BEAR GARDEN RID - FED		(6)	(6)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - BREMO RIDER Total		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - BRUNSWICK RIDER		174	174				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - BRUNSWICK RIDER - FED		6	6				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - FED EFFECT OF STATE		171	171				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - GREENSVILLE RIDER		(38)	(38)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - GREENSVILLE RIDER - FED		2	2				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - HALIFAX RIDER Total		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - HOPEWELL RIDER		(3)	(3)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - HOPEWELL RIDER - FED		(1)	(1)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - NAIII RIDER Total		(9,776)	(9,776)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - NAIII RIDER - FED EFFECT		(293)	(293)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - PP7 RIDER Total		(14)	(14)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - REMINGTON SOLAR RIDER		(3)	(3)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - REMINGTON SOLAR RIDER - FED		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - SOUTHAMPTON RID		45	45				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - SOUTHAMPTON RIDER - FED		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - VCHEC RIDER Total		(305)	(305)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - VCHEC RIDER - FED EFFECT		(53)	(53)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - WARREN RIDER Total		(1,411)	(1,411)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DFIT GROSSUP (283) - WARREN RIDER - FED EFFECT		(6)	(6)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP DC Total		(1)	(1)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP DC - ALTAVISTA RIDER		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP DC - BEAR GARDEN RIDER Total		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP DC - BRUNSWICK RIDER		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP DC - GREENSVILLE RIDER		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP DC - HALIFAX RIDER		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP DC - HOPEWELL RIDER			-				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP DC - NAIII RIDER Total		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP DC - PP7 RIDER		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP DC - SOUTHAMPTON RIDER		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP DC - VCHEC RIDER Total		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP DC - VCHEC RIDER CURR Total		-					Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP DC - WARREN RIDER Total		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC Total		(222)	(222)				Not applicable to Transmission Cost of Service calculation.

FAS 109 OTHER DSIT GROSSUP NC - ALTAVISTA RIDER		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - BEAR GARDEN RIDER Total		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - BRUNSWICK RIDER Total		2	2				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - GREENSVILLE RIDER		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - HALIFAX RIDER Total		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - HOPEWELL RIDER		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - NAIII RIDER Total		(90)	(90)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - PP7 RIDER Total		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - REMINGTON SOLAR RIDER		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - SOUTHAMPTON RIDER		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - VCHEC RIDER Total		(3)	(3)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - VCHEC RIDER CURR Total		-					Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - VCHEC RIDER NONCUR Total		-					Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP NC - WARREN RIDER Total		(12)	(12)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA Total		(4,369)	(4,369)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - ALTAVISTA RIDER		(8)	(8)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - BEAR GARDEN RIDER Total		3	3				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - BREMO RIDER Total		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - BRUNSWICK RIDER		31	31				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - GREENSVILLE RIDER Total		(6)	(6)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - HALIFAX RIDER Total		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - HOPEWELL RIDER		(1)	(1)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - NAIII RIDER Total		(1,710)	(1,710)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - PP7 RIDER Total		(2)	(2)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - REMINGTON SOLAR RIDER		(1)	(1)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - SOUTHAMPTON RIDER		8	8				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - VCHEC RIDER Total		(61)	(61)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - VCHEC RIDER CURR Total		-					Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - VCHEC RIDER NONCUR Total		-					Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP VA - WARREN RIDER Total		(241)	(241)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV Total		(130)	(130)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - ALTAVISTA RIDER		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - BEAR GARDEN RIDER Total		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - BREMO RIDER Total		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - BRUNSWICK RIDER Total		1	1				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - GREENSVILLE RIDER Total		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - HOPEWELL RIDER		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - NAIII RIDER Total		(50)	(50)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - PP7 RIDER Total		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - REMINGTON SOLAR RIDER		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - SOUTHAMPTON RIDER		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - VCHEC RIDER Total		(2)	(2)				Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - VCHEC RIDER CURR Total		-					Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - VCHEC RIDER NONCUR Total		-					Not applicable to Transmission Cost of Service calculation.
FAS 109 OTHER DSIT GROSSUP WV - WARREN RIDER Total		(7)	(7)				Not applicable to Transmission Cost of Service calculation.
FAS 133 Total		11	11				Not applicable to Transmission Cost of Service calculation.
FAS 133 - FTR HEDGE CURRENT ASSET Total		-					Not applicable to Transmission Cost of Service calculation.
FAS 133 REG FUEL HEDGE NONCURRENT Total		-					Not applicable to Transmission Cost of Service calculation.
FAS 133-DEBT VALUATION - MTM - CURRENT LIAB Total		(133)	(133)				Not applicable to Transmission Cost of Service calculation.
FAS 133-DEFERRED G/L CAPACITY HEDGE - NON CURRENT Total		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
FAS 133-DEFERRED G/L CAPACITY HEDGE CURRENT LIAB Total		(55)	(55)				Not applicable to Transmission Cost of Service calculation.
FAS 133-DEFERRED G/L POWER HEDGE - CURRENT LIAB Total		0	0				Not applicable to Transmission Cost of Service calculation.
FAS 133-DEFERRED VALUATION- MTM NON CURRENT LIAB Total		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133-FTR CURRENT LIAB Total		(6,960)	(6,960)				Not applicable to Transmission Cost of Service calculation.
FEDERAL EFFECT OF STATE NONOPERATING		(34,742)	(34,742)				Not applicable to Transmission Cost of Service calculation.
FEDERAL EFFECT OF STATE OPERATING		2,912	2,912				Not applicable to Transmission Cost of Service calculation.
FEDERAL EFFECT OF STATE OPERATING NC MICROGRID ITC		(36)	(36)				Not applicable to Transmission Cost of Service calculation.
FEDERAL TAX INTEREST EXPENSE Total		(712)	(712)				Not applicable to Transmission Cost of Service calculation.
FEDERAL TAX INTEREST EXPENSE NON CURRENT Total		70	70				Not applicable to Transmission Cost of Service calculation.
FIXED ASSETS FED EFFECT OF STATE		-	-				Not applicable to Transmission Cost of Service calculation.
FUEL HANDLING COSTS Total		(187)	(187)				Not applicable to Transmission Cost of Service calculation.
GOODWILL AMORTIZATION Total		-					Not applicable to Transmission Cost of Service calculation.
NON CURRENT CAPITALIZED RESTORATION COSTS 481A - D		(22,371)	(22,371)				Not applicable to Transmission Cost of Service calculation.
NON CURRENT REC A4 ELEC TRAN Total		(6,511)	(6,511)				Not applicable to Transmission Cost of Service calculation.
POWERTREE CARBON CO, LLC. Total		(34)	(34)				Not applicable to Transmission Cost of Service calculation.
REACQUIRED DEBT GAIN(LOSS) Total		(103)	(103)				Not applicable to Transmission Cost of Service calculation.
REG ASSET FTR		-					Not applicable to Transmission Cost of Service calculation.
REG ASSET - A4 RAC COSTS CURRENT		(5,484)	(5,484)				Not applicable to Transmission Cost of Service calculation.
REG ASSET - A4 RAC COSTS NONCURRENT		(25,338)	(25,338)				Not applicable to Transmission Cost of Service calculation.
REG ASSET - A5 REC COST VA		-	-				Not applicable to Transmission Cost of Service calculation.
REG ASSSET - ATRR CURRENT		(8,869)	(8,869)				Not applicable to Transmission Cost of Service calculation.
REG ASSSET - CUR - NUG		(436)	(436)				Not applicable to Transmission Cost of Service calculation.
REG ASSET - FTR CURRENT		-					Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A4 NON VA OTHER		-					Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A5 DSM		-					Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 BEAR GARDEN AFUDC DEBT		-					Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 BEAR GARDEN COST RESERV		-					Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 HALIFAX AFUDC DEBT		-					Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 VCHEC AFUDC DEBT		-					Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 VCHEC COST RESERVE		-					Not applicable to Transmission Cost of Service calculation.
REG ASSET - DEBT VALUATION - MTM - NON CURRENT		(1,311)	(1,311)				Not applicable to Transmission Cost of Service calculation.
REG ASSET - DEFERRED G/L CAPACITY HEDGE CURRENT		-	-				Not applicable to Transmission Cost of Service calculation.
REG ASSET - DEFERRED GAIN/LOSS CAPAC HEDGE NONCUR		-	-				Not applicable to Transmission Cost of Service calculation.
REG ASSET - FTR - CURRENT		-	-				Not applicable to Transmission Cost of Service calculation.
REG ASSET - NRC REQUIREMENT - NORTH ANNA		(6,005)	(6,005)				Not applicable to Transmission Cost of Service calculation.
REG ASSET - NRC REQUIREMENT - SURRY		(2,780)	(2,780)				Not applicable to Transmission Cost of Service calculation.
REG ASSET - PLANT		0	0				Not applicable to Transmission Cost of Service calculation.
REG ASSET - PLANT CURRENT		-	-				Not applicable to Transmission Cost of Service calculation.
REG ASSET ABANDONED PLANT NCUC CURRENT		(406)	(406)				Not applicable to Transmission Cost of Service calculation.
REG ASSET ABANDONED PLANT NCUC NON CURR		(2,318)	(2,318)				Not applicable to Transmission Cost of Service calculation.
REG ASSET ASSET IMPAIRMENT NCUC CURRENT		(86)	(86)				Not applicable to Transmission Cost of Service calculation.
REG ASSET ASSET IMPAIRMENT NCUC NONCURR		(355)	(355)				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A4 NON VA OTHER Total		(1,012)	(1,012)				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A5 DSM Total		-	-				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 ALTAVISTA AFUDC DEBT Total		(1)	(1)				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 ALTAVISTA COST RESERVE		518	518				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 BEAR GARDEN AFUDC DEBT Total		(826)	(826)				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 BEAR GARDEN COST RESERV Total		(2,093)	(2,093)				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 BRUNSWICK AFUDC DEBT		(86)	(86)				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 BRUNSWICK COST RESERVE		68	68				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 HOPEWELL AFUDC DEBT Total		1	1				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 HOPEWELL COST RESERVE		479	479				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 SOUTHAMPTON AFUDC DEBT Total		29	29				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 SOUTHAMPTON COST RESERV		461	461				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 HALIFAX AFUDC DEBT Total		-					Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 VCHEC AFUDC DEBT Total		(653)	(653)				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 VCHEC COST RESERVE Total		(4,291)	(4,291)				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 WARREN AFUDC DEBT Total		(644)	(644)				Not applicable to Transmission Cost of Service calculation.
REG ASSET CURRENT RIDER A6 WARREN COST RESERVE		140	140				Not applicable to Transmission Cost of Service calculation.
REG ASSET- DEBT VALUATION - MTM - NON CURRENT Total		(50,867)	(50,867)				Not applicable to Transmission Cost of Service calculation.
REG ASSET DEF A5 COST ENVIRONMENTAL COST RESERVE		(464)	(464)				Not applicable to Transmission Cost of Service calculation.
REG ASSET- DEFERRED GAIN/LOSS CAPAC HEDGE NONCUR Total		-	-				Not applicable to Transmission Cost of Service calculation.
REG ASSET DEFERRED NC RECPS REC COST CURRENT		(260)	(260)				Not applicable to Transmission Cost of Service calculation.
REG ASSET- HEDGE DEBT DE-DESIGNATED DEBT NOT ISSUE		1,034	1,034				Not applicable to Transmission Cost of Service calculation.
REG ASSET NATURAL DISASTER NCUC CURRENT		(476)	(476)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NATURAL DISASTER NCUC NONCURR		(79)	(79)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 ALTAVISTA AFUDC DEBT Total		(19)	(19)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 ALTAVISTA COST RESERVE		(4,113)	(4,113)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 BEAR GARDEN AFUDC DEBT Total		245	245				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 BEAR GARDEN COST RESERVE Total		(4,463)	(4,463)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 BRUNSWICK AFUDC DEBT Total		267	267				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 BRUNSWICK COST RESERVE		664	664				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 DISTRIBUTION UG		(178)	(178)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 GREENSVILLE AFUDC DEBT		(25)	(25)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 HALIFAX AFUDC DEBT Total		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 HOPEWELL AFUDC DEBT Total		(9)	(9)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 HOPEWELL COST RESERVE		(2,344)	(2,344)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 NAIII AFUDC DEBT Total		(6,154)	(6,154)				Not applicable to Transmission Cost of Service calculation.

REG ASSET NONCUR RIDER A6 NAIII COST RESERVE Total		5,342	5,342				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 PP7 AFUDC DEBT Total		(10)	(10)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 REMINGTON SOLAR AFUDC DEBT Total		(2)	(2)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 SOUTHAMPTON AFUDC DEBT Total		(9)	(9)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 SOUTHAMPTON COST RESERVE		(2,443)	(2,443)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 VCHEC AFUDC DEBT Total		(849)	(849)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 VCHEC COST RESERVE Total		(14,002)	(14,002)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 WARREN AFUDC DEBT Total		(146)	(146)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NONCUR RIDER A6 WARREN COST RESERVE Total		(482)	(482)				Not applicable to Transmission Cost of Service calculation.
REG ASSET NUCLEAR OUTAGE DEFERRAL - CURRENT		(26,472)	(26,472)				Not applicable to Transmission Cost of Service calculation.
REG ASSET RETIREMENT NCUC CURRENT		(40)	(40)				Not applicable to Transmission Cost of Service calculation.
REG ASSET RETIREMENT NCUC NONCURR		(307)	(307)				Not applicable to Transmission Cost of Service calculation.
REG ASSET RIDER PLANTS NCUC CURRENT		(208)	(208)				Not applicable to Transmission Cost of Service calculation.
REG ASSET RIDER PLANTS NCUC NONCURR		(277)	(277)				Not applicable to Transmission Cost of Service calculation.
REG ATRR NON CURRENT		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
REG NON CURRENT DSM A5 RIDER		(5,697)	(5,697)				Not applicable to Transmission Cost of Service calculation.
REG HEDGE DEBT - CURRENT		-					Not applicable to Transmission Cost of Service calculation.
REG POWER HEDGE - CURRENT		-					Not applicable to Transmission Cost of Service calculation.
REG POWER HEDGE		-					Not applicable to Transmission Cost of Service calculation.
REGULATORY ASSET - D & D		-					Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
REGULATORY ASSET - FAS 112		(1,700)				(1,700)	Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
REGULATORY ASSET - ISABEL		-					Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
REGULATORY ASSET - NUG		(1,141)	(1,141)				Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
REGULATORY ASSET - PJM CURRENT		-					Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
REGULATORY ASSET - VA SLS TAX		(2,131)	(2,131)				Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
REGULATORY ASSET - VA SLS TAX CURRENT		(16,320)	(16,320)				Represents cost that for regulatory purposes needs to be amortized over a prescribed life. However, allowable for tax when incurred.
RETIREMENT - EXEC SUPP RET (ESRP) - NONOP		(402)	(402)				Not applicable to Transmission Cost of Service calculation.
SO2 ALLOWANCES - NONCURRENT		-					Book expense for emissions allowances based on moving-average-cost, tax expense based on specific identification.
W.VA. STATE NOL CFWD		(0)	(0)				Represents the deferred state tax impact related to WV NOL. This deferral will turn around when the pollution control projects are placed in service.
W.VA. STATE POLLUTION CONTROL		(4,094)			(4,094)		Represents the deferred state tax impact related to WV Pollution control projects. This deferral will turn around once placed in service.
ADFIT - OTHER COMPREHENSIVE INCOME Total		(30,194)	(30,194)				Not applicable to Transmission Cost of Service calculation.
DEFERRED SIT NONOP - OCI Total		(5,700)	(5,700)				Not applicable to Transmission Cost of Service calculation.
DFIT EFFECT ON SIT NONOP - OCI Total		(12)	(12)				Not applicable to Transmission Cost of Service calculation.
CONTINGENT CLAIMS CURRENT		(727)	(727)				Not applicable to Transmission Cost of Service calculation.
DEDESIGNATED DEBT NOT ISSUED		(425)	(425)				Not applicable to Transmission Cost of Service calculation.
Fleet Lease Credit Current		-			-		Not applicable to Transmission Cost of Service calculation.
Reg Liab ATRR Current		-	-				Not applicable to Transmission Cost of Service calculation.
Deferred Revenue Current		-	-				Not applicable to Transmission Cost of Service calculation.
Fuel Def Current Liab		-	-				Not applicable to Transmission Cost of Service calculation.
REG LIAB - DEBT VALUATION - MTM - CURRENT		-	-				Not applicable to Transmission Cost of Service calculation.
REG LIAB CURRENT RIDER A6 BEAR GARDEN COST RESERVE		-	-				Not applicable to Transmission Cost of Service calculation.
RETENTION BONUS		(28)	(28)				Not applicable to Transmission Cost of Service calculation.
OPEB		(24,771)				(24,771)	Represents the difference between the book accrual expense and the actual funded amount.
Contingent Claims Non Current		-	-				Not applicable to Transmission Cost of Service calculation.
Reg Fuel Hedge		(4,662)	(4,662)				Not applicable to Transmission Cost of Service calculation.
Reg Liab A5 Rec Costs VA Non Current		-	-				Not applicable to Transmission Cost of Service calculation.
Reg Rate Refund Non Current		-	-				Not applicable to Transmission Cost of Service calculation.
Fixed Assets Effect Non Current Current		-	-				Not applicable to Transmission Cost of Service calculation.
VA PROPERTY TAX		-	-				Not applicable to Transmission Cost of Service calculation.
Retirement - (FASB 87)		-	-				Not applicable to Transmission Cost of Service calculation.
RESTRICTED STOCK AWARDS		(390)	(390)				Not applicable to Transmission Cost of Service calculation.
Retirement Exex Supp Ret ESRP Nonop		(63)	(63)				Not applicable to Transmission Cost of Service calculation.
DOE Settlement Current		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133 Deferred G/L Power Hedge Non Current Liab		-	-				Not applicable to Transmission Cost of Service calculation.
FAS 133 - Debt Valuation - MTM - Current Liab		-	-				Not applicable to Transmission Cost of Service calculation.
Reg Asset - A5 Rec Cost VA		-	-				Not applicable to Transmission Cost of Service calculation.
Reg Asset Current Rider A5 DSM		-	-				Not applicable to Transmission Cost of Service calculation.
Reg Asset Current Rider A6 Bear Garden Cost Reserve		(173)	(173)				Not applicable to Transmission Cost of Service calculation.
Emissions Allowances		-	-				Not applicable to Transmission Cost of Service calculation.
Federal Tax Interest Expense NC		(70)	(70)				Not applicable to Transmission Cost of Service calculation.
Reg Asset - Plant		-	-				Not applicable to Transmission Cost of Service calculation.
Reg Asset - Hedge Debt De-Designated Debt Not Issued		(1,034)	(1,034)				Not applicable to Transmission Cost of Service calculation.
Reg Asset - Noncur Rider A6 ALTAVISTA Cost Reserve		(518)	(518)				Not applicable to Transmission Cost of Service calculation.
Reg Asset - NonCur Rider A6 BRUNSWICK AFUDC Debt		(267)	(267)				Not applicable to Transmission Cost of Service calculation.
Reg Asset - NonCur Rider A6 BRUNSWICK Cost Reserve		(664)	(664)				Not applicable to Transmission Cost of Service calculation.
Reg Asset - NonCur Rider A6 HOPEWELL AFUDC Debt		(1)	(1)				Not applicable to Transmission Cost of Service calculation.
Reg Asset - NonCur Rider A6 HOPEWELL Cost Reserve		(479)	(479)				Not applicable to Transmission Cost of Service calculation.
Reg Asset - NonCur Rider A6 Southampton AFUDC Debt		(29)	(29)				Not applicable to Transmission Cost of Service calculation.
Reg Asset - NonCur Rider A6 Southampton Cost Reserve		(461)	(461)				Not applicable to Transmission Cost of Service calculation.
Reg ATRR Non Current		-	-				Not applicable to Transmission Cost of Service calculation.
Reg Asset - NonCur Rider A6 Halifax AFUDC Debt		-	-				Not applicable to Transmission Cost of Service calculation.
Reg Non Current DSM A5 Rider		-	-				Not applicable to Transmission Cost of Service calculation.
FIXED ASSETS NONCURRENT CURRENT		-					Not applicable to Transmission Cost of Service calculation.
Charitable Contributions CFWD		-	-				Not applicable to Transmission Cost of Service calculation.
ROUND		(0)	(0)				Not applicable to Transmission Cost of Service calculation.
Subtotal - p277 (Form 1-F filer: see note 6, below)		(1,234,425)	(1,203,860)	0	(4,094)	(26,471)	
Less FASB 109 Above if not separately removed		(44,291)	(44,291)	-	-	-	
Less FASB 106 Above if not separately removed		(24,771)	-	-	-	(24,771)	
Total		(1,165,363)	(1,159,569)	-	(4,094)	(1,700)	

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

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

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

		Item	Balance	Amortization
1 Amortization				(4,204)
2 Amortization to line 136 of Appendix A		Total		137
3 Total			-	(4,067)
4 Total Form No. 1 (p 266 & 267)		Form No. 1 balance	(p.266) for amortiz	(4,067)
5 Difference /1			-	-

/1 Difference must be zero

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 1B
Accumulated Deferred Income Taxes
Associated with Pro-rata Liberalized Depreciation
2016

Effective on and After January 1, 2015

(Not Applicable to the True-up of 2014 and Earlier)

NOTE: Attachment 1B is effective Subject to Refund. See FERC Docket No. ER14-1831.

Sheet 1 of 4

Part 1: Account 282, Transmission Plant In Service

Columns 3, 4, 7, 8, and 9 are in dollars (except line 15).

Line 1 Number of Days in Year: 366 (Enter 365, or for Leap Year enter 366)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Line	Year	Month	Transmission Plant In Service ADIT	Activity	Remaining Days	Ratio	Pro Rata Activity	Pro-rated ADIT	13 Month Average
2	2015	Dec	(1,086,044,488)					(1,086,044,488)	
3	2016	Jan	(1,089,821,907)	(3,777,419)	336	0.918033	(3,467,795)	(1,089,512,283)	
4	2016	Feb	(1,093,590,151)	(3,768,244)	307	0.838798	(3,160,795)	(1,092,673,078)	
5	2016	Mar	(1,097,350,792)	(3,760,641)	276	0.754098	(2,835,893)	(1,095,508,971)	
6	2016	Apr	(1,101,101,565)	(3,750,773)	246	0.672131	(2,521,011)	(1,098,029,982)	
7	2016	May	(1,104,829,243)	(3,727,678)	215	0.587432	(2,189,756)	(1,100,219,738)	
8	2016	Jun	(1,108,503,571)	(3,674,328)	185	0.505464	(1,857,242)	(1,102,076,980)	
9	2016	Jul	(1,112,098,918)	(3,595,347)	154	0.420765	(1,512,796)	(1,103,589,776)	
10	2016	Aug	(1,115,643,719)	(3,544,801)	123	0.336066	(1,191,286)	(1,104,781,062)	
11	2016	Sep	(1,119,180,537)	(3,536,819)	93	0.254098	(898,700)	(1,105,679,762)	
12	2016	Oct	(1,122,691,423)	(3,510,886)	62	0.169399	(594,740)	(1,106,274,502)	
13	2016	Nov	(1,126,176,045)	(3,484,621)	32	0.087432	(304,666)	(1,106,579,168)	
14	2016	Dec	(1,129,626,972)	(3,450,928)	1	0.002732	(9,429)	(1,106,588,597)	(1,099,812,184)
15	Total Transmission Plant In Service Net of GSU and GI Plant as a Percentage of Total Transmission Plant In Service:								94.98%
16	Transmission Plant In Service ADIT Associated with Pro-rata Liberalized Depreciation:								(1,044,553,058)

Explanations:

Col. 1, Lines 2-3	The year prior to the subject year and the subject year, respectively.
Col. 3	Account 282 month-end ADIT as projected or from accounting records reconciling to Form1 (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 2	Amount from col. 3, line 2.
Col. 8, Lines 3-14	Col. 8 of previous month plus col. 7 of current month.
Col. 9, Line 14	The average of the 13 amounts in col. 8.
Col. 9, Line 15	Appendix A, Line 24 ÷ Appendix A, Line 21
Col. 9, Line 16	Col. 9, Line 14, multiplied by line 15. To be entered (in thousands) into Column D of the Account 282 section of Attachments 1 and 1A.

Attachment 1B (Continued)
2016
Sheet 2 of 4

Part 2: Account 282, General Plant

Columns 3, 4, 7, 8, and 9 are in dollars.

Line	(1) Year	(2) Month	(3) General Plant ADIT	(4) Activity	(5) Remaining Days	(6) Ratio	(7) Pro Rata Activity	(8) Pro-rated ADIT	(9) 13 Month Average
1	2015	Dec	(58,979,183)					(58,979,183)	
2	2016	Jan	(58,979,183)	0	336	0.918033	0	(58,979,183)	
3	2016	Feb	(58,979,183)	0	307	0.838798	0	(58,979,183)	
4	2016	Mar	(58,979,183)	0	276	0.754098	0	(58,979,183)	
5	2016	Apr	(58,979,183)	0	246	0.672131	0	(58,979,183)	
6	2016	May	(58,979,183)	0	215	0.587432	0	(58,979,183)	
7	2016	Jun	(58,979,183)	0	185	0.505464	0	(58,979,183)	
8	2016	Jul	(58,979,183)	0	154	0.420765	0	(58,979,183)	
9	2016	Aug	(58,979,183)	0	123	0.336066	0	(58,979,183)	
10	2016	Sep	(58,979,183)	0	93	0.254098	0	(58,979,183)	
11	2016	Oct	(58,979,183)	0	62	0.169399	0	(58,979,183)	
12	2016	Nov	(58,979,183)	0	32	0.087432	0	(58,979,183)	
13	2016	Dec	(58,979,183)	0	1	0.002732	0	(58,979,183)	
14				General Plant ADIT Associated with Pro-rata Liberalized Depreciation:					(58,979,183)

Explanations:

Col. 3	Account 282 month-end ADIT as projected or from accounting records reconciling to Form1 (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. 9, Line 14	The average of the 13 amounts in col. 8. To be entered (in thousands) into Column F of the Account 282 section of Attachments 1 and 1A.

Attachment 1B (Continued)
2016
Sheet 3 of 4

Columns 3, 4, 7, 8, and 9 are in dollars.
The column and line explanations and the use of line 14 are as described for Part 2.

Part 3: Account 282, Computer Software - Book Amortization

Line	(1) Year	(2) Month	(3) Comp Software Book Amort ADIT	(4) Activity	(5) Remaining Days	(6) Ratio	(7) Pro Rata Activity	(8) Pro-rated ADIT	(9) 13 Month Average
1	2015	Dec	47,669,776					47,669,776	
2	2016	Jan	47,669,776	0	336	0.918033	0	47,669,776	
3	2016	Feb	47,669,776	0	307	0.838798	0	47,669,776	
4	2016	Mar	47,669,776	0	276	0.754098	0	47,669,776	
5	2016	Apr	47,669,776	0	246	0.672131	0	47,669,776	
6	2016	May	47,669,776	0	215	0.587432	0	47,669,776	
7	2016	Jun	47,669,776	0	185	0.505464	0	47,669,776	
8	2016	Jul	47,669,776	0	154	0.420765	0	47,669,776	
9	2016	Aug	47,669,776	0	123	0.336066	0	47,669,776	
10	2016	Sep	47,669,776	0	93	0.254098	0	47,669,776	
11	2016	Oct	47,669,776	0	62	0.169399	0	47,669,776	
12	2016	Nov	47,669,776	0	32	0.087432	0	47,669,776	
13	2016	Dec	47,669,776	0	1	0.002732	0	47,669,776	
14			Computer Software - Book Amortization ADIT Associated with Pro-rata Liberalized Depreciation:						47,669,776

Attachment 1B (Continued)
2016
Sheet 4 of 4

Columns 3, 4, 7, 8, and 9 are in dollars.
The column and line explanations and the use of line 14 are as described for Part 2.

Part 4: Account 282, Computer Software - Tax Amortization

Line	(1) Year	(2) Month	(3) Comp Software Tax Amort ADIT	(4) Activity	(5) Remaining Days	(6) Ratio	(7) Pro Rata Activity	(8) Pro-rated ADIT	(9) 13 Month Average
1	2015	Dec	(70,721,645)					(70,721,645)	
2	2016	Jan	(70,721,645)	0	336	0.918033	0	(70,721,645)	
3	2016	Feb	(70,721,645)	0	307	0.838798	0	(70,721,645)	
4	2016	Mar	(70,721,645)	0	276	0.754098	0	(70,721,645)	
5	2016	Apr	(70,721,645)	0	246	0.672131	0	(70,721,645)	
6	2016	May	(70,721,645)	0	215	0.587432	0	(70,721,645)	
7	2016	Jun	(70,721,645)	0	185	0.505464	0	(70,721,645)	
8	2016	Jul	(70,721,645)	0	154	0.420765	0	(70,721,645)	
9	2016	Aug	(70,721,645)	0	123	0.336066	0	(70,721,645)	
10	2016	Sep	(70,721,645)	0	93	0.254098	0	(70,721,645)	
11	2016	Oct	(70,721,645)	0	62	0.169399	0	(70,721,645)	
12	2016	Nov	(70,721,645)	0	32	0.087432	0	(70,721,645)	
13	2016	Dec	(70,721,645)	0	1	0.002732	0	(70,721,645)	
14			Computer Software - Tax Amortization ADIT Associated with Pro-rata Liberalized Depreciation:						(70,721,645)

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

Effective Only for the True-up of 2014

NOTE: Attachment 1B-2014 is effective Subject to Refund. See FERC Docket No. ER14-1831.

Sheet 1 of 4

Part 1: Account 282, Transmission Plant In Service

Columns 3, 4, 7, 8, and 9 are in dollars (except lines 16, 19, and 22).

Line 1: 365 days in 2014.

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
Line	Year	Month	Transmission Plant In Service ADIT	Activity	Remaining Days	Ratio	Pro Rata Activity	Pro-rated ADIT	As Indicated by Explanation
2	2013	Dec						0	
3	2014	Jan		0	335	0.917808	0	0	
4	2014	Feb		0	307	0.841096	0	0	
5	2014	Mar		0	276	0.756164	0	0	
6	2014	Apr		0	246	0.673973	0	0	
7	2014	May		0	215	0.589041	0	0	
8	2014	Jun		0	185	0.506849	0	0	
9	2014	Jul		0	154	0.421918	0	0	
10	2014	Aug		0	123	0.336986	0	0	
11	2014	Sep		0	93	0.254795	0	0	
12	2014	Oct		0	62	0.169863	0	0	
13	2014	Nov		0	32	0.087671	0	0	
14	2014	Dec		0	1	0.002740	0	0	

15	Pre-change -- Average of December 2013 ADIT and April 2014 ADIT:	0
16	4 Months Divided by 12 Months:	33.33%
17	Component of Average ADIT Attributable to January Through April 2014:	0
18	Post-change -- Average Pro-rated ADIT for April Through December 2014:	0
19	8 Months Divided by 12 Months:	66.67%
20	Component of Average Pro-rated ADIT Attributable to May Through December 2014:	0
21	Average ADIT Attributable to January Through December 2014:	0
22	Total Transmission Plant In Service Net of GSU and GI Plant as a Percentage of Total Transmission Plant In Service:	
23	Transmission Plant In Service ADIT Attributable to January through December 2014:	0

Explanations:

Col. 3	Account 282 month-end ADIT from accounting records reconciling to Form1 (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 365 days.
Col. 7	Col. 4 multiplied by col. 6.
Col. 8, Line 2	Amount from col. 3, line 2.
Col. 8, Lines 3-14	Col. 8 of previous month plus col. 7 of current month.
Col. 9, Line 15	Average of col. 3, line 2 and col. 3, line 6.
Col. 9, Line 17	Line 15 multiplied by line 16.
Col. 9, Line 18	Average of the nine amounts in col. 8, lines 6 through 14.
Col. 9, Line 20	Line 18 multiplied by line 19.
Col. 9, Line 21	Line 17 plus line 20.
Col. 9, Line 22	Appendix A, Line 24 ÷ Appendix A, Line 21
Col. 9, Line 23	Line 21 multiplied by line 22. To be entered (in thousands) into Column D of the Account 282 section of Attachments 1 and 1A only for calculation of the 2014 true-up.

Attachment 1B-2014 (Continued)
2014 True-up
Sheet 2 of 4

Part 2: Account 282, General Plant

Columns 3, 4, 7, 8, and 9 are in dollars (except lines 15 and 18).

Line	(1) Year	(2) Month	(3) General Plant ADIT	(4) Activity	(5) Remaining Days	(6) Ratio	(7) Pro Rata Activity	(8) Pro-rated ADIT	(9) As Indicated by Explanation
1	2013	Dec						0	
2	2014	Jan		0	335	0.917808	0	0	
3	2014	Feb		0	307	0.841096	0	0	
4	2014	Mar		0	276	0.756164	0	0	
5	2014	Apr		0	246	0.673973	0	0	
6	2014	May		0	215	0.589041	0	0	
7	2014	Jun		0	185	0.506849	0	0	
8	2014	Jul		0	154	0.421918	0	0	
9	2014	Aug		0	123	0.336986	0	0	
10	2014	Sep		0	93	0.254795	0	0	
11	2014	Oct		0	62	0.169863	0	0	
12	2014	Nov		0	32	0.087671	0	0	
13	2014	Dec		0	1	0.002740	0	0	

14	Pre-change -- Average of December 2013 ADIT and April 2014 ADIT:	0
15	4 Months Divided by 12 Months:	33.33%
16	Component of Average ADIT Attributable to January Through April 2014:	0
17	Post-change -- Average Pro-rated ADIT for April Through December 2014:	0
18	8 Months Divided by 12 Months:	66.67%
19	Component of Average Pro-rated ADIT Attributable to May Through December 2014:	0
20	General Plant ADIT Attributable to January through December 2014:	0

Explanations:

Col. 3	Account 282 month-end ADIT from accounting records reconciling to Form1 (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 365 days.
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. 9, Line 14	Average of col. 3, line 1 and col. 3, line 5.
Col. 9, Line 16	Line 14 multiplied by line 15.
Col. 9, Line 17	Average of the nine amounts in col. 8, lines 5 through 13.
Col. 9, Line 19	Line 17 multiplied by line 18.
Col. 9, Line 20	Line 16 plus line 19. To be entered (in thousands) into Column F of the Account 282 section of Attachments 1 and 1A only for calculation of the 2014 true-up.

Attachment 1B-2014 (Continued)
2014 True-up
Sheet 3 of 4

Columns 3, 4, 7, 8, and 9 are in dollars (except lines 15 and 18).
The column and line explanations and the use of line 20 are as described for Part 2.

Part 3: Account 282, Computer Software - Book Amortization

Line	(1) Year	(2) Month	(3) Comp Software Book Amort ADIT	(4) Activity	(5) Remaining Days	(6) Ratio	(7) Pro Rata Activity	(8) Pro-rated ADIT	(9) As Indicated by Explanation
1	2013	Dec						0	
2	2014	Jan		0	335	0.917808	0	0	
3	2014	Feb		0	307	0.841096	0	0	
4	2014	Mar		0	276	0.756164	0	0	
5	2014	Apr		0	246	0.673973	0	0	
6	2014	May		0	215	0.589041	0	0	
7	2014	Jun		0	185	0.506849	0	0	
8	2014	Jul		0	154	0.421918	0	0	
9	2014	Aug		0	123	0.336986	0	0	
10	2014	Sep		0	93	0.254795	0	0	
11	2014	Oct		0	62	0.169863	0	0	
12	2014	Nov		0	32	0.087671	0	0	
13	2014	Dec		0	1	0.002740	0	0	

Line		
14	Pre-change -- Average of December 2013 ADIT and April 2014 ADIT:	0
15	4 Months Divided by 12 Months:	33.33%
16	Component of Average ADIT Attributable to January Through April 2014:	0
17	Post-change -- Average Pro-rated ADIT for April Through December 2014:	0
18	8 Months Divided by 12 Months:	66.67%
19	Component of Average Pro-rated ADIT Attributable to May Through December 2014:	0
20	Computer Software - Book Amortization ADIT Attributable to January through December 2014:	0

Attachment 1B-2014 (Continued)
2014 True-up
Sheet 4 of 4

Columns 3, 4, 7, 8, and 9 are in dollars (except lines 15 and 18).
The column and line explanations and the use of line 20 are as described for Part 2.

Part 4: Account 282, Computer Software - Tax Amortization

Line	(1) Year	(2) Month	(3) Comp Software Tax Amort ADIT	(4) Activity	(5) Remaining Days	(6) Ratio	(7) Pro Rata Activity	(8) Pro-rated ADIT	(9) As Indicated by Explanation
1	2013	Dec						0	
2	2014	Jan		0	335	0.917808	0	0	
3	2014	Feb		0	307	0.841096	0	0	
4	2014	Mar		0	276	0.756164	0	0	
5	2014	Apr		0	246	0.673973	0	0	
6	2014	May		0	215	0.589041	0	0	
7	2014	Jun		0	185	0.506849	0	0	
8	2014	Jul		0	154	0.421918	0	0	
9	2014	Aug		0	123	0.336986	0	0	
10	2014	Sep		0	93	0.254795	0	0	
11	2014	Oct		0	62	0.169863	0	0	
12	2014	Nov		0	32	0.087671	0	0	
13	2014	Dec		0	1	0.002740	0	0	

14 Pre-change -- Average of December 2013 ADIT and April 2014 ADIT: 0
15 4 Months Divided by 12 Months: 33.33%
16 Component of Average ADIT Attributable to January Through April 2014: 0

17 Post-change -- Average Pro-rated ADIT for April Through December 2014: 0
18 8 Months Divided by 12 Months: 66.67%
19 Component of Average Pro-rated ADIT Attributable to May Through December 2014: 0

20 Computer Software - Tax Amortization ADIT Attributable to January through December 2014: 0

Virginia Electric and Power Company

ATTACHMENT H-16A

Attachment 2 - Taxes Other Than Income Worksheet

2016 Projection (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)	$ 41,191	100.0000%	$ 41,191
1a	Other Plant Related Taxes	0	19.1906%	-
2				-
3				-
4				-
5				-
				-
	Total Plant Related	$ 41,191		$ 41,191
	Labor Related		***Wages & Salary Allocator***	
6	Federal FICA & Unemployment & State Unemployment	$ 42,673		
	Total Labor Related	$ 42,673	6.8537%	$ 2,925
	Other Included		***Gross Plant Allocator***	
7	Sales and Use Tax	$ -		
	Total Other Included	$ -	19.1906%	$ -
	Total Included	$ 83,863		$ 44,115
	Currently Excluded			
8	Business and Occupation Tax - West Virginia	$ 19,244		
9	Gross Receipts Tax	0		
10	IFTA Fuel Tax	0		
11	Property Taxes - Other	169,121		
12	Property Taxes - Generator Step-Ups and Interconnects	1,861		
13	Sales and Use Tax - not allocated to Transmission	4,795		
14	Sales and Use Tax - Retail	0		
15	Other	20,616		
16		0		
17		0		
18		0		
19		0		
20		0		
21	Total "Other" Taxes (included on p. 263)	$ 215,637		
22	Total "Taxes Other Than Income Taxes" - acct 408.10 (p. 114.14)	$ 299,500		
23	Difference	$ (83,863)		

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
2016 - Projection

Directly Assigned Property Taxes	$	212,173
Production Property Tax		86,756
Transmission Property Tax		41,071
GSU/Interconnect Facilities		1,861
Distribution Property tax		80,744
General Property Tax		1,741
Total check		212,173

Allocation of General Property Tax to Transmission

General Property Tax	$	1,741
Wages & Salary Allocator		6.8537%
Trans General		119

Total Transmission Property Taxes

Transmission	$	41,071
General		119
Total Transmission Property Taxes	$	41,191

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 3 - Revenue Credit Workpaper
2016 - Projection (000's)

			Transmission Related	Production/Other Related	Total
	Account 454 - Rent from Electric Property				
1	Rent from Electric Property - Transmission Related (Note 3)		8,276		8,276
2	Total Rent Revenues	(Sum Lines 1)	8,276	-	8,276
	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)		1,980		1,980
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)		6,240		6,240
9	Revenues from Directly Assigned Transmission Facility Charges (Note 2)		2,749		2,749
10	Rent or Attachment Fees associated with Transmission Facilities (Note 3)				-
11	Gross Revenue Credits (Accounts 454 and 456)	(Sum Lines 2-10)	19,245	-	19,245
12	Less line 14g		(9,640)	-	(9,640)
13	Total Revenue Credits		9,605	-	9,605
	Revenue Adjustment to Determine Revenue Credit				
14a	Revenues included in lines 1-11 which are subject to 50/50 sharing. (Lines 1 + 8 + 10)		14,516	-	14,516
14b	Costs associated with revenues in line 14a		4,765	-	4,765
14c	Net Revenues (14a - 14b)		9,751	-	9,751
14d	50% Share of Net Revenues (14c / 2)		4,876	-	4,876
14e	Cost associated with revenues in line 14b that are included in FERC accounts recovered through the formula times the allocator used to functionalize the amounts in the FERC account to the transmission service at issue		-	-	-
14f	Net Revenue Credit (14d + 14e)		4,876	-	4,876
14g	Line 14f less line 14a		(9,640)	-	(9,640)

Revenue Adjustment to Determine Revenue Credit

Note 1: All revenues related to transmission that are received as a transmission owner (*i.e*., not received as a LSE), for which the cost of the service is recovered under this formula, except as specifically provided for elsewhere in this Attachment or elsewhere in the formula will be included as a revenue credit or included in the peak on line 169 of Appendix A.

Note 2: If the costs associated with the Directly Assigned Transmission Facility Charges are included in the Rates, the associated revenues are included in the Rates. If the costs associated with the Directly Assigned Transmission Facility Charges are not included in the Rates, the associated revenues are not included in the Rates.

Note 3: Ratemaking treatment for the following specified secondary uses of transmission assets: (1) right-of-way leases and leases for space on transmission facilities for telecommunications; (2) transmission tower licenses for wireless antennas; (3) right-of-way property leases for farming, grazing or nurseries; (4) licenses of intellectual property (including a portable oil degasification process and scheduling software); and (5) transmission maintenance and consulting services (including energized circuit maintenance, high-voltage substation maintenance, safety training, transformer oil testing, and circuit breaker testing) to other utilities and large customers (collectively, products). VEPCO will retain 50% of net revenues consistent with *Pacific Gas and Electric Company*, 90 FERC ¶ 61,314. In order to use lines 14a - 14g, the utility must track in separate subaccounts the revenues and costs associated with each secondary use (except for the cost of the associated income taxes).

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

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 4 - Calculation of 100 Basis Point Increase in ROE
2016 - Projection (000's)

	Return and Taxes with Basis Point increase in ROE			
A	Basis Point increase in ROE and Income Taxes		(Line 130 + 140)	616,334
B	100 Basis Point increase in ROE	(Note J from Appendix A)	Fixed	1.00%
Return Calculation				
Line Ref.				
62	Rate Base		(Line 44 + 61)	4,656,127
	Long Term Interest			
104	**Long Term Interest**		p117.62c through 67c	423,948
105	Less LTD Interest on Securitization Bonds	(Note P)	Attachment 8	0
106	Long Term Interest		(Line 104 - 105)	423,948
107	Preferred Dividends	enter positive	p118.29c	10,867
	Common Stock			
108	Proprietary Capital		p112.16c,d/2	10,055,447
109	Less Preferred Stock	enter negative	(Line 117)	-129,507
110	Less Account 219 - Accumulated Other Comprehensive Income	enter negative	p112.15c,d/2	-49,044
111	Common Stock		(Sum Lines 108 to 110)	9,876,896
	Capitalization			
112	Long Term Debt		p112.24c,d/2	8,484,459
113	Less Loss on Reacquired Debt	enter negative	p111.81c,d/2	-6,305
114	Plus Gain on Reacquired Debt	enter positive	p113.61c,d/2	4,032
115	Less LTD on Securitization Bonds	enter negative	Attachment 8	0
116	Total Long Term Debt		(Sum Lines 112 to 115)	8,482,187
117	Preferred Stock		p112.3c,d/2	129,507
118	Common Stock		(Line 111)	9,876,896
119	Total Capitalization		(Sum Lines 116 to 118)	18,488,589
120	Debt %	Total Long Term Debt	(Line 116 / 119)	45.9%
121	Preferred %	Preferred Stock	(Line 117 / 119)	0.7%
122	Common %	Common Stock	(Line 118 / 119)	53.4%
123	Debt Cost	Total Long Term Debt	(Line 106 / 116)	0.0500
124	Preferred Cost	Preferred Stock	(Line 107 / 117)	0.0839
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)	0.0229
127	Weighted Cost of Preferred	Preferred Stock	(Line 121 * 124)	0.0006
128	Weighted Cost of Common	Common Stock	(Line 122 * 125)	0.0662
129	Total Return (R)		**(Sum Lines 126 to 128)**	**0.0898**
130	Investment Return = Rate Base * Rate of Return		**(Line 62 * 129)**	**417,937**
Return Calculation				
	Income Tax Rates			
131	FIT=Federal Income Tax Rate			0.3500
132	SIT=State Income Tax Rate or Composite			0.0609
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)} =		0.3896
135	T/ (1-T)			0.6383
	ITC Adjustment			
136	Amortized Investment Tax Credit	enter negative	Attachment 1	-137
137	T/(1-T)		(Line 135)	0.6383
138	**ITC Adjustment Allocated to Transmission**	(Note I from Appendix A)	(Line 136 * (1 + 137))	**-225**
139	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		198,621
140	**Total Income Taxes**		**(Line 138 + 139)**	**198,396**

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 5 - Cost Support
2016 - Projection

Electric / Non-electric Cost Support

				Previous Year	Current Year														
Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Form 1 Dec	Average	Non-electric Portion	Details
	Plant Allocation Factors																		
8	Electric Plant in Service	(Notes A & Q)	p207.104g/Plant-Acc. Deprc Wkst	33,659,818	33,876,186	34,004,135	34,089,904	34,224,278	34,436,244	35,782,884	36,006,630	36,085,624	36,157,797	36,296,003	36,512,232	36,713,399	35,218,856	0	
15	Accumulated Depreciation (Total Electric Plant)	(Notes A & Q)	p219.29c	11,996,826	12,076,936	12,156,382	12,233,600	12,313,903	12,397,591	12,481,125	12,565,722	12,650,691	12,732,846	12,816,358	12,901,238	12,988,875	12,485,546	0	
12	Accumulated Intangible Amortization	(Notes A & Q)	p200.21c	87,473	89,309	91,145	92,981	94,817	96,653	98,489	100,325	102,161	103,997	105,832	107,668	109,504	98,489	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	6,776,130	6,806,632	6,808,126	6,833,146	6,842,539	6,913,685	7,028,585	7,189,109	7,204,852	7,216,946	7,295,287	7,308,538	7,412,784	7,048,951	0	
15	Generator Step-Ups		Trans. Input Sht	304,755	304,755	304,755	304,755	304,755	304,755	304,755	304,755	304,755	304,755	304,755	304,755	304,755	304,755	0	
23	Generator Interconnect Facilities		Input Sht	49,413	49,413	49,413	49,413	49,413	49,413	49,413	49,413	49,413	49,413	49,413	49,413	49,413	49,413		
25	General & Intangible		p205.5.g & p207.99.g/G&I Wksht	927,329	928,273	929,217	930,161	931,105	932,049	932,993	933,937	934,881	935,825	936,769	937,713	938,658	932,993	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	1,137,674	1,147,675	1,157,707	1,167,765	1,177,856	1,188,025	1,198,375	1,208,992	1,219,780	1,230,594	1,241,497	1,252,488	1,263,594	1,199,386	0	
33	Transmission Accumulated Depreciation - Generator Step-Ups		GSU Input Sht	58,838	59,572	60,306	61,041	61,775	62,510	63,244	63,979	64,713	65,447	66,182	66,916	67,651	63,244	0	
34	Transmission Accumulated Depreciation - Interconnection Facilities		Input Sht	7,793	7,912	8,031	8,150	8,269	8,388	8,507	8,626	8,746	8,865	8,984	9,103	9,222	8,507		
36	Accumulated General Depreciation	(Notes A & Q)	p219.28.b	333,816	334,156	334,496	334,836	335,175	335,515	335,855	336,195	336,535	336,875	337,215	337,554	337,894	335,855	0	
	Materials and Supplies																		
50	Undistributed Stores Exp	(Notes A & R)	p227.6c & 16.c	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	Respondent is Electric Utility only.
	Allocated General & Common Expenses																		
68	Common Plant O&M	(Note A)	p356	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0	
	Depreciation Expense																Electric		
86	Depreciation-Transmission	(Note A)	p336.7.b&c														162,949	0	
91	Depreciation-General	(Note A)															24,447	0	
92	Depreciation-Intangible	(Note A)	p336.1d&e/Attachment 5														22,032	0	Respondent is Electric Utility only.
87	Depreciation - Generator Step-Ups																8,813	0	
88	Depreciation - Interconnection Facilities																1,429	0	
96	Common Depreciation - Electric Only	(Note A)	p336.11.b														-	0	
97	Common Amortization - Electric Only	(Note A)	p356 or p336.11d														-	0	

O&M Expenses

				Previous Year	Current Year														
Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Form 1 Dec	Totals	Non-electric Portion	Details
63	Transmission O&M	(Note A)	p321.112.b/Trans. Input Sht	-	(241)	1,082	1,001	550	477	367	1,161	935	1,263	2,171	378	1,900	11,045	12,333	
64	Generator Step-Ups		Input Sheet		-	-	-	-	-	-	-	-	-	-	-	-	61	0	
65	Transmission by Others		p321.96.b	-	(5,701)	(5,701)	(5,701)	(5,701)	(5,701)	(5,701)	(5,701)	(5,701)	(5,701)	(5,701)	(5,701)	(5,701)	(68,414)	0	

Wages & Salary

				Previous Year	Current Year														
Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Form 1 Dec	Totals	Non-electric Portion	Details
4	Total Wage Expense	(Note A)	p354.28b/Trans. Wksht														611,279	0	
5	Total A&G Wages Expense	(Note A)	p354.27b/Trans. Wksht														89,584	0	
1	Transmission Wages	(Note A)	p354.21b/Trans. Wksht														35,758	0	
2	Generator Step-Ups		Trans. Wksht														3	0	

Transmission / Non-transmission Cost Support

				Previous Year	Current Year														Specific identification
Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Form 1 Dec	Average	Non-transmission Related	Details
																			Specific identification based on plant records. The following plant investments are included:
30	Plant Held for Future Use (Including Land)	(Notes C & Q)	p214.47.d	11,656	11,656	11,656	11,656	11,656	11,656	11,656	11,656	11,656	11,656	11,656	11,656	11,656	11,656	4,473	
																Form 1 Amount	Transmission Related	Non-transmission Related	
																11,656	7,183	4,473	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	$3,088	3,088	See Form 1

Regulatory Expense Related to Transmission Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1 Amount	Transmission Related	Non-transmission Related	Details
	Allocated General & Common Expenses						
71	Less Regulatory Commission Exp Account 928	(Note E)	p323.189b/Attachment 5	$ 28,622		28,622	See FERC Form 1 pages 350-351.
	Directly Assigned A&G						
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b/Attachment 5		0		

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 5 - Cost Support
2016 - Projection

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	3,817	-	3,817	

MultiState Workpaper

Line #s	Descriptions	Notes	Page #'s & Instructions	State 1	State 2	State 3	State 4	State 5	Details
	Income Tax Rates								
				Va	NC	Wva			Enter Calculation
132	SIT=State Income Tax Rate or Composite	(Note I)		5.59%	0.34%	0.17%			6.09%

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	3,817	0	3,817	-

Excluded Plant Cost Support

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

Instructions:

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

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

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

Transmission Related Account 242 Reserves

Line #s	Descriptions	Notes	Page #'s & Instructions	Beginning Year Balance	End of Year Balance	Average Balance	Allocation	Transmission Related		Details
47	Transmission Related Account 242 Reserves (exclude current year environmental site related reserves)			Enter $	Enter $			Amount		
	Directly Assignable to Transmission			$ 6,466	$ 7,700	$ 7,083	100%	7,083		
	Labor Related, General plant related or Common Plant related			$ 302	$ 469	$ 386	6.854%	26		
	Plant Related			$ 5,865	$ 6,073	$ 5,969	19.19%	1,145		
	Other			$ 164,425	$ 131,186	$ 147,805	0.00%	-		
	Total Transmission Related Reserves			$ -	$ -	$ -		8,255	To line 47	

Prepayments

Line #s	Descriptions	Notes	Page #'s & Instructions	Beginning Year Balance	End of Year Balance	Average Balance Before Exclusion	Fixed Prepayments Exclusion Amount [1]			To Line 48	Description of the Prepayments
48	Prepayments										
	Wages & Salary Allocator								6.854%		
	Pension Liabilities, if any, in Account 242			$ 70	$ 35			$ 53	6.854%	4	
				$ -	$ -			$ -			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	$ 35,011	$ 33,822	$ 34,417	$ 3,980	$ 30,437	6.854%	2,359	Projections.
	Prepaid Pensions if not included in Prepayments							$ -	6.854%	-	

[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	$ -

Virginia Electric and Power Company
ATTACHMENT H-16A
Attachment 5 - Cost Support
2016 - Projection

Interest on Outstanding Network Credits Cost Support

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

Facility Credits under Section 30.9 of the PJM OATT.

Line #s	Descriptions	Notes	Page #'s & Instructions	Amount	Description & PJM Documentation
	Revenue Requirement				
165	Facility Credits under Section 30.9 of the PJM OATT.			2,479	ODEC/NCEMC Transmission Charges

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	21,651.0	

A&G Expenses - Other Post Employment Benefits

Line #s	Descriptions	Notes	Page #'s & Instructions	Amount
	Total A&G Expenses		p323.197b	359,931
	Less OPEB Current Year			23,418
	Plus: Stated OPEB		Fixed (from FERC accepted § 205 Filing)	(15,540)
69	Current Year Total A&G Expenses			367,809

Interest on Long-Term Debt

Line #s	Descriptions	Notes	Page #'s & Instructions	Amount
	Interest on Long-Term Debt		p117.62c through 67c	424,819
	Less Interest on Short-Term Debt Included in Account 430			(871)
104	Total Interest on Long-Term Debt			423,948

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.	676,980.28
B	ATRR based on projected costs included for the previous calendar year but excludes the true-up adjustment.	659,928.29
C	Difference (A-B)	17,052
D	Future Value Factor (1+i)^24	1.06685
E	True-up Adjustment (C*D)	18,192

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

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

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

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

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

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

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

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

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

Summary of Formula Rate Process including True-Up Adjustment

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

---

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

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

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

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

1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if not a CIAC**			
		Formula Line		
3	A	154	Net Plant Carrying Charge without Depreciation	12.8790%
4	B	161	Net Plant Carrying Charge with 100 Basis Point increase in ROE without Depreciation	13.6110%
5	C		Line B less Line A	0.7320%
6	**FCR if a CIAC**			
7	D	155	Net Plant Carrying Charge without Depreciation, Return, or Income Taxes	2.5401%

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

8 **The FCR resulting from Formula is for the rate period only.**

9 **Therefore actual revenues collected or the lack of revenues collected in other years are not applicable. Depreciation will be calculated for each project using the applicable Life input in effect during the months of each calendar year the project was in service.**

10			10	Details		**Project A**				**Project A-1**			
11	Schedule 12	(Yes or No)	11	Schedule 12	(Yes or No)	Yes	b0217			Yes	b0217		
12	Life		12	Life		43	Upgrade Mt.Storm - Doubs 500 kV			43	Upgrade Mt.Storm - Doubs 500 kV		
13	FCR W/O incentive	Line 3	13	FCR W/O incentive	Line 3	12.8790%				12.8790%	Replace Capacitors		
14	Incentive Factor (Basis Points /100)		14	Incentive Factor (Basis Points /100)		0				0			
15	FCR W incentive L.13 +(L.14*L.5)		15	FCR W incentive L.13 +(L.14*L.5)		12.8790%				12.8790%			
16	Investment		16	Investment		1,200,114				913,159			
17	Annual Depreciation Exp		17	Annual Depreciation Exp		27,910				21,236			
18	In Service Month (1-12)		18	In Service Month (1-12)		12				7			
19			19		**Invest Yr**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006	20	W / O incentive	2006								
21	W incentive	2006	21	W incentive	2006								
22	W / O incentive	2007	22	W / O incentive	2007	1,200,114	980	1,199,134					
23	W incentive	2007	23	W incentive	2007	1,200,114	980	1,199,134					
24	W / O incentive	2008	24	W / O incentive	2008	1,199,134	23,532	1,175,602					
25	W incentive	2008	25	W incentive	2008	1,199,134	23,532	1,175,602					
26	W / O incentive	2009	26	W / O incentive	2009	1,175,602	23,532	1,152,070					
27	W incentive	2009	27	W incentive	2009	1,175,602	23,532	1,152,070					
28	W / O incentive	2010	28	W / O incentive	2010	1,152,070	23,532	1,128,539					
29	W incentive	2010	29	W incentive	2010	1,152,070	23,532	1,128,539					
30	W / O incentive	2011	30	W / O incentive	2011	1,128,539	23,532	1,105,007					
31	W incentive	2011	31	W incentive	2011	1,128,539	23,532	1,105,007					
32	W / O incentive	2012	32	W / O incentive	2012	1,105,007	23,532	1,081,475					
33	W incentive	2012	33	W incentive	2012	1,105,007	23,532	1,081,475					
34	W / O incentive	2013	34	W / O incentive	2013	1,081,475	26,815	1,054,660					
35	W incentive	2013	35	W incentive	2013	1,081,475	26,815	1,054,660					
36	W / O incentive	2014	36	W / O incentive	2014	1,054,660	27,910	1,026,751		913,159	9,733	903,426	
37	W incentive	2014	37	W incentive	2014	1,054,660	27,910	1,026,751		913,159	9,733	903,426	
38	W / O incentive	2015	38	W / O incentive	2015	1,026,751	27,910	998,841		903,426	21,236	882,189	
39	W incentive	2015	39	W incentive	2015	1,026,751	27,910	998,841		903,426	21,236	882,189	
40	W / O incentive	2016	40	W / O incentive	2016	998,841	27,910	970,931	154,753	882,189	21,236	860,953	133,486
41	W incentive	2016	41	W incentive	2016	998,841	27,910	970,931	154,753	882,189	21,236	860,953	133,486

Lines continue as new rate years are added.

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

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

A	A	Projected Revenue Requirement without Incentive for Previous Calendar Year*	268,389	
B	B	Projected Revenue Requirement with Incentive for Previous Calendar Year*	268,389	
C	C	Actual Revenue Requirement without Incentive for Previous Calendar Year *	167,020	65,380
D	D	Actual Revenue Requirement with Incentive for Previous Calendar Year *	167,020	65,380
E	E	True-Up Adjustment Before Interest without Incentive for Previous Calendar Year (C-A)	(101,369)	65,380
F	F	True-Up Adjustment Before Interest with Incentive for Previous Calendar Year (B-D)	(101,369)	65,380
G	G	Future Value Factor (1+i)^24 months from Attachment 6	1.06685	1.06685
H	H	True-Up Adjustment without Incentive (E*G)	(108,146)	69,751
I	I	True-Up Adjustment with Incentive (F*G)	(108,146)	69,751

* 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	46,608	203,237
W incentive	W incentive	46,608	203,237

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

10			Project B				Project B-1				Project E			
11	Schedule 12 (Yes or No)		Yes	b0222			Yes	b0222			Yes	B0226		
12	Life		43	Install 150 MVAR capacitor			43	Install 150 MVAR capacitor			43	Install 500/230 kV transformer at		
13	FCR W/O incentive Line 3		12.8790%	at Loudoun			12.8790%	at Loudoun - Replacement of			12.8790%	Clifton and Clifton 500 KV 150 MVAR		
14	Incentive Factor (Basis Points /100)		0				0	Circuit Breaker			0	capacitor		
15	FCR W incentive L.13 +(L.14*L.5)		12.8790%				12.8790%				12.8790%			
16	Investment		1,076,817				591,996				8,135,715			
17	Annual Depreciation Exp		25,042				13,767				189,203			
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	1,076,817	6,158	1,070,659									
21	W incentive	2006	1,076,817	6,158	1,070,659									
22	W / O incentive	2007	1,070,659	21,114	1,049,545						8,135,715	59,821	8,075,894	
23	W incentive	2007	1,070,659	21,114	1,049,545						8,135,715	59,821	8,075,894	
24	W / O incentive	2008	1,049,545	21,114	1,028,431						8,075,894	159,524	7,916,370	
25	W incentive	2008	1,049,545	21,114	1,028,431						8,075,894	159,524	7,916,370	
26	W / O incentive	2009	1,028,431	21,114	1,007,317						7,916,370	159,524	7,756,846	
27	W incentive	2009	1,028,431	21,114	1,007,317						7,916,370	159,524	7,756,846	
28	W / O incentive	2010	1,007,317	21,114	986,202						7,756,846	159,524	7,597,322	
29	W incentive	2010	1,007,317	21,114	986,202						7,756,846	159,524	7,597,322	
30	W / O incentive	2011	986,202	21,114	965,088						7,597,322	159,524	7,437,798	
31	W incentive	2011	986,202	21,114	965,088						7,597,322	159,524	7,437,798	
32	W / O incentive	2012	965,088	21,114	943,974						7,437,798	159,524	7,278,274	
33	W incentive	2012	965,088	21,114	943,974						7,437,798	159,524	7,278,274	
34	W / O incentive	2013	943,974	24,060	919,914		591,996	9,752	582,244		7,278,274	181,783	7,096,491	
35	W incentive	2013	943,974	24,060	919,914		591,996	9,752	582,244		7,278,274	181,783	7,096,491	
36	W / O incentive	2014	919,914	25,042	894,872		582,244	13,767	568,477		7,096,491	189,203	6,907,289	
37	W incentive	2014	919,914	25,042	894,872		582,244	13,767	568,477		7,096,491	189,203	6,907,289	
38	W / O incentive	2015	894,872	25,042	869,830		568,477	13,767	554,709		6,907,289	189,203	6,718,086	
39	W incentive	2015	894,872	25,042	869,830		568,477	13,767	554,709		6,907,289	189,203	6,718,086	
40	W / O incentive	2016	869,830	25,042	844,787	135,455	554,709	13,767	540,942	84,322	6,718,086	189,203	6,528,883	1,042,243
41	W incentive	2016	869,830	25,042	844,787	135,455	554,709	13,767	540,942	84,322	6,718,086	189,203	6,528,883	1,042,243
A						229,025								1,149,410
B						229,025								1,149,410
C						146,333				90,676				1,125,144
D						146,333				90,676				1,125,144
E						(82,692)				90,676				(24,266)
F						(82,692)				90,676				(24,266)
G						1.06685				1.06685				1.06685
H						(88,220)				96,738				(25,888)
I						(88,220)				96,738				(25,888)
	W / O incentive					47,236				181,060				1,016,355
	W incentive					47,236				181,060				1,016,355

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

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

10			**Project G-1**		**Project G-2**		**Project H-1**	
11	Schedule 12	(Yes or No)	Yes	B0403	Yes	B0403	Yes	b0328.1
12	Life		43	2nd Dooms 500/230 kV transformer	43	2nd Dooms 500/230 kV transformer	43	Build new Meadowbrook-Loudon 500kV circuit
13	FCR W/O incentive	Line 3	12.8790%	addition	12.8790%	addition	12.8790%	(30 of 50 miles)
14	Incentive Factor (Basis Points /100)		0		0		1.5	
15	FCR W incentive L.13 +(L.14*L.5)		12.8790%		12.8790%	Spare Transformer Addition	13.9770%	line 2101 v11
16	Investment		7,200,504		2,414,294		21,850,320	
17	Annual Depreciation Exp		167,454		56,146		508,147	
18	In Service Month (1-12)		11		4		6	

19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007	7,200,504	17,648	7,182,856									
23	W incentive	2007	7,200,504	17,648	7,182,856									
24	W / O incentive	2008	7,182,856	141,186	7,041,669									
25	W incentive	2008	7,182,856	141,186	7,041,669									
26	W / O incentive	2009	7,041,669	141,186	6,900,483		2,414,294	33,532	2,380,762		21,850,320	232,070	21,618,250	
27	W incentive	2009	7,041,669	141,186	6,900,483		2,414,294	33,532	2,380,762		21,850,320	232,070	21,618,250	
28	W / O incentive	2010	6,900,483	141,186	6,759,297		2,380,762	47,339	2,333,423		21,618,250	428,438	21,189,812	
29	W incentive	2010	6,900,483	141,186	6,759,297		2,380,762	47,339	2,333,423		21,618,250	428,438	21,189,812	
30	W / O incentive	2011	6,759,297	141,186	6,618,110		2,333,423	47,339	2,286,084		21,189,812	428,438	20,761,374	
31	W incentive	2011	6,759,297	141,186	6,618,110		2,333,423	47,339	2,286,084		21,189,812	428,438	20,761,374	
32	W / O incentive	2012	6,618,110	141,186	6,476,924		2,286,084	47,339	2,238,745		20,761,374	428,438	20,332,937	
33	W incentive	2012	6,618,110	141,186	6,476,924		2,286,084	47,339	2,238,745		20,761,374	428,438	20,332,937	
34	W / O incentive	2013	6,476,924	160,887	6,316,037		2,238,745	53,945	2,184,800		20,332,937	488,220	19,844,717	
35	W incentive	2013	6,476,924	160,887	6,316,037		2,238,745	53,945	2,184,800		20,332,937	488,220	19,844,717	
36	W / O incentive	2014	6,316,037	167,454	6,148,584		2,184,800	56,146	2,128,654		19,844,717	508,147	19,336,570	
37	W incentive	2014	6,316,037	167,454	6,148,584		2,184,800	56,146	2,128,654		19,844,717	508,147	19,336,570	
38	W / O incentive	2015	6,148,584	167,454	5,981,130		2,128,654	56,146	2,072,508		19,336,570	508,147	18,828,423	
39	W incentive	2015	6,148,584	167,454	5,981,130		2,128,654	56,146	2,072,508		19,336,570	508,147	18,828,423	
40	W / O incentive	2016	5,981,130	167,454	5,813,676	926,982	2,072,508	56,146	2,016,361	319,450	18,828,423	508,147	18,320,276	2,900,343
41	W incentive	2016	5,981,130	167,454	5,813,676	926,982	2,072,508	56,146	2,016,361	319,450	18,828,423	508,147	18,320,276	3,104,286

A	1,005,385	347,655	3,156,307
B	1,005,385	347,655	3,380,734
C	1,000,525	344,436	3,126,824
D	1,000,525	344,436	3,342,818
E	(4,860)	(3,219)	(29,482)
F	(4,860)	(3,219)	(37,915)
G	1.06685	1.06685	1.06685
H	(5,185)	(3,434)	(31,453)
I	(5,185)	(3,434)	(40,450)

W / O incentive	921,797	316,015	2,868,890
W incentive	921,797	316,015	3,063,836

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

10			**Project H-2**				**Project H-3**				**Project H-4**			
11	Schedule 12	(Yes or No)	Yes	b0328.1			Yes	b0328.1			Yes	b0328.1		
12	Life		43	Build new Meadowbrook-Loudon 500kV circuit			43	Build new Meadowbrook-Loudon 500kV circuit			43	Build new Meadowbrook-Loudon 500kV circuit		
13	FCR W/O incentive	Line 3	12.8790%	(30 of 50 miles)			12.8790%	(30 of 50 miles)			12.8790%	(30 of 50 miles)		
14	Incentive Factor (Basis Points /100)		1.5				1.5				1.5			
15	FCR W incentive L.13 +(L.14*L.5)		13.9770%	Line 2030 & 559 v12 & v13			13.9770%	Line 580 - Phase 1			13.9770%	Line 124		
16	Investment		45,089,209				13,581,000				11,224,282			
17	Annual Depreciation Exp		1,048,586				315,837				261,030			
18	In Service Month (1-12)		12				7				4			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009	45,089,209	36,838	45,052,371									
27	W incentive	2009	45,089,209	36,838	45,052,371									
28	W / O incentive	2010	45,052,371	884,102	44,168,269		13,581,000	122,051	13,458,949		11,224,282	155,893	11,068,389	
29	W incentive	2010	45,052,371	884,102	44,168,269		13,581,000	122,051	13,458,949		11,224,282	155,893	11,068,389	
30	W / O incentive	2011	44,168,269	884,102	43,284,167		13,458,949	266,294	13,192,654		11,068,389	220,084	10,848,305	
31	W incentive	2011	44,168,269	884,102	43,284,167		13,458,949	266,294	13,192,654		11,068,389	220,084	10,848,305	
32	W / O incentive	2012	43,284,167	884,102	42,400,065		13,192,654	266,294	12,926,360		10,848,305	220,084	10,628,221	
33	W incentive	2012	43,284,167	884,102	42,400,065		13,192,654	266,294	12,926,360		10,848,305	220,084	10,628,221	
34	W / O incentive	2013	42,400,065	1,007,465	41,392,600		12,926,360	303,451	12,622,909		10,628,221	250,793	10,377,428	
35	W incentive	2013	42,400,065	1,007,465	41,392,600		12,926,360	303,451	12,622,909		10,628,221	250,793	10,377,428	
36	W / O incentive	2014	41,392,600	1,048,586	40,344,014		12,622,909	315,837	12,307,072		10,377,428	261,030	10,116,398	
37	W incentive	2014	41,392,600	1,048,586	40,344,014		12,622,909	315,837	12,307,072		10,377,428	261,030	10,116,398	
38	W / O incentive	2015	40,344,014	1,048,586	39,295,427		12,307,072	315,837	11,991,234		10,116,398	261,030	9,855,368	
39	W incentive	2015	40,344,014	1,048,586	39,295,427		12,307,072	315,837	11,991,234		10,116,398	261,030	9,855,368	
40	W / O incentive	2016	39,295,427	1,048,586	38,246,841	6,041,933	11,991,234	315,837	11,675,397	1,839,854	9,855,368	261,030	9,594,338	1,513,497
41	W incentive	2016	39,295,427	1,048,586	38,246,841	6,467,631	11,991,234	315,837	11,675,397	1,969,781	9,855,368	261,030	9,594,338	1,620,273
A						6,574,435				2,001,759				1,646,770
B						7,042,589				2,144,539				1,764,147
C						6,511,445				1,982,030				1,630,733
D						6,962,033				2,119,461				1,743,709
E						(62,991)				(19,729)				(16,038)
F						(80,557)				(25,078)				(20,438)
G						1.06685				1.06685				1.06685
H						(67,202)				(21,048)				(17,110)
I						(85,942)				(26,754)				(21,804)
	W / O incentive					5,974,731				1,818,806				1,496,387
	W incentive					6,381,689				1,943,026				1,598,469

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

10			**Project H-5**				**Project H-6**				**Project H-7**			
11	Schedule 12	(Yes or No)	Yes	b0328.1			Yes	b0328.1			Yes	b0328.1		
12	Life		43	Build new Meadowbrook-Loudon 500kV circuit			43	Build new Meadowbrook-Loudon 500kV circuit			43	Build new Meadowbrook-Loudon 500kV circuit		
13	FCR W/O incentive	Line 3	12.8790%	(30 of 50 miles)			12.8790%	(30 of 50 miles)			12.8790%	(30 of 50 miles)		
14	Incentive Factor (Basis Points /100)		1.5				1.5				1.5			
15	FCR W incentive L.13 +(L.14*L.5)		13.9770%	Line 114			13.9770%	Clevenger DP/580			13.9770%	Line 580 - Phase 2		
16	Investment		14,655,559				16,900,800				11,362,770			
17	Annual Depreciation Exp		340,827				393,042				264,250			
18	In Service Month (1-12)		6				9				12			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010	14,655,559	155,655	14,499,904		16,900,800	96,655	16,804,145		11,362,770	9,283	11,353,487	
29	W incentive	2010	14,655,559	155,655	14,499,904		16,900,800	96,655	16,804,145		11,362,770	9,283	11,353,487	
30	W / O incentive	2011	14,499,904	287,364	14,212,540		16,804,145	331,388	16,472,757		11,353,487	222,799	11,130,687	
31	W incentive	2011	14,499,904	287,364	14,212,540		16,804,145	331,388	16,472,757		11,353,487	222,799	11,130,687	
32	W / O incentive	2012	14,212,540	287,364	13,925,176		16,472,757	331,388	16,141,369		11,130,687	222,799	10,907,888	
33	W incentive	2012	14,212,540	287,364	13,925,176		16,472,757	331,388	16,141,369		11,130,687	222,799	10,907,888	
34	W / O incentive	2013	13,925,176	327,461	13,597,715		16,141,369	377,628	15,763,740		10,907,888	253,888	10,654,000	
35	W incentive	2013	13,925,176	327,461	13,597,715		16,141,369	377,628	15,763,740		10,907,888	253,888	10,654,000	
36	W / O incentive	2014	13,597,715	340,827	13,256,888		15,763,740	393,042	15,370,698		10,654,000	264,250	10,389,750	
37	W incentive	2014	13,597,715	340,827	13,256,888		15,763,740	393,042	15,370,698		10,654,000	264,250	10,389,750	
38	W / O incentive	2015	13,256,888	340,827	12,916,061		15,370,698	393,042	14,977,656		10,389,750	264,250	10,125,499	
39	W incentive	2015	13,256,888	340,827	12,916,061		15,370,698	393,042	14,977,656		10,389,750	264,250	10,125,499	
40	W / O incentive	2016	12,916,061	340,827	12,575,234	1,982,343	14,977,656	393,042	14,584,615	2,296,709	10,125,499	264,250	9,861,249	1,551,300
41	W incentive	2016	12,916,061	340,827	12,575,234	2,122,287	14,977,656	393,042	14,584,615	2,459,003	10,125,499	264,250	9,861,249	1,661,025
A						2,156,825				2,498,730				1,687,666
B						2,310,629				2,677,041				1,808,184
C						2,135,652				2,473,909				1,670,707
D						2,283,693				2,645,543				1,786,715
E						(21,174)				(24,821)				(16,959)
F						(26,937)				(31,498)				(21,469)
G						1.06685				1.06685				1.06685
H						(22,589)				(26,480)				(18,093)
I						(28,738)				(33,604)				(22,904)
	W / O incentive					1,959,754				2,270,229				1,533,208
	W incentive					2,093,550				2,425,399				1,638,121

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

10			**Project H-8**				**Project H-9**				**Project H-10**			
11	Schedule 12	(Yes or No)	Yes	b0328.1			Yes	b0328.3			Yes	b0328.4		
12	Life		43	Build new Meadowbrook-Loudon 500kV circuit			43	Upgrade Mt Storm 500 kV Substation			43	Upgrade Loudoun 500 kV Substation		
13	FCR W/O incentive	Line 3	12.8790%	(30 of 50 miles)			12.8790%				12.8790%			
14	Incentive Factor (Basis Points /100)		1.5				1.5				1.5			
15	FCR W incentive L.13 +(L.14*L.5)		13.9770%	Line 535			13.9770%				13.9770%			
16	Investment		92,112,336				13,726,825				3,123,926			
17	Annual Depreciation Exp		2,142,147				319,228				72,649			
18	In Service Month (1-12)		4				5				5			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011	92,112,336	1,279,338	90,832,998		13,726,825	168,221	13,558,604		3,123,926	38,283	3,085,643	
31	W incentive	2011	92,112,336	1,279,338	90,832,998		13,726,825	168,221	13,558,604		3,123,926	38,283	3,085,643	
32	W / O incentive	2012	90,832,998	1,806,124	89,026,874		13,558,604	269,153	13,289,451		3,085,643	61,253	3,024,389	
33	W incentive	2012	90,832,998	1,806,124	89,026,874		13,558,604	269,153	13,289,451		3,085,643	61,253	3,024,389	
34	W / O incentive	2013	89,026,874	2,058,142	86,968,732		13,289,451	306,710	12,982,741		3,024,389	69,800	2,954,589	
35	W incentive	2013	89,026,874	2,058,142	86,968,732		13,289,451	306,710	12,982,741		3,024,389	69,800	2,954,589	
36	W / O incentive	2014	86,968,732	2,142,147	84,826,585		12,982,741	319,228	12,663,512		2,954,589	72,649	2,881,939	
37	W incentive	2014	86,968,732	2,142,147	84,826,585		12,982,741	319,228	12,663,512		2,954,589	72,649	2,881,939	
38	W / O incentive	2015	84,826,585	2,142,147	82,684,437		12,663,512	319,228	12,344,284		2,881,939	72,649	2,809,290	
39	W incentive	2015	84,826,585	2,142,147	82,684,437		12,663,512	319,228	12,344,284		2,881,939	72,649	2,809,290	
40	W / O incentive	2016	82,684,437	2,142,147	80,542,290	12,653,158	12,344,284	319,228	12,025,055	1,888,496	2,809,290	72,649	2,736,640	429,780
41	W incentive	2016	82,684,437	2,142,147	80,542,290	13,549,255	12,344,284	319,228	12,025,055	2,022,281	2,809,290	72,649	2,736,640	460,227
A						13,463,249				2,054,326				467,520
B						14,425,555				2,201,196				500,944
C						13,624,070				2,033,293				462,733
D						14,571,123				2,174,673				494,908
E						160,821				(21,033)				(4,787)
F						145,569				(26,523)				(6,036)
G						1.06685				1.06685				1.06685
H						171,572				(22,439)				(5,107)
I						155,300				(28,296)				(6,440)
	W / O incentive					12,824,730				1,866,057				424,674
	W incentive					13,704,556				1,993,985				453,787

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

10			**Project I-1**				**Project I-2A**				**Project I-2B**			
11	Schedule 12	(Yes or No)	Yes	b0329			Yes	b0329			Yes	b0329		
12	Life		43	Carson-Suffolk 500 kV line +			43	Carson-Suffolk 500 kV line +			43	Carson-Suffolk 500 kV line +		
13	FCR W/O incentive	Line 3	12.8790%	Suffolk 500/230 # 2 transformer +			12.8790%	Suffolk 500/230 # 2 transformer +			12.8790%	Suffolk 500/230 # 2 transformer +		
14	Incentive Factor (Basis Points /100)		1.5	Suffolk - Thrasher 230kV line			1.5	Suffolk - Thrasher 230kV line			1.5	Suffolk - Thrasher 230kV line		
15	FCR W incentive L.13 +(L.14*L.5)		13.9770%				13.9770%				13.9770%			
16	Investment		2,434,850	Cost associated with below 500 kV elements.			38,971,417	Cost associated with below 500 kV elements.			163,402,608	Cost associated with Regional Facilities and		
17	Annual Depreciation Exp		56,624				906,312				3,800,061	Necessary Lower Voltage Facilities.		
18	In Service Month (1-12)		12				6				5			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009	2,434,850	1,989	2,432,861									
27	W incentive	2009	2,434,850	1,989	2,432,861									
28	W / O incentive	2010	2,432,861	47,742	2,385,119									
29	W incentive	2010	2,432,861	47,742	2,385,119									
30	W / O incentive	2011	2,385,119	47,742	2,337,376		38,971,417	413,912	38,557,505		163,402,608	2,002,483	161,400,125	
31	W incentive	2011	2,385,119	47,742	2,337,376		38,971,417	413,912	38,557,505		163,402,608	2,002,483	161,400,125	
32	W / O incentive	2012	2,337,376	47,742	2,289,634		38,557,505	764,145	37,793,359		161,400,125	3,203,973	158,196,152	
33	W incentive	2012	2,337,376	47,742	2,289,634		38,557,505	764,145	37,793,359		161,400,125	3,203,973	158,196,152	
34	W / O incentive	2013	2,289,634	54,404	2,235,230		37,793,359	870,770	36,922,589		158,196,152	3,651,039	154,545,114	
35	W incentive	2013	2,289,634	54,404	2,235,230		37,793,359	870,770	36,922,589		158,196,152	3,651,039	154,545,114	
36	W / O incentive	2014	2,235,230	56,624	2,178,606		36,922,589	906,312	36,016,277		154,545,114	3,800,061	150,745,053	
37	W incentive	2014	2,235,230	56,624	2,178,606		36,922,589	906,312	36,016,277		154,545,114	3,800,061	150,745,053	
38	W / O incentive	2015	2,178,606	56,624	2,121,982		36,016,277	906,312	35,109,965		150,745,053	3,800,061	146,944,992	
39	W incentive	2015	2,178,606	56,624	2,121,982		36,016,277	906,312	35,109,965		150,745,053	3,800,061	146,944,992	
40	W / O incentive	2016	2,121,982	56,624	2,065,357	326,269	35,109,965	906,312	34,203,653	5,369,773	146,944,992	3,800,061	143,144,932	22,480,446
41	W incentive	2016	2,121,982	56,624	2,065,357	349,257	35,109,965	906,312	34,203,653	5,750,298	146,944,992	3,800,061	143,144,932	24,073,009
A						355,024				5,842,792				24,440,644
B						380,305				6,260,605				26,187,974
C						351,623				5,781,174				24,204,098
D						375,955				6,183,263				25,887,067
E						(3,402)				(61,618)				(236,546)
F						(4,350)				(77,342)				(300,908)
G						1.06685				1.06685				1.06685
H						(3,629)				(65,738)				(252,360)
I						(4,641)				(82,513)				(321,024)
	W / O incentive					322,640				5,304,036				22,228,086
	W incentive					344,616				5,667,785				23,751,985

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

10			Project J				Project K-1				Project K-2			
11	Schedule 12	(Yes or No)	Yes	b0512			No				No			
12	Life		43	MAPP Project -- Dominion Portion			43	Loudoun Bank # 1 transformer			43	Loudoun Bank # 2 transformer		
13	FCR W/O incentive	Line 3	12.8790%				12.8790%	replacement			12.8790%	replacement		
14	Incentive Factor (Basis Points /100)		1.5				1.5				1.5			
15	FCR W incentive L.13 +(L.14*L.5)		13.9770%				13.9770%				13.9770%			
16	Investment						13,672,006				14,627,173			
17	Annual Depreciation Exp		-				317,954				340,167			
18	In Service Month (1-12)						12				5			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009					13,672,006	11,170	13,660,836					
27	W incentive	2009					13,672,006	11,170	13,660,836					
28	W / O incentive	2010					13,660,836	268,079	13,392,758		14,627,173	179,255	14,447,918	
29	W incentive	2010					13,660,836	268,079	13,392,758		14,627,173	179,255	14,447,918	
30	W / O incentive	2011					13,392,758	268,079	13,124,679		14,447,918	286,807	14,161,111	
31	W incentive	2011					13,392,758	268,079	13,124,679		14,447,918	286,807	14,161,111	
32	W / O incentive	2012	-	-	-		13,124,679	268,079	12,856,600		14,161,111	286,807	13,874,304	
33	W incentive	2012	-	-	-		13,124,679	268,079	12,856,600		14,161,111	286,807	13,874,304	
34	W / O incentive	2013	-	-	-	-	12,856,600	305,485	12,551,116		13,874,304	326,827	13,547,477	
35	W incentive	2013	-	-	-	-	12,856,600	305,485	12,551,116		13,874,304	326,827	13,547,477	
36	W / O incentive	2014	-	-	-		12,551,116	317,954	12,233,162		13,547,477	340,167	13,207,310	
37	W incentive	2014	-	-	-		12,551,116	317,954	12,233,162		13,547,477	340,167	13,207,310	
38	W / O incentive	2015	-	-	-		12,233,162	317,954	11,915,208		13,207,310	340,167	12,867,143	
39	W incentive	2015	-	-	-		12,233,162	317,954	11,915,208		13,207,310	340,167	12,867,143	
40	W / O incentive	2016	-	-	-	-	11,915,208	317,954	11,597,255	1,832,042	12,867,143	340,167	12,526,976	1,975,425
41	W incentive	2016	-	-	-	-	11,915,208	317,954	11,597,255	1,961,123	12,867,143	340,167	12,526,976	2,114,836
A										1,993,508				2,149,466
B										2,135,463				2,302,709
C						-				1,974,408				2,128,320
D						-				2,111,036				2,275,811
E						-				(19,100)				(21,145)
F						-				(24,426)				(26,898)
G						1.06685				1.06685				1.06685
H						-				(20,377)				(22,559)
I						-				(26,059)				(28,696)
	W / O incentive					-				1,811,665				1,952,866
	W incentive					-				1,935,064				2,086,140

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

10			Project L-1a				Project L-1b				Project L-2			
11	Schedule 12	(Yes or No)	No				No				No			
12	Life		43	Ox Bank # 1 transformer			43	Ox Bank # 1 transformer			43	Ox Bank # 2 transformer		
13	FCR W/O incentive	Line 3	12.8790%	replacement			12.8790%	spare			12.8790%	replacement		
14	Incentive Factor (Basis Points /100)		1.5				1.5				1.5			
15	FCR W incentive L.13 +(L.14*L.5)		13.9770%				13.9770%				13.9770%			
16	Investment		10,714,404				3,072,185				11,501,538			
17	Annual Depreciation Exp		249,172				71,446				267,478			
18	In Service Month (1-12)		7				12				3			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009	10,714,404	96,290	10,618,114		3,072,185	2,510	3,069,675		11,501,538	178,537	11,323,001	
27	W incentive	2009	10,714,404	96,290	10,618,114		3,072,185	2,510	3,069,675		11,501,538	178,537	11,323,001	
28	W / O incentive	2010	10,618,114	210,086	10,408,028		3,069,675	60,239	3,009,436		11,323,001	225,520	11,097,481	
29	W incentive	2010	10,618,114	210,086	10,408,028		3,069,675	60,239	3,009,436		11,323,001	225,520	11,097,481	
30	W / O incentive	2011	10,408,028	210,086	10,197,942		3,009,436	60,239	2,949,197		11,097,481	225,520	10,871,960	
31	W incentive	2011	10,408,028	210,086	10,197,942		3,009,436	60,239	2,949,197		11,097,481	225,520	10,871,960	
32	W / O incentive	2012	10,197,942	210,086	9,987,855		2,949,197	60,239	2,888,958		10,871,960	225,520	10,646,440	
33	W incentive	2012	10,197,942	210,086	9,987,855		2,949,197	60,239	2,888,958		10,871,960	225,520	10,646,440	
34	W / O incentive	2013	9,987,855	239,401	9,748,455		2,888,958	68,644	2,820,314		10,646,440	256,988	10,389,452	
35	W incentive	2013	9,987,855	239,401	9,748,455		2,888,958	68,644	2,820,314		10,646,440	256,988	10,389,452	
36	W / O incentive	2014	9,748,455	249,172	9,499,282		2,820,314	71,446	2,748,868		10,389,452	267,478	10,121,974	
37	W incentive	2014	9,748,455	249,172	9,499,282		2,820,314	71,446	2,748,868		10,389,452	267,478	10,121,974	
38	W / O incentive	2015	9,499,282	249,172	9,250,110		2,748,868	71,446	2,677,422		10,121,974	267,478	9,854,496	
39	W incentive	2015	9,499,282	249,172	9,250,110		2,748,868	71,446	2,677,422		10,121,974	267,478	9,854,496	
40	W / O incentive	2016	9,250,110	249,172	9,000,938	1,424,451	2,677,422	71,446	2,605,975	411,671	9,854,496	267,478	9,587,019	1,519,417
41	W incentive	2016	9,250,110	249,172	9,000,938	1,524,648	2,677,422	71,446	2,605,975	440,677	9,854,496	267,478	9,587,019	1,626,149
A						1,550,135				447,954				1,653,601
B						1,660,383				479,852				1,771,092
C						1,535,593				443,662				1,638,357
D						1,641,699				474,363				1,751,430
E						(14,542)				(4,292)				(15,244)
F						(18,684)				(5,489)				(19,662)
G						1.06685				1.06685				1.06685
H						(15,514)				(4,579)				(16,263)
I						(19,933)				(5,856)				(20,977)
	W / O incentive					1,408,937				407,093				1,503,154
	W incentive					1,504,715				434,821				1,605,172

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

			Project M				Project N				Project O			
10														
11	Schedule 12	(Yes or No)	No				No				No			
12	Life		43	Yadkin Bank # 2 transformer			43	Carson Bank # 1 transformer			43	Lexington Bank # 1 transformer		
13	FCR W/O incentive	Line 3	12.8790%	replacement			12.8790%	replacement			12.8790%	replacement		
14	Incentive Factor (Basis Points /100)		1.5				1.5				1.5			
15	FCR W incentive L.13 +(L.14*L.5)		13.9770%				13.9770%				13.9770%			
16	Investment		16,559,471				18,887,180				10,471,304			
17	Annual Depreciation Exp		385,104				439,237				243,519			
18	In Service Month (1-12)		6				5				12			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010	16,559,471	175,877	16,383,594		18,887,180	231,461	18,655,719					
29	W incentive	2010	16,559,471	175,877	16,383,594		18,887,180	231,461	18,655,719					
30	W / O incentive	2011	16,383,594	324,696	16,058,899		18,655,719	370,337	18,285,383		10,471,304	8,555	10,462,749	
31	W incentive	2011	16,383,594	324,696	16,058,899		18,655,719	370,337	18,285,383		10,471,304	8,555	10,462,749	
32	W / O incentive	2012	16,058,899	324,696	15,734,203		18,285,383	370,337	17,915,046		10,462,749	205,320	10,257,429	
33	W incentive	2012	16,058,899	324,696	15,734,203		18,285,383	370,337	17,915,046		10,462,749	205,320	10,257,429	
34	W / O incentive	2013	15,734,203	370,002	15,364,201		17,915,046	422,012	17,493,034		10,257,429	233,969	10,023,460	
35	W incentive	2013	15,734,203	370,002	15,364,201		17,915,046	422,012	17,493,034		10,257,429	233,969	10,023,460	
36	W / O incentive	2014	15,364,201	385,104	14,979,097		17,493,034	439,237	17,053,797		10,023,460	243,519	9,779,942	
37	W incentive	2014	15,364,201	385,104	14,979,097		17,493,034	439,237	17,053,797		10,023,460	243,519	9,779,942	
38	W / O incentive	2015	14,979,097	385,104	14,593,993		17,053,797	439,237	16,614,560		9,779,942	243,519	9,536,423	
39	W incentive	2015	14,979,097	385,104	14,593,993		17,053,797	439,237	16,614,560		9,779,942	243,519	9,536,423	
40	W / O incentive	2016	14,593,993	385,104	14,208,889	2,239,870	16,614,560	439,237	16,175,324	2,550,746	9,536,423	243,519	9,292,904	1,456,036
41	W incentive	2016	14,593,993	385,104	14,208,889	2,397,995	16,614,560	439,237	16,175,324	2,730,759	9,536,423	243,519	9,292,904	1,559,407
A						2,437,020				2,770,585				1,583,705
B						2,610,805				2,968,109				1,697,107
C						2,413,095				2,748,171				1,567,077
D						2,580,368				2,938,617				1,676,247
E						(23,924)				(22,414)				(16,628)
F						(30,436)				(29,493)				(20,860)
G						1.06685				1.06685				1.06685
H						(25,524)				(23,912)				(17,740)
I						(32,471)				(31,464)				(22,255)
	W / O incentive					2,214,346				2,526,834				1,438,296
	W incentive					2,365,524				2,699,295				1,537,152

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

10			Project P				Project Q				Project R-1			
11	Schedule 12	(Yes or No)	No				No				No	s0124		
12	Life		43	Dooms Bank # 7 transformer			43	Valley Bank # 1 transformer			43	Garrisonville 230 kV UG line		
13	FCR W/O incentive	Line 3	12.8790%	replacement			12.8790%	replacement			12.8790%	Phase 1		
14	Incentive Factor (Basis Points /100)		1.5				1.5				1.25			
15	FCR W incentive L.13 +(L.14*L.5)		13.9770%				13.9770%				13.7940%			
16	Investment		18,897,652				12,056,414				91,286,696			
17	Annual Depreciation Exp		439,480				280,382				2,122,946			
18	In Service Month (1-12)		8				12				6			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010					12,056,414	9,850	12,046,564		91,286,696	969,548	90,317,148	
29	W incentive	2010					12,056,414	9,850	12,046,564		91,286,696	969,548	90,317,148	
30	W / O incentive	2011	18,897,652	138,953	18,758,699		12,046,564	236,400	11,810,164		90,317,148	1,789,935	88,527,213	
31	W incentive	2011	18,897,652	138,953	18,758,699		12,046,564	236,400	11,810,164		90,317,148	1,789,935	88,527,213	
32	W / O incentive	2012	18,758,699	370,542	18,388,156		11,810,164	236,400	11,573,763		88,527,213	1,789,935	86,737,277	
33	W incentive	2012	18,758,699	370,542	18,388,156		11,810,164	236,400	11,573,763		88,527,213	1,789,935	86,737,277	
34	W / O incentive	2013	18,388,156	422,246	17,965,911		11,573,763	269,386	11,304,377		86,737,277	2,039,694	84,697,584	
35	W incentive	2013	18,388,156	422,246	17,965,911		11,573,763	269,386	11,304,377		86,737,277	2,039,694	84,697,584	
36	W / O incentive	2014	17,965,911	439,480	17,526,430		11,304,377	280,382	11,023,995		84,697,584	2,122,946	82,574,637	
37	W incentive	2014	17,965,911	439,480	17,526,430		11,304,377	280,382	11,023,995		84,697,584	2,122,946	82,574,637	
38	W / O incentive	2015	17,526,430	439,480	17,086,950		11,023,995	280,382	10,743,614		82,574,637	2,122,946	80,451,691	
39	W incentive	2015	17,526,430	439,480	17,086,950		11,023,995	280,382	10,743,614		82,574,637	2,122,946	80,451,691	
40	W / O incentive	2016	17,086,950	439,480	16,647,470	2,611,814	10,743,614	280,382	10,463,232	1,646,000	80,451,691	2,122,946	78,328,744	12,347,637
41	W incentive	2016	17,086,950	439,480	16,647,470	2,797,012	10,743,614	280,382	10,463,232	1,762,423	80,451,691	2,122,946	78,328,744	13,074,044

A		2,841,011	1,790,690	13,545,136
B		3,044,261	1,918,565	14,350,061
C		2,811,607	1,772,696	13,302,568
D		3,007,265	1,895,786	14,071,001
E		(29,403)	(17,994)	(242,568)
F		(36,995)	(22,779)	(279,060)
G		1.06685	1.06685	1.06685
H		(31,369)	(19,197)	(258,784)
I		(39,469)	(24,302)	(297,715)
	W / O incentive	2,580,445	1,626,803	12,088,853
	W incentive	2,757,543	1,738,121	12,776,328

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

10			**Project R-2**				**Project R-3**				**Project S-1**			
11	Schedule 12	(Yes or No)	No	s0124			No	s0124			No	s0133		
12	Life		43	Garrisonville 230 kV UG line			43	Garrisonville 230 kV UG line			43	Pleasant View Hamilton 230kV		
13	FCR W/O incentive	Line 3	12.8790%	Phase 2			12.8790%	Phase 3			12.8790%	transmission line		
14	Incentive Factor (Basis Points /100)		1.25				1.25				1.25			
15	FCR W incentive L.13 +(L.14*L.5)		13.7940%				13.7940%				13.7940%			
16	Investment		32,204,664				13,426,813				84,729,725			
17	Annual Depreciation Exp		748,946				312,251				1,970,459			
18	In Service Month (1-12)		6				2				10			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010									84,729,725	346,118	84,383,607	
29	W incentive	2010									84,729,725	346,118	84,383,607	
30	W / O incentive	2011	32,204,664	342,043	31,862,621						84,383,607	1,661,367	82,722,240	
31	W incentive	2011	32,204,664	342,043	31,862,621						84,383,607	1,661,367	82,722,240	
32	W / O incentive	2012	31,862,621	631,464	31,231,157		13,426,813	230,362	13,196,451		82,722,240	1,661,367	81,060,873	
33	W incentive	2012	31,862,621	631,464	31,231,157		13,426,813	230,362	13,196,451		82,722,240	1,661,367	81,060,873	
34	W / O incentive	2013	31,231,157	719,575	30,511,582		13,196,451	300,006	12,896,445		81,060,873	1,893,186	79,167,687	
35	W incentive	2013	31,231,157	719,575	30,511,582		13,196,451	300,006	12,896,445		81,060,873	1,893,186	79,167,687	
36	W / O incentive	2014	30,511,582	748,946	29,762,636		12,896,445	312,251	12,584,193		79,167,687	1,970,459	77,197,228	
37	W incentive	2014	30,511,582	748,946	29,762,636		12,896,445	312,251	12,584,193		79,167,687	1,970,459	77,197,228	
38	W / O incentive	2015	29,762,636	748,946	29,013,690		12,584,193	312,251	12,271,942		77,197,228	1,970,459	75,226,769	
39	W incentive	2015	29,762,636	748,946	29,013,690		12,584,193	312,251	12,271,942		77,197,228	1,970,459	75,226,769	
40	W / O incentive	2016	29,013,690	748,946	28,264,745	4,437,399	12,271,942	312,251	11,959,690	1,872,651	75,226,769	1,970,459	73,256,311	11,532,050
41	W incentive	2016	29,013,690	748,946	28,264,745	4,699,443	12,271,942	312,251	11,959,690	1,983,509	75,226,769	1,970,459	73,256,311	12,211,347

A	4,826,969	2,030,238	12,541,993
B	5,114,613	2,151,439	13,288,006
C	4,777,367	2,015,247	12,421,092
D	5,054,261	2,132,303	13,139,417
E	(49,603)	(14,991)	(120,901)
F	(60,352)	(19,136)	(148,589)
G	1.06685	1.06685	1.06685
H	(52,919)	(15,993)	(128,984)
I	(64,387)	(20,416)	(158,522)

W / O incentive	4,384,481	1,856,658	11,403,066
W incentive	4,635,057	1,963,093	12,052,824

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

10		Project S-2		Project T-1		Project T-2	
11	Schedule 12 (Yes or No)	No	s0133	Yes	b0768	Yes	b0768
12	Life	43	Pleasant View Hamilton 230kV	43	Glen Carlyn Line 251 GIB substation project	43	Glen Carlyn Line 251 GIB substation project
13	FCR W/O incentive Line 3	12.8790%	transmission line	12.8790%		12.8790%	
14	Incentive Factor (Basis Points /100)	1.25		1.25	Loop Line 251 Idylwood -- Arlington into	1.25	Loop Line 251 Idylwood -- Arlington into
15	FCR W incentive L.13 +(L.14*L.5)	13.7940%		13.7940%	the GIS sub	13.7940%	the GIS sub
16	Investment	1,301,988		205,578		23,483,583	
17	Annual Depreciation Exp	30,279		4,781		546,130	
18	In Service Month (1-12)	2		6		6	

19			Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010					205,578	2,183	203,395					
29	W incentive	2010					205,578	2,183	203,395					
30	W / O incentive	2011	1,301,988	22,338	1,279,650		203,395	4,031	199,364		23,483,583	249,417	23,234,166	
31	W incentive	2011	1,301,988	22,338	1,279,650		203,395	4,031	199,364		23,483,583	249,417	23,234,166	
32	W / O incentive	2012	1,279,650	25,529	1,254,121		199,364	4,031	195,333		23,234,166	460,462	22,773,703	
33	W incentive	2012	1,279,650	25,529	1,254,121		199,364	4,031	195,333		23,234,166	460,462	22,773,703	
34	W / O incentive	2013	1,254,121	29,091	1,225,029		195,333	4,593	190,739		22,773,703	524,713	22,248,990	
35	W incentive	2013	1,254,121	29,091	1,225,029		195,333	4,593	190,739		22,773,703	524,713	22,248,990	
36	W / O incentive	2014	1,225,029	30,279	1,194,751		190,739	4,781	185,958		22,248,990	546,130	21,702,861	
37	W incentive	2014	1,225,029	30,279	1,194,751		190,739	4,781	185,958		22,248,990	546,130	21,702,861	
38	W / O incentive	2015	1,194,751	30,279	1,164,472		185,958	4,781	181,178		21,702,861	546,130	21,156,731	
39	W incentive	2015	1,194,751	30,279	1,164,472		185,958	4,781	181,178		21,702,861	546,130	21,156,731	
40	W / O incentive	2016	1,164,472	30,279	1,134,193	178,302	181,178	4,781	176,397	27,807	21,156,731	546,130	20,610,601	3,235,744
41	W incentive	2016	1,164,472	30,279	1,134,193	188,818	181,178	4,781	176,397	29,443	21,156,731	546,130	20,610,601	3,426,825

A	193,443	30,254	3,519,817
B	204,960	32,052	3,729,566
C	192,005	29,957	3,483,647
D	203,121	31,688	3,685,558
E	(1,439)	(297)	(36,170)
F	(1,839)	(364)	(44,009)
G	1.06685	1.06685	1.06685
H	(1,535)	(317)	(38,588)
I	(1,962)	(389)	(46,951)

W / O incentive	176,767	27,490	3,197,156
W incentive	186,856	29,054	3,379,875

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

10			**Project U-1**				**Project U-2**				**Project V**			
11	Schedule 12	(Yes or No)	Yes	b0453.1			Yes	b0453.2			Yes	b0337		
12	Life		43	Convert Remington - Sowego			43	Add Sowego - Gainsville 230 kV			43	Build Lexington 230kV ring bus		
13	FCR W/O incentive	Line 3	12.8790%	115kV to 230kV			12.8790%				12.8790%			
14	Incentive Factor (Basis Points /100)		1.25				1.25				1.25			
15	FCR W incentive L.13 +(L.14*L.5)		13.7940%				13.7940%				13.7940%			
16	Investment		1,472,605				13,530,243				6,407,258			
17	Annual Depreciation Exp		34,247				314,657				149,006			
18	In Service Month (1-12)		9				5				3			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009									6,407,258	99,459	6,307,799	
27	W incentive	2009									6,407,258	99,459	6,307,799	
28	W / O incentive	2010	1,472,605	8,422	1,464,183						6,307,799	125,633	6,182,166	
29	W incentive	2010	1,472,605	8,422	1,464,183						6,307,799	125,633	6,182,166	
30	W / O incentive	2011	1,464,183	28,875	1,435,309						6,182,166	125,633	6,056,534	
31	W incentive	2011	1,464,183	28,875	1,435,309						6,182,166	125,633	6,056,534	
32	W / O incentive	2012	1,435,309	28,875	1,406,434		13,530,243	165,812	13,364,431		6,056,534	125,633	5,930,901	
33	W incentive	2012	1,435,309	28,875	1,406,434		13,530,243	165,812	13,364,431		6,056,534	125,633	5,930,901	
34	W / O incentive	2013	1,406,434	32,904	1,373,530		13,364,431	302,317	13,062,114		5,930,901	143,163	5,787,739	
35	W incentive	2013	1,406,434	32,904	1,373,530		13,364,431	302,317	13,062,114		5,930,901	143,163	5,787,739	
36	W / O incentive	2014	1,373,530	34,247	1,339,284		13,062,114	314,657	12,747,457		5,787,739	149,006	5,638,733	
37	W incentive	2014	1,373,530	34,247	1,339,284		13,062,114	314,657	12,747,457		5,787,739	149,006	5,638,733	
38	W / O incentive	2015	1,339,284	34,247	1,305,037		12,747,457	314,657	12,432,800		5,638,733	149,006	5,489,727	
39	W incentive	2015	1,339,284	34,247	1,305,037		12,747,457	314,657	12,432,800		5,638,733	149,006	5,489,727	
40	W / O incentive	2016	1,305,037	34,247	1,270,791	200,117	12,432,800	314,657	12,118,143	1,895,619	5,489,727	149,006	5,340,721	846,434
41	W incentive	2016	1,305,037	34,247	1,270,791	211,902	12,432,800	314,657	12,118,143	2,007,937	5,489,727	149,006	5,340,721	895,983
A						217,720				2,053,550				921,185
B						230,667				2,176,223				975,728
C						215,557				2,039,637				912,693
D						228,020				2,158,204				965,185
E						(2,163)				(13,913)				(8,492)
F						(2,648)				(18,020)				(10,543)
G						1.06685				1.06685				1.06685
H						(2,307)				(14,843)				(9,060)
I						(2,825)				(19,225)				(11,248)
	W / O incentive					197,810				1,880,776				837,374
	W incentive					209,077				1,988,712				884,735

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

10			**Project W**				**Project X**				**Project AA - 1**			
11	Schedule 12	(Yes or No)	Yes	b0467.2			Yes	b0311			Yes	b0231		
12	Life		43	Reconductor the Dickerson - Pleasant			43	Reconductor Idylwood to Arlington			43	Install 500 kV breakers and		
13	FCR W/O incentive	Line 3	12.8790%	View 230 kV circuit			12.8790%	230 kV			12.8790%	500 kV bus work at Suffolk		
14	Incentive Factor (Basis Points /100)		1.25				1.25				0			
15	FCR W incentive L.13 +(L.14*L.5)		13.7940%				13.7940%				12.8790%			
16	Investment		5,246,724				3,196,608				21,912,291			
17	Annual Depreciation Exp		122,017				74,340				509,588			
18	In Service Month (1-12)		6				8				11			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009					3,196,608	23,504	3,173,104		21,912,291	53,707	21,858,584	
27	W incentive	2009					3,196,608	23,504	3,173,104		21,912,291	53,707	21,858,584	
28	W / O incentive	2010					3,173,104	62,679	3,110,425		21,858,584	429,653	21,428,932	
29	W incentive	2010					3,173,104	62,679	3,110,425		21,858,584	429,653	21,428,932	
30	W / O incentive	2011	5,246,724	55,725	5,190,999		3,110,425	62,679	3,047,746		21,428,932	429,653	20,999,279	
31	W incentive	2011	5,246,724	55,725	5,190,999		3,110,425	62,679	3,047,746		21,428,932	429,653	20,999,279	
32	W / O incentive	2012	5,190,999	102,877	5,088,122		3,047,746	62,679	2,985,068		20,999,279	429,653	20,569,626	
33	W incentive	2012	5,190,999	102,877	5,088,122		3,047,746	62,679	2,985,068		20,999,279	429,653	20,569,626	
34	W / O incentive	2013	5,088,122	117,232	4,970,890		2,985,068	71,424	2,913,643		20,569,626	489,604	20,080,022	
35	W incentive	2013	5,088,122	117,232	4,970,890		2,985,068	71,424	2,913,643		20,569,626	489,604	20,080,022	
36	W / O incentive	2014	4,970,890	122,017	4,848,873		2,913,643	74,340	2,839,304		20,080,022	509,588	19,570,434	
37	W incentive	2014	4,970,890	122,017	4,848,873		2,913,643	74,340	2,839,304		20,080,022	509,588	19,570,434	
38	W / O incentive	2015	4,848,873	122,017	4,726,857		2,839,304	74,340	2,764,964		19,570,434	509,588	19,060,845	
39	W incentive	2015	4,848,873	122,017	4,726,857		2,839,304	74,340	2,764,964		19,570,434	509,588	19,060,845	
40	W / O incentive	2016	4,726,857	122,017	4,604,840	722,933	2,764,964	74,340	2,690,624	425,653	19,060,845	509,588	18,551,257	2,931,625
41	W incentive	2016	4,726,857	122,017	4,604,840	765,625	2,764,964	74,340	2,690,624	450,612	19,060,845	509,588	18,551,257	2,931,625
A						786,401				463,201				3,167,420
B						833,263				490,661				3,167,420
C						778,320				458,837				3,159,622
D						823,431				485,266				3,159,622
E						(8,081)				(4,364)				(7,797)
F						(9,832)				(5,395)				(7,797)
G						1.06685				1.06685				1.06685
H						(8,621)				(4,656)				(8,319)
I						(10,490)				(5,756)				(8,319)
	W / O incentive					714,311				420,997				2,923,307
	W incentive					755,135				444,856				2,923,307

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

10			Project AB-2				Project AC				Project AG			
11	Schedule 12	(Yes or No)	Yes	b0456			Yes	b0227			Yes	b0455		
12	Life		43	Re-Conductor 9.4 miles of Edinburg - Mt. Jackso			43	Install 500/230 kV transformer at Bristers;			43	Add 2nd Endless Caverns 230/115kV		
13	FCR W/O incentive	Line 3	12.8790%	115 kV			12.8790%	build new 230 kV Bristers- Gainesville circuit,			12.8790%	transformer		
14	Incentive Factor (Basis Points /100)		0				0	upgrade two Loudoun - Brambleton circuits			0			
15	FCR W incentive L.13 +(L.14*L.5)		12.8790%				12.8790%				12.8790%			
16	Investment		4,839,985				21,403,678				3,554,673			
17	Annual Depreciation Exp		112,558				497,760				82,667			
18	In Service Month (1-12)		11				6				5			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009	4,839,985	11,863	4,828,122		21,403,678	227,327	21,176,351		3,554,673	43,562	3,511,111	
27	W incentive	2009	4,839,985	11,863	4,828,122		21,403,678	227,327	21,176,351		3,554,673	43,562	3,511,111	
28	W / O incentive	2010	4,828,122	94,902	4,733,221		21,176,351	419,680	20,756,671		3,511,111	69,699	3,441,411	
29	W incentive	2010	4,828,122	94,902	4,733,221		21,176,351	419,680	20,756,671		3,511,111	69,699	3,441,411	
30	W / O incentive	2011	4,733,221	94,902	4,638,319		20,756,671	419,680	20,336,991		3,441,411	69,699	3,371,712	
31	W incentive	2011	4,733,221	94,902	4,638,319		20,756,671	419,680	20,336,991		3,441,411	69,699	3,371,712	
32	W / O incentive	2012	4,638,319	94,902	4,543,417		20,336,991	419,680	19,917,311		3,371,712	69,699	3,302,012	
33	W incentive	2012	4,638,319	94,902	4,543,417		20,336,991	419,680	19,917,311		3,371,712	69,699	3,302,012	
34	W / O incentive	2013	4,543,417	108,144	4,435,274		19,917,311	478,240	19,439,072		3,302,012	79,425	3,222,587	
35	W incentive	2013	4,543,417	108,144	4,435,274		19,917,311	478,240	19,439,072		3,302,012	79,425	3,222,587	
36	W / O incentive	2014	4,435,274	112,558	4,322,716		19,439,072	497,760	18,941,312		3,222,587	82,667	3,139,921	
37	W incentive	2014	4,435,274	112,558	4,322,716		19,439,072	497,760	18,941,312		3,222,587	82,667	3,139,921	
38	W / O incentive	2015	4,322,716	112,558	4,210,158		18,941,312	497,760	18,443,552		3,139,921	82,667	3,057,254	
39	W incentive	2015	4,322,716	112,558	4,210,158		18,941,312	497,760	18,443,552		3,139,921	82,667	3,057,254	
40	W / O incentive	2016	4,210,158	112,558	4,097,600	647,537	18,443,552	497,760	17,945,792	2,841,057	3,057,254	82,667	2,974,587	471,088
41	W incentive	2016	4,210,158	112,558	4,097,600	647,537	18,443,552	497,760	17,945,792	2,841,057	3,057,254	82,667	2,974,587	471,088
A						704,620				3,091,789				512,672
B						704,620				3,091,789				512,672
C						697,897				3,062,909				507,904
D						697,897				3,062,909				507,904
E						(6,723)				(28,880)				(4,768)
F						(6,723)				(28,880)				(4,768)
G						1.06685				1.06685				1.06685
H						(7,172)				(30,810)				(5,087)
I						(7,172)				(30,810)				(5,087)
	W / O incentive					640,365				2,810,247				466,001
	W incentive					640,365				2,810,247				466,001

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

10			**2009 Add-1**				**2009 Add-6**				**Project AJ**			
11	Schedule 12	(Yes or No)	Yes	B0453.3			Yes	B0837			Yes	B0327		
12	Life		43	Add Sowego 230/115/ kV transformer			43	At Mt. Storm, replace the existing MOD on			43	Build 2nd Harrisonburg - Valley 230 kV		
13	FCR W/O incentive	Line 3	12.8790%				12.8790%	the 500 kV side of the transformer with a			12.8790%			
14	Incentive Factor (Basis Points /100)		1.25				0	circuit breaker			0			
15	FCR W incentive L.13 +(L.14*L.5)		13.7940%				12.8790%				12.8790%			
16	Investment		3,355,513				779,172				6,211,387			
17	Annual Depreciation Exp		78,035				18,120				144,451			
18	In Service Month (1-12)		9				6				7			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009	3,355,513	19,190	3,336,323		779,172	8,276	770,896					
27	W incentive	2009	3,355,513	19,190	3,336,323		779,172	8,276	770,896					
28	W / O incentive	2010	3,336,323	65,794	3,270,529		770,896	15,278	755,619		6,211,387	55,821	6,155,566	
29	W incentive	2010	3,336,323	65,794	3,270,529		770,896	15,278	755,619		6,211,387	55,821	6,155,566	
30	W / O incentive	2011	3,270,529	65,794	3,204,734		755,619	15,278	740,341		6,155,566	121,792	6,033,774	
31	W incentive	2011	3,270,529	65,794	3,204,734		755,619	15,278	740,341		6,155,566	121,792	6,033,774	
32	W / O incentive	2012	3,204,734	65,794	3,138,940		740,341	15,278	725,063		6,033,774	121,792	5,911,982	
33	W incentive	2012	3,204,734	65,794	3,138,940		740,341	15,278	725,063		6,033,774	121,792	5,911,982	
34	W / O incentive	2013	3,138,940	74,975	3,063,965		725,063	17,410	707,653		5,911,982	138,786	5,773,196	
35	W incentive	2013	3,138,940	74,975	3,063,965		725,063	17,410	707,653		5,911,982	138,786	5,773,196	
36	W / O incentive	2014	3,063,965	78,035	2,985,930		707,653	18,120	689,533		5,773,196	144,451	5,628,745	
37	W incentive	2014	3,063,965	78,035	2,985,930		707,653	18,120	689,533		5,773,196	144,451	5,628,745	
38	W / O incentive	2015	2,985,930	78,035	2,907,895		689,533	18,120	671,413		5,628,745	144,451	5,484,294	
39	W incentive	2015	2,985,930	78,035	2,907,895		689,533	18,120	671,413		5,628,745	144,451	5,484,294	
40	W / O incentive	2016	2,907,895	78,035	2,829,859	447,519	671,413	18,120	653,292	103,425	5,484,294	144,451	5,339,843	841,473
41	W incentive	2016	2,907,895	78,035	2,829,859	473,768	671,413	18,120	653,292	103,425	5,484,294	144,451	5,339,843	841,473
A						486,987				112,552				915,522
B						515,864				112,552				915,522
C						482,379				111,501				906,498
D						510,172				111,501				906,498
E						(4,608)				(1,051)				(9,023)
F						(5,692)				(1,051)				(9,023)
G						1.06685				1.06685				1.06685
H						(4,916)				(1,122)				(9,627)
I						(6,072)				(1,122)				(9,627)
	W / O incentive					442,603				102,303				831,846
	W incentive					467,696				102,303				831,846

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

10			Project AK-1				Project AK-2				Project AK-3			
11	Schedule 12	(Yes or No)	Yes	B1507			Yes	B1507			Yes	B1507		
12	Life		43	Rebuild Mt Storm - Doubs 500 kV			43	Rebuild Mt Storm - Doubs 500 kV			43	Rebuild Mt. Storm-Doubs 500 kV		
13	FCR W/O incentive	Line 3	12.8790%				12.8790%				12.8790%			
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		12.8790%				12.8790%				12.8790%			
16	Investment		23,947,642				21,791,010				120,381,556			
17	Annual Depreciation Exp		556,922				506,768				2,799,571			
18	In Service Month (1-12)		12				5				5			
19			Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011	23,947,642	19,565	23,928,077									
31	W incentive	2011	23,947,642	19,565	23,928,077									
32	W / O incentive	2012	23,928,077	469,562	23,458,515		21,791,010	267,047	21,523,963					
33	W incentive	2012	23,928,077	469,562	23,458,515		21,791,010	267,047	21,523,963					
34	W / O incentive	2013	23,458,515	535,082	22,923,433		21,523,963	486,894	21,037,069		120,381,556	1,749,732	118,631,824	
35	W incentive	2013	23,458,515	535,082	22,923,433		21,523,963	486,894	21,037,069		120,381,556	1,749,732	118,631,824	
36	W / O incentive	2014	22,923,433	556,922	22,366,512		21,037,069	506,768	20,530,301		118,631,824	2,799,571	115,832,253	
37	W incentive	2014	22,923,433	556,922	22,366,512		21,037,069	506,768	20,530,301		118,631,824	2,799,571	115,832,253	
38	W / O incentive	2015	22,366,512	556,922	21,809,590		20,530,301	506,768	20,023,534		115,832,253	2,799,571	113,032,682	
39	W incentive	2015	22,366,512	556,922	21,809,590		20,530,301	506,768	20,023,534		115,832,253	2,799,571	113,032,682	
40	W / O incentive	2016	21,809,590	556,922	21,252,668	3,329,923	20,023,534	506,768	19,516,766	3,052,971	113,032,682	2,799,571	110,233,111	17,176,807
41	W incentive	2016	21,809,590	556,922	21,252,668	3,329,923	20,023,534	506,768	19,516,766	3,052,971	113,032,682	2,799,571	110,233,111	17,176,807

A		3,621,899	3,320,389	18,387,881
B		3,621,899	3,320,389	18,387,881
C		3,583,871	3,284,919	18,469,954
D		3,583,871	3,284,919	18,469,954
E		(38,028)	(35,470)	82,073
F		(38,028)	(35,470)	82,073
G		1.06685	1.06685	1.06685
H		(40,570)	(37,841)	87,560
I		(40,570)	(37,841)	87,560
	W / O incentive	3,289,352	3,015,130	17,264,366
	W incentive	3,289,352	3,015,130	17,264,366

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

10			**Project AK-4**				**Project AK-5**				**Project AL**			
11	Schedule 12	(Yes or No)	Yes	B1507			Yes	B1507			Yes	B0457		
12	Life		43	Rebuild Mt. Storm-Doubs 500 kV			43	Rebuild Mt. Storm-Doubs 500 kV			43	Replace both wave traps on		
13	FCR W/O incentive	Line 3	12.8790%				12.8790%				12.8790%	Dooms - Lexington 500 kV		
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		12.8790%				12.8790%				12.8790%			
16	Investment		139,885,565				23,000,000				108,763			
17	Annual Depreciation Exp		3,253,153				534,884				2,529			
18	In Service Month (1-12)		5				5				12			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011									108,763	89	108,674	
31	W incentive	2011									108,763	89	108,674	
32	W / O incentive	2012									108,674	2,133	106,542	
33	W incentive	2012									108,674	2,133	106,542	
34	W / O incentive	2013									106,542	2,430	104,111	
35	W incentive	2013									106,542	2,430	104,111	
36	W / O incentive	2014	139,885,565	2,033,220	137,852,345						104,111	2,529	101,582	
37	W incentive	2014	139,885,565	2,033,220	137,852,345						104,111	2,529	101,582	
38	W / O incentive	2015	137,852,345	3,253,153	134,599,192		23,000,000	334,302	22,665,698		101,582	2,529	99,053	
39	W incentive	2015	137,852,345	3,253,153	134,599,192		23,000,000	334,302	22,665,698		101,582	2,529	99,053	
40	W / O incentive	2016	134,599,192	3,253,153	131,346,039	20,378,737	22,665,698	334,302	22,331,395	3,231,897	99,053	2,529	96,523	15,124
41	W incentive	2016	134,599,192	3,253,153	131,346,039	20,378,737	22,665,698	334,302	22,331,395	3,231,897	99,053	2,529	96,523	15,124
A						11,983,459								16,450
B						11,983,459								16,450
C						13,634,836								16,277
D						13,634,836								16,277
E						1,651,377				-				(173)
F						1,651,377				-				(173)
G						1.06685				1.06685				1.06685
H						1,761,776				-				(184)
I						1,761,776				-				(184)
	W / O incentive					22,140,513				3,231,897				14,939
	W incentive					22,140,513				3,231,897				14,939

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

10			Project AM				Project AO				Project AP-1			
11	Schedule 12	(Yes or No)	Yes	B0784			Yes	B1224			Yes	B1508.3		
12	Life		43	Replace wave traps on North Anna to			43	Install 2nd Clover 500/230			43	Upgrade a 115 kV shunt capacitor banks		
13	FCR W/O incentive	Line 3	12.8790%	Ladysmith 500 kV			12.8790%	kV transformer and a 150			12.8790%	at Merck and Edinburg		
14	Incentive Factor (Basis Points /100)		0				0	MVAr capacitor			0			
15	FCR W incentive L.13 +(L.14*L.5)		12.8790%				12.8790%				12.8790%	Merck		
16	Investment		75,695				14,160,502				511,009			
17	Annual Depreciation Exp		1,760				329,314				11,884			
18	In Service Month (1-12)		10				4				7			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011	75,695	309	75,386									
31	W incentive	2011	75,695	309	75,386									
32	W / O incentive	2012	75,386	1,484	73,902						511,009	4,592	506,417	
33	W incentive	2012	75,386	1,484	73,902						511,009	4,592	506,417	
34	W / O incentive	2013	73,902	1,691	72,210		14,160,502	233,264	13,927,238		506,417	11,418	494,999	
35	W incentive	2013	73,902	1,691	72,210		14,160,502	233,264	13,927,238		506,417	11,418	494,999	
36	W / O incentive	2014	72,210	1,760	70,450		13,927,238	329,314	13,597,924		494,999	11,884	483,115	
37	W incentive	2014	72,210	1,760	70,450		13,927,238	329,314	13,597,924		494,999	11,884	483,115	
38	W / O incentive	2015	70,450	1,760	68,690		13,597,924	329,314	13,268,610		483,115	11,884	471,231	
39	W incentive	2015	70,450	1,760	68,690		13,597,924	329,314	13,268,610		483,115	11,884	471,231	
40	W / O incentive	2016	68,690	1,760	66,929	10,494	13,268,610	329,314	12,939,296	2,016,976	471,231	11,884	459,347	71,809
41	W incentive	2016	68,690	1,760	66,929	10,494	13,268,610	329,314	12,939,296	2,016,976	471,231	11,884	459,347	71,809
A						11,414				2,177,637				37,630
B						11,414				2,177,637				37,630
C						11,295				2,168,955				77,256
D						11,295				2,168,955				77,256
E						(119)				(8,681)				39,627
F						(119)				(8,681)				39,627
G						1.06685				1.06685				1.06685
H						(127)				(9,262)				42,276
I						(127)				(9,262)				42,276
	W / O incentive					10,367				2,007,714				114,084
	W incentive					10,367				2,007,714				114,084

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

10			**Project AP-2**				**Project AQ**				**Project AR**			
11	Schedule 12	(Yes or No)	Yes	B1508.3			Yes	B1647			Yes	B1648		
12	Life		43	Upgrade a 115 kV shunt capacitor banks			43	Upgrade the name plate			43	Upgrade the name plate rating		
13	FCR W/O incentive	Line 3	12.8790%	at Merck and Edinburg			12.8790%	rating at Morrisville 500 kV			12.8790%	at Morrisville 500 kV		
14	Incentive Factor (Basis Points /100)		0				0	breaker 'H1T573' with			0	breaker 'H2T545' with		
15	FCR W incentive L.13 +(L.14*L.5)		12.8790%	Edinburg			12.8790%	50kA breaker			12.8790%	50kA breaker		
16	Investment		755,038				16,278				16,278			
17	Annual Depreciation Exp		17,559				379				379			
18	In Service Month (1-12)		2				1				1			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012	755,038	12,954	742,084									
33	W incentive	2012	755,038	12,954	742,084									
34	W / O incentive	2013	742,084	16,870	725,213		16,278	350	15,928		16,278	350	15,928	
35	W incentive	2013	742,084	16,870	725,213		16,278	350	15,928		16,278	350	15,928	
36	W / O incentive	2014	725,213	17,559	707,654		15,928	379	15,549		15,928	379	15,549	
37	W incentive	2014	725,213	17,559	707,654		15,928	379	15,549		15,928	379	15,549	
38	W / O incentive	2015	707,654	17,559	690,095		15,549	379	15,170		15,549	379	15,170	
39	W incentive	2015	707,654	17,559	690,095		15,549	379	15,170		15,549	379	15,170	
40	W / O incentive	2016	690,095	17,559	672,536	105,306	15,170	379	14,792	2,308	15,170	379	14,792	2,308
41	W incentive	2016	690,095	17,559	672,536	105,306	15,170	379	14,792	2,308	15,170	379	14,792	2,308
A						114,536				308				308
B						114,536				308				308
C						113,325				2,482				2,482
D						113,325				2,482				2,482
E						(1,211)				2,174				2,174
F						(1,211)				2,174				2,174
G						1.06685				1.06685				1.06685
H						(1,292)				2,319				2,319
I						(1,292)				2,319				2,319
	W / O incentive					104,014				4,627				4,627
	W incentive					104,014				4,627				4,627

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

10			Project AS				Project AT				Project AU-1			
11	Schedule 12 (Yes or No)		Yes	B1649			Yes	B1650			Yes	B1188.6		
12	Life		43	Replace Morrisville 500 kV			43	Replace Morrisville 500 kV			43	Install one 500/230 kV		
13	FCR W/O incentive Line 3		12.8790%	breaker 'H1T580' with			12.8790%	breaker 'H2T569' with			12.8790%	transformer and two 230 kV breakers		
14	Incentive Factor (Basis Points /100)		0	50kA breaker			0	50kA breaker			0	at Brambleton		
15	FCR W incentive L.13 +(L.14*L.5)		12.8790%				12.8790%				12.8790%			
16	Investment		858,877				858,877				235,892			
17	Annual Depreciation Exp		19,974				19,974				5,486			
18	In Service Month (1-12)		1				1				6			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012									235,892	2,505	233,387	
33	W incentive	2012									235,892	2,505	233,387	
34	W / O incentive	2013	858,877	18,489	840,388		858,877	18,489	840,388		233,387	5,271	228,116	
35	W incentive	2013	858,877	18,489	840,388		858,877	18,489	840,388		233,387	5,271	228,116	
36	W / O incentive	2014	840,388	19,974	820,414		840,388	19,974	820,414		228,116	5,486	222,630	
37	W incentive	2014	840,388	19,974	820,414		840,388	19,974	820,414		228,116	5,486	222,630	
38	W / O incentive	2015	820,414	19,974	800,440		820,414	19,974	800,440		222,630	5,486	217,144	
39	W incentive	2015	820,414	19,974	800,440		820,414	19,974	800,440		222,630	5,486	217,144	
40	W / O incentive	2016	800,440	19,974	780,466	121,777	800,440	19,974	780,466	121,777	217,144	5,486	211,658	33,099
41	W incentive	2016	800,440	19,974	780,466	121,777	800,440	19,974	780,466	121,777	217,144	5,486	211,658	33,099
A						134,628				134,628				35,997
B						134,628				134,628				35,997
C						130,973				130,973				35,611
D						130,973				130,973				35,611
E						(3,654)				(3,654)				(386)
F						(3,654)				(3,654)				(386)
G						1.06685				1.06685				1.06685
H						(3,898)				(3,898)				(412)
I						(3,898)				(3,898)				(412)
	W / O incentive					117,878				117,878				32,687
	W incentive					117,878				117,878				32,687

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

10			**Project AU-2**				**Project AV-1**				**Project AV-2**			
11	Schedule 12	(Yes or No)	Yes	B1188.6			Yes	B1188			Yes	B1188		
12	Life		43	Install one 500/230 kV			43	Build new Brambleton 500 kV three			43	Build new Brambleton 500 kV three ring bus		
13	FCR W/O incentive	Line 3	12.8790%	transformer and two 230 kV breakers			12.8790%	ring bus connected to the Loudoun			12.8790%	connected to the Loudoun to Pleasant View		
14	Incentive Factor (Basis Points /100)		0	at Brambleton			0	to Pleasant View 500 kV line			0	500 kV line		
15	FCR W incentive L.13 +(L.14*L.5)		12.8790%				12.8790%				12.8790%			
16	Investment		16,717,801				8,552,833				1,617,569			
17	Annual Depreciation Exp		388,786				198,903				37,618			
18	In Service Month (1-12)		12				12				1			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012												
33	W incentive	2012												
34	W / O incentive	2013	16,717,801	16,199	16,701,602		8,552,833	8,288	8,544,545					
35	W incentive	2013	16,717,801	16,199	16,701,602		8,552,833	8,288	8,544,545					
36	W / O incentive	2014	16,701,602	388,786	16,312,816		8,544,545	198,903	8,345,642		1,617,569	36,050	1,581,519	
37	W incentive	2014	16,701,602	388,786	16,312,816		8,544,545	198,903	8,345,642		1,617,569	36,050	1,581,519	
38	W / O incentive	2015	16,312,816	388,786	15,924,029		8,345,642	198,903	8,146,739		1,581,519	37,618	1,543,901	
39	W incentive	2015	16,312,816	388,786	15,924,029		8,345,642	198,903	8,146,739		1,581,519	37,618	1,543,901	
40	W / O incentive	2016	15,924,029	388,786	15,535,243	2,414,611	8,146,739	198,903	7,947,836	1,235,316	1,543,901	37,618	1,506,283	234,035
41	W incentive	2016	15,924,029	388,786	15,535,243	2,414,611	8,146,739	198,903	7,947,836	1,235,316	1,543,901	37,618	1,506,283	234,035
A						2,417,989				1,100,386				
B						2,417,989				1,100,386				
C						2,595,301				1,327,757				240,952
D						2,595,301				1,327,757				240,952
E						177,312				227,371				240,952
F						177,312				227,371				240,952
G						1.06685				1.06685				1.06685
H						189,166				242,571				257,061
I						189,166				242,571				257,061
	W / O incentive					2,603,777				1,477,887				491,096
	W incentive					2,603,777				1,477,887				491,096

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

10			**Project AW**				**Project AX-1**				**Project AX-2**			
11	Schedule 12	(Yes or No)	Yes	B1698.1			Yes	B1321			Yes	B1321		
12	Life		43	Install a 500 kV breaker at			43	Build a new 230 kV line North Anna -- Oak			43	Build a new 230 kV line North Anna -- Oak		
13	FCR W/O incentive	Line 3	12.8790%	Brambleton			12.8790%	Green and install a 224 MVA 230/115			12.8790%	Green and install a 224 MVA 230/115		
14	Incentive Factor (Basis Points /100)		0				0	kV transformer at Oak Green			0	kV transformer at Oak Green		
15	FCR W incentive L.13 +(L.14*L.5)		12.8790%				12.8790%				12.8790%			
16	Investment		246,157				30,749,389				7,500,000			
17	Annual Depreciation Exp		5,725				715,102				174,419			
18	In Service Month (1-12)		8				3				6			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012												
33	W incentive	2012												
34	W / O incentive	2013												
35	W incentive	2013												
36	W / O incentive	2014												
37	W incentive	2014												
38	W / O incentive	2015	246,157	2,147	244,010		30,749,389	566,122	30,183,267		7,500,000	94,477	7,405,523	
39	W incentive	2015	246,157	2,147	244,010		30,749,389	566,122	30,183,267		7,500,000	94,477	7,405,523	
40	W / O incentive	2016	244,010	5,725	238,286	36,782	30,183,267	715,102	29,468,164	4,556,365	7,405,523	174,419	7,231,105	1,116,947
41	W incentive	2016	244,010	5,725	238,286	36,782	30,183,267	715,102	29,468,164	4,556,365	7,405,523	174,419	7,231,105	1,116,947
A						106,498				2,623,809				
B						106,498				2,623,809				
C						-				-				
D						-				-				
E						(106,498)				(2,623,809)				-
F						(106,498)				(2,623,809)				-
G						1.06685				1.06685				1.06685
H						(113,618)				(2,799,217)				-
I						(113,618)				(2,799,217)				-
	W / O incentive					(76,836)				1,757,148				1,116,947
	W incentive					(76,836)				1,757,148				1,116,947

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

10			**Project AY-1**				**Project AY-2**				**Project AZ**			
11	Schedule 12	(Yes or No)	Yes	B0756.1			Yes	B0756.1			Yes	B1797		
12	Life		43	Install two 500 kV breakers at			43	Install two 500 kV breakers at			43	Wreck and rebuild 7 miles of the		
13	FCR W/O incentive	Line 3	12.8790%	Chancellor 500 kV			12.8790%	Chancellor 500 kV			12.8790%	Dominion owned section of Cloverdale -		
14	Incentive Factor (Basis Points /100)		0				0				0	Lexington 500 kV		
15	FCR W incentive L.13 +(L.14*L.5)		12.8790%				12.8790%				12.8790%			
16	Investment		4,076,165				116,523				18,453,911			
17	Annual Depreciation Exp		94,795				2,710				429,161			
18	In Service Month (1-12)		5				12				10			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012												
33	W incentive	2012												
34	W / O incentive	2013	4,076,165	59,247	4,016,918						18,453,911	89,408	18,364,503	
35	W incentive	2013	4,076,165	59,247	4,016,918						18,453,911	89,408	18,364,503	
36	W / O incentive	2014	4,016,918	94,795	3,922,124		116,523	113	116,410		18,364,503	429,161	17,935,342	
37	W incentive	2014	4,016,918	94,795	3,922,124		116,523	113	116,410		18,364,503	429,161	17,935,342	
38	W / O incentive	2015	3,922,124	94,795	3,827,329		116,410	2,710	113,700		17,935,342	429,161	17,506,181	
39	W incentive	2015	3,922,124	94,795	3,827,329		116,410	2,710	113,700		17,935,342	429,161	17,506,181	
40	W / O incentive	2016	3,827,329	94,795	3,732,535	581,613	113,700	2,710	110,990	17,179	17,506,181	429,161	17,077,020	2,656,151
41	W incentive	2016	3,827,329	94,795	3,732,535	581,613	113,700	2,710	110,990	17,179	17,506,181	429,161	17,077,020	2,656,151
A						528,916				-				2,049,011
B						528,916				-				2,049,011
C						625,400				762				2,855,257
D						625,400				762				2,855,257
E						96,484				762				806,247
F						96,484				762				806,247
G						1.06685				1.06685				1.06685
H						102,934				812				860,146
I						102,934				812				860,146
	W / O incentive					684,547				17,991				3,516,298
	W incentive					684,547				17,991				3,516,298

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

10			Project BA				Project BB-1				Project BB-2			
11	Schedule 12	(Yes or No)	Yes	B1799			Yes	B1798			Yes	B1798		
12	Life		43	Build 150 MVAR Switched Shunt at Pleasant			43	Build a 450 MVAR SVC and 300 MVAR			43	Build a 450 MVAR SVC and 300 MVAR		
13	FCR W/O incentive	Line 3	12.8790%	View 500 kV			12.8790%	switched shunt at Loudoun 500 kV			12.8790%	switched shunt at Loudoun 500 kV		
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		12.8790%				12.8790%				12.8790%			
16	Investment		25,652,240				3,131,641				39,193,327			
17	Annual Depreciation Exp		596,564				72,829				911,473			
18	In Service Month (1-12)		11				12				5			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012												
33	W incentive	2012												
34	W / O incentive	2013					3,131,641	3,035	3,128,606					
35	W incentive	2013					3,131,641	3,035	3,128,606					
36	W / O incentive	2014	25,652,240	74,570	25,577,670		3,128,606	72,829	3,055,778		39,193,327	569,670	38,623,657	
37	W incentive	2014	25,652,240	74,570	25,577,670		3,128,606	72,829	3,055,778		39,193,327	569,670	38,623,657	
38	W / O incentive	2015	25,577,670	596,564	24,981,106		3,055,778	72,829	2,982,949		38,623,657	911,473	37,712,184	
39	W incentive	2015	25,577,670	596,564	24,981,106		3,055,778	72,829	2,982,949		38,623,657	911,473	37,712,184	
40	W / O incentive	2016	24,981,106	596,564	24,384,542	3,775,472	2,982,949	72,829	2,910,120	452,314	37,712,184	911,473	36,800,711	5,709,742
41	W incentive	2016	24,981,106	596,564	24,384,542	3,775,472	2,982,949	72,829	2,910,120	452,314	37,712,184	911,473	36,800,711	5,709,742

A						1,069,883				5,659,293				
B						1,069,883				5,659,293				
C						502,564				486,162				3,820,227
D						502,564				486,162				3,820,227
E						(567,319)				(5,173,131)				3,820,227
F						(567,319)				(5,173,131)				3,820,227
G						1.06685				1.06685				1.06685
H						(605,246)				(5,518,967)				4,075,618
I						(605,246)				(5,518,967)				4,075,618
	W / O incentive					3,170,226				(5,066,654)				9,785,361
	W incentive					3,170,226				(5,066,654)				9,785,361

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

10			Project BB-3				Project BB-4				Project BB-5			
11	Schedule 12	(Yes or No)	Yes	B1798			Yes	B1798			Yes	B1798		
12	Life		43	Build a 450 MVAR SVC and 300 MVAR			43	Build a 450 MVAR SVC and 300 MVAR			43	Build a 450 MVAR SVC and 300 MVAR		
13	FCR W/O incentive	Line 3	12.8790%	switched shunt at Loudoun 500 kV			12.8790%	switched shunt at Loudoun 500 kV			12.8790%	switched shunt at Loudoun 500 kV		
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		12.8790%				12.8790%				12.8790%			
16	Investment		18,443,400				35,386,814				4,668,185			
17	Annual Depreciation Exp		428,916				822,949				108,562			
18	In Service Month (1-12)		6				8				12			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012												
33	W incentive	2012												
34	W / O incentive	2013												
35	W incentive	2013												
36	W / O incentive	2014	18,443,400	232,330	18,211,070		35,386,814	308,606	35,078,208		4,668,185	4,523	4,663,662	
37	W incentive	2014	18,443,400	232,330	18,211,070		35,386,814	308,606	35,078,208		4,668,185	4,523	4,663,662	
38	W / O incentive	2015	18,211,070	428,916	17,782,154		35,078,208	822,949	34,255,259		4,663,662	108,562	4,555,099	
39	W incentive	2015	18,211,070	428,916	17,782,154		35,078,208	822,949	34,255,259		4,663,662	108,562	4,555,099	
40	W / O incentive	2016	17,782,154	428,916	17,353,238	2,691,465	34,255,259	822,949	33,432,310	5,181,701	4,555,099	108,562	4,446,537	688,224
41	W incentive	2016	17,782,154	428,916	17,353,238	2,691,465	34,255,259	822,949	33,432,310	5,181,701	4,555,099	108,562	4,446,537	688,224
A														
B														
C						1,559,303				2,074,677				30,511
D						1,559,303				2,074,677				30,511
E						1,559,303				2,074,677				30,511
F						1,559,303				2,074,677				30,511
G						1.06685				1.06685				1.06685
H						1,663,547				2,213,374				32,550
I						1,663,547				2,213,374				32,550
	W / O incentive					4,355,012				7,395,075				720,775
	W incentive					4,355,012				7,395,075				720,775

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

10			**Project BB-6**				**Project BC**				**Project BD-1**			
11	Schedule 12	(Yes or No)	Yes	B1798			Yes	B1805			Yes	B1508.1		
12	Life		43	Build a 450 MVAR SVC and 300 MVAR switched shunt at Loudoun 500 kV			43	Install a 250 MVAR SVC at the existing Mt. Storm 500 kV substation			43	Build a 2nd 230kV line Harrisonburg to Endless Caverns		
13	FCR W/O incentive	Line 3	12.8790%				12.8790%				12.8790%			
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		12.8790%				12.8790%				12.8790%			
16	Investment		4,584,008				36,855,489				4,488,202			
17	Annual Depreciation Exp		106,605				857,104				104,377			
18	In Service Month (1-12)		1				6				10			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012												
33	W incentive	2012												
34	W / O incentive	2013									4,488,202	21,745	4,466,457	
35	W incentive	2013									4,488,202	21,745	4,466,457	
36	W / O incentive	2014					36,855,489	464,265	36,391,224		4,466,457	104,377	4,362,080	
37	W incentive	2014					36,855,489	464,265	36,391,224		4,466,457	104,377	4,362,080	
38	W / O incentive	2015	4,584,008	102,163	4,481,845		36,391,224	857,104	35,534,120		4,362,080	104,377	4,257,703	
39	W incentive	2015	4,584,008	102,163	4,481,845		36,391,224	857,104	35,534,120		4,362,080	104,377	4,257,703	
40	W / O incentive	2016	4,481,845	106,605	4,375,240	676,958	35,534,120	857,104	34,677,015	5,378,361	4,257,703	104,377	4,153,326	646,006
41	W incentive	2016	4,481,845	106,605	4,375,240	676,958	35,534,120	857,104	34,677,015	5,378,361	4,257,703	104,377	4,153,326	646,006
A										2,597,405				
B										2,597,405				
C										2,965,087				694,431
D										2,965,087				694,431
E						-				367,683				694,431
F						-				367,683				694,431
G						1.06685				1.06685				1.06685
H						-				392,263				740,856
I						-				392,263				740,856
	W / O incentive					676,958				5,770,625				1,386,862
	W incentive					676,958				5,770,625				1,386,862

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

10			Project BD-2				Project BD-3				Project BD-4			
11	Schedule 12	(Yes or No)	Yes	B1508.1			Yes	B1508.1			Yes	B1508.1		
12	Life		43	Build a 2nd 230kV line Harrisonburg to			43	Build a 2nd 230kV line Harrisonburg to			43	Build a 2nd 230kV line Harrisonburg to		
13	FCR W/O incentive	Line 3	12.8790%	Endless Caverns			12.8790%	Endless Caverns			12.8790%	Endless Caverns		
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		12.8790%				12.8790%				12.8790%			
16	Investment		51,000,438				2,000,000				5,427,713			
17	Annual Depreciation Exp		1,186,057				46,512				126,226			
18	In Service Month (1-12)		9				12				6			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012												
33	W incentive	2012												
34	W / O incentive	2013												
35	W incentive	2013												
36	W / O incentive	2014	51,000,438	345,933	50,654,505		2,000,000	1,938	1,998,062					
37	W incentive	2014	51,000,438	345,933	50,654,505		2,000,000	1,938	1,998,062					
38	W / O incentive	2015	50,654,505	1,186,057	49,468,448		1,998,062	46,512	1,951,550		5,427,713	68,372	5,359,341	
39	W incentive	2015	50,654,505	1,186,057	49,468,448		1,998,062	46,512	1,951,550		5,427,713	68,372	5,359,341	
40	W / O incentive	2016	49,468,448	1,186,057	48,282,391	7,480,737	1,951,550	46,512	1,905,039	294,857	5,359,341	126,226	5,233,115	808,329
41	W incentive	2016	49,468,448	1,186,057	48,282,391	7,480,737	1,951,550	46,512	1,905,039	294,857	5,359,341	126,226	5,233,115	808,329

A														
B														
C						2,215,965				13,072				
D						2,215,965				13,072				
E						2,215,965				13,072				-
F						2,215,965				13,072				-
G						1.06685				1.06685				1.06685
H						2,364,108				13,946				-
I						2,364,108				13,946				-
	W / O incentive					9,844,845				308,803				808,329
	W incentive					9,844,845				308,803				808,329

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

10			Project BD-5		Project BE		Project BF-1	
11	Schedule 12	(Yes or No)	Yes	B1508.1	Yes	B1508.2	Yes	B2053
12	Life		43	Build a 2nd 230kV line Harrisonburg to	43	Install a 3rd 230 - 115 kV Tx at	43	Rebuild 28 mile line
13	FCR W/O incentive	Line 3	12.8790%	Endless Caverns	12.8790%	Endless Caverns	12.8790%	(Altavista - Skimmer, 115kV)
14	Incentive Factor (Basis Points /100)		0		0		0	
15	FCR W incentive L.13 +(L.14*L.5)		12.8790%		12.8790%		12.8790%	
16	Investment		1,157,623		12,005,264		6,782,738	
17	Annual Depreciation Exp		26,921		279,192		157,738	
18	In Service Month (1-12)		9		9		11	

19			Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req	Beginning	Depreciation	Ending	Rev Req
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012												
33	W incentive	2012												
34	W / O incentive	2013												
35	W incentive	2013												
36	W / O incentive	2014					12,005,264	81,431	11,923,833		6,782,738	19,717	6,763,021	
37	W incentive	2014					12,005,264	81,431	11,923,833		6,782,738	19,717	6,763,021	
38	W / O incentive	2015	1,157,623	7,852	1,149,771		11,923,833	279,192	11,644,641		6,763,021	157,738	6,605,283	
39	W incentive	2015	1,157,623	7,852	1,149,771		11,923,833	279,192	11,644,641		6,763,021	157,738	6,605,283	
40	W / O incentive	2016	1,149,771	26,921	1,122,849	173,267	11,644,641	279,192	11,365,449	1,760,930	6,605,283	157,738	6,447,545	998,277
41	W incentive	2016	1,149,771	26,921	1,122,849	173,267	11,644,641	279,192	11,365,449	1,760,930	6,605,283	157,738	6,447,545	998,277

A			
B			
C		547,893	132,883
D		547,893	132,883
E	-	547,893	132,883
F	-	547,893	132,883
G	1.06685	1.06685	1.06685
H	-	584,521	141,767
I	-	584,521	141,767

W / O incentive	173,267	2,345,452	1,140,044
W incentive	173,267	2,345,452	1,140,044

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

10			**Project BF-2**				**Project BF-3**				**Project BG-1**			
11	Schedule 12	(Yes or No)	Yes	B2053			Yes	B2053			Yes	B1906.1		
12	Life		43	Rebuild 28 mile line			43	Rebuild 28 mile line			43	At Yadkin 500 kV, install six 500 kV breakers		
13	FCR W/O incentive	Line 3	12.8790%	(Altavista - Skimmer, 115kV)			12.8790%	(Altavista - Skimmer, 115kV)			12.8790%			
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		12.8790%				12.8790%				12.8790%			
16	Investment		19,434,819				12,653,720				4,398,307			
17	Annual Depreciation Exp		451,973				294,273				102,286			
18	In Service Month (1-12)		3				7				5			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012												
33	W incentive	2012												
34	W / O incentive	2013												
35	W incentive	2013												
36	W / O incentive	2014												
37	W incentive	2014												
38	W / O incentive	2015	19,434,819	357,812	19,077,007		12,653,720	134,875	12,518,845		4,398,307	63,929	4,334,378	
39	W incentive	2015	19,434,819	357,812	19,077,007		12,653,720	134,875	12,518,845		4,398,307	63,929	4,334,378	
40	W / O incentive	2016	19,077,007	451,973	18,625,035	2,879,801	12,518,845	294,273	12,224,573	1,887,629	4,334,378	102,286	4,232,092	653,925
41	W incentive	2016	19,077,007	451,973	18,625,035	2,879,801	12,518,845	294,273	12,224,573	1,887,629	4,334,378	102,286	4,232,092	653,925
A														
B														
C														
D														
E						-				-				-
F						-				-				-
G						1.06685				1.06685				1.06685
H						-				-				-
I						-				-				-
	W / O incentive					2,879,801				1,887,629				653,925
	W incentive					2,879,801				1,887,629				653,925

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

10			**Project BG-2**				**Project BH-2**				**Project BH-3**			
11	Schedule 12	(Yes or No)	Yes	B1906.1			Yes	B1908			Yes	B1908		
12	Life		43	At Yadkin 500 kV, install six 500 kV breakers			43	Rebuild Lexington-Dooms 500 kV			43	Rebuild Lexington-Dooms 500 kV		
13	FCR W/O incentive	Line 3	12.8790%				12.8790%				12.8790%			
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		12.8790%				12.8790%				12.8790%			
16	Investment		5,008,695				50,476,196				42,555,845			
17	Annual Depreciation Exp		116,481				1,173,865				989,671			
18	In Service Month (1-12)		11				5				12			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012												
33	W incentive	2012												
34	W / O incentive	2013												
35	W incentive	2013												
36	W / O incentive	2014												
37	W incentive	2014												
38	W / O incentive	2015	5,008,695	14,560	4,994,135		50,476,196	733,666	49,742,530		42,555,845	41,236	42,514,609	
39	W incentive	2015	5,008,695	14,560	4,994,135		50,476,196	733,666	49,742,530		42,555,845	41,236	42,514,609	
40	W / O incentive	2016	4,994,135	116,481	4,877,654	752,177	49,742,530	1,173,865	48,568,665	7,504,630	42,514,609	989,671	41,524,938	6,401,411
41	W incentive	2016	4,994,135	116,481	4,877,654	752,177	49,742,530	1,173,865	48,568,665	7,504,630	42,514,609	989,671	41,524,938	6,401,411

A				
B				
C				
D				
E		-	-	-
F		-	-	-
G		1.06685	1.06685	1.06685
H		-	-	-
I		-	-	-
	W / O incentive	752,177	7,504,630	6,401,411
	W incentive	752,177	7,504,630	6,401,411

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

10			Project BI				Project BK				Project BM			
11	Schedule 12	(Yes or No)	Yes	B1698			Yes	B1905.2			Yes	B1905.4		
12	Life		43	Install a 2nd 500/230 kV transformer			43	Surry 500 kV Station Work			43	Skiffes Creek - Whealton 230 kV line		
13	FCR W/O incentive	Line 3	12.8790%	at Brambleton			12.8790%				12.8790%			
14	Incentive Factor (Basis Points /100)		0				0				0			
15	FCR W incentive L.13 +(L.14*L.5)		12.8790%				12.8790%				12.8790%			
16	Investment		16,733,835				1,813,244				70,000,000			
17	Annual Depreciation Exp		389,159				42,168				1,627,907			
18	In Service Month (1-12)		5				5				12			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012												
33	W incentive	2012												
34	W / O incentive	2013												
35	W incentive	2013												
36	W / O incentive	2014					1,813,244	26,355	1,786,889					
37	W incentive	2014					1,813,244	26,355	1,786,889					
38	W / O incentive	2015					1,786,889	42,168	1,744,720					
39	W incentive	2015					1,786,889	42,168	1,744,720					
40	W / O incentive	2016	16,733,835	243,224	16,490,611	1,580,408	1,744,720	42,168	1,702,552	264,156	70,000,000	67,829	69,932,171	443,286
41	W incentive	2016	16,733,835	243,224	16,490,611	1,580,408	1,744,720	42,168	1,702,552	264,156	70,000,000	67,829	69,932,171	443,286

A														
B														
C										176,739				
D										176,739				
E						-				176,739				-
F						-				176,739				-
G						1.06685				1.06685				1.06685
H						-				188,555				-
I						-				188,555				-
	W / O incentive					1,580,408				452,711				443,286
	W incentive					1,580,408				452,711				443,286

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

10		**Project BS**		**Project BT**		**Project BU**	
11	Schedule 12 (Yes or No)	Yes	B1907	Yes	B1909	Yes	B1328
12	Life	43	Install a 3rd 500/230 kV TX at Clover	43	Uprate Bremo – Midlothian 230 kV to	43	Uprate the 3.63 mile line section between
13	FCR W/O incentive Line 3	12.8790%		12.8790%	its maximum operating temperature	12.8790%	Possum and Dumfries substations,
14	Incentive Factor (Basis Points /100)	0		0		0	Replace 1600 amp wave trap at Possum Point
15	FCR W incentive L.13 +(L.14*L.5)	12.8790%		12.8790%		12.8790%	
16	Investment	18,589,932		4,726,653		3,987,669	
17	Annual Depreciation Exp	432,324		109,922		92,736	
18	In Service Month (1-12)	7		7		1	

19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012												
33	W incentive	2012												
34	W / O incentive	2013												
35	W incentive	2013												
36	W / O incentive	2014												
37	W incentive	2014												
38	W / O incentive	2015												
39	W incentive	2015												
40	W / O incentive	2016	18,589,932	198,149	18,391,784	1,289,643	4,726,653	50,381	4,676,272	327,903	3,987,669	88,872	3,898,797	575,562
41	W incentive	2016	18,589,932	198,149	18,391,784	1,289,643	4,726,653	50,381	4,676,272	327,903	3,987,669	88,872	3,898,797	575,562

A				
B				
C				
D				
E		-	-	-
F		-	-	-
G		1.06685	1.06685	1.06685
H		-	-	-
I		-	-	-
	W / O incentive	1,289,643	327,903	575,562
	W incentive	1,289,643	327,903	575,562

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

10			Project BV				Project BW				Project BX			
11	Schedule 12	(Yes or No)	Yes	B1912			Yes	B1701			Yes	B1791		
12	Life		43	Install a 500 MVAR SVC at			43	Reconductor line #2104			43	Wreck and rebuild 2.1 mile section of		
13	FCR W/O incentive	Line 3	12.8790%	Landstown 230 kV			12.8790%	(Fredericksburg - Cranes Corner 230 kV)			12.8790%	Gordonsville and Somerset (Line #11)		
14	Incentive Factor (Basis Points /100)		0	(Includes project modifications.)			0				0			
15	FCR W incentive L.13 +(L.14*L.5)		12.8790%				12.8790%				12.8790%			
16	Investment		67,852,889				4,241,924				3,148,794			
17	Annual Depreciation Exp		1,577,974				98,649				73,228			
18	In Service Month (1-12)		10				5				6			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012												
33	W incentive	2012												
34	W / O incentive	2013												
35	W incentive	2013												
36	W / O incentive	2014												
37	W incentive	2014												
38	W / O incentive	2015									3,148,794	39,665	3,109,129	
39	W incentive	2015									3,148,794	39,665	3,109,129	
40	W / O incentive	2016	67,852,889	328,745	67,524,144	2,144,917	4,241,924	61,656	4,180,268	400,624	3,109,129	73,228	3,035,901	468,938
41	W incentive	2016	67,852,889	328,745	67,524,144	2,144,917	4,241,924	61,656	4,180,268	400,624	3,109,129	73,228	3,035,901	468,938
A														
B														
C														
D														
E						-				-				-
F						-				-				-
G						1.06685				1.06685				1.06685
H						-				-				-
I						-				-				-
	W / O incentive					2,144,917				400,624				468,938
	W incentive					2,144,917				400,624				468,938

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

10			**Project BY**				**Project CC**				**Project CE**			
11	Schedule 12	(Yes or No)	Yes	B1694			Yes	B1911			Yes	B2471		
12	Life		43	Rebuild Loudoun - Brambleton 500 kV			43	Add a second Valley 500/230 kV TX			43	R/P Midlothian 500 kV breaker and		
13	FCR W/O incentive	Line 3	12.8790%				12.8790%				12.8790%	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)		12.8790%				12.8790%				12.8790%	#576 Midlothian - North Anna,		
16	Investment		32,750,184				18,667,472				7,035,218	Transformer #2 in new ring		
17	Annual Depreciation Exp		761,632				434,127				163,610			
18	In Service Month (1-12)		6				7				12			
19			**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**	**Beginning**	**Depreciation**	**Ending**	**Rev Req**
20	W / O incentive	2006												
21	W incentive	2006												
22	W / O incentive	2007												
23	W incentive	2007												
24	W / O incentive	2008												
25	W incentive	2008												
26	W / O incentive	2009												
27	W incentive	2009												
28	W / O incentive	2010												
29	W incentive	2010												
30	W / O incentive	2011												
31	W incentive	2011												
32	W / O incentive	2012												
33	W incentive	2012												
34	W / O incentive	2013												
35	W incentive	2013												
36	W / O incentive	2014												
37	W incentive	2014												
38	W / O incentive	2015									7,035,218	6,817	7,028,401	
39	W incentive	2015									7,035,218	6,817	7,028,401	
40	W / O incentive	2016	32,750,184	412,551	32,337,633	2,682,860	18,667,472	198,975	18,468,497	1,295,023	7,028,401	163,610	6,864,791	1,058,264
41	W incentive	2016	32,750,184	412,551	32,337,633	2,682,860	18,667,472	198,975	18,468,497	1,295,023	7,028,401	163,610	6,864,791	1,058,264

A				
B				
C				
D				
E		-	-	-
F		-	-	-
G		1.06685	1.06685	1.06685
H		-	-	-
I		-	-	-
	W / O incentive	2,682,860	1,295,023	1,058,264
	W incentive	2,682,860	1,295,023	1,058,264

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

10					
11	Schedule 12	(Yes or No)	If Yes for Schedule 12 Include in this Total.	If No for Schedule 12 include in this Sum.	
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 including Incentive if Applicable	Annual Revenue Requirement excluding Incentive
17	Annual Depreciation Exp				
18	In Service Month (1-12)				
19			**Total**	**Sum**	**Sum**
20	W / O incentive	2006			
21	W incentive	2006			
22	W / O incentive	2007			
23	W incentive	2007			
24	W / O incentive	2008			
25	W incentive	2008			
26	W / O incentive	2009			
27	W incentive	2009			
28	W / O incentive	2010			
29	W incentive	2010			
30	W / O incentive	2011			
31	W incentive	2011			
32	W / O incentive	2012			
33	W incentive	2012			
34	W / O incentive	2013			
35	W incentive	2013			
36	W / O incentive	2014			
37	W incentive	2014			
38	W / O incentive	2015			
39	W incentive	2015			
40	W / O incentive	2016	211,556,732		48,035,512
41	W incentive	2016	216,351,713	51,072,189	

A
B
C
D
E
F
G
H
I

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 and After April 1, 2013

Plant Type	Applied Depreciation Rate
Transmission Plant	
Land	
Land Rights	1.17%
Structures and Improvements	1.53%
Station Equipment	2.89%
Station Equipment - Power Supply Computer Equipment	10.46%
Towers and Fixtures	2.08%
Poles and Fixtures	2.11%
Overhead conductors and Devices	1.92%
Underground Conduit	1.65%
Underground Conductors and Devices	1.92%
Roads and Trails	1.06%
General Plant	
Land	
Land Rights	1.71%
Structures and Improvements - Major	1.95%
Structures and Improvements - Other	2.82%
Office Furniture and Equipment	2.68%
Office Furniture and Equipment - EDP Hardware	15.26%
Office Furniture and Equipment - EDP Fixed Location	7.26%
Transportation Equipment	3.90%
Stores Equipment	2.52%
Tools, Shop and Garage Equipment	4.32%
Laboratory Equipment	3.69%
Power Operated Equipment	4.75%
Communication Equipment	3.14%
Communication Equipment - Massed	5.97%
Communication Equipment - 25 Years	2.48%
Miscellaneous Equipment	6.67%

---

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

Attachment 10

PSE&G Formula Rate for January 1, 2016 to December 31, 2016

Public Service Electric and Gas Company
ATTACHMENT H-10A

Formula Rate -- Appendix A

Shaded cells are input cells

		Notes	FERC Form 1 Page # or Instruction	12 Months Ended 12/31/2016
	Allocators			
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense	(Note O)	Attachment 5	29,830,445
2	Total Wages Expense	(Note O)	Attachment 5	198,680,651
3	Less A&G Wages Expense	(Note O)	Attachment 5	6,226,170
4	Total Wages Less A&G Wages Expense		(Line 2 - Line 3)	192,454,482
5	**Wages & Salary Allocator**		(Line 1 / Line 4)	**15.5000%**
	Plant Allocation Factors			
6	Electric Plant in Service	(Note B)	Attachment 5	16,924,862,786
7	Common Plant in Service - Electric		(Line 22)	145,824,542
8	Total Plant in Service		(Line 6 + 7)	17,070,687,329
9	Accumulated Depreciation (Total Electric Plant)	(Note B & J)	Attachment 5	3,319,374,990
10	Accumulated Intangible Amortization - Electric	(Note B)	Attachment 5	5,264,202
11	Accumulated Common Plant Depreciation & Amortization - Electric	(Note B & J)	Attachment 5	17,761,451
12	Accumulated Common Amortization - Electric	(Note B)	Attachment 5	38,924,891
13	Total Accumulated Depreciation		(Line 9 + Line 10 + Line 11 + Line 12)	3,381,325,534
14	Net Plant		(Line 8 - Line 13)	13,689,361,794
15	Transmission Gross Plant		(Line 31)	8,330,672,215
16	**Gross Plant Allocator**		(Line 15 / Line 8)	**48.8010%**
17	Transmission Net Plant		(Line 43)	7,535,121,583
18	**Net Plant Allocator**		(Line 17 / Line 14)	**55.0436%**
	Plant Calculations			
	Plant In Service			
19	Transmission Plant In Service	(Note B)	Attachment 5	8,259,324,176
20	General	(Note B)	Attachment 5	227,839,129
21	Intangible - Electric	(Note B)	Attachment 5	7,967,491
22	Common Plant - Electric	(Note B)	Attachment 5	145,824,542
23	Total General, Intangible & Common Plant		(Line 20 + Line 21 + Line 22)	381,631,162
24	Less: General Plant Account 397 -- Communications	(Note B)	Attachment 5	21,195,573
25	Less: Common Plant Account 397 -- Communications	(Note B)	Attachment 5	10,236,825
26	General and Intangible Excluding Acct. 397		(Line 23 - Line 24 - Line 25)	350,198,765
27	Wage & Salary Allocator		(Line 5)	15.5000%
28	General and Intangible Plant Allocated to Transmission		(Line 26 * Line 27)	54,280,809
29	Account No. 397 Directly Assigned to Transmission	(Note B)	Attachment 5	17,067,231
30	Total General and Intangible Functionalized to Transmission		(Line 28 + Line 29)	71,348,039
31	**Total Plant In Rate Base**		(Line 19 + Line 30)	**8,330,672,215**
	Accumulated Depreciation			
32	Transmission Accumulated Depreciation	(Note B & J)	Attachment 5	756,323,290
33	Accumulated General Depreciation	(Note B & J)	Attachment 5	101,368,991
34	Accumulated Common Plant Depreciation - Electric	(Note B & J)	Attachment 5	56,686,342
35	Less: Amount of General Depreciation Associated with Acct. 397	(Note B & J)	Attachment 5	12,618,244
36	Balance of Accumulated General Depreciation		(Line 33 + Line 34 - Line 35)	145,437,089
37	Accumulated Intangible Amortization - Electric	(Note B)	(Line 10)	5,264,202
38	Accumulated General and Intangible Depreciation Ex. Acct. 397		(Line 36 + 37)	150,701,292
39	Wage & Salary Allocator		(Line 5)	15.5000%
40	Subtotal General and Intangible Accum. Depreciation Allocated to Transmission		(Line 38 * Line 39)	23,358,700
41	Accumulated General Depreciation Associated with Acct. 397 Directly Assigned to Transmission	(Note B & J)	Attachment 5	15,868,641
42	**Total Accumulated Depreciation**		(Lines 32 + 40 + 41)	**795,550,632**
43	**Total Net Property, Plant & Equipment**		(Line 31 - Line 42)	**7,535,121,583**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Formula Rate -- Appendix A

Shaded cells are input cells

	Formula Rate -- Appendix A	Notes	FERC Form 1 Page # or Instruction	12 Months Ended 12/31/2016
	Adjustment To Rate Base			
	Accumulated Deferred Income Taxes			
44	**ADIT net of FASB 106 and 109**	(Note Q)	Attachment 1	-1,781,469,260
	CWIP for Incentive Transmission Projects			
45	CWIP Balances for Current Rate Year	(Note B & H)	Attachment 6	324,287,973
	Abandoned Transmission Projects			
45a	Unamortized Abandoned Transmission Projects	(Note R)	Attachment 5	0
46	**Plant Held for Future Use**	(Note C & Q)	Attachment 5	26,120,911
	Prepayments			
47	Prepayments	(Note A & Q)	Attachment 5	-288,864
	Materials and Supplies			
48	Undistributed Stores Expense	(Note Q)	Attachment 5	0
49	Wage & Salary Allocator		(Line 5)	15.5000%
50	Total Undistributed Stores Expense Allocated to Transmission		(Line 48 * Line 49)	0
51	Transmission Materials & Supplies	(Note N & Q))	Attachment 5	9,654,089
52	Total Materials & Supplies Allocated to Transmission		(Line 50 + Line 51)	9,654,089
	Cash Working Capital			
53	Operation & Maintenance Expense		(Line 80)	133,152,694
54	1/8th Rule		1/8	12.5%
55	Total Cash Working Capital Allocated to Transmission		(Line 53 * Line 54)	16,644,087
	Network Credits			
56	Outstanding Network Credits	(Note N & Q))	Attachment 5	0
57	**Total Adjustment to Rate Base**		**(Lines 44 + 45 + 45a + 46 + 47 + 52 + 55 - 56)**	**(1,405,051,064)**
58	**Rate Base**		(Line 43 + Line 57)	**6,130,070,519**
	Operations & Maintenance Expense			
	Transmission O&M			
59	Transmission O&M	(Note O)	Attachment 5	100,364,698
60	Plus Transmission Lease Payments	(Note O)	Attachment 5	0
61	**Transmission O&M**		(Lines 59 + 60)	**100,364,698**
	Allocated Administrative & General Expenses			
62	Total A&G	(Note O)	Attachment 5	215,993,171
63	Plus: Actual PBOP expense	(Note J)	Attachment 5	28,522,987
64	Less: Actual PBOP expense	(Note O)	Attachment 5	33,272,121
65	Less Property Insurance Account 924	(Note O)	Attachment 5	4,631,400
66	Less Regulatory Commission Exp Account 928	(Note E & O)	Attachment 5	10,672,984
67	Less General Advertising Exp Account 930.1	(Note O)	Attachment 5	2,844,680
68	Less EPRI Dues	(Note D & O)	Attachment 5	0
69	**Administrative & General Expenses**		Sum (Lines 62 to 63) - Sum (Lines 64 to 68)	193,094,974
70	Wage & Salary Allocator		(Line 5)	15.5000%
71	**Administrative & General Expenses Allocated to Transmission**		(Line 69 * Line 70)	**29,929,721**
	Directly Assigned A&G			
72	Regulatory Commission Exp Account 928	(Note G & O)	Attachment 5	308,984
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)	308,984
75	Property Insurance Account 924		(Line 65)	4,631,400
76	General Advertising Exp Account 930.1	(Note F & O)	Attachment 5	0
77	Total Accounts 928 and 930.1 - General		(Line 75 + Line 76)	4,631,400
78	Net Plant Allocator		(Line 18)	55.0436%
79	**A&G Directly Assigned to Transmission**		(Line 77 * Line 78)	**2,549,291**
80	**Total Transmission O&M**		**(Lines 61 + 71 + 74 + 79)**	**133,152,694**

Public Service Electric and Gas Company
ATTACHMENT H-10A

	Formula Rate -- Appendix A		Notes	FERC Form 1 Page # or Instruction	12 Months Ended 12/31/2016
	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	196,487,978
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	17,537,763
83	Less: Amount of General Depreciation Expense Associated with Acct. 397		(Note J & O)	Attachment 5	3,244,255
84	Balance of General Depreciation Expense			(Line 82 - Line 83)	14,293,508
85	Intangible Amortization		(Note A & O)	Attachment 5	9,439,036
86	Total			(Line 84 + Line 85)	23,732,543
87	Wage & Salary Allocator			(Line 5)	15.50%
88	General Depreciation & Intangible Amortization Allocated to Transmission			(Line 86 * Line 87)	3,678,544
89	General Depreciation Expense for Acct. 397 Directly Assigned to Transmission		(Note J & O)	Attachment 5	1,698,462
90	**General Depreciation and Intangible Amortization Functionalized to Transmission**			(Line 88 + Line 89)	**5,377,006**
91	**Total Transmission Depreciation & Amortization**			**(Lines 81 + 81a + 90)**	**201,864,984**
	Taxes Other than Income Taxes				
92	Taxes Other than Income Taxes		(Note O)	Attachment 2	10,150,418
93	**Total Taxes Other than Income Taxes**			(Line 92)	**10,150,418**
	Return \ Capitalization Calculations				
94	**Long Term Interest**			p117.62.c through 67.c	252,018,266
95	**Preferred Dividends**		enter positive	p118.29.d	0
	Common Stock				
96	Proprietary Capital		(Note P)	Attachment 5	6,377,924,573
97	Less Accumulated Other Comprehensive Income Account 219		(Note P)	Attachment 5	1,408,022
98	Less Preferred Stock			(Line 106)	0
99	Less Account 216.1		(Note P)	Attachment 5	3,430,285
100	**Common Stock**			(Line 96 - 97 - 98 - 99)	6,373,086,266
	Capitalization				
101	Long Term Debt		(Note P)	Attachment 5	5,939,268,873
102	Less Loss on Reacquired Debt		(Note P)	Attachment 5	77,696,491
103	Plus Gain on Reacquired Debt		(Note P)	Attachment 5	0
104	Less ADIT associated with Gain or Loss		(Note P)	Attachment 5	23,902,953
105	Total Long Term Debt			(Line 101 - 102 + 103 - 104)	5,837,669,430
106	Preferred Stock		(Note P)	Attachment 5	0
107	Common Stock			(Line 100)	6,373,086,266
108	**Total Capitalization**			(Sum Lines 105 to 107)	12,210,755,696
109	Debt %	Total Long Term Debt		(Line 105 / Line 108)	47.81%
110	Preferred %	Preferred Stock		(Line 106 / Line 108)	0.00%
111	Common %	Common Stock		(Line 107 / Line 108)	52.19%
112	Debt Cost	Total Long Term Debt		(Line 94 / Line 105)	0.0432
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)	0.0206
116	Weighted Cost of Preferred	Preferred Stock		(Line 110 * Line 113)	0.0000
117	Weighted Cost of Common	Common Stock		(Line 111 * Line 114)	0.0610
118	**Rate of Return on Rate Base (ROR)**			(Sum Lines 115 to 117)	**0.0816**
119	**Investment Return = Rate Base * Rate of Return**			**(Line 58 * Line 118)**	**500,212,287**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Formula Rate -- Appendix A

Shaded cells are input cells

			Notes	FERC Form 1 Page # or Instruction	12 Months Ended 12/31/2016
	Composite Income Taxes				
	Income Tax Rates				
120	FIT=Federal Income Tax Rate		(Note I)		35.00%
121	SIT=State Income Tax Rate or Composite				9.00%
122	p	(percent of federal income tax deductible for state purposes)		Per State Tax Code	0.00%
123	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			40.85%
124	T / (1-T)				69.06%
	ITC Adjustment				
125	Amortized Investment Tax Credit	enter negative	(Note O)	Attachment 5	-868,658
126	1/(1-T)			1 / (1 - Line 123)	169.06%
127	Net Plant Allocation Factor			(Line 18)	55.04%
128	**ITC Adjustment Allocated to Transmission**			(Line 125 * Line 126 * Line 127)	**-808,353**
129	**Income Tax Component =**	(T/1-T) * Investment Return * (1-(WCLTD/ROR)) =		[Line 124 * Line 119 * (1- (Line 115 / Line 118))]	**258,079,126**
130	**Total Income Taxes**			**(Line 128 + Line 129)**	**257,270,773**
	Revenue Requirement				
	Summary				
131	Net Property, Plant & Equipment			(Line 43)	7,535,121,583
132	Total Adjustment to Rate Base			(Line 57)	-1,405,051,064
133	**Rate Base**			(Line 58)	**6,130,070,519**
134	Total Transmission O&M			(Line 80)	133,152,694
135	Total Transmission Depreciation & Amortization			(Line 91)	201,864,984
136	Taxes Other than Income			(Line 93)	10,150,418
137	Investment Return			(Line 119)	500,212,287
138	Income Taxes			(Line 130)	257,270,773
139	**Gross Revenue Requirement**			**(Sum Lines 134 to 138)**	**1,102,651,156**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
140	Transmission Plant In Service			(Line 19)	8,259,324,176
141	Excluded Transmission Facilities		(Note B & M)	Attachment 5	0
142	Included Transmission Facilities			(Line 140 - Line 141)	8,259,324,176
143	Inclusion Ratio			(Line 142 / Line 140)	100.00%
144	Gross Revenue Requirement			(Line 139)	1,102,651,156
145	**Adjusted Gross Revenue Requirement**			(Line 143 * Line 144)	**1,102,651,156**
	Revenue Credits & Interest on Network Credits				
146	**Revenue Credits**		(Note O)	Attachment 3	26,187,113
147	**Interest on Network Credits**		(Note N & O)	Attachment 5	0
148	**Net Revenue Requirement**			**(Line 145 - Line 146 + Line 147)**	**1,076,464,043**
	Net Plant Carrying Charge				
149	Gross Revenue Requirement			(Line 144)	**1,102,651,156**
150	Net Transmission Plant, CWIP and Abandoned Plant			(Line 19 - Line 32 + Line 45 + Line 45a)	**7,827,288,859**
151	Net Plant Carrying Charge			(Line 149 / Line 150)	**14.0873%**
152	Net Plant Carrying Charge without Depreciation			(Line 149 - Line 81) / Line 150	**11.5770%**
153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes			(Line 149 - Line 81 - Line 119 - Line 130) / Line 15	**1.8995%**
	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)	**345,168,096**
155	Increased Return and Taxes			Attachment 4	**811,573,184**
156	Net Revenue Requirement per 100 Basis Point increase in ROE			(Line 154 + Line 155)	**1,156,741,280**
157	Net Transmission Plant, CWIP and Abandoned Plant			(Line 19 - Line 32 + Line 45 + Line 45a)	**7,827,288,859**
158	Net Plant Carrying Charge per 100 Basis Point increase in ROE			(Line 156 / Line 157)	**14.7783%**
159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation			(Line 156 - Line 81) / Line 157	**12.2680%**
160	**Net Revenue Requirement**			(Line 148)	**1,076,464,043**
161	True-up amount			Attachment 6	**-20,019,061**
162	Plus any increased ROE calculated on Attachment 7 other than PJM Sch. 12 projects not paid by other PJM transmission zones			Attachment 7	**7,783,969**
163	Facility Credits under Section 30.9 of the PJM OATT			Attachment 5	**0**
164	**Net Zonal Revenue Requirement**			(Line 160 + 161 + 162 + 163)	**1,064,228,952**
	Network Zonal Service Rate				
165	1 CP Peak		(Note L)	Attachment 5	**9,594.9**
166	Rate ($/MW-Year)			(Line 164 / 165)	**110,916**
167	**Network Service Rate ($/MW/Year)**			**(Line 166)**	**110,916**

Public Service Electric and Gas Company ATTACHMENT H-10A Formula Rate -- Appendix A	Notes	FERC Form 1 Page # or Instruction	12 Months Ended 12/31/2016

Shaded cells are input cells

Notes

A Electric portion only

B Calculated using 13-month average balances.

C Includes Transmission portion only. At each annual informational filing, Company will identify for each parcel of land an intended use within a 15 year period.

D Includes all EPRI Annual Membership Dues

E Includes all Regulatory Commission Expenses

F Includes Safety related advertising included in Account 930.1

G Includes Regulatory Commission Expenses directly related to transmission service, RTO filings, or transmission siting itemized in Form 1 at 351.h.

H CWIP can only be included if authorized by the Commission.

I The currently effective income tax rate where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = the percentage of federal income tax deductible for state income taxes.

J ROE will be supported in the original filing and no change in ROE will be made absent a filing at FERC.

PBOP expense shall be based upon the Company's Actual Annual PBOP Expense until changed by a filing at FERC.

The actual Annual PBOP Expense to be included in the Formula Rate Annual Update that is required to be filed on or before October 15 of each year shall be based upon the Actual Annual PBOP Expense as charged to FERC Account 926 on behalf of electric employees for PBOP and as included by the Company in its most recent True-up Adjustment filing.

PSEG will provide, in connection with each annual True-Up Adjustment filing a confidential copy of relevant pages from annual actuarial valuation report supporting the derivation of the Actual Annual PBOP Expense as charged to FERC Account 926 on behalf of electric employees.

Depreciation rates shown in Attachment 8 are fixed until changed as the result of a filing at FERC.

If book depreciation rates are different than the Attachment 8 rates, PSE&G will provide workpapers at the annual update to reconcile formula depreciation expense and depreciation accruals to FERC Form 1 amounts.

K Education and outreach expenses relating to transmission, for example siting or billing

L As provided for in Section 34.1 of the PJM OATT; the PJM established billing determinants will not be revised or updated in the annual rate reconciliations.

M Amount of transmission plant excluded from rates per Attachment 5.

N Outstanding Network Credits is the balance of Network Facilities Upgrades Credits due Transmission Customers who have made lump-sum payments towards the construction of Network Transmission Facilities consistent with Paragraph 657 of Order 2003-A.

Interest on the Network Credits as booked each year is added to the revenue requirement to make the Transmission Owner whole on Line "&A248&"."

O Expenses reflect full year plan

P The projected capital structure shall reflect the capital structure from the FERC Form 1 data. For all other formula rate calculations, the projected capital structure and actual capital structure shall reflect the capital structure from the most recent FERC Form 1 data available.

Calculated using the average of the prior year and current year balances.

Q Calculated using beginning and year end projected balances.

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

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31,2016

	Only Transmission Related	*Plant Related*	*Labor Related*	*Total ADIT*	
ADIT- 282	0	(2,919,714,523)	0		From Acct. 282 total, below
ADIT-283	0	(403,873,845)	0		From Acct. 283 total, below
ADIT-190	0	(945,635)	5,505,113		From Acct. 190 total, below
Subtotal	0	(3,324,534,003)	5,505,113		
Wages & Salary Allocator			15.5000%		
Net Plant Allocator		55.0436%			
End of Year ADIT	0	(1,829,944,178)	853,292	**(1,829,090,886)**	
End of Previous Year ADIT (from Sheet 1A-ADIT (3))	0	(1,734,700,927)	853,292	**(1,733,847,634)**	
Average Beginning and End of Year ADIT	0	(1,782,322,553)	853,292	**(1,781,469,260)**	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

(10,210,019) < From Acct 283, below

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

A	B	C	D	E	F	G
ADIT-190	*Total*	*Gas, Prod Or Other Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
ADIT - Real Estate Taxes	(945,635)			(945,635)		Book estimate accrued and expensed, tax deduction when paid related to plant
FIN 47	223,825	223,825				Asset Retirement Obligation - Legal liability for environmental removal costs
Vacation Pay	2,390,354				2,390,354	Vacation pay earned and expensed for books, tax deduction when paid - employees in all functions
OPEB	157,699,092				157,699,092	FASB 106 - Post Retirement Obligation, labor related.
Deferred Dividend Equivalents	3,714,155				3,714,155	Book accrual of dividends on employee stock options affecting all functions
Deferred Compensation	321,705				321,705	Book estimate accrued and expensed, tax deduction when paid - employees in all functions
ADIT - Unallowable PIP Accrual	(358,461)				(358,461)	Book estimate accrued and expensed, tax deduction when paid - employees in all functions
Bankruptcies $ Acfc	115,363	115,363				Book estimate accrued and expensed, tax deduction when paid - Generation Related
Unrealized L/G Rabbi Trust	(562,642)				(562,642)	Book estimate accrued and expensed, tax deduction when paid for Executive Compensation
Federal Taxes Deferred	11,166,995			11,166,995		FASB 109 - deferred tax asset primarily associated with items previously flowed through due to regulation
Fed Taxes Req Requirement	7,712,117			7,712,117		FASB 109 - deferred tax asset primarily associated with items previously flowed through due to regulation
Subtotal - p234	**181,476,871**	**339,189**		**17,933,477**	**163,204,205**	
Less FASB 109 Above if not separately removed	18,879,112			18,879,112		
Less FASB 106 Above if not separately removed	157,699,092				157,699,092	
Total	**4,898,666**	**339,189**		**(945,635)**	**5,505,113**	

Instructions for Account 190:

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

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

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

4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31,2016

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

A	B	C	D	E	F	G
ADIT- 282	*Total*	*Gas, Prod Or Other Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
Depreciation - Liberalized Depreciation	(2,833,610,567)			(2,833,610,567)		Basis difference resulting from accelerated tax depreciation versus depreciation used for ratemaking purposes - related to all functions
Cost of Removal	(86,103,956)			(86,103,956)		Book estimate accrued and expensed, tax deduction when paid. Retail related - Component of Liberalized Depreciation
Accounting for Income Taxes	(307,991,280)			(307,991,280)		FASB 109 - deferred tax liability primarily associated with plant related items previously flowed through due to regulation
Subtotal - p275	**(3,227,705,804)**			**(3,227,705,804)**		
Less FASB 109 Above if not separately removed	(307,991,280)			(307,991,280)		
Less FASB 106 Above if not separately removed						
Total	**(2,919,714,523)**			**(2,919,714,523)**		

Instructions for Account 282:

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

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

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

4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31,2016

A *ADIT-283*	B *Total*	C Gas, Prod or Other Related	D Only Transmission Related	E Plant	F Labor	G
Securitization Regulatory Asset	1,022,247,426	1,022,247,426				Generation Related (Securitization of Stranded Costs)
Securitization - Federal	(968,676,613)	(968,676,613)				Generation Related (Securitization of Stranded Costs)
Securitization - State	(161,907,377)	(161,907,377)				Generation Related (Securitization of Stranded Costs)
Environmental Cleanup Costs	(24,412,903)	(24,412,903)				Book estimate accrued and expensed, tax deduction when paid - Manufactured Gas Plants
New Jersey Corporation Business Tax	(293,553,367)	100,110,459		(393,663,826)		New Jersey Corporate Income Tax - Plant Related- Contra Account of 190 NJCBT
NJCBT - Step Up Basis	115,317,595	115,317,595				New Jersey Corporate Income Tax for Utility - Gets return on but no return of prior book vs tax timing differences
Fuel Cost Adjustment	(1,913,316)	(1,913,316)				Book deferral of Underrecovered Fuel Costs - Retail Related
Accelerated Activity Plan	(113,677,936)	(113,677,936)				Demand Side management and Associated Programs - Retail Related
Loss on Reacquired Debt	(10,210,019)			(10,210,019)		Tax deduction when reacquired, booked amortizes to expense
Additional Pension Deduction	(161,702,087)	(161,702,087)				Associated with Pension Liability not in rates
Public Utility Tax Assessment	(1,781,312)	(1,781,312)				BPU and Rate Payer Advocate Assessment
Sales Tax Reserve	1,122,289	1,122,289				Sales tax audit reserve
Miscellaneous	(1,270,089)	(1,270,089)				Miscellaneous Tax Adjustments
Deferred Gain	(53,280,535)	(53,280,535)				Deferred gain resulted from 2000 deregulation step up basis
Accounting for Income Taxes (FAS109) - Federal	(1,618,471)			(1,618,471)		FASB 109 - deferred tax liability primarily non-plant related items previously flowed through due to regulation
Accounting for Income Taxes (FAS109) - Regulatory Requirement	(212,704,037)			(212,704,037)		FASB 109 - gross-up
Subtotal - p277	**(868,020,751)**	**(249,824,398)**		**(618,196,353)**		
Less FASB 109 Above if not separately removed	(214,322,508)			(214,322,508)		
Less FASB 106 Above if not separately removed						
Total	**(653,698,243)**	**(249,824,398)**		**(403,873,845)**		

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

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31,2015

	Only Transmission Related	*Plant Related*	*Labor Related*	*Total ADIT*	
ADIT- 282	0	(2,776,299,686)	0		From Acct. 282 total, below
ADIT-283	0	(374,256,393)	0		From Acct. 283 total, below
ADIT-190	0	(945,635)	5,505,113		From Acct. 190 total, below
Subtotal	0	(3,151,501,714)	5,505,113		
Wages & Salary Allocator			15.5000%		
Net Plant Allocator		55.0436%			
End of Year ADIT	0	(1,734,700,927)	853,292	**(1,733,847,634)**	

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

(13,596,067) < From Acct 283, below

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

A *ADIT-190*	B *Total*	C *Gas, Prod Or Other Related*	D *Only Transmission Related*	E *Plant Related*	F *Labor Related*	G *Justification*
ADIT - Real Estate Taxes	(945,635)			(945,635)		Book estimate accrued and expensed, tax deduction when paid related to plant
FIN 47	223,825	223,825				Asset Retirement Obligation - Legal liability for environmental removal costs
Vacation Pay	2,390,354				2,390,354	Vacation pay earned and expensed for books, tax deduction when paid - employees in all functions
OPEB	157,699,092				157,699,092	FASB 106 - Post Retirement Obligation, labor related.
Deferred Dividend Equivalents	3,714,155				3,714,155	Book accrual of dividends on employee stock options affecting all functions
Deferred Compensation	321,705				321,705	Book estimate accrued and expensed, tax deduction when paid - employees in all functions
ADIT - Unallowable PIP Accrual	(358,461)				(358,461)	Book estimate accrued and expensed, tax deduction when paid - employees in all functions
Bankruptcies $ Acfc	115,363	115,363				Book estimate accrued and expensed, tax deduction when paid - Generation Related
Unrealized L/G Rabbi Trust	(562,642)				(562,642)	Book estimate accrued and expensed, tax deduction when paid for Executive Compensation
Federal Taxes Deferred	11,166,995			11,166,995		FASB 109 - deferred tax asset primarily associated with items previously flowed through due to regulation
Fed Taxes Req Requirement	7,712,117			7,712,117		FASB 109 - deferred tax asset primarily associated with items previously flowed through due to regulation
Subtotal - p234	**181,476,871**	**339,189**		**17,933,477**	**163,204,205**	
Less FASB 109 Above if not separately removed	18,879,112			18,879,112		
Less FASB 106 Above if not separately removed	157,699,092				157,699,092	
Total	**4,898,666**	**339,189**		**(945,635)**	**5,505,113**	

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 31,2015

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

A	B	C	D	E	F	G
ADIT- 282	***Total***	***Gas, Prod Or Other Related***	***Only Transmission Related***	***Plant Related***	***Labor Related***	***Justification***
Depreciation - Liberalized Depreciation	(2,699,600,707)			(2,699,600,707)		Basis difference resulting from accelerated tax depreciation versus depreciation used for ratemaking purposes - related to all functions
Cost of Removal	(76,698,979)			(76,698,979)		Book estimate accrued and expensed, tax deduction when paid. Retail related - Component of Liberalized Depreciation
Accounting for Income Taxes	(304,052,079)			(304,052,079)		FASB 109 - deferred tax liability primarily associated with plant related items previously flowed through due to regulation
Subtotal - p275	**(3,080,351,765)**			**(3,080,351,765)**		
Less FASB 109 Above if not separately removed	(304,052,079)			(304,052,079)		
Less FASB 106 Above if not separately removed						
Total	**(2,776,299,686)**			**(2,776,299,686)**		

Instructions for Account 282:

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

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

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

4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet - December 31,2015

Page 3 of 3

A	B	C	D	E	F	G
ADIT-283	***Total***	**Related**	**Related**	**Plant**	**Labor**	
Securitization Regulatory Asset	1,022,247,426	1,022,247,426				Generation Related (Securitization of Stranded Costs)
Securitization - Federal	(968,676,613)	(968,676,613)				Generation Related (Securitization of Stranded Costs)
Securitization - State	(161,907,377)	(161,907,377)				Generation Related (Securitization of Stranded Costs)
Environmental Cleanup Costs	(24,412,903)	(24,412,903)				Book estimate accrued and expensed, tax deduction when paid - Manufactured Gas Plants
New Jersey Corporation Business Tax	(293,553,367)	67,106,960		(360,660,327)		New Jersey Corporate Income Tax - Plant Related- Contra Account of 190 NJCBT
NJCBT - Step Up Basis	115,317,595	115,317,595				New Jersey Corporate Income Tax for Utility - Gets return on but no return of prior book vs tax timing differences
Fuel Cost Adjustment	(1,913,316)	(1,913,316)				Book deferral of Underrecovered Fuel Costs - Retail Related
Accelerated Activity Plan	(113,677,936)	(113,677,936)				Demand Side management and Associated Programs - Retail Related
Loss on Reacquired Debt	(13,596,067)			(13,596,067)		Tax deduction when reacquired, booked amortizes to expense
Additional Pension Deduction	(161,702,087)	(161,702,087)				Associated with Pension Liability not in rates
Public Utility Tax Assessment	(1,781,312)	(1,781,312)				BPU and Rate Payer Advocate Assessment
Sales Tax Reserve	1,122,289	1,122,289				Sales tax audit reserve
Miscellaneous	(1,270,089)	(1,270,089)				Miscellaneous Tax Adjustments
Deferred Gain	(53,280,535)	(53,280,535)				Deferred gain resulted from 2000 deregulation step up basis
Accounting for Income Taxes (FAS109) - Federal	(1,618,471)			(1,618,471)		FASB 109 - deferred tax liability primarily non-plant related items previously flowed through due to regulation
Accounting for Income Taxes (FAS109) - Regulatory Requirement	(209,983,558)			(209,983,558)		FASB 109 - gross-up
Subtotal - p277	**(868,686,319)**	**(282,827,897)**		**(585,858,422)**		
Less FASB 109 Above if not separately removed	(211,602,029)			(211,602,029)		
Less FASB 106 Above if not separately removed						
Total	**(657,084,291)**	**(282,827,897)**		**(374,256,393)**		

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

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 2 - Taxes Other Than Income Worksheet - December 31, 2016

	Other Taxes	*Page 263 Col (i)*	*Allocator*	*Allocated Amount*	
	Plant Related				
1	Real Estate	20,497,000			Attachment #5
2	***Total Plant Related***	20,497,000	N/A	7,837,000	
	Labor Related		***Wages & Salary Allocator***		
3	FICA	13,860,326			
4	Federal Unemployment Tax	158,745			
5	New Jersey Unemployment Tax	584,731			
6	New Jersey Workforce Development	321,478			
7					
8	***Total Labor Related***	14,925,280	15.5000%	2,313,418	
	Other Included		***Net Plant Allocator***		
9					
10					
11					
12					
13	***Total Other Included***	0	55.0436%	0	
14	***Total Included (Lines 8 + 14 + 19)***	35,422,280		10,150,418	
	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)**	35,422,280			
24	**Total Other Taxes from p114.14.g - Actual**	35,422,280			
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, 2016

	Accounts 450 & 451		
1	Late Payment Penalties Allocated to Transmission		0
	Account 454 - Rent from Electric Property		
2	Rent from Electric Property - Transmission Related (Note 2)		600,000
	Account 456 - Other Electric Revenues		
3	Transmission for Others		0
4	Schedule 1A		4,900,000
5	Net revenues associated with Network Integration Transmission Service (NITS) for which the load is not included in the divisor (difference between NITS credits from PJM and PJM NITS charges paid by Transmission Owner)		0
6	Point to Point Service revenues for which the load is not included in the divisor received by Transmission Owner		9,600,000
7	Professional Services (Note 2)		60,000
8	Revenues from Directly Assigned Transmission Facility Charges (Note 1)		10,079,639
9	Rent or Attachment Fees associated with Transmission Facilities (Note 2)		4,775,246
10	Gross Revenue Credits	(Sum Lines 1-9)	30,014,885
11	Less line 18	- line 18	(3,827,772)
12	Total Revenue Credits	line 10 + line 11	26,187,113
13	Revenues associated with lines 2, 7, and 9 (Note 2)		5,435,246
14	Income Taxes associated with revenues in line 13		2,220,298
15	One half margin (line 13 - line 14)/2		1,607,474
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		1,607,474
18	Line 13 less line 17		3,827,772

Note 1 If the costs associated with the Directly Assigned Transmission Facility Charges are included in the Rates, the associated revenues are included in the Rates. If the costs associated with the Directly Assigned Transmission Facility Charges are not included in the Rates, the associated revenues are not included in the Rates.

Note 2 Ratemaking treatment for the following specified secondary uses of transmission assets: (1) right-of-way leases and leases for space on transmission facilities for telecommunications; (2) transmission tower licenses for wireless antennas; (3) right-of-way property leases for farming, grazing or nurseries; (4) licenses of intellectual property (including a portable oil degasification process and scheduling software); and (5) transmission maintenance and consulting services (including energized circuit maintenance, high-voltage substation maintenance, safety training, transformer oil testing, and circuit breaker testing) to other utilities and large customers (collectively, products). PSE&G will retain 50% of net revenues consistent with *Pacific Gas and Electric Company* , 90 FERC ¶ 61,314. Note: in order to use lines 13-18, the utility must track in separate subaccounts the revenues and costs associated with each secondary use (except for the cost of the associated income taxes).

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 4 - Calculation of 100 Basis Point Increase in ROE

	Return and Taxes with 100 Basis Point increase in ROE		
A	100 Basis Point increase in ROE and Income Taxes	Line 27 + Line 42 from below	811,573,184
B	100 Basis Point increase in ROE		1.00%

Return Calculation

			Appendix A Line or Source Reference	
1	**Rate Base**		(Line 43 + Line 57)	6,130,070,519
2	**Long Term Interest**		p117.62.c through 67.c	252,018,266
3	**Preferred Dividends**	enter positive	p118.29.d	0
	Common Stock			
4	Proprietary Capital		Attachment 5	6,377,924,573
5	Less Accumulated Other Comprehensive Income Account 219		p112.15.c	1,408,022
6	Less Preferred Stock		(Line 106)	0
7	Less Account 216.1		Attachment 5	3,430,285
8	Common Stock		(Line 96 - 97 - 98 - 99)	6,373,086,266
	Capitalization			
9	Long Term Debt		Attachment 5	5,939,268,873
10	Less Loss on Reacquired Debt		Attachment 5	77,696,491
11	Plus Gain on Reacquired Debt		Attachment 5	0
12	Less ADIT associated with Gain or Loss		Attachment 5	23,902,953
13	Total Long Term Debt		(Line 101 - 102 + 103 - 104)	5,837,669,430
14	Preferred Stock		Attachment 5	0
15	Common Stock		(Line 100)	6,373,086,266
16	Total Capitalization		(Sum Lines 105 to 107)	12,210,755,696
17	Debt %	Total Long Term Debt	(Line 105 / Line 108)	47.8%
18	Preferred %	Preferred Stock	(Line 106 / Line 108)	0.0%
19	Common %	Common Stock	(Line 107 / Line 108)	52.2%
20	Debt Cost	Total Long Term Debt	(Line 94 / Line 105)	0.0432
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)	0.0206
24	Weighted Cost of Preferred	Preferred Stock	(Line 110 * Line 113)	0.0000
25	Weighted Cost of Common	Common Stock	(Line 111 * Line 114)	0.0662
26	**Rate of Return on Rate Base (ROR)**		**(Sum Lines 115 to 117)**	**0.0868**
27	**Investment Return = Rate Base * Rate of Return**		**(Line 58 * Line 118)**	**532,206,595**

Composite Income Taxes

	Income Tax Rates			
28	FIT=Federal Income Tax Rate			35.00%
29	SIT=State Income Tax Rate or Composite			9.00%
30	p = percent of federal income tax deductible for state purposes		Per State Tax Code	0.00%
31	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		40.85%
35	CIT = T / (1-T)			69.06%
36	1 / (1-T)			169.06%
	ITC Adjustment			
37	Amortized Investment Tax Credit	enter negative	Attachment 5	-868,658
38	1/(1-T)		1 / (1 - Line 123)	169%
39	Net Plant Allocation Factor		(Line 18)	55.0436%
40	**ITC Adjustment Allocated to Transmission**		(Line 125 * Line 126 * Line 127)	**-808,353**
41	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		280,174,942
42	**Total Income Taxes**			**279,366,589**

Public Service Electric and Gas Company

ATTACHMENT H-10A

Attachment 5 - Cost Support - December 31, 2016

Electric / Non-electric Cost Support

				Previous Year	Current Year - 2016 Projected													
Line #s	Descriptions	Notes	Page #'s & Instructions	Form 1Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Form 1 Dec	Average	Non-electric Portion
	Plant Allocation Factors																	
6	Electric Plant in Service (Excludes Asset Retirement Costs - ARC)	(Note B)	p207.104g	15,980,817,613	16,039,076,846	16,099,722,410	16,321,132,280	16,438,775,290	16,773,982,994	17,320,101,205	17,355,545,109	17,376,695,961	17,405,932,844	17,455,131,674	17,532,211,826	17,924,090,172	16,924,862,786	
7	Common Plant in Service - Electric	(Note B)	p356	138,172,854	139,132,743	141,197,500	139,721,061	141,451,903	143,151,799	145,224,173	146,822,236	147,798,546	149,430,067	150,804,145	152,055,717	160,756,306	145,824,542	
9	Accumulated Depreciation (Total Electric Plant)	(Note B & J)	p219.29c	3,172,741,477	3,194,044,284	3,216,812,690	3,240,929,136	3,266,073,789	3,290,475,396	3,317,305,721	3,347,391,695	3,365,999,493	3,394,629,272	3,422,056,969	3,449,326,545	3,474,088,407	3,319,374,990	
10	Accumulated Intangible Amortization	(Note B)	p200.21c	4,488,131	4,616,787	4,745,443	4,874,099	5,002,755	5,131,411	5,260,067	5,388,722	5,517,378	5,646,034	5,774,690	5,903,346	6,085,765	5,264,202	
11	Accumulated Common Plant Depreciation - Electric	(Note B & J)	p356	18,977,676	19,305,773	19,498,488	15,855,479	16,191,921	16,589,993	17,002,498	17,427,499	17,166,091	17,599,037	18,027,023	18,426,485	18,830,895	17,761,451	
12	Accumulated Common Amortization - Electric	(Note B)	p356	35,082,320	35,708,285	36,337,062	36,971,478	37,608,706	38,248,746	38,893,813	39,541,693	40,192,384	40,846,881	41,504,189	42,164,310	42,923,722	38,924,891	
	Plant In Service																	
19	Transmission Plant in Service (Excludes Asset Retirement Costs - ARC)	(Note B)	p207.58.g	7,562,948,414	7,589,922,081	7,621,476,748	7,812,068,414	7,864,207,081	8,148,051,235	8,621,101,901	8,627,249,568	8,631,197,235	8,638,827,901	8,641,864,568	8,655,415,235	8,956,883,901	8,259,324,176	
20	General (Excludes Asset Retirement Costs - ARC)	(Note B)	p207.99.g	225,961,970	226,599,498	227,786,249	228,958,771	230,244,515	231,244,669	232,396,468	233,677,456	222,630,117	223,954,750	225,064,963	226,389,597	226,999,650	227,839,129	
21	Intangible - Electric	(Note B)	p205.5.g	7,719,354	7,719,354	7,719,354	7,719,354	7,719,354	7,719,354	7,719,354	7,719,354	7,719,354	7,719,354	7,719,354	7,719,354	10,945,138	7,967,491	
22	Common Plant in Service - Electric	(Note B)	p356	138,172,854	139,132,743	141,197,500	139,721,061	141,451,903	143,151,799	145,224,173	146,822,236	147,798,546	149,430,067	150,804,145	152,055,717	160,756,306	145,824,542	
24	General Plant Account 397 -- Communications	(Note B)	p207.94g	17,471,478	18,313,791	19,156,104	19,998,417	20,840,731	21,683,044	22,525,357	23,367,670	20,752,545	21,594,858	22,437,171	23,279,484	24,121,797	21,195,573	
25	Common Plant Account 397 -- Communications	(Note B)	p356	1,839,050	2,586,270	4,586,353	6,341,126	7,844,680	9,269,057	10,665,933	11,987,861	13,369,062	14,544,298	15,656,901	16,684,727	17,703,402	10,236,825	
29	Account No. 397 Directly Assigned to Transmission	(Note B)	Company Records	18,058,583	18,058,583	18,058,583	18,058,583	18,058,583	18,058,583	18,058,583	18,058,583	15,481,067	15,481,067	15,481,067	15,481,067	15,481,067	17,067,231	
	Accumulated Depreciation																	
32	Transmission Accumulated Depreciation	(Note B & J)	p219.25.c	684,373,298	694,817,880	704,695,461	714,998,314	726,989,567	739,485,522	753,177,724	767,974,952	782,670,569	796,433,025	809,488,113	822,462,743	834,635,606	756,323,290	
33	Accumulated General Depreciation	(Note B & J)	p219.28.b	105,622,999	105,245,844	105,390,747	105,538,086	105,807,059	105,797,455	105,951,313	106,246,595	94,133,229	94,406,712	94,480,081	94,784,746	94,392,021	101,368,991	
34	Accumulated Common Plant Depreciation & Amortization - Electric	(Note B & J)	p356	54,059,996	55,014,058	55,835,551	52,826,957	53,800,627	54,838,739	55,896,311	56,969,191	57,358,475	58,445,918	59,531,212	60,590,795	61,754,617	56,686,342	
35	Accumulated General Depreciation Associated with Acct. 397	(Note B & J)	Company Records	12,048,566	12,296,060	12,567,241	12,860,064	13,172,436	13,503,697	13,853,617	14,221,574	11,121,809	11,496,296	11,887,073	12,293,435	12,715,305	12,618,244	
41	Acc. Deprec. Acct. 397 Directly Assigned to Transmission	(Note B & J)	Company Records	15,981,848	16,132,336	16,282,824	16,433,313	16,583,801	16,734,289	16,884,777	17,035,265	14,586,758	14,715,767	14,844,776	14,973,785	15,102,794	15,868,641	

Wages & Salary

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
2	Total Wage Expense	(Note A)	p354.28b	198,680,651
3	Total A&G Wages Expense	(Note A)	p354.27b	6,226,170
1	Transmission Wages		p354.21b	29,830,445

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	26,451,572	30,151,572	28,301,572
46	Transmission Only			24,270,911	27,970,911	26,120,911

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	(1,863,641)	(1,863,641)	(1,863,641)	-1,863,641	15.500%	(288,864)

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	9,654,089	9,654,089	9,654,089

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	100,364,698
60	Transmission Lease Payments		p321.96.b	-

Property Insurance Expenses

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
65	Property Insurance Account 924	(Note O)	p323.185b	4,631,400

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 5 - Cost Support - December 31, 2016

Adjustments to A & G Expense

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
62	Total A&G Expenses		p323.197b	215,993,171
63	Actual PBOP expense	(Note J)	Company Records	28,522,987
64	Actual PBOP expense	(Note O)	Company Records	33,272,121

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	10,672,984	0
	Directly Assigned A&G				
72	Regulatory Commission Exp Account 928	(Note G & O)	p351.11-13h	308,984	308,984

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	2,844,680	0	2,844,680

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	2,844,680	0	2,844,680

Depreciation Expense

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
	Depreciation Expense			
81	Depreciation-Transmission	(Note J & O)	p336.7.f	196,487,978
82	Depreciation-General & Common	(Note J & O)	p336.10&11.f	17,537,763
83	Depreciation-General Expense Associated with Acct. 397	(Note J & O)	Company Records	3,244,255
85	Depreciation-Intangible	(Note A & O)	p336.1.f	9,439,036
89	Transmission Depreciation Expense for Acct. 397	(Note J & O)	Company Records	1,698,462

Direct Assignment of Transmission Real Estate Taxes

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year	Transmission Related	Non-Transmission
92	Real Estate Taxes - Directly Assigned to Transmission		p263.33i	20,497,000	7,837,000	12.660.000

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.

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 5 - Cost Support - December 31, 2016

Return \ Capitalization

Line #s	Descriptions	Notes	Page #'s & Instructions	2013 End of Year	2014 End of Year	Average
96	Proprietary Capital	(Note P)	p112.16.c,d	5,920,315,656	6,835,533,489	6,377,924,573
97	Accumulated Other Comprehensive Income Account 219	(Note P)	p112.15.c,d	1,083,198	1,732,845	1,408,022
99	Account 216.1	(Note P)	p119.53.c&d	3,537,410	3,323,160	3,430,285
101	Long Term Debt	(Note P)	p112.18.c,d thru 23.c,d	5,566,162,652	6,312,375,094	5,939,268,873
102	Loss on Reacquired Debt	(Note P)	p111.81.c,d	81,363,909	74,029,072	77,696,491
103	Gain on Reacquired Debt	(Note P)	p113.61.c,d	0	0	0
104	ADIT associated with Gain or Loss on Reacquired Debt	(Note P)	p277.3.k (footnote)	30,823,791	16,982,115	23,902,953
106	Preferred Stock	(Note P)	p112.3.c,d	0	0	0

MultiState Workpaper

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

Amortized Investment Tax Credit

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
125	Amortized Investment Tax Credit	(Note O)	p266.8.f	868,658

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	9,594.9

Abandoned Transmission Projects

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

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6 - True-up Adjustment for Network Integration Transmission Service - December 31, 2016

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

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

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

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

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

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

Summary of Formula Rate Process including True-Up Adjustment

Month	Year	Action
July	2008	TO populates the formula with Year 2008 estimated data
October	2008	TO populates the formula with Year 2009 estimated data
June	2009	TO populates the formula with Year 2008 actual data and calculates the 2008 True-Up Adjustment Before Interest
October	2009	TO calculates the Interest to include in the 2008 True-Up Adjustment
October	2009	TO populates the formula with Year 2010 estimated data and 2008 True-Up Adjustment
June	2010	TO populates the formula with Year 2009 actual data and calculates the 2009 True-Up Adjustment Before Interest
October	2010	TO calculates the Interest to include in the 2009 True-Up Adjustment
October	2010	TO populates the formula with Year 2011 estimated data and 2009 True-Up Adjustment
June	2011	TO populates the formula with Year 2010 actual data and calculates the 2010 True-Up Adjustment Before Interest
October	2011	TO calculates the Interest to include in the 2010 True-Up Adjustment
October	2011	TO populates the formula with Year 2012 estimated data and 2010 True-Up Adjustment
June	2012	TO populates the formula with Year 2011 actual data and calculates the 2011 True-Up Adjustment Before Interest
October	2012	TO calculates the Interest to include in the 2011 True-Up Adjustment
October	2012	TO populates the formula with Year 2013 estimated data and 2011 True-Up Adjustment
June	2013	TO populates the formula with Year 2012 actual data and calculates the 2012 True-Up Adjustment Before Interest
October	2013	TO calculates the Interest to include in the 2012 True-Up Adjustment
October	2013	TO populates the formula with Year 2014 estimated data and 2012 True-Up Adjustment
June	2014	TO populates the formula with Year 2013 actual data and calculates the 2013 True-Up Adjustment Before Interest
October	2014	TO calculates the Interest to include in the 2013 True-Up Adjustment
October	2014	TO populates the formula with Year 2015 estimated data and 2013 True-Up Adjustment
June	2015	TO populates the formula with Year 2014 actual data and calculates the 2014 True-Up Adjustment Before Interest
October	2015	TO calculates the Interest to include in the 2014 True-Up Adjustment
October	2015	TO populates the formula with Year 2016 estimated data and 2014 True-Up Adjustment

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

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

Calendar Year Complete for Each Calendar Year beginning in 2009

A	ATRR based on actual costs included for the previous calendar year but excludes the true-up adjustment.	717,516,447
B	ATRR based on projected costs included for the previous calendar year but excludes the true-up adjustment.	736,263,946
C	Difference (A-B)	-18,747,499
D	Future Value Factor (1+i)^24	1.06783
E	True-up Adjustment (C*D)	-20,019,061

<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.

Where:
i = average interest rate as calculated below

Interest on Amount of Refunds or Surcharges

Month	Yr	Month
January	Year 1	0.2800%
February	Year 1	0.2500%
March	Year 1	0.2800%
April	Year 1	0.2700%
May	Year 1	0.2800%
June	Year 1	0.2700%
July	Year 1	0.2800%
August	Year 1	0.2800%
September	Year 1	0.2700%
October	Year 1	0.2800%
November	Year 1	0.2700%
December	Year 1	0.2800%
January	Year 2	0.2500%
February	Year 2	0.2800%
March	Year 2	0.2800%
April	Year 2	0.2700%
May	Year 2	0.2800%
June	Year 2	0.2700%
July	Year 2	0.2800%
August	Year 2	0.2800%
September	Year 2	0.2700%
Average Interest Rate		0.2738%

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2016

Estimated Additions - 2016

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
	Other Projects PIS (monthly additions)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (monthly additions)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (monthly additions)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (monthly additions)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (monthly additions)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91) (monthly additions)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (monthly additions)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (monthly additions)	Ridge Road 69kV Breaker Station (B1255) (monthly additions)	Cox's Corner-Lumberton 230kV Circuit (B1787) (monthly additions)	Sewaren Switch 230kV Conversion (B2276) (monthly additions)		Susquehanna Roseland Breakers (B0489.5-B0489.15) (monthly additions)	Susquehanna Roseland <500kV (B0489.4) (monthly additions)	Susquehanna Roseland >= 500KV (B0489) (monthly additions)	Burlington - Camden 230kV Conversion (B1156) (monthly additions)
		(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)		(in service)	(in service)	(in service)	(in-service)
Dec-15										15,515,959	12,035,060		5,857,687	40,538,248	723,503,148	354,730,847
Jan	18,477,450	1,292,000	-	-	-	-	-	-	-	292,589	6,161,628		-	-	-	-
Feb	30,129,943	-	-	-	-	-	-	-	-	12,153	662,570		-	-	-	-
Mar	89,201,680	-	-	-	-	-	-	-	-	17,462,834	695,152		-	-	-	-
Apr	51,470,985	-	-	-	-	-	-	-	-	456,590	211,091		-	-	-	-
May	55,847,505	-	-	-	-	-	-	-	27,803,197	10,247	3,114,183		-	-	-	-
Jun	90,921,487	152,684,178	19,694,890	19,694,890	27,239,122	19,694,915	25,264,003	25,264,003	5,906,041	13,190	84,128,104		-	-	-	-
Jul	3,045,137	-	-	-	-	-	-	-	18,290	-	1,754,239		-	-	-	-
Aug	1,741,545	-	-	-	-	-	-	-	18,290	-	1,837,832		-	-	-	-
Sep	7,027,342	-	-	-	-	-	-	-	18,290	-	235,035		-	-	-	-
Oct	2,771,205	-	-	-	-	-	-	-	-	-	195,462		-	-	-	-
Nov	13,085,768	-	-	-	-	-	-	-	-	-	464,899		-	-	-	-
Dec	300,958,144	-	-	-	-	-	-	-	-	-	510,522		-	-	-	-
Total	**664,678,193**	**153,976,178**	**19,694,890**	**19,694,890**	**27,239,122**	**19,694,915**	**25,264,003**	**25,264,003**	**33,764,108**	**33,763,562**	**112,005,777**		**5,857,687**	**40,538,248**	**723,503,148**	**354,730,847**

Estimated Transmission Enhancement Charges (Before True-Up) - 2016

Total Projects	Branchburg (B0130)	Kittatinny (B0134)	Essex Aldene (B0145)	New Freedom Trans.(B0411)	New Freedom Loop (B0498)	Metuchen Transformer (B0161)	Branchburg-Flagtown-Somerville (B0169)	Flagtown-Somerville-Bridgewater (B0170)	Roseland Transformers (B0274)	Wave Trap Branchburg (B0172.2)	Reconductor Hudson - South Waterfront (B0813)	Reconductor South Mahwah J-3410 Circuit (B1017)	Reconductor South Mahwah K-3411 Circuit (B1018)	Branchburg 400 MVAR Capacitor (B0290)	Saddle Brook - Athenia Upgrade Cable (B0472)
530,687,571	**2,316,538**	**939,068**	**10,074,454**	**2,551,745**	**3,238,044**	**3,140,998**	**1,908,350**	**834,421**	**2,561,882**	**3,277**	**1,150,001**	**2,616,920**	**2,717,165**	**10,418,379**	**1,867,140**

Actual Transmission Enhancement Charges - 2014

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)	Branchburg 400 MVAR Capacitor (B0290)	Saddle Brook - Athenia Upgrade Cable (B0472)
349,823,024	**2,555,172**	**1,034,441**	**11,097,629**	**2,812,043**	**3,563,358**	**3,454,841**	**2,099,276**	**918,263**	**2,817,996**	**3,609**	**1,263,663**	**2,874,636**	**2,983,683**	**11,437,086**	**2,049,664**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2016

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)	Branchburg 400 MVAR Capacitor (B0290)	Saddle Brook - Athenia Upgrade Cable (B0472)
12,872,004	**706,819**	**281,907**	**3,109,603**	**781,172**	**(239,002)**	**1,037,886**	**(872,430)**	**262,584**	**473,282**	**(928)**	**50,074**	**784,120**	**150,037**	**6,299,082**	**1,005,135**

Interest	*1.06783*	*1.06783*	*1.06783*	*1.06783*	*1.06783*	*1.06783*	*1.06783*	*1.06783*	*1.06783*	*1.06783*	*1.06783*	*1.06783*	*1.06783*	*1.06783*	*1.06783*

True Up by Project (with interest) - 2014

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)	Branchburg 400 MVAR Capacitor (B0290)	Saddle Brook - Athenia Upgrade Cable (B0472)
13,745,056	**754,759**	**301,028**	**3,320,514**	**834,155**	**(255,213)**	**1,108,281**	**(931,603)**	**280,394**	**505,383**	**(991)**	**53,470**	**837,303**	**160,214**	**6,726,321**	**1,073,309**

Estimated Transmission Enhancement Charges (After True Up) - 2016

Total Projects	Branchburg (B0130)	Kittatinny (B0134)	Essex Aldene (B0145)	New Freedom Trans.(B0411)	New Freedom Loop (B0498)	Metuchen Transformer (B0161)	Branchburg-Flagtown-Somerville (B0169)	Flagtown-Somerville-Bridgewater (B0170)	Roseland Transformers (B0274)	Wave Trap Branchburg (B0172.2)	Reconductor Hudson - South Waterfront (B0813)	Reconductor South Mahwah J-3410 Circuit (B1017)	Reconductor South Mahwah K-3411 Circuit (B1018)	Branchburg 400 MVAR Capacitor (B0290)	Saddle Brook - Athenia Upgrade Cable (B0472)
544,432,627	**3,071,297**	**1,240,095**	**13,394,968**	**3,385,901**	**2,982,832**	**4,249,280**	**976,747**	**1,114,815**	**3,067,264**	**2,285**	**1,203,471**	**3,454,222**	**2,877,379**	**17,144,701**	**2,940,449**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2016

Estimated Additions - 2016

(Q)	(R)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	(AF)	(AG)
Mickleton-Gloucester-Camden (B1398-B1398.7) (monthly additions)	North Central Reliability (West Orange Conversion) (B1154) (monthly additions)	Northeast Grid Reliability Project (B1304.1-B1304.4) (monthly additions)	Susquehanna Roseland < 500kV (B0489.4) (monthly additions)	Susquehanna Roseland >= 500kV (B0489) (monthly additions)	North Central Reliability (West Orange Conversion) (B1154) (monthly additions)	Mickleton-Gloucester-Camden (B1398-B1398.7) (monthly additions)	Mickleton-Gloucester-Camden Breakers (B1398.15-B1398.19) (monthly additions)	Burlington - Camden 230kV Conversion (B1156) (monthly additions)	Burlington - Camden 230kV Conversion (B1156.13-B1156.20) (monthly additions)	Northeast Grid Reliability Project (B1304.1-B1304.4) (monthly additions)	Northeast Grid Reliability Project (B1304.5-B1304.21) (monthly additions)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (monthly additions)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (monthly additions)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (monthly additions)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33) (monthly additions)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34) (monthly additions)
(in-service)	(in service)	(in service)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)
426,457,348	368,260,297	556,734,941	-	-	-	-	-	-	-	201,881,920	6,516,892	84,176,263	14,821,498	14,895,803	7,554,938	1,867,294
750,000	-	-	-	-	-	-	-	-	-	6,379,785	2,863,215	8,174,117	464,936	443,041	1,788,069	1,257,968
750,000	-	-	-	-	-	-	-	-	-	5,845,761	3,662,739	9,858,798	795,393	771,086	1,848,131	1,216,452
-	-	83,232,000	-	-	-	-	-	-	-	(64,773,045)	(10,055,655)	10,106,025	576,115	547,120	2,715,958	1,591,387
-	-	-	-	-	-	-	-	-	-	13,096,109	4,455,691	7,979,932	679,024	655,207	3,210,260	2,277,562
-	-	197,069,021	-	-	-	-	-	-	-	(162,430,530)	(7,442,882)	5,969,842	756,020	708,592	3,261,753	2,145,257
-	-	2,545,844	-	-	-	-	-	-	-	-	-	(125,602,783)	(16,299,388)	(16,370,159)	3,523,357	1,873,264
-	-	1,330,000	-	-	-	-	-	-	-	-	-	1,071,325	256,343	173,130	3,300,333	2,283,094
-	-	350,000	-	-	-	-	-	-	-	-	-	847,822	851,579	507,670	3,598,113	3,293,819
-	-	350,000	-	-	-	-	-	-	-	-	-	155,864	1,191,612	322,165	4,218,543	3,406,951
-	-	70,000	-	-	-	-	-	-	-	-	-	126,765	9,497,321	262,019	3,404,297	2,770,804
-	-	-	-	-	-	-	-	-	-	-	-	131,804	4,006,513	1,818,213	4,787,231	4,691,976
-	-	-	-	-	-	-	-	-	-	-	-	112,624	2,290,289	399,245	2,943,207	2,781,105
427,957,348	**368,260,297**	**841,681,806**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**3,108,397**	**19,887,254**	**5,133,133**	**46,154,190**	**31,456,933**

Estimated Transmission Enhancement Charges (Before True-Up) - 2016

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)	Bergen Substation Transformer (B1082)	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)	Mickleton-Gloucester-Camden(B1398-B1398.7)	North Central Reliability (West Orange Conversion) (B1154)	Northeast Grid Reliability Project (B1304.1-B1304.4)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)
2,414,181	**832,651**	**6,038,051**	**2,163,341**	**2,926,137**	**-**	**9,243,999**	**9,831,890**	**1,517,260**	**783,397**	**5,742,497**	**103,815,086**	**47,474,838**	**58,791,720**	**48,774,658**	**103,807,445**	**11,640,166**

Actual Transmission Enhancement Charges - 2014

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)	Bergen Substation Transformer (B1082)	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)	Mickleton-Gloucester-Camden(B1398-B1398.7)	North Central Reliability (West Orange Conversion) (B1154)	Northeast Grid Reliability Project (B1304.1-B1304.4)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)
2,650,353	**913,777**	**6,607,679**	**1,755,636**	**3,209,866**	**-**	**8,878,852**	**3,438,903**	**234,599**	**859,361**	**4,647,913**	**66,426,879**	**37,392,933**	**5,279,191**	**47,135,528**	**14,884,013**	

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2016

Reconciliation by Project (without interest)

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)	Bergen Substation Transformer (B1082)	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)	Mickleton-Gloucester-Camden(B1398-B1398.7)	North Central Reliability (West Orange Conversion) (B1154)	Northeast Grid Reliability Project (B1304.1-B1304.4)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)
2,551,429	**527,890**	**7,661,689**	**1,486,192**	**313,509**	**(1,706,913)**	**4,393,883**	**(235,937)**	**234,599**	**(467,903)**	**537,530**	**21,836,726**	**(4,583,542)**	**5,279,191**	**(495,834)**	**14,851,882**	

1.06783	***1.06783***	***1.06783***	***1.06783***	***1.06783***	***1.06783***	***1.06783***	***1.06783***	***1.06783***	***1.06783***	***1.06783***	***1.06783***	***1.06783***	***1.06783***	***1.06783***	***1.06783***	***1.06783***

True Up by Project (with interest) - 2014

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)	Bergen Substation Transformer (B1082)	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)	Mickleton-Gloucester-Camden(B1398-B1398.7)	North Central Reliability (West Orange Conversion) (B1154)	Northeast Grid Reliability Project (B1304.1-B1304.4)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)
2,724,481	**563,695**	**8,181,348**	**1,586,994**	**334,773**	**(1,822,685)**	**4,691,901**	**(251,940)**	**250,511**	**(499,639)**	**573,988**	**23,317,816**	**(4,894,424)**	**5,637,255**	**(529,464)**	**15,859,221**	**-**

Estimated Transmission Enhancement Charges (After True Up) - 2016

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)	Bergen Substation Transformer (B1082)	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)	Mickleton-Gloucester-Camden(B1398-B1398.7)	North Central Reliability (West Orange Conversion) (B1154)	Northeast Grid Reliability Project (B1304.1-B1304.4)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)
5,138,662	**1,396,346**	**14,219,399**	**3,750,335**	**3,260,909**	**(1,822,685)**	**13,935,901**	**9,579,950**	**1,767,771**	**283,758**	**6,316,485**	**127,132,902**	**42,580,414**	**64,428,975**	**48,245,194**	**119,666,666**	**11,640,166**

Public Service Electric and Gas Company

ATTACHMENT H-10A

Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2016

Estimated Additions - 2016														
(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)	(AN)	(AO)	(AP)	(AQ)	(AR)	(AS)	(AT)	(AU)	(AV)
Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50) (monthly additions)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (monthly additions)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70) (monthly additions)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81) (monthly additions	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83) (monthly additions)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) (monthly additions)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (monthly additions)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (monthly additions)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91) (monthly additions)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (monthly additions)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (monthly additions)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20) (monthly additions)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (monthly additions)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (monthly additions)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33) (monthly additions)
(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)
3,309,282	4,404,029	6,053,980	3,338,989	3,338,989	5,782,211	5,782,211	15,432,721	14,219,415	19,427,024	19,665,474	2,990,285	2,991,005	1,715,265	233,966
592,995	288,330	325,607	298,042	298,042	405,746	405,746	565,629	333,434	1,192,722	332,722	144,832	144,832	597,110	107,174
603,980	236,768	480,510	328,276	328,276	344,185	344,185	2,408,793	746,630	1,314,800	454,800	159,376	159,376	657,555	21,755
743,599	850,301	273,245	1,701,230	1,701,230	853,196	853,196	2,641,682	427,737	1,168,824	2,028,824	659,573	659,573	40,562	116,161
1,148,822	671,180	543,237	1,331,090	1,331,090	488,476	488,476	1,632,381	566,428	871,049	1,731,049	325,601	325,601	597,802	65,789
2,716,363	871,325	2,469,307	1,230,536	1,230,536	1,246,551	1,246,551	660,583	594,220	10,178	10,178	555,140	555,140	358,942	110,060
2,254,897	1,478,270	3,490,603	2,034,206	2,034,206	2,048,041	2,048,041	(22,929,813)	(16,468,986)	(21,718,250)	(21,718,250)	1,185,130	1,185,130	575,513	95,081
2,731,821	976,189	3,261,820	1,134,625	1,134,625	1,150,892	1,150,892	83,232	56,954	3,748	3,748	551,021	551,021	3,244,186	111,797
2,690,501	994,361	2,608,327	917,882	917,882	913,416	913,416	67,421	46,578	2,973	2,973	295,814	295,814	1,860,783	457,618
3,148,383	837,175	2,578,248	1,129,217	1,129,217	1,123,600	1,123,600	83,031	56,817	3,739	3,739	379,764	379,764	2,142,744	260,979
3,059,719	643,891	1,742,928	1,031,291	1,031,291	1,126,514	1,126,514	81,744	46,210	3,041	3,041	271,970	271,970	1,501,082	212,256
4,157,535	692,382	5,249,978	1,086,970	1,086,970	1,075,271	1,075,271	92,823	48,984	3,127	3,127	14,052	14,052	1,543,262	1,765,576
1,995,538	507,421	3,037,872	860,285	860,285	775,548	775,548	86,342	41,055	2,702	2,702	11,391	11,391	1,333,627	355,033
29,153,435	**13,451,622**	**32,115,662**	**16,422,638**	**16,422,638**	**17,333,648**	**17,333,648**	**906,569**	**715,475**	**2,285,677**	**2,524,127**	**7,543,949**	**7,544,669**	**16,168,432**	**3,913,246**

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)	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)	Upgrade Eagle Point-Gloucester 230kV Circuit (B1588)	Mickleton-Gloucester 230kV Circuit (B2139)	Ridge Road 69kV Breaker Station (B1255)	Cox's Corner-Lumberton 230kV Circuit (B1787)	Sewaren Switch 230kV Conversion (B2276)	Susquehanna Roseland < 500KV (B0489.4) (CWIP)	Susquehanna Roseland >= 500KV (B0489) (CWIP)	North Central Reliability (West Orange Conversion) (B1154) (CWIP)	Mickleton-Gloucester-Camden (B1398-B1398.7) (CWIP)	Mickleton-Gloucester-Camden Breakers (B1398.15-B1398.19) (CWIP)	Burlington - Camden 230kV Conversion (B1156) (CWIP)
1,480,230	**1,480,230**	**2,047,240**	**1,480,232**	**1,898,794**	**1,898,794**	**1,654,204**	**2,525,192**	**2,807,871**	**4,125,793**	**9,480,938**	**-**	**-**	**-**	**-**	**-**	**-**

Actual Transmission Enhancement Charges - 2014																
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)	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)	Upgrade Eagle Point-Gloucester 230kV Circuit (B1588)	Mickleton-Gloucester 230kV Circuit (B2139)	Ridge Road 69kV Breaker Station (B1255)	Cox's Corner-Lumberton 230kV Circuit (B1787)	Sewaren Switch 230kV Conversion (B2276)	Susquehanna Roseland < 500KV (B0489.4) (CWIP)	Susquehanna Roseland >= 500KV (B0489) (CWIP)	North Central Reliability (West Orange Conversion) (B1154) (CWIP)	Mickleton-Gloucester-Camden (B1398-B1398.7) (CWIP)	Mickleton-Gloucester-Camden Breakers (B1398.15-B1398.19) (CWIP)	Burlington - Camden 230kV Conversion (B1156) (CWIP)
											1,646,580	**31,002,624**	**3,895,715**	**16,099,944**	**65,596**	**7,020,285**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2016

Reconciliation by Project (without interest)

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)	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)	Upgrade Eagle Point-Gloucester 230kV Circuit (B1588)	Mickleton-Gloucester 230kV Circuit (B2139)	Ridge Road 69kV Breaker Station (B1255)	Cox's Corner-Lumberton 230kV Circuit (B1787)	Sewaren Switch 230kV Conversion (B2276)	Susquehanna Roseland < 500KV (B0489.4) (CWIP)	Susquehanna Roseland >= 500KV (B0489) (CWIP)	North Central Reliability (West Orange Conversion) (B1154) (CWIP)	Mickleton-Gloucester-Camden (B1398-B1398.7) (CWIP)	Mickleton-Gloucester-Camden Breakers (B1398.15-B1398.19) (CWIP)	Burlington - Camden 230kV Conversion (B1156) (CWIP)
											(5,248,317)	**(18,976,078)**	**(2,198,692)**	**(6,756,619)**	**(29,566)**	**8,909,571**

1.06783	***1.06783***	***1.06783***	***1.06783***	***1.06783***	***1.06783***	***1.06783***	***1.06783***	***1.06783***	***1.06783***	***1.06783***	***1.06783***	***1.06783***	***1.06783***	***1.06783***	***1.06783***	***1.06783***

True Up by Project (with interest) - 2014

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)	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)	Upgrade Eagle Point-Gloucester 230kV Circuit (B1588)	Mickleton-Gloucester 230kV Circuit (B2139)	Ridge Road 69kV Breaker Station (B1255)	Cox's Corner-Lumberton 230kV Circuit (B1787)	Sewaren Switch 230kV Conversion (B2276)	Susquehanna Roseland < 500KV (B0489.4) (CWIP)	Susquehanna Roseland >= 500KV (B0489) (CWIP)	North Central Reliability (West Orange Conversion) (B1154) (CWIP)	Mickleton-Gloucester-Camden (B1398-B1398.7) (CWIP)	Mickleton-Gloucester-Camden Breakers (B1398.15-B1398.19) (CWIP)	Burlington - Camden 230kV Conversion (B1156) (CWIP)
-	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**(5,604,287)**	**(20,263,143)**	**(2,347,820)**	**(7,214,891)**	**(31,572)**	**9,513,868**

Estimated Transmission Enhancement Charges (After True Up) - 2016

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)	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)	Upgrade Eagle Point-Gloucester 230kV Circuit (B1588)	Mickleton-Gloucester 230kV Circuit (B2139)	Ridge Road 69kV Breaker Station (B1255)	Cox's Corner-Lumberton 230kV Circuit (B1787)	Sewaren Switch 230kV Conversion (B2276)	Susquehanna Roseland < 500KV (B0489.4) (CWIP)	Susquehanna Roseland >= 500KV (B0489) (CWIP)	North Central Reliability (West Orange Conversion) (B1154) (CWIP)	Mickleton-Gloucester-Camden (B1398-B1398.7) (CWIP)	Mickleton-Gloucester-Camden Breakers (B1398.15-B1398.19) (CWIP)	Burlington - Camden 230kV Conversion (B1156) (CWIP)
1,480,230	**1,480,230**	**2,047,240**	**1,480,232**	**1,898,794**	**1,898,794**	**1,654,204**	**2,525,192**	**2,807,871**	**4,125,793**	**9,480,938**	**(5,604,287)**	**(20,263,143)**	**(2,347,820)**	**(7,214,891)**	**(31,572)**	**9,513,868**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2016

	(AW)	(AX)	(AY)	(AZ)	(BA)	(BB)	(BC)	(BD)	(BE)	(BF)	(BG)	(BH)
		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)	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)	Ridge Road 69kV Breaker Station (B1255)	Cox's Corner-Lumberton 230kV Circuit (B1787)	Sewaren Switch 230kV Conversion (B2276)	
		(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	
15-Dec		-	-	-	-	-	-	-	-	15,515,959	12,035,060	
Jan	18,477,450	1,292,000	-	-	-	-	-	-	-	15,808,548	18,196,687	
Feb	30,129,943	1,292,000	-	-	-	-	-	-	-	15,820,701	18,859,258	
Mar	89,201,680	1,292,000	-	-	-	-	-	-	-	33,283,535	19,554,410	
Apr	51,470,985	1,292,000	-	-	-	-	-	-	-	33,740,125	19,765,501	
May	55,847,505	1,292,000	-	-	-	-	-	-	27,803,197	33,750,372	22,879,684	
Jun	90,921,487	153,976,178	19,694,890	19,694,890	27,239,122	19,694,915	25,264,003	25,264,003	33,709,238	33,763,562	107,007,789	
Jul	3,045,137	153,976,178	19,694,890	19,694,890	27,239,122	19,694,915	25,264,003	25,264,003	33,727,528	33,763,562	108,762,028	
Aug	1,741,545	153,976,178	19,694,890	19,694,890	27,239,122	19,694,915	25,264,003	25,264,003	33,745,818	33,763,562	110,599,860	
Sep	7,027,342	153,976,178	19,694,890	19,694,890	27,239,122	19,694,915	25,264,003	25,264,003	33,764,108	33,763,562	110,834,894	
Oct	2,771,205	153,976,178	19,694,890	19,694,890	27,239,122	19,694,915	25,264,003	25,264,003	33,764,108	33,763,562	111,030,356	
Nov	13,085,768	153,976,178	19,694,890	19,694,890	27,239,122	19,694,915	25,264,003	25,264,003	33,764,108	33,763,562	111,495,255	
Dec	300,958,144	153,976,178	19,694,890	19,694,890	27,239,122	19,694,915	25,264,003	25,264,003	33,764,108	33,763,562	112,005,777	
Total	**664,678,193**	**1,084,293,249**	**137,864,227**	**137,864,227**	**190,673,856**	**137,864,402**	**176,848,020**	**176,848,020**	**264,042,213**	**384,264,178**	**883,026,559**	
13 Month Average CWIP to Appendix A, line 45	**51,129,092**	**83,407,173** **7.04**	**10,604,941** **7.00**	**10,604,941** **7.00**	**14,667,220** **7.00**	**10,604,954** **7.00**	**13,603,694** **7.00**	**13,603,694** **7.00**	**20,310,939** **7.82**	**29,558,783** **11.38**	**67,925,120** **7.88**	

Burlington - Camden 230kV Conversion (B1156.13-B1156.20) (CWIP)	Northeast Grid Reliability Project (B1304.1-B1304.4) (CWIP)	Northeast Grid Reliability Project (B1304.5-B1304.21) (CWIP)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (CWIP)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (CWIP)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (CWIP)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33) (CWIP)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34) (CWIP)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50) (CWIP)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (CWIP)	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
-	**8,459,954**	**355,835**	**5,826,722**	**1,426,555**	**1,064,877**	**2,887,183**	**1,636,015**	**1,549,513**	**1,007,913**	**1,793,514**	**1,119,514**	**1,119,514**

Actual Transmission Enhancement Charges - 2014

Burlington - Camden 230kV Conversion (B1156.13-B1156.20) (CWIP)	Northeast Grid Reliability Project (B1304.1-B1304.4) (CWIP)	Northeast Grid Reliability Project (B1304.5-B1304.21) (CWIP)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (CWIP)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (CWIP)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (CWIP)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33) (CWIP)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34) (CWIP)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50) (CWIP)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (CWIP)	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)
461,551	**29,152,116**	**3,752,145**	**391,383**	**61,526**	**58,653**	**74,197**	**58,912**	**41,991**	**21,259**	**56,093**	**24,145**	**24,145**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2016

Reconciliation by Project (without interest)

Burlington - Camden 230kV Conversion (B1156.13-B1156.20) (CWIP)	Northeast Grid Reliability Project (B1304.1-B1304.4) (CWIP)	Northeast Grid Reliability Project (B1304.5-B1304.21) (CWIP)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (CWIP)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (CWIP)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (CWIP)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33) (CWIP)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34) (CWIP)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50) (CWIP)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (CWIP)	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)
(615,050)	**(26,513,038)**	**(3,159,564)**	**391,383**	**61,526**	**58,653**	**74,197**	**58,912**	**41,991**	**21,259**	**56,093**	**24,145**	**24,145**

1.06783	***1.06783***	***1.06783***	***1.06783***	***1.06783***	***1.06783***	***1.06783***	***1.06783***	***1.06783***	***1.06783***	***1.06783***	***1.06783***	***1.06783***

True Up by Project (with interest) - 2014

Burlington - Camden 230kV Conversion (B1156.13-B1156.20) (CWIP)	Northeast Grid Reliability Project (B1304.1-B1304.4) (CWIP)	Northeast Grid Reliability Project (B1304.5-B1304.21) (CWIP)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (CWIP)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (CWIP)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (CWIP)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33) (CWIP)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34) (CWIP)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50) (CWIP)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (CWIP)	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)
(656,766)	**(28,311,302)**	**(3,373,863)**	**417,929**	**65,699**	**62,631**	**79,229**	**62,908**	**44,839**	**22,701**	**59,898**	**25,783**	**25,783**

Estimated Transmission Enhancement Charges (After True Up) - 2016

Burlington - Camden 230kV Conversion (B1156.13-B1156.20) (CWIP)	Northeast Grid Reliability Project (B1304.1-B1304.4) (CWIP)	Northeast Grid Reliability Project (B1304.5-B1304.21) (CWIP)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (CWIP)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (CWIP)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (CWIP)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33) (CWIP)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34) (CWIP)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50) (CWIP)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (CWIP)	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)
(656,766)	**(19,851,348)**	**(3,018,028)**	**6,244,651**	**1,492,254**	**1,127,509**	**2,966,412**	**1,698,923**	**1,594,352**	**1,030,614**	**1,853,412**	**1,145,297**	**1,145,297**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2016

(BI)	(BJ)	(BK)	(BL)	(BM)	(BN)	(BO)	(BP)	(BQ)	(BR)	(BS)	(BT)	(BU)	(BV)
Susquehanna Roseland Breakers (B0489.5-B0489.15)	Susquehanna Roseland <500kV (B0489.4)	Susquehanna Roseland >= 500kV (B0489)	Burlington - Camden 230kV Conversion (B1156)	Mickleton-Gloucester-Camden (B1398-B1398.7)	North Central Reliability (West Orange Conversion) (B1154)	Northeast Grid Reliability Project (B1304.1-B1304.4) (monthly additions)	Susquehanna Roseland < 500kV (B0489.4)	Susquehanna Roseland >= 500KV (B0489)	North Central Reliability (West Orange Conversion) (B1154)	Mickleton-Gloucester-Camden (B1398-B1398.7)	Mickleton-Gloucester-Camden Breakers (B1398.15-B1398.19)	Burlington - Camden 230kV Conversion (B1156)	Burlington - Camden 230kV Conversion (B1156.13-B1156.20)
(in service)	(in service)	(in service)	(in-service)	(in-service)	(in service)	(in service)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)
5,857,687	40,538,248	723,503,148	354,730,847	426,457,348	368,260,297	556,734,941	-	-	-	-	-	-	-
5,857,687	40,538,248	723,503,148	354,730,847	427,207,348	368,260,297	556,734,941	-	-	-	-	-	-	-
5,857,687	40,538,248	723,503,148	354,730,847	427,957,348	368,260,297	556,734,941	-	-	-	-	-	-	-
5,857,687	40,538,248	723,503,148	354,730,847	427,957,348	368,260,297	639,966,941	-	-	-	-	-	-	-
5,857,687	40,538,248	723,503,148	354,730,847	427,957,348	368,260,297	639,966,941	-	-	-	-	-	-	-
5,857,687	40,538,248	723,503,148	354,730,847	427,957,348	368,260,297	837,035,962	-	-	-	-	-	-	-
5,857,687	40,538,248	723,503,148	354,730,847	427,957,348	368,260,297	839,581,806	-	-	-	-	-	-	-
5,857,687	40,538,248	723,503,148	354,730,847	427,957,348	368,260,297	840,911,806	-	-	-	-	-	-	-
5,857,687	40,538,248	723,503,148	354,730,847	427,957,348	368,260,297	841,261,806	-	-	-	-	-	-	-
5,857,687	40,538,248	723,503,148	354,730,847	427,957,348	368,260,297	841,611,806	-	-	-	-	-	-	-
5,857,687	40,538,248	723,503,148	354,730,847	427,957,348	368,260,297	841,681,806	-	-	-	-	-	-	-
5,857,687	40,538,248	723,503,148	354,730,847	427,957,348	368,260,297	841,681,806	-	-	-	-	-	-	-
5,857,687	40,538,248	723,503,148	354,730,847	427,957,348	368,260,297	841,681,806	-	-	-	-	-	-	-
76,149,931	**526,997,224**	**9,405,540,919**	**4,611,501,015**	**5,561,195,526**	**4,787,383,865**	**9,675,587,314**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
5,857,687	**40,538,248**	**723,503,148**	**354,730,847**	**427,784,271**	**368,260,297**	**744,275,947**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
13.00	**13.00**	**13.00**	**13.00**	**12.99**	**13.00**	**11.50**	**-**	**-**	**-**	**-**	**-**	**-**	**-**

Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) CWIP	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (CWIP)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (CWIP)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91) (CWIP)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (CWIP)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (CWIP)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20) (CWIP)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (CWIP)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (CWIP)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33) (CWIP)	BRH Project (B0829-B0830) Abandoned
1,276,434	**1,276,434**	**1,081,821**	**863,750**	**1,326,708**	**1,323,679**	**639,295**	**639,379**	**851,765**	**145,981**	**-**

Actual Transmission Enhancement Charges - 2014

Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) (CWIP)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (CWIP)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (CWIP)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91) (CWIP)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (CWIP)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (CWIP)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20) (CWIP)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (CWIP)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (CWIP)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33) (CWIP)	BRH Project (B0829-B0830) Abandoned
24,114	**24,114**	**63,898**	**48,434**	**220,160**	**223,171**	**4,946**	**4,952**	**13,854**	**5,677**	**-**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2016

Reconciliation by Project (without interest)

Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) (CWIP)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (CWIP)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (CWIP)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91) (CWIP)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (CWIP)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (CWIP)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20) (CWIP)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (CWIP)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (CWIP)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33) (CWIP)	BRH Project (B0829-B0830) Abandoned
24,114	**24,114**	**63,898**	**48,434**	**220,160**	**223,171**	**4,946**	**4,952**	**13,854**	**5,677**	**-**

1.06783	*1.06783*	*1.06783*	*1.06783*	*1.06783*	*1.06783*	*1.06783*	*1.06783*	*1.06783*	*1.06783*	*1.06783*

True Up by Project (with interest) - 2014

Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) (CWIP)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (CWIP)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (CWIP)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91) (CWIP)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (CWIP)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (CWIP)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20) (CWIP)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (CWIP)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (CWIP)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33) (CWIP)	BRH Project (B0829-B0830) Abandoned
25,750	**25,750**	**68,232**	**51,719**	**235,093**	**238,307**	**5,281**	**5,288**	**14,794**	**6,062**	**-**

Estimated Transmission Enhancement Charges (After True Up) - 2016

Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) (CWIP)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (CWIP)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (CWIP)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91) (CWIP)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (CWIP)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (CWIP)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20) (CWIP)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (CWIP)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (CWIP)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33) (CWIP)	BRH Project (B0829-B0830) Abandoned
1,302,184	**1,302,184**	**1,150,053**	**915,470**	**1,561,801**	**1,561,986**	**644,576**	**644,666**	**866,559**	**152,043**	**-**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2016

(BW)	(BX)	(BY)	(BZ)	(CA)	(CB)	(CC)	(CD)	(CE)	(CF)	(CG)	(CH)	(CI)	(CJ)	(CK)	(CL)	(CM)	(CN)	(CO)	(CQ)	(CR)	(CS)
Northeast Grid Reliability Project (B1304.1-B1304.4)	Northeast Grid Reliability Project (B1304.5-B1304.21)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated substation upgrades (B2436.91)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33)
(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)
201,881,920	6,516,892	84,176,263	14,821,498	14,895,803	7,554,938	1,867,294	3,309,282	4,404,029	6,053,980	3,338,989	3,338,989	5,782,211	5,782,211	15,432,721	14,219,415	19,427,024	19,665,474	2,990,285	2,991,005	1,715,265	233,966
208,261,705	9,380,107	92,350,380	15,286,434	15,338,844	9,343,007	3,125,262	3,902,277	4,692,359	6,379,587	3,637,031	3,637,031	6,187,957	6,187,957	15,998,349	14,552,849	20,619,745	19,998,196	3,135,116	3,135,836	2,312,374	341,140
214,107,466	13,042,846	102,209,178	16,081,827	16,109,930	11,191,138	4,341,714	4,506,257	4,929,126	6,860,096	3,965,307	3,965,307	6,532,142	6,532,142	18,407,142	15,299,479	21,934,545	20,452,995	3,294,492	3,295,213	2,969,929	362,896
149,334,421	2,987,191	112,315,203	16,657,942	16,657,050	13,907,096	5,933,101	5,249,856	5,779,428	7,133,342	5,666,536	5,666,536	7,385,339	7,385,339	21,048,824	15,727,216	23,103,369	22,481,819	3,954,066	3,954,786	3,010,492	479,057
162,430,530	7,442,882	120,295,135	17,336,966	17,312,257	17,117,356	8,210,663	6,398,678	6,450,607	7,676,579	6,997,626	6,997,626	7,873,815	7,873,815	22,681,206	16,293,643	23,974,418	24,212,868	4,279,666	4,280,386	3,608,293	544,845
-	-	126,264,977	18,092,986	18,020,849	20,379,108	10,355,920	9,115,041	7,321,932	10,145,886	8,228,162	8,228,162	9,120,366	9,120,366	23,341,789	16,887,863	23,984,596	24,223,046	4,834,806	4,835,526	3,967,235	654,906
-	-	662,194	1,793,598	1,650,690	23,902,465	12,229,184	11,369,937	8,800,202	13,636,489	10,262,368	10,262,368	11,168,407	11,168,407	411,976	418,878	2,266,346	2,504,796	6,019,936	6,020,656	4,542,748	749,986
-	-	1,733,519	2,049,941	1,823,820	27,202,798	14,512,278	14,101,758	9,776,392	16,898,310	11,396,993	11,396,993	12,319,300	12,319,300	495,207	475,831	2,270,094	2,508,545	6,570,958	6,571,678	7,786,934	861,783
-	-	2,581,341	2,901,519	2,331,490	30,800,911	17,806,097	16,792,259	10,770,752	19,506,637	12,314,875	12,314,875	13,232,716	13,232,716	562,629	522,410	2,273,067	2,511,518	6,866,771	6,867,492	9,647,717	1,319,401
-	-	2,737,205	4,093,132	2,653,655	35,019,454	21,213,048	19,940,643	11,607,928	22,084,884	13,444,092	13,444,092	14,356,316	14,356,316	645,660	579,227	2,276,807	2,515,257	7,246,536	7,247,256	11,790,461	1,580,380
-	-	2,863,970	13,590,452	2,915,675	38,423,752	23,983,852	23,000,361	12,251,819	23,827,812	14,475,383	14,475,383	15,482,830	15,482,830	727,404	625,436	2,279,848	2,518,298	7,518,506	7,519,226	13,291,543	1,792,636
-	-	2,995,774	17,596,966	4,733,888	43,210,983	28,675,828	27,157,897	12,944,201	29,077,790	15,562,353	15,562,353	16,558,101	16,558,101	820,227	674,421	2,282,975	2,521,425	7,532,557	7,533,278	14,834,805	3,558,212
-	-	3,108,397	19,887,254	5,133,133	46,154,190	31,456,933	29,153,435	13,451,622	32,115,662	16,422,638	16,422,638	17,333,648	17,333,648	906,569	715,475	2,285,677	2,524,127	7,543,949	7,544,669	16,168,432	3,913,246
936,016,043	**39,369,918**	**654,293,537**	**160,190,517**	**119,577,082**	**324,207,194**	**183,711,171**	**173,997,682**	**113,180,399**	**201,397,054**	**125,712,354**	**125,712,354**	**143,333,149**	**143,333,149**	**121,479,703**	**96,992,142**	**148,978,510**	**148,638,363**	**71,787,643**	**71,797,006**	**95,646,229**	**16,392,454**
13.00	**13.00**	**210.49**	**8.05**	**23.30**	**7.02**	**5.84**	**5.97**	**8.41**	**6.27**	**7.65**	**7.65**	**8.27**	**8.27**	**134.00**	**135.56**	**65.18**	**58.89**	**9.52**	**9.52**	**5.92**	**4.19**
72,001,234	**3,028,455**	**50,330,272**	**12,322,347**	**9,198,237**	**24,939,015**	**14,131,629**	**13,384,437**	**8,706,185**	**15,492,081**	**9,670,181**	**9,670,181**	**11,025,627**	**11,025,627**	**9,344,593**	**7,460,934**	**11,459,885**	**11,433,720**	**5,522,126**	**5,522,847**	**7,357,402**	**1,260,958**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2016

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2016

1	New Plant Carrying Charge				
2	**Fixed Charge Rate (FCR) if if not a CIAC**				
			Formula Line		
3		A	152	Net Plant Carrying Charge without Depreciation	11.58%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	12.27%
5		C		Line B less Line A	0.69%
6	**FCR if a CIAC**				
7		D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.90%

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

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

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 **For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the**
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

10		Details		**Branchburg (B0130)**	**Kittatinny (B0134)**	**Essex Aldene (B0145)**	**New Freedom Trans.(B0411)**
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		11.58%	11.58%	11.58%	11.58%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.58%	11.58%	11.58%	11.58%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		20,680,597	8,069,022	86,565,629	22,188,863
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		492,395	192,120	2,061,086	528,306
19	Months in service for depreciation expense from Attachment 6			13.00	13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)			2006	2007	2007	2007

21		Invest Yr	**Ending**	**Depreciation 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	2,470,088	6,644,135	192,120	1,000,786	71,279,238	2,061,086	10,736,580	18,006,439	528,306	2,719,894
41	W Increased ROE	2015	16,249,041	492,395	2,470,088	6,644,135	192,120	1,000,786	71,279,238	2,061,086	10,736,580	18,006,439	528,306	2,719,894
42	W 11.68 % ROE	2016	15,756,645	492,395	2,316,538	6,452,016	192,120	939,068	69,218,152	2,061,086	10,074,454	17,478,132	528,306	2,551,745
43	W Increased ROE	2016	15,756,645	492,395	2,316,538	6,452,016	192,120	939,068	69,218,152	2,061,086	10,074,454	17,478,132	528,306	2,551,745

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2016

1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if if not a CIAC**			
		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	11.58%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	12.27%
5	C		Line B less Line A	0.69%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.90%

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

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

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

10		Details		**New Freedom Loop (B0498)**			**Metuchen Transformer (B0161)**			**Branchburg-Flagtown-Somerville (B0169)**			**Flagtown-Somerville-Bridgewater (B0170)**	
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes			Yes			Yes			Yes		
12	Useful life of the project	Life		42			42			42			42		
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No			No			No			No		
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0			0			0			0		
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		11.58%			11.58%			11.58%			11.58%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.58%			11.58%			11.58%			11.58%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		27,005,248			25,799,055			15,731,554			6,961,495		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		642,982			614,263			374,561			165,750		
19	Months in service for depreciation expense from Attachment 6			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	3,449,489	22,439,786	614,263	3,345,440	13,623,182	374,561	2,032,657	5,941,623	165,750	888,913
41		W Increased ROE	2015	23,058,705	642,982	3,449,489	22,439,786	614,263	3,345,440	13,623,182	374,561	2,032,657	5,941,623	165,750	888,913
42		W 11.68 % ROE	2016	22,415,723	642,982	3,238,044	21,825,523	614,263	3,140,998	13,248,621	374,561	1,908,350	5,775,874	165,750	834,421
43		W Increased ROE	2016	22,415,723	642,982	3,238,044	21,825,523	614,263	3,140,998	13,248,621	374,561	1,908,350	5,775,874	165,750	834,421

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2016

1 New Plant Carrying Charge

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

		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	11.58%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	12.27%
5	C		Line B less Line A	0.69%

6 **FCR if a CIAC**

7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.90%

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.

				Roseland Transformers (B0274)	**Wave Trap Branchburg (B0172.2)**	**Reconductor Hudson - South Waterfront (B0813)**	**Reconductor South Mahwah J-3410 Circuit (B1017)**
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		11.58%	11.58%	11.58%	11.58%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.58%	11.58%	11.58%	11.58%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		21,073,706	27,988	9,158,918	20,626,991
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		501,755	666	218,069	491,119
19	Months in service for depreciation expense from Attachment 6			13.00	13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)			2009	2008	2010	2011

			Roseland Transformers (B0274)			Wave Trap Branchburg (B0172.2)			Reconductor Hudson - South Waterfront (B0813)			Reconductor South Mahwah J-3410 Circuit (B1017)		
21		**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008				36,369	577	5,114						
27	W Increased ROE	2008				36,369	577	5,114						
28	W 11.68 % ROE	2009	21,092,458	268,347	2,634,066	35,792	866	8,379						
29	W Increased ROE	2009	21,092,458	268,347	2,634,066	35,792	866	8,379						
30	W 11.68 % ROE	2010	20,797,967	501,579	4,507,079	27,122	666	5,890	8,806,222	18,700	169,959			
31	W Increased ROE	2010	20,797,967	501,579	4,507,079	27,122	666	5,890	8,806,222	18,700	169,959			
32	W 11.68 % ROE	2011	20,302,520	501,725	4,128,443	25,878	666	5,289	9,140,218	218,069	1,850,822	20,623,951	300,198	2,435,793
33	W Increased ROE	2011	20,302,520	501,725	4,128,443	25,878	666	5,289	9,140,218	218,069	1,850,822	20,623,951	300,198	2,435,793
34	W 11.68 % ROE	2012	19,802,055	501,755	3,475,512	25,212	666	4,453	8,922,149	218,069	1,557,946	20,326,793	491,119	3,543,678
35	W Increased ROE	2012	19,802,055	501,755	3,475,512	25,212	666	4,453	8,922,149	218,069	1,557,946	20,326,793	491,119	3,543,678
36	W 11.68 % ROE	2013	19,300,300	501,755	3,183,218	24,546	666	4,077	8,704,079	218,069	1,427,360	19,835,674	491,119	3,246,963
37	W Increased ROE	2013	19,300,300	501,755	3,183,218	24,546	666	4,077	8,704,079	218,069	1,427,360	19,835,674	491,119	3,246,963
38	W 11.68 % ROE	2014	18,798,545	501,755	2,817,996	23,880	666	3,609	8,486,010	218,069	1,263,663	19,344,555	491,119	2,874,636
39	W Increased ROE	2014	18,798,545	501,755	2,817,996	23,880	666	3,609	8,486,010	218,069	1,263,663	19,344,555	491,119	2,874,636
40	W 11.68 % ROE	2015	18,296,790	501,755	2,728,682	23,213	666	3,492	8,267,940	218,069	1,224,372	18,853,437	491,119	2,785,796
41	W Increased ROE	2015	18,296,790	501,755	2,728,682	23,213	666	3,492	8,267,940	218,069	1,224,372	18,853,437	491,119	2,785,796
42	W 11.68 % ROE	2016	17,795,036	501,755	2,561,882	22,547	666	3,277	8,049,871	218,069	1,150,001	18,362,318	491,119	2,616,920
43	W Increased ROE	2016	17,795,036	501,755	2,561,882	22,547	666	3,277	8,049,871	218,069	1,150,001	18,362,318	491,119	2,616,920

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2016

1	New Plant Carrying Charge				
2	**Fixed Charge Rate (FCR) if if not a CIAC**				
			Formula Line		
3		A	152	Net Plant Carrying Charge without Depreciation	11.58%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	12.27%
5		C		Line B less Line A	0.69%
6	**FCR if a CIAC**				
7		D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.90%

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

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

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

10		Details		**Reconductor South Mahwah K-3411 Circuit (B1018)**	**Branchburg 400 MVAR Capacitor (B0290)**	**Saddle Brook - Athenia Upgrade Cable (B0472)**	**Branchburg-Sommerville-Flagtown Reconductor (B0664 & B0665)**
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		11.58%	11.58%	11.58%	11.58%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.58%	11.58%	11.58%	11.58%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		21,170,273	80,435,315	14,404,842	18,664,931
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		504,054	1,915,127	342,972	444,403
19	Months in service for depreciation expense from Attachment 6			13.00	13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)			2011	2012	2012	2012

21		**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011	20,511,158	37,566	284,735									
33	W Increased ROE	2011	20,511,158	37,566	284,735									
34	W 11.68 % ROE	2012	21,132,707	504,054	3,677,641	79,937,194	1,240,233	9,062,770	14,401,477	210,412	1,537,549	19,820,557	318,342	2,326,229
35	W Increased ROE	2012	21,132,707	504,054	3,677,641	79,937,194	1,240,233	9,062,770	14,401,477	210,412	1,537,549	19,820,557	318,342	2,326,229
36	W 11.68 % ROE	2013	20,628,652	504,054	3,370,070	79,195,082	1,915,127	12,917,996	14,194,429	342,972	2,315,058	18,294,505	443,163	2,984,887
37	W Increased ROE	2013	20,628,652	504,054	3,370,070	79,195,082	1,915,127	12,917,996	14,194,429	342,972	2,315,058	18,294,505	443,163	2,984,887
38	W 11.68 % ROE	2014	20,124,598	504,054	2,983,683	77,279,955	1,915,127	11,437,086	13,851,457	342,972	2,049,664	17,903,425	444,403	2,650,353
39	W Increased ROE	2014	20,124,598	504,054	2,983,683	77,279,955	1,915,127	11,437,086	13,851,457	342,972	2,049,664	17,903,425	444,403	2,650,353
40	W 11.68 % ROE	2015	19,620,544	504,054	2,892,097	75,375,411	1,915,127	11,089,171	13,508,484	342,972	1,987,109	17,463,626	444,403	2,569,925
41	W Increased ROE	2015	19,620,544	504,054	2,892,097	75,375,411	1,915,127	11,089,171	13,508,484	342,972	1,987,109	17,463,626	444,403	2,569,925
42	W 11.68 % ROE	2016	19,116,490	504,054	2,717,165	73,449,702	1,915,127	10,418,379	13,165,512	342,972	1,867,140	17,014,619	444,403	2,414,181
43	W Increased ROE	2016	19,116,490	504,054	2,717,165	73,449,702	1,915,127	10,418,379	13,165,512	342,972	1,867,140	17,014,619	444,403	2,414,181

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2016

1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if if not a CIAC**			
		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	11.58%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	12.27%
5	C		Line B less Line A	0.69%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.90%

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

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

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,

which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

10		Details		**Somerville-Bridgewater Reconductor (B0668)**			**New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie (B0814)**			**Salem 500 kV breakers (B1410-B1415)**			**230kV Lawrence Switching Station Upgrade (B1228)**		
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes			Yes			Yes			Yes		
12	Useful life of the project	Life		42			42			42			42		
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No			No			No			No		
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0			0			0			0		
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		11.58%			11.58%			11.58%			11.58%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.58%			11.58%			11.58%			11.58%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		6,390,403			46,073,296			16,316,117			22,040,646		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		152,152			1,096,983			388,479			524,777		
19	Months in service for depreciation expense from Attachment 6			13.00			13.00			13.00			13.00		
20	Year placed in Service (0 if CWIP)			2012			2012			2011			2013		
21			**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**
22		W 11.68 % ROE	2006												
23		W Increased ROE	2006												
24		W 11.68 % ROE	2007												
25		W Increased ROE	2007												
26		W 11.68 % ROE	2008												
27		W Increased ROE	2008												
28		W 11.68 % ROE	2009												
29		W Increased ROE	2009												
30		W 11.68 % ROE	2010												
31		W Increased ROE	2010												
32		W 11.68 % ROE	2011							2,640,253	9,537	73,000			
33		W Increased ROE	2011							2,640,253	9,537	73,000			
34		W 11.68 % ROE	2012	4,404,012	57,853	422,751	22,800,866	123,008	898,857	7,275,941	108,279	790,336			
35		W Increased ROE	2012	4,404,012	57,853	422,751	22,800,866	123,008	898,857	7,275,941	108,279	790,336			
36		W 11.68 % ROE	2013	6,291,725	151,180	1,025,313	45,385,800	1,083,543	7,389,162	9,926,683	192,972	1,305,797	22,127,065	248,542	1,698,840
37		W Increased ROE	2013	6,291,725	151,180	1,025,313	45,385,800	1,083,543	7,389,162	9,926,683	192,972	1,305,797	22,127,065	248,542	1,698,840
38		W 11.68 % ROE	2014	6,181,332	152,152	913,777	44,747,660	1,094,148	6,607,679	15,445,872	289,093	1,755,636	21,792,104	524,777	3,209,866
39		W Increased ROE	2014	6,181,332	152,152	913,777	44,747,660	1,094,148	6,607,679	15,445,872	289,093	1,755,636	21,792,104	524,777	3,209,866
40		W 11.68 % ROE	2015	5,989,364	151,180	880,154	43,605,982	1,092,466	6,399,809	15,622,924	385,269	2,286,756	21,341,402	524,777	3,122,268
41		W Increased ROE	2015	5,989,364	151,180	880,154	43,605,982	1,092,466	6,399,809	15,622,924	385,269	2,286,756	21,341,402	524,777	3,122,268
42		W 11.68 % ROE	2016	5,878,038	152,152	832,651	42,680,131	1,096,983	6,038,051	15,330,967	388,479	2,163,341	20,742,550	524,777	2,926,137
43		W Increased ROE	2016	5,878,038	152,152	832,651	42,680,131	1,096,983	6,038,051	15,330,967	388,479	2,163,341	20,742,550	524,777	2,926,137

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2016

1	New Plant Carrying Charge				
2	**Fixed Charge Rate (FCR) if if not a CIAC**				
			Formula Line		
3		A	152	Net Plant Carrying Charge without Depreciation	11.58%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	12.27%
5		C		Line B less Line A	0.69%
6	**FCR if a CIAC**				
7		D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.90%

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		**Bergen Substation Transformer (B1082)**	**Branchburg-Middlesex Switch Rack (B1155)**	**Aldene-Springfield Rd. Conversion (B1399)**	**Upgrade Camden-Richmond 230kV Circuit (B1590)**
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		11.58%	11.58%	11.58%	11.58%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.58%	11.58%	11.58%	11.58%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		-	68,260,260	71,564,861	10,901,749
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		-	1,625,244	1,703,925	259,565
19	Months in service for depreciation expense from Attachment 6				13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)				2013	2014	2014

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				20,876,286	101,812	695,908						
37		W Increased ROE	2013				20,876,286	101,812	695,908						
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
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
40		W 11.68 % ROE	2015				37,378,572	908,985	5,458,382	33,025,871	799,927	4,819,551			
41		W Increased ROE	2015				37,378,572	908,985	5,458,382	33,025,871	799,927	4,819,551			
42		W 11.68 % ROE	2016				65,809,557	1,625,244	9,243,999	70,208,024	1,703,925	9,831,890	10,863,757	259,565	1,517,260
43		W Increased ROE	2016				65,809,557	1,625,244	9,243,999	70,208,024	1,703,925	9,831,890	10,863,757	259,565	1,517,260

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2016

1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if if not a CIAC**			
		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	11.58%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	12.27%
5	C		Line B less Line A	0.69%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.90%

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

10		Details		**Susquehanna Roseland Breakers (b0489.5-B0489.15)**			**Susquehanna Roseland < 500KV (B0489.4)**			**Susquehanna Roseland > 500KV (B0489)**			**Burlington - Camden 230kV Conversion (B1156)**		
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			125			0		
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		11.58%			11.58%			11.58%			11.58%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		12.44%			12.44%			12.44%			11.58%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		5,857,687			40,538,248			723,503,148			354,730,847		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		139,469			965,196			17,226,265			8,445,973		
19	Months in service for depreciation expense from Attachment 6				13.00			13.00			13.00			13.00	
20	Year placed in Service (0 if CWIP)			2010			2011			2012			2011		
21			**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**
22		W 11.68 % ROE	2006												
23		W Increased ROE	2006												
24		W 11.68 % ROE	2007												
25		W Increased ROE	2007												
26		W 11.68 % ROE	2008												
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	7,844,331	111,778	905,525				19,902,939	147,204	1,150,144
33		W Increased ROE	2011	5,849,885	116,061	1,014,845	7,844,331	111,778	952,449				19,902,939	147,204	1,150,144
34		W 11.68 % ROE	2012	5,733,823	139,469	1,000,541	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	5,733,823	139,469	1,051,531	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	5,594,354	139,469	916,713	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
37		W Increased ROE	2013	5,594,354	139,469	967,047	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
38		W 11.68 % ROE	2014	5,454,886	139,469	811,586	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
39		W Increased ROE	2014	5,454,886	139,469	859,361	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
40		W 11.68 % ROE	2015	5,315,417	139,469	786,415	39,413,941	965,196	5,762,321	718,988,609	16,720,459	101,351,556	327,911,640	8,048,113	47,958,686
41		W Increased ROE	2015	5,315,417	139,469	832,840	39,413,941	965,196	6,106,563	718,988,609	16,720,459	107,424,698	327,911,640	8,048,113	47,958,686
42		W 11.68 % ROE	2016	5,175,948	139,469	738,687	38,400,330	965,196	5,410,793	696,007,937	17,226,265	97,802,922	337,124,933	8,445,973	47,474,838
43		W Increased ROE	2016	5,175,948	139,469	783,397	38,400,330	965,196	5,742,497	696,007,937	17,226,265	103,815,086	337,124,933	8,445,973	47,474,838

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2016

1 New Plant Carrying Charge

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

		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	11.58%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	12.27%
5	C		Line B less Line A	0.69%

6 **FCR if a CIAC**

7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.90%

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

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

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

10		Details		**Mickleton-Gloucester-Camden(B1398-B1398.7)**			**North Central Reliability (West Orange Conversion (B1154)**			**Northeast Grid Reliability Project (B1304.1-B1304.4)**			**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			0			25			0		
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		11.58%			11.58%			11.58%			11.58%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.58%			11.58%			11.75%			11.58%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		427,957,348			368,260,297			841,681,806			153,976,178		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		10,189,461			8,768,102			20,040,043			3,666,099		
19	Months in service for depreciation expense from Attachment 6			12.99			13.00			11.50			7.04		
20	Year placed in Service (0 if CWIP)			2013			2012			2013			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				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	777,714	1,424	9,736	257,640,264	6,135,009	41,929,935	23,466,022	86,647	592,253			
37		W Increased ROE	2013	777,714	1,424	9,736	257,640,264	6,135,009	41,929,935	23,466,022	86,647	598,801			
38		W 11.68 % ROE	2014	83,696,796	854,944	5,279,191	360,673,484	7,742,354	47,135,528	274,113,325	2,382,627	14,708,781			
39		W Increased ROE	2014	83,696,796	854,944	5,279,191	360,673,484	7,742,354	47,135,528	274,113,325	2,382,627	14,884,013			
40		W 11.68 % ROE	2015	411,828,630	7,077,175	43,254,699	356,261,842	8,782,756	52,036,324	744,741,989	10,657,466	65,130,424	7,600,000	27,839	170,148
41		W Increased ROE	2015	411,828,630	7,077,175	43,254,699	356,261,842	8,782,756	52,036,324	744,741,989	10,657,466	65,912,222	7,600,000	27,839	170,148
42		W 11.68 % ROE	2016	420,023,804	10,185,340	58,791,720	345,570,065	8,768,102	48,774,658	828,555,066	17,720,856	102,541,677	153,948,340	1,985,885	11,640,166
43		W Increased ROE	2016	420,023,804	10,185,340	58,791,720	345,570,065	8,768,102	48,774,658	828,555,066	17,720,856	103,807,445	153,948,340	1,985,885	11,640,166

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2016

1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if if not a CIAC**			
		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	11.58%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	12.27%
5	C		Line B less Line A	0.69%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.90%

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.

				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)**	**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)**
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		11.58%	11.58%	11.58%	11.58%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.58%	11.58%	11.58%	11.58%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		19,694,890	19,694,890	27,239,122	19,694,915
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		468,926	468,926	648,551	468,927
19	Months in service for depreciation expense from Attachment 6			7.00	7.00	7.00	7.00
20	Year placed in Service (0 if CWIP)			2016	2016	2016	2016

21		**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011												
33	W Increased ROE	2011												
34	W 11.68 % ROE	2012												
35	W Increased ROE	2012												
36	W 11.68 % ROE	2013												
37	W Increased ROE	2013												
38	W 11.68 % ROE	2014												
39	W Increased ROE	2014												
40	W 11.68 % ROE	2015												
41	W Increased ROE	2015												
42	W 11.68 % ROE	2016	19,694,890	252,499	1,480,230	19,694,890	252,499	1,480,230	27,239,122	349,220	2,047,240	19,694,915	252,499	1,480,232
43	W Increased ROE	2016	19,694,890	252,499	1,480,230	19,694,890	252,499	1,480,230	27,239,122	349,220	2,047,240	19,694,915	252,499	1,480,232

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2016

1 New Plant Carrying Charge

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

Line		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	11.58%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	12.27%
5	C		Line B less Line A	0.69%

6 **FCR if a CIAC**

Line		Formula Line		
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.90%

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

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

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

10		Details		**New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10)**			**New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11)**			**Upgrade Eagle Point-Gloucester 230kV Circuit (B1588)**			**Mickleton-Gloucester 230kV Circuit (B2139)**		
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes			Yes			Yes			Yes		
12	Useful life of the project	Life		42			42			42			42		
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No			No			No			No		
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0			0			0			0		
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		11.58%			11.58%			11.58%			11.58%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.58%			11.58%			11.58%			11.58%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		25,264,003			25,264,003			11,954,175			18,237,729		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		601,524			601,524			284,623			434,232		
19	Months in service for depreciation expense from Attachment 6			7.00			7.00			13.00			13.00		
20	Year placed in Service (0 if CWIP)			2016			2016			2015			2015		
21			**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**
22		W 11.68 % ROE	2006												
23		W Increased ROE	2006												
24		W 11.68 % ROE	2007												
25		W Increased ROE	2007												
26		W 11.68 % ROE	2008												
27		W Increased ROE	2008												
28		W 11.68 % ROE	2009												
29		W Increased ROE	2009												
30		W 11.68 % ROE	2010												
31		W Increased ROE	2010												
32		W 11.68 % ROE	2011												
33		W Increased ROE	2011												
34		W 11.68 % ROE	2012												
35		W Increased ROE	2012												
36		W 11.68 % ROE	2013												
37		W Increased ROE	2013												
38		W 11.68 % ROE	2014												
39		W Increased ROE	2014												
40		W 11.68 % ROE	2015							10,157,273	123,958	757,614	13,755,622	176,354	1,077,855
41		W Increased ROE	2015							10,157,273	123,958	757,614	13,755,622	176,354	1,077,855
42		W 11.68 % ROE	2016	25,264,003	323,897	1,898,794	25,264,003	323,897	1,898,794	11,830,218	284,623	1,654,204	18,061,375	434,232	2,525,192
43		W Increased ROE	2016	25,264,003	323,897	1,898,794	25,264,003	323,897	1,898,794	11,830,218	284,623	1,654,204	18,061,375	434,232	2,525,192

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2016

1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if if not a CIAC**			
		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	11.58%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	12.27%
5	C		Line B less Line A	0.69%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.90%

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		**Ridge Road 69kV Breaker Station (B1255)**			**Cox's Corner-Lumberton 230kV Circuit (B1787)**			**Sewaren Switch 230kV Conversion (B2276)**			**Susquehanna Roseland < 500KV (B0489.4) (CWIP)**		
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes			Yes			Yes			Yes		
12	Useful life of the project	Life		42			42			42			42		
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No			No			No			No		
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0			0			0			125		
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		11.58%			11.58%			11.58%			11.58%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.58%			11.58%			11.58%			12.44%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		33,764,108			33,763,562			112,005,777			-		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		803,907			803,894			2,666,804			-		
19	Months in service for depreciation expense from Attachment 6			7.82			11.38			7.88			-		
20	Year placed in Service (0 if CWIP)			2016			2015			2015					
21			**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**
22		W 11.68 % ROE	2006												
23		W Increased ROE	2006												
24		W 11.68 % ROE	2007												
25		W Increased ROE	2007												
26		W 11.68 % ROE	2008												
27		W Increased ROE	2008												
28		W 11.68 % ROE	2009										8,601,534		794,647
29		W Increased ROE	2009										8,601,534		833,737
30		W 11.68 % ROE	2010										10,121,290		1,719,499
31		W Increased ROE	2010										10,121,290		1,811,185
32		W 11.68 % ROE	2011										30,831,150		3,376,923
33		W Increased ROE	2011										30,831,150		3,565,874
34		W 11.68 % ROE	2012										38,077,851		5,359,127
35		W Increased ROE	2012										38,077,851		5,676,479
36		W 11.68 % ROE	2013										40,538,248		5,381,625
37		W Increased ROE	2013										40,538,248		5,730,133
38		W 11.68 % ROE	2014										12,476,737		1,537,307
39		W Increased ROE	2014										12,476,737		1,646,580
40		W 11.68 % ROE	2015	31,269,172	389,350	2,379,660									
41		W Increased ROE	2015	31,269,172	389,350	2,379,660									
42		W 11.68 % ROE	2016	33,374,758	483,594	2,807,871	33,763,562	703,781	4,125,793	112,005,777	1,617,265	9,480,938			
43		W Increased ROE	2016	33,374,758	483,594	2,807,871	33,763,562	703,781	4,125,793	112,005,777	1,617,265	9,480,938			

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2016

1	New Plant Carrying Charge				
2	**Fixed Charge Rate (FCR) if if not a CIAC**				
			Formula Line		
3		A	152	Net Plant Carrying Charge without Depreciation	11.58%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	12.27%
5		C		Line B less Line A	0.69%
6	**FCR if a CIAC**				
7		D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.90%

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

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

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

10		Details		**Susquehanna Roseland >= 500kV (B0489) (CWIP)**	**North Central Reliability (West Orange Conversion) (B1154) (CWIP)**	**Mickleton-Gloucester-Camden(B1398-B1398.7) (CWIP)**	**Mickleton-Gloucester-Camden Breakers (B1398.15-B1398.19) (CWIP)**
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	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		11.58%	11.58%	11.58%	11.58%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		12.44%	11.58%	11.58%	11.58%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		-	-	-	-
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		-	-	-	-
19	Months in service for depreciation expense from Attachment 6			-	-	-	-
20	Year placed in Service (0 if CWIP)						

21			Invest Yr	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**
22		W 11.68 % ROE	2006												
23		W Increased ROE	2006												
24		W 11.68 % ROE	2007												
25		W Increased ROE	2007												
26		W 11.68 % ROE	2008	8,927,082		819,421									
27		W Increased ROE	2008	8,927,082		858,682									
28		W 11.68 % ROE	2009	33,993,795		3,927,226									
29		W Increased ROE	2009	33,993,795		4,120,411									
30		W 11.68 % ROE	2010	83,961,998		10,780,919									
31		W Increased ROE	2010	83,961,998		11,355,769									
32		W 11.68 % ROE	2011	133,618,838		19,674,374	19,588,655		1,299,846	1,648,851		56,106			
33		W Increased ROE	2011	133,618,838		20,775,227	19,588,655		1,299,846	1,648,851		56,106			
34		W 11.68 % ROE	2012	264,235,891		27,190,938	139,052,337		10,137,161	22,706,717		1,587,335	532,375		24,600
35		W Increased ROE	2012	264,235,891		28,801,108	139,052,337		10,137,161	22,706,717		1,587,335	532,375		24,600
36		W 11.68 % ROE	2013	567,928,477		56,420,758	79,292,223		21,408,869	117,558,986		7,924,475	532,375		73,965
37		W Increased ROE	2013	567,928,477		60,074,507	79,292,223		21,408,869	117,558,986		7,924,475	532,375		73,965
38		W 11.68 % ROE	2014	34,481,067		28,945,163	31,617,517		3,895,715	160,260,925		16,099,944	532,375		65,596
39		W Increased ROE	2014	34,481,067		31,002,624	31,617,517		3,895,715	160,260,925		16,099,944	532,375		65,596
40		W 11.68 % ROE	2015	18,053,234		2,197,284				83,162,211		10,121,786	245,712		29,906
41		W Increased ROE	2015	18,053,234		2,354,961				83,162,211		10,121,786	245,712		29,906
42		W 11.68 % ROE	2016												
43		W Increased ROE	2016												

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2016

1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if if not a CIAC**			
		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	11.58%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	12.27%
5	C		Line B less Line A	0.69%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.90%

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		**Burlington - Camden 230kV Conversion (B1156) (CWIP)**			**Burlington - Camden 230kV Conversion (B1156.13-B1156.20) (CWIP)**			**Northeast Grid Reliability Project (B1304.1-B1304.4) (CWIP)**			**Northeast Grid Reliability Project (B1304.5-B1304.21) (CWIP)**		
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			25			25		
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		11.58%			11.58%			11.58%			11.58%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.58%			11.58%			11.75%			11.75%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		-			-			72,001,234			3,028,455		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		-			-			1,714,315			72,106		
19	Months in service for depreciation expense from Attachment 6			-			-			13.00			13.00		
20	Year placed in Service (0 if CWIP)														
21			**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**
22		W 11.68 % ROE	2006												
23		W Increased ROE	2006												
24		W 11.68 % ROE	2007												
25		W Increased ROE	2007												
26		W 11.68 % ROE	2008												
27		W Increased ROE	2008												
28		W 11.68 % ROE	2009												
29		W Increased ROE	2009												
30		W 11.68 % ROE	2010												
31		W Increased ROE	2010												
32		W 11.68 % ROE	2011	22,089,378		1,874,440									
33		W Increased ROE	2011	22,089,378		1,874,440									
34		W 11.68 % ROE	2012	128,653,138		10,501,318	9,231,712		791,084	81,587,177		6,341,372	5,537,185		457,198
35		W Increased ROE	2012	128,653,138		10,501,318	9,231,712		791,084	81,587,177		6,416,475	5,537,185		462,613
36		W 11.68 % ROE	2013	155,344,760		22,819,788	8,854,018		1,275,855	184,611,449		18,512,179	18,052,410		1,627,531
37		W Increased ROE	2013	155,344,760		22,819,788	8,854,018		1,275,855	184,611,449		18,751,945	18,052,410		1,648,610
38		W 11.68 % ROE	2014	56,976,438		7,020,285	3,745,932		461,551	211,553,988		28,743,491	33,293,621		3,699,551
39		W Increased ROE	2014	56,976,438		7,020,285	3,745,932		461,551	211,553,988		29,152,116	33,293,621		3,752,145
40		W 11.68 % ROE	2015							129,109,243		15,714,062	25,032,697		3,046,764
41		W Increased ROE	2015							129,109,243		15,939,591	25,032,697		3,090,491
42		W 11.68 % ROE	2016							72,001,234		8,335,564	3,028,455		350,603
43		W Increased ROE	2016							72,001,234		8,459,954	3,028,455		355,835

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2016

1 New Plant Carrying Charge

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

		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	11.58%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	12.27%
5	C		Line B less Line A	0.69%

6 **FCR if a CIAC**

7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.90%

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 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)**		
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes			Yes			Yes			Yes		
12	Useful life of the project	Life		42			42			42			42		
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No			No			No			No		
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0			0			0			0		
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		11.58%			11.58%			11.58%			11.58%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.58%			11.58%			11.58%			11.58%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		3,108,397			19,887,254			5,133,133			46,154,190		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		74,009			473,506			122,217			1,098,909		
19	Months in service for depreciation expense from Attachment 6			210.49			8.05			23.30			7.02		
20	Year placed in Service (0 if CWIP)														
21			**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**
22		W 11.68 % ROE	2006												
23		W Increased ROE	2006												
24		W 11.68 % ROE	2007												
25		W Increased ROE	2007												
26		W 11.68 % ROE	2008												
27		W Increased ROE	2008												
28		W 11.68 % ROE	2009												
29		W Increased ROE	2009												
30		W 11.68 % ROE	2010												
31		W Increased ROE	2010												
32		W 11.68 % ROE	2011												
33		W Increased ROE	2011												
34		W 11.68 % ROE	2012												
35		W Increased ROE	2012												
36		W 11.68 % ROE	2013												
37		W Increased ROE	2013												
38		W 11.68 % ROE	2014	9,496,612		391,383	1,589,541		61,526	1,531,032		58,653	2,114,342		74,197
39		W Increased ROE	2014	9,496,612		391,383	1,589,541		61,526	1,531,032		58,653	2,114,342		74,197
40		W 11.68 % ROE	2015	32,184,737		1,789,839	7,086,018		435,427	7,014,415		429,818	6,990,065		519,891
41		W Increased ROE	2015	32,184,737		1,789,839	7,086,018		435,427	7,014,415		429,818	6,990,065		519,891
42		W 11.68 % ROE	2016	3,108,397		5,826,722	19,887,254		1,426,555	5,133,133		1,064,877	46,154,190		2,887,183
43		W Increased ROE	2016	3,108,397		5,826,722	19,887,254		1,426,555	5,133,133		1,064,877	46,154,190		2,887,183

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2016

1 New Plant Carrying Charge

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

		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	11.58%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	12.27%
5	C		Line B less Line A	0.69%

6 **FCR if a CIAC**

7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.90%

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.

				Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34) (CWIP)	**Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50) (CWIP)**	**Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (CWIP)**	**Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70) (CWIP)**
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		11.58%	11.58%	11.58%	11.58%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.58%	11.58%	11.58%	11.58%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		31,456,933	29,153,435	13,451,622	32,115,662
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		748,975	694,129	320,277	764,659
19	Months in service for depreciation expense from Attachment 6			5.84	5.97	8.41	6.27
20	Year placed in Service (0 if CWIP)						

21		**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011												
33	W Increased ROE	2011												
34	W 11.68 % ROE	2012												
35	W Increased ROE	2012												
36	W 11.68 % ROE	2013												
37	W Increased ROE	2013												
38	W 11.68 % ROE	2014	1,476,460		58,912	838,906		41,991	433,918		21,259	1,370,003		56,093
39	W Increased ROE	2014	1,476,460		58,912	838,906		41,991	433,918		21,259	1,370,003		56,093
40	W 11.68 % ROE	2015	6,370,913		298,854	2,485,441		164,003	560,875		34,539	3,398,194		271,319
41	W Increased ROE	2015	6,370,913		298,854	2,485,441		164,003	560,875		34,539	3,398,194		271,319
42	W 11.68 % ROE	2016	31,456,933		1,636,015	29,153,435		1,549,513	13,451,622		1,007,913	32,115,662		1,793,514
43	W Increased ROE	2016	31,456,933		1,636,015	29,153,435		1,549,513	13,451,622		1,007,913	32,115,662		1,793,514

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2016

1 New Plant Carrying Charge

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

		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	11.58%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	12.27%
5	C		Line B less Line A	0.69%

6 **FCR if a CIAC**

7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.90%

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

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

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

10		Details		**Relocate the 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)**
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		11.58%	11.58%	11.58%	11.58%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.58%	11.58%	11.58%	11.58%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		16,422,638	16,422,638	17,333,648	17,333,648
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		391,015	391,015	412,706	412,706
19	Months in service for depreciation expense from Attachment 6			7.65	7.65	8.27	8.27
20	Year placed in Service (0 if CWIP)						

21		Invest Yr	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011												
33	W Increased ROE	2011												
34	W 11.68 % ROE	2012												
35	W Increased ROE	2012												
36	W 11.68 % ROE	2013												
37	W Increased ROE	2013												
38	W 11.68 % ROE	2014	597,317		24,145	597,317		24,145	569,297		24,114	569,297		24,114
39	W Increased ROE	2014	597,317		24,145	597,317		24,145	569,297		24,114	569,297		24,114
40	W 11.68 % ROE	2015	3,791,995		208,938	3,791,995		208,938	3,803,715		209,880	3,803,715		209,880
41	W Increased ROE	2015	3,791,995		208,938	3,791,995		208,938	3,803,715		209,880	3,803,715		209,880
42	W 11.68 % ROE	2016	16,422,638		1,119,514	16,422,638		1,119,514	17,333,648		1,276,434	17,333,648		1,276,434
43	W Increased ROE	2016	16,422,638		1,119,514	16,422,638		1,119,514	17,333,648		1,276,434	17,333,648		1,276,434

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2016

1 New Plant Carrying Charge

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

		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	11.58%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	12.27%
5	C		Line B less Line A	0.69%

6 **FCR if a CIAC**

7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.90%

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.

				Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (CWIP)			Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91) (CWIP)			New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (CWIP)			New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (CWIP)		
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		11.58%			11.58%			11.58%			11.58%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.58%			11.58%			11.58%			11.58%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		906,569			715,475			2,285,677			2,524,127		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		21,585			17,035			54,421			60,098		
19	Months in service for depreciation expense from Attachment 6			134.00			135.56			65.18			58.89		
20	Year placed in Service (0 if CWIP)														
21			**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**
22		W 11.68 % ROE	2006												
23		W Increased ROE	2006												
24		W 11.68 % ROE	2007												
25		W Increased ROE	2007												
26		W 11.68 % ROE	2008												
27		W Increased ROE	2008												
28		W 11.68 % ROE	2009												
29		W Increased ROE	2009												
30		W 11.68 % ROE	2010												
31		W Increased ROE	2010												
32		W 11.68 % ROE	2011												
33		W Increased ROE	2011												
34		W 11.68 % ROE	2012												
35		W Increased ROE	2012												
36		W 11.68 % ROE	2013												
37		W Increased ROE	2013												
38		W 11.68 % ROE	2014	1,581,597		63,898	1,286,903		48,434	4,799,334		220,160	5,002,105		223,171
39		W Increased ROE	2014	1,581,597		63,898	1,286,903		48,434	4,799,334		220,160	5,002,105		223,171
40		W 11.68 % ROE	2015	6,978,388		428,764	6,748,815		409,201	13,083,452		881,430	13,083,452		881,430
41		W Increased ROE	2015	6,978,388		428,764	6,748,815		409,201	13,083,452		881,430	13,083,452		881,430
42		W 11.68 % ROE	2016	906,569		1,081,821	715,475		863,750	2,285,677		1,326,708	2,524,127		1,323,679
43		W Increased ROE	2016	906,569		1,081,821	715,475		863,750	2,285,677		1,326,708	2,524,127		1,323,679

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2016

1	New Plant Carrying Charge				
2	**Fixed Charge Rate (FCR) if if not a CIAC**				
			Formula Line		
3		A	152	Net Plant Carrying Charge without Depreciation	11.58%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	12.27%
5		C		Line B less Line A	0.69%
6	**FCR if a CIAC**				
7		D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.90%

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 #1 and any associated substation upgrades (B2437.20) (CWIP)**	**New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (CWIP)**	**New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (CWIP)**	**New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33) (CWIP)**
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		11.58%	11.58%	11.58%	11.58%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		11.58%	11.58%	11.58%	11.58%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		7,543,949	7,544,669	16,168,432	3,913,246
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		179,618	179,635	384,963	93,173
19	Months in service for depreciation expense from Attachment 6			9.52	9.52	5.92	4.19
20	Year placed in Service (0 if CWIP)						

21		**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011												
33	W Increased ROE	2011												
34	W 11.68 % ROE	2012												
35	W Increased ROE	2012												
36	W 11.68 % ROE	2013												
37	W Increased ROE	2013												
38	W 11.68 % ROE	2014	123,509		4,946	124,051		4,952	337,481		13,854	133,460		5,677
39	W Increased ROE	2014	123,509		4,946	124,051		4,952	337,481		13,854	133,460		5,677
40	W 11.68 % ROE	2015	300,607		14,347	300,607		14,347	3,392,144		187,534	148,687		12,403
41	W Increased ROE	2015	300,607		14,347	300,607		14,347	3,392,144		187,534	148,687		12,403
42	W 11.68 % ROE	2016	7,543,949		639,295	7,544,669		639,379	16,168,432		851,765	3,913,246		145,981
43	W Increased ROE	2016	7,543,949		639,295	7,544,669		639,379	16,168,432		851,765	3,913,246		145,981

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2016

1 New Plant Carrying Charge

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

		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	11.58%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	12.27%
5	C		Line B less Line A	0.69%

6 **FCR if a CIAC**

7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.90%

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		**BRH Project (B0829-B0830) Abandoned**
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes
12	Useful life of the project	Life		1
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		0.00%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		0.00%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		-
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		-
19	Months in service for depreciation expense from Attachment 6			-
20	Year placed in Service (0 if CWIP)			

21		Invest Yr	Ending	Depreciation or Amortization	Revenue	Total	Incentive Charged	Revenue Credit	
22	W 11.68 % ROE	2006				$ 4,652,471		$ 4,652,471	
23	W Increased ROE	2006				$ 4,652,471	$ 4,652,471		$ -
24	W 11.68 % ROE	2007				$ 29,476,571		$ 29,476,571	
25	W Increased ROE	2007				$ 29,476,571	$ 29,476,571		$ -
26	W 11.68 % ROE	2008				$ 32,346,385		$ 32,346,385	
27	W Increased ROE	2008				$ 32,385,646	$ 32,385,646		39,261
28	W 11.68 % ROE	2009				$ 51,356,608		$ 51,356,608	
29	W Increased ROE	2009				$ 51,588,883	$ 51,588,883		232,275
30	W 11.68 % ROE	2010				$ 61,349,032		$ 61,349,032	
31	W Increased ROE	2010				$ 62,015,568	$ 62,015,568		666,536
32	W 11.68 % ROE	2011				$ 78,438,322		$ 78,438,322	-
33	W Increased ROE	2011				$ 79,823,709	$ 79,823,709		1,385,386
34	W 11.68 % ROE	2012				$ 129,728,618		$ 129,728,618	
35	W Increased ROE	2012				$ 131,858,773	$ 131,858,773		$ 2,130,155
36	W 11.68 % ROE	2013	1,750,000	3,500,000	3,721,715	$ 279,708,533		$ 279,708,533	
37	W Increased ROE	2013	1,750,000	3,500,000	3,721,715	$ 284,314,797	$ 284,314,797		4,606,265
38	W 11.68 % ROE	2014				$ 342,977,142		$ 342,977,142	
39	W Increased ROE	2014				$ 349,823,024	$ 349,823,024		6,845,883
40	W 11.68 % ROE	2015				$ 434,277,698		$ 434,277,698	
41	W Increased ROE	2015				$ 441,950,239	$ 441,950,239		7,672,541
42	W 11.68 % ROE	2016				$ 522,903,602		$ 522,903,602	
43	W Increased ROE	2016				$ 530,687,571	$ 530,687,571		7,783,969

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, 2016

Required Transmission Enhancements

Upgrade ID	RTEP Baseline Project Description	Estimated/Actual Project Cost (thru 2016) *	Anticipated / Actual In-Service Date *
b0130	Replace all derated Branchburg 500/230 kv transformers	$ 20,680,597	Jan-06
b0134	Reconductor Kittatinny - Newtown 230 kV with 1590 ACSS	$ 8,069,022	Aug-07
b0145	Build new Essex - Aldene 230 kV cable connected through phase angle regulator at Essex	$ 86,565,629	Aug-07
b0161	Install 230-138kV transformer at Metuchen substation	$ 25,799,055	May-09
b0169	Build a new 230 kV section from Branchburg - Flagtown and move the Flagtown - Somerville 230 kV circuit to the new section	$ 15,731,554	May-09
b0170	Reconductor the Flagtown-Somerville-Bridgewater 230 kV circuit with 1590 ACSS	$ 6,961,495	Nov-08
b0172.2	Replace wave trap at Branchburg 500kV substation	$ 27,988	May-08
b0274	Replace both 230/138 kV transformers at Roseland	$ 21,073,706	May-09
b0290	Branchburg 400 MVAR Capacitor	$ 80,435,315	Apr-12
b0411	Install 4th 500/230 kV transformer at New Freedom	$ 22,188,863	Feb-07
b0472	Saddle Brook - Athenia Upgrade Cable	$ 14,404,842	May-12
b0489	Build new 500 kV transmission facilities from Pennsylvania - New Jersey border at Bushkill to Roseland (500kV and above elements of the project)	$ 723,503,148	Dec-12
b0489.4	Build new 500 kV transmission facilities from Pennsylvania - New Jersey border at Bushkill to Roseland (Below 500 kV elements of the project)	$ 40,538,248	May-11
b0489.5-b0489.15	Susquehanna Roseland Breakers	$ 5,857,687	Nov-10
b0498	Loop the 5021 circuit into New Freedom 500 kV substation	$ 27,005,248	Nov-08
b0664-b0665	Branchburg-Somerville-Flagtown Reconductor	$ 18,664,931	Apr-12
b0668	Somerville -Bridgewater Reconductor	$ 6,390,403	Apr-12
b0813	Reconductor Hudson - South Waterfront 230kV circuit	$ 9,158,918	Dec-10
b0814	New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie	$ 46,073,296	Oct-12
b1017	Reconductor South Mahwah 345 kV J-3410 Circuit	$ 20,626,991	May-11
b1018	Reconductor South Mahwah 345 kV K-3411 Circuit	$ 21,170,273	Dec-11
b1154	North Central Reliability (West Orange Conversion)	$ 368,260,297	Dec-12
b1155	Branchburg-Middlesex Switch Rack	$ 68,260,260	Apr-13
b1156	Burlington - Camden 230kV Conversion	$ 354,730,847	May-11
b1228	230kV Lawrence Switching Station Upgrade	$ 22,040,646	Dec-13
b1255	Ridge Road 69kV Breaker Station	$ 33,764,108	May-16
b1304.1-b1304.4	Northeast Grid Reliability Project	$ 841,681,806	Nov-13
b1398 - b1398.7	Mickleton-Gloucester-Camden	$ 427,957,348	Dec-13
b1399	Aldene-Springfield Rd. Conversion	$ 71,564,861	Jun-14
b1410-b1415	Replace Salem 500 kV breakers	$ 16,316,117	Nov-11
b1588	Upgrade Eagle Point-Gloucester 230kV Circuit	$ 11,954,175	Mar-15
b1590	Upgrade Camden-Richmond 230kV Circuit	$ 10,901,749	Oct-14
b1787	Cox's Corner-Lumberton 230kV Circuit	$ 33,763,562	Jun-15
b2139	Mickleton-Gloucester 230kV Circuit	$ 18,237,729	Jun-15
b2276	Sewaren Switch 230kV Conversion	$ 112,005,777	Jun-15
b2436.10	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades	$ 153,976,178	Jan-16
b2436.21	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades	$ 19,694,890	Jun-16
b2436.22	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades	$ 19,694,890	Jun-16
b2436.90	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades	$ 27,239,122	Jun-16
b2436.91	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades	$ 19,694,915	Jun-16
b2437.10	New Bergen 345/230 kV transformer and any associated substation upgrades	$ 25,264,003	Jun-16
b2437.11	New Bergen 345/138 kV transformer #1 and any associated substation upgrades	$ 25,264,003	Jun-16
b2436.10-b2437.33	Bergen Linden Corridor (BLC) (CWIP)	$ 289,575,343	Various