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VIA ELECTRONIC MAIL & OVERNIGHT MAIL

September 26, 2018

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, 2016
-and-
In the Matter of the Provision of
Basic Generation Service for the Period Beginning June 1, 2017
and-
In the Matter of the Provision of
Basic Generation Service for the Period Beginning June 1, 2018

Docket Nos. EO03050394, ER15040485, ER16040337, ER17040335
+++
Compliance Tariff Filing Reflecting Changes to Schedule 12 Charges in PJM Open Access Transmission Tariff Docket No.

Aida Camacho-Welch, Secretary
New Jersey Board of Public Utilities
Office of the Secretary
44 South Clinton Avenue, 3rd Floor, Suite 314
Trenton, New Jersey 08625-0350

Dear Secretary Camacho-Welch:

Enclosed for filing on behalf of Jersey Central Power & Light Company ("JCP&L"), Atlantic City Electric Company ("ACE"), Public Service Electric and Gas Company ("PSE&G") and Rockland Electric Company ("RECO") (collectively, the "EDCs"), please find an original and ten copies of revised tariff sheets and supporting exhibits to modify the filings made by the EDCs on February 13, 2018, June 20, 2018, June 25, 2018, and July 11, 2018 in the above-captioned dockets (the "Filings").

A. Purpose of Revised Tariff Sheet Filing

The attached revised tariff sheets and supporting exhibits listed below incorporate changes to the PJM Open Access Transmission Tariff ("OATT") pursuant to a Federal Energy Regulatory Commission ("FERC") Order issued on May 31, 2018, in Docket No. EL05-121-009 ("7th Circuit Settlement Order"). The 7th Circuit Settlement Order approved the contested settlement submitted to FERC on June 15, 2016 and ordered PJM to file a compliance filing. Although the time period effected by the settlement begins January 1, 2016, PJM implemented these changes in the OATT effective July 1, 2018 on a go forward basis. As a result, the Transmission Enhancement Charges in Schedule 12 have been adjusted to reflect the revised cost allocation. One aspect of the 7th Circuit Settlement Order is subject to a pending rehearing request at FERC.

B. Updated Tariff Sheets

The following tariff sheets and supporting documentation are attached to this filing.

- Attachment 1a (Derivation of PSE&G NITS Charge)
- Attachment 1b (Derivation of JCP&L NITS Charge)
- Attachment 1c (Derivation of ACE NITS Charge)

- 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 JCP&L TEC into Customer Rates)
- Attachment 2d (PSE&G Translation of ACE TEC into Customer Rates)
- Attachment 2e (PSE&G Translation of VEPCo TEC into Customer Rates)
- Attachment 2f (PSE&G Translation of PATH TEC into Customer Rates)
- Attachment 2g (PSE&G Translation of TrailCo TEC into Customer Rates)
- Attachment 2h (PSE&G Translation of Delmarva TEC into Customer Rates)
- Attachment 2i (PSE&G Translation of PEPCO TEC into Customer Rates)
- Attachment 2j (PSE&G Translation of PPL TEC into Customer Rates)
- Attachment 2k (PSE&G Translation of BG&E TEC into Customer Rates)
- Attachment 2l (PSE&G Translation of MAIT TEC into Customer Rates)
- Attachment 2m (PSE&G Translation of EL05-121 into Customer Rates)
- Attachment 2n (PSE&G Translation of PECO TEC into Customer Rates)
- Attachment 2o (PSE&G Translation of AEP East TEC into Customer Rates)

- Attachment 3a (Pro-forma JCPL Tariff Sheets)
- Attachment 3b (JCP&L Translation of NITS Charge into Customer Rates)
- Attachment 3c (JCP&L Translation of PSE&G TEC into Customer Rates)
- Attachment 3d (JCP&L Translation of ACE TEC into Customer Rates)

- Attachment 3e (JCP&L Translation of VEPCo TEC into Customer Rates)
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- Attachment 3n (JCP&L Translation of PECO TEC into Customer Rates)
- Attachment 3o (JCP&L Translation of AEP East TEC into Customer Rates)

- Attachment 4a (ACE Pro-forma Tariff Sheets)
- Attachment 4b (ACE Translation of NITS Charge into Customer Rates)
- Attachment 4c (ACE Translation of PSE&G TEC into Customer Rates)
- Attachment 4d (ACE Translations of JCP&L TEC into Customer Rates
- Attachment 4e (ACE Translation of VEPCo TEC into Customer Rates)
- Attachment 4f (ACE Translation of PATH TEC into Customer Rates)
- Attachment 4g (ACE Translation of TrailCo TEC into Customer Rates)
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- Attachment 4l (ACE Translation of MAIT TEC into Customer Rates)
- Attachment 4m (ACE Translation of EL05-121 into Customer Rates)
- Attachment 4n (ACE Translation of PECO TEC into Customer Rates)
- Attachment 4o (ACE Translation of AEP East TEC into Customer Rates)

- Attachment 5a (RECO Pro-forma Tariff Sheets)
- Attachment 5b (RECO Translation of PSE&G TEC into Customer Rates)
- Attachment 5c (RECO Translation of JCP&L TEC into Customer Rates)
- Attachment 5d (RECO Translation of ACE TEC into Customer Rates)
- Attachment 5e (RECO Translation of VEPCo TEC into Customer Rates)
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- Attachment 5m (RECO Translation of EL05-121 into Customer Rates)
- Attachment 5n (RECO Translation of PECO TEC into Customer Rates)
- Attachment 5o (RECO Translation of AEP East TEC into Customer Rates)

- Attachment 6a (PSE&G Transmission Enhancement Charges)
- Attachment 6b (JCP&L Transmission Enhancement Charges)
- Attachment 6c (ACE Transmission Enhancement Charges)
- Attachment 6d (VEPCo Transmission Enhancement Charges)
- Attachment 6e (PATH Transmission Enhancement Charges)
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- Attachment 6i (PPL Transmission Enhancement Charges)
- Attachment 6j (BG&E Transmission Enhancement Charges)
- Attachment 6k (MAIT Transmission Enhancement Charges)
- Attachment 6l(EL05-121 Settlement Charges)
- Attachment 6m (PECO Transmission Enhancement Charges)
- Attachment 6n (AEP East Transmission Enhancement Charges)

- Attachment 7a (PSE&G OATT)
- Attachment 7b (JCP&L OATT)
- Attachment 7c (ACE OATT)
- Attachment 7d (VEPCo OATT)
- Attachment 7e (PATH OATT)
- Attachment 7f (TrailCo OATT)
- Attachment 7g(Delmarva OATT)
- Attachment 7h (PEPCO OATT)
- Attachment 7i (PPL OATT)
- Attachment 7j (BG&E OATT)
- Attachment 7k (MAIT OATT)
- Attachment 7l (PECO OATT)
- Attachment 7m (AEP OATT)

- Attachment 8 (EL05-121 Settlement FERC Order)

- Attachment 9 (PSE&G FERC Formula Rate filing)

- Attachment 10 (JCP&L Formula Rate Offer of Settlement)

- Attachment 11 (ACE 2018 Formula Rate Petition)

C. Request for Authority to Collect Adjusted Rate and to Pay Suppliers

The EDCs respectfully reiterate the request for approval set forth in the 2018 Filings as if incorporated herein. More specifically, the EDCs request approval to implement the attached tariff sheets effective October 1, 2018.

Also, the EDCs respectfully request that the Board issue a waiver of the 30-day filing requirement that would otherwise apply to this submission, because Basic Generation Service ("BGS") suppliers began paying these revised transmission charges for transmission service effective July 1, 2018 pursuant to the PJM OATT changes implementing the 7th Circuit Settlement Order. The EDCs hereby also seek authority from the Board to remit payment to suppliers for the increased charges they incur.

Under the Supplier Master Agreement ("SMA"), EDCs are permitted to recover increases in Firm Transmission Service charges from BGS customers subject to Board approval. SMA, Section 15.9. After collecting such charges, EDCs are required to remit payment of the increased charges to suppliers upon, among other things, the issuance of a "FERC Final Order" approving the Firm Transmission Service increase. In addition, in a recent order, the Board noted that it has the authority to direct the EDCs to pay suppliers prior to the issuance of a FERC Final Order. (In the Matter of the Provision of Basic Generation Service (BGS) for the Period Beginning June 1, 2018, Docket No. ER17040335).

We also note that the 7th Circuit Settlement Order rate adjustments in the attached tariffs are intended to implement adjustments to Transmission Enhancement Charges ("TECs") rather than the Firm Transmission Rate. Thus, there will not be a FERC Final Order approving a Firm Transmission Rate.

The EDCs specifically request that the Board find that, upon the EDCs collection of the increase due to the 7th Circuit Settlement Order cost reallocations, the EDCs be authorized to remit to BGS suppliers the cost increases collected due to the cost reallocations. Any difference between the payments to the BGS suppliers and charges to customers would flow through each EDC's BGS Reconciliation Charge.

Prompt payment to suppliers of PJM initiated cost reallocations is important to the continued success of the BGS auction process which benefits customers. BGS suppliers have a reasonable expectation that they will be reimbursed on a timely basis for increased charges imposed by PJM. Payment to the suppliers for the 7th Circuit Settlement Order related charges will help ensure that BGS suppliers, when establishing their bid prices, can rely upon the provision of the SMA that permits BGS suppliers to be made whole for increased PJM charges.

D. Conclusion

For the foregoing reasons, the EDCs respectfully request that the Board accept the tariff revision proposed herein and the Board authorize the EDCs to remit payment to suppliers for the increased charges they incur due to the PJM implemented cost reallocation arising the implementation of the 7th Circuit Settlement Order

We thank the Board for all courtesies extended.

Respectfully submitted,

Attachments

C Stacy Peterson, NJBPU
Stefanie Brand, Division of Rate Counsel
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Attachment 1a (Derivation of PSE&G NITS Charge)

Attachment 1a PSE&G Network Integration Service Calculation.

Derived Network Integration Service Rate Applicable to PSE&G customers - Effective January 1, 2018 through December 31, 2018

Line #	Description	Rate		Source
(1)	Transmission Service Annual Revenue Requirement	$ 1,248,819,352.00		Page 4 of Attachment 9 -Line 164
(2)	Total Schedule 12 TEC Included in above	$ (480,678,136.00)		Attachment 6a Column (a)
(3)	PSE&G Customer Share of Schedule 12 TEC	$ 314,039,527.76		Attachment 6a Column (h)
(4)	Total Transmission Costs Borne by PSE&G customers	$ 1,082,180,743.76		=(1) +(2) +(3)
(5)	2018 PSE&G Network Service Peak	9,566.9	MW	Page 4 of Attachment 9 -Line 165
(6)	2018 Derived Network Integration Transmission Service Rate	$ 113,117.18	per MW-year	
	Resulting 2018 BGS Firm Transmission Service Supplier Rate	$ 309.91	per MW-day	= (6)/365

Attachment 1b (Derivation of JCP&L NITS Charge)

Attachment 1b JCP&L Network Integration Transmission Service Calculation

Derived Network Integration Transmission Service Rate Applicable to JCP&L customers - Effective July 1, 2018 through December 31, 2018

Line #	Description	Rate			Source
(1)	Transmission Service Annual Revenue Requirement	$	156,605,928		Settlement Agreement in ER17-217-003, sum of provision 2.1a and 2.1b*
(2)	Total Schedule 12 TEC Included in Above	$	(21,605,928)		Settlement Agreement in ER17-217-003, provision 2.1b
(3)	JCP&L Customer Share of Schedule 12 TEC	$	8,665,841		Attachment 6, Column g
(4)	Total Transmission Costs Borne by JCP&L Customers	$	143,665,841		=(1) + (2) + (3)
(5)	2018 JCP&L Network Service Peak		5,721.0	MW	PJM network service peak loads for 2018
(6)	2018 Derived Network Integration Transmission Service Rate	$	25,112.02	per MW-year	
	Resulting 2018 BGS Firm Transmission Service Supplier Rate	$	68.80	per MW-day	= (6)/365

*The settlement agreement in ER17-217-003 specifies (1) JCP&L's annual stated revenue requirement for NITS is $135,000,000 and (2) JCP&L's stated revenue requirement for its projects listed on Schedule 12 of the PJM OATT (that are not included in JCP&L's NITS revenue requirement) is an average of $20 million/year. For 2018, the settlement agreement specifies the annual revenue requirement for TEC is $21,605,928.

Attachment 1c (Derivation of ACE NITS Charge)

ATLANTIC CITY ELECTRIC
Proposed Transmission Rate Design
Formula Rate Effective July 1, 2018

Line			
1	Transmission Service Annual Revenue Requirement	$	136,632,319
2	Less Total Schedule 12 TEC Included in Line (1)	$	(10,761,631)
3	ACE Customer Share of Schedule 12 TEC included in Line 2	$	5,640,237
4	Total Transmission Costs Borne by ACE Customers	$	131,510,925
5	2018 ACE Newtwork Service Peak		2,541
6	2018 Network Integration Transmission Service Rate (per MW Per Year)	**$**	**51,759.65**

PJM Schedule 12 - Transmission Enhancement Charges for June 2018 - May 2019
Calculation of costs and monthly PJM charges for ACE Projects

	Required Transmission Enhancement *per PJM website*	**PJM Upgrade ID** *per PJM spreadsheet*		**June 2018 - May 2019 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share** *per PJM Open Access Transmission Tariff*		**ACE Zone Charges**
7	Upgrade AE portion of Delco Tap	b0265	$	501,690	89.87%	$	450,869
8	Replace Monroe 230/69 kV TXfmrs	b0276	$	772,567	91.46%	$	706,590
9	Reconductor Union - Corson 138 kV	b0211	$	1,317,619	65.23%	$	859,483
10	New 500/230 Kv Sub on Salem-East Windsor (>500 kV portion)	b0210.A	$	1,310,850	1.66%	$	21,760
11	Replace line trap-Keeney	b0210.A_dfax	$	1,310,850	63.29%	$	829,637
12	New 500/230kV Sub on Salem-East Windsor (< 500kV) portion[2]	b0210.B	$	1,869,368	65.23%	$	1,219,389
13	Reconductor the existing Mickleton - Goucestr 230 kV circuit (AE portion)	b1398.5	$	469,607	0.00%	$	-
14	Build second 230kV parallel from Mickelton to Gloucester	b1398.3.1	$	1,468,794	0.00%	$	-
15	Upgrade to Mill T2 138/69 kV transformer	b1600	$	1,740,287	89.21%	$	1,552,510
	Total			**$10,761,631**			**$5,640,237**

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 JCP&L TEC into Customer Rates)
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Attachment 2o (PSE&G Translation of AEP TEC into Customer Rates)

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

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

APPLICABLE TO:

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

BGS ENERGY CHARGES:

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

Charges per kilowatthour:

	For usage in each of the months of October through May		For usage in each of the months of June through September	
Rate Schedule	Charges	Charges Including SUT	Charges	Charges Including SUT
RS – first 600 kWh	$0.120641	$0.128633	$0.120616	$0.128607
RS – in excess of 600 kWh	0.120641	0.128633	0.129712	0.138305
RHS – first 600 kWh	0.094833	0.101116	0.090228	0.096206
RHS – in excess of 600 kWh	0.094833	0.101116	0.102390	0.109173
RLM On-Peak	0.209729	0.223624	0.222556	0.237300
RLM Off-Peak	0.060917	0.064953	0.055828	0.059527
WH	0.049065	0.052316	0.046813	0.049914
WHS	0.049245	0.052507	0.046520	0.049602
HS	0.102437	0.109223	0.104359	0.111273
BPL	0.046908	0.050016	0.041926	0.044704
BPL-POF	0.046908	0.050016	0.041926	0.044704
PSAL	0.046908	0.050016	0.041926	0.044704

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

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

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

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

BGS CAPACITY CHARGES:

Applicable to Rate Schedules GLP and LPL-Sec.

Charges per kilowatt of Generation Obligation:

Charge applicable in the months of June through September ....$ 5.1628
Charge including New Jersey Sales and Use Tax (SUT) ....$ 5.5048

Charge applicable in the months of October through May...$ 5.1628
Charge including New Jersey Sales and Use Tax (SUT) ....$ 5.5048

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

BGS TRANSMISSION CHARGES

Applicable to Rate Schedules GLP and LPL-Sec.

Charges per kilowatt of Transmission Obligation:

Currently effective Annual Transmission Rate for
Network Integration Transmission Service for the
Public Service Transmission Zone as derived from the
FERC Electric Tariff of the PJM Interconnection, LLC .... $113,117.18 per MW per year
EL05-121……...$ 20,069.91 per MW per year
PJM Seams Elimination Cost Assignment Charges .... $ 0.00 per MW per month
PJM Reliability Must Run Charge... $ 2.82 per MW per month
PJM Transmission Enhancements
Trans-Allegheny Interstate Line Company .... $ 46.80 per MW per month
Virginia Electric and Power Company .... $ 43.35 per MW per month
Potomac-Appalachian Transmission Highline L.L.C. ....($18.29) per MW per month
PPL Electric Utilities Corporation... $ 218.59 per MW per month
American Electric Power Service Corporation .... $ 19.61 per MW per month
Atlantic City Electric Company. .... $ 9.32 per MW per month
Delmarva Power and Light Company... $ 0.16 per MW per month
Potomac Electric Power Company. .... $ 3.24 per MW per month
Baltimore Gas and Electric Company... $ 3.61 per MW per month
Jersey Central Power and Light .... $ 68.84 per MW per month
Mid Atlantic Interstate Transmission... $ 7.60 per MW per month
PECO Energy Company………………………………................. $ 20.34 per MW per month

Above rates converted to a charge per kW of Transmission
Obligation, applicable in all months.. $11.5248
Charge including New Jersey Sales and Use Tax (SUT) $12.2883

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

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

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

BGS TRANSMISSION CHARGES

Charges per kilowatt of Transmission Obligation:

Currently effective Annual Transmission Rate for
Network Integration Transmission Service for the
Public Service Transmission Zone as derived from the
FERC Electric Tariff of the PJM Interconnection, LLC ....$113,117.18 per MW per year
EL05-121…….. .... $ 20,069.91 per MW per year
PJM Seams Elimination Cost Assignment Charges .... $ 0.00 per MW per month
PJM Reliability Must Run Charge .... $ 2.82 per MW per month
PJM Transmission Enhancements
Trans-Allegheny Interstate Line Company .... $ 46.80 per MW per month
Virginia Electric and Power Company .... $ 43.35 per MW per month
Potomac-Appalachian Transmission Highline L.L.C. ....($18.29) per MW per month
PPL Electric Utilities Corporation... $ 218.59 per MW per month
American Electric Power Service Corporation .... $ 19.61 per MW per month
Atlantic City Electric Company. .... $ 9.32 per MW per month
Delmarva Power and Light Company .... $ 0.16 per MW per month
Potomac Electric Power Company. .... $ 3.24 per MW per month
Baltimore Gas and Electric Company.. $ 3.61 per MW per month
Jersey Central Power and Light .... $ 68.84 per MW per month
Mid Atlantic Interstate Transmission.. $7.60 per MW per month
PECO Energy Company……………………………….................. $ 20.34 per MW per month

Above rates converted to a charge per kW of Transmission
Obligation, applicable in all months $11.5248
Charge including New Jersey Sales and Use Tax (SUT) $12.2883

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

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

Network Integration Service Calculation - BGS-RSCP
NITS Charges for January 2018 - December 2018

NITS Charges for Jan 2018 - Dec 2018	$ 1,059,012,354.50						
PSE&G Zonal Transmission Load for Effective Yr. (MW)	9,566.90						
Term (Months)	12						
OATT rate	$ 9,224.62	/MW/month		all values show w/o NJ SUT			
converted to $/MW/yr =	$ 110,695.46	/MW/yr	**Jan 18 - Dec 18 NITS Charge**				
	$ 82,474.75	/MW/yr	**2015 - 2017 Weighted Average of:**		**$ 72,688.29**	**$ 82,516.44**	**$ 92,569.05**
	$ 95,441.90	/MW/yr	**2016- 2018 Weighted Average of:**		**$ 82,516.44**	**$ 92,569.05**	**$ 110,695.46**
	$ 90,038.92	/MW/yr	**Jan 18 - Dec 18 Weighted Average**				
Resulting Increase in Transmission Rate	$ 20,656.53	/MW/yr					
Resulting Increase in Transmission Rate	$ 1,721.38	/MW/month					

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL	
Trans Obl - MW	3,892.6	25.5	73.1	0.0	0.0	2.8	0.0	0.0	
Total Annual Energy - MWh	12,201,595.6	133,055.9	218,245.6	1,283.0	27.0	15,196.6	158,968.0	296,268.0	
Change in energy charge									
in $/MWh	$ 6.5899	$ 3.9588	$ 6.9188	$ -	$ -	$ 3.8060	$ -	$ -	
in $/kWh - rounded to 6 places	**$ 0.006590**	**$ 0.003959**	**$ 0.006919**	**$ -**	**$ -**	**$ 0.003806**	**$ -**	**$ -**	
Revised NITS Charge	**$ 113,117.18**								
Difference Per MW/Year	**$ 2,421.72**								
Difference Per MW/month	**$ 201.81**								
Numerber of Months July-December)	**6**	**July - December**							
Changein NITS $'s	$ 4,713,401.00	$ 30,876.98	$ 88,514.00			$ 3,390.41			$4,836,182.39
Remaining MWhs July -December)	6,659,032	49,101	113,896			5,261			6,827,290
Change in energy charge									
in $/MWh	$ 0.7078	$ 0.6288	$ 0.7771			$ 0.6444			
Revised Change in $/MWh	$ 7.2977	$ 4.5876	$ 7.6959	$ -	$ -	$ 4.4504			
in $/kWh - rounded to 6 places	**$ 0.007298**	**$ 0.004588**	**$ 0.007696**			**$ 0.004450**			

Line #					
1	Total BGS-RSCP Trans Obl	6,658.8 MW			= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust	23,949,599 MWh			= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes	25,728,145 MWh		unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 137,547,734		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl adjusted for migration
5	Change in Average Supplier Payment Rate	$ 5.3462	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ 5.35	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ 137,645,573		unrounded	= (6) * (3)
8	Difference due to rounding	$ 97,839		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges effective July 1, 2018
Calculation of costs and monthly PJM charges for JCP&L

TEC Charges for July 2018 - December 2018	$	7,903,305.53	
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,566.90	
Term (Months)		12	
OATT rate	$	68.84	/MW/month
Resulting Increase in Transmission Rate	$	826.08	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	3,750.5	21.7	71.8	0.0	0.0	2.8	0.0	0.0
Total Annual Energy - MWh	12,175,045.4	114,167.8	209,061.6	1,060.0	19.0	12,369.0	155,848.0	295,094.0
Change in energy charge								
in $/MWh	$ 0.2545	$ 0.1570	$ 0.2837	$ -	$ -	$ 0.1870	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000254**	**$ 0.000157**	**$ 0.000284**	**$ -**	**$ -**	**$ 0.000187**	**$ -**	**$ -**

Line #						
1	Total BGS-RSCP Trans Obl		6,539.3	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust		24,078,111	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes		25,878,575	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	5,401,985		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.2087	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	0.21	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	5,434,501		unrounded	= (6) * (3)
8	Difference due to rounding	$	32,516		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges effective July 1, 2018
Calculation of costs and monthly PJM charges for ACE Projects

TEC Charges for June 2018 - May 2019	$	1,069,664.31	
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,566.9	
Term (Months)		12	
OATT rate	$	9.32	/MW/month
converted to $/MW/yr =	$	111.84	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	3,750.5	21.7	71.8	0.0	0.0	2.8	0.0	0.0
Total Annual Energy - MWh	12,175,045	114,168	209,062	1,060	19	12,369	155,848	295,094
Energy charge								
in $/MWh	$ 0.034452	$ 0.021258	$ 0.038410	$ -	$ -	$ 0.025317	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000034**	**$ 0.000021**	**$ 0.000038**	**$ -**	**$ -**	**$ 0.000025**	**$ -**	**$ -**

Line #					
1	Total BGS-RSCP eligbile Trans Obl	6,539.3	MW		= sum of BGS-RSCP eligible Trans Obl
2	Total BGS-RSCP eligbile energy @ cust	24,078,111	MWh		= sum of BGS-RSCP eligible kWh @ cust
3	Total BGS-RSCP eligbile energy @ trans nodes	25,878,575	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 731,355		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$ 0.0283	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ 0.03	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ 776,357		unrounded	= (6) * (3)
8	Difference due to rounding	$ 45,002		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges effective July 1, 2018
Calculation of costs and monthly PJM charges for VEPCO Projects

TEC Charges for Jan 2018 - Dec 2018	$ 4,977,029.72	
PSE&G Zonal Transmission Load for Effective Yr. (MW)	9,566.9	
Term (Months)	12	
OATT rate	$ 43.35	/MW/month
Resulting Increase in Transmission Rate	$ 520.20	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	3,750.5	21.7	71.8	0.0	0.0	2.8	0.0	0.0
Total Annual Energy - MWh	12,175,045.4	114,167.8	209,061.6	1,060.0	19.0	12,369.0	155,848.0	295,094.0
Change in energy charge								
in $/MWh	$ 0.1602	$ 0.0989	$ 0.1787	$ -	$ -	$ 0.1178	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000160**	**$ 0.000099**	**$ 0.000179**	**$ -**	**$ -**	**$ 0.000118**	**$ -**	**$ -**

Line #					
1	Total BGS-RSCP Trans Obl	6,539.3	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust	24,078,110.6	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes	25,878,575.4	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 3,401,744		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$ 0.1315	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ 0.13	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ 3,364,215		unrounded	= (6) * (3)
8	Difference due to rounding	$ (37,529)		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges effective July 1, 2018
Calculation of costs and monthly PJM charges for PATH Project

TEC Charges for Jan 2018 - Dec 2018	$	(2,099,457.53)	
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,566.9	
Term (Months)		12	
OATT rate	$	(18.29)	/MW/month
Resulting Increase in Transmission Rate	$	(219.48)	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	3,750.5	21.7	71.8	0.0	0.0	2.8	0.0	0.0
Total Annual Energy - MWh	12,175,045.4	114,167.8	209,061.6	1,060.0	19.0	12,369.0	155,848.0	295,094.0
Change in energy charge								
in $/MWh	$ (0.0676)	$ (0.0417)	$ (0.0754)	$ -	$ -	$ (0.0497)	$ -	$ -
in $/kWh - rounded to 6 places	**$ (0.000068)**	**$ (0.000042)**	**$ (0.000075)**	**$ -**	**$ -**	**$ (0.000050)**	**$ -**	**$ -**

Line #						
1	Total BGS-RSCP Trans Obl		6,539.3	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust		24,078,111	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes		25,878,575	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	(1,435,246)		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	(0.0555)	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	(0.06)	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	(1,552,715)		unrounded	= (6) * (3)
8	Difference due to rounding	$	(117,469)		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges effective July 1, 2018
Calculation of costs and monthly PJM charges for Allegheny TrAILCo Projects

TEC Charges for June 2018 - May 2019	$ 5,372,690.05	
PSE&G Zonal Transmission Load for Effective Yr. (MW)	9,566.9	
Term (Months)	12	
OATT rate	$ 46.80	/MW/month
converted to $/MW/yr =	$ 561.60	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	3,750.5	21.7	71.8	0.0	0.0	2.8	0.0	0.0
Total Annual Energy - MWh	12,175,045	114,168	209,062	1,060	19	12,369	155,848	295,094
Energy Charge								
in $/MWh	$ 0.173000	$ 0.106744	$ 0.192876	$ -	$ -	$ 0.127131	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000173**	**$ 0.000107**	**$ 0.000193**	**$ -**	**$ -**	**$ 0.000127**	**$ -**	**$ -**

Line #					
1	Total BGS-RSCP eligbile Trans Obl	6,539.3	MW		= sum of BGS-RSCP eligible Trans Obl
2	Total BGS-RSCP eligbile energy @ cust	24,078,111	MWh		= sum of BGS-RSCP eligible kWh @ cust
3	Total BGS-RSCP eligbile energy @ trans nodes	25,878,575	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 3,672,471		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$ 0.1419	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ 0.14	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ 3,623,001		unrounded	= (6) * (3)
8	Difference due to rounding	$ (49,470)		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges effective July 1, 2018
Calculation of costs and monthly PJM charges for Delmarva Projects

TEC Charges for June 2018 - May 2019	$	18,423.72		
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,566.9		
Term (Months)		12		
OATT rate	$	0.16	/MW/month	all values show w/o NJ SUT
converted to $/MW/yr =	$	1.92	/MW/yr	

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	3,750.5	21.7	71.8	0.0	0.0	2.8	0.0	0.0
Total Annual Energy - MWh	12,175,045	114,168	209,062	1,060	19	12,369	155,848	295,094
Energy charge								
in $/MWh	$ 0.000591	$ 0.000365	$ 0.000659	$ -	$ -	$ 0.000435	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000001**	**$ -**	**$ 0.000001**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Line #						
1	Total BGS-RSCP eligbile Trans Obl		6,539.3	MW		= sum of BGS-RSCP eligible Trans Obl
2	Total BGS-RSCP eligbile energy @ cust		24,078,111	MWh		= sum of BGS-RSCP eligible kWh @ cust
3	Total BGS-RSCP eligbile energy @ trans nodes		25,878,575	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	12,555		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.0005	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	-	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	-		unrounded	= (6) * (3)
8	Difference due to rounding	$	(12,555)		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges effective July 1, 2018
Calculation of costs and monthly PJM charges for PEPCO Projects

TEC Charges for June 2018 - May 2019	$	371,754.31	
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,566.9	
Term (Months)		12	
OATT rate	$	3.24	/MW/month
converted to $/MW/yr =	$	38.88	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	3,750.5	21.7	71.8	0.0	0.0	2.8	0.0	0.0
Total Annual Energy - MWh	12,175,045	114,168	209,062	1,060	19	12,369	155,848	295,094
Energy Charge								
in $/MWh	$ 0.011977	$ 0.007390	$ 0.013353	$ -	$ -	$ 0.008801	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000012**	**$ 0.000007**	**$ 0.000013**	**$ -**	**$ -**	**$ 0.000009**	**$ -**	**$ -**

Line #						
1	Total BGS-RSCP eligbile Trans Obl		6,539.3	MW		= sum of BGS-RSCP eligible Trans Obl
2	Total BGS-RSCP eligbile energy @ cust		24,078,111	MWh		= sum of BGS-RSCP eligible kWh @ cust
3	Total BGS-RSCP eligbile energy @ trans nodes		25,878,575	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	254,248		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.0098	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	0.01	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	258,786		unrounded	= (6) * (3)
8	Difference due to rounding	$	4,538		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges effective July 1, 2018
Calculation of costs and monthly PJM charges for PPL Projects

TEC Charges for June 2018 - May 2019	$ 25,094,495.84	
PSE&G Zonal Transmission Load for Effective Yr. (MW)	9,566.9	
Term (Months)	12	
OATT rate	$ 218.59	/MW/month
converted to $/MW/yr =	$ 2,623.08	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	3,750.5	21.7	71.8	0.0	0.0	2.8	0.0	0.0
Total Annual Energy - MWh	12,175,045	114,168	209,062	1,060	19	12,369	155,848	295,094
Energy charge								
in $/MWh	$ 0.808035	$ 0.498572	$ 0.900869	$ -	$ -	$ 0.593793	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000808**	**$ 0.000499**	**$ 0.000901**	**$ -**	**$ -**	**$ 0.000594**	**$ -**	**$ -**

Line #					
1	Total BGS-RSCP eligbile Trans Obl	6,539.3	MW		= sum of BGS-RSCP eligible Trans Obl
2	Total BGS-RSCP eligbile energy @ cust	24,078,111	MWh		= sum of BGS-RSCP eligible kWh @ cust
3	Total BGS-RSCP eligbile energy @ trans nodes	25,878,575	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 17,153,107		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$ 0.6628	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ 0.66	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ 17,079,860		unrounded	= (6) * (3)
8	Difference due to rounding	$ (73,247)		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges effective July 1, 2018
Calculation of costs and monthly PJM charges for BG&E

TEC Charges for June 2018 - May 2019	$	414,110.78	
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,566.9	
Term (Months)		12	
OATT rate	$	3.61	/MW/month
converted to $/MW/yr =	$	43.32	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	3,750.5	21.7	71.8	0.0	0.0	2.8	0.0	0.0
Total Annual Energy - MWh	12,175,045	114,168	209,062	1,060	19	12,369	155,848	295,094
Energy Charge								
in $/MWh	$ 0.013345	$ 0.008234	$ 0.014878	$ -	$ -	$ 0.009806	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000013**	**$ 0.000008**	**$ 0.000015**	**$ -**	**$ -**	**$ 0.000010**	**$ -**	**$ -**

Line #						
1	Total BGS-RSCP eligbile Trans Obl		6,539.3	MW		= sum of BGS-RSCP eligible Trans Obl
2	Total BGS-RSCP eligbile energy @ cust		24,078,111	MWh		= sum of BGS-RSCP eligible kWh @ cust
3	Total BGS-RSCP eligbile energy @ trans nodes		25,878,575	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	283,282		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.0109	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	0.01	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	258,786		unrounded	= (6) * (3)
8	Difference due to rounding	$	(24,497)		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges effective July 1, 2018
Calculation of costs and monthly PJM charges for Mid Atlantic Interstate Transmission Projects

TEC Charges for Jan 2018 - December 2018	$	872,805	
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,566.9	
Term (Months)		12	
OATT rate	$	7.60	/MW/month
converted to $/MW/yr =	$	91.20	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	3,750.5	21.7	71.8	0.0	0.0	2.8	0.0	0.0
Total Annual Energy - MWh	12,175,045	114,168	209,062	1,060	19	12,369	155,848	295,094
Energy charge								
in $/MWh	$ 0.028094	$ 0.017334	$ 0.031322	$ -	$ -	$ 0.020645	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000028**	**$ 0.000017**	**$ 0.000031**	**$ -**	**$ -**	**$ 0.000021**	**$ -**	**$ -**

Line #						
1	Total BGS-RSCP eligbile Trans Obl		6,539.30	MW		= sum of BGS-RSCP eligible Trans Obl
2	Total BGS-RSCP eligbile energy @ cust		24,078,111	MWh		= sum of BGS-RSCP eligible kWh @ cust
3	Total BGS-RSCP eligbile energy @ trans nodes		25,878,575	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	596,384		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.0230	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	0.02	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	517,572		unrounded	= (6) * (3)
8	Difference due to rounding	$	(78,813)		unrounded	= (7) - (4)

Incremental Network Integration Service Calculation - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges effective July 1, 2018
Summary of EL05-121 Settlement Adjustments for July 2018 - June 2019

		Effective 7/1/18 - 12/31/18	
PSE&G Annual Transmission Service Revenue Requirement			
Total Schedule 12 TEC Included in above			
PSE&G Customer Share of Reallocated Schedule 12 NITS	$	192,006,813.51	
Summary of EL05-121 Settlement Adjustments for July 2018 - June 2019	$	192,006,813.51	
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,566.90	
Term (Months)		12	
OATT rate	$	1,672.49	/MW/month
converted to $/MW/yr =	$	20,069.91	/MW/yr
Resulting Increase in Transmission Rate	$	20,069.91	/MW/yr
Resulting Increase in Transmission Rate	$	1,672.49	/MW/month

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	3,750.5	21.7	71.8	0.0	0.0	2.8	0.0	0.0
Total Annual Energy - MWh	12,175,045.4	114,167.8	209,061.6	1,060.0	19.0	12,369.0	155,848.0	295,094.0
Change in energy charge								
in $/MWh	$ 6.1825	$ 3.8147	$ 6.8928	$ -	$ -	$ 4.5433	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.006182**	**$ 0.003815**	**$ 0.006893**	**$ -**	**$ -**	**$ 0.004543**	**$ -**	**$ -**

Line #					
1	Total BGS-RSCP Trans Obl	6,539.3	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust	24,078,111	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes	25,878,575	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 131,243,157		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl adjusted for migration
5	Change in Average Supplier Payment Rate	$ 5.0715	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ 5.07	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ 131,204,377		unrounded	= (6) * (3)
8	Difference due to rounding	$ (38,779)		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges effective July 1, 2018
Calculation of costs and monthly PJM charges for PECO Energy Company Transmission Projects

TEC Charges for June 2018 - May 2019	$	2,335,584	
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,566.9	
Term (Months)		12	
OATT rate	$	20.34	/MW/month
converted to $/MW/yr =	$	244.08	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	3,750.5	21.7	71.8	0.0	0.0	2.8	0.0	0.0
Total Annual Energy - MWh	12,175,045	114,168	209,062	1,060	19	12,369	155,848	295,094
Energy charge								
in $/MWh	$ 0.075188	$ 0.046393	$ 0.083827	$ -	$ -	$ 0.055253	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000075**	**$ 0.000046**	**$ 0.000084**	**$ -**	**$ -**	**$ 0.000055**	**$ -**	**$ -**

Line #						
1	Total BGS-RSCP eligbile Trans Obl		6,539.3	MW		= sum of BGS-RSCP eligible Trans Obl
2	Total BGS-RSCP eligbile energy @ cust		24,078,111	MWh		= sum of BGS-RSCP eligible kWh @ cust
3	Total BGS-RSCP eligbile energy @ trans nodes		25,878,575	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	1,596,112		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.0617	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	0.06	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	1,552,715		unrounded	= (6) * (3)
8	Difference due to rounding	$	(43,398)		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges effective July 1, 2018
Calculation of costs and monthly PJM charges for AEP -East Projects

TEC Charges for January 2018 - December 2018	$	2,251,677	
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,566.9	
Term (Months)		12	
OATT rate	$	19.61	/MW/month
converted to $/MW/yr =	$	235.32	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	3,750.5	21.7	71.8	0.0	0.0	2.8	0.0	0.0
Total Annual Energy - MWh	12,175,045	114,168	209,062	1,060	19	12,369	155,848	295,094
Energy Charge								
in $/MWh	$ 0.072490	$ 0.044728	$ 0.080818	$ -	$ -	$ 0.053270	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000072**	**$ 0.000045**	**$ 0.000081**	**$ -**	**$ -**	**$ 0.000053**	**$ -**	**$ -**

Line #						
1	Total BGS-RSCP eligbile Trans Obl		6,539.3	MW		= sum of BGS-RSCP eligible Trans Obl
2	Total BGS-RSCP eligbile energy @ cust		24,078,111	MWh		= sum of BGS-RSCP eligible kWh @ cust
3	Total BGS-RSCP eligbile energy @ trans nodes		25,878,575	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	1,538,828		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.0595	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	0.06	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	1,552,715		unrounded	= (6) * (3)
8	Difference due to rounding	$	13,886		unrounded	= (7) - (4)

Attachment 3a (Pro-forma JCPL Tariff Sheets)
Attachment 3b (JCP&L –Translation of NITS Charge into Customer Rates)
Attachment 3c (JCP&L Translation of PSE&G TEC into Customer Rates)
Attachment 3d (JCP&L Translation of ACE TEC into Customer Rates)
Attachment 3e (JCP&L Translation of VEPCo TEC into Customer Rates)
Attachment 3f (JCP&L Translation of PATH TEC into Customer Rates)
Attachment 3g (JCP&LTranslation of TrailCo TEC into Customer Rates)
Attachment 3h (JCP&L Translation of Delmarva TEC into Customer Rates)
Attachment 3i (JCP&L Translation of PEPCo TEC into Customer Rates)
Attachment 3j (JCP&L Translation of PPL TEC into Customer Rates)
Attachment 3k (JCP&L Translation of BG&E TEC into Customer Rate)
Attachment 3l (JCP&L Translation of MAIT into Customer Rates)
Attachment 3m (JCP&L Translation of El05-121 into Customer Rates)
Attachment 3k (JCP&L Translation of PECO TEC into Customer Rate)
Attachment 3l (JCP&L Translation of AEP TEC into Customer Rates)

JERSEY CENTRAL POWER & LIGHT COMPANY

XX Rev. Sheet No. 3
BPU No. 12 ELECTRIC - PART III **Superseding XX Rev. Sheet No. 3**

Service Classification RS
Residential Service

APPLICABLE TO USE OF SERVICE FOR: Service Classification RS is available for: (a) Individual Residential Structures; (b) separately metered residences in Multiple Residential Structures; (c) incidental use for non-residential purposes when included along with the residence; and/or (d) Auxiliary Residential Purposes whether metered separately from the residence or not.

This Service Classification is optional for customers which elect to be billed hereunder rather than under Service Classification RT. (Also see Part II, Section 2.03)

CHARACTER OF SERVICE: Single-phase service, with limited applications of three-phase service, at secondary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT): All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)

2) **Transmission Charge: $0.008047** per KWH for all KWH including Water Heating

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge: $2.83** per month
Supplemental Customer Charge: $1.47 per month Off-Peak/Controlled Water Heating

2) **Distribution Charge:**

June through September:
$0.015336 per KWH for the first 600 KWH (except Water Heating)
$0.060646 per KWH for all KWH over 600 KWH (except Water Heating)

October through May:
$0.025123 per KWH for all KWH (except Water Heating)

Water Heating Service:
$0.016767 per KWH for all KWH for Off-Peak Water Heating
$0.022085 per KWH for all KWH for Controlled Water Heating

Service Classification RT
Residential Time-of-Day Service

APPLICABLE TO USE OF SERVICE FOR: Service Classification RT is available for: (a) Individual Residential Structures; (b) separately metered residences in Multiple Residential Structures; (c) incidental use for non-residential purposes when included along with the residence; and/or (d) Auxiliary Residential Purposes whether metered separately from the residence or not.

This Service Classification is optional for customers which elect to be billed hereunder rather than under Service Classification RS. (Also see Part II, Section 2.03)

CHARACTER OF SERVICE: Single-phase service, with limited applications of three-phase service, at secondary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)

2) **Transmission Charge: $0.008047** per KWH for all KWH on-peak and off-peak

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge: $5.27** per month
Solar Water Heating Credit: $1.32 per month

2) **Distribution Charge:**
$ 0.047006 per KWH for all KWH on-peak for June through September
$ 0.034528 per KWH for all KWH on-peak for October through May
$ 0.021957 per KWH for all KWH off-peak

3) **Non-utility Generation Charge (Rider NGC): (See Rider NGC for any applicable St. Lawrence Hydroelectric Power credit)**
$ 0.001664 per KWH for all KWH on-peak and off-peak

4) **Societal Benefits Charge (Rider SBC):**
$ 0.007296 per KWH for all KWH on-peak and off-peak

5) **System Control Charge (Rider SCC):**
$ 0.000000 per KWH for all KWH on-peak and off-peak

6) **RGGI Recovery Charge (Rider RRC):**
See Rider RRC for rate per KWH for all KWH on-peak and off-peak

7) **Storm Recovery Charge (Rider SRC):**
$ 0.003288 per KWH for all KWH on-peak and off-peak

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 12 ELECTRIC - PART III **XX Rev. Sheet No. 8**
Superseding XX Rev. Sheet No. 8

Service Classification RGT
Residential Geothermal & Heat Pump Service

APPLICABLE TO USE OF SERVICE FOR: Service Classification RGT is available for residential customers residing in individual residential structures, or in separately metered residences in multiple-unit residential structures, who have one of the following types of electric space heating systems as the primary source of heat for such structure or unit and which system meets the corresponding energy efficiency criterion:

Geothermal Systems with Energy Efficiency Ratio (EER) of 13.0 or greater;
Heat Pump Systems with Seasonal Energy Efficiency Ratio (SEER) of 11.0 or greater, and a Heating Season Performance Factor (HSPF) which meets the then current Federal HSPF standards;
Room Unit Heat Pump Systems with Energy Efficiency Ratio (EER) of 9.5 or greater.

Service Classification RGT is not available for customers residing in individual residential structures, or in separately metered residences in multiple-unit residential structures, which have an electric resistance heating system as the primary source of space heating for such structure or unit.

CHARACTER OF SERVICE: Single-phase service, with limited applications of three-phase service, at secondary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)

2) **Transmission Charge:**
$0.008047 per KWH for all KWH on-peak and off-peak for June through September
$0.008047 per KWH for all KWH for October through May

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge: $5.27** per month

2) **Distribution Charge:**

June through September:
$0.047006 per KWH for all KWH on-peak
$0.021957 per KWH for all KWH off-peak

October through May:
$0.025123 per KWH for all KWH

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XX Rev. Sheet No. 10
BPU No. 12 ELECTRIC - PART III **Superseding XX Rev. Sheet No. 10**

Service Classification GS
General Service Secondary

APPLICABLE TO USE OF SERVICE FOR: Service Classification GS is available for general service purposes at secondary voltages not included under Service Classifications RS, RT, RGT or GST.

CHARACTER OF SERVICE: Single or three-phase service at secondary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly BGS-FP) **or Rider BGS-CIEP (Basic Generation Service – Commercial Industrial Energy Pricing)**

2) **Transmission Charge:**
$ 0.008047 per KWH for all KWH including Water Heating

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge:** **$ 3.15** per month single-phase
$11.30 per month three-phase

Supplemental Customer Charge: **$ 1.47** per month Off-Peak/Controlled Water Heating
$ 2.58 per month Day/Night Service
$11.74 per month Traffic Signal Service

2) **Distribution Charge:**

KW Charge: (Demand Charge)
$ 6.73 per maximum KW during June through September, in excess of 10 KW
$ 6.27 per maximum KW during October through May, in excess of 10 KW
$ 3.05 per KW Minimum Charge, in excess of 10 KW

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XX Rev. Sheet No. 14
BPU No. 12 ELECTRIC - PART III **Superseding XX Rev. Sheet No. 14**

Service Classification GST
General Service Secondary Time-Of-Day

APPLICABLE TO USE OF SERVICE FOR: Service Classification GST is available for general Service purposes for commercial and industrial customers establishing demands in excess of 750 KW in two consecutive months during the current 24-month period. Customers which were served under this Service Classification as part of its previous experimental implementation may continue such Service until voluntarily transferring to Service Classification GS.

CHARACTER OF SERVICE: Single or three-phase service at secondary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP) **or Rider BGS-CIEP (Basic Generation Service – Commercial Industrial Energy Pricing)**

2) **Transmission Charge: $0.008047** per KWH for all KWH on-peak and off-peak

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge:** **$30.30** per month single-phase
$43.25 per month three-phase

2) **Distribution Charge:**

KW Charge: (Demand Charge)
$ 7.12 per maximum KW during June through September
$ 6.65 per maximum KW during October through May
$ 3.10 per KW Minimum Charge

KWH Charge:
$0.004736 per KWH for all KWH on-peak
$0.004736 per KWH for all KWH off-peak

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Service Classification GP
General Service Primary

APPLICABLE TO USE OF SERVICE FOR: Service Classification GP is available for general service purposes for commercial and industrial customers.

CHARACTER OF SERVICE: Single or three-phase service at primary voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy, Capacity and Reconciliation Charges as provided in Rider BGS-CIEP (Basic Generation Service – Commercial Industrial Energy Pricing).**

2) **Transmission Charge: $0.005369** per KWH for all KWH

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge: $53.36** per month

2) **Distribution Charge:**

KW Charge: (Demand Charge)
$ 5.57 per maximum KW during June through September
$ 5.16 per maximum KW during October through May
$ 1.89 per KW Minimum Charge

KVAR Charge: (Kilovolt-Ampere Reactive Charge)
$0.35 per KVAR based upon the 15-minute integrated KVAR demand which occurs coincident with the maximum on-peak KW demand in the current billing month (See Part II, Section 5.05)

KWH Charge:
$0.003415 per KWH for all KWH on-peak and off-peak

3) **Non-utility Generation Charge (Rider NGC):**
$ 0.001580 per KWH for all KWH on-peak and off-peak

4) **Societal Benefits Charge (Rider SBC)**:
$ 0.007296 per KWH for all KWH on-peak and off-peak

5) **CIEP – Standby Fee as provided in Rider CIEP – Standby Fee** (formerly Rider DSSAC)

6) **System Control Charge (Rider SCC):**
$ 0.000000 per KWH for all KWH on-peak and off peak

7) **RGGI Recovery Charge (Rider RRC):**
See Rider RRC for rate per KWH for all KWH on-peak and off-peak

8) **Storm Recovery Charge (Rider SRC):**
$ 0.003288 per KWH for all KWH on-peak and off peak

JERSEY CENTRAL POWER & LIGHT COMPANY

XX Rev. Sheet No. 19
BPU No. 12 ELECTRIC - PART III **Superseding XX Rev. Sheet No. 19**

Service Classification GT
General Service Transmission

APPLICABLE TO USE OF SERVICE FOR: Service Classification GT is available for general service purposes for commercial and industrial customers.

CHARACTER OF SERVICE: Three-phase service at transmission voltages.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy, Capacity and Reconciliation Charges as provided in Rider BGS-CIEP (Basic Generation Service – Commercial Industrial Energy Pricing).**

2) **Transmission Charge: $0.004892** per KWH for all KWH
$0.001207 per KWH for all KWH High Tension Service

DELIVERY SERVICE (Customer and Distribution charges include Corporation Business Tax as provided in Rider CBT):

1) **Customer Charge: $229.23** per month

2) **Distribution Charge:**

KW Charge: (Demand Charge)
$ 3.57 per maximum KW
$ 0.95 per KW High Tension Service Credit
$ 2.37 per KW DOD Service Credit

KW Minimum Charge: (Demand Charge)
$ 1.09 per KW Minimum Charge
$ 0.71 per KW DOD Service Credit
$ 0.46 per KW Minimum Charge Credit

KVAR Charge: (Kilovolt-Ampere Reactive Charge)
$0.34 per KVAR based upon the 15-minute integrated KVAR demand which occurs coincident with the maximum on-peak KW demand in the current billing month (See Part II, Section 5.05)

KWH Charge:
$0.002636 per KWH for all KWH on-peak and off-peak
$0.000936 per KWH High Tension Service Credit
$0.001713 per KWH DOD Service Credit

3) **Non-utility Generation Charge (Rider NGC):**
$ 0.001549 per KWH for all KWH on-peak and off-peak – excluding High Tension Service
$ 0.001517 per KWH for all KWH on-peak and off-peak – High Tension Service

4) **Societal Benefits Charge (Rider SBC)**:
$ 0.007296 per KWH for all KWH on-peak and off-peak

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XX Rev. Sheet No. 22
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Service Classification OL
Outdoor Lighting Service

RESTRICTION: Mercury vapor (MV) area lighting is no longer available for replacement and shall be removed from service when existing MV area lighting fails.

APPLICABLE TO USE OF SERVICE FOR: Service Classification OL is available for outdoor flood and area lighting service operating on a standard illumination schedule of 4200 hours per year, and installed on existing wood distribution poles where secondary facilities exist. This Service is not available for the lighting of public streets and highways. This Service is also not available where, in the Company's judgment, it may be objectionable to others, or where, having been installed, it is objectionable to others.

CHARACTER OF SERVICE: Sodium vapor (SV) flood lighting, high pressure sodium (HPS) and mercury vapor (MV) area lighting for limited period (dusk to dawn) at nominal 120 volts.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):

(A) FIXTURE CHARGE:

Nominal Ratings					
Lamp Wattage	Lamp & Ballast Wattage	Billing Month KWH *	HPS Area Lighting	MV Area Lighting	SV Flood Lighting
100	121	42	Not Available	**$ 2.50**	Not Available
175	211	74	Not Available	**$ 2.50**	Not Available
70	99	35	**$10.37**	Not Available	Not Available
100	137	48	**$10.37**	Not Available	Not Available
150	176	62	Not Available	Not Available	**$12.18**
250	293	103	Not Available	Not Available	**$12.80**
400	498	174	Not Available	Not Available	**$13.13**

* Based on standard illumination schedule of 4200 hours per year. Billing Month KWH is calculated to the nearest whole KWH based on the nominal lamp & ballast wattage of the light, times the light's annual burning hours per year, divided by 12 months per year, divided by 1000 watts per KWH.

(B) KWH CHARGES: The following charges apply to all Billing Month KWH and to all billing months (January through December). All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):
1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)
2) **Transmission Charge: $0.000000** per KWH

DELIVERY SERVICE (Distribution Charge includes Corporation Business Tax as provided in Rider CBT):
1) **Distribution Charge: $0.046800** per KWH
2) **Non-utility Generation Charge (Rider NGC): $0.001664** per KWH
3) **Societal Benefits Charge (Rider SBC): $0.007296** per KWH
4) **System Control Charge (Rider SCC): $0.000000** per KWH
5) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
6) **Storm Recovery Charge (Rider SRC): $0.003288** per KWH

Service Classification SVL
Sodium Vapor Street Lighting Service

APPLICABLE TO USE OF SERVICE FOR: Service Classification SVL is available for series and multiple circuit street lighting Service operating on a standard illumination schedule of 4200 hours per year supplied from overhead or underground facilities on streets and roads (and parking areas at the option of the Company) where required by City, Town, County, State or other Municipal or Public Agency or by an incorporated association of local residents.

Sodium vapor conversions of mercury vapor or incandescent street lights shall be scheduled in accordance with the Company's SVL Conversion Program, and may be limited to no more than 5% of the lamps served under this Service Classification at the end of the previous year.

CHARACTER OF SERVICE: Sodium vapor lighting for limited period (dusk to dawn) at secondary voltage.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
(A) FIXTURE CHARGE:

Nominal Ratings					
Lamp Wattage	Lamp & Ballast Wattage	Billing Month KWH *	Company Fixture	Contribution Fixture	Customer Fixture
50	60	21	**$ 6.05**	**$ 1.70**	**$ 0.82**
70	85	30	**$ 6.05**	**$ 1.70**	**$ 0.82**
100	121	42	**$ 6.05**	**$ 1.70**	**$ 0.82**
150	176	62	**$ 6.05**	**$ 1.70**	**$ 0.82**
250	293	103	**$ 7.15**	**$ 1.70**	**$ 0.82**
400	498	174	**$ 7.15**	**$ 1.70**	**$ 0.82**

* Based on standard illumination schedule of 4200 hours per year. Billing Month KWH is calculated to the nearest whole KWH based on the nominal lamp & ballast wattage of the light, times the light's annual burning hours per year, divided by 12 months per year, divided by 1000 watts per KWH.

(B) KWH CHARGES: The following charges apply to all Billing Month KWH and to all billing months (January through December). All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)
2) **Transmission Charge: $0.000000** per KWH

DELIVERY SERVICE (Distribution Charge includes Corporation Business Tax as provided in Rider CBT):

1) **Distribution Charge: $0.046800** per KWH
2) **Non-utility Generation Charge (Rider NGC): $0.001664** per KWH
3) **Societal Benefits Charge (Rider SBC): $0.007296** per KWH
4) **System Control Charge (Rider SCC): $0.000000** per KWH
5) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
6) **Storm Recovery Charge (Rider SRC): $0.003288** per KWH

TERM OF CONTRACT: Five years for each Company Fixture installation and thereafter on a monthly basis. Where special circumstances apply or special or unusual facilities are supplied, contracts of more than five years may be required. Service which is terminated before the end of the contract term shall be billed the total of 1) the light's monthly Fixture Charge plus 2) the per KWH Distribution Charge applicable to the light's Billing Month KWH, times the remaining months of the contract term. Restoration of Service to lamps before the end of the contract term shall be made at the expense of the customer.

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XX Rev. Sheet No. 27

BPU No. 12 ELECTRIC - PART III **Superseding XX Rev. Sheet No. 27**

Service Classification MVL
Mercury Vapor Street Lighting Service

RESTRICTION: Service Classification MVL is in process of elimination and is withdrawn except for the installations of customers receiving Service hereunder on July 21, 1982, and only for the specific premises and class of service of such customer served hereunder on such date.

APPLICABLE TO USE OF SERVICE FOR: Series and multiple circuit street lighting service operating on a standard illumination schedule of 4200 hours per year supplied from overhead or underground facilities on streets and roads where required by City, Town, County, State or other Municipal or Public Agency or by an incorporated association of local residents. At the option of the Company, Service may also be provided for lighting service on streets, roads or parking areas on municipal or private property where supplied directly from the Company's facilities when such Service is contracted for by the owner or agency operating such property.

CHARACTER OF SERVICE: Mercury vapor lighting for limited period (dusk to dawn) at secondary voltage or on constant current series circuits.

RATE PER BILLING MONTH (All charges include Sale and Use Tax as provided in Rider SUT):
(A) FIXTURE CHARGE:

Nominal Ratings					
Lamp Wattage	Lamp & Ballast Wattage	Billing Month KWH *	Company Fixture	Contribution Fixture	Customer Fixture
100	121	42	**$ 4.22**	**$ 1.60**	**$ 0.81**
175	211	74	**$ 4.22**	**$ 1.60**	**$ 0.81**
250	295	103	**$ 4.22**	**$ 1.60**	**$ 0.81**
400	468	164	**$ 4.57**	**$ 1.60**	**$ 0.81**
700	803	281	**$ 5.54**	**$ 1.60**	**$ 0.81**
1000	1135	397	**$ 5.54**	**$ 1.60**	**$ 0.81**

* Based on standard illumination schedule of 4200 hours per year. Billing Month KWH is calculated to the nearest whole KWH based on the nominal lamp & ballast wattage of the light, times the light's annual burning hours per year, divided by 12 months per year, divided by 1000 watts per KWH.

(B) KWH CHARGES: The following charges apply to all Billing Month KWH and to all billing months (January through December). All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)
2) **Transmission Charge: $0.000000** per KWH

DELIVERY SERVICE (Distribution Charge includes Corporation Business Tax as provided in Rider CBT):

1) **Distribution Charge: $0.046800** per KWH
2) **Non-utility Generation Charge (Rider NGC): $0.001664** per KWH
3) **Societal Benefits Charge (Rider SBC): $0.007296** per KWH
4) **System Control Charge (Rider SCC): $0.000000** per KWH
5) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
6) **Storm Recovery Charge (Rider SRC): $0.003288** per KWH

JERSEY CENTRAL POWER & LIGHT COMPANY

XX Rev. Sheet No. 30
BPU No. 12 ELECTRIC - PART III **Superseding XX Rev. Sheet No. 30**

Service Classification ISL
Incandescent Street Lighting Service

RESTRICTION: Service Classification ISL is in process of elimination and is withdrawn except for the installations of customers currently receiving Service, and except for fire alarm and police box lamps provided under Special Provision (c). The obsolescence of this Service Classification's facilities further dictates that Service be discontinued to any installation that requires the replacement of a fixture, bracket or street light pole.

APPLICABLE TO USE OF SERVICE FOR: Series and multiple circuit street lighting service operating on a standard illumination schedule of 4200 hours per year supplied from overhead or underground facilities on streets or roads where required by city, town, county, State or other principal or public agency or by an incorporated association of local residents.

CHARACTER OF SERVICE: Incandescent lighting for limited period (dusk to dawn) at secondary voltage or on constant current series circuits.

RATE PER BILLING MONTH (All Charges include Sales and Use Tax as provided in Rider SUT):

(A) FIXTURE CHARGE:

Nominal Ratings Lamp Wattage	Billing Month KWH *	Company Fixture	Customer Fixture
105	37	**$ 1.78**	**$ 0.81**
205	72	**$ 1.78**	**$ 0.81**
327	114	**$ 1.78**	**$ 0.81**
448	157	**$ 1.78**	**$ 0.81**
690	242	**$ 1.78**	**$ 0.81**
860	301	**$ 1.78**	**$ 0.81**

* Based on standard illumination schedule of 4200 hours per year. Billing Month KWH is calculated to the nearest whole KWH based on the nominal lamp & ballast wattage of the light, times the light's annual burning hours per year, divided by 12 months per year, divided by 1000 watts per KWH.

(B) KWH CHARGES: The following charges apply to all Billing Month KWH and to all billing months (January through December). All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)
2) **Transmission Charge: $0.000000** per KWH

DELIVERY SERVICE (Distribution Charge includes Corporation Business Tax as provided in Rider CBT):

1) **Distribution Charge: $0.046800** per KWH
2) **Non-utility Generation Charge (Rider NGC): $0.001664** per KWH
3) **Societal Benefits Charge (Rider SBC): $0.007296** per KWH
4) **System Control Charge (Rider SCC): $0.000000** per KWH
5) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
6) **Storm Recovery Charge (Rider SRC): $0.003288** per KWH

Issued: **Effective:**

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

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

JERSEY CENTRAL POWER & LIGHT COMPANY

XX Rev. Sheet No. 33

BPU No. 12 ELECTRIC - PART III **Superseding XX Rev. Sheet No. 33**

Service Classification LED
LED Street Lighting Service

APPLICABLE TO USE OF SERVICE FOR: Service Classification LED is available for installation of 12 or more LED (light emitting diode) fixtures per request for series and multiple circuit street lighting Service operating on a standard illumination schedule of 4200 hours per year supplied from overhead or underground facilities on streets and roads (and parking areas at the option of the Company) where required by City, Town, County, State or other Municipal or Public Agency or by an incorporated association of local residents.

LED conversions of sodium vapor, mercury vapor or incandescent street lights shall be scheduled at the Company's reasonable discretion.

CHARACTER OF SERVICE: LED lighting for limited period (dusk to dawn) at secondary voltage.

RATE PER BILLING MONTH (All charges include Sales and Use Tax as provided in Rider SUT):
(A) FIXTURE CHARGE:

Lamp Wattage	Type	Lumens	Billing Month KWH*	Company Fixture
50	Cobra Head	4000	18	**$ 6.46**
90	Cobra Head	7000	32	**$ 7.14**
130	Cobra Head	11500	46	**$ 8.51**
260	Cobra Head	24000	91	**$ 10.99**
50	Acorn	2500	18	**$ 15.48**
90	Acorn	5000	32	**$ 16.19**
50	Colonial	2500	18	**$ 8.85**
90	Colonial	5000	32	**$ 12.56**

* Based on standard illumination schedule of 4200 hours per year. Billing Month KWH is calculated to the nearest whole KWH based on the lamp wattage of the light, times the light's annual burning hours per year, divided by 12 months per year, divided by 1000 watts per KWH.

(B) KWH CHARGES: The following charges apply to all Billing Month KWH and to all billing months (January through December). All charges are applicable to Full Service Customers. All charges, excluding Basic Generation Service (default service), are applicable to Delivery Service Customers.

BASIC GENERATION SERVICE (default service):

1) **BGS Energy and Reconciliation Charges as provided in Rider BGS-RSCP (Basic Generation Service – Residential Small Commercial Pricing)** (formerly Rider BGS-FP)
2) **Transmission Charge: $0.000000** per KWH

DELIVERY SERVICE (Distribution Charge includes Corporation Business Tax as provided in Rider CBT):

1) **Distribution Charge: $0.046800** per KWH
2) **Non-utility Generation Charge (Rider NGC): $0.001664** per KWH
3) **Societal Benefits Charge (Rider SBC): $0.007296** per KWH
4) **System Control Charge (Rider SCC): $0.000000** per KWH
5) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
6) **Storm Recovery Charge (Rider SRC): $0.003288** per KWH

TERM OF CONTRACT: Ten years for each Company Fixture installation and thereafter on a monthly basis. Where special circumstances apply or special or unusual facilities are supplied, contracts of more than ten years may be required. Service which is terminated before the end of the contract term shall be billed the total of 1) the light's monthly Fixture Charge plus 2) the per KWH Distribution Charge applicable to the light's Billing Month KWH, times the remaining months of the contract term. Restoration of Service to lamps before the end of the contract term shall be made at the expense of the customer.

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

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

2) BGS Transmission Charge per KWH: As provided in the respective tariff for Service Classifications RS, RT, RGT, GS, GST, OL, SVL, MVL, ISL and LED. Effective September 1, 2017, a RMR (BL England) surcharge of **$0.000131** per KWH (includes Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage. Effective January 1, 2018, a RMR (Yorktown) surcharge of **$0.000011** 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 **October 1, 2018**, the following TEC surcharges (include Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage, except lighting under Service Classifications OL, SVL, MVL, ISL and LED:

PSEG-TEC surcharge of **$0.002472** per KWH
VEPCO-TEC surcharge of **$0.000167** per KWH
PATH-TEC surcharge of **($0.000082)** per KWH
TRAILCO-TEC surcharge of **$0.000211** per KWH
Delmarva-TEC surcharge of **$0.000001** per KWH
ACE-TEC surcharge of **$0.000097** per KWH
PEPCO-TEC surcharge of **$0.000014** per KWH
PPL-TEC surcharge of **$0.000808** per KWH
AEP-East-TEC surcharge of **$0.000071** per KWH
BG&E-TEC surcharge of **$0.000016** per KWH
MAIT-TEC surcharge of **$0.000032** per KWH
PECO-TEC surcharge of **$0.000064** per KWH
EL05-121-TEC surcharge of **$0.005884** per KWH

3) BGS Reconciliation Charge per KWH: $0.009943 (includes Sales and Use Tax as provided in Rider SUT)

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

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

3) BGS Transmission Charge per KWH: (Continued)

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

	PSEG-TEC	VEPCO-TEC	PATH-TEC
GS and GST	**$0.002472**	**$0.000167**	**($0.000082)**
GP	**$0.001649**	**$0.000112**	**($0.000054)**
GT	**$0.001502**	**$0.000101**	**($0.000050)**
GT – High Tension Service	**$0.000371**	**$0.000026**	**($0.000013)**

	TRAILCO-TEC	Delmarva-TEC	ACE-TEC
GS and GST	**$0.000211**	**$0.000001**	**$0.000097**
GP	**$0.000141**	**$0.000000**	**$0.000065**
GT	**$0.000128**	**$0.000000**	**$0.000059**
GT – High Tension Service	**$0.000032**	**$0.000000**	**$0.000015**

	PEPCO-TEC	PPL-TEC	AEP-East-TEC
GS and GST	**$0.000014**	**$0.000808**	**$0.000071**
GP	**$0.000010**	**$0.000540**	**$0.000048**
GT	**$0.000009**	**$0.000492**	**$0.000044**
GT – High Tension Service	**$0.000002**	**$0.000122**	**$0.000011**

	BG&E-TEC	MAIT-TEC	PECO-TEC
GS and GST	**$0.000016**	**$0.000032**	**$0.000064**
GP	**$0.000011**	**$0.000021**	**$0.000043**
GT	**$0.000010**	**$0.000019**	**$0.000039**
GT – High Tension Service	**$0.000002**	**$0.000005**	**$0.000010**

	EL05-121-TEC
GS and GST	**$0.005884**
GP	**$0.003926**
GT	**$0.003577**
GT – High Tension Service	**$0.000883**

4) BGS Reconciliation Charge per KWH: $0.004769 (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 NITS Charge into BGS Customer Rates - RSCP and CIEP
NITS Charges for July 2018 - December 2018

JCP&L Annual Transmission Service Revenue Requirements	$	156,605,928	
Total Schedule 12 TEC Included in Above	$	(21,605,928)	
JCP&L Customer Share of Schedule 12 TEC	$	8,665,841	
NITS Charges for 2018	$	143,665,841	
JCP&L Zonal Transmission Load for 2018		5,721.0	(MW)
2018 NITS Rate	$	25,112.02	(per MW-yr)
Resulting BGS Firm Transmission Service Supplier Rate	$	68.80	(per MW-day)
Increase in BGS Firm Transmission Service Supplier Rate	$	27.40	(per MW-day)

					Effective October 1, 2018:	
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery	BGS Eligible Sales (kWh)	Transmission Rate ($/kWh)		Transmission Rate w/SUT ($/kWh)
Secondary (excluding lighting)	4,947.8	$ 124,249,231	16,463,811,980	$ 0.007547		$ 0.008047
Primary	343.5	$ 8,625,977	1,713,078,580	$ 0.005035		$ 0.005369
Transmission @ 34.5 kV	285.6	$ 7,171,992	1,563,196,375	$ 0.004588		$ 0.004892
Transmission @ 230 kV	15.3	$ 384,214	339,327,213	$ 0.001132		$ 0.001207
Total	5,592.2	$ 140,431,413	20,079,414,148			

BGS-RSCP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales January through December @ Customer		15,493,967	MWH
2	BGS-RSCP Eligible Sales January through December @ Transmission Node		17,191,398	MWH
3	BGS-RSCP Eligible Transmission Obligation		4,694	MW
4	Change in Transmission Payment to RSCP Suppliers	$	46,944,767	= Line 3 x $27.40 x 365
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	2.73	= Line 4 / Line 2

Attachment 3c

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

2018 Average Monthly PSEG-TEC Costs Allocated to JCP&L Zone	$ 3,677,676.47	(1)
2018 JCP&L Zone Transmission Peak Load (MW)	5,721.0	
PSEG-Transmission Enhancement Rate ($/MW-month)	$ 642.84	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	**Effective October 1, 2018:** PSEG-TEC Surcharge ($/kWh)	PSEG-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	4947.8	38,167,609	16,463,811,980	$ 0.002318	$ 0.002472
Primary	343.5	2,649,778	1,713,078,580	$ 0.001547	$ 0.001649
Transmission @ 34.5 kV	285.6	2,203,135	1,563,196,375	$ 0.001409	$ 0.001502
Transmission @ 230 kV	15.3	118,025	339,327,213	$ 0.000348	$ 0.000371
Total	5592.2	43,138,547	20,079,414,148		

(1) Cost Allocation of PSEG Project Schedule 12 Charges to JCP&L Zone for 2018
(2) Based on 12 months PSEG Project costs from January through December 2018
(3) October 2018 through September 2019

BGS-RSCP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales January through December @ Customer		15,493,967	MWH
2	BGS-RSCP Eligible Sales January through December @ Transmission Node		17,191,398	MWH
3	BGS-RSCP Eligible Transmission Obligation		4,694	MW
4	PSEG-Transmission Enhancement Costs to RSCP Suppliers	$	36,205,925	= Line 3 x $642.84 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	2.11	= Line 4 / Line 2

Attachment 3d

Jersey Central Power & Light Company
Proposed ACE Project Transmission Enhancement Charge (ACE-TEC Surcharge) effective July 1, 2018
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) for June 2018 - May 2019

2018/2019 Average Monthly ACE-TEC Costs Allocated to JCP&L Zone	$	144,806.98	(1)
2018 JCP&L Zone Transmission Peak Load (MW)		5,721.0	
ACE-Transmission Enhancement Rate ($/MW-month)	$	25.31	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	**Effective October 1, 2018:** ACE-TEC Surcharge ($/kWh)	ACE-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	4947.8	1,502,834	16,463,811,980	$ 0.000091	$ 0.000097
Primary	343.5	104,334	1,713,078,580	$ 0.000061	$ 0.000065
Transmission @ 34.5 kV	285.6	86,748	1,563,196,375	$ 0.000055	$ 0.000059
Transmission @ 230 kV	15.3	4,647	339,327,213	$ 0.000014	$ 0.000015
Total	5592.2	1,698,562	20,079,414,148		

(1) Cost Allocation of ACE Project Schedule 12 Charges to JCP&L Zone for 2018/2019
(2) Based on 12 months ACE Project costs from June 2018 through May 2019
(3) October 2018 through September 2019

BGS-RSCP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales January through December @ Customer		15,493,967	MWH
2	BGS-RSCP Eligible Sales January through December @ Transmission Node		17,191,398	MWH
3	BGS-RSCP Eligible Transmission Obligation		4,694	MW
4	ACE-Transmission Enhancement Costs to RSCP Suppliers	$	1,425,593	= Line 3 x $25.31 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.08	= Line 4 / Line 2

Attachment 3e

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

2018 Average Monthly VEPCO-TEC Costs Allocated to JCP&L Zone	$	248,516.16	(1)
2018 JCP&L Zone Transmission Peak Load (MW)		5,721.0	
VEPCO-Transmission Enhancement Rate ($/MW-month)	$	43.44	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	Effective October 1, 2018: VEPCO-TEC Surcharge ($/kWh)	VEPCO-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	4947.8	2,579,147	16,463,811,980	$ 0.000157	$ 0.000167
Primary	343.5	179,057	1,713,078,580	$ 0.000105	$ 0.000112
Transmission @ 34.5 kV	285.6	148,875	1,563,196,375	$ 0.000095	$ 0.000101
Transmission @ 230 kV	15.3	7,975	339,327,213	$ 0.000024	$ 0.000026
Total	5592.2	2,915,054	20,079,414,148		

(1) Cost Allocation of VEPCO Project Schedule 12 Charges to JCP&L Zone for 2018
(2) Based on 12 months VEPCO Project costs from January through December 2018
(3) October 2018 through September 2019

BGS-RSCP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales January through December @ Customer		15,493,967	MWH
2	BGS-RSCP Eligible Sales January through December @ Transmission Node		17,191,398	MWH
3	BGS-RSCP Eligible Transmission Obligation		4,694	MW
4	VEPCO-Transmission Enhancement Costs to RSCP Suppliers	$	2,446,588	= Line 3 x $43.44 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.14	= Line 4 / Line 2

Attachment 3f

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

2018 Average Monthly PATH-TEC Costs Allocated to JCP&L Zone	$	(121,645.78)	(1)
2018 JCP&L Zone Transmission Peak Load (MW)		5,721.0	
PATH-Transmission Enhancement Rate ($/MW-month)	$	(21.26)	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	Effective October 1, 2018: PATH-TEC Surcharge ($/kWh)		PATH-TEC Surcharge w/ SUT($/kWh)	
Secondary (excluding lighting)	4947.8	(1,262,462)	16,463,811,980	$	(0.000077)	$	(0.000082)
Primary	343.5	(87,646)	1,713,078,580	$	(0.000051)	$	(0.000054)
Transmission @ 34.5 kV	285.6	(72,873)	1,563,196,375	$	(0.000047)	$	(0.000050)
Transmission @ 230 kV	15.3	(3,904)	339,327,213	$	(0.000012)	$	(0.000013)
Total	5592.2	(1,426,885)	20,079,414,148				

(1) Cost Allocation of PATH Project Schedule 12 Charges to JCP&L Zone for 2018
(2) Based on 12 months PATH Project costs from January through December 2018
(3) October 2018 through September 2019

BGS-RSCP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales January through December @ Customer		15,493,967	MWH
2	BGS-RSCP Eligible Sales January through December @ Transmission Node		17,191,398	MWH
3	BGS-RSCP Eligible Transmission Obligation		4,694	MW
4	PATH-Transmission Enhancement Costs to RSCP Suppliers	$	(1,197,576)	= Line 3 x ($21.26) x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	(0.07)	= Line 4 / Line 2

Attachment 3g

Jersey Central Power & Light Company
Proposed TRAILCO Project Transmission Enhancement Charge (TRAILCO-TEC Surcharge) effective July 1, 2018
To reflect FERC-approved TRAILCO Project Transmission Enhancement Charge (Schedule 12 PJM OATT) for June 2018 - May 2019

2018/2019 Average Monthly TRAILCO-TEC Costs Allocated to JCP&L Zone	$ 313,889.18	(1)
2018 JCP&L Zone Transmission Peak Load (MW)	5,721.0	
TRAILCO-Transmission Enhancement Rate ($/MW-month)	$ 54.87	

				Effective October 1, 2018:	
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	TRAILCO-TEC Surcharge ($/kWh)	TRAILCO-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	4947.8	3,257,600	16,463,811,980	$ 0.000198	$ 0.000211
Primary	343.5	226,158	1,713,078,580	$ 0.000132	$ 0.000141
Transmission @ 34.5 kV	285.6	188,037	1,563,196,375	$ 0.000120	$ 0.000128
Transmission @ 230 kV	15.3	10,073	339,327,213	$ 0.000030	$ 0.000032
Total	5592.2	3,681,869	20,079,414,148		

(1) Cost Allocation of TRAILCO Project Schedule 12 Charges to JCP&L Zone for 2018/2019
(2) Based on 12 months TRAILCO Project costs from June 2018 through May 2019
(3) October 2018 through September 2019

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

Line No.				
1	BGS-RSCP Eligible Sales January through December @ Customer		15,493,967	MWH
2	BGS-RSCP Eligible Sales January through December @ Transmission Node		17,191,398	MWH
3	BGS-RSCP Eligible Transmission Obligation		4,694	MW
4	TRAILCO-Transmission Enhancement Costs to RSCP Suppliers	$	3,090,171	= Line 3 x $54.87 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.18	= Line 4 / Line 2

Attachment 3h

Jersey Central Power & Light Company
Proposed DELMARVA Project Transmission Enhancement Charge (DELMARVA-TEC Surcharge) effective July 1, 2018
To reflect FERC-approved DELMARVA Project Transmission Enhancement Charge (Schedule 12 PJM OATT) for June 2018 - May 2019

2018/2019 Average Monthly DELMARVA Costs Allocated to JCP&L Zone	$	917.26	(1)
2018 JCP&L Zone Transmission Peak Load (MW)		5,721.0	
DELMARVA-Transmission Enhancement Rate ($/MW-month)	$	0.16	

Effective October 1, 2018:

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	DELMARVA-TEC Surcharge ($/kWh)	DELMARVA-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	4947.8	9,519	16,463,811,980	$ 0.000001	$ 0.000001
Primary	343.5	661	1,713,078,580	$ -	$ -
Transmission @ 34.5 kV	285.6	549	1,563,196,375	$ -	$ -
Transmission @ 230 kV	15.3	29	339,327,213	$ -	$ -
Total	5592.2	10,759	20,079,414,148		

(1) Cost Allocation of DELMARVA Project Schedule 12 Charges to JCP&L Zone for 2018/2019
(2) Based on 12 months DELMARVA Project costs from June 2018 through May 2019
(3) October 2018 through September 2019

BGS-RSCP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales January through December @ Customer		15,493,967	MWH
2	BGS-RSCP Eligible Sales January through December @ Transmission Node		17,191,398	MWH
3	BGS-RSCP Eligible Transmission Obligation		4,694	MW
4	DELMARVA-Transmission Enhancement Costs to RSCP Suppliers	$	9,030	= Line 3 x $0.16 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	-	= Line 4 / Line 2

Jersey Central Power & Light Company
Proposed PEPCO Project Transmission Enhancement Charge (PEPCO-TEC Surcharge) effective July 1, 2018
To reflect FERC-approved PEPCO Project Transmission Enhancement Charge (Schedule 12 PJM OATT) for June 2018 - May 2019

2018/2019 Average Monthly PEPCO-TEC Costs Allocated to JCP&L Zone	$	20,518.22	(1)
2018 JCP&L Zone Transmission Peak Load (MW)		5,721.0	
PEPCO-Transmission Enhancement Rate ($/MW-month)	$	3.59	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	**Effective October 1, 2018:** PEPCO-TEC Surcharge ($/kWh)	PEPCO-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	4947.8	212,942	16,463,811,980	$ 0.000013	$ 0.000014
Primary	343.5	14,783	1,713,078,580	$ 0.000009	$ 0.000010
Transmission @ 34.5 kV	285.6	12,292	1,563,196,375	$ 0.000008	$ 0.000009
Transmission @ 230 kV	15.3	658	339,327,213	$ 0.000002	$ 0.000002
Total	5592.2	240,675	20,079,414,148		

(1) Cost Allocation of PEPCO Project Schedule 12 Charges to JCP&L Zone for 2018/2019
(2) Based on 12 months PEPCO Project costs from June 2018 through May 2019
(3) October 2018 through September 2019

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

Line No.				
1	BGS-RSCP Eligible Sales January through December @ Customer		15,493,967	MWH
2	BGS-RSCP Eligible Sales January through December @ Transmission Node		17,191,398	MWH
3	BGS-RSCP Eligible Transmission Obligation		4,694	MW
4	PEPCO-Transmission Enhancement Costs to RSCP Suppliers	$	201,997	= Line 3 x $3.59 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.01	= Line 4 / Line 2

Attachment 3j

Jersey Central Power & Light Company
Proposed PPL Project Transmission Enhancement Charge (PPL-TEC Surcharge) effective July 1, 2018
To reflect FERC-approved PPL Project Transmission Enhancement Charge (Schedule 12 PJM OATT) for June 2018 - May 2019

2018/2019 Average Monthly PPL-TEC Costs Allocated to JCP&L Zone	$ 1,203,214.73	(1)
2018 JCP&L Zone Transmission Peak Load (MW)	5,721.0	
PPL-Transmission Enhancement Rate ($/MW-month)	$ 210.32	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	Effective October 1, 2018: PPL-TEC Surcharge ($/kWh)	PPL-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	4947.8	12,487,186	16,463,811,980	$ 0.000758	$ 0.000808
Primary	343.5	866,920	1,713,078,580	$ 0.000506	$ 0.000540
Transmission @ 34.5 kV	285.6	720,793	1,563,196,375	$ 0.000461	$ 0.000492
Transmission @ 230 kV	15.3	38,614	339,327,213	$ 0.000114	$ 0.000122
Total	5592.2	14,113,513	20,079,414,148		

(1) Cost Allocation of PPL Project Schedule 12 Charges to JCP&L Zone for 2018/2019
(2) Based on 12 months PPL Project costs from June 2018 through May 2019
(3) October 2018 through September 2019

BGS-RSCP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales January through December @ Customer		15,493,967	MWH
2	BGS-RSCP Eligible Sales January through December @ Transmission Node		17,191,398	MWH
3	BGS-RSCP Eligible Transmission Obligation		4,694	MW
4	PPL-Transmission Enhancement Costs to RSCP Suppliers	$	11,845,387	= Line 3 x $210.32 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.69	= Line 4 / Line 2

Attachment 3k

Jersey Central Power & Light Company
Proposed BG&E Project Transmission Enhancement Charge (BG&E-TEC Surcharge) effective July 1, 2018
To reflect FERC-approved BG&E Project Transmission Enhancement Charge (Schedule 12 PJM OATT) for June 2018 - May 2019

2018/2019 Average Monthly BG&E-TEC Costs Allocated to JCP&L Zone	$	23,649.42	(1)
2018 JCP&L Zone Transmission Peak Load (MW)		5,721.0	
BG&E-Transmission Enhancement Rate ($/MW-month)	$	4.13	

				Effective October 1, 2018:			
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)		BG&E-TEC Surcharge ($/kWh)		BG&E-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	4947.8	245,438	16,463,811,980	$	0.000015	$	0.000016
Primary	343.5	17,039	1,713,078,580	$	0.000010	$	0.000011
Transmission @ 34.5 kV	285.6	14,167	1,563,196,375	$	0.000009	$	0.000010
Transmission @ 230 kV	15.3	759	339,327,213	$	0.000002	$	0.000002
Total	5592.2	277,404	20,079,414,148				

(1) Cost Allocation of BG&E Project Schedule 12 Charges to JCP&L Zone for 2018/2019
(2) Based on 12 months BG&E Project costs from June 2018 through May 2019
(3) October 2018 through September 2019

BGS-RSCP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales January through December @ Customer		15,493,967	MWH
2	BGS-RSCP Eligible Sales January through December @ Transmission Node		17,191,398	MWH
3	BGS-RSCP Eligible Transmission Obligation		4,694	MW
4	BG&E-Transmission Enhancement Costs to RSCP Suppliers	$	232,823	= Line 3 x $4.13 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.01	= Line 4 / Line 2

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

2018 Average Monthly MAIT-TEC Costs Allocated to JCP&L Zone	$ 48,069.09	(1)
2018 JCP&L Zone Transmission Peak Load (MW)	5,721.0	
MAIT-Transmission Enhancement Rate ($/MW-month)	$ 8.40	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	Effective October 1, 2018: MAIT-TEC Surcharge ($/kWh)	MAIT-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	4947.8	498,870	16,463,811,980	$ 0.000030	$ 0.000032
Primary	343.5	34,634	1,713,078,580	$ 0.000020	$ 0.000021
Transmission @ 34.5 kV	285.6	28,796	1,563,196,375	$ 0.000018	$ 0.000019
Transmission @ 230 kV	15.3	1,543	339,327,213	$ 0.000005	$ 0.000005
Total	5592.2	563,843	20,079,414,148		

(1) Cost Allocation of MAIT Project Schedule 12 Charges to JCP&L Zone for 2018
(2) Based on 12 months MAIT Project costs from January through December 2018
(3) October 2018 through September 2019

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

Line No.				
1	BGS-RSCP Eligible Sales January through December @ Customer		15,493,967	MWH
2	BGS-RSCP Eligible Sales January through December @ Transmission Node		17,191,398	MWH
3	BGS-RSCP Eligible Transmission Obligation		4,694	MW
4	MAIT-Transmission Enhancement Costs to RSCP Suppliers	$	473,230	= Line 3 x $8.40 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.03	= Line 4 / Line 2

Attachment 3m

Jersey Central Power & Light Company

Proposed EL05-121 Settlement Adjustment Transmission Enhancement Charge (EL05-121-TEC Surcharge) effective July 1, 2018

To reflect FERC-approved EL05-121 Settlement Adjustment for July 2018 - June 2019:

BLI-1108A - Current Aggregate Recovery Charge Transitional Period - Catch-up	$	67,946,499.64	
BLI-1108A - Estimated Current Aggregate Recovery Charge Interest August 2018 to June 2019	$	1,517,679.70	
BLI-1115 - Transmission Enhancement Charge Adjustments (Black Box) Transitional Period - Catch-up	$	25,286,407.13	
BLI-1115 - Transmission Enhancement Charge Adjustments (Black Box)	$	9,726,167.88	
BLI-1115 - Estimated Transmission Enhancement Charge Adjustment (Black Box) Interest August 2018 - June 2019	$	564,807.12	
Total Annual Adjustments Allocated to JCP&L Zone	$	105,041,561.47	
July 2018 through June 2019 Monthly Adjustments Allocated to JCP&L Zone	$	8,753,463.46	(1)
2018 JCP&L Zone Transmission Peak Load (MW)		5,721.0	
EL05-121 Settlement Adjustment Transmission Enhancement Charge Rate ($/MW-month)	$	1,530.06	

Effective October 1, 2018:

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	EL05-121-TEC Surcharge ($/kWh)	EL05-121-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	4947.8	90,845,069	16,463,811,980	$ 0.005518	$ 0.005884
Primary	343.5	6,306,900	1,713,078,580	$ 0.003682	$ 0.003926
Transmission @ 34.5 kV	285.6	5,243,816	1,563,196,375	$ 0.003355	$ 0.003577
Transmission @ 230 kV	15.3	280,919	339,327,213	$ 0.000828	$ 0.000883
Total	5592.2	102,676,703	20,079,414,148		

(1) Monthly Cost Allocation of EL05-121 Settlement Adjustments to JCP&L Zone
(2) Based on 12 months Cost Allocation from July 2018 through June 2019
(3) October 2018 through September 2019

Attachment 3n

Jersey Central Power & Light Company
Proposed PECO Project Transmission Enhancement Charge (PECO-TEC Surcharge) effective July 1, 2018
To reflect FERC-approved PECO Project Transmission Enhancement Charge (Schedule 12 PJM OATT) for June 2018 - May 2019

2018/2019 Average Monthly PECO-TEC Costs Allocated to JCP&L Zone	$	95,668.44	(1)
2018 JCP&L Zone Transmission Peak Load (MW)		5,721.0	
PECO-Transmission Enhancement Rate ($/MW-month)	$	16.72	

				Effective October 1, 2018:			
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)		PECO-TEC Surcharge ($/kWh)		PECO-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	4947.8	992,865	16,463,811,980	$	0.000060	$	0.000064
Primary	343.5	68,929	1,713,078,580	$	0.000040	$	0.000043
Transmission @ 34.5 kV	285.6	57,311	1,563,196,375	$	0.000037	$	0.000039
Transmission @ 230 kV	15.3	3,070	339,327,213	$	0.000009	$	0.000010
Total	5592.2	1,122,175	20,079,414,148				

(1) Cost Allocation of PECO Project Schedule 12 Charges to JCP&L Zone for 2018/2019
(2) Based on 12 months PECO Project costs from June 2018 through May 2019
(3) October 2018 through September 2019

BGS-RSCP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales January through December @ Customer		15,493,967	MWH
2	BGS-RSCP Eligible Sales January through December @ Transmission Node		17,191,398	MWH
3	BGS-RSCP Eligible Transmission Obligation		4,694	MW
4	PECO-Transmission Enhancement Costs to RSCP Suppliers	$	941,835	= Line 3 x $16.72 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.05	= Line 4 / Line 2

Attachment 3o

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

2018 Average Monthly AEP-East-TEC Costs Allocated to JCP&L Zone	$	106,541.27	(1)
2018 JCP&L Zone Transmission Peak Load (MW)		5,721.0	
AEP-East-Transmission Enhancement Rate ($/MW-month)	$	18.62	

Effective October 1, 2018:

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	AEP-East-TEC Surcharge ($/kWh)	AEP-East-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	4947.8	1,105,705	16,463,811,980	$ 0.000067	$ 0.000071
Primary	343.5	76,763	1,713,078,580	$ 0.000045	$ 0.000048
Transmission @ 34.5 kV	285.6	63,824	1,563,196,375	$ 0.000041	$ 0.000044
Transmission @ 230 kV	15.3	3,419	339,327,213	$ 0.000010	$ 0.000011
Total	5592.2	1,249,712	20,079,414,148		

(1) Cost Allocation of AEP-East Project Schedule 12 Charges to JCP&L Zone for 2018
(2) Based on 12 months AEP-East Project costs from January through December 2018
(3) October 2018 through September 2019

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

Line No.				
1	BGS-RSCP Eligible Sales January through December @ Customer		15,493,967	MWH
2	BGS-RSCP Eligible Sales January through December @ Transmission Node		17,191,398	MWH
3	BGS-RSCP Eligible Transmission Obligation		4,694	MW
4	AEP-East-Transmission Enhancement Costs to RSCP Suppliers	$	1,048,876	= Line 3 x $18.62 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$	0.06	= Line 4 / Line 2

Attachment 4a (ACE Pro-forma Tariff Sheets)
Attachment 4b (ACE – Translation of NITS Charge into Customer Rates)
Attachment 4c (ACE Translation of PSE&G TEC into Customer Rates)
Attachment 4d (ACE Translation of JCP&L TEC into Customer Rates)
Attachment 4e (ACE Translation of VEPCo TEC into Customer Rates)
Attachment 4f (ACE Translation of PATH TEC into Customer Rates)
Attachment 4g (ACE Translation of TrailCo TEC into Customer Rates)
Attachment 4h (ACE Translation of Delmarva TEC into Customer Rates)
Attachment 4i (ACE Translation of PEPCo TEC into Customer Rates)
Attachment 4j (ACE Translation of PPL TEC into Customer Rates)
Attachment 4k (ACE Translation of BG&E TEC into Customer Rates)
Attachment 4l (ACE Translation of MAIT TEC into Customer Rates)
Attachment 4m (ACE Translation of EL05-121 into Customer Rates)
Attachment 4n (ACE Translation of PECO into Customer Rates)
Attachment 4o (ACE Translation of AEP TEC into Customer Rates)

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV Revised Sheet Replaces Revised Sheet No. 5

RATE SCHEDULE RS
(Residential Service)

AVAILABILITY
Available for full domestic service to individually metered residential customers, including rural domestic customers, engaged principally in agricultural pursuits.

	SUMMER June Through September	**WINTER** October Through May
Delivery Service Charges:		
Customer Charge ($/Month)	$4.83	$4.83
Distribution Rates ($/kWH)		
First Block (Summer <= 750 kWh; Winter<= 500kWh)	$0.055619	$0.051319
Excess kWh	$0.063942	$0.051319
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC	
Societal Benefits Charge ($/kWh)		
Clean Energy Program	See Rider SBC	
Universal Service Fund	See Rider SBC	
Lifeline	See Rider SBC	
Uncollectible Accounts	See Rider SBC	
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC	
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC	
Transmission Service Charges ($/kWh):		
Transmission Rate	$0.020481	$0.020481
Reliability Must Run Transmission Surcharge	$0.003737	$0.003737
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI	

CORPORATE BUSINESS TAX (CBT)
Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)
Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

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

RATE SCHEDULE MGS-SECONDARY
(Monthly General Service)

AVAILABILITY
Available at any point within the Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer delivered at one point and metered at or compensated to the voltage of delivery. This schedule is not available to residential customers.

	SUMMER June Through September	**WINTER** October Through May
Delivery Service Charges:		
Customer Charge		
Single Phase	$8.35	$8.35
Three Phase	$9.72	$9.72
Distribution Demand Charge (per kW)	$2.07	$1.70
Reactive Demand Charge	$0.48	$0.48
(For each kvar over one-third of kW demand**)**		
Distribution Rates ($/kWh)	$0.049365	$0.044591
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC	
Societal Benefits Charge ($/kWh)		
Clean Energy Program	See Rider SBC	
Universal Service Fund	See Rider SBC	
Lifeline	See Rider SBC	
Uncollectible Accounts	See Rider SBC	
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC	
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC	
CIEP Standby Fee ($/kWh)	See Rider BGS	
Transmission Demand Charge ($/kW for each kW in excess of 3 kW)	$3.45	$3.07
Reliability Must Run Transmission Surcharge ($/kWh)	$0.003737	$0.003737
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI	

The minimum monthly bill will be $8.35 per month plus any applicable adjustment.

Date of Issue: **Effective Date:**

Issued by:

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV Revised Sheet Replaces Revised Sheet No. 14

RATE SCHEDULE MGS-PRIMARY
(Monthly General Service)

AVAILABILITY
Available at any point within the Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer delivered at one point and metered at or compensated to the voltage of delivery. This schedule is not available to residential customers.

	SUMMER June Through September	**WINTER** October Through May
Delivery Service Charges:		
Customer Charge		
Single Phase	$14.80	$14.80
Three Phase	$16.08	$16.08
Distribution Demand Charge (per kW)	$1.58	$1.23
Reactive Demand Charge	$0.44	$0.44
(For each kvar over one-third of kW demand)		
Distribution Rates ($/kWh)	$0.044522	$0.043240
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC	
Societal Benefits Charge ($/kWh)		
Clean Energy Program	See Rider SBC	
Universal Service Fund	See Rider SBC	
Lifeline	See Rider SBC	
Uncollectible Accounts	See Rider SBC	
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC	
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC	
CIEP Standby Fee ($/kWh)	See Rider BGS	
Transmission Demand Charge ($/kW for each kW in excess of 3 kW)	$2.43	$2.09
Reliability Must Run Transmission Surcharge ($/kWh)	$0.003650	$0.003650
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI	

The minimum monthly bill will be $14.80 per month plus any applicable adjustment.

Date of Issue: **Effective Date:**

Issued by:

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV Revised Sheet Replaces Revised Sheet No. 17

RATE SCHEDULE AGS-SECONDARY
(Annual General Service)

AVAILABILITY

Available at any point within the Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer contracting for annual service delivered at one point and metered at or compensated to the voltage of delivery.

MONTHLY RATE

Delivery Service Charges:

Customer Charge	$161.98
Distribution Demand Charge ($/kW)	$9.44
Reactive Demand (for each kvar over one-third of kW demand)	$0.73
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC
Societal Benefits Charge ($/kWh)	
Clean Energy Program	See Rider SBC
Universal Service Fund	See Rider SBC
Lifeline	See Rider SBC
Uncollectible Accounts	See Rider SBC
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC
CIEP Standby Fee ($/kWh)	See Rider BGS
Transmission Demand Charge ($/kW)	$3.70
Reliability Must Run Transmission Surcharge ($/kWh)	$0.003737
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV Revised Sheet Replaces Revised Sheet No. 19

RATE SCHEDULE AGS-PRIMARY
(Annual General Service)

AVAILABILITY

Available at any point within the Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer contracting for annual service delivered at one point and metered at or compensated to the voltage of delivery.

MONTHLY RATE

Delivery Service Charges:

Customer Charge	$585.08
Distribution Demand Charge ($/kW)	$7.56
Reactive Demand (for each kvar over one-third of kW demand)	$0.56
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC
Societal Benefits Charge ($/kWh)	
Clean Energy Program	See Rider SBC
Universal Service Fund	See Rider SBC
Lifeline	See Rider SBC
Uncollectible Accounts	See Rider SBC
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC
CIEP Standby Fee ($/kWh)	See Rider BGS
Transmission Demand Charge ($/kW)	$3.82
Reliability Must Run Transmission Surcharge ($/kWh)	$0.003650
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI

Date of Issue: **Effective Date:**

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ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV Revised Sheet Replaces Revised Sheet No. 29

RATE SCHEDULE TGS
(Transmission General Service)
(Sub Transmission Service Taken at 23kV and 34.5 kV)

AVAILABILITY

Available at any point within the Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer contracting for annual service delivered at one point and metered at or compensated to the voltage subtransmission level (23 or 34.5 kV).

MONTHLY RATE

Delivery Service Charges:

Customer Charge

Maximum billed demand within the most recent 12 billing months.	
Less than 5,000 kW	$132.67
5,000 – 9,000 kW	$4,393.94
Greater than 9,000 kW	$7,976.15

Distribution Demand Charge ($/kW)

Maximum billed demand within the most recent 12 billing months.	
Less than 5,000 kW	$3.81
5,000 – 9,000 kW	$2.93
Greater than 9,000 kW	$1.46

Reactive Demand (for each kvar over one-third of kW demand)	$0.52
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC
Societal Benefits Charge ($/kWh)	
Clean Energy Program	See Rider SBC
Universal Service Fund	See Rider SBC
Lifeline	See Rider SBC
Uncollectible Accounts	See Rider SBC
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC
CIEP Standby Fee ($/kWh)	See Rider BGS
Transmission Demand Charge ($/kW)	$4.54
Reliability Must Run Transmission Surcharge ($/kWh)	$0.003570
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI

Date of Issue: **Effective Date:**

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ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV Revised Sheet Replaces Revised Sheet No. 29a

RATE SCHEDULE TGS
(Transmission General Service)
(Transmission Service Taken at or above 69kV)

AVAILABILITY
Available at any point within the Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer contracting for annual service delivered at one point and metered at or compensated to the voltage at transmission level (69 kV or higher).

MONTHLY RATE

Delivery Service Charges:

Customer Charge

Maximum billed demand within the most recent 12 billing months.		
Less than 5,000 kW	$129.11	
5,000 – 9,000 kW	$4,275.98	
Greater than 9,000 kW	$19,450.62	
Distribution Demand Charge ($/kW)		
Maximum billed demand within the most recent 12 billing months.		
Less than 5,000 kW	$2.96	
5,000 – 9,000 kW	$2.29	
Greater than 9,000 kW	$0.15	
Reactive Demand (for each kvar over one-third of kW demand)	$0.50	
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC	
Societal Benefits Charge ($/kWh)		
Clean Energy Program	See Rider SBC	
Universal Service Fund	See Rider SBC	
Lifeline	See Rider SBC	
Uncollectible Accounts	See Rider SBC	
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC	
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC	
CIEP Standby Fee ($/kWh)	See Rider BGS	
Transmission Demand Charge ($/kW)	$2.15	
Reliability Must Run Transmission Surcharge ($/kWh)	$0.003570	$0.003570
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI	

Date of Issue: **Effective Date:**

Issued by:

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service – Section IV Revised Sheet Replaces Revised Sheet No. 31

RATE SCHEDULE DDC
(Direct Distribution Connection)

AVAILABILITY
Available at any point within the Company's existing distribution system where facilities of adequate character exist for the connection of fixed, constant and predictable non-residential loads not to exceed one kilowatt

MONTHLY RATES

Distribution:

Service and Demand (per day per connection)	$0.162252
Energy (per day for each kW of effective load)	$0.781508
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC
Societal Benefits Charge ($/kWh)	
Clean Energy Program	See Rider SBC
Universal Service Fund	See Rider SBC
Lifeline See Rider SBC	
Uncollectible Accounts	See Rider SBC
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC
Transmission Rate ($/kWh)	$0.007706
Reliability Must Run Transmission Surcharge ($/kWh)	$0.003737
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI

CORPORATE BUSINESS TAX (CBT)
Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)
Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

LOAD CONSUMPTION
Effective load shall be determined by the Company and be specified in the contract. Effective load is defined as the sum of the products of the connected load in kilowatts times the percent load on at one time. No changes in attached load may be made by the customer without the permission of the Company and customer shall allow the Company access to his premises to assure conformance with this provision.

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV Revised Sheet Replaces Revised Sheet No. 44

RIDER STB-STANDBY SERVICE
(Applicable to MGS, AGS, TGS and SPP Rate Schedules)

AVAILABILITY
This rider is available to customers having other sources of electrical energy supply, but who desire to purchase Standby Service from the Company. The terms of this rider shall not be available in any month when the customer's Generation Availability for the current and preceding five (5) months does not exceed 50%.

DEFINITIONS

Standby Service:
Standby Service is defined as the additional electrical capacity available to a customer in the event of a forced outage and during a mutually agreed upon customer's scheduled maintenance shutdown of the customer owned electrical energy source.

Standby Service Capacity:
The Standby Service Capacity shall be the maximum electrical capacity in kW supplied by the customer owned electrical energy source during the current and preceding five (5) months. Such Standby Service Capacity may be revised with the Company's approval as changes in the customer's load conditions warrant.

Generation Availability:
Generation Availability is defined as the availability of the customer owned electrical energy source during the current and preceding five (5) months and shall be determined by dividing the Kwhrs produced during this period by the product of the Standby Service Capacity times 4380 hours.

MODIFICATION OF DEMAND DETERMINATION
The monthly billing demand shall be as defined under the "Demand Determination" section of the applicable rate schedule.

The Standby Service Demand shall be the "Standby Service Capacity" as defined above.

During the billing months in which a forced outage or mutually agreed upon customer's scheduled maintenance shutdown occurs, the billing demand will be determined by subtracting the Standby Service Capacity from the total demand and waives the minimum charge provision of the applicable rate schedule. Electric service is provided under the terms of the applicable rate schedule. Total demand is defined as the sum of the Company's demand meter plus demand supplied by the other sources of electrical energy, all computed to the nearest whole kilowatt during a fifteen minute period.

STANDBY SERVICE CHARGE
This rider imposes a Standby Service Charge at the following voltage levels:

Tariff	Transmission Stand By Rate ($/kW)	Distribution Stand By Rate ($/kW)
MGS-Secondary	$0.35	$0.11
MGS Primary	$0.25	$0.14
AGS Secondary	$0.38	$0.96
AGS Primary	$0.39	$0.77
TGS Sub Transmission	$0.22	$0.00
TGS Transmission	$0.22	$0.00

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

RIDER (BGS) continued
Basic Generation Service (BGS)

CIEP Standby Fee $0.000160 per kWh
This charge recovers the costs associated with the winning BGS-CIEP bidders maintaining the availability of the hourly priced default electric supply service plus administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT. This charge is assessed on all kWhs delivered to all CIEP- eligible customers on Rate Schedules MGS Secondary, MGS Primary, AGS Secondary, AGS Primary or TGS.

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

	Rate Class							
	RS	MGS Secondary	MGS Primary	AGS Secondary	AGS Primary	TGS	SPL/ CSL	DDC
VEPCo	0.000203	0.000168	0.000166	0.000116	0.000095	0.000084	-	0.000081
TrAILCo	0.000276	0.000230	0.000228	0.000159	0.000129	0.000116	-	0.000111
PSE&G	0.000484	0.000403	0.000399	0.000277	0.000226	0.000203	-	0.000194
PATH	(0.000094)	(0.000079)	(0.000078)	(0.000054)	(0.000044)	(0.000039)	-	(0.000037)
PPL	0.000112	0.000093	0.000092	0.000064	0.000052	0.000047	-	0.000045
PECO	0.000197	0.000164	0.000162	0.000113	0.000093	0.000082	-	0.000079
Pepco	0.000020	0.000017	0.000017	0.000012	0.000010	0.000009	-	0.000009
MAIT	0.000030	0.000026	0.000025	0.000017	0.000014	0.000013		0.000012
JCP&L	0.000003	0.000002	0.000002	0.000002	0.000001	0.000001	-	0.000001
EL05-121	(0.000814)	(0.000677)	(0.000671)	(0.000468)	(0.000381)	(0.000340)		(0.000326)
Delmarva	0.000001	0.000001	0.000001	-	-	-	-	-
BG&E	0.000039	0.000033	0.000032	0.000022	0.000018	0.000016	-	0.000016
AEP - East	0.000070	0.000059	0.000058	0.000041	0.000033	0.000030	-	0.000028
Total	0.000527	0.000440	0.000433	0.000301	0.000246	0.000222	-	0.000213

Date of Issue: **Effective Date:**

Issued by:

ATLANTIC CITY ELECTRIC
Proposed Transmission Rate Design
Formula Rate Effective July 1, 2018

Line			
1	Transmission Service Annual Revenue Requirement	$	136,632,319
2	Less Total Schedule 12 TEC Included in Line (1)	$	(10,761,631)
3	ACE Customer Share of Schedule 12 TEC included in Line 2	$	5,640,237
4	Total Transmission Costs Borne by ACE Customers	$	131,510,925
5	2018 ACE Newtwork Service Peak		2,541
6	2018 Network Integration Transmission Service Rate (per MW Per Year)	**$**	**51,759.65**

PJM Schedule 12 - Transmission Enhancement Charges for June 2018 - May 2019
Calculation of costs and monthly PJM charges for ACE Projects

	Required Transmission Enhancement *per PJM website*	**PJM Upgrade ID** *per PJM spreadsheet*		**June 2018 - May 2019 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share** *per PJM Open Access Transmission Tariff*		**ACE Zone Charges**
7	Upgrade AE portion of Delco Tap	b0265	$	501,690	89.87%	$	450,869
8	Replace Monroe 230/69 kV TXfmrs	b0276	$	772,567	91.46%	$	706,590
9	Reconductor Union - Corson 138 kV	b0211	$	1,317,619	65.23%	$	859,483
10	New 500/230 Kv Sub on Salem-East Windsor (>500 kV portion)	b0210.A	$	1,310,850	1.66%	$	21,760
11	Replace line trap-Keeney	b0210.A_dfax	$	1,310,850	63.29%	$	829,637
12	New 500/230kV Sub on Salem-East Windsor (< 500kV) portion[2]	b0210.B	$	1,869,368	65.23%	$	1,219,389
13	Reconductor the existing Mickleton - Goucestr 230 kV circuit (AE portion)	b1398.5	$	469,607	0.00%	$	-
14	Build second 230kV parallel from Mickelton to Gloucester	b1398.3.1	$	1,468,794	0.00%	$	-
15	Upgrade to Mill T2 138/69 kV transformer	b1600	$	1,740,287	89.21%	$	1,552,510
	Total			**$10,761,631**			**$5,640,237**

Atlantic City Electric Company
Proposed Transmission Rate Design
Formula Rate Effective July 1, 2018
Change in FERC Formual Based Rate

	2017 Booked Total Revenue ($)	Annualized Transmission Revenue based on Current Billing Determinants ($)	Transmission Peak Load Share (kW)	Transmission Revenue based on Peak Load Share ($)	Increase/(Decrease) ($)	(%)
Residential						
Residential	$ 619,204,272	$ 74,229,687	1,439,427	$ 74,687,379	$ 457,692	0.07%
Commercial and Industrial						
MGS Secondary	$ 155,662,730	$ 18,379,130	356,582	$ 18,501,918	$ 122,788	0.08%
MGS Primary	$ 5,722,594	$ 453,788	8,789	$ 456,034	$ 2,246	0.04%
AGS Secondary	$ 120,841,461	$ 19,689,880	381,603	$ 19,800,164	$ 110,284	0.09%
AGS Primary	$ 28,446,328	$ 4,939,537	95,815	$ 4,971,562	$ 32,025	0.11%
TGS - Subtransmission	$ 31,645,550	$ 1,940,512	83,853	$ 4,350,845	$ 2,410,333	7.62%
TGS - Transmission	$ 14,782,273	$ 2,473,834	48,058	$ 2,493,559	$ 19,725	0.13%
SPL/CSL	$ 19,130,073	$ -	-	$ -	$ -	0.00%
DDC	$ 1,015,862	$ 95,803	1,858	$ 96,395	$ 593	0.06%
Subtotal Commercial and Industrial	$ 377,246,871	$ 47,972,484	976,557	$ 50,670,477	$ 2,697,993	0.72%
Total Jurisdiction	$ 996,451,143	$ 122,202,171	2,415,984	$ 125,357,856	$ 3,155,685	0.32%

Wholesale Transmission Rate		$ 51.76
Rate Including Regulatory Assessment		$ 51.89

ATLANTIC CITY ELECTRIC
Proposed Transmission Rate Design
Formula Rate Effective July 1, 2018

Residential ("RS")

	Billing Determinants	Rate	Rate w/o SUT	Annualized Present Revenue w/o SUT	Rate Adjustment	Proposed Rate w/o SUT	Proposed Rate w/SUT
kWh	3,888,406,860	$ 0.020355	$ 0.019090	$ 74,229,687	$ 0.000118	$ 0.019208	$ 0.020481
Transmission Rate Change				$ 457,692			

ATLANTIC CITY ELECTRIC
Proposed Transmission Rate Design
Formula Rate Effective July 1, 2018

Monthly General Service - Secondary (MGS Secondary)

	Billing Determinants	Rate	Rate w/o SUT	Annualized Present Revenue w/o SUT	Rate Adjustment	Proposed Rate w/o SUT	Proposed Rate w/SUT
Demand							
SUM > 3 KW	2,987,112	$ 3.43	$ 3.22	$ 9,618,501	$ 0.020000	$ 3.24	$ 3.45
WIN > 3 KW	3,063,157	$ 3.05	$ 2.86	$ 8,760,629	$ 0.020000	$ 2.88	$ 3.07
TOTAL KW	6,050,269			$ 18,379,130			
Transmission Rate Change				$ 122,788			

ATLANTIC CITY ELECTRIC
Proposed Transmission Rate Design
Formula Rate Effective July 1, 2018

Monthly General Service - Primary (MGS Primary)

	Billing Determinants	Rate	Rate w/o SUT	Annualized Present Revenue w/o SUT	Rate Adjustment	Proposed Rate w/o SUT	Proposed Rate w/SUT
Demand							
SUM > 3 KW	87,682	$ 2.42	$ 2.27	$ 199,038	$ 0.01	$ 2.28	$ 2.43
WIN > 3 KW	130,641	$ 2.08	$ 1.95	$ 254,750	$ 0.01	$ 1.96	$ 2.09
TOTAL KW	218,323			$ 453,788			
Transmission Rate Change				$ 2,246			

ATLANTIC CITY ELECTRIC
Proposed Transmission Rate Design
Formula Rate Effective July 1, 2018

Annual General Service Secondary (AGS Secondary)

	Billing Determinants	Rate	Rate w/o SUT	Annualized Present Revenue w/o SUT	Rate Adjustment	Proposed Rate w/o SUT	Proposed Rate w/SUT
Demand KW	5,707,212	$ 3.68	$ 3.45	$ 19,689,880	$ 0.02	$ 3.47	$ 3.70
Transmission Rate Change				$ 110,284			

ATLANTIC CITY ELECTRIC
Proposed Transmission Rate Design
Formula Rate Effective July 1, 2018

Annual General Service Primary (AGS Primary)

	Billing Determinants	Rate	Rate w/o SUT	Annualized Present Revenue w/o SUT	Rate Adjustment	Proposed Rate w/o SUT	Proposed Rate w/SUT
Demand KW	1,387,511	$ 3.80	$ 3.56	$ 4,939,537	$ 0.02	$ 3.58	$ 3.82
Transmission Rate Change				$ 32,025			

ATLANTIC CITY ELECTRIC
Proposed Transmission Rate Design
Formula Rate Effective July 1, 2018

Sub Transmission General Service (TGS)

	Billing Determinants	Rate	Rate w/o SUT	Annualized Present Revenue w/o SUT	Rate Adjustment	Proposed Rate w/o SUT	Proposed Rate w/SUT
Demand KW	1,021,322	$ 2.03	$ 1.90	$ 1,940,512	$ 2.36	$ 4.26	$ 4.54
Transmission Rate Change				$ 2,410,333			

ATLANTIC CITY ELECTRIC
Proposed Transmission Rate Design
Formula Rate Effective July 1, 2018

Transmission General Service (TGS)

	Billing Determinants	Rate	Rate w/o SUT	Annualized Present Revenue w/o SUT	Rate Adjustment	Proposed Rate w/o SUT	Proposed Rate w/SUT
Demand KW	1,236,917	$ 2.13	$ 2.00	$ 2,473,834	$ 0.02	$ 2.02	$ 2.15
Transmission Rate Change				$ 19,725			

ATLANTIC CITY ELECTRIC
Proposed Transmission Rate Design
Formula Rate Effective July 1, 2018

Street and Private Lighting (SPL)
Contributed Street Lighting (CSL)

	Billing Determinants	Rate	Rate w/o SUT	Annualized Present Revenue w/o SUT	Rate Adjustment	Proposed Rate w/o SUT	Proposed Rate w/SUT
Kilowatthour charge							
Annual	72,902,499	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Rate Change				$ -	$ -		

ATLANTIC CITY ELECTRIC
Proposed Transmission Rate Design
Formula Rate Effective July 1, 2018

Direct Distribution Connection (DDC)

	Billing Determinants	Rate	Rate w/o SUT	Annualized Present Revenue w/o SUT	Rate Adjustment	Proposed Rate w/o SUT	Proposed Rate w/SUT
Kilowatthour charge							
Annual	13,337,433	$ 0.007659	$ 0.007183	$ 95,803	$ 0.000044	$ 0.007227	$ 0.007706
Transmission Rate Change				$ 593			

Atlantic City Electric Company
Standby Rate Development
Formula Rate Effective July 1, 2018

Rate Schedule	Demand Rates ($/kW) Transmission	Standby Rates ($/kW) Transmission	Transmission Standby Factor
MGS Secondary	$ 3.45	$ 0.35	0.101604278
MGS Primary	$ 2.43	$ 0.25	0.101604278
AGS Secondary	$ 3.70	$ 0.38	0.101604278
AGS Primary	$ 3.82	$ 0.39	0.101604278
TGS Transmission	$ 2.15	$ 0.22	0.101604278

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

Transmission Enhancement Costs Allocated to ACE Zone (2018)	$	270,252
	$	270,252
2018 ACE Zone Transmission Peak Load (MW)		2,541
Transmission Enhancement Rate ($/MW)	$	106.37

Rate Class	Col. 1 Transmission Obligation (MW)	Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2018 - May 2019 (kWh)	Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)	Col. 5 = Col. 4 x 1/(1-Effective Rate) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)	Col. 6 = Col. 5 x 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,439	$ 1,837,256	4,059,095,046	$ 0.000453	$ 0.000454	$ 0.000484
MGS Secondary	357	$ 455,134	1,208,290,228	$ 0.000377	$ 0.000378	$ 0.000403
MGS Primary	9	$ 11,218	30,079,842	$ 0.000373	$ 0.000374	$ 0.000399
AGS Secondary	382	$ 487,070	1,873,810,489	$ 0.000260	$ 0.000260	$ 0.000277
AGS Primary	96	$ 122,297	576,381,592	$ 0.000212	$ 0.000212	$ 0.000226
TGS	132	$ 168,367	888,340,177	$ 0.000190	$ 0.000190	$ 0.000203
SPL/CSL	0	$ -	69,443,692	$ -	$ -	$ -
DDC	2	$ 2,371	13,058,581	$ 0.000182	$ 0.000182	$ 0.000194
	2,416	$ 3,083,714	8,718,499,648			

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

Transmission Enhancement Costs Allocated to ACE Zone (2018)	$	1,729
	$	1,729
2018 ACE Zone Transmission Peak Load (MW)		2,541
Transmission Enhancement Rate ($/MW)	$	0.68

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2018 - May 2019 (kWh)		Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)		Col. 5 = Col. 4 x 1/(1-Effective Rate) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)		Col. 6 = Col. 5 x 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,439	$	11,754	4,059,095,046	$	0.000003	$	0.000003	$	0.000003
MGS Secondary	357	$	2,912	1,208,290,228	$	0.000002	$	0.000002	$	0.000002
MGS Primary	9	$	72	30,079,842	$	0.000002	$	0.000002	$	0.000002
AGS Secondary	382	$	3,116	1,873,810,489	$	0.000002	$	0.000002	$	0.000002
AGS Primary	96	$	782	576,381,592	$	0.000001	$	0.000001	$	0.000001
TGS	132	$	1,077	888,340,177	$	0.000001	$	0.000001	$	0.000001
SPL/CSL	-	$	-	69,443,692	$	-	$	-	$	-
DDC	2	$	15	13,058,581	$	0.000001	$	0.000001	$	0.000001
	2,416	$	19,729	8,718,499,648						

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

Transmission Enhancement Costs Allocated to ACE Zone (2018)	$	113,302
	$	113,302
2018 ACE Zone Transmission Peak Load (MW)		2,541
Transmission Enhancement Rate ($/MW)	$	44.59

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2018 - May 2019 (kWh)		Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)		Col. 5 = Col. 4 x 1/(1-Effective Rate) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)		Col. 6 = Col. 5 x 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,439	$	770,263	4,059,095,046	$	0.000190	$	0.000190	$	0.000203
MGS Secondary	357	$	190,813	1,208,290,228	$	0.000158	$	0.000158	$	0.000168
MGS Primary	9	$	4,703	30,079,842	$	0.000156	$	0.000156	$	0.000166
AGS Secondary	382	$	204,202	1,873,810,489	$	0.000109	$	0.000109	$	0.000116
AGS Primary	96	$	51,273	576,381,592	$	0.000089	$	0.000089	$	0.000095
TGS	132	$	70,587	888,340,177	$	0.000079	$	0.000079	$	0.000084
SPL/CSL	-	$	-	69,443,692	$	-	$	-	$	-
DDC	2	$	994	13,058,581	$	0.000076	$	0.000076	$	0.000081
	2,416	$	1,292,836	8,718,499,648						

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

Transmission Enhancement Costs Allocated to ACE Zone (2018)	$	(52,755)
	$	(52,755)
2018 ACE Zone Transmission Peak Load (MW)		2,541
Transmission Enhancement Rate ($/MW)	$	(20.76)

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2018 - May 2019 (kWh)		Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)		l. 5 = Col. 4 x 1/(1-Effective Rate) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)		Col. 6 = Col. 5 x 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,439	$	(358,647)	4,059,095,046	$	(0.000088)	$	(0.000088)	$	(0.000094)
MGS Secondary	357	$	(88,846)	1,208,290,228	$	(0.000074)	$	(0.000074)	$	(0.000079)
MGS Primary	9	$	(2,190)	30,079,842	$	(0.000073)	$	(0.000073)	$	(0.000078)
AGS Secondary	382	$	(95,080)	1,873,810,489	$	(0.000051)	$	(0.000051)	$	(0.000054)
AGS Primary	96	$	(23,873)	576,381,592	$	(0.000041)	$	(0.000041)	$	(0.000044)
TGS	132	$	(32,867)	888,340,177	$	(0.000037)	$	(0.000037)	$	(0.000039)
SPL/CSL	-	$	-	69,443,692	$	-	$	-	$	-
DDC	2	$	(463)	13,058,581	$	(0.000035)	$	(0.000035)	$	(0.000037)
	2,416	$	(601,965)	8,718,499,648						

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

Transmission Enhancement Costs Allocated to ACE Zone (2018)	$	154,742
	$	154,742
2018 ACE Zone Transmission Peak Load (MW)		2,541
Transmission Enhancement Rate ($/MW)	$	60.90

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2018 - May 2019 (kWh)		Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)		Col. 5 = Col. 4 x 1/(1-Effective Rate) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)		Col. 6 = Col. 5 x 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,439	$	1,051,982	4,059,095,046	$	0.000259	$	0.000259	$	0.000276
MGS Secondary	357	$	260,602	1,208,290,228	$	0.000216	$	0.000216	$	0.000230
MGS Primary	9	$	6,423	30,079,842	$	0.000214	$	0.000214	$	0.000228
AGS Secondary	382	$	278,888	1,873,810,489	$	0.000149	$	0.000149	$	0.000159
AGS Primary	96	$	70,025	576,381,592	$	0.000121	$	0.000121	$	0.000129
TGS	132	$	96,404	888,340,177	$	0.000109	$	0.000109	$	0.000116
SPL/CSL	0	$	-	69,443,692	$	-	$	-	$	-
DDC	2	$	1,358	13,058,581	$	0.000104	$	0.000104	$	0.000111
	2,416	$	1,765,683	8,718,499,648						

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

Transmission Enhancement Costs Allocated to ACE Zone (2018)	$	407
	$	407
2018 ACE Zone Transmission Peak Load (MW)		2,541
Transmission Enhancement Rate ($/MW-Month)	$	0.16

Rate Class	Col. 1 Transmission Obligation (MW)	Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2018 - May 2019 (kWh)	Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)	Col. 5 = Col. 4 x 1/(1-Effective Rate) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)	Col. 6 = Col. 5 x 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,439	$ 2,768	4,059,095,046	$ 0.000001	$ 0.000001	$ 0.000001
MGS Secondary	357	$ 686	1,208,290,228	$ 0.000001	$ 0.000001	$ 0.000001
MGS Primary	9	$ 17	30,079,842	$ 0.000001	$ 0.000001	$ 0.000001
AGS Secondary	382	$ 734	1,873,810,489	$ -	$ -	$ -
AGS Primary	96	$ 184	576,381,592	$ -	$ -	$ -
TGS	132	$ 254	888,340,177	$ -	$ -	$ -
SPL/CSL	0	$ -	69,443,692	$ -	$ -	$ -
DDC	2	$ 4	13,058,581	$ -	$ -	$ -
	2,416	$ 4,646	8,718,499,648			

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

Transmission Enhancement Costs Allocated to ACE Zone (2018)	$	11,314
	$	11,314
2018 ACE Zone Transmission Peak Load (MW)		2,541
Transmission Enhancement Rate ($/MW-Month)	$	4.45

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2018 - May 2019 (kWh)		Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)		Col. 5 = Col. 4 x 1/(1-Effective Rate) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)		Col. 6 = Col. 5 x 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,439	$	76,915	4,059,095,046	$	0.000019	$	0.000019	$	0.000020
MGS Secondary	357	$	19,054	1,208,290,228	$	0.000016	$	0.000016	$	0.000017
MGS Primary	9	$	470	30,079,842	$	0.000016	$	0.000016	$	0.000017
AGS Secondary	382	$	20,391	1,873,810,489	$	0.000011	$	0.000011	$	0.000012
AGS Primary	96	$	5,120	576,381,592	$	0.000009	$	0.000009	$	0.000010
TGS	132	$	7,049	888,340,177	$	0.000008	$	0.000008	$	0.000009
SPL/CSL	0	$	-	69,443,692	$	-	$	-	$	-
DDC	2	$	99	13,058,581	$	0.000008	$	0.000008	$	0.000009
	2,416	$	129,096	8,718,499,648						

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

Transmission Enhancement Costs Allocated to ACE Zone (2018)	$	62,499
	$	62,499
2018 ACE Zone Transmission Peak Load (MW)		2,541
Transmission Enhancement Rate ($/MW-Month)	$	24.60

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2018 - May 2019 (kWh)		Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)		Col. 5 = Col. 4 x 1/(1-Effective Rate) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)		Col. 6 = Col. 5 x 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,439	$	424,885	4,059,095,046	$	0.000105	$	0.000105	$	0.000112
MGS Secondary	357	$	105,254	1,208,290,228	$	0.000087	$	0.000087	$	0.000093
MGS Primary	9	$	2,594	30,079,842	$	0.000086	$	0.000086	$	0.000092
AGS Secondary	382	$	112,640	1,873,810,489	$	0.000060	$	0.000060	$	0.000064
AGS Primary	96	$	28,282	576,381,592	$	0.000049	$	0.000049	$	0.000052
TGS	132	$	38,937	888,340,177	$	0.000044	$	0.000044	$	0.000047
SPL/CSL	-	$	-	69,443,692	$	-	$	-	$	-
DDC	2	$	548	13,058,581	$	0.000042	$	0.000042	$	0.000045
	2,416	$	713,141	8,718,499,648						

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

Transmission Enhancement Costs Allocated to ACE Zone (2018)	$	22,082
	$	22,082
2018 ACE Zone Transmission Peak Load (MW)		2,541
Transmission Enhancement Rate ($/MW-Month)	$	8.69

Rate Class	Col. 1 Transmission Obligation (MW)	Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2018 - May 2019 (kWh)	Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)	Col. 5 = Col. 4 x 1/(1-Effective Rate) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)	Col. 6 = Col. 5 x 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,439	$ 150,118	4,059,095,046	$ 0.000037	$ 0.000037	$ 0.000039
MGS Secondary	357	$ 37,188	1,208,290,228	$ 0.000031	$ 0.000031	$ 0.000033
MGS Primary	9	$ 917	30,079,842	$ 0.000030	$ 0.000030	$ 0.000032
AGS Secondary	382	$ 39,797	1,873,810,489	$ 0.000021	$ 0.000021	$ 0.000022
AGS Primary	96	$ 9,993	576,381,592	$ 0.000017	$ 0.000017	$ 0.000018
TGS	132	$ 13,757	888,340,177	$ 0.000015	$ 0.000015	$ 0.000016
SPL/CSL	0	$ -	69,443,692	$ -	$ -	$ -
DDC	2	$ 194	13,058,581	$ 0.000015	$ 0.000015	$ 0.000016
	2,416	$ 251,963	8,718,499,648			

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

Transmission Enhancement Costs Allocated to ACE Zone (2018)	$ 16,997
	$ 16,997
2018 ACE Zone Transmission Peak Load (MW)	2,541
Transmission Enhancement Rate ($/MW-Month)	$ 6.69

Rate Class	Col. 1 Transmission Obligation (MW)	Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2018 - May 2019 (kWh)	Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)	Col. 5 = Col. 4 x 1/(1-Effective Rate) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)	Col. 6 = Col. 5 x 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,439	$ 115,553	4,059,095,046	$ 0.000028	$ 0.000028	$ 0.000030
MGS Secondary	357	$ 28,625	1,208,290,228	$ 0.000024	$ 0.000024	$ 0.000026
MGS Primary	9	$ 706	30,079,842	$ 0.000023	$ 0.000023	$ 0.000025
AGS Secondary	382	$ 30,634	1,873,810,489	$ 0.000016	$ 0.000016	$ 0.000017
AGS Primary	96	$ 7,692	576,381,592	$ 0.000013	$ 0.000013	$ 0.000014
TGS	132	$ 10,589	888,340,177	$ 0.000012	$ 0.000012	$ 0.000013
SPL/CSL	0	$ -	69,443,692	$ -	$ -	$ -
DDC	2	$ 149	13,058,581	$ 0.000011	$ 0.000011	$ 0.000012
	2,416	$ 193,948	8,718,499,648			

Atlantic City Electric Company
Proposed EL05-121 Transmission Enhancement Charge effective July 1, 2018

Transmission Enhancement Costs Allocated to ACE Zone (July 2018 - Jun 2019)	$	(455,201)
	$	(455,201)
2018 ACE Zone Transmission Peak Load (MW)		2,541
Transmission Enhancement Rate ($/MW)	$	(179.16)

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales Jun 2018 - May 2019 (kWh)		Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)		Col. 5 = Col. 4 x 1/(1-Effective Rate) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)		Col. 6 = Col. 5 x 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,439	$	(3,094,593)	4,059,095,046	$	(0.000762)	$	(0.000763)	$	(0.000814)
MGS Secondary	357	$	(766,608)	1,208,290,228	$	(0.000634)	$	(0.000635)	$	(0.000677)
MGS Primary	9	$	(18,895)	30,079,842	$	(0.000628)	$	(0.000629)	$	(0.000671)
AGS Secondary	382	$	(820,399)	1,873,810,489	$	(0.000438)	$	(0.000439)	$	(0.000468)
AGS Primary	96	$	(205,991)	576,381,592	$	(0.000357)	$	(0.000357)	$	(0.000381)
TGS	132	$	(283,591)	888,340,177	$	(0.000319)	$	(0.000319)	$	(0.000340)
SPL/CSL	-	$	-	69,443,692	$	-	$	-	$	-
DDC	2	$	(3,994)	13,058,581	$	(0.000306)	$	(0.000306)	$	(0.000326)
	2,416	$	(5,194,071)	8,718,499,648						

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

Transmission Enhancement Costs Allocated to ACE Zone (2018)	$	110,507
	$	110,507
2018 ACE Zone Transmission Peak Load (MW)		2,541
Transmission Enhancement Rate ($/MW)	$	43.49

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales Jun 2018 - May 2019 (kWh)		Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)		Col. 5 = Col. 4 x 1/(1-Effective Rate) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)		Col. 6 = Col. 5 x 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,439	$	751,257	4,059,095,046	$	0.000185	$	0.000185	$	0.000197
MGS Secondary	357	$	186,105	1,208,290,228	$	0.000154	$	0.000154	$	0.000164
MGS Primary	9	$	4,587	30,079,842	$	0.000152	$	0.000152	$	0.000162
AGS Secondary	382	$	199,164	1,873,810,489	$	0.000106	$	0.000106	$	0.000113
AGS Primary	96	$	50,007	576,381,592	$	0.000087	$	0.000087	$	0.000093
TGS	132	$	68,846	888,340,177	$	0.000077	$	0.000077	$	0.000082
SPL/CSL	-	$	-	69,443,692	$	-	$	-	$	-
DDC	2	$	970	13,058,581	$	0.000074	$	0.000074	$	0.000079
	2,416	$	1,260,935	8,718,499,648						

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

Transmission Enhancement Costs Allocated to ACE Zone (2018)	$ 39,326
	$ 39,326
2018 ACE Zone Transmission Peak Load (MW)	2,541
Transmission Enhancement Rate ($/MW-Month)	$ 15.48

Rate Class	Col. 1 Transmission Obligation (MW)	Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales Jun 2018 - May 2019 (kWh)	Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)	Col. 5 = Col. 4 x 1/(1-Effective Rate) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)	Col. 6 = Col. 5 x 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,439	$ 267,349.25	4,059,095,046	$ 0.000066	$ 0.000066	$ 0.000070
MGS Secondary	357	$ 66,229	1,208,290,228	$ 0.000055	$ 0.000055	$ 0.000059
MGS Primary	9	$ 1,632	30,079,842	$ 0.000054	$ 0.000054	$ 0.000058
AGS Secondary	382	$ 70,876	1,873,810,489	$ 0.000038	$ 0.000038	$ 0.000041
AGS Primary	96	$ 17,796	576,381,592	$ 0.000031	$ 0.000031	$ 0.000033
TGS	132	$ 24,500	888,340,177	$ 0.000028	$ 0.000028	$ 0.000030
SPL/CSL	-	$ -	69,443,692	$ -	$ -	$ -
DDC	2	$ 345	13,058,581	$ 0.000026	$ 0.000026	$ 0.000028
	2,416	$ 448,728	8,718,499,648			

Attachment 5a (RECO Pro-forma Tariff Sheets)
Attachment 5b (RECO –Translation of PSE&G TEC into Customer Rates)
Attachment 5c (RECO Translation of JCP&L TEC into Customer Rates)
Attachment 5d (RECO Translation of ACE TEC into Customer Rates)
Attachment 5e (RECO Translation of VEPCo TEC into Customer Rates)
Attachment 5f (RECO Translation of PATH TEC into Customer Rates)
Attachment 5g (RECO Translation of TrailCo TEC into Customer Rates)
Attachment 5h (RECO Translation of Delmarva TEC into Customer Rates)
Attachment 5i (RECO Translation of PEPCo TEC into Customer Rates)
Attachment 5j (RECO Translation of PPL TEC into Customer Rates)
Attachment 5k (RECO Translation of BG&E TEC into Customer Rates)
Attachment 5l (RECO Translation of MAIT TEC into Customer Rates)
Attachment 5m (RECO Translation of EL05-121 into Customer Rates)
Attachment 5n (RECO Translation of PECO TEC into Customer Rates)
Attachment 5o (RECO Translation of AEP TEC into Customer Rates)

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SERVICE CLASSIFICATION NO. 1
RESIDENTIAL SERVICE (Continued)

RATE – MONTHLY (Continued)

(3) Transmission Charges

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

	Summer Months*	Other Months
All kWh .... @	1.583 ¢ per kWh	1.583 ¢ per kWh

(b) Transmission Surcharge – This charge is applicable to all customers taking Basic Generation Service from the Company and includes surcharges related to Reliability Must Run, EL05-121 Settlement and Transmission Enhancement Charges.

All kWh .... @	1.805 ¢ per kWh	1.805 ¢ per kWh

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

The provisions of the Company’s Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, Securitization Charges, and the Temporary Tax Act Credit as described in General Information Section Nos. 33, 34, 35, and 36, 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, EL05-121 Settlement and Transmission Enhancement Charges.

	Summer Months*	Other Months
Secondary Voltage Service Only		
All kWh ....@	1.089 ¢ per kWh	1.089 ¢ per kWh
Primary Voltage Service Only		
All kWh ....@	1.127 ¢ per kWh	1.127 ¢ per kWh

(4) Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, Securitization Surcharges, and Temporary Tax Act Credit

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

* Definition of Summer Billing Months - June through September

(Continued)

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

RATE – MONTHLY (Continued)

(3) Transmission Charge

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

	Summer Months*	Other Months
Peak All kWh measured between 10:00 a.m. and 10:00 p.m., Monday through Friday .....@	1.583 ¢ per kWh	1.583 ¢ per kWh
Off-Peak All other kWh ......@	1.583 ¢ per kWh	1.583 ¢ per kWh

(b) Transmission Surcharge – This charge is applicable to all customers taking Basic Generation Service from the Company and includes surcharges related to Reliability Must Run, EL05-121 Settlement and Transmission Enhancement Charges.

All kWh .....@	1.192 ¢ per kWh	1.192 ¢ per kWh

(4) Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, Securitization Charges, and Temporary Tax Act Credit

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

* Definition of Summer Billing Months - June through September

(Continued)

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

RATE - MONTHLY (Continued)

(3) Transmission Charge

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

	Summer Months*	Other Months
All kWh ……….. @	1.583 ¢ per kWh	1.583 ¢ per kWh

(b) Transmission Surcharge – This charge is applicable to all customers taking Basic Generation Service from the Company and includes surcharges related to Reliability Must Run, EL05-121 Settlement and Transmission Enhancement Charges.

All kWh ……….. @	1.143 ¢ per kWh	1.143 ¢ per kWh

(4) Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, Securitization Charges, and Temporary Tax Act Credit

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

* Definition of Summer Billing Months - June through September

(Continued)

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

RATE– MONTHLY (Continued)

(3) Transmission Charges (Continued)

(a) (Continued)

		Primary	High Voltage Distribution
Demand Charge			
Period I	All kW @	$2.55 per kW	$2.55 per kW
Period II	All kW @	0.67 per kW	0.67 per kW
Period III	All kW @	2.55 per kW	2.55 per kW
Period IV	All kW @	0.67 per kW	0.67 per kW
Usage Charge			
Period I	All kWh @	0.421 ¢ per kWh	0.421 ¢ per kWh
Period II	All kWh @	0.421 ¢ per kWh	0.421 ¢ per kWh
Period III	All kWh @	0.421 ¢ per kWh	0.421 ¢ per kWh
Period IV	All kWh @	0.421 ¢ per kWh	0.421 ¢ per kWh

(b) Transmission Surcharge – This charge is applicable to all customers taking Basic Generation Service from the Company and includes surcharges related to Reliability Must Run, EL05-121 Settlement and Transmission Enhancement Charges.

		Primary	High Voltage Distribution
All Periods	All kWh @	0.668 ¢ per kWh	0.668 ¢ per kWh

(4) Societal Benefits Charge, Regional Greenhouse Gas Initiative Surcharge, Securitization Charges, and Temporary Tax Act Credit

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

(Continued)

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

SPECIAL PROVISIONS

(A) Space Heating

Customers who take service under this classification for 10 kW or more of permanently installed space heating equipment may elect to have the electricity for this service billed separately. All monthly use shall be billed at a Distribution Charge of 2.883 ¢ per kWh during the billing months of October through May and 4.662 ¢ per kWh during the summer billing months, a Transmission Charge of 0.421 ¢ per kWh and a Transmission Surcharge of 0.668 ¢ per kWh during all billing months. The applicability of Transmission Charges and the Transmission Surcharge is described in Part (3) of RATE – MONTHLY.

When this option is requested it shall apply for at least 12 months and shall be subject to a minimum charge of $26.87 per year per kW of space heating capacity. This provision applies for both heating and cooling where the two services are combined by the manufacturer in a single self-contained unit.

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

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

(B) Budget Billing Plan

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

(Continued)

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (PSE&G Project) effective October 1, 2018
To reflect FERC-approved PSE&G Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period July 2018 to June 2019

2018/2019 Average Monthly PSE&G-TEC Costs Allocated to RECO	$	811,572	(1)
2018 RECO Zone Transmission Peak Load (MW)		445.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	1,820.54	
SUT		6.625%	

	Col. 1	Col. 2	Col.3=Col.2 x $811,572 x 12	Col. 4	Col. 5 = Col. 3/Col. 4	Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)	Allocated Cost Recovery (1)	BGS Eligible Sales July 2018- June 2019 (kWh)	Transmission Enhancement Charge ($/kWh)	Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	268.6	60.25%	$ 5,867,248	676,513,000	$ 0.00867	$ 0.00924
SC2 Secondary	124.9	28.02%	$ 2,729,237	523,253,000	$ 0.00522	$ 0.00557
SC2 Primary	15.7	3.52%	$ 342,632	63,350,000	$ 0.00541	$ 0.00577
SC3	0.1	0.02%	$ 1,540	269,000	$ 0.00572	$ 0.00610
SC4	0.0	0.00%	$ -	6,486,000	$ -	$ -
SC5	3.6	0.81%	$ 79,017	14,392,000	$ 0.00549	$ 0.00585
SC6	0.0	0.00%	$ -	5,587,000	$ -	$ -
SC7	32.9	7.38%	$ 719,191	223,900,000	$ 0.00321	$ 0.00342
Total	445.8 (2)	100.00%	$ 9,738,865	1,513,750,000		

(1) Attachment 4 - Cost Allocation of PSE&G Project Schedule 12 Charges to RECO Zone for July 2018 through June 2019
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales Jan - Dec @ cust (RECO Eastern Division)		1,240,830	MWH
2	BGS-RSCP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)		1,155,097	MWH
3	BGS-RSCP Eligible Transmission Obligation		413	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	9,027,406.75	= Line 3 x $1820.54 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	7.82	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (JCP&L) effective October 1, 2018
To reflect FERC-approved JCP&L Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period July 2018 to June 2019

2018/2019 Average Monthly JCP&L-TEC Costs Allocated to RECO	$	27,195	(1)
2018 RECO Zone Transmission Peak Load (MW)		445.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	61.00	
SUT		6.625%	

	Col. 1	Col. 2		Col.3=Col.2 x $27,195 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales July 2018- June 2019 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	268.6	60.25%	$	196,605	676,513,000	$	0.00029	$	0.00031
SC2 Secondary	124.9	28.02%	$	91,454	523,253,000	$	0.00017	$	0.00018
SC2 Primary	15.7	3.52%	$	11,481	63,350,000	$	0.00018	$	0.00019
SC3	0.1	0.02%	$	52	269,000	$	0.00019	$	0.00020
SC4	0.0	0.00%	$	-	6,486,000	$	-	$	-
SC5	3.6	0.81%	$	2,648	14,392,000	$	0.00018	$	0.00019
SC6	0.0	0.00%	$	-	5,587,000	$	-	$	-
SC7	32.9	7.38%	$	24,099	223,900,000	$	0.00011	$	0.00012
Total	445.8 (2)	100.00%	$	326,339	1,513,750,000				

(1) Attachment 2 - Cost Allocation of JCP&L Schedule 12 Charges to RECO Zone for July 2018 to June 2019
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales Jan - Dec @ cust (RECO Eastern Division)		1,240,830	MWH
2	BGS-RSCP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)		1,155,097	MWH
3	BGS-RSCP Eligible Transmission Obligation		413	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	302,477.18	= Line 3 x $61 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.26	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (ACE) effective October 1, 2018
To reflect FERC-approved ACE Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period July 2018 to June 2019

2018/2019 Average Monthly ACE-TEC Costs Allocated to RECO	$	2,817	(1)
2018 RECO Zone Transmission Peak Load (MW)		445.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	6.32	
SUT		6.625%	

	Col. 1	Col. 2		Col.3=Col.2 x $2,817 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales July 2018- June 2019 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	268.6	60.25%	$	20,366	676,513,000	$	0.00003	$	0.00003
SC2 Secondary	124.9	28.02%	$	9,474	523,253,000	$	0.00002	$	0.00002
SC2 Primary	15.7	3.52%	$	1,189	63,350,000	$	0.00002	$	0.00002
SC3	0.1	0.02%	$	5	269,000	$	0.00002	$	0.00002
SC4	0.0	0.00%	$	-	6,486,000	$	-	$	-
SC5	3.6	0.81%	$	274	14,392,000	$	0.00002	$	0.00002
SC6	0.0	0.00%	$	-	5,587,000	$	-	$	-
SC7	32.9	7.38%	$	2,496	223,900,000	$	0.00001	$	0.00001
Total	445.8 (2)	100.00%	$	33,804	1,513,750,000				

(1) Attachment 2 - Cost Allocation of ACE Schedule 12 Charges to RECO Zone for July 2018 to June 2019
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales May - Apr @ cust (RECO Eastern Division)		1,240,830	MWH
2	BGS-RSCP Eligible Sales May - Apr @ trans node (RECO Eastern Division)		1,155,097	MWH
3	BGS-RSCP Eligible Transmission Obligation		413	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	31,338.62	= Line 3 x $6.32 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.03	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (VEPCo) effective October 1, 2018
To reflect FERC-approved VEPCo Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period July 2018 through June 2019

2018/2019 Average Monthly VEPCo-TEC Costs Allocated to RECO	$	17,226	(1)
2018 RECO Zone Transmission Peak Load (MW)		445.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	38.64	
SUT		6.625%	

	Col. 1	Col. 2		Col.3=Col.2 x $17,226 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales July 2018- June 2019 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	268.6	60.25%	$	124,536	676,513,000	$	0.00018	$	0.00019
SC2 Secondary	124.9	28.02%	$	57,930	523,253,000	$	0.00011	$	0.00012
SC2 Primary	15.7	3.52%	$	7,273	63,350,000	$	0.00011	$	0.00012
SC3	0.1	0.02%	$	33	269,000	$	0.00012	$	0.00013
SC4	0.0	0.00%	$	-	6,486,000	$	-	$	-
SC5	3.6	0.81%	$	1,677	14,392,000	$	0.00012	$	0.00013
SC6	0.0	0.00%	$	-	5,587,000	$	-	$	-
SC7	32.9	7.38%	$	15,265	223,900,000	$	0.00007	$	0.00007
Total	445.8 (2)	100.00%	$	206,714	1,513,750,000				

(1) Attachment 4 - Cost Allocation of VEPCo Schedule 12 Charges to RECO Zone for July 2018 through June 2019
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales Jan - Dec @ cust (RECO Eastern Division)		1,240,830	MWH
2	BGS-RSCP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)		1,155,097	MWH
3	BGS-RSCP Eligible Transmission Obligation		413	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	191,601.94	= Line 3 x $38.64 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.17	= Line 4/Line 2

Rockland Electric Company

Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (PATH) effective October 1, 2018
To reflect FERC-approved PATH Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period July 2018 to June 2019.

2018/2019 Average Monthly PATH-TEC Costs Allocated to RECO	$	(6,723)	(1)
2018 RECO Zone Transmission Peak Load (MW)		445.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	(15.08)	
SUT		6.625%	

	Col. 1	Col. 2	Col.3=Col.2 x $-6,723 x 12	Col. 4	Col. 5 = Col. 3/Col. 4	Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)	Allocated Cost Recovery (1)	BGS Eligible Sales July 2018- June 2019 (kWh)	Transmission Enhancement Charge ($/kWh)	Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	268.6	60.25%	$ (48,603)	676,513,000	$ (0.00007)	$ (0.00007)
SC2 Secondary	124.9	28.02%	$ (22,609)	523,253,000	$ (0.00004)	$ (0.00004)
SC2 Primary	15.7	3.52%	$ (2,838)	63,350,000	$ (0.00004)	$ (0.00004)
SC3	0.1	0.02%	$ (13)	269,000	$ (0.00005)	$ (0.00005)
SC4	0.0	0.00%	$ -	6,486,000	$ -	$ -
SC5	3.6	0.81%	$ (655)	14,392,000	$ (0.00005)	$ (0.00005)
SC6	0.0	0.00%	$ -	5,587,000	$ -	$ -
SC7	32.9	7.38%	$ (5,958)	223,900,000	$ (0.00003)	$ (0.00003)
Total	445.8 (2)	100.00%	$ (80,676)	1,513,750,000		

(1) Attachment 4 - Cost Allocation of PATH Project Schedule 12 Charges to RECO Zone for July 2018 through June 2019.
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales Jan - Dec @ cust (RECO Eastern Division)		1,240,830	MWH
2	BGS-RSCP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)		1,155,097	MWH
3	BGS-RSCP Eligible Transmission Obligation		413	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	(74,776.33)	= Line 3 x $-15.08 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	(0.06)	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (TrAILCo) effective October 1, 2018
To reflect FERC-approved TrailCo Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period July 2018 to June 2019

2018/2019 Average Monthly TrAILCo-TEC Costs Allocated to RECO	$	18,183	(1)
2018 RECO Zone Transmission Peak Load (MW)		445.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	40.79	
SUT		6.625%	

	Col. 1	Col. 2		Col.3=Col.2 x $18,183 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales July 2018- June 2019 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	268.6	60.25%	$	131,456	676,513,000	$	0.00019	$	0.00020
SC2 Secondary	124.9	28.02%	$	61,149	523,253,000	$	0.00012	$	0.00013
SC2 Primary	15.7	3.52%	$	7,677	63,350,000	$	0.00012	$	0.00013
SC3	0.1	0.02%	$	35	269,000	$	0.00013	$	0.00014
SC4	0.0	0.00%	$	-	6,486,000	$	-	$	-
SC5	3.6	0.81%	$	1,770	14,392,000	$	0.00012	$	0.00013
SC6	0.0	0.00%	$	-	5,587,000	$	-	$	-
SC7	32.9	7.38%	$	16,113	223,900,000	$	0.00007	$	0.00007
Total	445.8 (2)	100.00%	$	218,200	1,513,750,000				

(1) Attachment 2 - Cost Allocation of TrAILCo Schedule 12 Charges to RECO Zone for July 2018 to June 2019
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales May - Apr @ cust (RECO Eastern Division)		1,240,830	MWH
2	BGS-RSCP Eligible Sales May - Apr @ trans node (RECO Eastern Division)		1,155,097	MWH
3	BGS-RSCP Eligible Transmission Obligation		413	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	202,263.02	= Line 3 x $40.79 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.18	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (Delmarva) effective October 1, 2018
To reflect FERC-approved Delmarva Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period July 2018 to June 2019

2018/2019 Average Monthly Delmarva-TEC Costs Allocated to RECO	$	64	(1)
2018 RECO Zone Transmission Peak Load (MW)		445.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	0.14	
SUT		6.625%	

	Col. 1	Col. 2	Col.3=Col.2 x $064 x 12	Col. 4	Col. 5 = Col. 3/Col. 4	Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)	Allocated Cost Recovery (1)	BGS Eligible Sales July 2018- June 2019 (kWh)	Transmission Enhancement Charge ($/kWh)	Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	268.6	60.25%	$ 461	676,513,000	$ -	$ -
SC2 Secondary	124.9	28.02%	$ 214	523,253,000	$ -	$ -
SC2 Primary	15.7	3.52%	$ 27	63,350,000	$ -	$ -
SC3	0.1	0.02%	$ -	269,000	$ -	$ -
SC4	0.0	0.00%	$ -	6,486,000	$ -	$ -
SC5	3.6	0.81%	$ 6	14,392,000	$ -	$ -
SC6	0.0	0.00%	$ -	5,587,000	$ -	$ -
SC7	32.9	7.38%	$ 57	223,900,000	$ -	$ -
Total	445.8 (2)	100.00%	$ 765	1,513,750,000		

(1) Attachment 2 - Cost Allocation of Delmarva Schedule 12 Charges to RECO Zone for July 2018 to June 2019
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales May - Apr @ cust (RECO Eastern Division)		1,240,830	MWH
2	BGS-RSCP Eligible Sales May - Apr @ trans node (RECO Eastern Division)		1,155,097	MWH
3	BGS-RSCP Eligible Transmission Obligation		413	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	694.21	= Line 3 x $0.14 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	-	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (PEPCO) effective October 1, 2018
To reflect FERC-approved PEPCO Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period July 2018 to June 2019

2018/2019 Average Monthly PEPCO-TEC Costs Allocated to RECO	$	855	(1)
2018 RECO Zone Transmission Peak Load (MW)		445.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	1.92	
SUT		6.625%	

Rate Class	Col. 1 BGS-Eligible Transmission Obligation (MW)	Col. 2 Transmission Obligation (Pct)		Col.3=Col.2 x $855 x 12 Allocated Cost Recovery (1)	Col. 4 BGS Eligible Sales July 2018- June 2019 (kWh)		Col. 5 = Col. 3/Col. 4 Transmission Enhancement Charge ($/kWh)		Col. 6 = Col. 5 x 1.07 Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	268.6	60.25%	$	6,180	676,513,000	$	0.00001	$	0.00001
SC2 Secondary	124.9	28.02%	$	2,875	523,253,000	$	0.00001	$	0.00001
SC2 Primary	15.7	3.52%	$	361	63,350,000	$	0.00001	$	0.00001
SC3	0.1	0.02%	$	2	269,000	$	0.00001	$	0.00001
SC4	0.0	0.00%	$	-	6,486,000	$	-	$	-
SC5	3.6	0.81%	$	83	14,392,000	$	0.00001	$	0.00001
SC6	0.0	0.00%	$	-	5,587,000	$	-	$	-
SC7	32.9	7.38%	$	758	223,900,000	$	-	$	-
Total	445.8 (2)	100.00%	$	10,259	1,513,750,000				

(1) Attachment 2 - Cost Allocation of PEPCO Schedule 12 Charges to RECO Zone for July 2018 to June 2019
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales May - Apr @ cust (RECO Eastern Division)		1,240,830	MWH
2	BGS-RSCP Eligible Sales May - Apr @ trans node (RECO Eastern Division)		1,155,097	MWH
3	BGS-RSCP Eligible Transmission Obligation		413	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	9,520.59	= Line 3 x $1.92 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.01	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (PPL) effective October 1, 2018
To reflect FERC-approved PPL Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period July 2018 to June 2019

2018/2019 Average Monthly PPL-TEC Costs Allocated to RECO	$	84,277	(1)
2018 RECO Zone Transmission Peak Load (MW)		445.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	189.05	
SUT		6.625%	

	Col. 1	Col. 2		Col.3=Col.2 x $84,277 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales July 2018- June 2019 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	268.6	60.25%	$	609,277	676,513,000	$	0.00090	$	0.00096
SC2 Secondary	124.9	28.02%	$	283,414	523,253,000	$	0.00054	$	0.00058
SC2 Primary	15.7	3.52%	$	35,580	63,350,000	$	0.00056	$	0.00060
SC3	0.1	0.02%	$	160	269,000	$	0.00059	$	0.00063
SC4	0.0	0.00%	$	-	6,486,000	$	-	$	-
SC5	3.6	0.81%	$	8,205	14,392,000	$	0.00057	$	0.00061
SC6	0.0	0.00%	$	-	5,587,000	$	-	$	-
SC7	32.9	7.38%	$	74,683	223,900,000	$	0.00033	$	0.00035
Total	445.8 (2)	100.00%	$	1,011,319	1,513,750,000				

(1) Attachment 2 - Cost Allocation of PPL Schedule 12 Charges to RECO Zone for July 2018 to June 2019
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.					
1	BGS-RSCP Eligible Sales May - Apr @ cust (RECO Eastern Division)		1,240,830	MWH	
2	BGS-RSCP Eligible Sales May - Apr @ trans node (RECO Eastern Division)		1,155,097	MWH	
3	BGS-RSCP Eligible Transmission Obligation		413	MW	
4	Transmission Enhancement Costs to RSCP Suppliers	$	937,431.34	= Line 3 x $189.05 * 12	
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.81	= Line 4/Line 2	

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (BG&E) effective October 1, 2018
To reflect FERC-approved BG&E Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period July 2018 to June 2019

2018/2019 Average Monthly BG&E-TEC Costs Allocated to RECO	$	1,272	(1)
2018 RECO Zone Transmission Peak Load (MW)		445.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	2.85	
SUT		6.625%	

	Col. 1	Col. 2	Col.3=Col.2 x $1,272 x 12	Col. 4	Col. 5 = Col. 3/Col. 4	Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)	Allocated Cost Recovery (1)	BGS Eligible Sales July 2018- June 2019 (kWh)	Transmission Enhancement Charge ($/kWh)	Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	268.6	60.25%	$ 9,195	676,513,000	$ 0.00001	$ 0.00001
SC2 Secondary	124.9	28.02%	$ 4,277	523,253,000	$ 0.00001	$ 0.00001
SC2 Primary	15.7	3.52%	$ 537	63,350,000	$ 0.00001	$ 0.00001
SC3	0.1	0.02%	$ 2	269,000	$ 0.00001	$ 0.00001
SC4	0.0	0.00%	$ -	6,486,000	$ -	$ -
SC5	3.6	0.81%	$ 124	14,392,000	$ 0.00001	$ 0.00001
SC6	0.0	0.00%	$ -	5,587,000	$ -	$ -
SC7	32.9	7.38%	$ 1,127	223,900,000	$ 0.00001	$ 0.00001
Total	445.8 (2)	100.00%	$ 15,262	1,513,750,000		

(1) Attachment 2 - Cost Allocation of BG&E Schedule 12 Charges to RECO Zone for July 2018 to June 2019
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales May - Apr @ cust (RECO Eastern Division)		1,240,830	MWH
2	BGS-RSCP Eligible Sales May - Apr @ trans node (RECO Eastern Division)		1,155,097	MWH
3	BGS-RSCP Eligible Transmission Obligation		413	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	14,132.13	= Line 3 x $2.85 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.01	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (MAIT) effective October 1, 2018
To reflect FERC-approved MAIT Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period July 2018 to June 2019

2018/2019 Average Monthly MAIT-TEC Costs Allocated to RECO	$	2,034	(1)
2018 RECO Zone Transmission Peak Load (MW)		445.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	4.56	
SUT		6.625%	

	Col. 1	Col. 2		Col.3=Col.2 x $2,034 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales July 2018- June 2019 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	268.6	60.25%	$	14,707	676,513,000	$	0.00002	$	0.00002
SC2 Secondary	124.9	28.02%	$	6,841	523,253,000	$	0.00001	$	0.00001
SC2 Primary	15.7	3.52%	$	859	63,350,000	$	0.00001	$	0.00001
SC3	0.1	0.02%	$	4	269,000	$	0.00001	$	0.00001
SC4	0.0	0.00%	$	-	6,486,000	$	-	$	-
SC5	3.6	0.81%	$	198	14,392,000	$	0.00001	$	0.00001
SC6	0.0	0.00%	$	-	5,587,000	$	-	$	-
SC7	32.9	7.38%	$	1,803	223,900,000	$	0.00001	$	0.00001
Total	445.8 (2)	100.00%	$	24,412	1,513,750,000				

(1) Attachment 2 - Cost Allocation of MAIT Schedule 12 Charges to RECO Zone for July 2018 to June 2019
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales Jan - Dec @ cust (RECO Eastern Division)		1,240,830	MWH
2	BGS-RSCP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)		1,155,097	MWH
3	BGS-RSCP Eligible Transmission Obligation		413	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	22,611.41	= Line 3 x $4.56 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.02	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (EL05-121 Project) effective October 1, 2018
To reflect FERC-approved EL05-121 Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period July 2018 to June 2019

2018/2019 Average Monthly EL05-121-TEC Costs Allocated to RECO	$	611,364	(1)
2018 RECO Zone Transmission Peak Load (MW)		445.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	1,371.43	
SUT		6.625%	

	Col. 1	Col. 2	Col.3=Col.2 x $611,364 x 12		Col. 4	Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07	
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales July 2018- June 2019 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	268.6	60.25%	$	4,419,846	676,513,000	$	0.00653	$	0.00696
SC2 Secondary	124.9	28.02%	$	2,055,956	523,253,000	$	0.00393	$	0.00419
SC2 Primary	15.7	3.52%	$	258,108	63,350,000	$	0.00407	$	0.00434
SC3	0.1	0.02%	$	1,160	269,000	$	0.00431	$	0.00460
SC4	0.0	0.00%	$	-	6,486,000	$	-	$	-
SC5	3.6	0.81%	$	59,524	14,392,000	$	0.00414	$	0.00441
SC6	0.0	0.00%	$	-	5,587,000	$	-	$	-
SC7	32.9	7.38%	$	541,772	223,900,000	$	0.00242	$	0.00258
Total	445.8 (2)	100.00%	$	7,336,366	1,513,750,000				

(1) Attachment 4 - Cost Allocation of EL05-121 Project Schedule 12 Charges to RECO Zone for July 2018 through June 2019
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales Jan - Dec @ cust (RECO Eastern Division)		1,240,830	MWH
2	BGS-RSCP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)		1,155,097	MWH
3	BGS-RSCP Eligible Transmission Obligation		413	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	6,800,430.88	= Line 3 x $1371.43 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	5.89	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (PECO) effective October 1, 2018
To reflect FERC-approved PECO Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period July 2018 to June 2019

2018/2019 Average Monthly PECO-TEC Costs Allocated to RECO	$	7,525	(1)
2018 RECO Zone Transmission Peak Load (MW)		445.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	16.88	
SUT		6.625%	

	Col. 1	Col. 2		Col.3=Col.2 x $7,525 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales July 2018- June 2019 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	268.6	60.25%	$	54,404	676,513,000	$	0.00008	$	0.00009
SC2 Secondary	124.9	28.02%	$	25,307	523,253,000	$	0.00005	$	0.00005
SC2 Primary	15.7	3.52%	$	3,177	63,350,000	$	0.00005	$	0.00005
SC3	0.1	0.02%	$	14	269,000	$	0.00005	$	0.00005
SC4	0.0	0.00%	$	-	6,486,000	$	-	$	-
SC5	3.6	0.81%	$	733	14,392,000	$	0.00005	$	0.00005
SC6	0.0	0.00%	$	-	5,587,000	$	-	$	-
SC7	32.9	7.38%	$	6,669	223,900,000	$	0.00003	$	0.00003
Total	445.8 (2)	100.00%	$	90,304	1,513,750,000				

(1) Attachment 2 - Cost Allocation of PECO Schedule 12 Charges to RECO Zone for July 2018 to June 2019
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales Jan - Dec @ cust (RECO Eastern Division)		1,240,830	MWH
2	BGS-RSCP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)		1,155,097	MWH
3	BGS-RSCP Eligible Transmission Obligation		413	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	83,701.88	= Line 3 x $16.88 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.07	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (AEP East) effective October 1, 2018
To reflect FERC-approved AEP-East Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period July 2018 to June 2019

2018/2019 Average Monthly AEP-East-TEC Costs Allocated to RECO	$	7,700	(1)
2018 RECO Zone Transmission Peak Load (MW)		445.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	17.27	
SUT		6.625%	

	Col. 1	Col. 2		Col.3=Col.2 x $7,700 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales July 2018 - June 2019 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	268.6	60.25%	$	55,669	676,513,000	$	0.00008	$	0.00009
SC2 Secondary	124.9	28.02%	$	25,895	523,253,000	$	0.00005	$	0.00005
SC2 Primary	15.7	3.52%	$	3,251	63,350,000	$	0.00005	$	0.00005
SC3	0.1	0.02%	$	15	269,000	$	0.00006	$	0.00006
SC4	0.0	0.00%	$	-	6,486,000	$	-	$	-
SC5	3.6	0.81%	$	750	14,392,000	$	0.00005	$	0.00005
SC6	0.0	0.00%	$	-	5,587,000	$	-	$	-
SC7	32.9	7.38%	$	6,824	223,900,000	$	0.00003	$	0.00003
Total	445.8 (2)	100.00%	$	92,404	1,513,750,000				

(1) Attachment 2 - Cost Allocation of AEP East Schedule 12 Charges to RECO Zone for July 2018 through June 2019.
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.					
1	BGS-RSCP Eligible Sales Jun - May @ cust (RECO Eastern Division)		1,240,830	MWH
2	BGS-RSCP Eligible Sales Jun - may @ trans node (RECO Eastern Division)		1,155,097	MWH
3	BGS-RSCP Eligible Transmission Obligation		413	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	85,635.75	= Line 3 x $17.27 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.07	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting proposed changes effective October 1, 2018
To reflect: RMR Costs
FERC-approved ACE Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved AEP-East Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved BG&E Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved Delmarva Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved PATH Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved PEPCO Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved PPL Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved PSE&G Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved TrailCo Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved VEPCo Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved MAIT Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved JCP&L Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved PECO Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved EL05-121 Project Schedule 12 Charges (Schedule 12 PJM OATT)

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

Transmission Project	Note	SC1	SC2 Sec	SC2 Pri	SC3	SC4	SC5	SC6	SC7
Reliability Must Run	(1)	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001
ACE - TEC	(2)	0.00003	0.00002	0.00002	0.00002	0.00000	0.00002	0.00000	0.00001
AEP-East - TEC	(3)	0.00008	0.00005	0.00005	0.00006	0.00000	0.00005	0.00000	0.00003
BG&E- TEC	(4)	0.00001	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00001
Delmarva - TEC	(5)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
PATH - TEC	(6)	(0.00007)	(0.00004)	(0.00004)	(0.00005)	0.00000	(0.00005)	0.00000	(0.00003)
PEPCO - TEC	(7)	0.00001	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00000
PPL - TEC	(8)	0.00090	0.00054	0.00056	0.00059	0.00000	0.00057	0.00000	0.00033
PSE&G - TEC	(9)	0.00867	0.00522	0.00541	0.00572	0.00000	0.00549	0.00000	0.00321
TrAILCo - TEC	(10)	0.00019	0.00012	0.00012	0.00013	0.00000	0.00012	0.00000	0.00007
VEPCo - TEC	(11)	0.00018	0.00011	0.00011	0.00012	0.00000	0.00012	0.00000	0.00007
MAIT -TEC	(12)	0.00002	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00001
JCP&L -TEC	(13)	0.00029	0.00017	0.00018	0.00019	0.00000	0.00018	0.00000	0.00011
PECO -TEC	(14)	0.00008	0.00005	0.00005	0.00005	0.00000	0.00005	0.00000	0.00003
EL05-121	(15)	0.00653	0.00393	0.00407	0.00431	0.00000	0.00414	0.00000	0.00242
Total ($/kWh and excl SUT)		$0.01693	$0.01021	$0.01057	$0.01118	$0.00001	$0.01073	$0.00001	$0.00628
Total (¢/kWh and excl SUT)		1.693 ¢	1.021 ¢	1.057 ¢	1.118 ¢	0.001 ¢	1.073 ¢	0.001 ¢	0.628 ¢

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

Transmission Project	Note	SC1	SC2 Sec	SC2 Pri	SC3	SC4	SC5	SC6	SC7
Reliability Must Run	(1)	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001
ACE - TEC	(2)	0.00003	0.00002	0.00002	0.00002	0.00000	0.00002	0.00000	0.00001
AEP-East - TEC	(3)	0.00009	0.00005	0.00005	0.00006	0.00000	0.00005	0.00000	0.00003
BG&E- TEC	(4)	0.00001	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00001
Delmarva - TEC	(5)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
PATH - TEC	(6)	(0.00007)	(0.00004)	(0.00004)	(0.00005)	0.00000	(0.00005)	0.00000	(0.00003)
PEPCO - TEC	(7)	0.00001	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00000
PPL - TEC	(8)	0.00096	0.00058	0.00060	0.00063	0.00000	0.00061	0.00000	0.00035
PSE&G - TEC	(9)	0.00924	0.00557	0.00577	0.00610	0.00000	0.00585	0.00000	0.00342
TrAILCo - TEC	(10)	0.00020	0.00013	0.00013	0.00014	0.00000	0.00013	0.00000	0.00007
VEPCo - TEC	(11)	0.00019	0.00012	0.00012	0.00013	0.00000	0.00013	0.00000	0.00007
MAIT -TEC	(12)	0.00002	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00001
JCP&L -TEC	(13)	0.00031	0.00018	0.00019	0.00020	0.00000	0.00019	0.00000	0.00012
PECO -TEC	(14)	0.00009	0.00005	0.00005	0.00005	0.00000	0.00005	0.00000	0.00003
EL05-121	(15)	0.00696	0.00419	0.00434	0.00460	0.00000	0.00441	0.00000	0.00258
Total ($/kWh and incl SUT)		$0.01805	$0.01089	$0.01127	$0.01192	$0.00001	$0.01143	$0.00001	$0.00668
Total (¢/kWh and incl SUT)		1.805 ¢	1.089 ¢	1.127 ¢	1.192 ¢	0.001 ¢	1.143 ¢	0.001 ¢	0.668 ¢

Notes:

(1) RMR rates based on allocations by transmission zone.
(2) ACE-TEC rates calculated in Attachment 5 of the joint filing.
(3) AEP-East-TEC rates calculated in Attachment 5 of the joint filing.
(4) BG&E-TEC rates calculated in Attachment 5 of the joint filing.
(5) Delmarva-TEC rates calculated in Attachment 5 of the joint filing.
(6) PATH-TEC rates calculated in Attachment 5 of the joint filing.
(7) PEPCO-TEC rates calculated in Attachment 5 of the joint filing.
(8) PPL-TEC rates calculated in Attachment 5 of the joint filing.
(9) PSE&G-TEC rates calculated in Attachment 5 of the joint filing.
(10) TrAILCo-TEC rates calculated in Attachment 5 of the joint filing.
(11) VEPCo-TEC rates calculated in Attachment 5 of the joint filing.
(12) MAIT-TEC rates calculated in Attachment 5 of the joint filing.
(13) JCP&L-TEC rates calculated in Attachment 5 of the joint filing.
(14) PECO-TEC rates calculated in Attachment 5 of the joint filing.

Attachment 6a (PSE&G Transmission Enhancement Charges)
Attachment 6b (JCP&L Transmission Enhancement Charges)
Attachment 6c (ACE Transmission Enhancement Charges)
Attachment 6d (VEPCo Transmission Enhancement Charges)
Attachment 6e (PATH Transmission Enhancement Charges)
Attachment 6f (TrailCo Transmission Enhancement Charges)
Attachment 6g (Delmarva Transmission Enhancement Charges)
Attachment 6h (PEPCo Transmission Enhancement Charges)
Attachment 6i (PPL East Transmission Enhancement Charges)
Attachment 6j (BG&E Transmission Enhancement Charges)
Attachment 6k (MAIT Transmission Enhancement Charges)
Attachment 6l (EL05-121 Transmission Enhancement Charges)
Attachment 6j (PECO Transmission Enhancement Charges)
Attachment 6k (AEP Transmission Enhancement Charges)

Attachment 6a -PJM Schedule 12 - Transmission Enhancement Charges for July 2018 - December 2018 **Attachment 6a**
Calculation of costs and monthly PJM charges for PSE&G Projects

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				Estimated New Jersey EDC Zone Charges by Project				
Required Transmission Enhancement *per PJM website*	**PJM Upgrade ID** *per PJM spreadsheet*	**Jan - Dec 2018 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share**	**JCP&L Zone Share** *per PJM Open Access Transmission Tariff*	**PSE&G Zone Share1,2**	**RE Zone Share**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
Replace all derated Branchburg 500/230 kava transformers	b0130	$ 1,877,462.00	1.36%	47.76%	50.88%	0.00%	$25,533	$896,676	$955,253	$0	$1,877,462
Reconductor Kittatinny - Newtown 230 kV with 1590 ACSS	b0134	$ 763,586.00	0.00%	51.11%	45.96%	2.93%	$0	$390,269	$350,944	$22,373	$763,586
Build new Essex - Aldene 230 kV cable connected through phase angle regulator at Essex	b0145	$ 8,165,842.00	0.00%	73.45%	21.78%	4.77%	$0	$5,997,811	$1,778,520	$389,511	$8,165,842
Install 230-138kV transformer at Metuchen substation	b0161	$ 2,535,989.00	0.00%	0.00%	99.80%	0.20%	$0	$0	$2,530,917	$5,072	$2,535,989
Build a new 230 kV section from Branchburg - Flagtown and move the Flagtown - Somerville 230 kV circuit to the new section	b0169	$ 1,551,830.00	1.76%	26.50%	60.89%	0.00%	$27,312	$411,235	$944,909	$0	$1,383,456
Reconductor the Flagtown-Somerville-Bridgewater 230 kV circuit with 1590 ACSS	b0170	$ 678,523.00	0.00%	42.95%	38.36%	0.79%	$0	$291,426	$260,281	$5,360	$557,067
Replace wave trap at Branchburg 500kV substation	b0172.2	$ 1,332.00	1.66%	3.74%	6.26%	0.26%	$22	$50	$83	$3	$159
Replace wave trap at Branchburg 500kV substation	b0172.2_dfax	$ 1,332.00	5.32%	33.44%	53.73%	2.16%	$71	$445	$716	$29	$1,261
Replace both 230/138 kV transformers at Roseland	b0274	$ 2,067,525.00	0.00%	0.00%	100.00%	0.00%	$0	$0	$2,067,525	$0	$2,067,525
Branchburg 400 MVAR Capacitor	b0290	$ 3,830,659.50	1.66%	3.74%	6.26%	0.26%	$63,589	$143,267	$239,799	$9,960	$456,615
Branchburg 400 MVAR Capacitor	b0290_dfax	$ 3,830,659.50	5.32%	33.44%	53.73%	2.16%	$203,791	$1,280,973	$2,058,213	$82,742	$3,625,719
Inst Conemaugh 250 MVAR Cap	b0376	$ 147,205.50	1.66%	3.74%	6.26%	0.26%	$2,444	$5,505	$9,215	$383	$17,547
Inst Conemaugh 250 MVAR Cap	b0376_dfax	$ 147,205.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Install 4th 500/230 kV transformer at New Freedom	b0411	$ 2,074,869.00	47.01%	7.04%	22.31%	0.00%	$975,396	$146,071	$462,903	$0	$1,584,370
Saddle Brook - Athenia Upgrade Cable	b0472	$ 1,518,454.00	0.00%	0.00%	96.40%	3.60%	$0	$0	$1,463,790	$54,664	$1,518,454
Build new 500 kV transmission facilities from Pennsylvania - New Jersey border at Bushkill to Roseland (500kV and above elements of the project)	b0489	$ 41,863,323.00	1.66%	3.74%	6.26%	0.26%	$694,931	$1,565,688	$2,620,644	$108,845	$4,990,108
Build new 500 kV transmission facilities from Pennsylvania - New Jersey border at Bushkill to Roseland (500kV and above elements of the project)	b0489_dfax	$ 41,863,323.00	0.00%	39.91%	54.05%	2.18%	$0	$16,707,652	$22,627,126	$912,620	$40,247,399
Build new 500 kV transmission facilities from Pennsylvania - New Jersey border at Bushkill to Roseland (Below 500 kV elements of the project) (In Service)	b0489.4	$ 4,655,898.00	5.14%	33.04%	41.10%	1.53%	$239,313	$1,538,309	$1,913,574	$71,235	$3,762,431
Susquehanna Roseland Breakers (In-Service)	b0489.5	$ 317,504.50	1.66%	3.74%	6.26%	0.26%	$5,271	$11,875	$19,876	$826	$37,847
Susquehanna Roseland Breakers (In-Service)	b0489.5_dfax	$ 317,504.50	0.00%	39.91%	54.05%	2.18%	$0	$126,716	$171,611	$6,922	$305,249
Loop the 5021 circuit into New Freedom 500 kV substation	b0498	$ 1,316,533.50	1.66%	3.74%	6.26%	0.26%	$21,854	$49,238	$82,415	$3,423	$156,931

Calculation of costs and monthly PJM charges for PSE&G Projects

Required Transmission Enhancement *per PJM website*	PJM Upgrade ID *per PJM spreadsheet*	(a) Jan - Dec 2018 Annual Revenue Requirement *per PJM website*	(b) Responsible Customers - Schedule 12 Appendix: ACE Zone Share	(c) JCP&L Zone Share	(d) PSE&G Zone Share1,2	(e) RE Zone Share	(f) Estimated New Jersey EDC Zone Charges by Project: ACE Zone Charges	(g) JCP&L Zone Charges	(h) PSE&G Zone Charges	(i) RE Zone Charges	(j) Total NJ Zones Charges
			per PJM Open Access Transmission Tariff								
Loop the 5021 circuit into New Freedom 500 kV substation	b0498_dfax	$ 1,316,533.50	9.56%	26.03%	41.34%	1.66%	$125,861	$342,694	$544,255	$21,854	$1,034,664
Branchburg-Somerville-Flagtown Reconductor	b0664-b0665	$ 1,963,330.00	0.00%	36.35%	43.24%	1.61%	$0	$713,670	$848,944	$31,610	$1,594,224
Somerville -Bridgewater Reconductor	b0668	$ 676,946.00	0.00%	39.41%	38.76%	1.45%	$0	$266,784	$262,384	$9,816	$538,984
Reconductor Hudson - South Waterfront 230kV circuit	b0813	$ 935,200.00	0.00%	9.92%	83.73%	3.12%	$0	$92,772	$783,043	$29,178	$904,993
New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie	b0814	$ 4,903,080.00	0.00%	23.49%	67.03%	2.50%	$0	$1,151,733	$3,286,535	$122,577	$4,560,845
Reconductor South Mahwah 345 kV J-3410 Circuit	b1017	$ 2,128,153.00	0.00%	29.27%	65.42%	2.55%	$0	$622,910	$1,392,238	$54,268	$2,069,416
Reconductor South Mahwah 345 kV K-3411 Circuit	b1018	$ 2,209,709.00	0.00%	29.44%	65.25%	2.55%	$0	$650,538	$1,441,835	$56,348	$2,148,721
West Orange Conversion (North Central Reliability)	b1154	$ 40,101,459.00	0.00%	0.00%	96.18%	3.82%	$0	$0	$38,569,583	$1,531,876	$40,101,459
Branchburg-Middlesex Sw Rack	b1155	$ 6,761,094.00	0.00%	4.61%	91.75%	3.64%	$0	$311,686	$6,203,304	$246,104	$6,761,094
Conversion	b1156	$ 38,998,661.00	0.00%	0.00%	96.18%	3.82%	$0	$0	$37,508,912	$1,489,749	$38,998,661
Reconf Kearny Loop in P2216	b1589	$ 1,639,441.00	0.00%	0.00%	77.16%	3.08%	$0	$0	$1,264,993	$50,495	$1,315,487
230kV Lawrence Switching Station Upgrade	b1228	$ 2,299,055.00	0.00%	0.00%	96.18%	3.82%	$0	$0	$2,211,231	$87,824	$2,299,055
Ridge Rd 69kV Breaker Station	b1255	$ 1,698,080.00	0.00%	0.00%	96.18%	3.82%	$0	$0	$1,633,213	$64,867	$1,698,080
Northeast Grid Reliability Project	b1304.1-b1304.4	$ 43,961,786.00	0.28%	1.43%	85.73%	3.40%	$123,093	$628,654	$37,688,439	$1,494,701	$39,934,886
Mickleton-Gloucester-Camden	b1398-b1398.7	$ 51,110,727.00	0.00%	13.03%	31.99%	1.27%	$0	$6,659,728	$16,350,322	$649,106	$23,659,156
Aldene-Springfield Rd. Conv	b1399	$ 8,012,066.00	0.00%	0.00%	96.18%	3.82%	$0	$0	$7,706,005	$306,061	$8,012,066
Replace Salem 500 kV breakers	b1410-b1415	$ 821,989.00	1.66%	3.74%	6.26%	0.26%	$13,645	$30,742	$51,457	$2,137	$97,981
Replace Salem 500 kV breakers	b1410-b1416_dfax	$ 821,989.00	0.00%	0.00%	96.13%	3.87%	$0	$0	$790,178	$31,811	$821,989
Uprate Eagle Point-Gloucester 230 kV Circuit	b1588	$ 1,360,297.00	0.00%	10.48%	55.03%	2.19%	$0	$142,559	$748,571	$29,791	$920,921
Upgrade Camden Richmon 230kV	b1590	$ 1,274,565.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
New Cox's Corner-Lumberton 230kV Circuit	b1787	$ 4,013,704.00	4.97%	44.34%	48.23%	1.93%	$199,481	$1,779,676	$1,935,809	$77,464	$3,992,431
Build Mickleton-Gloucester Corridor Ultimate Design	b2139	$ 2,314,572.00	0.00%	0.00%	61.11%	2.44%	$0	$0	$1,414,435	$56,476	$1,470,911
Reconfigure Brunswick New 69kV	b2146	$ 10,815,286.00	0.00%	0.00%	96.16%	3.84%	$0	$0	$10,399,979	$415,307	$10,815,286
Convert Bergen Marion 138 kV to double circuit 345kV and Sub	b2436.10_dfax	$ 11,117,605.00	0.00%	0.00%	100.00%	0.00%	$0	$0	$11,117,605	$0	$11,117,605
Convert Bergen Marion 138 kV to double circuit 345kV and Sub	b2436.10	$ 11,117,605.00	1.66%	3.74%	6.26%	0.26%	$184,552	$415,798	$695,962	$28,906	$1,325,219
Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.21_dfax	$ 3,723,348.50	0.00%	0.00%	100.00%	0.00%	$0	$0	$3,723,349	$0	$3,723,349
Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.21	$ 3,723,348.50	1.66%	3.74%	6.26%	0.26%	$61,808	$139,253	$233,082	$9,681	$443,823
Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.22_dfax	$ 2,819,272.00	0.00%	0.00%	100.00%	0.00%	$0	$0	$2,819,272	$0	$2,819,272
Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.22	$ 2,819,272.00	1.66%	3.74%	6.26%	0.26%	$46,800	$105,441	$176,486	$7,330	$336,057

Attachment 6a -PJM Schedule 12 - Transmission Enhancement Charges for July 2018 - December 2018 Attachment 6a

Calculation of costs and monthly PJM charges for PSE&G Projects

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				Estimated New Jersey EDC Zone Charges by Project				
Required Transmission Enhancement	PJM Upgrade ID	Jan - Dec 2018 Annual Revenue Requirement	ACE Zone Share	JCP&L Zone Share	PSE&G Zone Share1,2	RE Zone Share	ACE Zone Charges	JCP&L Zone Charges	PSE&G Zone Charges	RE Zone Charges	Total NJ Zones Charges
per PJM website	*per PJM spreadsheet*	*per PJM website*	*per PJM Open Access Transmission Tariff*								
Construct New Bayway-Bayonne 345kV Circuit	b2436.33	$ 19,138,377.00	0.00%	0.00%	100.00%	0.00%	$0	$0	$19,138,377	$0	$19,138,377
Construct New North Ave-Bayonne 345kV Circuit	b2436.34	$ 13,179,230.00	0.00%	0.00%	100.00%	0.00%	$0	$0	$13,179,230	$0	$13,179,230
Construct North Ave-Airport 345kV Circuit and Substation Upgrades	b2436.50	$ 6,293,352.00	0.00%	0.00%	100.00%	0.00%	$0	$0	$6,293,352	$0	$6,293,352
Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (CWIP)	b2436.60	$ 5,234,688.00	0.00%	0.00%	96.13%	3.87%	$0	$0	$5,032,106	$202,582	$5,234,688
Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (CWIP)	b2436.70	$ 10,406,460.00	0.00%	0.00%	100.00%	0.00%	$0	$0	$10,406,460	$0	$10,406,460
Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation	b2436.81_dfax	$ 2,769,919.50	0.00%	0.00%	96.13%	3.87%	$0	$0	$2,662,724	$107,196	$2,769,920
Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation	b2436.81	$ 2,769,919.50	1.66%	3.74%	6.26%	0.26%	$45,981	$103,595	$173,397	$7,202	$330,174
Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.83_dfax	$ 2,769,765.00	0.00%	0.00%	96.13%	3.87%	$0	$0	$2,662,575	$107,190	$2,769,765
Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.83	$ 2,769,765.00	1.66%	3.74%	6.26%	0.26%	$45,978	$103,589	$173,387	$7,201	$330,156
Convert Bayway-Linden "W" to 138kV circuit to 345kV	b2436.84_dfax	$ 2,744,165.50	0.00%	0.00%	96.13%	3.87%	$0	$0	$2,637,966	$106,199	$2,744,166
Convert Bayway-Linden "W" to 138kV circuit to 345kV	b2436.84	$ 2,744,165.50	1.66%	3.74%	6.26%	0.26%	$45,553	$102,632	$171,785	$7,135	$327,105
Convert Bayway-Linden "M" to 138kV circuit to 345kV	b2436.85_dfax	$ 2,744,165.50	0.00%	0.00%	96.13%	3.87%	$0	$0	$2,637,966	$106,199	$2,744,166
Convert Bayway-Linden "M" to 138kV circuit to 345kV	b2436.85	$ 2,744,165.50	1.66%	3.74%	6.26%	0.26%	$45,553	$102,632	$171,785	$7,135	$327,105
Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades	b2436.90_dfax	$ 2,038,208.00	0.00%	0.00%	96.13%	3.87%	$0	$0	$1,959,329	$78,879	$2,038,208
Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades	b2436.90	$ 2,038,208.00	1.66%	3.74%	6.26%	0.26%	$33,834	$76,229	$127,592	$5,299	$242,954
New Bergen 345/230 kV transformer and any associated substation upgrades	b2437.10	$ 3,191,830.00	0.00%	0.00%	96.13%	3.87%	$0	$0	$3,068,306	$123,524	$3,191,830
New Bergen 345/138 kV transformer #1 and any associated substation upgrades	b2437.11	$ 3,201,998.00	0.00%	0.00%	100.00%	0.00%	$0	$0	$3,201,998	$0	$3,201,998
New Bayway 345/138 kV transformer #1 and any associated substation upgrades	b2437.20	$ 1,818,772.00	0.00%	0.00%	96.13%	3.87%	$0	$0	$1,748,386	$70,386	$1,818,772

Attachment 6a -PJM Schedule 12 - Transmission Enhancement Charges for July 2018 - December 2018 **Attachment 6a**
Calculation of costs and monthly PJM charges for PSE&G Projects

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				**Estimated New Jersey EDC Zone Charges by Project**				
Required Transmission Enhancement	**PJM Upgrade ID**	**Jan - Dec 2018 Annual Revenue Requirement**	**ACE Zone Share**	**JCP&L Zone Share**	**PSE&G Zone Share1,2**	**RE Zone Share**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
per PJM website	*per PJM spreadsheet*	*per PJM website*	*per PJM Open Access Transmission Tariff*								
New Bayway 345/138 kV transformer #2 and any associated substation upgrades	b2437.21	$ 1,820,116.00	0.00%	0.00%	96.13%	3.87%	$0	$0	$1,749,678	$70,438	$1,820,116
New Linden 345/230 kV transformer and any associated substation upgrades	b2437.30	$ 3,907,406.00	0.00%	0.00%	96.13%	3.87%	$0	$0	$3,756,189	$151,217	$3,907,406
Install two 175 MVAR Re at Hptcg	b2702_dfax	$ 684,363.00	0.00%	0.00%	100.00%	0.00%	$0	$0	$684,363	$0	$684,363
Install two 175 MVAR Re at Hptcg	b2702	$ 684,363.00	1.66%	3.74%	6.26%	0.26%	$11,360	$25,595	$42,841	$1,779	$81,576
Totals		**$ 480,678,136.00**					**$3,243,027**	**$44,132,118**	**$314,039,528**	**$9,738,864**	**$371,153,537**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) +

	(k)	(l)	(m)	(n)	(o)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 2018**	**2018 Trans. Peak Load [2]**	**Rate in $/MW-mo. [1]**	**2018/2019 Impact (12 months)**	
PSE&G	$ 26,169,960.65	9,566.9	$ 2,735.47	$ 314,039,528	
JCP&L	$ 3,677,676.47	5,721.0	$ 642.84	$ 44,132,118	
ACE	$ 270,252.23	2,540.8	$ 106.37	$ 3,243,027	
RE	$ 811,572.03	401.7	$ 2,020.34	$ 9,738,864	
Total Impact on NJ Zones	**$ 30,929,461.38**	**18,230.4**		**$ 371,153,537**	
Notes on calculations >>>			= (k) / (l)	= (k) *12	

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

Attachment 6b -PJM Schedule 12 - Transmission Enhancement Charges for July 2018 - December 2018
Calculation of costs and monthly PJM charges for JCP&L Projects

Attachment 6b

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				Estimated New Jersey EDC Zone Charges by Project				
Required Transmission Enhancement *per PJM website*	**PJM Upgrade ID** *per PJM spreadsheet*	**Jan - Dec 2018 Annual Revenue Requirement** *per PJM spreadsheet*	**ACE Zone Share** *per PJM Open Access Transmission Tariff*	**JCP&L Zone Share**	**PSE&G Zone Share**	**RE Zone Share**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
Upgrade the Portland - Greystone 230kV circuit	b0174	$ 1,273,748	0.00%	35.98%	55.27%	2.99%	$0	$458,295	$704,001	$38,085	$1,200,380
Reconductor the 8 mile Gilbert - Glen Gardner 230kV circuit	b0268	$ 646,180	0.00%	62.43%	33.08%	1.46%	$0	$403,410	$213,756	$9,434	$626,601
Add a 2nd Raritan River 230/115 kV transformer	b0726	$ 846,872	2.45%	97.55%	0.00%	0.00%	$20,748	$826,124	$0	$0	$846,872
Build a new 230kV circuit from Larrabee to Oceanview	b2015	$ 18,839,128	0.00%	37.04%	37.08%	1.48%	$0	$6,978,013	$6,985,549	$278,819	$14,242,381
Totals		**$ 21,605,928**					**$20,748**	**$8,665,841**	**$7,903,306**	**$326,338**	**$16,916,234**
							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	=(f)+(g)+(h)+(i)

	(k)	(l)	(m)	(n)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 2018**	**2018 Trans. Peak Load [1]**	**Rate in $/MW-mo.**	**2018 Impact (12 months)**
PSE&G	$ 658,608.79	9,566.9	$ 68.84	$ 7,903,306
JCP&L	$ 722,153.45	5,721.0	$ 126.23	$ 8,665,841
ACE	$ 1,729.03	2,540.8	$ 0.68	$ 20,748
RE	$ 27,194.87	401.7	$ 67.70	$ 326,338
Total Impact on NJ Zones	**$ 1,409,686**	**18,230.4**		**$ 16,916,234**
			= (k) / (l)	= (k) *12

Note:
1) Data on PJM website

Attachment 6c PJM Schedule 12 - Transmission Enhancement Charges for June 2018 - May 2019 **Attachment 6c**
Calculation of costs and monthly PJM charges for ACE 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*	June 2018 - May 2019 Annual Revenue Requirement *per PJM website*	ACE Zone Share[1]	JCP&L Zone Share[1]	PSE&G Zone Share[1]	RE Zone Share[1] *per PJM Open Access Transmission Tariff*	ACE Zone Charges	JCP&L Zone Charges	PSE&G Zone Charges	RE Zone Charges	Total NJ Zones Charges
Upgrade AE portion of Delco Tap	b0265	$ 501,690	89.87%	9.48%	0.00%	0.00%	$450,869	$47,560	$0	$0	$498,429
Replace Monroe 230/69 kV TXfmrs	b0276	$ 772,567	91.46%	0.00%	8.31%	0.23%	$706,590	$0	$64,200	$1,777	$772,567
Reconductor Union - Corson 138 kV	b0211	$ 1,317,619	65.23%	25.87%	6.35%	0.00%	$859,483	$340,868	$83,669	$0	$1,284,020
New 500/230 Kv Sub on Salem-East Windsor (>500 kV portion)	b0210.A	$ 1,310,850	1.66%	3.74%	6.26%	0.26%	$21,760	$49,026	$82,059	$3,408	$156,253
New 500/230 Kv Sub on Salem-East Windsor (>500 kV portion)	b0210.A_dfax	$ 1,310,850	63.29%	36.71%	0.00%	0.00%	$829,637	$481,213	$0	$0	$1,310,850
New 500/230kV Sub on Salem-East Windsor (< 500kV) portion[2]	b0210.B	$ 1,869,368	65.23%	25.87%	6.35%	0.00%	$1,219,389	$483,606	$118,705	$0	$1,821,699
Reconductor the existing Mickleton – Goucester 230 kV circuit (AE portion)	b1398.5	$ 469,607	0.00%	13.03%	31.99%	1.27%	$0	$61,190	$150,227	$5,964	$217,381
Build second 230kV parallel from Mickelton to Gloucester	b1398.3.1	$ 1,468,794	0.00%	13.03%	31.99%	1.27%	$0	$191,384	$469,867	$18,654	$679,905
Upgrade the Mill T2 138/69 kV Transformer	b1600	$ 1,740,287	89.21%	4.76%	5.80%	0.23%	$1,552,510	$82,838	$100,937	$4,003	$1,740,287
							$5,640,237	**$1,737,684**	**$1,069,664**	**$33,805**	**$8,481,391**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

	(k)	(l)	(m)	(n)	(o)	(p)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 18/19**	**2018TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2018 Impact (7 months)**	**2019 Impact (5 months)**	**2018-2019 Impact (12 months)**
PSE&G	$ 89,138.69	9,566.9	$ 9.32	$ 623,971	$ 445,693	$ 1,069,664
JCP&L	$ 144,806.98	5,721.0	$ 25.31	$ 1,013,649	$ 724,035	$ 1,737,684
ACE	$ 470,019.76	2,540.8	$ 184.99	$ 3,290,138	$ 2,350,099	$ 5,640,237
RE	$ 2,817.12	401.7	$ 7.01	$ 19,720	$ 14,086	$ 33,805
Total Impact on NJ Zones	**$ 706,782.55**			**$ 4,947,478**	**$ 3,533,913**	**$ 8,481,391**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

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

Attachment 6d - PJM Schedule 12 - Transmission Enhancement Charges for July 2018 - December 2018 **Attachment 6d**
Calculation of costs and monthly PJM charges for VEPCO Projects

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				Estimated New Jersey EDC Zone Charges by Project				
Required Transmission Enhancement *per PJM website*	PJM Upgrade ID *per PJM spreadsheet*	Jan - Dec 2018 Annual Revenue Requirement *per PJM website*	ACE Zone Share	JCP&L Zone Share	PSE&G Zone Share1	RE Zone Share	ACE Zone Charges	JCP&L Zone Charges	PSE&G Zone Charges	RE Zone Charges	Total NJ Zones Charges
			per PJM Open Access Transmission Tariff								
Upgrade Mt Storm - Doubs 500kV	b0217	$105,825.38	1.66%	3.74%	6.26%	0.26%	$1,757	$3,958	$6,625	$275	$12,614
Upgrade Mt Storm - Doubs 500kV	b0217_dfax	$105,825.38	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Loudoun 150 MVA capacitor @ 500 kV	b0222	$96,180.47	1.66%	3.74%	6.26%	0.26%	$1,597	$3,597	$6,021	$250	$11,465
Loudoun 150 MVA capacitor @ 500 kV	b0222_dfax	$96,180.47	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
500 kV breakers and bus work at Suffolk	b0231	$1,282,817.34	1.66%	3.74%	6.26%	0.26%	$21,295	$47,977	$80,304	$3,335	$152,912
500 kV breakers and bus work at Suffolk	b0231_dfax	$1,282,817.34	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Meadowbrook-Loudon 500kV circuit	b0328.1	$14,805,815.20	1.66%	3.74%	6.26%	0.26%	$245,777	$553,737	$926,844	$38,495	$1,764,853
Meadowbrook-Loudon 500kV circuit	b0328.1_dfax	$14,805,815.20	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Upgrade Mt. Storm 500 KV Substation	b0328.3	$883,456.88	1.66%	3.74%	6.26%	0.26%	$14,665	$33,041	$55,304	$2,297	$105,308
Upgrade Mt. Storm 500 KV Substation	b0328.3_dfax	$883,456.88	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Upgrade Loudoun 500 KV Substation	b0328.4	$201,055.52	1.66%	3.74%	6.26%	0.26%	$3,338	$7,519	$12,586	$523	$23,966
Upgrade Loudoun 500 KV Substation	b0328.4_dfax	$201,055.52	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Carson – Suffolk 500 kV, Suffolk 500/230 kV transformer & build Suffolk – Trascher 230 kV circuit	B0329.2B	$10,517,965.03	1.66%	3.74%	6.26%	0.26%	$174,598	$393,372	$658,425	$27,347	$1,253,741
Carson – Suffolk 500 kV, Suffolk 500/230 kV transformer & build Suffolk – Trascher 230 kV circuit	B0329.2B_dfax	$10,517,965.03	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
500/230 KV transformer at Bristers, new 230 Bristers - Gainsville circuit	b0227	$2,411,792.43	0.71%	0.00%	0.00%	0.00%	$17,124	$0	$0	$0	$17,124
Rebuild Mt Storm-Doubs 500 KV circuit	b1507	$21,148,429.13	1.66%	3.74%	6.26%	0.26%	$351,064	$790,951	$1,323,892	$54,986	$2,520,893
Rebuild Mt Storm-Doubs 500 KV circuit	b1507_dfax	$21,148,429.13	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Replace wave traps on Dooms-Lexington 500KV circuit	b0457	$6,624.60	1.66%	3.74%	6.26%	0.26%	$110	$248	$415	$17	$790
Replace wave traps on Dooms-Lexington 500KV circuit	b0457_dfax	$6,624.60	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Morrisville H1T573	b1647	$1,011.49	1.66%	3.74%	6.26%	0.26%	$17	$38	$63	$3	$121
Morrisville H1T573	b1647_dfax	$1,011.49	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Morrisville H2T545	b1648	$1,011.49	1.66%	3.74%	6.26%	0.26%	$17	$38	$63	$3	$121
Morrisville H2T545	b1648_dfax	$1,011.49	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Morrisville H1T580	b1649	$53,369.35	1.66%	3.74%	6.26%	0.26%	$886	$1,996	$3,341	$139	$6,362
Morrisville H1T580	b1649_dfax	$53,369.35	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Morrisville H2T569	b1650	$53,369.35	1.66%	3.74%	6.26%	0.26%	$886	$1,996	$3,341	$139	$6,362
Morrisville H2T569	b1650_dfax	$53,369.35	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Replace wave traps on North Anna-Ladysmith 500KV circuit	b0784	$4,596.15	1.66%	3.74%	6.26%	0.26%	$76	$172	$288	$12	$548
Replace wave traps on North Anna-Ladysmith 500KV circuit	b0784_dfax	$4,596.15	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0

Attachment 6d - PJM Schedule 12 - Transmission Enhancement Charges for July 2018 - December 2018 **Attachment 6d**
Calculation of costs and monthly PJM charges for VEPCO Projects

Required Transmission Enhancement *per PJM website*	PJM Upgrade ID *per PJM spreadsheet*	(a) Jan - Dec 2018 Annual Revenue Requirement *per PJM website*	(b) ACE Zone Share	(c) JCP&L Zone Share	(d) PSE&G Zone Share1	(e) RE Zone Share	(f) ACE Zone Charges	(g) JCP&L Zone Charges	(h) PSE&G Zone Charges	(i) RE Zone Charges	(j) Total NJ Zones Charges
			Responsible Customers - Schedule 12 Appendix *per PJM Open Access Transmission Tariff*				Estimated New Jersey EDC Zone Charges by Project				
Reconductor the Dickerson-Pleasant View 230 KV circuit	b0467.2	$669,979.57	1.75%	0.71%	0.00%	0.00%	$11,725	$4,757	$0	$0	$16,481
Install 500/230 kV transformer and two 230 kV breakers at Brambleton	b1188.6	$2,146,442.64	0.22%	0.00%	0.00%	0.00%	$4,722	$0	$0	$0	$4,722
New Brambleton 500 kV line, 3 ring bus, to Loudon to Pleasant View 500 kV	b1188	($561,284.53)	1.66%	3.74%	6.26%	0.26%	-$9,317	-$20,992	-$35,136	-$1,459	-$66,905
New Brambleton 500 kV line, 3 ring bus, to Loudon to Pleasant View 500 kV	b1188_dfax	($561,284.53)	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
500 kV breaker at Brambleton	b1698.1	($19,713.02)	1.66%	3.74%	6.26%	0.26%	-$327	-$737	-$1,234	-$51	-$2,350
501 kV breaker at Brambleton	b1698.1_dfax	($19,713.02)	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Install 2 500kV breakers at Chancellor 500 kV	b0756.1	$262,473.31	1.66%	3.74%	6.26%	0.26%	$4,357	$9,817	$16,431	$682	$31,287
Install 2 500kV breakers at Chancellor 500 kV	b0756.1_dfax	$262,473.31	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Wreck and Rebuild 7 miles of Cloverdale - Lexington 500 kV Line	b1797	$1,165,365.35	1.66%	3.74%	6.26%	0.26%	$19,345	$43,585	$72,952	$3,030	$138,912
Wreck and Rebuild 7 miles of Cloverdale - Lexington 500 kV Line	b1797_dfax	$1,165,365.35	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Build 450 MVAR SVC and 300 MVAR switched shunt at Loudoun 500 kV	b1798	$7,579,086.98	1.66%	3.74%	6.26%	0.26%	$125,813	$283,458	$474,451	$19,706	$903,427
Build 450 MVAR SVC and 300 MVAR switched shunt at Loudoun 500 kV	b1798_dfax	$7,579,086.98	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Build 150 MVAR Switched Shunt at Pleasant View 500 kV Line	b1799	$1,713,009.64	1.66%	3.74%	6.26%	0.26%	$28,436	$64,067	$107,234	$4,454	$204,191
Build 150 MVAR Switched Shunt at Pleasant View 500 kV Line	b1799_dfax	$1,713,009.64	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Install 250 MVAR SVC at Mt. Storm 500 kV Substation	b1805	$2,401,180.00	1.66%	3.74%	6.26%	0.26%	$39,860	$89,804	$150,314	$6,243	$286,221
Install 250 MVAR SVC at Mt. Storm 500 kV Substation	b1805_dfax	$2,401,180.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
At Yadkin 500 kV, install six 500 kV Breakers	b1906.1	$710,165.90	1.66%	3.74%	6.26%	0.26%	$11,789	$26,560	$44,456	$1,846	$84,652
At Yadkin 500 kV, install six 500 kV Breakers	b1906.1_dfax	$710,165.90	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Rebuild Lexington-Dooms 500 kV Line	b1908	$9,089,946.54	1.66%	3.74%	6.26%	0.26%	$150,893	$339,964	$569,031	$23,634	$1,083,522
Rebuild Lexington-Dooms 500 kV Line	b1908_dfax	$9,089,946.54	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Surry 500 kV Station Work	b1905.2	$118,861.59	1.66%	3.74%	6.26%	0.26%	$1,973	$4,445	$7,441	$309	$14,168
Surry 500 kV Station Work	b1905.2_dfax	$118,861.59	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Mt Storm - Replace MOD with breaker on 500kV side of Transformer	b0837	$45,246.69	1.66%	3.74%	6.26%	0.26%	$751	$1,692	$2,832	$118	$5,393
Mt Storm - Replace MOD with breaker on 500kV side of Transformer	b0837_dfax	$45,246.69	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0

Attachment 6d - PJM Schedule 12 - Transmission Enhancement Charges for July 2018 - December 2018 **Attachment 6d**
Calculation of costs and monthly PJM charges for VEPCO Projects

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				**Estimated New Jersey EDC Zone Charges by Project**				
Required Transmission Enhancement *per PJM website*	**PJM Upgrade ID** *per PJM spreadsheet*	**Jan - Dec 2018 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share** *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**
Uprate Section between Possum and Dumfries Substation	b1328	$520,887.02	0.66%	0.00%	0.00%	0.00%	$3,438	$0	$0	$0	$3,438
Rebuild Loudoun - Brambleto 500kV	b1694	$4,476,589.09	1.66%	3.74%	6.26%	0.26%	$74,311	$167,424	$280,234	$11,639	$533,609
Rebuild Loudoun - Brambleto 500kV	b1694_dfax	$4,476,589.09	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
R/P Midlothian 500kV 3 breaker Ring Bus	b2471	$588,596.80	1.66%	3.74%	6.26%	0.26%	$9,771	$22,014	$36,846	$1,530	$70,161
Surry to Skiffes Creek 500kV Line	b1905.1	$585,632.25	1.66%	3.74%	6.26%	0.26%	$9,721	$21,903	$36,661	$1,523	$69,807
Surry to Skiffes Creek 500kV Line	b1905.1_dfax	$585,632.25	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Install Breaker and half scheme with minimum of eight 230kV Breakers	b1696	$615,636.33	0.46%	0.64%	0.00%	0.00%	$2,832	$3,940	$0	$0	$6,772
Build a second Loudon - Brambleton 500kV line	b2373	$11,245,190.14	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Rebuild Carson Rogers 500kV Ckt	b2744	$2,188,583.17	1.66%	3.74%	6.26%	0.26%	$36,330	$81,853	$137,005	$5,690	$260,879
Totals		**$173,843,282.44**					**$1,359,628**	**$2,982,194**	**$4,977,030**	**$206,714**	**$9,525,565**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

	(k)	(l)	(m)	(n)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 2018**	**2018 Trans. Peak Load** [2]	**Rate in \$/MW-mo.** [1]	**2018 Impact (12 months)**
PSE&G	$ 414,752.48	9,566.9	$ 43.35	$ 4,977,030
JCP&L	$ 248,516.16	5,721.0	$ 43.44	$ 2,982,194
ACE	$ 113,302.31	2,540.8	$ 44.59	$ 1,359,628
RE	$ 17,226.14	401.7	$ 42.88	$ 206,714
Total Impact on NJ Zones	**$ 793,797.09**	**18,230.4**		**$ 9,525,565**
Notes on calculations >>>			= (k) / (l)	= (k) *12

Attachment 6e PJM Schedule 12 - Transmission Enhancement Charges for July 2018 - December 2018
Calculation of costs and monthly PJM charges for PATH Project

Required Transmission Enhancement *per PJM website*	PJM Upgrade ID *per PJM spreadsheet*		(a) Jan - Dec 2018 Annual Revenue Requirement *per PJM website*	(b) ACE Zone Share	(c) JCP&L Zone Share	(d) PSE&G Zone Share[1]	(e) RE Zone Share	(f) ACE Zone Charges	(g) JCP&L Zone Charges	(h) PSE&G Zone Charges	(i) RE Zone Charges	(j) Total NJ Zones Charges
				Responsible Customers - Schedule 12 Appendix *per PJM Open Access Transmission Tariff*				Estimated New Jersey EDC Zone Charges by Project				
Amos-Bedington 765 kV Circuit (AEP)	b0490 &b 0491	$	(5,889,758.50)	1.66%	3.74%	6.26%	0.26%	-$97,770	-$220,277	-$368,699	-$15,313	-$702,059
Amos-Bedington 765 kV Circuit (AEP)	b0490 & b0491	$	(5,889,758.50)	5.01%	11.64%	15.86%	0.59%	-$295,077	-$685,568	-$934,116	-$34,750	-$1,949,510
Bedington-Kemptown 500 kV Circuit	b0492 & b560	$	(3,601,460.00)	1.66%	3.74%	6.26%	0.26%	-$59,784	-$134,695	-$225,451	-$9,364	-$429,294
Bedington-Kemptown 500 kV Circuit	b0492 & b560	$	(3,601,460.00)	5.01%	11.64%	15.86%	0.59%	-$180,433	-$419,210	-$571,192	-$21,249	-$1,192,083
Totals		**$**	**(18,982,437.00)**					**-$633,064**	**-$1,459,749**	**-$2,099,458**	**-$80,675**	**-$4,272,947**
Notes on calculations >>>								= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

Zonal Cost Allocation for New Jersey Zones	(k)	Average Monthly Impact on Zone Customers in 2018	(l) 2018 Trans. Peak Load[2]	(m) Rate in \$/MW-mo.[1]	(n) 2018 Impact (12 months)
PSE&G	$	(174,954.79)	9,566.9	(\$18.29)	\$ (2,099,458)
JCP&L	$	(121,645.78)	5,721.0	(\$21.26)	\$ (1,459,749)
ACE	$	(52,755.36)	2,540.8	(\$20.76)	\$ (633,064)
RE	$	(6,722.95)	401.7	(\$16.74)	\$ (80,675)
Total Impact on NJ Zones	**$**	**(356,078.88)**	**18,230.4**		**\$ (4,272,947)**
Notes on calculations >>>				= (k) / (l)	= (k) *12

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

Attachment 6f PJM Schedule 12 - Transmission Enhancement Charges for June 2018 - May 2019 Attachment 6f
Calculation of costs and monthly PJM charges for Allegheny TrAILCo Projects

Required Transmission Enhancement *per PJM website*	PJM Upgrade ID *per PJM spreadsheet*	(a) June 2018-May 2019 Annual Revenue Requirement *per PJM website*	(b) Responsible Customers - Schedule 12 Appendix ACE Zone Share[1] *per PJM Open Access Transmission Tariff*	(c) JCP&L Zone Share[1]	(d) PSE&G Zone Share[1]	(e) RE Zone Share[1]	(f) Estimated New Jersey EDC Zone Charges by Project ACE Zone Charges	(g) JCP&L Zone Charges	(h) PSE&G Zone Charges	(i) RE Zone Charges	(j) Total NJ Zones Charges
502 Junction-Mt Storm-Meadowbrook (>=500kV) - CWIP[1]	b0328.1; b0328.2; b0347.1; b0347.2; b0347.3; b0347.4	$ 58,195,183.55	1.66%	3.74%	6.26%	0.26%	$966,040	$2,176,500	$3,643,018	$151,307	$6,936,866
503 Junction-Mt Storm-Meadowbrook (>=500kV) - CWIP[1]	b0328.1; b0328.2; b0347.1; b0347.2; b0347.3; b0347.5(_dfax)	$ 58,195,183.55	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Wylie Ridge [2]	b0218	$ 2,327,769.14	11.83%	15.56%	0.00%	0.00%	$275,375	$362,201	$0	$0	$637,576
Black Oak	b0216	$ 2,404,656.04	1.66%	3.74%	6.26%	0.26%	$39,917	$89,934	$150,531	$6,252	$286,635
Black Oak	b0216_dfax	$ 2,404,656.04	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Meadowbrook 200 MVAR capacitor	b0559	$ 326,984.76	1.66%	3.74%	6.26%	0.26%	$5,428	$12,229	$20,469	$850	$38,977
Meadowbrook 200 MVAR capacitor	b0559_dfax	$ 326,984.76	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Replace Kammer 765/500 kV TXfmr	b0495	$ 1,979,748.46	1.66%	3.74%	6.26%	0.26%	$32,864	$74,043	$123,932	$5,147	$235,986
Replace Kammer 765/500 kV TXfmr	b0495_dfax	$ 1,979,748.46	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Doubs TXfmr 2	b0343	$ 521,436.22	1.85%	0.00%	0.00%	0.00%	$9,647	$0	$0	$0	$9,647
Doubs TXfmr 3	b0344	$ 477,541.75	1.86%	0.00%	0.00%	0.00%	$8,882	$0	$0	$0	$8,882
Doubs TXfmr 4	b0345	$ 591,741.74	1.85%	0.00%	0.00%	0.00%	$10,947	$0	$0	$0	$10,947
New Osage 138KV Ckt	b0674	$ 2,021,189.84	0.00%	0.00%	0.25%	0.01%	$0	$0	$5,053	$202	$5,255
Cap at Grover 230	b0556	$ 93,468.58	8.64%	18.30%	26.32%	0.98%	$8,076	$17,105	$24,601	$916	$50,697
Upgrade transformer 500/230	b1153	$ 3,063,019.33	3.86%	12.95%	21.15%	0.74%	$118,233	$396,661	$647,829	$22,666	$1,185,388
Build a 300 MVAR Switched Shunt at Doubs 500kV	b1803	$ 273,997.82	1.66%	3.74%	6.26%	0.26%	$4,548	$10,248	$17,152	$712	$32,661
Build a 300 MVAR Switched Shunt at Doubs 500kV	b1803_dfax	$ 273,997.82	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Install 500 MVAR svc at Hunterstown 500kV Sub	b1800	$ 2,412,032.04	1.66%	3.74%	6.26%	0.26%	$40,040	$90,210	$150,993	$6,271	$287,514
Install 500 MVAR svc at Hunterstown 500kV Sub	b1800_dfax	$ 2,412,032.04	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Install a new 600 MVAR SVC at Meadowbrook 500 kV	b1804	$ 3,356,773.39	1.66%	3.74%	6.26%	0.26%	$55,722	$125,543	$210,134	$8,728	$400,127
Install a new 600 MVAR SVC at Meadowbrook 500 kV	b1804_dfax	$ 3,356,773.39	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Build 250 MVAR svc at Altoona 230kV	b1801	$ 3,979,083.16	6.48%	8.15%	8.19%	0.33%	$257,845	$324,295	$325,887	$13,131	$921,158

Attachment 6f PJM Schedule 12 - Transmission Enhancement Charges for June 2018 - May 2019 **Attachment 6f**
Calculation of costs and monthly PJM charges for Allegheny TrAILCo 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*	**June 2018-May 2019 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share[1]**	**JCP&L Zone Share[1]**	**PSE&G Zone Share[1]**	**RE Zone Share[1]** *per PJM Open Access Transmission Tariff*	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
Convert Moshannon sub to 4 breaker 230 kv ring bus	b1964	$ 856,936.63	0.00%	5.48%	0.00%	0.00%	$0	$46,960	$0	$0	$46,960
Build a 100 MVAR Fast Switched Shunt and 200 MVAR Switched Shunt at Mansfield 345 kV	b1802	$ 155,919.37	6.48%	8.15%	8.19%	0.33%	$10,104	$12,707	$12,770	$515	$36,095
Install 100 MVAR capacitor at Johnstown 230 kV substation	b0555	$ 153,191.13	8.64%	18.30%	26.32%	0.98%	$13,236	$28,034	$40,320	$1,501	$83,091
Install 300 MVAR capacitor at Conemaugh 500 kV substation	b0376	$ -	1.66%	3.74%	6.26%	0.26%	$0	$0	$0	$0	$0
							$1,856,903	**$3,766,670**	**$5,372,690**	**$218,200**	**$11,214,463**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

	(k)	(l)	(m)	(n)	(o)	(p)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 18/19**	**2018TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2018 Impact (7 months)**	**2019 Impact (5 months)**	**2018-2019 Impact (12 months)**
PSE&G	$ 447,724.17	9,566.9	$ 46.80	$ 3,134,069	$ 2,238,621	$ 5,372,690
JCP&L	$ 313,889.18	5,721.0	$ 54.87	$ 2,197,224	$ 1,569,446	$ 3,766,670
ACE	$ 154,741.91	2,540.8	$ 60.90	$ 1,083,193	$ 773,710	$ 1,856,903
RE	$ 18,183.30	401.7	$ 45.27	$ 127,283	$ 90,917	$ 218,200
Total Impact on NJ Zones	**$ 934,538.56**			**$ 6,541,770**	**$ 4,672,693**	**$ 11,214,463**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

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

Attachment 6g PJM Schedule 12 - Transmission Enhancement Charges for June 2018 - May 2019
Calculation of costs and monthly PJM charges for Delmarva 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*	**June 2018-May 2019 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share[1]**	**JCP&L Zone Share[1]**	**PSE&G Zone Share[1]**	**RE Zone Share[1]**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
			per PJM Open Access Transmission Tariff								
Replace line trap-Keeney	b0272.1	$ 12,149	1.66%	3.74%	6.26%	0.26%	$202	$454	$761	$32	$1,448
Replace line trap-Keeney	b0272.1_dfax	$ 12,149	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Add two breakers- Keeney	b0751	$ 282,159	1.66%	3.74%	6.26%	0.26%	$4,684	$10,553	$17,663	$734	$33,633
Add two breakers- Keeney	b0751_dfax	$ 282,159	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Totals							**$4,886**	**$11,007**	**$18,424**	**$765**	**$35,082**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

	(k)	(l)	(m)	(n)	(o)	(p)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 18/19**	**2018TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2018 Impact (7 months)**	**2019 Impact (5 months)**	**2018-2019 Impact (12 months)**
PSE&G	$ 1,535.31	9,566.9	$ 0.16	$ 10,747	$ 7,677	$ 18,424
JCP&L	$ 917.26	5,721.0	$ 0.16	$ 6,421	$ 4,586	$ 11,007
ACE	$ 407.13	2,540.8	$ 0.16	$ 2,850	$ 2,036	$ 4,886
RE	$ 63.77	401.7	$ 0.16	$ 446	$ 319	$ 765
Total Impact on NJ Zones	**$ 2,923.47**			**$ 20,464**	**$ 14,617**	**$ 35,082**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

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

Attachment 6h PJM Schedule 12 - Transmission Enhancement Charges for June 2018 to May 2019 **Attachment 6h**
Calculation of costs and monthly PJM charges for PEPCO 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*	**June 2018-May 2019 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share[1]**	**JCP&L Zone Share[1]**	**PSE&G Zone Share[1]** *per PJM Open Access Transmission Tariff*	**RE Zone Share[1]**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
Reconductor 23035 for Dickerson-Quince	b0367.1-2	$ 2,686,508	1.78%	2.67%	3.82%	0.00%	$47,820	$71,730	$102,625	$0	$222,174
Replace 230 1A breaker	b0512.7	$ 128,172	1.66%	3.74%	6.26%	0.26%	$2,128	$4,794	$8,024	$333	$15,278
Replace 230 1A breaker	b0512.7_dfax	$ 128,172	3.94%	9.43%	14.71%	0.54%	$5,050	$12,087	$18,854	$692	$36,683
Replace 230 1B breaker	b0512.8	$ 128,172	1.66%	3.74%	6.26%	0.26%	$2,128	$4,794	$8,024	$333	$15,278
Replace 230 1B breaker	b0512.8_dfax	$ 128,172	3.94%	9.43%	14.71%	0.54%	$5,050	$12,087	$18,854	$692	$36,683
Replace 230 2A breaker	b0512.9	$ 128,172	1.66%	3.74%	6.26%	0.26%	$2,128	$4,794	$8,024	$333	$15,278
Replace 230 2A breaker	b0512.9_dfax	$ 128,172	3.94%	9.43%	14.71%	0.54%	$5,050	$12,087	$18,854	$692	$36,683
Replace 230 3A breaker	b0512.12	$ 129,372	1.66%	3.74%	6.26%	0.26%	$2,148	$4,838	$8,099	$336	$15,421
Replace 230 3A breaker	b0512.12_dfax	$ 129,372	3.94%	9.43%	14.71%	0.54%	$5,097	$12,200	$19,031	$699	$37,026
Ritchie-Benning 230 lines	b0526	$ 7,684,181	0.77%	1.39%	2.10%	0.08%	$59,168	$106,810	$161,368	$6,147	$333,493
Totals							**$135,766**	**$246,219**	**$371,754**	**$10,258**	**$763,997**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

	(k)	(l)	(m)	(n)	(o)	(p)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 18/19**	**2018TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2018 Impact (7 months)**	**2019 Impact (5 months)**	**2018-2019 Impact (12 months)**
PSE&G	$ 30,979.53	9,566.9	$ 3.24	$ 216,857	$ 154,898	$ 371,754
JCP&L	$ 20,518.22	5,721.0	$ 3.59	$ 143,628	$ 102,591	$ 246,219
ACE	$ 11,313.80	2,540.8	$ 4.45	$ 79,197	$ 56,569	$ 135,766
RE	$ 854.87	401.7	$ 2.13	$ 5,984	$ 4,274	$ 10,258
Total Impact on NJ Zones	**$ 63,666.42**			**$ 445,665**	**$ 318,332**	**$ 763,997**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

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

Attachment 6i PJM Schedule 12 - Transmission Enhancement Charges for June 2018 - May 2019 — Attachment 6i

Calculation of costs and monthly PJM charges for PPL 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**	**June 2018- May 2019 Annual Revenue Requirement**	**ACE Zone Share[1]**	**JCP&L Zone Share[1]**	**PSE&G Zone Share[1]**	**RE Zone Share[1]**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
per PJM website	*per PJM spreadsheet*	*per PJM website*	*per PJM Open Access Transmission Tariff*								
New 500 KV Susquehana-Roseland Line	b0487	$ 36,735,443.00	1.66%	3.74%	6.26%	0.26%	$609,808	$1,373,906	$2,299,639	$95,512	$4,378,865
New 500 KV Susquehana-Roseland Line	b0487_dfax	$ 36,735,443.00	0.00%	33.89%	59.46%	2.39%	$0	$12,449,642	$21,842,894	$877,977	$35,170,513
Replace wave trap at Alburtus 500 kV Sub	b0171.2	$ 4,190.50	1.66%	3.74%	6.26%	0.26%	$70	$157	$262	$11	$500
Replace wave trap at Alburtus 500 kV Sub	b0171.2_dfax	$ 4,190.50	6.06%	21.17%	0.01%	0.00%	$254	$887	$0	$0	$1,141
Replace wavetrap at Hosensack 500KV Sub	b0172.1	$ 3,005.00	1.66%	3.74%	6.26%	0.26%	$50	$112	$188	$8	$358
Replace wavetrap at Hosensack 500KV Sub	b0172.1_dfax	$ 3,005.00	5.32%	33.44%	53.73%	2.16%	$160	$1,005	$1,615	$65	$2,844
Replace wavetraps at Juniata 500KV Sub	b0284.2	$ 6,076.50	1.66%	3.74%	6.26%	0.26%	$101	$227	$380	$16	$724
Replace wavetraps at Juniata 500KV Sub	b0284.2_dfax	$ 6,076.50	5.35%	19.57%	24.65%	0.99%	$325	$1,189	$1,498	$60	$3,072
New S-R additions < 500kV[2]	b0487.1	$ 1,756,533.00	0.00%	0.00%	5.14%	0.19%	$0	$0	$90,286	$3,337	$93,623
New substation and transformers Middletown	b0468	$ 2,408,736.00	0.00%	4.56%	5.94%	0.22%	$0	$109,838	$143,079	$5,299	$258,216
Install Lauschtown 500/230 kV Sub below 500kv portion	b2006	$ 2,618,100.00	1.11%	9.68%	11.43%	0.45%	$29,061	$253,432	$299,249	$11,781	$593,523
Install Lauschtown 500/230 kV Sub 500kv portion tie line	b2006.1	$ 4,349,337.50	1.66%	3.74%	6.26%	0.26%	$72,199	$162,665	$272,269	$11,308	$518,441
Install Lauschtown 500/230 kV Sub 500kv portion tie line	b2006.1_dfax	$ 4,349,337.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
200 MVAR shunt reactor at Alburtis 500kv	b2237	$ 2,286,532.50	1.66%	3.74%	6.26%	0.26%	$37,956	$85,516	$143,137	$5,945	$272,555
200 MVAR shunt reactor at Alburtis 500kv	b2237_dfax	$ 2,286,532.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Totals							**$749,984**	**$14,438,577**	**$25,094,496**	**$1,011,320**	**$41,294,377**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

	(k)	(l)	(m)	(n)	(o)	(p)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 18/19**	**2018 Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2018 Impact (7 months)**	**2019 Impact (5 months)**	**2018-2019 Impact (12 months)**
PSE&G	$ 2,091,207.99	9,566.9	$ 218.59	$ 14,638,456	$ 10,456,040	$ 25,094,496
JCP&L	$ 1,203,214.73	5,721.0	$ 210.32	$ 8,422,503	$ 6,016,074	$ 14,438,577
ACE	$ 62,498.66	2,540.8	$ 24.60	$ 437,491	$ 312,493	$ 749,984
RE	$ 84,276.68	401.7	$ 209.80	$ 589,937	$ 421,383	$ 1,011,320
Total Impact on NJ Zones	**$ 3,441,198.05**			**$ 24,088,386**	**$ 17,205,990**	**$ 41,294,377**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

Notes:

1) 2018 allocation share percentages are from PJM OATT

Attachment 6j PJM Schedule 12 - Transmission Enhancement Charges for June 2018 - May 2019 **Attachment 6j**
Calculation of costs and monthly PJM charges for BG&E 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*	**June 2018 - May 2019 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share[1]** *per PJM Open Access Transmission Tariff*	**JCP&L Zone Share[1]**	**PSE&G Zone Share[1]**	**RE Zone Share[1]**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
Install a second Conastone – Graceton 230 kV circuit	b0497	$ 2,934,126	9.03%	9.67%	14.11%	0.52%	$264,952	$283,730	$414,005	$15,257	$977,944
install new 500 kV transmission from Possum Point to Calvert Cliffs	b0512	$ 1,687	1.66%	3.74%	6.26%	0.26%	$28	$63	$106	$4	$201
Totals							**$264,980**	**$283,793**	**$414,111**	**$15,262**	**$978,145**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

	(k)	(l)	(m)	(n)	(o)	(p)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 18/19**	**2018TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2018 Impact (7 months)**	**2019 Impact (5 months)**	**2018-2019 Impact (12 months)**
PSE&G	$ 34,509.23	9,566.9	$ 3.61	$ 241,565	$ 172,546	$ 414,111
JCP&L	$ 23,649.42	5,721.0	$ 4.13	$ 165,546	$ 118,247	$ 283,793
ACE	$ 22,081.63	2,540.8	$ 8.69	$ 154,571	$ 110,408	$ 264,980
RE	$ 1,271.82	401.7	$ 3.17	$ 8,903	$ 6,359	$ 15,262
Total Impact on NJ Zones	**$ 81,512.11**			**$ 570,585**	**$ 407,561**	**$ 978,145**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

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

Attachment 6k - Transmission Enhancement Charges for July 2018 - December 2018
Calculation of costs and monthly PJM charges for Mid Atlantic Interstate Transmission Projects

Required Transmission Enhancement *per PJM website*	PJM Upgrade ID *per PJM spreadsheet*	(a) Jan-Dec 2018 Annual Revenue Requirement *per PJM website*	(b) Responsible Customers - Schedule 12 Appendix: ACE Zone Share[1]	(c) JCP&L Zone Share[1]	(d) PSE&G Zone Share[1]	(e) RE Zone Share[1] *per PJM Open Access Transmission Tariff*	(f) Estimated New Jersey EDC Zone Charges by Project: ACE Zone Charges	(g) JCP&L Zone Charges	(h) PSE&G Zone Charges	(i) RE Zone Charges	(j) Total NJ Zones Charges
Install 230kV series reactor and 2-100MVAR PLC switched capacitors at Hunterstown	b0215	$ 1,722,473.00	6.75%	16.96%	22.82%	0.34%	$116,267	$292,131	$393,068	$5,856	$807,323
Replace wave trap at Kestone 500kV Sub	b0284.3	$ -	1.66%	3.74%	6.26%	0.26%	$0	$0	$0	$0	$0
Install 100 MVAR Cap Banks at Jack's Mountain 500 kV Sub	b0369	$ -	1.66%	3.74%	6.26%	0.26%	$0	$0	$0	$0	$0
Install 250 MVAR Capacitor at Keystone 500kV Sub	b0549	$ 228,231.00	1.66%	3.74%	6.26%	0.26%	$3,789	$8,536	$14,287	$593	$27,205
Install 250 MVAR Capacitor at Keystone 500kV Sub	b0549_dfax	$ 228,231.00	5.39%	17.99%	22.05%	0.89%	$12,302	$41,059	$50,325	$2,031	$105,717
Install 25 MVAR capacitor at Saxton 115 kV Sub	b0551	$ 187,275.00	8.64%	18.30%	26.32%	0.98%	$16,181	$34,271	$49,291	$1,835	$101,578
Install 50 MVAR capacitor at Altoona 230 kV Sub	b0552	$ 150,010.00	8.64%	18.30%	26.32%	0.98%	$12,961	$27,452	$39,483	$1,470	$81,365
Install 50 MVAR capacitor at Raystoon 230 kV Sub	b0553	$ 132,043.00	8.64%	18.30%	26.32%	0.98%	$11,409	$24,164	$34,754	$1,294	$71,620
Install 75 MVAR capacitor at East Towanda 230 kV Sub	b0557	$ 309,489.00	8.64%	18.30%	26.32%	0.98%	$26,740	$56,636	$81,458	$3,033	$167,867
Relocate the Erie South 345 kV Line Terminal	b1993	$ 1,570,347.00	0.00%	5.19%	12.21%	0.48%	$0	$81,501	$191,739	$7,538	$280,778
Conver Lewis Run-Farmers Valley to 230kV using 1033.5 Conductor	b1994	$ 15,407.00	0.00%	8.72%	13.67%	0.54%	$0	$1,343	$2,106	$83	$3,533
Loop the 2026 kV Line to Laushtown Substation	b2006.1.1	$ 260,294.00	1.66%	3.74%	6.26%	0.26%	$4,321	$9,735	$16,294	$677	$31,027
Loop the 2026 kV Line to Laushtown Substation	b2006.1.1_dfax	$ 302,983.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
							$203,968	**$576,829**	**$872,805**	**$24,411**	**$1,678,013**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

Zonal Cost Allocation for New Jersey Zones	(k) Average Monthly Impact on Zone Customers in 2018	(l) 2018TX Peak Load *per PJM website*	(m) Rate in $/MW-mo.	(n) 2018 Impact (12 months)
PSE&G	$ 72,733.76	9,566.9	$ 7.60	$ 872,805
JCP&L	$ 48,069.09	5,721.0	$ 8.40	$ 576,829
ACE	$ 16,997.32	2,540.8	$ 6.69	$ 203,968
RE	$ 2,034.26	401.7	$ 5.06	$ 24,411
Total Impact on NJ Zones	**$ 139,834.42**			**$ 1,678,013**
Notes on calculations >>>			= (k) * (l)	= (k) *12

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

Attachment 6l Summary of EL05-121 Settlement Adjustments for July 2018 - June 2019

Annual Total - July 2018 - June 2019	AE	JCPL	PSEG	Rockland
BLI-1108A - Current Aggregate Recovery Charge Transitional Period - Catch-up	$ (6,347,290.24)	$ 67,946,499.64	$ 107,210,711.22	$ 4,184,319.56
BLI-1108A - Estimated Interest August 2018 - June 2019	$ (141,775.57)	$ 1,517,679.70	$ 2,394,700.55	$ 93,462.60
BLI-1115 - Transmission Enhancement Charge Adjustments (Black Box) Transitional Period - Catch-up	$ 729,688.58	$ 25,286,407.13	$ 58,566,293.14	$ 2,173,870.30
BLI-1115 - Transmission Enhancement Charge Adjustments (Black Box)	$ 280,667.52	$ 9,726,167.88	$ 22,526,948.88	$ 836,157.84
BLI-1115 - Estimated Transmission Enhancement Charge Adjustment (Black Box) Interest August 2018 - June 2019	$ 16,298.61	$ 564,807.12	$ 1,308,159.72	$ 48,556.42
Total Annual Adjustments Allocated to NJ Zones	$ (5,462,411.10)	$ 105,041,561.47	$ 192,006,813.51	$ 7,336,366.73

Monthly Total - July 2018 - June 2019	AE	JCPL	PSEG	Rockland
BLI-1108A - Current Aggregate Recovery Charge Transitional Period - Catch-up	$ (528,940.85)	$ 5,662,208.30	$ 8,934,225.94	$ 348,693.30
BLI-1108A - Estimated Interest August 2018 - June 2019	$ (11,814.63)	$ 126,473.31	$ 199,558.38	$ 7,788.55
BLI-1115 - Transmission Enhancement Charge Adjustments (Black Box) Transitional Period - Catch-up	$ 60,807.38	$ 2,107,200.59	$ 4,880,524.43	$ 181,155.86
BLI-1115 - Transmission Enhancement Charge Adjustments (Black Box)	$ 23,388.96	$ 810,513.99	$ 1,877,245.74	$ 69,679.82
BLI-1115 - Estimated Transmission Enhancement Charge Adjustment (Black Box) Interest August 2018 - June 2019	$ 1,358.22	$ 47,067.26	$ 109,013.31	$ 4,046.37
Total Monthly Adjustments Allocated to NJ Zones	$ (455,200.92)	$ 8,753,463.46	$ 16,000,567.79	$ 611,363.89

BLI-1108A - Current Aggregate Recovery Charge Transitional Period - Catch-up

	AE	JCPL	PSEG	Rockland
Total Transitional Period Aggregate Differences (January 2016 - June 2018)	$ (6,018,648.21)	$ 64,323,438.16	$ 101,571,207.09	$ 3,964,914.18
Total Transitional Period Interest (January 2016 - June 2018)	$ (328,642.03)	$ 3,623,061.48	$ 5,639,504.13	$ 219,405.38
Monthly Current Recovery Charge Transitional Period Charge - 1108A (July 2018 - June 2019)	$ (528,940.85)	$ 5,662,208.30	$ 8,934,225.93	$ 348,693.30
Annual Current Recovery Charge Transitional Period Charge - 1108A (July 2018 - June 2019)	$ (6,347,290.24)	$ 67,946,499.64	$ 107,210,711.22	$ 4,184,319.56

*A negative value represents a refund to the zone or merchant transmission facility, a positive value represents a charge

Source: PJM Current Recovery Charge Transitional Period Summary (EL05-121 Settlement)

Transmission Enhancement Charge Adjustments (Black Box) Transitional Period Summary

CHARGES

Zone or MTF	Total Monthly TEC Adjustment Months 1-24	Total Monthly TEC Adjustment Months 25-30	Sum of Months 1-24	Sum of Months 25-30	Total TEC Adjustment Months 1-30	Total Interest Charge	Monthly Charge July 2018 through June 2019	Total Charge
AE	$ 23,039.57	$ 23,388.96	$ 552,949.68	$ 140,333.76	$ 693,283.44	$ 36,405.14	**$ 60,807.38**	$ 729,688.58
APS	$ 1,007,362.89	$ 1,022,639.42	$ 24,176,709.36	$ 6,135,836.52	$ 30,312,545.88	$ 1,591,747.93	**$ 2,658,691.15**	$ 31,904,293.81
BGE	$ 1,279,330.93	$ 1,298,731.81	$ 30,703,942.32	$ 7,792,390.86	$ 38,496,333.18	$ 2,021,488.36	**$ 3,376,485.13**	$ 40,517,821.54
Dominion	$ 2,518,708.88	$ 2,556,904.76	$ 60,449,013.12	$ 15,341,428.56	$ 75,790,441.68	$ 3,979,846.48	**$ 6,647,524.01**	$ 79,770,288.16
HTP	$ 67,067.41	$ -	$ 1,609,617.84	$ -	$ 1,609,617.84	$ 100,892.02	**$ 142,542.49**	$ 1,710,509.86
JCPL	$ 798,406.27	$ 810,513.99	$ 19,161,750.48	$ 4,863,083.94	$ 24,024,834.42	$ 1,261,572.71	**$ 2,107,200.59**	$ 25,286,407.13
Neptune	$ 73,621.60	$ 74,738.06	$ 1,766,918.40	$ 448,428.36	$ 2,215,346.76	$ 116,330.50	**$ 194,306.44**	$ 2,331,677.26
PEPCODC	$ 796,929.46	$ 809,014.78	$ 19,126,307.04	$ 4,854,088.68	$ 23,980,395.72	$ 1,259,239.18	**$ 2,103,302.91**	$ 25,239,634.90
PEPCOMD	$ 1,158,741.03	$ 1,176,313.18	$ 27,809,784.72	$ 7,057,879.08	$ 34,867,663.80	$ 1,830,942.61	**$ 3,058,217.20**	$ 36,698,606.41
PEPCOSMECO	$ 276,634.36	$ 280,829.48	$ 6,639,224.64	$ 1,684,976.88	$ 8,324,201.52	$ 437,113.75	**$ 730,109.61**	$ 8,761,315.27
PSEG	$ 1,849,202.83	$ 1,877,245.74	$ 44,380,867.92	$ 11,263,474.44	$ 55,644,342.36	$ 2,921,950.78	**$ 4,880,524.43**	$ 58,566,293.14
Rockland	$ 68,638.92	$ 69,679.82	$ 1,647,334.08	$ 418,078.92	$ 2,065,413.00	$ 108,457.30	**$ 181,155.86**	$ 2,173,870.30
EastCoastPower	$ 82,315.86	$ -	$ 1,975,580.64	$ -	$ 1,975,580.64	$ 123,830.83	**$ 174,950.96**	$ 2,099,411.47

CREDITS

Zone or MTF	Total Monthly TEC Adjustment Months 1-30	30 Month Sum	Total Interest Credit	Monthly Credit July 2018 through June 2019	Total Credit
AEP	$ (2,619,301.30)	$ (78,579,039.00)	$ (4,135,828.96)	**$ (6,892,905.66)**	$ (82,714,867.96)
ATSI	$ (1,166,340.94)	$ (34,990,228.20)	$ (1,841,631.06)	**$ (3,069,321.61)**	$ (36,831,859.26)
ComEd	$ (2,829,797.23)	$ (84,893,916.90)	$ (4,468,198.20)	**$ (7,446,842.92)**	$ (89,362,115.10)
ConEd	$ (75,593.18)	$ (2,267,795.40)	$ (119,360.25)	**$ (198,929.64)**	$ (2,387,155.65)
Dayton	$ (410,151.95)	$ (12,304,558.50)	$ (647,622.45)	**$ (1,079,348.41)**	$ (12,952,180.95)
DukeOH/KY	$ (322,963.42)	$ (9,688,902.60)	$ (509,953.35)	**$ (849,904.66)**	$ (10,198,855.95)
Duquesne	$ (347,410.74)	$ (10,422,322.20)	$ (548,555.22)	**$ (914,239.79)**	$ (10,970,877.42)
DelmarvaDE	$ (120,132.43)	$ (3,603,972.90)	$ (189,686.92)	**$ (316,138.32)**	$ (3,793,659.82)
DelmarvaMD	$ (74,683.72)	$ (2,240,511.60)	$ (117,924.23)	**$ (196,536.32)**	$ (2,358,435.83)
DelmarvaVA	$ (10,180.71)	$ (305,421.30)	$ (16,075.16)	**$ (26,791.37)**	$ (321,496.46)
EKPC	$ (92,076.35)	$ (2,762,290.50)	$ (145,386.88)	**$ (242,306.45)**	$ (2,907,677.38)
MedEd	$ (276,128.54)	$ (8,283,856.20)	$ (436,001.93)	**$ (726,654.84)**	$ (8,719,858.13)
PECO	$ (634,062.44)	$ (19,021,873.20)	$ (1,001,173.02)	**$ (1,668,587.19)**	$ (20,023,046.22)
Penelec	$ (254,434.53)	$ (7,633,035.90)	$ (401,747.48)	**$ (669,565.28)**	$ (8,034,783.38)
PPLPPLEU	$ (766,702.23)	$ (23,001,066.90)	$ (1,210,608.83)	**$ (2,017,639.64)**	$ (24,211,675.73)
PPLUGI	$ (40.31)	$ (1,209.30)	$ (63.65)	**$ (106.08)**	$ (1,272.95)

Source: PJM Transmission Enhancement Charge Adjustemnts (Black Box) Transitional Period Summary (EL05-121 Settlement)

BLI-1115 - Transmission Enhancement Charge Adjustments (Black Box) Transitional Period - Catch-up

	Total Monthly TEC Adjustment Months 1-24	Total Monthly TEC Adjustment Months 25-30	Sum of Months 1-24	Sum of Months 25-30	Total TEC Adjustment Months 1-30	Total Interest Charge	Monthly Charge July 2018 through June 2019	Annual Charge July 2018 through June 2019
AE	$ 23,039.57	$ 23,388.96	$ 552,949.68	$ 140,333.76	$ 693,283.44	$ 36,405.14	**$ 60,807.38**	**$ 729,688.58**
JCPL	$ 798,406.27	$ 810,513.99	$ 19,161,750.48	$ 4,863,083.94	$ 24,024,834.42	$ 1,261,572.71	**$ 2,107,200.59**	**$ 25,286,407.13**
PSEG	$ 1,849,202.83	$ 1,877,245.74	$ 44,380,867.92	$ 11,263,474.44	$ 55,644,342.36	$ 2,921,950.78	**$ 4,880,524.43**	**$ 58,566,293.14**
Rockland	$ 68,638.92	$ 69,679.82	$ 1,647,334.08	$ 418,078.92	$ 2,065,413.00	$ 108,457.30	**$ 181,155.86**	**$ 2,173,870.30**

BLI-1115 - Transmission Enhancement Charge Adjustments (Black Box)

	Total Monthly TEC Adjustment Months 1-24	Total Monthly TEC Adjustment Months 25-30	Sum of Months 1-24	Sum of Months 25-30	Total TEC Adjustment Months 1-30	Total Interest Charge	Monthly Charge July 2018 through June 2019	Annual Charge July 2018 through June 2019
AE	$ 23,039.57	$ 23,388.96	$ 552,949.68	$ 140,333.76	$ 693,283.44	$ 36,405.14	**$ 23,388.96**	**$ 280,667.52**
JCPL	$ 798,406.27	$ 810,513.99	$ 19,161,750.48	$ 4,863,083.94	$ 24,024,834.42	$ 1,261,572.71	**$ 810,513.99**	**$ 9,726,167.88**
PSEG	$ 1,849,202.83	$ 1,877,245.74	$ 44,380,867.92	$ 11,263,474.44	$ 55,644,342.36	$ 2,921,950.78	**$ 1,877,245.74**	**$ 22,526,948.88**
Rockland	$ 68,638.92	$ 69,679.82	$ 1,647,334.08	$ 418,078.92	$ 2,065,413.00	$ 108,457.30	**$ 69,679.82**	**$ 836,157.84**

Estimated Current Recovery Charge (1108A) Interest

Zone or MTF	August 2018	September 2018	October 2018	November 2018	December 2018	January 2019	February 2019	March 2019	April 2019	May 2019	June 2019	Total Interest
AE	($26,166.63)	($23,787.85)	($17,127.25)	($19,030.28)	($13,321.19)	($11,418.17)	($11,893.92)	($7,612.11)	($5,709.08)	($3,806.06)	($1,903.03)	($141,775.57)
JCPL	$280,108.67	$254,644.24	$183,343.86	$203,715.40	$142,600.78	$122,229.24	$127,322.12	$81,486.16	$61,114.62	$40,743.08	$20,371.54	$1,517,679.70
PSEG	$441,974.93	$401,795.39	$289,292.68	$321,436.31	$225,005.42	$192,861.79	$200,897.70	$128,574.53	$96,430.89	$64,287.26	$32,143.63	$2,394,700.55
Rockland	$17,249.81	$15,681.65	$11,290.78	$12,545.32	$8,781.72	$7,527.19	$7,840.82	$5,018.13	$3,763.59	$2,509.06	$1,254.53	$93,462.60

Source: PJM Estimated Current Recovery Charge (1108A) Interest (EL05-121 Settlement)

Estimated Transmission Enchancement Charge (1115) Interest

Zone or MTF	August 2018	September 2018	October 2018	November 2018	December 2018	January 2019	February 2019	March 2019	April 2019	May 2019	June 2019	Total Interest
AE	$3,008.13	$2,734.67	$1,968.96	$2,187.73	$1,531.41	$1,312.64	$1,367.33	$875.09	$656.32	$437.55	$218.77	$16,298.61
JCPL	$104,242.92	$94,766.30	$68,231.73	$75,813.04	$53,069.13	$45,487.82	$47,383.15	$30,325.21	$22,743.91	$15,162.61	$7,581.30	$564,807.12
PSEG	$241,438.87	$219,489.89	$158,032.72	$175,591.91	$122,914.34	$105,355.15	$109,744.94	$70,236.76	$52,677.57	$35,118.38	$17,559.19	$1,308,159.72
Rockland	$8,961.76	$8,147.05	$5,865.88	$6,517.64	$4,562.35	$3,910.58	$4,073.53	$2,607.06	$1,955.29	$1,303.53	$651.76	$48,556.42

Source: PJM Estimated Enhancement Charge Adjustment (1115) Interest (EL05-121 Settlement)

Attachment 6m - Transmission Enhancement Charges for June 2018 - May 2019 **Attachment 6m**
Calculation of costs and monthly PJM charges for PECO Energy Company Transmission Projects

			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
				Responsible Customers - Schedule 12 Appendix				Estimated New Jersey EDC Zone Charges by Project				
Required Transmission Enhancement *per PJM website*	**PJM Upgrade ID** *per PJM spreadsheet*		**2018/2019 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share[1]**	**JCP&L Zone Share[1]**	**PSE&G Zone Share[1]** *per PJM Open Access Transmission Tariff*	**RE Zone Share[1]**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
Install a new 500 kV Center Point substation in PECO by tapping the Elroy – Whitpain 500 kV circuit.	b0269	$	1,627,805.56	1.66%	3.74%	6.26%	0.26%	$27,022	$60,880	$101,901	$4,232	$194,034
Install a new 500 kV Center Point substation in PECO by tapping the Elroy – Whitpain 500 kV circuit.	b0269_dfax	$	1,627,805.56	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Add a new 230 kV circuit between Whitpain and Heaton substations	b0269.1	$	4,322,188.10	8.25%	0.00%	0.00%	0.00%	$356,581	$0	$0	$0	$356,581
Add a new 500kV brkr. at Whitpain bet. #3 transfmr. and 5029 line	b0269.6	$	235,377.62	1.66%	3.74%	6.26%	0.26%	$3,907	$8,803	$14,735	$612	$28,057
Add a new 500kV brkr. at Whitpain bet. #3 transfmr. and 5029 line	b0269.6_dfax	$	235,377.62	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Replace 2-500 kV circt brkrs and 2 wave traps at Elroy subs to increase rating of Elroy - Hosensack 500kV	b0171.1	$	316,585.91	1.66%	3.74%	6.26%	0.26%	$5,255	$11,840	$19,818	$823	$37,737
Replace 2-500 kV circt brkrs and 2 wave traps at Elroy subs to increase rating of Elroy - Hosensack 500kV	b0171.1_dfax	$	316,585.91	6.06%	21.17%	0.01%	0.00%	$19,185	$67,021	$32	$0	$86,238
Increase the rating of lines 220-39 and 220-43 (Linwood-Chicester 230kV lines) and install reactors.	b1900	$	5,111,503.52	0.00%	6.07%	21.01%	0.84%	$0	$310,268	$1,073,927	$42,937	$1,427,132
Rebuild Bryn Mawr-Plymouth Meeting 138 kV line (130-35 Line)	b0727	$	2,944,427.91	1.25%	0.00%	0.00%	0.00%	$36,805	$0	$0	$0	$36,805
Recndr Chichester - Saville 138 kV line and upgrade term equip	b1182	$	2,730,618.07	0.00%	5.12%	14.31%	0.57%	$0	$139,808	$390,751	$15,565	$546,124
Add a second 230/138 kV trans at Chichester. Add an inductor in series with the parallel tranfmrs	b1178	$	1,241,280.89	0.00%	4.17%	12.18%	0.48%	$0	$51,761	$151,188	$5,958	$208,908
Increase Bradford - Planebrook 230 kV Ckt.220-31 line rating. Replace terminal equipment	b0790	$	263,023.67	0.00%	17.46%	34.00%	1.32%	$0	$45,924	$89,428	$3,472	$138,824
Reconductor the North Wales - Hartman 230 kV circuit	b0506	$	328,431.58	8.58%	0.00%	0.00%	0.00%	$28,179	$0	$0	$0	$28,179
Reconductor the North Wales - Whitpain 230 kV circuit	b0505	$	367,996.92	8.58%	0.00%	0.00%	0.00%	$31,574	$0	$0	$0	$31,574
Increase Bradford - Planebrook 230 kV Ckt.220-02 line rating. Replace terminal equipment	b0789	$	359,974.48	0.73%	17.52%	33.83%	1.32%	$2,628	$63,068	$121,779	$4,752	$192,226
Install 161MVAR capacitor at Planebrook 230kV substation	b0206	$	490,491.51	14.20%	0.00%	3.47%	0.00%	$69,650	$0	$17,020	$0	$86,670
Install 161MVAR capacitor at Newlinville 230kV substation	b0207	$	661,052.44	14.20%	0.00%	3.47%	0.00%	$93,869	$0	$22,939	$0	$116,808

Attachment 6m - Transmission Enhancement Charges for June 2018 - May 2019 **Attachment 6m**
Calculation of costs and monthly PJM charges for PECO Energy Company Transmission Projects

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				Estimated New Jersey EDC Zone Charges by Project				
Required Transmission Enhancement *per PJM website*	**PJM Upgrade ID** *per PJM spreadsheet*	**2018/2019 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share[1]**	**JCP&L Zone Share[1]**	**PSE&G Zone Share[1]**	**RE Zone Share[1]**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
			per PJM Open Access Transmission Tariff								
Install 2% series reactor at Chichester substation on the Chichester - Mickleton 230kV circuit	b0209	$ 374,583.09	65.23%	25.87%	6.35%	0.00%	$244,341	$96,905	$23,786	$0	$365,031
Upgrade Chichester - Delco Tap 230kV and the PECO portion of the Delco Tap - Mickleton 230kV cicuit	b0264	$ 312,978.54	89.87%	9.48%	0.00%	0.00%	$281,274	$29,670	$0	$0	$310,944
Reconductor Buckingham - Pleasant Valley 230kV; same impedance as existing line; ratings of 760MVA normal/882MVA emergency	b0357	$ 313,715.97	0.00%	37.89%	55.19%	2.37%	$0	$118,867	$173,140	$7,435	$299,442
Reconductor Richmond-Waneeta kv and replace terminal equipment at Waneeta Substation	b1398.8	$ 266,682.62	0.00%	13.03%	31.99%	1.27%	$0	$34,749	$85,312	$3,387	$123,447
Install 600 MVAR cap banks at Elroy 500kv Substation	b0287	$ 435,396.26	1.66%	3.74%	6.26%	0.26%	$7,228	$16,284	$27,256	$1,132	$51,899
Install 600 MVAR cap banks at Elroy 500kv Substation	b0287_dfax	$ 435,396.26	6.06%	21.17%	0.01%	0.00%	$26,385	$92,173	$44	$0	$118,602
Install 161 MVAR capcitor at Heaton 230kV Substation	b0208	$ 649,263.76	14.20%	0.00%	3.47%	0.00%	$92,195	$0	$22,529	$0	$114,725
							$1,326,078	**$1,148,021**	**$2,335,584**	**$90,304**	**$4,899,988**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

	(k)	(l)	(m)	(n)	(o)	(n)	
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 18/19**	**2018TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2018 Impact (7 months)**	**2019 Impact (5 months)**	**2018 Impact (12 months)**	
PSE&G	$ 194,632.00	9,566.9	$ 20.34	$ 1,362,424	$ 973,160	$ 2,335,584	$ 2,335,584
JCP&L	$ 95,668.44	5,721.0	$ 16.72	$ 669,679	$ 478,342	$ 1,148,021	$ 1,148,021
ACE	$ 110,506.51	2,540.8	$ 43.49	$ 773,546	$ 552,533	$ 1,326,078	$ 1,326,078
RE	$ 7,525.35	401.7	$ 18.73	$ 52,677	$ 37,627	$ 90,304	$ 90,304
Total Impact on NJ Zones	**$ 408,332.31**			**$ 2,858,326**	**$ 2,041,662**	**$ 4,899,988**	
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (k) *12	

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

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

Required Transmission Enhancement *per PJM website*	PJM Upgrade ID *per PJM spreadsheet*	(a) Jan - Dec 2018 Annual Revenue Requirement *per PJM website*	(b) ACE Zone Share[1]	(c) JCP&L Zone Share[1]	(d) PSE&G Zone Share[1]	(e) RE Zone Share[1]	(f) ACE Zone Charges	(g) JCP&L Zone Charges	(h) PSE&G Zone Charges	(i) RE Zone Charges	(j) Total NJ Zones Charges
			Responsible Customers - Schedule 12 Appendix *per PJM Open Access Transmission Tariff*				Estimated New Jersey EDC Zone Charges by Project				
New 765 KV circuit breakers at Hanging Rock Sub	b0504	$ 398,319	1.66%	3.74%	6.26%	0.26%	$6,612	$14,897	$24,935	$1,036	$47,480
New 765 KV circuit breakers at Hanging Rock Sub	b0504_dfax	$ 398,319	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Rockport Reactor Bank	b1465.2	$ 846,192	1.66%	3.74%	6.26%	0.26%	$14,047	$31,648	$52,972	$2,200	$100,866
Rockport Reactor Bank	b1465.2_dfax	$ 846,192	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Transpose Rockport- Sullivan 765KV line	b1465.3	$ 1,253,089	1.66%	3.74%	6.26%	0.26%	$20,801	$46,866	$78,443	$3,258	$149,368
Transpose Rockport- Sullivan 765KV line	b1465.3_dfax	$ 1,253,089	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Switching changes Sullivan 765KV station	b1465.4	$ 1,174,674	1.66%	3.74%	6.26%	0.26%	$19,500	$43,933	$73,535	$3,054	$140,021
Switching changes Sullivan 765KV station	b1465.4_dfax	$ 1,174,674	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
765kV circuit breaker at Wyoming station	b1661	$ 242,119	1.66%	3.74%	6.26%	0.26%	$4,019	$9,055	$15,157	$630	$28,861
765kV circuit breaker at Wyoming station	b1661_dfax	$ 242,119	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Term Tsfmr #2 @ SW Lima - new bay position	b1957	$ 1,954,622	0.00%	0.00%	4.54%	0.18%	$0	$0	$88,740	$3,518	$92,258
Reconductor/Rebuild Sporn-Waterford-Muskingham River 345 kV Line	b2017	$ 12,537,774	0.00%	1.39%	2.00%	0.08%	$0	$174,275	$250,755	$10,030	$435,061
Add four 765 kV Breakers at Kammar	b1962	$ 1,245,570	1.66%	3.74%	6.26%	0.26%	$20,676	$46,584	$77,973	$3,238	$148,472
Add four 765 kV Breakers at Kammar	b1962_dfax	$ 1,245,570	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Ft. Wayne Relocate	b1659.14	$ 5,470,038	1.66%	3.74%	6.26%	0.26%	$90,803	$204,579	$342,424	$14,222	$652,029
Ft. Wayne Relocate	b1659.14_dfax	$ 5,470,038	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Sorenson 765/500kV Transformer	b1659	$ 7,019,322	0.00%	0.00%	0.92%	0.04%	$0	$0	$64,578	$2,808	$67,385
Sorenson Work 765kV	b1659.13	$ 4,499,117	1.66%	3.74%	6.26%	0.26%	$74,685	$168,267	$281,645	$11,698	$536,295
Sorenson Work 765kV	b1659.13_dfax	$ 4,499,117	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Baker Station 765/500kV Transformer	b1495	$ 7,030,717	0.41%	0.90%	1.48%	0.06%	$28,826	$63,276	$104,055	$4,218	$200,375
Cloverdale 765/500kV Transformer	b1660	$ (1,475,817)	1.66%	3.74%	6.26%	0.26%	($24,499)	($55,196)	($92,386)	($3,837)	($175,917)
Cloverdale 765/500kV Transformer	b1660_dfax	$ (1,475,817)	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Cloverdale 500kV Station	b1660.1	$ (1,228,805)	1.66%	3.74%	6.26%	0.26%	($20,398)	($45,957)	($76,923)	($3,195)	($146,473)
Cloverdale 500kV Station	b1660.1_dfax	$ (1,228,805)	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Jacksons-Ferry 765kV Breakers	b1663.2	$ 561,525	1.66%	3.74%	6.26%	0.26%	$9,321	$21,001	$35,151	$1,460	$66,934
Jacksons-Ferry 765kV Breakers	b1663.2_dfax	$ 561,525	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Reconductor Cloverdale-Lexington 500kV	b1797.1	$ 5,058,998	1.66%	3.74%	6.26%	0.26%	$83,979	$189,207	$316,693	$13,153	$603,033
Reconductor West Bellaire	b1970	$ 2,582,695	0.00%	1.68%	2.88%	0.11%	$0	$43,389	$74,382	$2,841	$120,612
Add a 3rd 2250 MVA 765/345 kV transformer at Sullivan station	b1465.1	$ 3,670,194	0.71%	1.58%	2.63%	0.10%	$26,058	$57,989	$96,526	$3,670	$184,244
Replace existing 150 MVAR reactor at Amos 765 kV sub	b2230	$ 1,387,358	1.66%	3.74%	6.26%	0.26%	$23,030	$51,887	$86,849	$3,607	$165,373
Install a 300 MVAR shunt reactor at AEP's Wyoming 765 kV station	b2423	$ 1,079,534	1.66%	3.74%	6.26%	0.26%	$17,920	$40,375	$67,579	$2,807	$128,680
Install a 450 MVAR SVC Jackson's Ferry 765kV Substation	b2687.1	$ 4,022,724	1.66%	3.74%	6.26%	0.26%	$66,777	$150,450	$251,823	$10,459	$479,509
Install 300 MVAR shunt line reactor	b2687.2	$ 587,436	1.66%	3.74%	6.26%	0.26%	$9,751	$21,970	$36,773	$1,527	$70,022
Totals							**$471,911**	**$1,278,495**	**$2,251,677**	**$92,403**	**$4,094,486**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

Zonal Cost Allocation for New Jersey Zones	(k) Average Monthly Impact on Zone Customers in 2018	(l) 2018TX Peak Load *per PJM website*	(m) Rate in $/MW-mo.	(n) 2018 Impact (12 months)
PSE&G	$ 187,639.75	9,566.9	$ 19.61	$ 2,251,677
JCP&L	$ 106,541.27	5,721.0	$ 18.62	$ 1,278,495
ACE	$ 39,325.89	2,540.8	$ 15.48	$ 471,911
RE	$ 7,700.27	401.7	$ 19.17	$ 92,403
Total Impact on NJ Zones	**$ 341,207.19**			**$ 4,094,486**
Notes on calculations >>>			= (k) * (l)	= (k) *12

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

Attachment 7a (PSE&G OATT)

SCHEDULE 12 – APPENDIX

(12) Public Service Electric and Gas Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0025	Convert the Bergen-Leonia 138 Kv circuit to 230 kV circuit.		PSEG (100%)
b0090	Add 150 MVAR capacitor at Camden 230 kV		PSEG (100%)
b0121	Add 150 MVAR capacitor at Aldene 230 kV		PSEG (100%)
b0122	Bypass the Essex 138 kV series reactors		PSEG (100%)
b0125	Add Special Protection Scheme at Bridgewater to automatically open 230 kV breaker for outage of Branchburg – Deans 500 kV and Deans 500/230 kV #1 transformer		PSEG (100%)
b0126	Replace wavetrap on Branchburg – Flagtown 230 kV		PSEG (100%)
b0127	Replace terminal equipment to increase Brunswick – Adams – Bennetts Lane 230 kV to conductor rating		PSEG (100%)
b0129	Replace wavetrap on Flagtown – Somerville 230 kV		PSEG (100%)
b0130	Replace all derated Branchburg 500/230 kV transformers		AEC (1.36%) / JCPL (47.76%) / PSEG (50.88%)
b0134	Upgrade or Retension PSEG portion of Kittatinny – Newton 230 kVcircuit		JCPL (51.11%) / PSEG (45.96%) / RE (2.93%)

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0145	Build new Essex – Aldene 230 kV cable connected through a phase angle regulator at Essex		PSEG (21.78%) / JCPL (73.45%) /RE (4.77%)
b0157	Add 100MVAR capacitor at West Orange 138kV substation		PSEG (100%)
b0158	Close the Sunnymeade "C" and "F" bus tie		PSEG (100%)
b0159	Make the Bayonne reactor permanent installation		PSEG (100%)
b0160	Relocate the X-2250 circuit from Hudson 1-6 bus to Hudson 7-12 bus		PSEG (100%)
b0161	Install 230/138kV transformer at Metuchen substation		PSEG (99.80%) / RE (0.20%)
b0162	Upgrade the Edison – Meadow Rd 138kV "Q" circuit		PSEG (100%)
b0163	Upgrade the Edison – Meadow Rd 138kV "R" circuit		PSEG (100%)
b0169	Build a new 230 kV section from Branchburg – Flagtown and move the Flagtown – Somerville 230 kV circuit to the new section		AEC (*1.76*%) / JCPL (*26.50*%) / Neptune* (*10.85*%) / PSEG (*60.89*%)
b0170	Reconductor the Flagtown-Somerville-Bridgewater 230 kV circuit with 1590 ACSS		JCLP (42.95%) / Neptune* (17.90%) / PSEG (38.36%) RE (0.79%)

* Neptune Regional Transmission System, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0172.2	Replace wave trap at Branchburg 500kV substation		**Load-Ratio Share Allocation;** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (5.32%) / JCPL (33.44%) / NEPTUNE (5.35%) / PSEG (53.73%) / RE (2.16%)
b0184	Replace Hudson 230kV circuit breakers #1-2		PSEG (100%)
b0185	Replace Deans 230kV circuit breakers #9-10		PSEG (100%)
b0186	Replace Essex 230kV circuit breaker #5-6		PSEG (100%)
b1082	Install 230/138 kV transformer at Bergen substation		PENELEC (16.52%) / PSEG (80.29%) / RE (3.19%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0201	Branchburg substation: replace wave trap on Branchburg – Readington 230 kV circuit		PSEG (100%)
b0213.1	Replace New Freedom 230 kV breaker BS2-6		PSEG (100%)
b0213.3	Replace New Freedom 230 kV breaker BS2-8		PSEG (100%)
b0274	Replace both 230/138 kV transformers at Roseland		PSEG (*100*%)
b0275	Upgrade the two 138 kV circuits between Roseland and West Orange		PSEG (100%)
b0278	Install 228 MVAR capacitor at Roseland 230 kV substation		PSEG (100%)
b0290	Install 400 MVAR capacitor in the Branchburg 500 kV vicinity		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (5.32%) / JCPL (33.44%) / NEPTUNE (5.35%) / PSEG (53.73%) / RE (2.16%)
b0358	Reconductor the PSEG portion of Buckingham – Pleasant Valley 230 kV, replace wave trap and metering transformer		PSEG (100%)

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Public Service Electric and Gas Company (cont.)

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0401.8	Replace W. Orange 138 kV breaker 132-4		PSEG (100%)
b0411	Install 4th 500/230 kV transformer at New Freedom		AEC (47.01%) / JCPL (7.04%) / Neptune* (0.28%) / PECO (23.36%) / PSEG (22.31%)
b0423	Reconductor Readington (2555) – Branchburg (4962) 230 kV circuit w/1590 ACSS		PSEG (100%)
b0424	Replace Readington wavetrap on Readington (2555) – Roseland (5017) 230 kV circuit		PSEG (100%)
b0425	Reconductor Linden (4996) – Tosco (5190) 230 kV circuit w/1590 ACSS (Assumes operating at 220 degrees C)		PSEG (100%)
b0426	Reconductor Tosco (5190) – G22_MTX5 (90220) 230 kV circuit w/1590 ACSS (Assumes operation at 220 degrees C)		PSEG (100%)
b0427	Reconductor Athenia (4954) – Saddle Brook (5020) 230 kV circuit river section		PSEG (100%)
b0428	Replace Roseland wavetrap on Roseland (5019) – West Caldwell "G" (5089) 138 kV circuit		PSEG (100%)
b0429	Reconductor Kittatinny (2553) – Newton (2535) 230 kV circuit w/1590 ACSS		JCPL (*42.63*%) / Neptune* (*3.65*%) / PSEG (*51.45*%) / RE (*2.27*%)
b0439	Spare Deans 500/230 kV transformer		PSEG (100%)
b0446.1	Upgrade Bayway 138 kV breaker #2-3		PSEG (100%)
b0446.2	Upgrade Bayway 138 kV breaker #3-4		PSEG (100%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0446.3	Upgrade Bayway 138 kV breaker #6-7		PSEG (100%)
b0446.4	Upgrade the breaker associated with TX 132-5 on Linden 138 kV		PSEG (100%)
b0470	Install 138 kV breaker at Roseland and close the Roseland 138 kV buses		PSEG (100%)
b0471	Replace the wave traps at both Lawrence and Pleasant Valley on the Lawrence – Pleasant Vallen 230 kV circuit		PSEG (100%)
b0472	Increase the emergency rating of Saddle Brook – Athenia 230 kV by 25% by adding forced cooling		PSEG (*96.40*%) / RE (*3.60*%)
b0473	Move the 150 MVAR mobile capacitor from Aldene 230 kV to Lawrence 230 kV substation		PSEG (100%)
b0489	Build new 500 kV transmission facilities from Pennsylvania – New Jersey border at Bushkill to Roseland		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)†
			DFAX Allocation: JCPL (39.91%) / NEPTUNE (3.86%) / PSEG (54.05%) / RE (2.18%)

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

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b489.1	Replace Athenia 230 kV breaker 31H		PSEG (100%)
b489.2	Replace Bergen 230 kV breaker 10H		PSEG (100%)
b489.3	Replace Saddlebrook 230 kV breaker 21P		PSEG (100%)
b0489.4	Install two Roseland 500/230 kV transformers as part of the Susquehanna – Roseland 500 kV project		AEC (*5.14*%) / ComEd (0.29%) / Dayton (0.03%) / DPL (*1.78*%) / JCPL (*33.04*%) / Neptune* (*6.38*%) / PECO (*10.14*%) / PENELEC (*0.57*%) / PSEG (*41.10*%) / RE (*1.53*%) ††
b0489.5	Replace Roseland 230 kV breaker '42H' with 80 kA		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: JCPL (39.91%) / NEPTUNE (3.86%) / PSEG (54.05%) / RE (2.18%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0489.6	Replace Roseland 230 kV breaker '51H' with 80 kA		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: JCPL (39.91%) / NEPTUNE (3.86%) / PSEG (54.05%) / RE (2.18%)
b0489.7	Replace Roseland 230 kV breaker '71H' with 80 kA		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: JCPL (39.91%) / NEPTUNE (3.86%) / PSEG (54.05%) / RE (2.18%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0489.8	Replace Roseland 230 kV breaker '31H' with 80 kA		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: JCPL (39.91%) / NEPTUNE (3.86%) / PSEG (54.05%) / RE (2.18%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0489.9	Replace Roseland 230 kV breaker '11H' with 80 kA		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: JCPL (39.91%) / NEPTUNE (3.86%) / PSEG (54.05%) / RE (2.18%)
b0489.10	Replace Roseland 230 kV breaker '21H'		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: JCPL (39.91%) / NEPTUNE (3.86%) / PSEG (54.05%) / RE (2.18%)

* Neptune Regional Transmission System, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0489.11	Replace Roseland 230 kV breaker '32H'		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: JCPL (39.91%) / NEPTUNE (3.86%) / PSEG (54.05%) / RE (2.18%)
b0489.12	Replace Roseland 230 kV breaker '12H'		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: JCPL (39.91%) / NEPTUNE (3.86%) / PSEG (54.05%) / RE (2.18%)

* Neptune Regional Transmission System, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0489.13	Replace Roseland 230 kV breaker '52H'		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: JCPL (39.91%) / NEPTUNE (3.86%) / PSEG (54.05%) / RE (2.18%)
b0489.14	Replace Roseland 230 kV breaker '41H'		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: JCPL (39.91%) / NEPTUNE (3.86%) / PSEG (54.05%) / RE (2.18%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0489.15	Replace Roseland 230 kV breaker '72H'		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: JCPL (39.91%) / NEPTUNE (3.86%) / PSEG (54.05%) / RE (2.18%)
b0498	Loop the 5021 circuit into New Freedom 500 kV substation		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (9.56%) / JCPL (26.03%) / NEPTUNE (3.02%) / PECO (18.39%) / PSEG (41.34%) / RE (1.66%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0498.1	Upgrade the 20H circuit breaker		PSEG (100%)
b0498.2	Upgrade the 22H circuit breaker		PSEG (100%)
b0498.3	Upgrade the 30H circuit breaker		PSEG (100%)
b0498.4	Upgrade the 32H circuit breaker		PSEG (100%)
b0498.5	Upgrade the 40H circuit breaker		PSEG (100%)
b0498.6	Upgrade the 42H circuit breaker		PSEG (100%)
b0512	MAPP Project – install new 500 kV transmission from Possum Point to Calvert Cliffs and install a DC line from Calvert Cliffs to Vienna and a DC line from Calvert Cliffs to Indian River		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0565	Install 100 MVAR capacitor at Cox's Corner 230 kV substation		PSEG (100%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0578	Replace Essex 138 kV breaker 4LM (C1355 line to ECRRF)		PSEG (100%)
b0579	Replace Essex 138 kV breaker 1LM (220-1 TX)		PSEG (100%)
b0580	Replace Essex 138 kV breaker 1BM (BS1-3 tie)		PSEG (100%)
b0581	Replace Essex 138 kV breaker 2BM (BS3-4 tie)		PSEG (100%)
b0582	Replace Linden 138 kV breaker 3 (132-7 TX)		PSEG (100%)
b0592	Replace Metuchen 138 kV breaker '2-2 Transfer'		PSEG (100%)
b0664	Reconductor with 2x1033 ACSS conductor		JCPL (36.35%) / NEPTUNE* (18.80%) / PSEG (43.24%) / RE (1.61%)
b0665	Reconductor with 2x1033 ACSS conductor		JCPL (36.35%) / NEPTUNE* (18.80%) / PSEG (43.24%) / RE (1.61%)
b0668	Reconductor with 2x1033 ACSS conductor		JCPL (39.41%) / NEPTUNE* (20.38%) / PSEG (38.76%) / RE (1.45%)
b0671	Replace terminal equipment at both ends of line		PSEG (100%)
b0743	Add a bus tie breaker at Roseland 138 kV		PSEG (100%)
b0812	Increase operating temperature on line for one year to get 925E MVA rating		PSEG (100%)
b0813	Reconductor Hudson – South Waterfront 230 kV circuit		BGE (1.25%) / JCPL (9.92%) / NEPTUNE* (0.87%) / PEPCO (1.11%) / PSEG (83.73%) / RE (3.12%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0814	New Essex – Kearney 138 kV circuit and Kearney 138 kV bus tie		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.1	Replace Kearny 138 kV breaker '1-SHT' with 80 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.2	Replace Kearny 138 kV breaker '15HF' with 80 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.3	Replace Kearny 138 kV breaker '14HF' with 80 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.4	Replace Kearny 138 kV breaker '10HF' with 80 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.5	Replace Kearny 138 kV breaker '2HT' with 80 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.6	Replace Kearny 138 kV breaker '22HF' with 80 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.7	Replace Kearny 138 kV breaker '4HT' with 80 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.8	Replace Kearny 138 kV breaker '25HF' with 80 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.9	Replace Essex 138 kV breaker '2LM' with 63 kA breaker and 2.5 cycle contact parting time		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)

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Public Service Electric and Gas Company (cont.)

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

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0814.18	Replace Marion 138 kV breaker '3LM' with 63 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.19	Replace Marion 138 kV breaker '1HM' with 63 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.20	Replace Marion 138 kV breaker '2PM3' with 63 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.21	Replace Marion 138 kV breaker '2PM1' with 63 kA breaker		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.22	Replace ECRR 138 kV breaker '903'		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.23	Replace Foundry 138 kV breaker '21P'		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.24	Change the contact parting time on Essex 138 kV breaker '3LM' to 2.5 cycles		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.25	Change the contact parting time on Essex 138 kV breaker '2BM' to 2.5 cycles		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0814.26	Change the contact parting time on Essex 138 kV breaker '1BM' to 2.5 cycles		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.27	Change the contact parting time on Essex 138 kV breaker '3PM' to 2.5 cycles		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.28	Change the contact parting time on Essex 138 kV breaker '4LM' to 2.5 cycles		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.29	Change the contact parting time on Essex 138 kV breaker '1PM' to 2.5 cycles		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)
b0814.30	Change the contact parting time on Essex 138 kV breaker '1LM' to 2.5 cycles		JCPL (23.49%) / NEPTUNE* (1.61%) / PENELEC (5.37%) / PSEG (67.03%) / RE (2.50%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0829	Build Branchburg to Roseland 500 kV circuit as part of Branchburg – Hudson 500 kV project		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0829.6	Replace Branchburg 500 kV breaker 91X		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: PSEG (96.13%) / RE (3.87%)
b0829.9	Replace Branchburg 230 kV breaker 102H		PSEG (100%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0829.11	Replace Branchburg 230 kV breaker 32H		PSEG (100%)
b0829.12	Replace Branchburg 230 kV breaker 52H		PSEG (100%)
b0830	Build Roseland - Hudson 500 kV circuit as part of Branchburg – Hudson 500 kV project		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0830.1	Replace Roseland 230 kV breaker '82H' with 80 kA		PSEG (100%
b0830.2	Replace Roseland 230 kV breaker '91H' with 80 kA		PSEG (100%)
b0830.3	Replace Roseland 230 kV breaker '22H' with 80 kA		PSEG (100%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0831	Replace 138/13 kV transformers with 230/13 kV units as part of Branchburg – Hudson 500 kV project		ComEd (*2.57*%) / Dayton (0.09%) / PENELEC (*2.82*%) / PSEG (*90.97*%) / RE (*3.55*%)
b0832	Build Hudson 500 kV switching station as part of Branchburg – Hudson 500 kV project		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0833	Build Roseland 500 kV switching station as part of Branchburg – Hudson 500 kV project		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0834	Convert the E-1305/F-1306 to one 230 kV circuit as part of Branchburg – Hudson 500 kV project		ComEd (2.57%) / Dayton (0.09%) / PENELEC (2.82%) / PSEG (90.97%) / RE (3.55%)
b0835	Build Hudson 230 kV transmission lines as part of Roseland – Hudson 500 kV project as part of Branchburg – Hudson 500 kV project		ComEd (2.57%) / Dayton (0.09%) / PENELEC (2.82%) / PSEG (90.97%) / RE (3.55%)
b0836	Install transformation at new Hudson 500 kV switching station and perform Hudson 230 kV and 345 kV station work as part of Branchburg – Hudson 500 kV project		ComEd (2.57%) / Dayton (0.09%) / PENELEC (2.82%) / PSEG (90.97%) / RE (3.55%)
b0882	Replace Hudson 230 kV breaker 1HA with 80 kA		PSEG (100%)
b0883	Replace Hudson 230 kV breaker 2HA with 80 kA		PSEG (100%)
b0884	Replace Hudson 230 kV breaker 3HB with 80 kA		PSEG (100%)
b0885	Replace Hudson 230 kV breaker 4HA with 80 kA		PSEG (100%)
b0886	Replace Hudson 230 kV breaker 4HB with 80 kA		PSEG (100%)
b0889	Replace Bergen 230 kV breaker '21H'		PSEG (100%)
b0890	Upgrade New Freedom 230 kV breaker '21H'		PSEG (100%)
b0891	Upgrade New Freedom 230 kV breaker '31H'		PSEG (100%)
b0899	Replace ECRR 138 kV breaker 901		PSEG (100%)
b0900	Replace ECRR 138 kV breaker 902		PSEG (100%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1013	Replace Linden 138 kV breaker '7PB'		PSEG (100%)
b1017	Reconductor South Mahwah - Waldwick 345 kV J-3410 circuit		JCPL (*29.27*%) / NEPTUNE* (*2.76*%) / PSEG (*65.42*%) / RE (*2.55*%)
b1018	Reconductor South Mahwah - Waldwick 345 kV K-3411 circuit		JCPL (*29.44*%) / NEPTUNE* (*2.76*%) / PSEG (*65.25*%) / RE (*2.55*%)
b1019.1	Replace wave trap, line disconnect and ground switch at Roseland on the F-2206 circuit		PSEG (100%)
b1019.2	Replace wave trap, line disconnect and ground switch at Roseland on the B-2258 circuit		PSEG (100%)
b1019.3	Replace 1-2 and 2-3 section disconnect and ground switches at Cedar Grove on the F-2206 circuit		PSEG (100%)
b1019.4	Replace 1-2 and 2-3 section disconnect and ground switches at Cedar Grove on the B-2258 circuit		PSEG (100%)
b1019.5	Replace wave trap, line disconnect and ground switch at Cedar Grove on the F-2206 circuit		PSEG (100%)
b1019.6	Replace line disconnect and ground switch at Cedar Grove on the K-2263 circuit		PSEG (100%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1019.7	Replace 2-4 and 4-5 section disconnect and ground switches at Clifton on the B-2258 circuit		PSEG (100%)
b1019.8	Replace 1-2 and 2-3 section disconnect and ground switches at Clifton on the K-2263 circuit		PSEG (100%)
b1019.9	Replace line, ground, 230 kV main bus disconnects at Athenia on the B-2258 circuit		PSEG (100%)
b1019.10	Replace wave trap, line, ground 230 kV breaker disconnect and 230 kV main bus disconnects at Athenia on the K-2263 circuit		PSEG (100%)

Public Service Electric and Gas Company (cont.)

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

Public Service Electric and Gas Company (cont.)

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

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1156.16	Replace New Freedom 230 kV breaker '50H' with 63 kA		PSEG (100%)
b1156.17	Replace New Freedom 230 kV breaker '41H' with 63 kA		PSEG (100%)
b1156.18	Replace New Freedom 230 kV breaker '51H' with 63 kA		PSEG (100%)
b1156.19	Rebuild Camden 230 kV to 80 kA		PSEG (100%)
b1156.20	Rebuild Burlington 230 kV to 80 kA		PSEG (100%)
b1197.1	Reconductor the PSEG portion of the Burlington – Croydon circuit with 1590 ACSS		PSEG (100%)
b1228	Re-configure the Lawrence 230 kV substation to breaker and half		PSEG (*96.18*%) / RE (*3.82*%)
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 (*0.28*%) / BGE (*1.18*%) / ComEd (*2.83*%) / Dayton (*0.16*%) / JCPL (*1.43*%) / Neptune (*0.09*%) / PENELEC (*3.63*%) / PEPCO (*1.27*%) / PSEG (*85.73*%) / RE (*3.40*%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1304.2	Expand existing Bergen 230 kV substation and reconfigure the Athenia 230 kV substation to breaker and a half scheme		AEC (*0.28*%) / BGE (*1.18*%) / ComEd (*2.83*%) / Dayton (*0.16*%) / JCPL (*1.43*%) / Neptune (*0.09*%) / PENELEC (*3.63*%) / PEPCO (*1.27*%) / PSEG (*85.73*%) / RE (*3.40*%)
b1304.3	Build second 230 kV underground cable from Bergen to Athenia		AEC (*0.28*%) / BGE (*1.18*%) / ComEd (*2.83*%) / Dayton (*0.16*%) / JCPL (*1.43*%) / Neptune (*0.09*%) / PENELEC (*3.63*%) / PEPCO (*1.27*%) / PSEG (*85.73*%) / RE (*3.40*%)
b1304.4	Build second 230 kV underground cable from Hudson to South Waterfront		AEC (*0.28*%) / BGE (*1.18*%) / ComEd (*2.83*%) / Dayton (*0.16*%) / JCPL (*1.43*%) / Neptune (*0.09*%) / PENELEC (*3.63*%) / PEPCO (*1.27*%) / PSEG (*85.73*%) / RE (*3.40*%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1304.5	Replace Athenia 230 kV breaker '21H' with 80 kA		PSEG (100%)
b1304.6	Replace Athenia 230 kV breaker '41H' with 80 kA		PSEG (100%)
b1304.7	Replace South Waterfront 230 kV breaker '12H' with 80 kA		PSEG (100%)
b1304.8	Replace South Waterfront 230 kV breaker '22H' with 80 kA		PSEG (100%)
b1304.9	Replace South Waterfront 230 kV breaker '32H' with 80 kA		PSEG (100%)
b1304.10	Replace South Waterfront 230 kV breaker '52H' with 80 kA		PSEG (100%)
b1304.11	Replace South Waterfront 230 kV breaker '62H' with 80 kA		PSEG (100%)
b1304.12	Replace South Waterfront 230 kV breaker '72H' with 80 kA		PSEG (100%)
b1304.13	Replace South Waterfront 230 kV breaker '82H' with 80 kA		PSEG (100%)
b1304.14	Replace Essex 230 kV breaker '20H' with 80 kA		PSEG (100%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1304.15	Replace Essex 230 kV breaker '21H' with 80 kA		PSEG (100%)
b1304.16	Replace Essex 230 kV breaker '10H' with 80 kA		PSEG (100%)
b1304.17	Replace Essex 230 kV breaker '11H' with 80 kA		PSEG (100%)
b1304.18	Replace Essex 230 kV breaker '11HL' with 80 kA		PSEG (100%)
b1304.19	Replace Newport R 230 kV breaker '23H' with 63 kA		PSEG (100%)
b1304.20	Rebuild Athenia 230 kV substation to 80 kA		PSEG (100%)
b1304.21	Rebuild Bergen 230 kV substation to 80 kA		PSEG (100%)
b1398	Build two new parallel underground circuits from Gloucester to Camden		JCPL (*13.03*%) / NEPTUNE (*1.20*%) / PECO (*51.93*%) / PEPCO (*0.58*%) / PSEG (*31.99*%) / RE (*1.27*%)
b1398.1	Install shunt reactor at Gloucester to offset cable charging		JCPL (*13.03*%) / NEPTUNE (*1.20*%) / PECO (*51.93*%) / PEPCO (*0.58*%) / PSEG (*31.99*%) / RE (*1.27*%)
b1398.2	Reconfigure the Cuthbert station to breaker and a half scheme		JCPL (*13.03*%) / NEPTUNE (*1.20*%) / PECO (*51.93*%) / PEPCO (*0.58*%) / PSEG (*31.99*%) / RE (*1.27*%)
b1398.3	Build a second 230 kV parallel overhead circuit from Mickelton – Gloucester		JCPL (*13.03*%) / NEPTUNE (*1.20*%) / PECO (*51.93*%) / PEPCO (*0.58*%) / PSEG (*31.99*%) / RE (*1.27*%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1398.4	Reconductor the existing Mickleton – Gloucester 230 kV circuit (PSEG portion)		JCPL (*13.03*%) / NEPTUNE (*1.20*%) / PECO (*51.93*%) / PEPCO (*0.58*%) / PSEG (*31.99*%) / RE (*1.27*%)
b1398.7	Reconductor the Camden – Richmond 230 kV circuit (PSEG portion) and upgrade terminal equipments at Camden substations		JCPL (*13.03*%) / NEPTUNE (*1.20*%) / PECO (*51.93*%) / PEPCO (*0.58*%) / PSEG (*31.99*%) / RE (*1.27*%)
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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1410	Replace Salem 500 kV breaker ‘11X’		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: PSEG (96.13%) / RE (3.87%)
b1411	Replace Salem 500 kV breaker ‘12X’		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: PSEG (96.13%) / RE (3.87%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1412	Replace Salem 500 kV breaker ‘20X’		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: PSEG (96.13%) / RE (3.87%)
b1413	Replace Salem 500 kV breaker ‘21X’		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: PSEG (96.13%) / RE (3.87%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1414	Replace Salem 500 kV breaker '31X'		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: PSEG (96.13%) / RE (3.87%)
b1415	Replace Salem 500 kV breaker '32X'		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: PSEG (96.13%) / RE (3.87%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1539	Replace Tosco 230 kV breaker 'CB1' with 63 kA		PSEG (100%)
b1540	Replace Tosco 230 kV breaker 'CB2' with 63 kA		PSEG (100%)
b1541	Open the Hudson 230 kV bus tie		PSEG (100%)
b1588	Reconductor the Eagle Point - Gloucester 230 kV circuit #1 and #2 with higher conductor rating		JCPL (*10.48*%) / Neptune* (*1.00*%) / PECO (*31.30*%) / PSEG (*55.03*%) / RE (*2.19*%)
b1589	Re-configure the Kearny 230 kV substation and loop the P-2216-1 (Essex - NJT Meadows) 230 kV circuit		ATSI (*10.02*%) / PENELEC (*9.74*%) / PSEG (*77.16*%) / RE (*3.08*%)
b1590	Upgrade the PSEG portion of the Camden Richmond 230 kV circuit to six wire conductor and replace terminal equipment at Camden		BGE (*3.06*%) / ME (0.83%) / PECO (*91.70*%) / PEPCO (*1.94*%) / PPL (*2.47*%)
b1749	Advance n1237 (Replace Essex 230 kV breaker '22H' with 80kA)		PSEG (100%)
b1750	Advance n0666.5 (Replace Hudson 230 kV breaker '1HB' with 80 kA (without TRV cap, so actually 63 kA))		PSEG (100%)
b1751	Advance n0666.3 (Replace Hudson 230 kV breaker '2HA' with 80 kA (without TRV cap, so actually 63 kA))		PSEG (100%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1752	Advance n0666.10 (Replace Hudson 230 kV breaker '2HB' with 80 kA (without TRV cap, so actually 63 kA))		PSEG (100%)
b1753	Marion 138 kV breaker '7PM' - delay the relay time to increase the contact parting time to 2.5 cycles		PSEG (100%)
b1754	Marion 138 kV breaker '3PM' - delay the relay time to increase the contact parting time to 2.5 cycles		PSEG (100%)
b1755	Marion 138 kV breaker '6PM' - delay the relay time to increase the contact parting time to 2.5 cycles		PSEG (100%)
b1787	Build a second 230 kV circuit from Cox's Corner - Lumberton		AEC (*4.97*%) / JCPL (*44.34*%) / NEPTUNE* (0.53%) / PSEG (*48.23*%) / RE (*1.93*%)
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%)

*Neptune Regional Transmission System, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2039	Replace Bayonne 138 kV breaker '11P'		PSEG (100%)
b2139	Reconductor the Mickleton - Gloucester 230 kV parallel circuits with double bundle conductor		PSEG (61.11%) / PECO (36.45%) / RE (2.44%)
b2146	Re-configure the Brunswick 230 kV and 69 kV substations		PSEG (96.16%) / RE (3.84%)
b2151	Construct Jackson Rd. 69 kV substation and loop the Cedar Grove - Hinchmans Ave into Jackson Rd. and construct Hawthorne 69 kV substation and build 69 kV circuit from Hinchmans Ave - Hawthorne - Fair Lawn		PSEG (100%)
b2159	Reconfigure the Linden, Bayway, North Ave, and Passaic Valley S.C. 138 kV substations. Construct and loop new 138 kV circuit to new airport station		PSEG (*96.16*%) / RE (*3.84*%)

*Neptune Regional Transmission System, LLC

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)		*PSEG (100%)*
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

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

Public Service Electric and Gas Company (cont.)

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

*Neptune Regional Transmission System, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2421.2	Install a second four (4) breaker 69kV ring bus at Bridgewater Switching Station		PSEG (100%)
b2436.10	Convert the Bergen – Marion 138 kV path to double circuit 345 kV and associated substation upgrades		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: PSEG (100%)
b2436.21	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: *PSEG* (100%)

*Neptune Regional Transmission System, 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 (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: PSEG (100%)
b2436.33	Construct a new Bayway – Bayonne 345 kV circuit and any associated substation upgrades		PSEG (100%)
b2436.34	Construct a new North Ave – Bayonne 345 kV circuit and any associated substation upgrades		PSEG (100%)

*Neptune Regional Transmission System, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2436.50	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades		PSEG (100%)
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		PSEG (96.13%) / RE (3.87%)
b2436.70	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades		PSEG (100%)
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 (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: PSEG (96.13%) / RE (3.87%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2436.83	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: PSEG (96.13%) / RE (3.87%)
b2436.84	Convert the Bayway – Linden “W” 138 kV circuit to 345 kV and any associated substation upgrades		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: PSEG (96.13%) / RE (3.87%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2436.85	Convert the Bayway – Linden “M” 138 kV circuit to 345 kV and any associated substation upgrades		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: PSEG (96.13%) / RE (3.87%)
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 (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: PSEG (96.13%) / RE (3.87%)
b2436.91	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades		PSEG (100%)

*Neptune Regional Transmission System, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2437.10	New Bergen 345/230 kV transformer and any associated substation upgrades		PSEG (96.13%) / RE (3.87%)
b2437.11	New Bergen 345/138 kV transformer #1 and any associated substation upgrades		PSEG (100%)
b2437.20	New Bayway 345/138 kV transformer #1 and any associated substation upgrades		PSEG (96.13%) / RE (3.87%)
b2437.21	New Bayway 345/138 kV transformer #2 and any associated substation upgrades		PSEG (96.13%) / RE (3.87%)
b2437.30	New Linden 345/230 kV transformer and any associated substation upgrades		PSEG (96.13%) / RE (3.87%)
b2437.33	New Bayonne 345/69 kV transformer and any associated substation upgrades		PSEG (100%)
b2438	Install two reactors at Tosco 230 kV		PSEG (100.00%)
b2439	Replace the Tosco 138kV breaker 'CB1/2 (CBT)' with 63kA		PSEG (100.00%)
b2474	Rebuild Athenia 138 kV to 80kA		PSEG (100%)
b2589	Install a 100 MVAR 230 kV shunt reactor at Mercer station		PSEG (100%)
b2590	Install two 75 MVAR 230 kV capacitors at Sewaren station		PSEG (100%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2633.3	Install an SVC at New Freedom 500 kV substation		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (0.01%) / DPL (99.98%) / JCPL (0.01%)
b2633.4	Add a new 500 kV bay at Hope Creek (Expansion of Hope Creek substation)		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (0.01%) / DPL (99.98%) / JCPL (0.01%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2633.5	Add a new 500/230 kV autotransformer at Hope Creek and a new Hope Creek 230 kV substation		AEC (0.01%) / DPL (99.98%) / JCPL (0.01%)
b2633.8	Implement high speed relaying utilizing OPGW on Salem – Orchard 500 kV, Hope Creek – New Freedom 500 kV, New Freedom - Salem 500 kV, Hope Creek – Salem 500 kV, and New Freedom – Orchard 500 kV lines		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (0.01%) / DPL (99.98%) / JCPL (0.01%)

*Neptune Regional Transmission System, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2633.91	Implement changes to the tap settings for the two Salem units' step up transformers		AEC (0.01%) / DPL (99.98%) / JCPL (0.01%)
b2633.92	Implement changes to the tap settings for the Hope Creek unit's step up transformers		AEC (0.01%) / DPL (99.98%) / JCPL (0.01%)
b2702	Install a 350 MVAR reactor at Roseland 500 kV		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: PSEG (100%)
b2703	Install a 100 MVAR reactor at Bergen 230 kV		PSEG (100%)
b2704	Install a 150 MVAR reactor at Essex 230 kV		PSEG (100%)
b2705	Install a 200 MVAR reactor (variable) at Bergen 345 kV		PSEG (100%)
b2706	Install a 200 MVAR reactor (variable) at Bayway 345 kV		PSEG (100%)
b2707	Install a 100 MVAR reactor at Bayonne 345 kV		PSEG (100%)

*Neptune Regional Transmission System, LLC

Public Service Electric and Gas Company (cont.)

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2836	Convert the N-1340 and T-1372/D-1330 (Brunswick – Trenton) 138 kV circuits to 230 kV circuits		PSEG (100%)
b2837	Convert the F-1358/Z1326 and K1363/Y-1325 (Trenton – Burlington) 138 kV circuits to 230 kV circuits		PSEG (100%)
b2870	Build new 138/26 kV Newark GIS station in a building (layout #1A) located adjacent to the existing Newark Switch and demolish the existing Newark Switch		PSEG (100%)
b2933	Third Source for Springfield Rd. and Stanley Terrace Stations		PSEG (100%)
b2933.1	Construct a 230/69 kV station at Springfield		PSEG (100%)
b2933.2	Construct a 230/69 kV station at Stanley Terrace		PSEG (100%)
b2933.3	Construct a 69 kV network between Front Street, Springfield and Stanley Terrace		PSEG (100%)
b2934	Build a new 69 kV line between Hasbrouck Heights and Carlstadt		PSEG (100%)
b2935	Third Supply for Runnemede 69 kV and Woodbury 69 kV		PSEG (100%)
b2935.1	Build a new 230/69 kV switching substation at Hilltop utilizing the PSE&G property and the K-2237 230 kV line		PSEG (100%)
b2935.2	Build a new line between Hilltop and Woodbury 69 kV providing the 3rd supply		PSEG (100%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2935.3	Convert Runnemede's straight bus to a ring bus and construct a 69 kV line from Hilltop to Runnemede 69 kV		PSEG (100%)
b2955	*Wreck and rebuild the VFT – Warinanco – Aldene 230 kV circuit with paired conductor*		*JCPL (93.78%) / NEPTUNE* (6.22%)*
b2956	*Replace existing cable on Cedar Grove - Jackson Rd. with 5000kcmil XLPE cable*		*JCPL (0.05%) / NEPTUNE* (0.01%) / PSEG (96.07%) / RE (3.87%)*
b2982	Construct a 230/69 kV station at Hillsdale Substation and tie to Paramus and Dumont at 69 kV		PSEG (100%)
b2982.1	Install a 69 kV ring bus and one (1) 230/69 kV transformer at Hillsdale		PSEG (100%)
b2982.2	Construct a 69 kV network between Paramus, Dumont, and Hillsdale Substation using existing 69 kV circuits		PSEG (100%)
b2983	Convert Kuller Road to a 69/13 kV station		PSEG (100%)
b2983.1	Install 69 kV ring bus and two (2) 69/13 kV transformers at Kuller Road		PSEG (100%)
b2983.2	Construct a 69 kV network between Kuller Road, Passaic, Paterson, and Harvey (new Clifton area switching station)		PSEG (100%)
b2986	Replace the existing Roseland – Branchburg – Pleasant Valley 230 kV corridor with new structures		PSEG (100%)

Attachment 7b (JCP&L OATT)

SCHEDULE 12 – APPENDIX

(4) Jersey Central Power & Light Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0123	Add 180 MVAR of distributed capacitors. 65 MVAR in northern JCPL and 115 MVAR in southern JCPL		JCPL (100%)
b0124.1	Add a 72 MVAR capacitor at Kittatinny 230 kV		JCPL (100%)
b0124.2	Add a 130 MVAR capacitor at Manitou 230 kV		JCPL (100%)
b0132	Reconductor Portland – Kittatinny 230 kV with 1590 ACSS		JCPL (100%)
b0132.1	Replace terminal equipment on the Portland – Kittatinny 230 kV and CB at the Kittatinny bus		JCPL (100%)
b0132.2	Replace terminal equipment on the Portland – Kittatinny 230 kV and CB at the Portland bus		JCPL (100%)
b0173	Replace a line trap at Newton 230kV substation for the Kittatinny-Newton 230kV circuit		JCPL (100%)
b0174	Upgrade the Portland – Greystone 230kV circuit	The following rates are consistent with the settlement agreement filed in and approved by the Commission in Docket No. ER17-217, 2017: $1,442,372 2018: $1,273,748 2019: $1,235,637	JCPL (35.40%) / Neptune* (5.67%) / PSEG (54.37%) RE (2.94%) / ECP** (1.62%)
b0199	Greystone 230kV substation: Change Tap of limiting CT and replace breaker on the Greystone Whippany (Q1031) 230kV line		JCPL (100%)
b0200	Greystone 230kV substation: Change Tap of limiting CT on the West Wharton Greystone (E1045) 230kV line		JCPL (100%)

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

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0202	Kittatinny 230kV substation: Replace line trap on Kittatinny Pohatcong (L2012) 230kV line; Pohatcong 230kV substation: Change Tap of limiting CT on Kittatinny Pohatcong (L2012) 230kV line		JCPL (100%)
b0203	Smithburg 230kV Substation: Replace line trap on the East Windsor Smithburg (E2005) 230kV line; East Windsor 230kV substation: Replace line trap on the East Windsor Smithburg (E2005) 230kV line		JCPL (100%)
b0204	Install 72Mvar capacitor at Cookstown 230kV substation		JCPL (100%)
b0267	Reconductor JCPL 2 mile portion of Kittatinny – Newton 230 kV line		JCPL (100%)
b0268	Reconductor the 8 mile Gilbert – Glen Gardner 230 kV circuit	The following rates are consistent with the settlement agreement filed in and approved by the Commission in Docket No. ER17-217, 2017: $734,194 2018: $646,180 2019: $628,066	JCPL (61.77%) / Neptune* (3%) / PSEG (32.73%) / RE (1.45%) / ECP** (1.05%)

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

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0279.1	Install 100 MVAR capacitor at Glen Gardner substation		JCPL (100%)
b0279.2	Install MVAR capacitor at Kittatinny 230 kV substation		JCPL (100%)
b0279.3	Install 17.6 MVAR capacitor at Freneau 34.5 kV substation		JCPL (100%)
b0279.4	Install 6.6 MVAR capacitor at Waretown #1 bank 34.5 kV substation		JCPL (100%)
b0279.5	Install 10.8 MVAR capacitor at Spottswood #2 bank .4.5 kV substation		JCPL (100%)
b0279.6	Install 6.6 MVAR capacitor at Pequannock N bus 34.5 kV substation		JCPL (100%)
b0279.7	Install 6.6 MVAR capacitor at Haskell P bus 34.5 kV substation		JCPL (100%)
b0279.8	Install 6.6 MVAR capacitor at Pinewald #2 Bank 34.5 kV substation		JCPL (100%)
b0279.9	Install 6.6 MVAR capacitor at Matrix 34.5 kV substation		JCPL (100%)
b0279.10	Install 6.6 MVAR capacitor at Hamburg Boro Q Bus 34.5 kV substation		JCPL (100%)
b0279.11	Install 6.6 MVAR capacitor at Newburg Q Bus 34.5 kV substation		JCPL (100%)
b0286	Install 130 MVAR capacitor at Whippany 230 kV		JCPL (100%)
b0289	Install 600 MVAR Dynamic Reactive Device in the Whippany 230 kV vicinity		AEC (0.65%) / JCPL (30.37%) / Neptune* (4.96%) / PSEG (59.65%) / RE (2.66%) / ECP** (1.71%)
b0289.1	Install additional 130 MVAR capacitor at West Wharton 230 kV substation		JCPL (100%)

* Neptune Regional Transmission System, LLC

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

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0292	Replace a 1600A line trap at Atlantic Larrabee 230 kV substation		JCPL (100%)
b0350	Implement Operating Procedure of closing the Glendon – Gilbert 115 kV circuit		JCPL (100%)
b0356	Replace wave trap on the Portland – Greystone 230 kV		JCPL (100%)
b0361	Change tap of limiting CT at Morristown 230 kV		JCPL (100%)
b0362	Change tap setting of limiting CT at Pohatcong 230 kV		JCPL (100%)
b0363	Change tap setting of limiting CT at Windsor 230 kV		JCPL (100%)
b0364	Change tap setting of CT at Cookstown 230 kV		JCPL (100%)
b0423.1	Upgrade terminal equipment at Readington (substation conductor)		JCPL (100%)
b0520	Replace Gilbert circuit breaker 12A		JCPL (100%)
b0657	Construct Boston Road 34.5 kV stations, construct Hyson 34.5 stations, add a 7.2 MVAR capacitor at Boston Road 34.5 kV		JCPL (100%)
b0726	Add a 2nd Raritan River 230/115 kV transformer	The following rates are consistent with the settlement agreement filed in and approved by the Commission in Docket No. ER17-217, 2017: $950,666 2018: $846,872 2019: $827,854	AEC (2.45%) / JCPL (97.55%)
b1020	Replace wave trap at Englishtown on the Englishtown - Manalapan circuit		JCPL (100%)

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1075	Replace the West Wharton - Franklin - Vermont D931 and J932 115 kV line conductors with 1590 45/7 ACSR wire between the tower structures 78 and 78-B		JCPL (100%)
b1154.1	Upgrade the Whippany 230 kV breaker 'JB'		JCPL (100%)
b1155.1	Upgrade the Red Oak 230 kV breaker 'G1047'		JCPL (100%)
b1155.2	Upgrade the Red Oak 230 kV breaker 'T1034'		JCPL (100%)
b1345	Install Martinsville 4-breaker 34.5 rink bus		JCPL (100%)
b1346	Reconductor the Franklin – Humburg (R746) 4.7 miles 34.5 kV line with 556 ACSR and build 2.7 miles 55 ACSR line extension to Sussex		JCPL (100%)
b1347	Replace 500 CU substation conductor with 795 ACSR on the Whitesville – Asbury Tap 34.5 kV (U47) line		JCPL (100%)
b1348	Upgrade the Newton – North Newton 34.5 kV (F708) line by adding a second underground 1250 CU egress cable		JCPL (100%)
b1349	Reconductor 5.2 miles of the Newton – Woodruffs Gap 34.5 kV (A703) line with 556 ACSR		JCPL (100%)
b1350	Upgrade the East Flemington – Flemington 34.5 kV (V724) line by adding second underground 1000 AL egress cable and replacing 4/0		JCPL (100%)

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1351	Add 34.5 kV breaker on the Larrabee A and D bus tie		JCPL (100%)
b1352	Upgrade the Smithburg – Centerstate Tap 34.5 kV (X752) line by adding second 200 ft underground 1250 CU egress cable		JCPL (100%)
b1353	Upgrade the Larrabee – Laurelton 34.5 kV (Q43) line by adding second 700 ft underground 1250 CU egress cable		JCPL (100%)

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1354	Add four 34.5 kV breakers and re-configure A/B bus at Rockaway		JCPL (100%)
b1355	Build a new section 3.3 miles 34.5 kV 556 ACSR line from Riverdale to Butler		JCPL (100%)
b1357	Build 10.2 miles new 34.5 kV line from Larrabee – Howell		JCPL (100%)
b1359	Install a Troy Hills 34.5 kV by-pass switch and reconfigure the Montville – Whippany 34.5 kV (D4) line		JCPL (100%)
b1360	Reconductor 0.7 miles of the Englishtown – Freehold Tap 34.5 kV (L12) line with 556 ACSR		JCPL (100%)
b1361	Reconductor the Oceanview – Neptune Tap 34.5 kV (D130) line with 795 ACSR		JCPL (100%)
b1362	Install a 23.8 MVAR capacitor at Wood Street 69 kV		JCPL (100%)
b1364	Upgrade South Lebanon 230/69 kV transformer #1 by replacing 69 kV substation conductor with 1590 ACSR		JCPL (100%)
b1399.1	Upgrade the Whippany 230 kV breaker 'QJ'		JCPL (100%)
b1673	Rocktown - Install a 230/34.5 kV transformer by looping the Pleasant Valley - E Flemington 230 kV Q-2243 line (0.4 miles) through the Rocktown Substation		JCPL (100%)

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1674	Build a new Englishtown - Wyckoff St 15 mile, 115 kV line and install 115/34.5 kV transformer at Wyckoff St		JCPL (100%)
b1689	Atlantic Sub - 230 kV ring bus reconfiguration. Put a "source" between the Red Bank and Oceanview "loads"		JCPL (100%)
b1690	Build a new third 230 kV line into the Red Bank 230 kV substation		JCPL (100%)
b1853	Install new 135 MVA 230/34.5 kV transformer with one 230 kV CB at Eaton Crest and create a new 34.5 kV CB straight bus to feed new radial lines to Locust Groove and Interdata/Woodbine		JCPL (100%)
b1854	Readington I737 34.5 kV Line - Parallel existing 1250 CU UG cable (440 feet)		JCPL (100%)
b1855	Oceanview Substation - Relocate the H216 breaker from the A bus to the B bus		JCPL (100%)
b1856	Madison Tp to Madison (N14) line - Upgrade limiting 250 Cu substation conductor with 795 ACSR at Madison sub		JCPL (100%)
b1857	Montville substation - Replace both the 397 ACSR and the 500 Cu substation conductor with 795 ACSR on the 34.5 kV (M117) line		JCPL (100%)

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1858	Reconductor the Newton - Mohawk (Z702) 34.5 kV line with 1.9 miles of 397 ACSR		JCPL (100%)
b2003	Construct a Whippany to Montville 230 kV line (6.4 miles)		JCPL (100%)
b2015	Build a new 230 kV circuit from Larrabee to Oceanview	The following rates are consistent with the settlement agreement filed in and approved by the Commission in Docket No. ER17-217, 2017: $9,616,241 2018: $18,839,128 2019: $19,935,489	JCPL (35.83%) / NEPTUNE* (23.61%) / HTP (1.77%) / ECP** (1.49%) / PSEG (35.87%) / RE (1.43%)
b2147	At Deep Run, install 115 kV line breakers on the B2 and C3 115 kV lines		JCPL (100%)

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

SCHEDULE 12 – APPENDIX A

(4) Jersey Central Power & Light Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2234	260 MVAR reactor at West Wharton 230 kV		JCPL (100%)
b2270	Advance Raritan River - Replace G1047E breaker at the 230kV Substation		JCPL (100%)
b2271	Advance Raritan River - Replace G1047F breaker at the 230kV Substation		JCPL (100%)
b2272	Advance Raritan River - Replace T1034E breaker at the 230kV Substation		JCPL (100%)
b2273	Advance Raritan River - Replace T1034F breaker at the 230kV Substation		JCPL (100%)
b2274	Advance Raritan River - Replace I1023E breaker at the 230kV Substation		JCPL (100%)
b2275	Advance Raritan River - Replace I1023F breaker at the 230kV Substation		JCPL (100%)
b2289	Freneau Substation - upgrade 2.5 inch pipe to bundled 1590 ACSR conductor at the K1025 230 kV Line Terminal		JCPL (100%)
b2292	Replace the Whippany 230 kV breaker B1 (CAP) with 63kA breaker		JCPL (100%)
b2357	Replace the East Windsor 230 kV breaker 'E1' with 63kA breaker		JCPL (100%)

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2495	Replace transformer leads on the Glen Gardner 230/34.5 kV #1 transformer		JCPL (100%)
b2496	Replace Franklin 115/34.5 kV transformer #2 with 90 MVA transformer		JCPL (100%)
b2497	Reconductor 0.9 miles of the Captive Plastics to Morris Park 34.5 kV circuit (397ACSR) with 556 ACSR		JCPL (100%)
b2498	Extend 5.8 miles of 34.5 kV circuit from North Branch substation to Lebanon substation with 397 ACSR and install 34.5 kV breaker at Lebanon substation		JCPL (100%)
b2500	Upgrade terminal equipment at Monroe on the Englishtown to Monroe (H34) 34.5 kV circuit		JCPL (100%)
b2570	Upgrade limiting terminal facilities at Feneau, Parlin, and Williams substations		JCPL (100%)
b2571	Upgrade the limiting terminal facilities at both Jackson and North Hanover		JCPL (100%)
b2586	Upgrade the V74 34.5 kV transmission line between Allenhurst and Elberon Substations		JCPL (100%)

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2633.6	Implement high speed relaying utilizing OPGW on Deans – East Windsor 500 kV		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (0.01%) / DPL (99.98%) / JCPL (0.01%)
b2633.6.1	Implement high speed relaying utilizing OPGW on East Windsor - New Freedom 500 kV		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (0.01%) / DPL (99.98%) / JCPL (0.01%)

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2676	Install one (1) 72 MVAR fast switched capacitor at the Englishtown 230 kV substation		JCPL (100%)
b2708	Replace the Oceanview 230/34.5 kV transformer #1		JCPL (100%)
b2709	Replace the Deep Run 230/34.5 kV transformer #1		JCPL (100%)
b2754.2	Install 5 miles of optical ground wire (OPGW) between Gilbert and Springfield 230 kV substations		JCPL (100%)
b2754.3	Install 7 miles of all-dielectric self-supporting (ADSS) fiber optic cable between Morris Park and Northwood 230 kV substations		JCPL (100%)
b2754.6	Upgrade relaying at Morris Park 230 kV		JCPL (100%)
b2754.7	Upgrade relaying at Gilbert 230 kV		JCPL (100%)

Attachment 7c (ACE OATT)

SCHEDULE 12 – APPENDIX

(1) Atlantic City Electric Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0135	Build new Cumberland – Dennis 230 kV circuit which replaces existing Cumberland – Corson 138 kV		AEC (100%)
b0136	Install Dennis 230/138 kV transformer, Dennis 150 MVAR SVC and 50 MVAR capacitor		AEC (100%)
b0137	Build new Dennis – Corson 138 kV circuit		AEC (100%)
b0138	Install Cardiff 230/138 kV transformer and a 50 MVAR capacitor at Cardiff		AEC (100%)
b0139	Build new Cardiff – Lewis 138 kV circuit		AEC (100%)
b0140	Reconductor Laurel – Woodstown 69 kV		AEC (100%)
b0141	Reconductor Monroe – North Central 69 kV		AEC (100%)
b0265	Upgrade AE portion of Delco Tap – Mickleton 230 kV circuit		AEC (89.87%) / JCPL (9.48%) / Neptune* (0.65%)
b0276	Replace both Monroe 230/69 kV transformers		AEC (91.46%) / PSEG (8.31%) / RE (0.23%)
b0276.1	Upgrade a strand bus at Monroe to increase the rating of transformer #2		AEC (100%)
b0277	Install a second Cumberland 230/138 kV transformer		AEC (100%)
b0281.1	Install 35 MVAR capacitor at Lake Ave 69 kV substation		AEC (100%)

Atlantic City Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0281.2	Install 15 MVAR capacitor at Shipbottom 69 kV substation		AEC (100%)
b0281.3	Install 8 MVAR capacitors on the AE distribution system		AEC (100%)
b0142	Reconductor Landis – Minotola 138 kV		AEC (100%)
b0143	Reconductor Beckett – Paulsboro 69 kV		AEC (100%)
b0210	Install a new 500/230kV substation in AEC area. The high side will be tapped on the Salem - East Windsor 500kV circuit and the low side will be tapped on the Churchtown - Cumberland 230kV circuit.		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (63.29%) / JCPL (36.71%)
b0210.1	Orchard – Cumberland – Install second 230 kV line		AEC (65.23%) / JCPL (25.87%) / Neptune * (2.55%) / PSEG (6.35%)††
b0210.2	Install a new 500/230kV substation in AEC area, the high side will be tapped on the Salem - East Windsor 500kV circuit and the low side will be tapped on the Churchtown - Cumberland 230kV circuit.		AEC (65.23%) / JCPL (25.87%) / Neptune* (2.55%) / PSEG (6.35%)††

* Neptune Regional Transmission System, LLC

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

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

The Annual Revenue Requirement associated with the Transmission Enhancement Charges are set forth and determined in Appendix A to Attachment H-1.

Atlantic City Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0211	Reconductor Union - Corson 138kV circuit		AEC (65.23%) / JCPL (25.87%) / Neptune* (2.55%) / PSEG (6.35%)
b0212	Substation upgrades at Union and Corson 138kV		AEC (65.23%) / JCPL (25.87%) / Neptune* (2.55%) / PSEG (6.35%)
b0214	Install 50 MVAR capacitor at Cardiff 230kV substation		AEC (100%)
b0431	Monroe Upgrade New Freedom strand bus		AEC (100%)
b0576	Move the Monroe 230/69 kV to Mickleton		AEC (100%)
b0744	Upgrade a strand bus at Mill 138 kV		AEC (100%)
b0871	Install 35 MVAR capacitor at Motts Farm 69 kV		AEC (100%)
b1072	Modify the existing EMS load shedding scheme at Cedar to additionally sense the loss of both Cedar 230/69 kV transformers and shed load accordingly		AEC (100%)
b1127	Build a new Lincoln-Minitola 138 kV line		AEC (100%)
b1195.1	Upgrade the Corson sub T2 terminal		AEC (100%)
b1195.2	Upgrade the Corson sub T1 terminal		AEC (100%)

Atlantic City Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1244	Install 10 MVAR capacitor at Peermont 69 kV substation		AEC (100%)
b1245	Rebuild the Newport-South Millville 69 kV line		AEC (100%)
b1250	Reconductor the Monroe – Glassboro 69 kV		AEC (100%)
b1250.1	Upgrade substation equipment at Glassboro		AEC (100%)
b1280	Sherman: Upgrade 138/69 kV transformers		AEC (100%)
b1396	Replace Lewis 138 kV breaker 'L'		AEC (100%)
b1398.5	Reconductor the existing Mickleton – Goucestr 230 kV circuit (AE portion)		JCPL (13.03%) / NEPTUNE (1.20%) / PECO (51.93%) / PEPCO (0.58%) / PSEG (31.99%) / RE (1.27%)
b1598	Reconductor Sherman Av – Carl's Corner 69kV circuit		AEC (100%)
b1599	Replace terminal equipments at Central North 69 kV substation		AEC (100%)
b1600	Upgrade the Mill T2 138/69 kV transformer		AEC (89.21%) / JCPL (4.76%) / PSEG (5.80%) / RE (0.23%)
b2157	Re-build 5.3 miles of the Corson - Tuckahoe 69 kV circuit		AEC (100%)

* Neptune Regional Transmission System, LLC

The Annual Revenue Requirement associated with the Transmission Enhancement Charges are set forth and determined in Appendix A to Attachment H-1.

SCHEDULE 12 – APPENDIX A

(1) Atlantic City Electric Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2123	Upgrade the 69 kV bus at Laurel		AEC (100%)
b2226	Upgrade the Tackahoe to Mill 69 kV circuit		AEC (100%)
b2227	50 MVAR shunt reactor at Mickleton 230 kV and relocate Mickleton #1 230 69 kV transformer		AEC (100%)
b2228	+150/-100 MVAR SVC at Cedar 230 kV		AEC (100%)
b2296	Replace the Mickleton 230kV breaker PCB U with 63kA breaker		AEC (100%)
b2297	Replace the Mickleton 230kV breaker PCB V with 63kA breaker		AEC (100%)
b2305	Rebuild and reconductor 1.2 miles of the US Silica to US Silica #1 69 kV circuit		AEC (100%)
b2306	Rebuild and reconductor 1.67 miles of the US Silica #1 to W1-089 TAP 69 kV circuit		AEC (100%)
b2351	Reconductor section A of Corson - Sea Isle - Swainton 69 kV line		AEC (100%)
b2353	Upgrade the overcurrent protective relaying at Middle T3 and T4 138/69 kV transformers		AEC (100%)
b2354	Install second 230/69 kV transformer and 230 kV circuit breaker at Churchtown substation		AEC (100%)

Atlantic City Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2354.1	Replace Churchtown 69kV breaker 'D'		AEC (100%)
b2476	Install new Dennis 230/69 kV transformer		AEC (100%)
b2477	Upgrade 138 kV and 69 kV breakers at Corson substation		AEC (100%)
b2478	Reconductor 2.74 miles of Sherman - Lincoln 138 kV line and associated substation upgrades		AEC (100%)
b2479	New Orchard - Cardiff 230 kV line (remove, rebuild and reconfigure existing 138 kV line) and associated substation upgrades		AEC (68.57%) / JCPL (31.43%)
b2480.1	New Upper Pittsgrove - Lewis 138 kV line and associated substation upgrades		AEC (100%)
b2480.2	Relocate Monroe to Deepwater Tap 138 kV to Landis 138 kV and associated substation upgrades		AEC (100%)
b2480.3	New Landis - Lewis 138 kV line and associated substation upgrades		AEC (100%)
b2481	New Cardiff - Lewis #2 138 kV line and associated substation upgrades		AEC (100%)
b2489	Install a 100 MVAR capacitor at BL England		AEC (100%)

Atlantic City Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2538	Replace the Mickleton 230kV ‘MK’ breaker with 63kA breaker		AEC (100%)
b2553	Replace Middle T3 138/69 kV transformer with 225 MVA nameplate		AEC (100%)
b2723.1	Replace the Mickleton 69 kV ‘PCB A’ breaker with 63kA breaker		AEC (100%)
b2723.2	Replace the Mickleton 69 kV ‘PCB B’ breaker with 63kA breaker		AEC (100%)
b2723.3	Replace the Mickleton 69 kV ‘PCB C’ breaker with 63kA breaker		AEC (100%)
b2723.4	Replace the Mickleton 69 kV ‘PCB Q’ breaker with 63kA breaker		AEC (100%)
b2839	Replace the Sickler 69 kV ‘H’ breaker with 63kA breaker		AEC (100%)
b2840	Replace the Sickler 69 kV ‘M’ breaker with 63kA breaker		AEC (100%)
b2841	Replace the Sickler 69 kV ‘A’ breaker with 63kA breaker		AEC (100%)
b2945.1	Rebuild the BL England – Middle Tap 138 kV line to 2000A on double circuited steel poles and new foundations		AEC (100%)
b2945.2	Reconductor BL England – Merion 138 kV (1.9 miles) line		AEC (100%)
b2945.3	Reconductor Merion – Corson 138 kV (8 miles) line		AEC (100%)

Attachment 7d (VEPCo OATT)

SCHEDULE 12 – APPENDIX

(20) Virginia Electric and Power Company

Required Transmission Enhancements		Annual Revenue Requirement***	Responsible Customer(s)
b0217	Upgrade Mt. Storm - Doubs 500kV		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (25.20%) / BGE (10.49%) / Dominion (52.48%) / PEPCO (11.83%)
b0222	Install 150 MVAR capacitor at Loudoun 500 kV		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: Dominion (100%)

* Neptune Regional Transmission System, LLC
** East Coast Power, L.L.C.
*** Hudson Transmission Partners, LLC
*** The Annual Revenue Requirement for all Virginia Electric and Power Company projects in this Section 20 shall be as specified in Attachment 7 to Appendix A of Attachment H-16A and under the procedures detailed in Attachment H-16B.

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0223	Install 150 MVAR capacitor at Asburn 230 kV		Dominion (100%)
b0224	Install 150 MVAR capacitor at Dranesville 230 kV		Dominion (100%)
b0225	Install 33 MVAR capacitor at Possum Pt. 115 kV		Dominion (100%)
b0226	Install 500/230 kV transformer at Clifton and Clifton 500 kV 150 MVAR capacitor	As specified in Attachment 7 to Appendix A of Attachment H-16A and under the procedures detailed in Attachment H-16B	APS (3.69%) / BGE (3.54%) / Dominion (85.73%) / PEPCO (7.04%)
b0227	Install 500/230 kV transformer at Bristers; build new 230 kV Bristers-Gainsville circuit, upgrade two Loudoun-Brambleton circuits		AEC (0.71%) / APS (3.36%) / BGE (10.93%) / DPL (1.66%) / Dominion (67.38%) / ME (0.89%) / PECO (2.33%) / PEPCO (12.20%) / PPL (0.54%)
b0227.1	Loudoun Sub – upgrade 6-230 kV breakers		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0231	Install 500 kV breakers & 500 kV bus work at Suffolk		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: Dominion (100%)
b0231.2	Install 500/230 kV Transformer, 230 kV breakers, & 230 kV bus work at Suffolk		Dominion (100%)
b0232	Install 150 MVAR capacitor at Lynnhaven 230 kV		Dominion (100%)
b0233	Install 150 MVAR capacitor at Landstown 230 kV		Dominion (100%)
b0234	Install 150 MVAR capacitor at Greenwich 230 kV		Dominion (100%)
b0235	Install 150 MVAR capacitor at Fentress 230 kV		Dominion (100%)

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0307	Reconductor Endless Caverns – Mt. Jackson 115 kV		Dominion (100%)
b0308	Replace L breaker and switches at Endless Caverns 115 kV		Dominion (100%)
b0309	Install SPS at Earleys 115 kV		Dominion (100%)
b0310	Reconductor Club House – South Hill and Chase City – South Hill 115 kV		Dominion (100%)
b0311	Reconductor Idylwood to Arlington 230 kV		Dominion (100%)
b0312	Reconductor Gallows to Ox 230 kV		Dominion (100%)
b0325	Install a 2nd Everetts 230/115 kV transformer		Dominion (100%)
b0326	Uprate/resag Remington-Brandywine-Culppr 115 kV		Dominion (100%)
b0327	Build 2nd Harrisonburg – Valley 230 kV		APS (19.79%) / Dominion (76.18%) / PEPCO (4.03%)
b0328.1	Build new Meadow Brook – Loudoun 500 kV circuit (30 of 50 miles)		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: 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)
b0328.3	Upgrade Mt. Storm 500 kV substation		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (33.78%) / Dominion (57.67%) / PEPCO (8.55%)
b0328.4	Upgrade Loudoun 500 kV substation		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: 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)
b0329	Build Carson – Suffolk 500 kV, install 2nd Suffolk 500/230 kV transformer & build Suffolk – Fentress 230 kV circuit		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%) **DFAX Allocation:** Dominion (100%)
b0329	Build Carson – Suffolk 500 kV, install 2nd Suffolk 500/230 kV transformer & build Suffolk – Fentress 230 kV circuit		Dominion (100%)††
b0329.1	Replace Thole Street 115 kV breaker ‘48T196’		Dominion (100%)
b0329.2	Replace Chesapeake 115 kV breaker ‘T242’		Dominion (100%)
b0329.3	Replace Chesapeake 115 kV breaker ‘8722’		Dominion (100%)
b0329.4	Replace Chesapeake 115 kV breaker ‘16422’		Dominion (100%)
b0330	Install Crewe 115 kV breaker and shift load from line 158 to 98		Dominion (100%)
b0331	Upgrade/resag Shell Bank – Whealton 115 kV (Line 165)		Dominion (100%)

* Neptune Regional Transmission System, LLC

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

*** Hudson Transmission Partners, LLC

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

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

Virginia Electric and Power Company (cont.)

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0412	Retension Pruntytown – Mt. Storm 500 kV to a 3502 MVA rating		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (51.45%) / DEOK (17.51%) / PEPCO (31.04%)
b0450	Install 150 MVAR Capacitor at Fredricksburg 230 kV		Dominion (100%)
b0451	Install 25 MVAR Capacitor at Somerset 115 kV		Dominion (100%)
b0452	Install 150 MVAR Capacitor at Northwest 230 kV		Dominion (100%)
b0453.1	Convert Remingtion – Sowego 115 kV to 230 kV		APS (0.31%) / BGE (3.01%) / DPL (0.04%) / Dominion (92.75%) / ME (0.03%) / PEPCO (3.86%)
b0453.2	Add Sowego – Gainsville 230 kV		APS (0.31%) / BGE (3.01%) / DPL (0.04%) / Dominion (92.75%) / ME (0.03%) / PEPCO (3.86%)
b0453.3	Add Sowego 230/115 kV transformer		APS (0.31%) / BGE (3.01%) / DPL (0.04%) / Dominion (92.75%) / ME (0.03%) / PEPCO (3.86%)
b0454	Reconductor 2.4 miles of Newport News – Chuckatuck 230 kV		Dominion (100%)

* Neptune Regional Transmission System, LLC

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0455	Add 2nd Endless Caverns 230/115 kV transformer		APS (32.70%) / BGE (7.01%) / DPL (1.80%) / Dominion (50.82%) / PEPCO (7.67%)
b0456	Reconductor 9.4 miles of Edinburg – Mt. Jackson 115 kV		APS (33.69%) / BGE (12.18%) / Dominion (40.08%) / PEPCO (14.05%)
b0457	Replace both wave traps on Dooms – Lexington 500 kV		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: Dominion (100%)
b0467.2	Reconductor the Dickerson – Pleasant View 230 kV circuit		AEC (1.75%) / APS (19.70%) / BGE (22.13%) / DPL (3.70%) / JCPL (0.71%) / ME (2.48%) / Neptune* (0.06%) / PECO (5.54%) / PEPCO (41.86%) / PPL (2.07%)

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0492.6	Replace Mount Storm 500 kV breaker 55072		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)
b0492.7	Replace Mount Storm 500 kV breaker 55172		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0492.8	Replace Mount Storm 500 kV breaker H1172-2		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)
b0492.9	Replace Mount Storm 500 kV breaker G2T550		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0492.10	Replace Mount Storm 500 kV breaker G2T554		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)
b0492.11	Replace Mount Storm 500 kV breaker G1T551		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0492.12	Upgrade nameplate rating of Mount Storm 500 kV breakers 55472, 57272, SX172, G3TSX1, G1TH11, G3T572, and SX22		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)
b0512	MAPP Project – install new 500 kV transmission from Possum Point to Calvert Cliffs and install a DC line from Calvert Cliffs to Vienna and a DC line from Calvert Cliffs to Indian River		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0512.5	Advance n0716 (Ox - Replace 230kV breaker L242)		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.6	Advance n0717 (Possum Point - Replace 230kV breaker SC192)		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0583	Install dual primary protection schemes on Gosport lines 62 and 51 at the remote terminals (Chesapeake on the 62 line and Reeves Ave on the 51 line)		Dominion (100%)
b0756	Install a second 500/115 kV autotransformer at Chancellor 500 kV		Dominion (100%)
b0756.1	Install two 500 kV breakers at Chancellor 500 kV		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0757	Reconductor one mile of Chesapeake – Reeves Avenue 115 kV line		Dominion (100%)
b0758	Install a second Fredericksburg 230/115 kV autotransformer		Dominion (100%)
b0760	Build 115 kV line from Kitty Hawk to Colington 115 kV (Colington on the existing line and Nag's Head and Light House DP on new line)		Dominion (100%)
b0761	Install a second 230/115 kV transformer at Possum Point		Dominion (100%)
b0762	Build a new Elko station and transfer load from Turner and Providence Forge stations		Dominion (100%)
b0763	Rebuild 17.5 miles of the line for a new summer rating of 262 MVA		Dominion (100%)
b0764	Increase the rating on 2.56 miles of the line between Greenwich and Thompson Corner; new rating to be 257 MVA		Dominion (100%)
b0765	Add a second Bull Run 230/115 kV autotransformer		Dominion (100%)
b0766	Increase the rating of the line between Loudoun and Cedar Grove to at least 150 MVA		Dominion (100%)
b0767	Extend the line from Old Church – Chickahominy 230 kV		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0768	Loop line #251 Idylwood – Arlington into the GIS sub		Dominion (100%)
b0769	Re-tension 15 miles of the line for a new summer rating of 216 MVA		Dominion (100%)
b0770	Add a second 230/115 kV autotransformer at Lanexa		Dominion (100%)
b0770.1	Replace Lanexa 115 kV breaker '8532'		Dominion (100%)
b0770.2	Replace Lanexa 115 kV breaker '9232'		Dominion (100%)
b0771	Build a parallel Chickahominy – Lanexa 230 kV line		Dominion (100%)
b0772	Install a second Elmont 230/115 kV autotransformer		Dominion (100%)
b0772.1	Replace Elmont 115 kV breaker '7392'		Dominion (100%)
b0774	Install a 33 MVAR capacitor at Bremo 115 kV		Dominion (100%)
b0775	Reconductor the Greenwich – Virginia Beach line to bring it up to a summer rating of 261 MVA; Reconductor the Greenwich – Amphibious Base line to bring it up to 291 MVA		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0776	Re-build Trowbridge – Winfall 115 kV		Dominion (100%)
b0777	Terminate the Thelma – Carolina 230 kV circuit into Lakeview 230 kV		Dominion (100%)
b0778	Install 29.7 MVAR capacitor at Lebanon 115 kV		Dominion (100%)
b0779	Build a new 230 kV line from Yorktown to Hayes but operate at 115 kV initially		Dominion (100%)
b0780	Reconductor Chesapeake – Yadkin 115 kV line		Dominion (100%)
b0781	Reconductor and replace terminal equipment on line 17 and replace the wave trap on line 88		Dominion (100%)
b0782	Install a new 115 kV capacitor at Dupont Waynesboro substation		Dominion (100%)
b0784	Replace wave traps on North Anna to Ladysmith 500 kV		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: Dominion (100%)
b0785	Rebuild the Chase City – Crewe 115 kV line		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0786	Reconductor the Moran DP – Crewe 115 kV segment		Dominion (100%)
b0787	Upgrade the Chase City – Twitty's Creek 115 kV segment		Dominion (100%)
b0788	Reconductor the line from Farmville – Pamplin 115 kV		Dominion (100%)
b0793	Close switch 145T183 to network the lines. Rebuild the section of the line #145 between Possum Point – Minnieville DP 115 kV		Dominion (100%)
b0815	Replace Elmont 230 kV breaker '22192'		Dominion (100%)
b0816	Replace Elmont 230 kV breaker '21692'		Dominion (100%)
b0817	Replace Elmont 230 kV breaker '200992'		Dominion (100%)
b0818	Replace Elmont 230 kV breaker '2009T2032'		Dominion (100%)
b0837	At Mt. Storm, replace the existing MOD on the 500 kV side of the transformer with a circuit breaker		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0888	Replace Loudoun 230 kV Cap breaker 'SC352'		Dominion (100%)
b0892	Replace Chesapeake 115 kV breaker SX522		Dominion (100%)
b0893	Replace Chesapeake 115 kV breaker T202		Dominion (100%)
b0894	Replace Possum Point 115 kV breaker SX-32		Dominion (100%)
b0895	Replace Possum Point 115 kV breaker L92-1		Dominion (100%)
b0896	Replace Possum Point 115 kV breaker L92-2		Dominion (100%)
b0897	Replace Suffolk 115 kV breaker T202		Dominion (100%)
b0898	Replace Peninsula 115 kV breaker SC202		Dominion (100%)
b0921	Reconductor Brambleton - Cochran Mill 230 kV line with 201 Yukon conductor		Dominion (100%)
b0923	Install 50-100 MVAR variable reactor banks at Carson 230 kV		Dominion (100%)
b0924	Install 50-100 MVAR variable reactor banks at Dooms 230 kV		Dominion (100%)
b0925	Install 50-100 MVAR variable reactor banks at Garrisonville 230 kV		Dominion (100%)
b0926	Install 50-100 MVAR variable reactor banks at Hamilton 230 kV		Dominion (100%)
b0927	Install 50-100 MVAR variable reactor banks at Yadkin 230 kV		Dominion (100%)

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Virginia Electric and Power Company (cont.)

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

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Virginia Electric and Power Company (cont.)

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

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1188	Build new Brambleton 500 kV three breaker ring bus connected to the Loudoun to Pleasant View 500 kV line		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: Dominion (100%)
b1188.1	Replace Loudoun 230 kV breaker ‘200852’ with a 63 kA breaker		Dominion (100%)
b1188.2	Replace Loudoun 230 kV breaker ‘2008T2094’ with a 63 kA breaker		Dominion (100%)
b1188.3	Replace Loudoun 230 kV breaker ‘204552’ with a 63 kA breaker		Dominion (100%)
b1188.4	Replace Loudoun 230 kV breaker ‘209452’ with a 63 kA breaker		Dominion (100%)
b1188.5	Replace Loudoun 230 kV breaker ‘WT2045’ with a 63 kA breaker		Dominion (100%)
b1188.6	Install one 500/230 kV transformer and two 230 kV breakers at Brambleton		AEC (0.22%) / BGE (7.90%) / DPL (0.59%) / Dominion (75.58%) / ME (0.22%) / PECO (0.73%) / PEPCO (14.76%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1224	Install 2nd Clover 500/230 kV transformer and a 150 MVAr capacitor		BGE (7.56%) / DPL (1.03%) / Dominion (78.21%) / ME (0.77%) / PECO (1.39%) / PEPCO (11.04%)
b1225	Replace Yorktown 115 kV breaker ‘L982-1’		Dominion (100%)
b1226	Replace Yorktown 115 kV breaker ‘L982-2’		Dominion (100%)
b1279	Line #69 Uprate – Increase rating on Locks – Purdy 115 kV to serve additional load at the Reams delivery point		Dominion (100%)
b1306	Reconfigure 115 kV bus at Endless Caverns substation such that the existing two 230/115 kV transformers at Endless Caverns operate in		Dominion (100%)
b1307	Install a 2nd 230/115 kV transformer at Northern Neck Substation		Dominion (100%)
b1308	Improve LSE’s power factor factor in zone to .973 PF, adjust LTC’s at Gordonsville and Remington, move existing shunt capacitor banks		Dominion (100%)
b1309	Install a 230 kV line from Lakeside to Northwest utilizing the idle line and 60 line ROW’s and reconductor the existing 221 line between Elmont and Northwest		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1310	Install a 115 kV breaker at Broadnax substation on the South Hill side of Broadnax		Dominion (100%)
b1311	Install a 230 kV 3000 amp breaker at Cranes Corner substation to sectionalize the 2104 line into two lines		Dominion (100%)
b1312	Loop the 2054 line in and out of Hollymeade and place a 230 kV breaker at Hollymeade. This creates two lines: Charlottesville - Hollymeade		Dominion (100%)
b1313	Resag wire to 125C from Chesterfield – Shockoe and replace line switch 1799 with 1200 amp switch. The new rating would be 231 MVA.		Dominion (100%)
b1314	Rebuild the 6.8 mile line #100 from Chesterfield to Harrowgate 115 kV for a minimum 300 MBA rating		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1315	Convert line #64 Trowbridge to Winfall to 230 kV and install a 230 kV capacitor bank at Winfall		Dominion (100%)
b1316	Rebuild 10.7 miles of 115 kV line #80, Battleboro – Heartsease DP		Dominion (100%)
b1317	LSE load power factor on the #47 line will need to meet MOA requirements of .973 in 2015 to further resolve this issue through at least 2019		Dominion (100%)
b1318	Install a 115 kV bus tie breaker at Acca substation between the Line #60 and Line #95 breakers		Dominion (100%)
b1319	Resag line #222 to 150 C and upgrade any associated equipment to a 2000A rating to achieve a 706 MVA summer line rating		Dominion (100%)
b1320	Install a 230 kV, 150 MVAR capacitor bank at Southwest substation		Dominion (100%)
b1321	Build a new 230 kV line North Anna – Oak Green and install a 224 MVA 230/115 kV transformer at Oak Green		BGE (0.85%) / Dominion (97.96%) / PEPCO (1.19%)
b1322	Rebuild the 39 Line (Dooms – Sherwood) and the 91 Line (Sherwood – Bremo)		Dominion (100%)
b1323	Install a 224 MVA 230/115 kV transformer at Staunton. Rebuild the 115 kV line #43 section Staunton - Verona		Dominion (100%)

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Virginia Electric and Power Company (cont.)

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

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Virginia Electric and Power Company (cont.)

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

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1506.1	At Gainesville Substation, create two 115 kV straight-buses with a normally open tie-breaker		Dominion (100%)
b1506.2	Upgrade Line 124 (radial from Loudoun) to a minimum continuous rating of 500 MVA and network it into the 115 kV bus feeding NOVEC's DP at Gainesville		Dominion (100%)
b1506.3	Install two additional 230 kV breakers in the ring at Gainesville (may require substation expansion) to accommodate conversion of NOVEC's Gainesville to Wheeler line		Dominion (100%)
b1506.4	Convert NOVEC's Gainesville-Wheeler line from 115 kV to 230 kV (will require Gainsville DP Upgrade replacement of three transformers total at Atlantic and Wheeler Substations)		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1507	Rebuild Mt Storm – Doubs 500 kV		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (25.20%) / BGE (10.49%) / Dominion (52.48%) / PEPCO (11.83%)
b1508.1	Build a 2nd 230 kV Line Harrisonburg to Endless Caverns		APS (37.05%) / Dominion (62.95%)
b1508.2	Install a 3rd 230-115 kV Tx at Endless Caverns		APS (37.05%) / Dominion (62.95%)
b1508.3	Upgrade a 115 kV shunt capacitor banks at Merck and Edinburg		APS (37.05%) / Dominion (62.95%)
b1536	Advance n1752 (Replace OX 230 breaker 24342 with an (63kA breaker)		Dominion (100%)
b1537	Advance n1753 (Replace OX 230 breaker 243T2097 with an 63kA breaker)		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1538	Replace Loudoun 230 kV breaker ‘29552’		Dominion (100%)
b1571	Replace Acca 115 kV breaker ‘6072’ with 40 kA		Dominion (100%)
b1647	Upgrade the name plate rating at Morrisville 500kV breaker ‘H1T573’ with 50kA breaker		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: Dominion (100%)
b1648	Upgrade name plate rating at Morrisville 500kV breaker ‘H2T545’ with 50kA breaker		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1649	Replace Morrisville 500kV breaker ‘H1T580’ with 50kA breaker		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: Dominion (100%)
b1650	Replace Morrisville 500kV breaker ‘H2T569’ with 50kA breaker		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: Dominion (100%)
b1651	Replace Loudoun 230kV breaker ‘295T2030’ with 63kA breaker		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1652	Replace Ox 230kV breaker '209742' with 63kA breaker		Dominion (100%)
b1653	Replace Clifton 230kV breaker '26582' with 63kA breaker		Dominion (100%)
b1654	Replace Clifton 230kV breaker '26682' with 63kA breaker		Dominion (100%)
b1655	Replace Clifton 230kV breaker '205182' with 63kA breaker		Dominion (100%)
b1656	Replace Clifton 230kV breaker '265T266' with 63kA breaker		Dominion (100%)
b1657	Replace Clifton 230kV breaker '2051T2063' with 63kA breaker		Dominion (100%)
b1694	Rebuild Loudoun - Brambleton 500 kV Rebuild Loudoun - Brambleton 500 kV		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: Dominion (84.25%) / PEPCO (15.75%)
b1696	Install a breaker and a half scheme with a minimum of eight 230 kV breakers for five existing lines at Idylwood 230 kV		AEC (0.46%) / APS (4.18%) / BGE (2.02%) / DPL (0.80%) / Dominion (88.45%) / JCPL (0.64%) / ME (0.50%) / NEPTUNE* (0.06%) / PECO (1.55%) / PEPCO (1.34%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1697	Build a 2nd Clark - Idylwood 230 kV line and install 230 kV gas-hybrid breakers at Clark		AEC (1.35%) / APS (15.65%) / BGE (10.53%) / DPL (2.59%) / Dominion (46.97%) / JCPL (2.36%) / ME (1.91%) / NEPTUNE* (0.23%) / PECO (4.48%) / PEPCO (11.23%) / PSEG (2.59%) / RE (0.11%)
b1698	Install a 2nd 500/230 kV transformer at Brambleton		APS (4.21%) / BGE (13.28%) / DPL (1.09%) / Dominion (59.38%) / PEPCO (22.04%)
b1698.1	Install a 500 kV breaker at Brambleton		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1698.6	Replace Brambleton 230 kV breaker ‘2094T2095’		Dominion (100%)
b1699	Reconfigure Line #203 to feed Edwards Ferry sub radial from Pleasant View 230 kV and install new breaker bay at Pleasant View Sub		Dominion (100%)
b1700	Install a 230/115 kV transformer at the new Liberty substation to relieve Gainesville Transformer #3		Dominion (100%)
b1701	Reconductor line #2104 (Fredericksburg - Cranes Corner 230 kV)		APS (8.66%) / BGE (10.95%) / Dominion (63.30%) / PEPCO (17.09%)
b1724	Install a 2nd 138/115 kV transformer at Edinburg		Dominion (100%)
b1728	Replace the 115/34.5 kV transformer #1 at Hickory with a 230/34.5 kV transformer		Dominion (100%)
b1729	Add 4 breaker ring bus at Burton 115 kV substation and construct a 115 kV line approximately 3.5 miles from Oakwood 115 kV substation to Burton 115 kV substation		Dominion (100%)

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Virginia Electric and Power Company (cont.)

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1795	Reconductor segment of Line #54 (Carolina to Woodland 115 kV) to a minimum of 300 MVA		Dominion (100%)
b1796	Install 115 kV 25 MVAR capacitor bank at Kitty Hawk Substation		Dominion (100%)
b1797	Wreck and rebuild 7 miles of the Dominion owned section of Cloverdale - Lexington 500 kV		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (56.31%) / ATSI (2.31%) / Dayton (0.70%) / DEOK (1.72%) / Dominion (4.80%) / EKPC (0.60%) / PEPCO (33.56%)
b1798	Build a 450 MVAR SVC and 300 MVAR switched shunt at Loudoun 500 kV		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1799	Build 150 MVAR Switched Shunt at Pleasant View 500 kV		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (0.36%) / DPL (0.07%) / Dominion (99.36%) / ME (0.07%) / PEPCO (0.14%)
b1805	Install a 250 MVAR SVC at the existing Mt. Storm 500kV substation		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (74.10%) / PEPCO (25.90%)
b1809	Replace Brambleton 230 kV Breaker ‘22702’		Dominion (100%)
b1810	Replace Brambleton 230 kV Breaker ‘227T2094’		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1905.1	Surry to Skiffes Creek 500 kV Line (7 miles overhead)		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%) **DFAX Allocation:** Dominion (100%)
b1905.2	Surry 500 kV Station Work		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%) **DFAX Allocation:** Dominion (100%)
b1905.3	Skiffes Creek 500-230 kV Tx and Switching Station		Dominion (99.84%) / PEPCO (0.16%)
b1905.4	New Skiffes Creek - Whealton 230 kV line		Dominion (99.84%) / PEPCO (0.16%)
b1905.5	Whealton 230 kV breakers		Dominion (99.84%) / PEPCO (0.16%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1905.6	Yorktown 230 kV work		Dominion (99.84%) / PEPCO (0.16%)
b1905.7	Lanexa 115 kV work		Dominion (99.84%) / PEPCO (0.16%)
b1905.8	Surry 230 kV work		Dominion (99.84%) / PEPCO (0.16%)
b1905.9	Kings Mill, Peninmen, Toano, Waller, Warwick		Dominion (99.84%) / PEPCO (0.16%)
b1906.1	At Yadkin 500 kV, install six 500 kV breakers		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: Dominion (100%)
b1906.2	Install a 2nd 230/115 kV TX at Yadkin		Dominion (100%)
b1906.3	Install a 2nd 230/115 kV TX at Chesapeake		Dominion (100%)
b1906.4	Uprate Yadkin – Chesapeake 115 kV		Dominion (100%)
b1906.5	Install a third 500/230 kV TX at Yadkin		Dominion (100%)
b1907	Install a 3rd 500/230 kV TX at Clover		APS (5.83%) / BGE (4.74%) / Dominion (81.79%) / PEPCO (7.64%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1908	Rebuild Lexington – Dooms 500 kV		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%) **DFAX Allocation:** Dominion (100%)
b1909	Uprate Bremo – Midlothian 230 kV to its maximum operating temperature		APS (6.31%) / BGE (3.81%) / Dominion (81. 90%) / PEPCO (7.98%)
b1910	Build a Suffolk – Yadkin 230 kV line (14 miles) and install 4 breakers		Dominion (100%)
b1911	Add a second Valley 500/230 kV TX		APS (14.85%) / BGE (3.10%) / Dominion (74.12%) / PEPCO (7.93%)
b1912	Install a 500 MVAR SVC at Landstown 230 kV		DEOK (0.46%) / Dominion (99.54%)
b2053	Rebuild 28 mile line		AEP (100%)
b2125	Install four additional 230 kV 100 MVAR variable shunt reactor banks at Clifton, Gallows Road, Garrisonville, and Virginia Hills substations		Dominion (100%)
b2126	Install two additional 230 kV 100 MVAR variable shunt reactor banks at Churchland and Shawboro substations		Dominion (100%)

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Virginia Electric and Power Company (cont.)

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

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SCHEDULE 12 – APPENDIX A

(20) Virginia Electric and Power Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1698.7	Replace Loudoun 230 kV breaker ‘203052’ with 63kA rating		Dominion (100%)
b1696.1	Replace the Idylwood 230 kV ‘25112’ breaker with 50kA breaker		Dominion (100%)
b1696.2	Replace the Idylwood 230 kV ‘209712’ breaker with 50kA breaker		Dominion (100%)
b1793.1	Remove the Carolina 22 SPS to include relay logic changes, minor control wiring, relay resets and SCADA programming upon completion of project		Dominion (100%)
b2281	Additional Temporary SPS at Bath County		Dominion (100%)
b2350	Reconductor 211 feet of 545.5 ACAR conductor on 59 Line Elmont - Greenwood DP 115 kV to achieve a summer emergency rating of 906 amps or greater		Dominion (100%)
b2358	Install a 230 kV 54 MVAR capacitor bank on the 2016 line at Harmony Village Substation		Dominion (100%)
b2359	Wreck and rebuild approximately 1.3 miles of existing 230 kV line between Cochran Mill - X4-039 Switching Station		Dominion (100%)
b2360	Build a new 39 mile 230 kV transmission line from Dooms - Lexington on existing right-of-way		Dominion (100%)
b2361	Construct 230 kV OH line along existing Line #2035 corridor, approx. 2.4 miles from Idylwood - Dulles Toll Road (DTR) and 2.1 miles on new right-of-way along DTR to new Scott's Run Substation		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2368	Replace the Brambleton 230 kV breaker '209502' with 63kA breaker		Dominion (100%)
b2369	Replace the Brambleton 230 kV breaker '213702' with 63kA breaker		Dominion (100%)
b2370	Replace the Brambleton 230 kV breaker 'H302' with 63kA breaker		Dominion (100%)
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 (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / Dominion (12.86%) / DPL (2.50%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (33.33%) / Dominion (66.67%)
b2397	Replace the Beaumeade 230 kV breaker '2079T2116' with 63kA		Dominion (100%)
b2398	Replace the Beaumeade 230 kV breaker '2079T2130' with 63kA		Dominion (100%)
b2399	Replace the Beaumeade 230 kV breaker '208192' with 63kA		Dominion (100%)
b2400	Replace the Beaumeade 230 kV breaker '209592' with 63kA		Dominion (100%)
b2401	Replace the Beaumeade 230 kV breaker '211692' with 63kA		Dominion (100%)
b2402	Replace the Beaumeade 230 kV breaker '227T2130' with 63kA		Dominion (100%)
b2403	Replace the Beaumeade 230 kV breaker '274T2130' with 63kA		Dominion (100%)

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

Virginia Electric and Power Company (cont.)

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

Virginia Electric and Power Company (cont.)

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2471	Replace Midlothian 500 kV breaker 563T576 and motor operated switches with 3 breaker 500 kV ring bus. Terminate Lines # 563 Carson – Midlothian, #576 Midlothian –North Anna, Transformer #2 in new ring		**Load-Ratio Share Allocation:** AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
			DFAX Allocation: Dominion (100%)
b2504	Rebuild 115 kV Line #32 from Halifax-South Boston (6 miles) for min. of 240 MVA and transfer Welco tap to Line #32. Moving Welco to Line #32 requires disabling auto-sectionalizing scheme		Dominion (100%)
b2505	Install structures in river to remove the 115 kV #65 line (Whitestone-Harmony Village 115 kV) from bridge and improve reliability of the line		Dominion (100%)
b2542	Replace the Loudoun 500 kV 'H2T502' breaker with a 50kA breaker		Dominion (100%)
b2543	Replace the Loudoun 500 kV 'H2T584' breaker with a 50kA breaker		Dominion (100%)
b2565	Reconductor wave trap at Carver Substation with a 2000A wave trap		Dominion (100%)
b2566	Reconductor 1.14 miles of existing line between ACCA and Hermitage and upgrade associated terminal equipment		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2582	Rebuild the Elmont – Cunningham 500 kV line		Dominion (100%)
b2583	Install 500 kV breaker at Ox Substation to remove Ox Tx#1 from H1T561 breaker failure outage.		Dominion (100%)
b2584	Relocate the Bremo load (transformer #5) to #2028 (Bremo-Charlottesville 230 kV) line and Cartersville distribution station to #2027 (Bremo-Midlothian 230 kV) line		Dominion (100%)
b2585	Reconductor 7.63 miles of existing line between Cranes and Stafford, upgrade associated line switches at Stafford		**DFAX Allocation:** PEPCO (100%)
b2620	Wreck and rebuild the Chesapeake – Deep Creek – Bowers Hill – Hodges Ferry 115 kV line; minimum rating 239 MVA normal/emergency, 275 MVA load dump rating		Dominion (100%)

Virginia Electric and Power Company (cont.)

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

Virginia Electric and Power Company (cont.)

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2649.1	Rebuild of 1.7 mile tap to Metcalf and Belfield DP (MEC) due to poor condition. The existing summer rating of the tap is 48 MVA and existing conductor is 4/0 ACSR on wood H-frames. The proposed new rating is 176 MVA using 636 ACSR conductor		Dominion (100%)
b2649.2	Rebuild of 4.1 mile tap to Brinks DP (MEC) due to wood poles built in 1962. The existing summer rating of the tap is 48 MVA and existing conductor is 4/0 ACSR and 393.6 ACSR on wood H-frames. The proposed new rating is 176 MVA using 636 ACSR conductor		Dominion (100%)
b2650	Rebuild Twittys Creek – Pamplin 115 kV Line #154 (17.8 miles) to current standards with summer emergency rating of 353 MVA at 115 kV.		Dominion (100%)

Virginia Electric and Power Company (cont.)

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2665	Rebuild the Cunningham – Dooms 500 kV line		Dominion (100%)
b2686	Pratts Area Improvement		Dominion (100%)
b2686.1	Build a 230 kV line from Remington Substation to Gordonsville Substation utilizing existing ROW		Dominion (100%)
b2686.11	Upgrading sections of the Gordonsville – Somerset 115 kV circuit		Dominion (100%)
b2686.12	Upgrading sections of the Somerset – Doubleday 115 kV circuit		Dominion (100%)
b2686.13	Upgrading sections of the Orange – Somerset 115 kV circuit		Dominion (100%)
b2686.14	Upgrading sections of the Mitchell – Mt. Run 115 kV circuit		Dominion (100%)
b2686.2	Install a 3rd 230/115 kV transformer at Gordonsville Substation		Dominion (100%)

*Neptune Regional Transmission System, LLC

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2686.3	Upgrade Line 2088 between Gordonsville Substation and Louisa CT Station		Dominion (100%)
b2717.1	De-energize Davis – Rosslyn #179 and #180 69 kV lines		Dominion (100%)
b2717.2	Remove splicing and stop joints in manholes		Dominion (100%)
b2717.3	Evacuate and dispose of insulating fluid from various reservoirs and cables		Dominion (100%)
b2717.4	Remove all cable along the approx. 2.5 mile route, swab and cap-off conduits for future use, leave existing communication fiber in place		Dominion (100%)
b2719.1	Expand Perth substation and add a 115 kV four breaker ring		Dominion (100%)
b2719.2	Extend the Hickory Grove DP tap 0.28 miles to Perth and terminate it at Perth		Dominion (100%)
b2719.3	Split Line #31 at Perth and terminate it into the new ring bus with 2 breakers separating each of the line terminals to prevent a breaker failure from taking out both 115 kV lines		Dominion (100%)
b2720	Replace the Loudoun 500 kV 'H1T569' breakers with 50kA breaker		Dominion (100%)
b2729	Optimal Capacitors Configuration: New 175 MVAR capacitor at Brambleton, new 175 MVAR capacitor at Ashburn, new 300 MVAR capacitor at Shelhorm, new 150 MVAR capacitor at Liberty		AEC (*1.97*%) / BGE (*14.46*%) / Dominion (*35.33*%) / DPL (*3.78*%) / JCPL (*3.33*%) / ME (*2.53*%) / Neptune (0.63%) / PECO (*6.30*%) / PEPCO (*20.36*%) / PPL (*3.97*%) / PSEG (*7.34*%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2744	Rebuild the Carson – Rogers Rd 500 kV circuit		**Load-Ratio Share Allocation:** AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
			DFAX Allocation: Dominion (100%)
b2745	Rebuild 21.32 miles of existing line between Chesterfield – Lakeside 230 kV		Dominion (100%)
b2746.1	Rebuild Line #137 Ridge Rd – Kerr Dam 115 kV, 8.0 miles, for 346 MVA summer emergency rating		Dominion (100%)
b2746.2	Rebuild Line #1009 Ridge Rd – Chase City 115 kV, 9.5 miles, for 346 MVA summer emergency rating		Dominion (100%)
b2746.3	Install a second 4.8 MVAR capacitor bank on the 13.8 kV bus of each transformer at Ridge Rd		Dominion (100%)
b2747	Install a Motor Operated Switch and SCADA control between Dominion's Gordonsville 115 kV bus and FirstEnergy's 115 kV line		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2757	Install a +/-125 MVAr Statcom at Colington 230 kV		Dominion (100%)
b2758	Rebuild Line #549 Dooms – Valley 500kV		Dominion (100%)
b2759	Rebuild Line #550 Mt. Storm – Valley 500kV		Dominion (100%)
b2800	The 7 mile section from Dozier to Thompsons Corner of line #120 will be rebuilt to current standards using 768.2 ACSS conductor with a summer emergency rating of 346 MVA at 115 kV. Line is proposed to be rebuilt on single circuit steel monopole structure		Dominion (100%)
b2801	Lines #76 and #79 will be rebuilt to current standard using 768.2 ACSS conductor with a summer emergency rating of 346 MVA at 115 kV. Proposed structure for rebuild is double circuit steel monopole structure		Dominion (100%)
b2802	Rebuild Line #171 from Chase City – Boydton Plank Road tap by removing end-of-life facilities and installing 9.4 miles of new conductor. The conductor used will be at current standards with a summer emergency rating of 393 MVA at 115kV		Dominion (100%)
b2815	Build a new Pinewood 115kV switching station at the tap serving North Doswell DP with a 115kV four breaker ring bus		Dominion (100%)
b2842	Update the nameplate for Mount Storm 500 kV "57272" to be 50kA breaker		Dominion (100%)
b2843	Replace the Mount Storm 500 kV "G2TY" with 50kA breaker		Dominion (100%)
b2844	Replace the Mount Storm 500 kV "G2TZ" with 50kA breaker		Dominion (100%)

Virginia Electric and Power Company (cont.)

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

Virginia Electric and Power Company (cont.)

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2978	Install 2-125 MVAR STATCOMs at Rawlings and 1-125 MVAR STATCOM at Clover 500 kV substations		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / Dominion (12.86%) / DPL (2.50%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: Dominion (100%)
b2980	Rebuild 115 kV Line #43 between Staunton and Harrisonburg (22.8 miles) to current standards with a summer emergency rating of 261 MVA at 115 kV		Dominion (100%)
b2981	Rebuild 115 kV Line #29 segment between Fredericksburg and Aquia Harbor to current 230 kV standards (operating at 115 kV) utilizing steel H-frame structures with 2-636 ACSR to provide a normal continuous summer rating of 524 MVA at 115 kV (1047 MVA at 230 kV)		Dominion (100%)

*Neptune Regional Transmission System, LLC

Attachment 7e (PATH OATT)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0460	Raise limiting structures on Albright – Bethelboro 138 kV to raise the rating to 175 MVA normal 214 MVA emergency		APS (100%)
b0491	Construct an Amos to Welton Spring to WV state line 765 kV circuit (APS equipment)	As specified under the procedures detailed in Attachment H-19B	**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)

*Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0492	Construct a Welton Spring to Kemptown 765 kV line (APS equipment)	As specified under the procedures detailed in Attachment H-19B	**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)
b0492.3	Replace Eastalco 230 kV breaker D-26		APS (100%)
b0492.4	Replace Eastalco 230 kV breaker D-28		APS (100%)

*Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0545	Remove instantaneous reclose from Eastalco circuit breaker D-28		APS (100%)
b0559	Install 200 MVAR capacitor at Meadow Brook 500 kV substation		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (33.78%) / Dominion (57.67%) / PEPCO (8.55%)
b0560	Install 250 MVAR capacitor at Kemptown 500 kV substation		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)

* Neptune Regional Transmission System, LLC

SCHEDULE 12 – APPENDIX

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0318	Install a 765/138 kV transformer at Amos		AEP (99.00%) / PEPCO (1.00%)
b0324	Replace entrance conductors, wave traps, and risers at the Tidd 345 kV station on the Tidd – Canton Central 345 kV circuit		AEP (100%)
b0447	Replace Cook 345 kV breaker M2		AEP (100%)
b0448	Replace Cook 345 kV breaker N2		AEP (100%)
b0490	Construct an Amos – Bedington 765 kV circuit (AEP equipment)	As specified under the procedures detailed in Attachment H-19B	**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)

* Neptune Regional Transmission System, LLC

Attachment 7f (TrailCo 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	**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (58.23%) / Dominion (29.31%) / PEPCO (12.46%)
b0218	Install third Wylie Ridge 500/345kV transformer	As specified under the procedures detailed in Attachment H-18B, Section 1.b	AEC (11.83%) / DPL (19.40%) / Dominion (13.81%) / JCPL (15.56%) / PECO (39.40%)
b0220	Upgrade coolers on Wylie Ridge 500/345 kV #7		AEC (11.83%) / DPL (19.40%) / Dominion (13.81%) / JCPL (15.56%) / PECO (39.40%)
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

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

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

* Neptune Regional Transmission System, LLC

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

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0328.2	Build new Meadow Brook – Loudoun 500 kV circuit (20 of 50 miles)	As specified under the procedures detailed in Attachment H-18B, Section 1.b	**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: Dominion (100%)
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%)

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	**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (74.10%) / PEPCO (25.90%)
b0347.2	Build new Mt. Storm – Meadow Brook 500 kV circuit	As specified under the procedures detailed in Attachment H-18B, Section 1.b	**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (33.78%) / Dominion (57.67%) / PEPCO (8.55%)

* Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.3	Build new 502 Junction 500 kV substation	As specified under the procedures detailed in Attachment H-18B, Section 1.b	**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (74.10%) / PEPCO (25.90%)
b0347.4	Upgrade Meadow Brook 500 kV substation	As specified under the procedures detailed in Attachment H-18B, Section 1.b	**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (33.78%) / Dominion (57.67%) / PEPCO (8.55%)

* Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.5	Replace Harrison 500 kV breaker HL-3		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (74.10%) / PEPCO (25.90%)
b0347.6	Upgrade (per ABB inspection) breaker HL-6		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (74.10%) / PEPCO (25.90%)

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)
b0347.7	Upgrade (per ABB inspection) breaker HL-7		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (74.10%) / PEPCO (25.90%)
b0347.8	Upgrade (per ABB inspection) breaker HL-8		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (74.10%) / PEPCO (25.90%)

*Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.9	Upgrade (per ABB inspection) breaker HL-10		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (74.10%) / PEPCO (25.90%)
b0347.10	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-1		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (74.10%) / PEPCO (25.90%)

*Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.11	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-3		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (74.10%) / PEPCO (25.90%)
b0347.12	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-4		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (74.10%) / PEPCO (25.90%)

*Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.13	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-6		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (74.10%) / PEPCO (25.90%)
b0347.14	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-7		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (74.10%) / PEPCO (25.90%)

*Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.15	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-9		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (74.10%) / PEPCO (25.90%)
b0347.16	Upgrade (per ABB inspection) Harrison 500 kV breaker 'HL-3'		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (74.10%) / PEPCO (25.90%)

*Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.17	Replace Meadow Brook 138 kV breaker 'MD-10'		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (33.78%) / Dominion (57.67%) / PEPCO (8.55%)
b0347.18	Replace Meadow Brook 138 kV breaker 'MD-11'		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (33.78%) / Dominion (57.67%) / PEPCO (8.55%)

*Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.19	Replace Meadow Brook 138 kV breaker 'MD-12'		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (33.78%) / Dominion (57.67%) / PEPCO (8.55%)
b0347.20	Replace Meadow Brook 138 kV breaker 'MD-13'		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (33.78%) / Dominion (57.67%) / PEPCO (8.55%)

*Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.21	Replace Meadow Brook 138 kV breaker 'MD-14'		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (33.78%) / Dominion (57.67%) / PEPCO (8.55%)
b0347.22	Replace Meadow Brook 138 kV breaker 'MD-15'		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (33.78%) / Dominion (57.67%) / PEPCO (8.55%)

*Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.23	Replace Meadow Brook 138 kV breaker 'MD-16'		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (33.78%) / Dominion (57.67%) / PEPCO (8.55%)
b0347.24	Replace Meadow Brook 138 kV breaker 'MD-17'		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (33.78%) / Dominion (57.67%) / PEPCO (8.55%)

*Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.25	Replace Meadow Brook 138 kV breaker 'MD-18'		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (33.78%) / Dominion (57.67%) / PEPCO (8.55%)
b0347.26	Replace Meadow Brook 138 kV breaker 'MD-22#1 CAP'		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (33.78%) / Dominion (57.67%) / PEPCO (8.55%)

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b0347.27	Replace Meadow Brook 138 kV breaker 'MD-4'		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (33.78%) / Dominion (57.67%) / PEPCO (8.55%)
b0347.28	Replace Meadow Brook 138 kV breaker 'MD-5'		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (33.78%) / Dominion (57.67%) / PEPCO (8.55%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.29	Replace Meadowbrook 138 kV breaker ‘MD-6’		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (33.78%) / Dominion (57.67%) / PEPCO (8.55%)
b0347.30	Replace Meadowbrook 138 kV breaker ‘MD-7’		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (33.78%) / Dominion (57.67%) / PEPCO (8.55%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.31	Replace Meadowbrook 138 kV breaker 'MD-8'		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (33.78%) / Dominion (57.67%) / PEPCO (8.55%)
b0347.32	Replace Meadowbrook 138 kV breaker 'MD-9'		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (33.78%) / Dominion (57.67%) / PEPCO (8.55%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0347.33	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		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: ATSI (35.12%) / Dayton (22.04%) / DEOK (36.72%) / EKPC (6.12%)

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)
b0406.1	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%)
b0406.6	Replace Mitchell 138 kV breaker “Charlerio #1”		APS (100%)
b0406.7	Replace Mitchell 138 kV breaker “Shepler Hill Jct”		APS (100%)
b0406.8	Replace Mitchell 138 kV breaker “Union Jct”		APS (100%)
b0406.9	Replace Mitchell 138 kV breaker “#1-2 138 kV bus tie”		APS (100%)
b0407.1	Replace Marlowe 138 kV breaker “#1 transf”		APS (100%)
b0407.2	Replace Marlowe 138 kV breaker “MBO”		APS (100%)
b0407.3	Replace Marlowe 138 kV breaker “BMA”		APS (100%)
b0407.4	Replace Marlowe 138 kV breaker “BMR”		APS (100%)
b0407.5	Replace Marlowe 138 kV breaker “WC-1”		APS (100%)

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

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0418	Install a breaker failure auto-restoration scheme at Cabot 500 kV for the failure of the #6 breaker		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0419	Install a breaker failure auto-restoration scheme at Bedington 500 kV for the failure of the #1 and #2 breakers		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%) **DFAX Allocation:** APS (100%)
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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0460	Raise limiting structures on Albright – Bethelboro 138 kV to raise the rating to 175 MVA normal 214 MVA emergency		APS (100%)
b0491	Construct an Amos to Welton Spring to WV state line 765 kV circuit (APS equipment)	As specified under the procedures detailed in Attachment H-19B	**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)

*Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0492	Construct a Welton Spring to Kemptown 765 kV line (APS equipment)	As specified under the procedures detailed in Attachment H-19B	**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)
b0492.3	Replace Eastalco 230 kV breaker D-26		APS (100%)
b0492.4	Replace Eastalco 230 kV breaker D-28		APS (100%)

*Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0492.5	Replace Eastalco 230 kV breaker D-31		APS (100%)
b0495	Replace existing Kammer 765/500 kV transformer with a new larger transformer		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (5.93%) / BGE (37.30%) / Dayton (5.03%) / DEOK (6.72%) / EKPC (1.12%) / PEPCO (43.90%)
b0533	Reconductor the Powell Mountain – Sutton 138 kV line		APS (100%)
b0534	Install a 28.61 MVAR capacitor on Sutton 138 kV		APS (100%)
b0535	Install a 44 MVAR capacitor on Dutch Fork 138 kV		APS (100%)
b0536	Replace Doubs circuit breaker DJ1		APS (100%)
b0537	Replace Doubs circuit breaker DJ7		APS (100%)
b0538	Replace Doubs circuit breaker DJ10		APS (100%)
b0572.1	Reconductor Albright – Mettiki – Williams – Parsons – Loughs Lane 138 kV with 954 ACSR		APS (100%)

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)
b0572.2	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		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (100%)
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%)

*Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
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%)
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 (*97.69*%) / DL (0.96%) / PENELEC (1.09%) / 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 (*82.01*%) / DPL (0.85%) / JCPL (1.75%) / ME (*6.38*%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%)
b0675.2	Convert Walkersville - Catoctin 138 kV to 230 kV		AEC (1.02%) / APS (*82.01*%) / DPL (0.85%) / JCPL (1.75%) / ME (*6.38*%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0675.3	Convert Ringgold - Catoctin 138 kV to 230 kV		AEC (1.02%) / APS (*82.01*%) / DPL (0.85%) / JCPL (1.75%) / ME (*6.38*%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%)
b0675.4	Convert Catoctin - Carroll 138 kV to 230 kV		AEC (1.02%) / APS (*82.01*%) / DPL (0.85%) / JCPL (1.75%) / ME (*6.38*%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%)
b0675.5	Convert portion of Ringgold Substation from 138 kV to 230 kV		AEC (1.02%) / APS (*82.01*%) / DPL (0.85%) / JCPL (1.75%) / ME (*6.38*%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%)
b0675.6	Convert Catoctin Substation from 138 kV to 230 kV		AEC (1.02%) / APS (*82.01*%) / DPL (0.85%) / JCPL (1.75%) / ME (*6.38*%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%)
b0675.7	Convert portion of Carroll Substation from 138 kV to 230 kV		AEC (1.02%) / APS (*82.01*%) / DPL (0.85%) / JCPL (1.75%) / ME (*6.38*%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%)
b0675.8	Convert Monocacy Substation from 138 kV to 230 kV		AEC (1.02%) / APS (*82.01*%) / DPL (0.85%) / JCPL (1.75%) / ME (*6.38*%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0675.9	Convert Walkersville Substation from 138 kV to 230 kV		AEC (1.02%) / APS (*82.01*%) / DPL (0.85%) / JCPL (1.75%) / ME (*6.38*%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%)
b0676.1	Reconductor Doubs - Lime Kiln (#207) 230kV		AEC (0.64%) / APS (*86.77*%) / DPL (0.53%) / JCPL (1.93%) / ME (*4.05*%) / NEPTUNE* (0.18%) / PECO (1.93%) / PENELEC (0.93%) / PSEG (2.92%) / RE (0.12%)
b0676.2	Reconductor Doubs - Lime Kiln (#231) 230kV		AEC (0.64%) / APS (*86.77*%) / DPL (0.53%) / JCPL (1.93%) / ME (*4.05*%) / NEPTUNE* (0.18%) / PECO (1.93%) / PENELEC (0.93%) / PSEG (2.92%) / RE (0.12%)
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%)

*Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0684	Reconductor Guilford – South Chambersburg with 954 ACSR		APS (100%)
b0685	Replace Ringgold 230/138 kV #3 with larger transformer		APS (*72.06*%) / JCPL (*4.18*%) / ME (*6.80*%) / NEPTUNE* (0.38%) / PECO (*4.06*%) / PENELEC (5.89%) / PSEG (*6.38*%) / RE (0.25%)
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%)

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

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

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

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

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

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

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)
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%)
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%)

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)
b0999	Replace Redbud 138 kV breaker 'BUS TIE'		APS(100%)
b1022.1	Reconfigure the Peters to Bethel Park 138 kV line and Elrama to Woodville 138 kV line to create a 138 kV path from Woodville to Peters and a 138 kV path from Elrama to Bethel Park		APS (96.98%) / DL (3.02%)
b1022.3	Add static capacitors at Smith 138 kV		APS (96.98%) / DL (3.02%)
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%)

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)
b1023.4	Construct Braddock 138 kV breaker station that connects the Charleroi - Gordon 138 kV line, Washington - Franklin 138 kV line and the Washington - Vanceville 138 kV line including a 66 MVAR capacitor		APS (100%)
b1027	Increase the size of the shunt capacitors at Enon 138 kV		APS (100%)
b1028	Raise three structures on the Osage - Collins Ferry 138 kV line to increase the line rating		APS (100%)
b1128	Reconductor the Edgewater – Vasco Tap; Edgewater – Loyalhanna 138 kV lines with 954 ACSR		APS (100%)
b1129	Reconductor the East Waynesboro – Ringgold 138 kV line with 954 ACSR		APS (100%)
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%)

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)
b1137	Reconductor the Eastgate – Luxor 138 kV; Eastgate – Sony 138 kV line with 954 ACSR		APS (*78.77*%) / PENELEC (*14.11*%) / PSEG (*6.85*%) / RE (0.27%)
b1138	Reconductor the King Farm – Sony 138 kV line with 954 ACSR		APS (100%)
b1139	Reconductor the Yukon – Waltz Mills 138 kV line with high temperature conductor		APS (100%)
b1140	Reconductor the Bracken Junction – Luxor 138 kV line with 954 ACSR		APS (100%)
b1141	Reconductor the Sewickley – Waltz Mills Tap 138 kV line with high temperature conductor		APS (100%)
b1142	Reconductor the Bartonsville – Stephenson 138 kV; Stonewall – Stephenson 138 kV line with 954 ACSR		APS (100%)
b1143	Reconductor the Youngwood – Yukon 138 kV line with high temperature conductor		APS (89.92%) / PENELEC (10.08%)
b1144	Reconductor the Bull Creek Junction – Cabot 138 kV line with high temperature conductor		APS (100%)

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

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

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)
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%)
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 (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
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%)

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

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

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)
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%)

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)
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%)
b1507.2	Terminal Equipment upgrade at Doubs substation		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (25.20%) / BGE (10.49%) / Dominion (52.48%) / PEPCO (11.83%)

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)
b1507.3	Mt. Storm – Doubs transmission line rebuild in Maryland – Total line mileage for APS is 2.71 miles		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%) **DFAX Allocation:** APS (25.20%) / BGE (10.49%) / Dominion (52.48%) / PEPCO (11.83%)
b1510	Install 59.4 MVAR capacitor at Waverly		APS (100%)
b1672	Install a 230 kV breaker at Carbon Center		APS (100%)
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%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0545	Remove instantaneous reclose from Eastalco circuit breaker D-28		APS (100%)
b0559	Install 200 MVAR capacitor at Meadow Brook 500 kV substation		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (33.78%) / Dominion (57.67%) / PEPCO (8.55%)
b0560	Install 250 MVAR capacitor at Kemptown 500 kV substation		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)

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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		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (25.20%) / BGE (10.49%) / Dominion (52.48%) / PEPCO (11.83%)
b1804	Install a new 600 MVAR SVC at Meadowbrook 500kV		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (33.78%) / Dominion (57.67%) / PEPCO (8.55%)
b1816.1	Replace relaying at the Mt. Airy substation on the Carroll - Mt. Airy 230 kV line		APS (100%)

* Neptune Regional Transmission System, LLC

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

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

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)
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%)

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)
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%)
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

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%)

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)
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%)
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%)

* Neptune Regional Transmission System, LLC

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

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

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)
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 A

(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)
b2117	Reconductor 0.33 miles of the Parkersburg - Belpre line and upgrade Parkersburg terminal equipment		APS (100%)
b2118	Add 44 MVAR Cap at New Martinsville		APS (100%)
b2120	Six-Wire Lake Lynn - Lardin 138 kV circuits		APS (100%)
b2142	Replace Weirton 138 kV breaker “Wylie Ridge 210” with 63 kA breaker		APS (100%)
b2143	Replace Weirton 138 kV breaker “Wylie Ridge 216” with 63 kA breaker		APS (100%)
b2174.8	Replace relays at Mitchell substation		APS (100%)
b2174.9	Replace primary relay at Piney Fork substation		APS (100%)
b2174.10	Perform relay setting changes at Bethel Park substation		APS (100%)
b2213	Armstrong Substation: Relocate 138 kV controls from the generating station building to new control building		APS (100%)
b2214	Albright Substation: Install a new control building in the switchyard and relocate controls and SCADA equipment from the generating station building the new control center		APS (100%)
b2215	Rivesville Switching Station: Relocate controls and SCADA equipment from the generating station building to new control building		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)
b2216	Willow Island: Install a new 138 kV cross bus at Belmont Substation and reconnect and reconfigure the 138 kV lines to facilitate removal of the equipment at Willow Island switching station		APS (100%)
b2235	130 MVAR reactor at Monocacy 230 kV		APS (100%)
b2260	Install a 32.4 MVAR capacitor at Bartonville		APS (100%)
b2261	Install a 33 MVAR capacitor at Damascus		APS (100%)
b2267	Replace 1000 Cu substation conductor and 1200 amp wave trap at Marlowe		APS (100%)
b2268	Reconductor 6.8 miles of 138kV 336 ACSR with 336 ACSS from Double Toll Gate to Riverton		APS (100%)
b2299	Reconductor from Collins Ferry - West Run 138 kV with 556 ACSS		APS (100%)
b2300	Reconductor from Lake Lynn - West Run 138 kV		APS (100%)
b2341	Install 39.6 MVAR Capacitor at Shaffers Corner 138 kV Substation		APS (100%)
b2342	Construct a new 138 kV switching station (Shuman Hill substation), which is next the Mobley 138 kV substation and install a 31.7 MVAR capacitor		APS (100%)
b2343	Install a 31.7 MVAR capacitor at West Union 138 kV substation		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)
b2362	Install a 250 MVAR SVC at Squab Hollow 230 kV		APS (100%)
b2362.1	Install a 230 kV breaker at Squab Hollow 230 kV substation		APS (100%)
b2363	Convert the Shingletown 230 kV bus into a 6 breaker ring bus		APS (100%)
b2364	Install a new 230/138 kV transformer at Squab Hollow 230 kV substation. Loop the Forest - Elko 230 kV line into Squab Hollow. Loop the Brookville - Elko 138 kV line into Squab Hollow		APS (100%)
b2412	Install a 44 MVAR 138 kV capacitor at the Hempfield 138 kV substation		APS (100%)
b2433.1	Install breaker and a half 138 kV substation (Waldo Run) with 4 breakers to accommodate service to MarkWest Sherwood Facility including metering which is cut into Glen Falls Lamberton 138 kV line		APS (100%)
b2433.2	Install a 70 MVAR SVC at the new WaldoRun 138 kV substation		APS (100%)
b2433.3	Install two 31.7 MVAR capacitors at the new WaldoRun 138 kV substation		APS (100%)
b2424	Replace the Weirton 138 kV breaker 'WYLIE RID210' with 63 kA breakers		APS (100%)
b2425	Replace the Weirton 138 kV breaker 'WYLIE RID216' with 63 kA breakers		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)
b2426	Replace the Oak Grove 138 kV breaker 'OG1' with 63 kA breakers		APS (100%)
b2427	Replace the Oak Grove 138 kV breaker 'OG2' with 63 kA breakers		APS (100%)
b2428	Replace the Oak Grove 138 kV breaker 'OG3' with 63 kA breakers		APS (100%)
b2429	Replace the Oak Grove 138 kV breaker 'OG4' with 63 kA breakers		APS (100%)
b2430	Replace the Oak Grove 138 kV breaker 'OG5' with 63 kA breakers		APS (100%)
b2431	Replace the Oak Grove 138 kV breaker 'OG6' with 63 kA breakers		APS (100%)
b2432	Replace the Ridgeley 138 kV breaker 'RC1' with a 40 kA rated breaker		APS (100%)
b2440	Replace the Cabot 138kV breaker 'C9-KISKI VLY' with 63kA		APS (100%)
b2472	Replace the Ringgold 138 kV breaker ‘RCM1’ with 40kA breakers		APS (100%)
b2473	Replace the Ringgold 138 kV breaker ‘#4 XMFR’ with 40kA breakers		APS (100%)
b2475	Construct a new line between Oak Mound 138 kV substation and Waldo Run 138 kV substation		APS (100%)
b2545.1	Construct a new 138 kV substation (Shuman Hill substation) connected to the Fairview –Willow Island (84) 138kV line		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)
b2545.2	Install a ring bus station with five active positions and two 52.8 MVAR capacitors with 0.941 mH reactors		APS (100%)
b2545.3	Install a +90/-30 MVAR SVC protected by a 138 kV breaker		APS (100%)
b2545.4	Remove the 31.7 MVAR capacitor bank at Mobley 138 kV		APS (100%)
b2546	Install a 51.8 MVAR (rated) 138 kV capacitor at Nyswaner 138 kV substation		APS (100%)
b2547.1	Construct a new 138 kV six breaker ring bus Hillman substation		APS (100%)
b2547.2	Loop Smith- Imperial 138 kV line into the new Hillman substation		APS (100%)
b2547.3	Install +125/-75 MVAR SVC at Hillman substation		APS (100%)
b2547.4	Install two 31.7 MVAR 138 kV capacitors		APS (100%)
b2548	Eliminate clearance de-rate on Wylie Ridge – Smith 138 kV line and upgrade terminals at Smith 138 kV, new line ratings 294 MVA (Rate A)/350 MVA (Rate B)		APS (100%)
b2612.1	Relocate All Dam 6 138 kV line and the 138 kV line to AE units 1&2		APS (100%)
b2612.2	Install 138 kV, 3000A bus-tie breaker in the open bus-tie position next to the Shaffers corner 138 kV line		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)
b2612.3	Install a 6-pole manual switch, foundation, control cable, and all associated facilities		APS (100%)
b2666	Yukon 138 kV Breaker Replacement		APS (100%)
b2666.1	Replace Yukon 138 kV breaker “Y-11(CHARL1)” with an 80 kA breaker		APS (100%)
b2666.2	Replace Yukon 138 kV breaker “Y-13(BETHEL)” with an 80 kA breaker		APS (100%)
b2666.3	Replace Yukon 138 kV breaker “Y-18(CHARL2)” with an 80 kA breaker		APS (100%)
b2666.4	Replace Yukon 138 kV breaker “Y-19(CHARL2)” with an 80 kA breaker		APS (100%)
b2666.5	Replace Yukon 138 kV breaker “Y-4(4B-2BUS)” with an 80 kA breaker		APS (100%)
b2666.6	Replace Yukon 138 kV breaker “Y-5(LAYTON)” with an 80 kA breaker		APS (100%)
b2666.7	Replace Yukon 138 kV breaker “Y-8(HUNTING)” with an 80 kA breaker		APS (100%)
b2666.8	Replace Yukon 138 kV breaker “Y-9(SPRINGD)” with an 80 kA breaker		APS (100%)
b2666.9	Replace Yukon 138 kV breaker “Y-10(CHRL-SP)” with an 80 kA breaker		APS (100%)
b2666.10	Replace Yukon 138 kV breaker “Y-12(1-1BUS)” with an 80 kA breaker		APS (100%)
b2666.11	Replace Yukon 138 kV breaker “Y-14(4-1BUS)” with an 80 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)
b2666.12	Replace Yukon 138 kV breaker “Y-2(1B-BETHE)” with an 80 kA breaker		APS (100%)
b2666.13	Replace Yukon 138 kV breaker “Y-21(SHEPJ)” with an 80 kA breaker		APS (100%)
b2666.14	Replace Yukon 138 kV breaker “Y-22(SHEPHJT)” with an 80 kA breaker		APS (100%)
b2672	Change CT Ratio at Seneca Caverns from 120/1 to 160/1 and adjust relay settings accordingly		APS (100%)
b2688.3	Carroll Substation: Replace the Germantown 138 kV wave trap, upgrade the bus conductor and adjust CT ratios		AEP (12.91%) / APS (19.04%) / ATSI (1.24%) / ComEd (0.35%) / Dayton (1.45%) / DEOK (2.30%) / DL (1.11%) / Dominion (44.85%) / EKPC (0.78%) / PEPCO (15.85%) / RECO (0.12%)
b2689.3	*Upgrade terminal equipment at structure 27A*		*APS (100%)*
b2696	Upgrade 138 kV substation equipment at Butler, Shanor Manor and Krendale substations. New rating of line will be 353 MVA summer normal/422 MVA emergency		APS (100%)
b2700	Remove existing Black Oak SPS		APS (100%)
b2743.6	Reconfigure the Ringgold 230 kV substation to double bus double breaker scheme		AEP (6.46%) / APS (8.74%) / BGE (19.74%) / ComEd (2.16%) / Dayton (0.59%) / DEOK (1.02%) / DL (0.01%) / Dominion (39.95%) / EKPC (0.45%) / PEPCO (20.88%)

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)
b2743.6.1	Replace the two Ringgold 230/138 kV transformers		AEP (6.46%) / APS (8.74%) / BGE (19.74%) / ComEd (2.16%) / Dayton (0.59%) / DEOK (1.02%) / DL (0.01%) / Dominion (39.95%) / EKPC (0.45%) / PEPCO (20.88%)
b2743.7	Rebuild/Reconductor the Ringgold – Catoctin 138 kV circuit and upgrade terminal equipment on both ends		AEP (6.46%) / APS (8.74%) / BGE (19.74%) / ComEd (2.16%) / Dayton (0.59%) / DEOK (1.02%) / DL (0.01%) / Dominion (39.95%) / EKPC (0.45%) / PEPCO (20.88%)
b2763	Replace the breaker risers and wave trap at Bredinville 138 kV substation on the Cabrey Junction 138 kV terminal		APS (100%)
b2764	Upgrade Fairview 138 kV breaker risers and disconnect leads; Replace 500 CU breaker risers and 556 ACSR disconnect leads with 795 ACSR		APS (100%)
b2964.1	Replace terminal equipment at Pruntytown and Glen Falls 138 kV station		APS (100%)
b2964.2	Reconductor approximately 8.3 miles of the McAlpin - White Hall Junction 138 kV circuit		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)
b2965	Reconductor the Charleroi – Allenport 138 kV line with 954 ACSR conductor. Replace breaker risers at Charleroi and Allenport		DL (100%)
b2966	Reconductor the Yukon - Smithton - Shepler Hill Jct 138 kV line with 795 ACSS conductor. Replace Line Disconnect Switch at Yukon		APS (100%)
b2967	Convert the existing 6 wire Butler - Shanor Manor - Krendale 138 kV line into two separate 138 kV lines. New lines will be Butler - Keisters and Butler - Shanor Manor - Krendale 138 kV		APS (100%)
b2970	Ringgold – Catoctin Solution		APS (100%)
b2970.1	Install two new 230 kV positions at Ringgold for 230/138 kV transformers		APS (100%)
b2970.2	Install new 230 kV position for Ringgold – Catoctin 230 kV line		APS (100%)
b2970.3	Install one new 230 kV breaker at Catoctin substation		APS (100%)
b2970.4	Install new 230/138 kV transformer at Catoctin substation. Convert Ringgold – Catoctin 138 kV line to 230 kV operation		APS (100%)

Attachment 7g (Delmarva OATT)

SCHEDULE 12 – APPENDIX

(3) Delmarva Power & Light Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0144.1	Build new Red Lion – Milford – Indian River 230 kV circuit		DPL (100%)
b0144.2	Indian River Sub – 230 kV Terminal Position		DPL (100%)
b0144.3	Red Lion Sub – 230 kV Terminal Position		DPL (100%)
b0144.4	Milford Sub – (2) 230 kV Terminal Positions		DPL (100%)
b0144.5	Indian River – 138 kV Transmission Line to AT-20		DPL (100%)
b0144.6	Indian River – 138 & 69 kV Transmission Ckts. Undergrounding		DPL (100%)
b0144.7	Indian River – (2) 230 kV bus ties		DPL (100%)
b0148	Re-rate Glasgow – Mt. Pleasant 138 kV and North Seaford – South Harrington 138 kV		DPL (100%)
b0149	Complete structure work to increase rating of Cheswold – Jones REA 138 kV		DPL (100%)
b0221	Replace disconnect switch on Edgewood-N. Salisbury 69 kV		DPL (100%)
b0241.1	Keeny Sub – Replace overstressed breakers		DPL (100%)
b0241.2	Edgemoor Sub – Replace overstressed breakers		DPL (100%)
b0241.3	Red Lion Sub – Substation reconfigure to provide for second Red Lion 500/230 kV transformer		DPL (84.5%) / PECO (15.5%)
b0261	Replace 1200 Amp disconnect switch on the Red Lion – Reybold 138 kV circuit		DPL (100%)

Delmarva Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0262	Reconductor 0.5 miles of Christiana – Edgemoor 138 kV		DPL (100%)
b0263	Replace 1200 Amp wavetrap at Indian River on the Indian River – Frankford 138 kV line		DPL (100%)
b0272.1	Replace line trap and disconnect switch at Keeney 500 kV substation – 5025 Line Terminal Upgrade		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (27.55%) / BGE (0.25%) / DPL (44.42%) / PECO (27.29%) / PEPCO (0.24%) / PPL (0.25%)
b0282	Install 46 MVAR capacitors on the DPL distribution system		DPL (100%)
b0291	Replace 1600A disconnect switch at Harmony 230 kV and for the Harmony – Edgemoor 230 kV circuit, increase the operating temperature of the conductor		DPL (100%)
b0295	Raise conductor temperature of North Seaford – Pine Street – Dupont Seaford		DPL (100%)

*Neptune Regional Transmission System, LLC

Delmarva Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0296	Rehoboth/Cedar Neck Tap (6733-2) upgrade		DPL (100%)
b0320	Create a new 230 kV station that splits the 2nd Milford to Indian River 230 kV line, add a 230/69 kV transformer, and run a new 69 kV line down to Harbeson 69 kV		DPL (100%)
b0382	Cambridge Sub – Close through to Todd Substation		DPL (100%)
b0383	Wye Mills AT-1 and AT-2 138/69 kV Replacements		DPL (100%)
b0384	Replace Indian River AT-20 (400 MVA)		DPL (100%)
b0385	Oak Hall to New Church (13765) Upgrade		DPL (100%)
b0386	Cheswold/Kent (6768) Rebuild		DPL (100%)
b0387	N. Seaford – Add a 2nd 138/69 kV autotransformer		DPL (100%)
b0388	Hallwood/Parksley (6790-2) Upgrade		DPL (100%)
b0389	Indian River AT-1 and AT-2 138/69 kV Replacements		DPL (100%)
b0390	Rehoboth/Lewes (6751-1 and 6751-2) Upgrade		DPL (100%)
b0391	Kent/New Meredith (6704-2) Upgrade		DPL (100%)
b0392	East New Market Sub – Establish a 69 kV Bus Arrangement		DPL (100%)
b0415	Increase the temperature ratings of the Edgemoor – Christiana – New Castle 138 kV by replacing six transmission poles		DPL (100%)

Delmarva Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0437	Spare Keeney 500/230 kV transformer		DPL (100%)
b0441	Additional spare Keeney 500/230 kV transformer		DPL (100%)
b0480	Rebuild Lank – Five Points 69 kV		DPL (100%)
b0481	Replace wave trap at Indian River 138 kV on the Omar – Indian River 138 kV circuit		DPL (100%)
b0482	Rebuild Millsboro – Zoar REA 69 kV		DPL (100%)
b0483	Replace Church 138/69 kV transformer and add two breakers		DPL (100%)
b0483.1	Build Oak Hall – Wattsville 138 kV line		DPL (100%)
b0483.2	Add 138/69 kV transformer at Wattsville		DPL (100%)
b0483.3	Establish 138 kV bus position at Oak Hall		DPL (100%)
b0484	Re-tension Worcester – Berlin 69 kV for 125ºC		DPL (100%)
b0485	Re-tension Taylor – North Seaford 69 kV for 125ºC		DPL (100%)
b0494.1	Install a 2nd Red Lion 230/138 kV		DPL (100%)
b0494.2	Hares Corner – Relay Improvement		DPL (100%)
b0494.3	Reybold – Relay Improvement		DPL (100%)
b0494.4	New Castle – Relay Improvement		DPL (100%)

Delmarva Power & Light 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		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (3.94%) / APS (0.33%) / BGE (34.54%) / DPL (14.69%) / Dominion (0.30%) / JCPL (9.43%) / ME (2.16%) / NEPTUNE (0.90%) / PECO (10.52%) / PEPCO (2.44%) / PPL (5.50%) / PSEG (14.71%) / RE (0.54%)
b0513	Rebuild the Ocean Bay – Maridel 69 kV line		DPL (100%)
b0527	Replace existing 12 MVAR capacitor at Bethany with a 30 MVAR capacitor		DPL (100%)
b0528	Replace existing 69/12 kV transformer at Bethany with a 138/12 kV transformer		DPL (100%)
b0529	Install an additional 8.4 MVAR capacitor at Grasonville 69 Kv		DPL (100%)
b0530	Replace existing 12 MVAR capacitor at Wye Mills with a 30 MVAR capacitor		DPL (100%)

Delmarva Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0531	Create a four breaker 138 kV ring bus at Wye Mills and add a second 138/69 kV transformer		DPL (100%)
b0566	Rebuild the Trappe Tap – Todd 69 kV line		DPL (100%)
b0567	Rebuild the Mt. Pleasant – Townsend 138 kV line		DPL (100%)
b0568	Install a third Indian River 230/138 kV transformer		DPL (100%)
b0725	Add a third Steele 230/138 kV transformer		DPL (100%)
b0732	Rebuild Vaugh – Wells 69 kV		DPL (100%)
b0733	Add a second 230/138 kV transformer at Harmony		DPL (97.06%) / PECO (2.94%)
b0734	Rebuild Church – Steele 138 kV		DPL (100%)
b0735	Rebuild Indian River – Omar – Bethany 138 kV		DPL (100%)
b0736	Rebuild Dupont Edgemoor – Edgemoor – Silverside 69 kV		DPL (*69.65*%) / PECO (*17.30*%) / PSEG (*12.56*%) / RE (0.49%)
b0737	Build a new Indian River – Bishop 138 kV line		DPL (100%)
b0750	Convert 138 kV network path from Vienna – Loretto – Piney - Grove to 230 kV, add 230/138 kV transformer to Loretto 230 kV		DPL (100%)

Delmarva Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0751	Add two additional breakers at Keeney 500 kV		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: DPL (100%)
b0752	Replace two circuit breakers to bring the emergency rating up to 348 MVA		DPL (100%)
b0753	Add a second Loretto 230/138 kV transformer		DPL (100%)
b0754	Rebuild 10 miles of Glasgow to Mt. Pleasant 138 kV line to bring the normal rating to 298 MVA and the emergency rating to 333 MVA		DPL (100%)
b0792	Reconfigure Cecil Sub into 230 and 138 kV ring buses, add a 230/138 kV transformer, and operate the 34.5 kV bus normally open		DPL (100%)
b0873	Build 2nd Glasgow-Mt Pleasant 138 kV line		DPL (100%)
b0874	Reconfigure Brandywine substation		DPL (100%)

*Neptune Regional Transmission System, LLC

Delmarva Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0876	Install 50 MVAR SVC at 138th St 138 kV		DPL (100%)
b0877	Build a 2nd Vienna-Steele 230 kV line		DPL (100%)
b0879.1	Apply a special protection scheme (load drop at Stevensville and Grasonville)		DPL (100%)
b1246	Re-build the Townsend – Church 138 kV circuit		DPL (100%)
b1247	Re-build the Glasgow – Cecil 138 kV circuit		DPL (72.06%) / PECO (27.94%)
b1248	Install two 15 MVAR capacitor at Loretto 69 kV		DPL (100%)
b1249	Reconfigure the existing Sussex 69 kV capacitor		DPL (100%)
b1603	Upgrade 19 miles conductor of the Wattsville - Signepost - Stockton - Kenney 69 kV circuit		DPL (100%)
b1604	Replace CT at Reybold 138 kV substation		DPL (100%)
b1723	Replace strand bus and disconnect switch at Glasgow 138 kV substation		DPL (100%)
b1899.1	Install new variable reactors at Indian River and Nelson 138 kV		DPL (100%)

* Neptune Regional Transmission System, LLC

The Annual Revenue Requirement associated with the Transmission Enhancement Charges are set forth and determined in Appendix A to Attachment H-3.

Delmarva Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1899.2	Install new variable reactors at Cedar Creek 230 kV		DPL (100%)
b1899.3	Install new variable reactors at New Castle 138 kV and Easton 69 kV		DPL (100%)

SCHEDULE 12 – APPENDIX A

(3) Delmarva Power & Light Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2288	Build a new 138 kV line from Piney Grove – Wattsville		DPL (100%)
b2395	Reconductor the Harmony – Chapel St 138 kV circuit		DPL (100%)
b2569	Replace Terminal equipment at Silverside 69 kV substation		DPL (100%)
b2633.7	Implement high speed relaying utilizing OPGW on Red Lion – Hope Creek 500 kV line		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (0.01%) / DPL (99.98%) / JCPL (0.01%)
b2633.10	Interconnect the new Silver Run 230 kV substation with existing Red Lion – Cartanza and Red Lion – Cedar Creek 230 kV lines		AEC (0.01%) / DPL (99.98%) / JCPL (0.01%)

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

Delmarva Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2695	Rebuild Worcester – Ocean Pine 69 kV ckt. 1 to 1400A capability summer emergency		DPL (100%)
b2946	*Convert existing Preston 69 kV substation to DPL's current design standard of a 3-breaker ring bus*		*DPL (100%)*
b2947.1	*Upgrade terminal equipment at DPL's Naamans substation (Darley - Naamans 69 kV)*		*DPL (100%)*
b2947.2	*Reconductor 0.11 mile section of Darley - Naamans 69 kV circuit*		*DPL (100%)*
b2948	*Upgrade terminal equipment at DPL's Silverside Road substation (Dupont Edge Moor – Silver R. 69 kV)*		*DPL (100%)*
b2987	Install a 30 MVAR capacitor bank at DPL's Cool Springs 69 kV substation. The capacitor bank would be installed in two separate 15 MVAR stages allowing DPL operational flexibility		DPL (100%)

Attachment 7h (PEPCo OATT)

SCHEDULE 12 – APPENDIX

(10) Potomac Electric Power Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0146	Installation of (2) new 230 kV circuit breakers at Quince Orchard substation on circuits 23028 and 23029		PEPCO (100%)
b0219	Install two new 230 kV circuits between Palmers Corner and Blue Plains		PEPCO (100%)
b0228	Upgrade Burtonsville – Sandy Springs 230 kV circuit		PEPCO (100%)
b0238.1	Modify Dickerson Station H 230 kV		PEPCO (100%)
b0251	Install 100 MVAR of 230 kV capacitors at Bells Mill		PEPCO (100%)
b0252	Install 100 MVAR of 230 kV capacitors at Bells Mill		PEPCO (100%)
b0288	Brighton Substation – add 2nd 1000 MVA 500/230 kV transformer, 2 500 kV circuit breakers and miscellaneous bus work		BGE (19.33%) / Dominion (17%) / PEPCO (63.67%)
b0319	Add a second 1000 MVA Bruches Hill 500/230 kV transformer		PEPCO (100%)
b0366	Install a 4th Ritchie 230/69 kV transformer		PEPCO (100%)

* Neptune Regional Transmission System, LLC

The Annual Revenue Requirement associated with the Transmission Enhancement Charges are set forth and determined in Appendix A to Attachment H-9.

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0367.1	Reconductor circuit “23035” for Dickerson – Quince Orchard 230 kV		AEC (1.78%) / BGE (*26.54*%) / DPL (3.25%) / JCPL (2.67%) / ME (1.16%) / Neptune* (0.25%) / PECO (*4.80*%) / PEPCO (*52.50*%) / PPL (3.23%) / PSEG (*3.82*%)
b0367.2	Reconductor circuit “23033” for Dickerson – Quince Orchard 230 kV		AEC (1.78%) / BGE (*26.54*%) / DPL (3.25%) / JCPL (2.67%) / ME (1.16%) / Neptune* (0.25%) / PECO (*4.80*%) / PEPCO (*52.50*%) / PPL (3.23%) / PSEG (*3.82*%)
b0375	Install 0.5% reactor at Dickerson on the Pleasant View – Dickerson 230 kV circuit		AEC (1.02%) / BGE (25.42%) / DPL (2.97%) / ME (1.72%) / PECO (3.47%) / PEPCO (65.40%)
b0467.1	Reconductor the Dickerson – Pleasant View 230 kV circuit		AEC (1.75%) / APS (19.70%) / BGE (22.13%) / DPL (3.70%) / JCPL (0.71%) / ME (2.48%) / Neptune* (0.06%) / PECO (5.54%) / PEPCO (41.86%) / PPL (2.07%)
b0478	Reconductor the four circuits from Burches Hill to Palmers Corner		APS (1.68%) / BGE (1.83%) / PEPCO (96.49%)
b0496	Replace existing 500/230 kV transformer at Brighton		APS (5.67%) / BGE (29.68%) / Dominion (10.91%) / PEPCO (53.74%)
b0499	Install third Burches Hill 500/230 kV transformer		APS (3.54%) / BGE (7.31%) / PEPCO (89.15%)

*Neptune Regional Transmission System, LLC

The Annual Revenue Requirement associated with the Transmission Enhancement Charges are set forth and determined in Appendix A to Attachment H-9.

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
0512	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		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (3.94%) / APS (0.33%) / BGE (34.54%) / DPL (14.69%) / Dominion (0.30%) / JCPL (9.43%) / ME (2.16%) / NEPTUNE (0.90%) / PECO (10.52%) / PEPCO (2.44%) / PPL (5.50%) / PSEG (14.71%) / RE (0.54%)
b0512.7	Advance n0772 (Replace Chalk Point 230 kV breaker (1A) with 80 kA breaker)		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (3.94%) / APS (0.33%) / BGE (34.54%) / DPL (14.69%) / Dominion (0.30%) / JCPL (9.43%) / ME (2.16%) / NEPTUNE (0.90%) / PECO (10.52%) / PEPCO (2.44%) / PPL (5.50%) / PSEG (14.71%) / RE (0.54%)

* Neptune Regional Transmission System, LLC

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.8	Advance n0773 (Replace Chalk Point 230 kV breaker (1B) with 80 kA breaker)		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (3.94%) / APS (0.33%) / BGE (34.54%) / DPL (14.69%) / Dominion (0.30%) / JCPL (9.43%) / ME (2.16%) / NEPTUNE (0.90%) / PECO (10.52%) / PEPCO (2.44%) / PPL (5.50%) / PSEG (14.71%) / RE (0.54%)
b0512.9	Advance n0774 (Replace Chalk Point 230 kV breaker (2A) with 80 kA breaker)		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (3.94%) / APS (0.33%) / BGE (34.54%) / DPL (14.69%) / Dominion (0.30%) / JCPL (9.43%) / ME (2.16%) / NEPTUNE (0.90%) / PECO (10.52%) / PEPCO (2.44%) / PPL (5.50%) / PSEG (14.71%) / RE (0.54%)

* Neptune Regional Transmission System, LLC

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.10	Advance n0775 (Replace Chalk Point 230 kV breaker (2B) with 80 kA breaker)		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (3.94%) / APS (0.33%) / BGE (34.54%) / DPL (14.69%) / Dominion (0.30%) / JCPL (9.43%) / ME (2.16%) / NEPTUNE (0.90%) / PECO (10.52%) / PEPCO (2.44%) / PPL (5.50%) / PSEG (14.71%) / RE (0.54%)
b0512.11	Advance n0776 (Replace Chalk Point 230 kV breaker (2C) with 80 kA breaker)		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (3.94%) / APS (0.33%) / BGE (34.54%) / DPL (14.69%) / Dominion (0.30%) / JCPL (9.43%) / ME (2.16%) / NEPTUNE (0.90%) / PECO (10.52%) / PEPCO (2.44%) / PPL (5.50%) / PSEG (14.71%) / RE (0.54%)

* Neptune Regional Transmission System, LLC

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.12	Advance n0777 (Replace Chalk Point 230 kV breaker (3A) with 80 kA breaker)		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (3.94%) / APS (0.33%) / BGE (34.54%) / DPL (14.69%) / Dominion (0.30%) / JCPL (9.43%) / ME (2.16%) / NEPTUNE (0.90%) / PECO (10.52%) / PEPCO (2.44%) / PPL (5.50%) / PSEG (14.71%) / RE (0.54%)
b0512.13	Advance n0778 (Replace Chalk Point 230 kV breaker (3B) with 80 kA breaker)		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (3.94%) / APS (0.33%) / BGE (34.54%) / DPL (14.69%) / Dominion (0.30%) / JCPL (9.43%) / ME (2.16%) / NEPTUNE (0.90%) / PECO (10.52%) / PEPCO (2.44%) / PPL (5.50%) / PSEG (14.71%) / RE (0.54%)

* Neptune Regional Transmission System, LLC

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.14	Advance n0779 (Replace Chalk Point 230 kV breaker (3C) with 80 kA breaker)		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (3.94%) / APS (0.33%) / BGE (34.54%) / DPL (14.69%) / Dominion (0.30%) / JCPL (9.43%) / ME (2.16%) / NEPTUNE (0.90%) / PECO (10.52%) / PEPCO (2.44%) / PPL (5.50%) / PSEG (14.71%) / RE (0.54%)
b0512.15	Advance n0780 (Replace Chalk Point 230 kV breaker (4A) with 80 kA breaker)		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (3.94%) / APS (0.33%) / BGE (34.54%) / DPL (14.69%) / Dominion (0.30%) / JCPL (9.43%) / ME (2.16%) / NEPTUNE (0.90%) / PECO (10.52%) / PEPCO (2.44%) / PPL (5.50%) / PSEG (14.71%) / RE (0.54%)

* Neptune Regional Transmission System, LLC

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.16	Advance n0781 (Replace Chalk Point 230 kV breaker (4B) with 80 kA breaker)		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (3.94%) / APS (0.33%) / BGE (34.54%) / DPL (14.69%) / Dominion (0.30%) / JCPL (9.43%) / ME (2.16%) / NEPTUNE (0.90%) / PECO (10.52%) / PEPCO (2.44%) / PPL (5.50%) / PSEG (14.71%) / RE (0.54%)
b0512.17	Advance n0782 (Replace Chalk Point 230 kV breaker (5A) with 80 kA breaker)		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (3.94%) / APS (0.33%) / BGE (34.54%) / DPL (14.69%) / Dominion (0.30%) / JCPL (9.43%) / ME (2.16%) / NEPTUNE (0.90%) / PECO (10.52%) / PEPCO (2.44%) / PPL (5.50%) / PSEG (14.71%) / RE (0.54%)

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Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.18	Advance n0783 (Replace Chalk Point 230 kV breaker (5B) with 80 kA breaker)		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (3.94%) / APS (0.33%) / BGE (34.54%) / DPL (14.69%) / Dominion (0.30%) / JCPL (9.43%) / ME (2.16%) / NEPTUNE (0.90%) / PECO (10.52%) / PEPCO (2.44%) / PPL (5.50%) / PSEG (14.71%) / RE (0.54%)
b0512.19	Advance n0784 (Replace Chalk Point 230 kV breaker (6A) with 80 kA breaker)		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (3.94%) / APS (0.33%) / BGE (34.54%) / DPL (14.69%) / Dominion (0.30%) / JCPL (9.43%) / ME (2.16%) / NEPTUNE (0.90%) / PECO (10.52%) / PEPCO (2.44%) / PPL (5.50%) / PSEG (14.71%) / RE (0.54%)

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Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.20	Advance n0785 (Replace Chalk Point 230 kV breaker (6B) with 80 kA breaker		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (3.94%) / APS (0.33%) / BGE (34.54%) / DPL (14.69%) / Dominion (0.30%) / JCPL (9.43%) / ME (2.16%) / NEPTUNE (0.90%) / PECO (10.52%) / PEPCO (2.44%) / PPL (5.50%) / PSEG (14.71%) / RE (0.54%)
b0512.21	Advance n0786 (Replace Chalk Point 230 kV breaker (7B) with 80 kA breaker)		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (3.94%) / APS (0.33%) / BGE (34.54%) / DPL (14.69%) / Dominion (0.30%) / JCPL (9.43%) / ME (2.16%) / NEPTUNE (0.90%) / PECO (10.52%) / PEPCO (2.44%) / PPL (5.50%) / PSEG (14.71%) / RE (0.54%)

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Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.22	Advance n0787 (Replace Chalk Point 230 kV breaker (8A) with 80 kA breaker)		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (3.94%) / APS (0.33%) / BGE (34.54%) / DPL (14.69%) / Dominion (0.30%) / JCPL (9.43%) / ME (2.16%) / NEPTUNE (0.90%) / PECO (10.52%) / PEPCO (2.44%) / PPL (5.50%) / PSEG (14.71%) / RE (0.54%)
b0512.23	Advance n0788 (Replace Chalk Point 230 kV breaker (8B) with 80 kA breaker)		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (3.94%) / APS (0.33%) / BGE (34.54%) / DPL (14.69%) / Dominion (0.30%) / JCPL (9.43%) / ME (2.16%) / NEPTUNE (0.90%) / PECO (10.52%) / PEPCO (2.44%) / PPL (5.50%) / PSEG (14.71%) / RE (0.54%)

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Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.24	Advance n0789 (Replace Chalk Point 230 kV breaker (7A) with 80 kA breaker)		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (3.94%) / APS (0.33%) / BGE (34.54%) / DPL (14.69%) / Dominion (0.30%) / JCPL (9.43%) / ME (2.16%) / NEPTUNE (0.90%) / PECO (10.52%) / PEPCO (2.44%) / PPL (5.50%) / PSEG (14.71%) / RE (0.54%)
b0512.25	Advance n0790 (Replace Chalk Point 230 Kv breaker (1C) with 80 kA breaker)		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (3.94%) / APS (0.33%) / BGE (34.54%) / DPL (14.69%) / Dominion (0.30%) / JCPL (9.43%) / ME (2.16%) / NEPTUNE (0.90%) / PECO (10.52%) / PEPCO (2.44%) / PPL (5.50%) / PSEG (14.71%) / RE (0.54%)

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Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.26	Advance n0791 (Replace Chalk Point 230 Kv breaker (4C) with 80 kA breaker)		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (3.94%) / APS (0.33%) / BGE (34.54%) / DPL (14.69%) / Dominion (0.30%) / JCPL (9.43%) / ME (2.16%) / NEPTUNE (0.90%) / PECO (10.52%) / PEPCO (2.44%) / PPL (5.50%) / PSEG (14.71%) / RE (0.54%)
b0512.27	Advance n0792 (Replace Chalk Point 230 Kv breaker (5C) with 80 kA breaker)		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (3.94%) / APS (0.33%) / BGE (34.54%) / DPL (14.69%) / Dominion (0.30%) / JCPL (9.43%) / ME (2.16%) / NEPTUNE (0.90%) / PECO (10.52%) / PEPCO (2.44%) / PPL (5.50%) / PSEG (14.71%) / RE (0.54%)

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Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.28	Advance n0793 (Replace Chalk Point 230 Kv breaker (6C) with 80 kA breaker)		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (3.94%) / APS (0.33%) / BGE (34.54%) / DPL (14.69%) / Dominion (0.30%) / JCPL (9.43%) / ME (2.16%) / NEPTUNE (0.90%) / PECO (10.52%) / PEPCO (2.44%) / PPL (5.50%) / PSEG (14.71%) / RE (0.54%)
b0512.29	Advance n0794 (Replace Chalk Point 230 Kv breaker (7C) with 80 kA breaker)		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (3.94%) / APS (0.33%) / BGE (34.54%) / DPL (14.69%) / Dominion (0.30%) / JCPL (9.43%) / ME (2.16%) / NEPTUNE (0.90%) / PECO (10.52%) / PEPCO (2.44%) / PPL (5.50%) / PSEG (14.71%) / RE (0.54%)
b0526	Build two Ritchie – Benning Station A 230 kV lines		AEC (0.77%) / BGE (16.76%) / DPL (1.22%) / JCPL (1.39%) / ME (0.59%) / Neptune* (0.13%) / PECO (2.10%) / PEPCO (74.86%) / PSEG (2.10%) / RE (0.08%)

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Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0561	Install 300 MVAR capacitor at Dickerson Station "D" 230 kV substation		AEC (8.64%) / APS (1.70%) / DPL (12.33%) / JCPL (18.30%) / ME (1.56%) / Neptune* (1.78%) / PECO (21.94%) / PPL (6.45%) / PSEG (26.32%) / RE (0.98%)
b0562	Install 500 MVAR capacitor at Brighton 230 kV substation		AEC (8.64%) / APS (1.70%) / DPL (12.33%) / JCPL (18.30%) / ME (1.56%) / Neptune* (1.78%) / PECO (21.94%) / PPL (6.45%) / PSEG (26.32%) / RE (0.98%)
b0637	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0638	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0639	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0640	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0641	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0642	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0643	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0644	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0645	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0646	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0647	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0648	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)
b0649	Replace 13 Oak Grove 230 kV breakers		PEPCO (100%)

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0701	Expand Benning 230 kV station, add a new 250 MVA 230/69 kV transformer at Benning Station ‘A’, new 115 kV Benning switching station		BGE (30.57%) / PEPCO (69.43%)
b0702	Add a second 50 MVAR 230 kV shunt reactor at the Benning 230 kV substation		PEPCO (100%)
b0720	Upgrade terminal equipment on both lines		PEPCO (100%)
b0721	Upgrade Oak Grove – Ritchie 23061 230 kV line		PEPCO (100%)
b0722	Upgrade Oak Grove – Ritchie 23058 230 kV line		PEPCO (100%)
b0723	Upgrade Oak Grove – Ritchie 23059 230 kV line		PEPCO (100%)
b0724	Upgrade Oak Grove – Ritchie 23060 230 kV line		PEPCO (100%)
b0730	Add slow oil circulation to the four Bells Mill Road – Bethesda 138 kV lines, add slow oil circulation to the two Buzzard Point – Southwest 138 kV lines; increasing the thermal ratings of these six lines allows for greater adjustment of the O Street phase shifters		PEPCO (100%)

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Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0731	Implement an SPS to automatically shed load on the 34 kV Bells Mill Road bus for this N-2 condition. The SPS will be in effect for 2013 and 2014 until a third Bells Mill 230/34 kV is placed in-service in 2015		PEPCO (100%)
b0746	Upgrade circuit for 3,000 amps using the ACCR		AEC (0.73%) / BGE (31.05%) / DPL (1.45%) / PECO (2.46%) / PEPCO (62.88%) / PPL (1.43%)
b0747	Upgrade terminal equipment on both lines: Quince Orchard - Bells Mill 230 kV (030) and (028)		PEPCO (100%)
b0802	Advance n0259 (Replace Dickerson Station H Circuit Breaker 412A)		PEPCO (100%)
b0803	Advance n0260 (Replace Dickerson Station H Circuit Breaker 42A)		PEPCO (100%)
b0804	Advance n0261 (Replace Dickerson Station H Circuit Breaker 42C)		PEPCO (100%)
b0805	Advance n0262 (Replace Dickerson Station H Circuit Breaker 43A)		PEPCO (100%)
b0806	Advance n0264 (Replace Dickerson Station H Circuit Breaker 44A)		PEPCO (100%)

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Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0809	Advance n0267 (Replace Dickerson Station H Circuit Breaker 45B)		PEPCO (100%)
b0810	Advance n0270 (Replace Dickerson Station H Circuit Breaker 47A)		PEPCO (100%)
b0811	Advance n0726 (Replace Dickerson Station H Circuit Breaker SPARE)		PEPCO (100%)
b0845	Replace Chalk Point 230 kV breaker (1A) with 80 kA breaker		PEPCO (100%)
b0846	Replace Chalk Point 230 kV breaker (1B) with 80 kA breaker		PEPCO (100%)
b0847	Replace Chalk Point 230 kV breaker (2A) with 80 kA breaker		PEPCO (100%)
b0848	Replace Chalk Point 230 kV breaker (2B) with 80 kA breaker		PEPCO (100%)
b0849	Replace Chalk Point 230 kV breaker (2C) with 80 kA breaker		PEPCO (100%)
b0850	Replace Chalk Point 230 kV breaker (3A) with 80 kA breaker		PEPCO (100%)
b0851	Replace Chalk Point 230 kV breaker (3B) with 80 kA breaker		PEPCO (100%)
b0852	Replace Chalk Point 230 kV breaker (3C) with 80 kA breaker		PEPCO (100%)
b0853	Replace Chalk Point 230 kV breaker (4A) with 80 kA breaker		PEPCO (100%)
b0854	Replace Chalk Point 230 kV breaker (4B) with 80 kA breaker		PEPCO (100%)
b0855	Replace Chalk Point 230 kV breaker (5A) with 80 kA breaker		PEPCO (100%)

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0856	Replace Chalk Point 230 kV breaker (5B) with 80 kA breaker		PEPCO (100%)
b0857	Replace Chalk Point 230 kV breaker (6A) with 80 kA breaker		PEPCO (100%)
b0858	Replace Chalk Point 230 kV breaker (6B) with 80 kA breaker		PEPCO (100%)
b0859	Replace Chalk Point 230 kV breaker (7B) with 80 kA breaker		PEPCO (100%)
b0860	Replace Chalk Point 230 kV breaker (8A) with 80 kA breaker		PEPCO (100%)
b0861	Replace Chalk Point 230 kV breaker (8B) with 80 kA breaker		PEPCO (100%)
b0862	Replace Chalk Point 230 kV breaker (7A) with 80 kA breaker		PEPCO (100%)
b0863	Replace Chalk Point 230 kV breaker (1C) with 80 kA breaker		PEPCO (100%)
b1104	Replace Burtonsville 230 kV breaker ‘1C’		PEPCO (100%)
b1105	Replace Burtonsville 230 kV breaker ‘2C’		PEPCO (100%)
b1106	Replace Burtonsville 230 kV breaker ‘3C’		PEPCO (100%)
b1107	Replace Burtonsville 230 kV breaker ‘4C’		PEPCO (100%)
b1125	Convert the 138 kV line from Buzzard 138 - Ritchie 851 to a 230 kV line and Remove 230/138 kV Transformer at Ritchie and install a spare 230/138 kV transformer at Buzzard Pt		APS (4.74%) / PEPCO (95.26%)
b1126	Upgrade the 230 kV line from Buzzard 016 – Ritchie 059		APS (4.74%) / PEPCO (95.26%)

Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1592	Reconductor the Oak Grove – Bowie 230 kV circuit and upgrade terminal equipments at Oak Grove and Bowie 230 kV substations		AEC (*2.40*%) / APS (*3.83*%) / BGE (*65.87*%) / DPL (*4.44*%) / JCPL (*3.94*%) / ME (2.16%) / Neptune* (0.39%) / PECO (*8.37*%) / PPL (*2.84*%) / PSEG (*5.54*%) / RE (0.22%)
b1593	Reconductor the Bowie - Burtonsville 230 kV circuit and upgrade terminal equipments at Bowie and Burtonsville 230 kV substations		AEC (*2.40*%) / APS (*3.83*%) / BGE (*65.87*%) / DPL (*4.44*%) / JCPL (*3.94*%) / ME (2.16%) / Neptune* (0.39%) / PECO (*8.37*%) / PPL (*2.84*%) / PSEG (*5.54*%) / RE (0.22%)
b1594	Reconductor the Oak Grove – Bowie 230 kV ‘23042’ circuit and upgrade terminal equipments at Oak Grove and Bowie 230 kV substations		AEC (*2.40*%) / APS (*3.83*%) / BGE (*65.87*%) / DPL (*4.44*%) / JCPL (*3.94*%) / ME (2.16%) / Neptune* (0.39%) / PECO (*8.37*%) / PPL (*2.84*%) / PSEG (*5.54*%) / RE (0.22%)
b1595	Reconductor the Bowie – Burtonsville 230 kV ‘23042’ circuit and upgrade terminal equipments at Oak Grove and Burtonsville 230 kV substations		AEC (*2.40*%) / APS (*3.83*%) / BGE (*65.87*%) / DPL (*4.44*%) / JCPL (*3.94*%) / ME (2.16%) / Neptune* (0.39%) / PECO (*8.37*%) / PPL (*2.84*%) / PSEG (*5.54*%) / RE (0.22%)
b1596	Reconductor the Dickerson station “H” – Quince Orchard 230 kV ‘23032’ circuit and upgrade terminal equipments at Dickerson station “H” and Quince Orchard 230 kV substations		AEC (0.80%) / BGE (33.68%) / DPL (2.09%) / PECO (3.07%) / PEPCO (60.36%)

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Potomac Electric Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1597	Reconductor the Oak Grove - Aquasco 230 kV ‘23062’ circuit and upgrade terminal equipments at Oak Grove and Aquasco 230 kV substations		AEC (1.44%) / BGE (48.60%) / DPL (2.52%) / PECO (5.00%) / PEPCO (42.44%)
b2008	Reconductor feeder 23032 and 23034 to high temp. conductor (10 miles)		BGE (33.05%) / DPL (1.38%) / PECO (1.35%) / PEPCO (64.22%) /
b2136	Reconductor the Morgantown - V3-017 230 kV '23086' circuit and replace terminal equipments at Morgantown		PEPCO (100%)
b2137	Reconductor the Morgantown - Talbert 230 kV '23085' circuit and replace terminal equipment at Morgantown		PEPCO (100%)
b2138	Replace terminal equipments at Hawkins 230 kV substation		PEPCO (100%)

SCHEDULE 12 – APPENDIX A

(10) Potomac Electric Power Company

Required Transmission Enhancements		*Annual Revenue Requirement*	*Responsible Customer(s)*
b2279	*Add two 100 MVAR reactors at Dickerson Station H and two 100 MVAR reactors at Brighton 230 kV substation*		*PEPCO (100%)*
b2372	Upgrade the Chalk Point - T133TAP 230 kV Ck. 1 (23063) and Ckt. 2 (23065) to 1200 MVA ACCR		BGE (100%)

The Annual Revenue Requirement associated with the Transmission Enhancement Charges are set forth and determined in Appendix A to Attachment H-9.

Attachment 7i (PPL OATT)

SCHEDULE 12 – APPENDIX

(9) PPL Electric Utilities Corporation

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0074	Rebuild 12 miles of S. Akron – Berks 230 kV to double circuit, looping Met Ed's S. Lebanon – S. Reading line into Berks; replacement of S. Reading 230 kV breaker 107252		PPL (100%)
b0171.2	Replace wavetrap at Hosensack 500kV substation to increase rating of Elroy - Hosensack 500 kV		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (6.06%) / DPL (8.20%) / JCPL (21.17%) / PECO (64.56%) / PSEG (0.01%)
b0172.1	Replace wave trap at Alburtis 500kV substation		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (5.32%) / JCPL (33.44%) / NEPTUNE (5.35%) / PSEG (53.73%) / RE (2.16%)

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

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0284.2	Replace two wave traps at Juniata 500 kV – on the two Juniata – Airydale 500 kV		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (5.35%) / BGE (19.46%) / DL (0.25%) / JCPL (19.57%) / ME (6.75%) / NEPTUNE (2.17%) / PECO (20.81%) / PSEG (24.65%) / RE (0.99%)
b0284.4	Changes at Juniata 500 kV substation		PPL (100%)
b0293.1	Replace wavetrap at the Martins Creek 230 kV bus		PPL (100%)
b0293.2	Raise the operating temperature of the 2-1590 ACSR to 140C for the Martins Creek – Portland 230 kV circuit		PPL (100%)
b0440	Spare Juniata 500/230 kV transformer		PPL (100%)
b0468	Build a new substation with two 150 MVA transformers between Dauphin and Hummelstown 230/69 kV substations by sectionalizing the Middletown Junction – New Lebanon 230 kV line		JCPL (*4.56*%) / Neptune* (0.37%) / PECO (1.79%) / PENELEC (0.33%) / PPL (*86.79*%) / PSEG (*5.94*%) / RE (0.22%)

* Neptune Regional Transmission System, LLC

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0469	Install 130 MVAR capacitor at West Shore 230 kV line		PPL (100%)
b0487	Build new 500 kV transmission facilities from Susquehanna to Pennsylvania – New Jersey border at Bushkill		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: JCPL (33.89%) / NEPTUNE (4.26%) / PSEG (59.46%) / RE (2.39%)
b0487.1	Install Lackawanna 500/230 kV transformer and upgrade 230 kV substation and switchyard		PENELEC (*16.93*%) / PPL (*77.74*%) / PSEG (*5.14*%) / RE (0.19%)
b0500.1	Conastone – Otter Creek 230 kV – Reconductor approximately 17.2 miles of 795 kcmil ACSR with new 795 kcmil ACSS operated at 160 deg C		AEC (*6.31*%) / DPL (*8.70*%) / JCPL (*14.62*%) / ME (*10.65*%) / Neptune* (*1.38*%) / PECO (*15.75*%) / PPL (*21.14*%) / PSEG (*20.68*%) / RE (0.77%)

*Neptune Regional Transmission System, LLC

The Annual Revenue Requirements associated with the Transmission Enhancement Charges are set forth and determined in Appendix A to Attachment H-8G.

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0558	Install 250 MVAR capacitor at Juniata 500 kV substation		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0593	Eldred – Pine Grove 69 kV line Rebuild Part 2: 8 miles		PPL (100%)
b0595	Rebuild Lackawanna – Edella 69 kV line to double circuit		PPL (100%)
b0596	Reconductor and rebuild Stanton – Providence 69 kV #1 and #2 lines with 69 kV design; approximately 8 miles total		PPL (100%)
b0597	Reconductor Suburban – Providence 69 kV #1 and resectionalize the Suburban 69 kV lines		PPL (100%)
b0598	Reconductor Suburban Taps #1 and #2 for 69 kV line portions		PPL (100%)

* Neptune Regional Transmission System, LLC

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0600	Tripp Park Substation: 69 kV tap off Stanton – Providence 69 kV line #3 to new substation		PPL (100%)
b0601	Jessup Substation: New 138/69 kV tap off of Peckville – Jackson 138/69 kV line		PPL (100%)
b0604	Add 150 MVA, 230/138/69 transformer #6 to Harwood substation		PPL (100%)
b0605	Reconductor Stanton – Old Forge 69 kV line and resectionalize the Jenkins – Scranton 69 kV #1 and #2 lines		PPL (100%)
b0606	New 138 kV tap off Monroe – Jackson 138 kV #1 line to Bartonsville substation		PPL (100%)
b0607	New 138 kV taps off Monroe – Jackson 138 kV lines to Stroudsburg substation		PPL (100%)
b0608	New 138 kV tap off Siegfried – Jackson 138 kV #2 to transformer #2 at Gilbert substation		PPL (100%)
b0610	At South Farmersville substation, a new 69 kV tap off Nazareth – Quarry #2 to transformer #2		PPL (100%)
b0612	Rebuild Siegfried – North Bethlehem portion (6.7 miles) of Siegfried – Quarry 69 kV line		PPL (100%)
b0613	East Tannersville Substation: New 138 kV tap to new substation		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0614	Elroy substation expansion and new Elroy – Hatfield 138/69 kV double circuit lines (1.9 miles)		PPL (100%)
b0615	Reconductor and rebuild 12 miles of Seidersville – Quakerstown 138/69 kV and a new 75 MVA, 230/69 kV transformer #4		PPL (100%)
b0616	New Springfield 230/69 kV substation and transmission line connections		PPL (100%)
b0620	New 138 kV line and terminal at Monroe 230/138 substation		PPL (100%)
b0621	New 138 kV line and terminal at Siegfried 230/138 kV substation and add a second circuit to Siegfried – Jackson for 8.0 miles		PPL (100%)
b0622	138 kV yard upgrades and transmission line rearrangements at Jackson 138/69 kV substation		PPL (100%)
b0623	New West Shore – Whitehill Taps 138/69 kV double circuit line (1.3 miles)		PPL (100%)
b0624	Reconductor Cumberland – Wertzville 69 kV portion (3.7 miles) of Cumberland – West Shore 69 kV line		PPL (100%)
b0625	Reconductor Mt. Allen – Rossmoyne 69 kV portions (1.6 miles) of West Shore – Cumberland #3 and #4 lines		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0627	Replace UG cable from Walnut substation to Center City Harrisburg substation for higher ampacity (0.25 miles)		PPL (100%)
b0629	Lincoln substation: 69 kV tap to convert to modified Twin A		PPL (100%)
b0630	W. Hempfield – Donegal 69 kV line: Reconductor / rebuild from Landisville Tap – Mt. Joy (2 miles)		PPL (100%)
b0631	W. Hempfield – Donegal 69 kV line: Reconductor / rebuild to double circuit from Mt. Joy – Donegal (2 miles)		PPL (100%)
b0632	Terminate new S. Manheim – Donegal 69 kV circuit into S. Manheim 69 kV #3		PPL (100%)
b0634	Rebuild S. Manheim – Fuller 69 kV portion (1.0 mile) of S. Manheim – West Hempfield 69 kV #3 line into a 69 kV double circuit		PPL (100%)
b0635	Reconductor Fuller Tap – Landisville 69 kV (4.1 miles) into a 69 kV double circuit		PPL (100%)
b0703	Berks substation modification on Berks – South Akron 230 kV line. Modification will isolate the line fault on the South Akron line and will allow Berks transformer #2 to be energized by the South Lebanon 230 kV circuit		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0705	New Derry – Millville 69 kV line		PPL (100%)
b0707	Construct Bohemia – Twin Lakes 69 kV line, install a 10.9 MVAR capacitor bank near Bohemia 69 kV substation		PPL (100%)
b0708	New 69 kV double circuit from Jackson – Lake Naomi Tap		PPL (100%)
b0709	Install new 69 kV double circuit from Carlisle – West Carlisle		PPL (100%)
b0710	Install a third 69 kV line from Reese's Tap to Hershey substation		PPL (100%)
b0711	New 69 kV that taps West Shore – Cumberland 69 kV #1 to Whitehill 69 kV substation		PPL (100%)
b0712	Construct a new 69 kV line between Strassburg Tap and the Millwood – Engleside 69 kV #1 line		PPL (100%)
b0713	Construct a new 138 kV double circuit line between Dillersville Tap and the West Hempfield – Prince 138 kV line		PPL (100%)
b0714	Prepare Roseville Tap for 138 kV conversion		PPL (100%)
b0715	Transfer S. Akron – S. Manheim #1 and #2 lines from the S. Akron 69 kV Yard to the S. Akron 138 kV Yard; Install switches on S. Akron – S. Manheim 138 kV #1 and #2 lines		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0716	Add a second 69 kV line from Morgantown – Twin Valley		PPL (100%)
b0717	Rebuild existing Brunner Island – West Shore 230 kV line and add a second Brunner Island – West Shore 230 kV line		PPL (100%)
b0718	SPS scheme to drop 190 MVA of 69 kV radial load at West Shore and 56 MVA of 69 kV radial load at Cumberland		PPL (100%)
b0719	SPS scheme at Jenkins substation to open the Stanton #1 and Stanton #2 230 kV circuit breakers after the second contingency		PPL (100%)
b0791	Add a fourth 230/69 kV transformer at Stanton		PENELEC (9.55%) / PPL (90.45%)
b1074	Install motor operators on the Jenkins 230 kV ‘2W’ disconnect switch and build out Jenkins Bay 3 and have MOD ‘3W’ operated as normally open		PPL (100%)
b0881	Install motor operators on Susquehanna T21 - Susquehanna 230 kV line East CB at Susquehanna 230 kV switching station		PPL (100%)
b0908	Install motor operators at South Akron 230 kV		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0909	Convert Jenkins 230 kV yard into a 3-breaker ring bus		PPL (100%)
b0910	Install a second 230 kV line between Jenkins and Stanton		PPL (100%)
b0911	Install motor operators at Frackville 230 kV		PPL (100%)
b0912	Install 2, 10.8 MVAR capacitor banks at Scranton 69 kV		PPL (100%)
b0913	Extend Cando Tap to the Harwood-Jenkins #2 69 kV line		PPL (100%)
b0914	Build a 3rd 69 kV line from Harwood to Valmont Taps		PPL (100%)
b0915	Replace Walnut-Center City 69 kV cable		PPL (100%)
b0916	Reconductor Sunbury-Dalmatia 69 kV line		PPL (100%)
b1021	Install a new (#4) 138/69 kV transformer at Wescosville		PPL (100%)
b1196	Remove the Siegfried bus tie breaker and install a new breaker on the Martins Creek 230 kV line west bay to maintain two ties between the 230 kV buses		PPL (100%)
b1201	Rebuild the Hercules Tap to Double Circuit 69 kV		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1202	Mack-Macungie Double Tap, Single Feed Arrangement		PPL (100%)
b1203	Add the 2nd Circuit to the East Palmerton-Wagners-Lake Naomi 138/69 kV Tap		PPL (100%)
b1204	New Breinigsville 230-69 kV Substation		PPL (100%)
b1205	Siegfried-East Palmerton #1 69 kV Line- Install new 69 kV LSAB, Sectionalize, and Transfer Treichlers Substation		PPL (100%)
b1206	Siegfried-Quarry #1 & #2 69 kV Lines- Rebuild 3.3 mi from Quarry Substation to Macada Taps		PPL (100%)
b1209	Convert Neffsville Taps from 69 kV to 138 kV Operation		PPL (100%)
b1210	Convert Roseville Taps from 69 kV to 138 kV Operation (Part 1 – operate on the 69 kV system)		PPL (100%)
b1211	Convert Roseville Taps from 69 kV to 138 kV Operation (Part 2 – operate on the 138 kV system)		PPL (100%)
b1212	New 138 kV Taps to Flory Mill 138/69 kV Substation		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1213	Convert East Petersburg Taps from 69 kV to 138 kV operation, install two 10.8 MVAR capacitor banks		PPL (100%)
b1214	Terminate South Manheim-Donegal #2 at South Manheim, Reduce South Manheim 69 kV Capacitor Bank, Resectionalize 69 kV		PPL (100%)
b1215	Reconductor and rebuild 16 miles of Peckville-Varden 69 kV line and 4 miles of Blooming Grove-Honesdale 69 kV line		PPL (100%)
b1216	Build approximately 2.5 miles of new 69 kV transmission line to provide a “double tap – single feed” connection to Kimbles 69/12 kV substation		PPL (100%)
b1217	Provide a “double tap – single feed” connection to Tafton 69/12 kV substation		PPL (100%)
b1524	Build a new Pocono 230/69 kV substation		PPL (100%)
b1524.1	Build approximately 14 miles new 230 kV South Pocono – North Pocono line		PPL (100%)
b1524.2	Install MOLSABs at Mt. Pocono substation		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1525	Build new West Pocono 230/69 kV Substation		PPL (100%)
b1525.1	Build approximately 14 miles new 230 kV Jenkins-West Pocono 230 kV Line		PPL (100%)
b1525.2	Install Jenkins 3E 230 kV circuit breaker		PPL (100%)
b1526	Install a new Honeybrook – Twin Valley 69/138 kV tie		PPL (100%)
b1527	Construct a new 230/69 kV North Lancaster substation. The sub will be supplied from the SAKR-BERK 230kV Line		PPL (100%)
b1527.1	Construct new 69/138 kV transmission from North Lancaster 230/69 kV sub to Brecknock and Honeybrook areas		PPL (100%)
b1528	Install Motor-Operated switches on the Wescosville-Trexlertown #1 & #2 69 kV lines at East Texas Substation		PPL (100%)
b1529	Add a double breaker 230 kV bay 3 at Hosensack		PPL (100%)
b1530	Replace Lock Haven 69kV ring bus with standard breaker and half design		PPL (100%)
b1532	Install new 32.4 MVAR capacitor bank at Sunbury		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1533	Rebuild Lycoming-Lock Haven #1 and Lycoming-Lock Haven #2 69kV lines		PPL (100%)
b1534	Rebuild 1.4 miles of the Sunbury-Milton 69kV		PPL (100%)
b1601	Re-configure the Breinigsville 500 kV substation with addition two 500 kV circuit breakers		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)†
b1602	Re-configure the Elimsport 230 kV substation to breaker and half scheme and install 80 MVAR capacitor		PPL (100%)
b1740	Install a 90 MVAR cap bank on the Frackville 230 kV bus #207973		PPL (100%)
b1756	Install a 3rd West Shore 230/69 kV transformer		PPL (100%)
b1757	Install a 230 kV motor-operated air-break switch on the Clinton - Elimsport 230 kV line		PPL (100%)

* Neptune Regional Transmission System, LLC

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1758	Rebuild 1.65 miles of Columbia - Danville 69 kV line		PPL (100%)
b1759	Install a 69 kV 16.2 MVAR Cap at Milton substation		PPL (100%)
b1760	Install motor operated devices on the existing disconnect switches that are located on each side of all four 230 kV CBs at Stanton		PPL (100%)
b1761	Build a new Paupack - North 230 kV line (Approximately 21 miles)		PPL (100%)
b1762	Replace 3.7 miles of the existing 230 kV Blooming Grove - Peckville line by building 8.4 miles of new 230 kV circuit onto the Lackawanna - Hopatcong tower-line		PPL (100%)
b1763	Re-terminate the Peckville - Jackson and the Peckville - Varden 69 kV lines from Peckville into Lackawanna		PPL (100%)
b1764	Build a new 230-69 kV substations (Paupack)		PPL (100%)
b1765	Install a 16.2 MVAR capacitor bank at Bohemia 69-12 kV substation		PPL (100%)
b1766	Reconductor/rebuild 3.3 miles of the Siegfried - Quarry #1 and #2 lines		PPL (100%)
b1767	Install 6 motor-operated disconnect switches at Quarry substation		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1788	Install a new 500 kV circuit breaker at Wescosville		PPL (100%)
b1890	Add a second 230/69 kV transformer at North Pocono (NE/Pocono Reliability Project)		PPL (100%)
b1891	Build a new 230/138 kV Yard at Lackawanna (138 kV conversion from Lackawanna to Jenkins)		PPL (100%)
b1892	Rebuild the Throop Taps for 138 kV operation (138 kV Conversion from Lackawanna to Jenkins)		PPL (100%)
b1893	Swap the Staton - Old Forge and Stanton - Brookside 69 kV circuits at Stanton (138 kV Conversion from Lackawanna to Jenkins)		PPL (100%)
b1894	Rebuild and re-conductor 2.5 miles of the Stanton - Avoca 69 kV line		PPL (100%)
b1895	Rebuild and re-conductor 4.9 miles of the Stanton - Providence #1 69 kV line		PPL (100%)
b1896	Install a second 230/138 kV transformer and expand the 138 kV yard at Monroe		PPL (100%)
b1897	Build a new 230/138 kV substation at Jenkins (138 kV Conversion from Lackawanna to Jenkins)		PPL (100%)
b1898	Install a 69 kV Tie Line between Richfield and Dalmatia substations		PPL (100%)
b2004	Replace the CTs and switch in South Akron Bay 4 to increase the rating		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2005	Replace the CTs and switch in SAKR Bay 3 to increase the rating of the Millwood-South Akron 230 kV Line and of the rating in Bay 3		PPL (100%)
b2006	Install North Lancaster 500/230 kV substation (below 500 kV portion)		AEC (*1.11*%) / JCPL (*9.68*%) / ME (*19.56*%) / Neptune* (*0.76*%) / PECO (*6.06*%) / PPL (*50.95*%) / PSEG (*11.43*%) / RE (0.45%)
b2006.1	Install North Lancaster 500/230 kV substation (500 kV portion)		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%) **DFAX Allocation:** PPL (100%)
b2007	Install a 90 MVAR capacitor bank at the Frackville 230 kV Substation		PPL (100%)
b2158	Install 10.8 MVAR capacitor at West Carlisle 69/12 kV substation		PPL (100%)

* Neptune Regional Transmission System, LLC

SCHEDULE 12 – APPENDIX A

(9) PPL Electric Utilities Corporation

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1813.12	Replace the Blooming Grove 230 kV breaker 'Peckville'		PPL (100%)
b2223	Rebuild and reconductor 2.6 miles of the Sunbury - Dauphin 69 kV circuit		PPL (100%)
b2224	Add a 2nd 150 MVA 230/69 kV transformer at Springfield		PPL (100%)
b2237	150 MVAR shunt reactor at Alburtis 500 kV		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: PPL (100%)
b2238	100 MVAR shunt reactor at Elimsport 230 kV		PPL (100%)

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

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2269	Rebuild approximately 23.7 miles of the Susquehanna - Jenkins 230kV circuit. This replaces a temporary SPS that is already planned to mitigate the violation until this solution is implemented		PPL (100%)
b2282	Rebuild the Siegfried-Frackville 230 kV line		PPL (100%)
b2406.1	Rebuild Stanton-Providence 69 kV 2&3 9.5 miles with 795 SCSR		PPL (100%)
b2406.2	Reconductor 7 miles of the Lackawanna - Providence 69 kV #1 and #2 with 795 ACSR		PPL (100%)
b2406.3	Rebuild SUB2 Tap 1 (Lackawanna - Scranton 1) 69 kV 1.5 miles 556 ACSR		PPL (100%)
b2406.4	Rebuild SUB2 Tap 2 (Lackawanna - Scranton 1) 69 kV 1.6 miles 556 ACSR		PPL (100%)
b2406.5	Create Providence - Scranton 69 kV #1 and #2, 3.5 miles with 795 ACSR		PPL (100%)
b2406.6	Rebuild Providence 69 kV switchyard		PPL (100%)
b2406.7	Install 2 - 10.8 MVAR capacitors at EYNO 69 kV		PPL (100%)
b2406.8	Rebuild Stanton 230 kV yard		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2446	Replace wave trap and protective relays at Montour		PPL (100%)
b2447	Replace wave trap and protective relays at Montour		PPL (100%)
b2448	Install a 2nd Sunbury 900MVA 500-230kV transformer and associated equipment		PPL (100%)
b2552.2	Reconductor the North Meshoppen - Oxbow – Lackawanna 230 kV circuit and upgrade terminal equipment (PPL portion)		PENELEC (100%)
b2574	Replace the Sunbury 230 kV ‘MONTOUR NORT’ breaker with a 63kA breaker		PPL (100%)
b2690	Reconductor two spans of the Graceton – Safe Harbor 230 kV transmission line. Includes termination point upgrades		PPL (100%)
b2691	Reconductor three spans limiting Brunner Island – Yorkana 230 kV line, add 2 breakers to Brunner Island switchyard, upgrade associated terminal equipment		PPL (100%)

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2716	Add a 200 MVAR shunt reactor at Lackawanna 500 kV substation		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: PPL (100%)
b2754.1	Install 7 miles of optical ground wire (OPGW) between Gilbert and Springfield 230 kV substations		PPL (100%)
b2754.4	Use ~ 40 route miles of existing fibers on PPL 230 kV system to establish direct fiber circuits		PPL (100%)
b2754.5	Upgrade relaying at Martins Creek 230 kV		PPL (100%)
b2756	Install 2% reactors at Martins Creek 230 kV		PPL (100%)
b2813	Expand existing Lycoming 69 kV yard to double bus double breaker arrangement		PPL (100%)

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

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2824	Reconfigure/Expand the Lackawanna 500 kV substation by adding a third bay with three breakers		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: PPL (100%)
b2838	Build a new 230/69 kV substation by tapping the Montour – Susquehanna 230 kV double circuits and Berwick – Hunlock & Berwick – Colombia 69 kV circuits		PPL (100%)
b2979	Replace Martins Creek 230 kV circuit breakers with 80 kA rating		PPL (100%)

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

Attachment 7j (BG&E OATT)

SCHEDULE 12 – APPENDIX

(2) Baltimore Gas and Electric Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0152	Add (2) 230 kV Breakers at High Ridge and install two Northwest 230 kV 120 MVAR capacitors		BGE (100%)
b0244	Install a 4th Waugh Chapel 500/230kV transformer, terminate the transformer in a new 500 kV bay and operate the existing in-service spare transformer on standby		BGE (85.56%) / ME (0.83%) / PEPCO (13.61%)
b0298	Replace both Conastone 500/230 kV transformers with larger transformers	As specified in Attachment H-2A, Attachment 7, the Transmission Enhancement Charge Worksheet	BGE (75.85%) / Dominion (11.54%) / ME (4.73%) / PEPCO (7.88%)
b0298.1	Replace Conastone 230 kV breaker 500-3/2323		BGE (100%)
b0474	Add a fourth 230/115 kV transformer, two 230 kV circuit breakers and a 115 kV breaker at Waugh Chapel		BGE (100%)
b0475	Create two 230 kV ring buses at North West, add two 230/ 115 kV transformers at North West and create a new 115 kV station at North West		BGE (100%)
b0476	Rebuild High Ridge 230 kV substation to Breaker and Half configuration		BGE (100%)
b0477	Replace the Waugh Chapel 500/230 kV transformer #1 with three single phase transformers		BGE (90.56%) / ME (1.51%) / PECO (.92%) / PEPCO (4.01%) / PPL (3.00%)

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

Baltimore Gas and Electric Company (cont.)

	Required Transmission Enhancements	Annual Revenue Requirement	Responsible Customer(s)
b0497	Install a second Conastone – Graceton 230 kV circuit		AEC (9.00%) / DPL (16.85%) / JCPL (9.64%) / ME (1.48%) / Neptune* (0.95%) / PECO (30.79%) / PPL (16.41%) / ECP** (0.29%) / PSEG (14.07%) / RE (0.52%)
b0497.1	Replace Conastone 230 kV breaker #4		BGE (100%)
b0497.2	Replace Conastone 230 kV breaker #7		BGE (100%)
b0500.2	Replace wavetrap and raise operating temperature on Conastone – Otter Creek 230 kV line to 165 deg		AEC (6.27%) / DPL (8.65 %) / JCPL (14.54%) / ME (10.59%) / Neptune* (1.37%) / PECO (15.66%) / PPL (21.02%) / ECP** (0.57%) / PSEG (20.56%) / RE (0.77%)
b0512.33	MAPP Project Install new Hallowing Point – Calvert Cliffs 500 kV circuit and associated substation work at Calvert Cliffs substation		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (11.40%) / ComEd (*6.13*%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

Baltimore Gas and Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.43	MAPP Project Install new Hallowing Point – Calvert Cliffs 500 kV circuit and associated substation work at Calvert Cliffs substation		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (11.40%) / ComEd (*6.13*%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0729	Rebuild both Harford – Perryman 110615-A and 110616-A 115 kV circuits		BGE (100%)
b0749	Replace 230 kV breaker and associated CT's at Riverside 230 kV on 2345 line; replace all dead-end structures at Brandon Shores, Hawkins Point, Sollers Point and Riverside; Install a second conductor per phase on the spans entering each station		BGE (100%)

Baltimore Gas and Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0795	Install a 115 kV breaker at Chesaco Park		BGE (100%)
b0796	Install 2, 115 kV breakers at Gwynnbrook		BGE (100%)
b0819	Remove line drop limitations at the substation terminations for Gwynnbrook – Mays Chapel 115 kV		BGE (100%)
b0820	Remove line drop limitations at the substation terminations and replace switch for Delight – Gwynnbrook 115 kV		BGE (100%)
b0821	Remove line drop limitations at the substation terminations for Northwest – Delight 115 kV		BGE (100%)
b0822	Remove line drop limitations at the substation terminations for Gwynnbrook – Sudbrook 115 kV		BGE (100%)
b0823	Remove line drop limitations at the substation terminations for Windy Edge – Texas 115 kV		BGE (100%)
b0824	Remove line drop limitations at the substation terminations for Granite – Harrisonville 115 kV		BGE (100%)
b0825	Remove line drop limitations at the substation terminations for Harrison – Dolefield 115 kV		BGE (100%)

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

Baltimore Gas and Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0826	Remove line drop limitations at the substation terminations for Riverside – East Point 115 kV		BGE (100%)
b0827	Install an SPS for one year to trip a Mays Chapel 115 kV breaker one line 110579 for line overloads 110509		BGE (100%)
b0828	Disable the HS throwover at Harrisonville for one year		BGE (100%)
b0870	Rebuild each line (0.2 miles each) to increase the normal rating to 968 MVA and the emergency rating to 1227 MVA		BGE (100%)
b0906	Increase contact parting time on Wagner 115 kV breaker 32-3/2		BGE (100%)
b0907	Increase contact parting time on Wagner 115 kV breaker 34-1/3		BGE (100%)
b1016	Rebuild Graceton - Bagley 230 kV as double circuit line using 1590 ACSR. Terminate new line at Graceton with a new circuit breaker.		APS (2.02%) / BGE (75.22%) / Dominion (16.1%) / PEPCO (6.6%)
b1055	Upgrade wire drops at Center 115kV on the Center - Westport 115 kV circuit		BGE (100%)
b1029	Upgrade wire sections at Wagner on both 110534 and 110535 115 kV circuits. Reconfigure Lipins Corner substation		BGE (100%)

The Annual Revenue Requirement associated with the Transmission Enhancement Charges are set forth and determined in Appendix A to Attachment H-2.

Baltimore Gas and Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1030	Move the Hillen Rd substation from circuits 110507/110508 to circuits 110505/110506		BGE (100%)
b1031	Replace wire sections on Westport - Pumphrey 115 kV circuits #110521, 110524, 110525, and 110526		BGE (100%)
b1083	Upgrade wire sections of the Mays Chapel – Mt Washington circuits (110701 and 110703) to improve the rating to 260/300 SN/SE MVA		BGE (100%)
b1084	Extend circuit 110570 from Deer Park to Northwest, and retire the section of circuit 110560 from Deer Park to Deer Park tap and retire existing Deer Park Breaker		BGE (100%)
b1085	Upgrade substation wire conductors at Lipins Corner to improve the rating of Solley-Lipins Corner sections of circuits 110534 and 110535 to 275/311 MVA SN/SE		BGE (100%)
b1086	Build a new 115 kV switching station between Orchard St. and Monument St.		BGE (100%)
b1175	Apply SPS at Mt. Washington to delay load pick-up for one outage and for the other outage temporarily drop load		BGE (100%)

Baltimore Gas and Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1176	Transfer 6 MW of load from Mt. Washington – East Towson		BGE (100%)
b1251	Build a second Raphael – Bagley 230 kV		APS (4.42%) / BGE (66.95%) / ComEd (4.12%) / Dayton (0.49%) / Dominion (18.76%) / PENELEC (0.05%) / PEPCO (5.21%)
b1251.1	Re-build the existing Raphael – Bagley 230 kV		APS (4.42%) / BGE (66.95%) / ComEd (4.12%) / Dayton (0.49%) / Dominion (18.76%) / PENELEC (0.05%) / PEPCO (5.21%)
b1252	Upgrade terminal equipment (remove terminal limitation at Pumphrey Tap to bring the circuit to 790N/941E		BGE (100%)

Baltimore Gas and Electric Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1253	Replace the existing Northeast 230/115 kV transformer #3 with 500 MVA		BGE (100%)
b1253.1	Replace the Northeast 230 kV breaker ‘2317/315’		BGE (100%)
b1253.2	Revise reclosing on Windy Edge 115 kV breaker ‘110515’		BGE (100%)
b1253.3	Revise reclosing on Windy Edge 115 kV breaker ‘110516’		BGE (100%)
b1253.4	Revise reclosing on Windy Edge 115 kV breaker ‘110517’		BGE (100%)
b1254	Build a new 500/230 kV substation (Emory Grove)		APS (4.07%) / BGE (53.19%) / ComEd (3.71%) / Dayton (0.50%) / Dominion (16.44%) / PENELEC (0.59%) / PEPCO (21.50%)
b1254.1	Bundle the Emory – North West 230 kV circuits		BGE (100%)
b1267	Rebuild existing Erdman 115 kV substation to a dual ring-bus configuration to enable termination of new circuits		BGE (100%)
b1267.1	Construct 115 kV double circuit underground line from existing Coldspring to Erdman substation		BGE (100%)
b1267.2	Replace Mays Chapel 115 kV breaker ‘110515A’		BGE (100%)
b1267.3	Replace Mays Chapel 115 kV breaker ‘110579C’		BGE (100%)

Baltimore Gas and Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1544	Advance the baseline upgrade B1252 to upgrade terminal equipment removing terminal limitation at Pumphrey Tap on BGE 230 kV circuit 2332-A		BGE (100%)
b1545	Upgrade terminal equipment at both Brandon Shores and Waugh Chapel removing terminal limitation on BGE 230 kV circuit 2343		BGE (100%)
b1546	Upgrade terminal equipment at Graceton removing terminal limitation on BGE portion of the 230 kV Graceton – Cooper circuit 2343		BGE (100%)
b1583	Replace Hazelwood 115 kV breaker '110602'		BGE (100%)
b1584	Replace Hazelwood 115 kV breaker '110604'		BGE (100%)
b1606.1	Moving the station supply connections of the Hazelwood 115/13kV station		BGE (100%)
b1606.2	Installing 115kV tie breakers at Melvale		BGE (100%)
b1785	Revise the reclosing for Pumphrey 115 kV breaker ‘110521 DR’		BGE (100%)
b1786	Revise the reclosing for Pumphrey 115 kV breaker ‘110526 DR’		BGE (100%)
b1789	Revise the reclosing for Pumphrey 115 kV breaker ‘110524DR’		BGE (100%)
b1806	Rebuild Wagner 115kV substation to 80kA		BGE (100%)

SCHEDULE 12 – APPENDIX A

(2) Baltimore Gas and Electric Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2219	Install a 115 kV tie breaker at Wagner to create a separation from line 110535 and transformer 110-2		BGE (100%)
b2220	Install four 115 kV breakers at Chestnut Hill		BGE (100%)
b2221	Install an SPS to trip approximately 19 MW load at Green St. and Concord		BGE (100%)
b2307	Install a 230/115kV transformer at Raphael Rd and construct approximately 3 miles of 115kV line from Raphael Rd. to Joppatowne. Construct a 115kV three breaker ring at Joppatowne		BGE (100%)
b2308	Build approximately 3 miles of 115kV underground line from Bestgate tap to Waugh Chapel. Create two breaker bay at Waugh Chapel to accommodate the new underground circuit		BGE (100%)
b2396	Build a new Camp Small 115 kV station and install 30 MVAR capacitor		BGE (100%)

Baltimore Gas and Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2396.1	Install a tie breaker at Mays Chapel 115 kV substation		BGE (100%)
b2567	Upgrade the Riverside 115kV substation strain bus conductors on circuits 115012 and 115011 with double bundled 1272 ACSR to achieve ratings of 491/577 MVA SN/SE on both transformer leads		BGE (100%)
b2568	Reconductor Northwest – Northwest #2 115kV 110574 substation tie circuit with 2167 ACSR to achieve ratings of 400/462 MVA SN/SE		BGE (100%)
b2752.6	Conastone 230 kV substation tie-in work (install a new circuit breaker at Conastone 230 kV and upgrade any required terminal equipment to terminate the new circuit)		AEP (6.46%) / APS (8.74%) / BGE (19.74%) / ComEd (2.16%) / Dayton (0.59%) / DEOK (1.02%) / DL (0.01%) / Dominion (39.95%) / EKPC (0.45%) / PEPCO (20.88%)
b2752.7	Reconductor/Rebuild the two Conastone – Northwest 230 kV lines and upgrade terminal equipment on both ends		AEP (6.46%) / APS (8.74%) / BGE (19.74%) / ComEd (2.16%) / Dayton (0.59%) / DEOK (1.02%) / DL (0.01%) / Dominion (39.95%) / EKPC (0.45%) / PEPCO (20.88%)
b2752.8	*Replace the Conastone 230 kV '2322 B5' breaker with a 63kA breaker*		*BGE (100%)*

Baltimore Gas and Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2752.9	*Replace the Conastone 230 kV '2322 B6' breaker with a 63kA breaker*		*BGE (100%)*
b2766.1	Upgrade substation equipment at Conastone 500 kV to increase facility rating to 2826 MVA normal and 3525 MVA emergency		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%) **DFAX Allocation:** AEC (0.05%) / APS (*11.40*%) / BGE (*22.83*%) / Dayton (*2.23*%) / DEOK (*4.28*%) / DPL (0.20%) / EKPC (*1.98*%) / JCPL (*11.06*%) / NEPTUNE* (*1.17*%) / POSEIDON**** (*0.64*%) / PENELEC (0.06%) / PEPCO (*19.38*%) / PSEG (*23.77*%) / RECO (*0.95*%)

*Neptune Regional Transmission System, LLC
****Poseidon Transmission 1, LLC

Baltimore Gas and Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2816	Re-connect the Crane – Windy Edge 110591 & 110592 115 kV circuits into the Northeast Substation with the addition of a new 115 kV 3-breaker bay		BGE (100%)
b2992.1	Reconductor the Conastone to Graceton 230 kV 2323 & 2324 circuits. Replace 7 disconnect switches at Conastone substation		AEP (2.25%) / APS (2.58%) / BGE (44.61%) / ComEd (0.51%) / Dayton (0.40%) / DEOK (1.39%) / DL (0.14%) / Dominion (27.05%) / EKPC (0.52%) / PENELEC (0.02%) / PEPCO (20.53%)
b2992.2	Add Bundle conductor on the Graceton – Bagley – Raphael Road 2305 & 2313 230 kV circuits		AEP (2.25%) / APS (2.58%) / BGE (44.61%) / ComEd (0.51%) / Dayton (0.40%) / DEOK (1.39%) / DL (0.14%) / Dominion (27.05%) / EKPC (0.52%) / PENELEC (0.02%) / PEPCO (20.53%)
b2992.3	Replacing short segment of substation conductor on the Windy Edge to Glenarm 110512 115 kV circuit		AEP (2.25%) / APS (2.58%) / BGE (44.61%) / ComEd (0.51%) / Dayton (0.40%) / DEOK (1.39%) / DL (0.14%) / Dominion (27.05%) / EKPC (0.52%) / PENELEC (0.02%) / PEPCO (20.53%)
b2992.4	Reconductor the Raphael Road – Northeast 2315 & 2337 230 kV circuits		AEP (2.25%) / APS (2.58%) / BGE (44.61%) / ComEd (0.51%) / Dayton (0.40%) / DEOK (1.39%) / DL (0.14%) / Dominion (27.05%) / EKPC (0.52%) / PENELEC (0.02%) / PEPCO (20.53%)

Attachment 7k (MAIT OATT)

SCHEDULE 12 – APPENDIX

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

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

* Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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

* Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1366	Reconductor the Collins – Cly – Newberry 115 kV (975) line 5 miles with 795 ACSR		ME (100%)
b1727	Reconductor 2.4 miles of existing 556 and 795 ACSR from Harley Davidson to Pleasureville 115 kV with 795 ACSS to raise the ratings		ME (100%)
b1800	Install a 500 MVAR SVC at the existing Hunterstown 500kV substation		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (0.01%) / DPL (55.56%) / ME (44.42%) / PSEG (0.01%)
b1801	Build a 250 MVAR SVC at Altoona 230 kV		AEC (6.48%) / AEP (2.58%) / APS (6.89%) / BGE (6.58%) / DPL (12.40%) / Dominion (14.90%) / JCPL (8.15%) / ME (6.21%) / Neptune* (0.82%) / PECO (21.58%) / PPL (4.89%) / PSEG (8.19%) / RE (0.33%)

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

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

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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

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

SCHEDULE 12 – APPENDIX

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0284.1	Build 500 kV substation in PENELEC – Tap the Keystone – Juniata and Conemaugh – Juniata 500 kV, connect the circuits with a breaker and half scheme, and install new 400 MVAR capacitor		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0284.3	Replace wave trap and upgrade a bus section at Keystone 500 kV – on the Keystone – Airydale 500 kV		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

* Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0285.1	Replace wave trap at Keystone 500 kV – on the Keystone – Conemaugh 500 kV		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0285.2	Replace wave trap and relay at Conemaugh 500 kV – on the Conemaugh – Keystone 500 kV		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

* Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0349	Upgrade Rolling Meadows-Gore Jct 115 kV		PENELEC (100%)
b0360	Construction of a ring bus on the 345 kV side of Wayne substation		PENELEC (100%)
b0365	Add a 50 MVAR, 230 kV cap bank at Altoona 230 kV		PENELEC (100%)
b0369	Install 100 MVAR Dynamic Reactive Device at Airydale 500 kV substation		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
b0370	Install 500 MVAR Dynamic Reactive Device at Airydale 500 kV substation		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)

* Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0376	Install 300 MVAR capacitor at Conemaugh 500 kV substation		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (5.35%) / BGE (19.46%) / DL (0.25%) / JCPL (19.57%) / ME (6.75%) / NEPTUNE (2.17%) / PECO (20.81%) / PSEG (24.65%) / RE (0.99%)
b0442	Spare Keystone 500/230 kV transformer		PENELEC (100%)
b0515	Replace Lewistown circuit breaker 1LY Yeagertown		PENELEC (100%)
b0516	Replace Lewistown circuit breaker 2LY Yeagertown		PENELEC (100%)
b0517	Replace Shawville bus section circuit breaker		PENELEC (100%)
b0518	Replace Homer City circuit breaker 201 Johnstown		PENELEC (100%)

* Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0519	Replace Keystone circuit breaker 4 Transformer - 20		PENELEC (100%)
b0549	Install 250 MVAR capacitor at Keystone 500 kV		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (5.39%) / BGE (23.28%) / JCPL (17.99%) / ME (7.64%) / NEPTUNE (1.99%) / PECO (20.77%) / PSEG (22.05%) / RE (0.89%)
b0550	Install 25 MVAR capacitor at Lewis Run 115 kV substation		AEC (*8.64*%) / APS (*1.70*%) / DPL (*12.33*%) / JCPL (*18.30*%) / ME (*1.56*%) / Neptune* (*1.78*%) / PECO (*21.94*%) / PPL (*6.45*%) / PSEG (*26.32*%) / RE (*0.98*%)
b0551	Install 25 MVAR capacitor at Saxton 115 kV substation		AEC (*8.64*%) / APS (*1.70*%) / DPL (*12.33*%) / JCPL (*18.30*%) / ME (*1.56*%) / Neptune* (*1.78*%) / PECO (*21.94*%) / PPL (*6.45*%) / PSEG (*26.32*%) / RE (*0.98*%)
b0552	Install 50 MVAR capacitor at Altoona 230 kV substation		AEC (*8.64*%) / APS (*1.70*%) / DPL (*12.33*%) / JCPL (*18.30*%) / ME (*1.56*%) / Neptune* (*1.78*%) / PECO (*21.94*%) / PPL (*6.45*%) / PSEG (*26.32*%) / RE (*0.98*%)

* Neptune Regional Transmission System, LLC

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

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

* Neptune Regional Transmission System, LLC

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

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

* Neptune Regional Transmission System, LLC

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

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

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

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

* Neptune Regional Transmission System, LLC

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

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

* Neptune Regional Transmission System, LLC

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

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

* Neptune Regional Transmission System, LLC

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

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

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

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

* Neptune Regional Transmission System, LLC

SCHEDULE 12 – APPENDIX A

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2006.1.1	Loop the 2026 (TMI – Hosensack 500 kV) line in to the Lauschtown		**Load-Ratio Share Allocation:** AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
			DFAX Allocation: PPL (*100*%)
b2006.2.1	Upgrade relay at South Reading on the 1072 230 V line		ME (100%)
b2006.4	Replace the South Reading 69 kV ‘81342’ breaker with 40kA breaker		ME (100%)
b2006.5	Replace the South Reading 69 kV ‘82842’ breaker with 40kA breaker		ME (100%)
b2452	Install 2nd Hunterstown 230/115 kV transformer		APS (8.30%) / BGE (14.70%) / DEOK (0.48%) / Dominion (36.92%) / ME (23.85%) / PEPCO (15.75%)

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

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

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

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

SCHEDULE 12 – APPENDIX A

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

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

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

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

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

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

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

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

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2951	*Seward, Blairsville East, Shelocta work*		*PENELEC (100%)*
b2951.1	*Upgrade Florence 115 kV line terminal equipment at Seward SS*		*PENELEC (100%)*
b2951.2	*Replace Blairsville East / Seward 115 kV line tuner, coax, line relaying and carrier set at Shelocta SS*		*PENELEC (100%)*
b2951.3	*Replace Seward / Shelocta 115 kV line CVT, tuner, coax, and line relaying at Blairsville East SS*		*PENELEC (100%)*
b2952	*Replace the North Meshoppen #3 230/115 kV transformer eliminating the old reactor and installing two breakers to complete a 230 kV ring bus at North Meshoppen*		*PENELEC (100%)*
b2953	*Replace the Keystone 500 kV breaker "NO. 14 Cabot" with 50kA breaker*		*PENELEC (100%)*
b2954	*Replace the Keystone 500 kV breaker "NO. 16 Cabot" with 50kA breaker*		*PENELEC (100%)*
b2984	Reconfigure the bus at Glory and install a 50.4 MVAR 115 kV capacitor		PENELEC (100%)

Attachment 7l (PECO OATT)

SCHEDULE 12 – APPENDIX

(8) PECO Energy Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0171.1	Replace two 500 kV circuit breakers and two wave traps at Elroy substation to increase rating of Elroy - Hosensack 500 kV		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (6.06%) / DPL (8.20%) / JCPL (21.17%) / PECO (64.56%) / PSEG (0.01%)
b0180	Replace Whitpain 230kV circuit breaker #165		PECO (100%)
b0181	Replace Whitpain 230kV circuit breaker #J105		PECO (100%)
b0182	Upgrade Plymouth Meeting 230kV circuit breaker #125		PECO (100%)
b0205	Install three 28.8Mvar capacitors at Planebrook 35kV substation		PECO (100%)
b0206	Install 161Mvar capacitor at Planebrook 230kV substation		AEC (14.20%) / DPL (24.39%) / PECO (57.94%) / PSEG (3.47%)

* Neptune Regional Transmission System, LLC

PECO Energy Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0207	Install 161Mvar capacitor at Newlinville 230kV substation		AEC (14.20%) / DPL (24.39%) / PECO (57.94%) / PSEG (3.47%)
b0208	Install 161Mvar capacitor Heaton 230kV substation		AEC (14.20%) / DPL (24.39%) / PECO (57.94%) / PSEG (3.47%)
b0209	Install 2% series reactor at Chichester substation on the Chichester - Mickleton 230kV circuit		AEC (65.23%) / JCPL (25.87%)/ Neptune* (2.55%) / PSEG (6.35%)
b0264	Upgrade Chichester – Delco Tap 230 kV and the PECO portion of the Delco Tap – Mickleton 230 kV circuit		AEC (89.87%) / JCPL (9.48%) / Neptune* (0.65%)
b0266	Replace two wave traps and ammeter at Peach Bottom, and two wave traps and ammeter at Newlinville 230 kV substations		PECO (100%)
b0269	Install a new 500/230 kV substation in PECO, and tap the high side on the Elroy – Whitpain 500 kV and the low side on the North Wales – Perkiomen 230 kV circuit		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)†
			DFAX Allocation: PECO (100%)

* Neptune Regional Transmission System, LLC

PECO Energy Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0269	Install a new 500/230 kV substation in PECO, and tap the high side on the Elroy – Whitpain 500 kV and the low side on the North Wales – Perkiomen 230 kV circuit		AEC (8.25%) / DPL (9.56%) / PECO (82.19%)††
b0269.1	Add a new 230 kV circuit between Whitpain and Heaton substations		AEC (8.25%) / DPL (9.56%) / PECO (82.19%)††
b0269.2	Reconductor the Whitpain 1 – Plymtg 1 230 kV circuit		AEC (8.25%) / DPL (9.56%) / PECO (82.19%)††
b0269.3	Convert the Heaton bus to a ring bus		AEC (8.25%) / DPL (9.56%) / PECO (82.19%)††
b0269.4	Reconductor the Heaton – Warminster 230 kV circuit		AEC (8.25%) / DPL (9.56%) / PECO (82.19%)††
b0269.5	Reconductor Warminster – Buckingham 230 kV circuit		AEC (8.25%) / DPL (9.56%) / PECO (82.19%)††

* Neptune Regional Transmission System, LLC

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

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

PECO Energy Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0269.6	Add a new 500 kV breaker at Whitpain between #3 transformer and 5029 line		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%) **DFAX Allocation:** PECO (100%)
b0269.7	Replace North Wales 230 kV breaker #105		PECO (100%)
b0280.1	Install 161 MVAR capacitor at Warrington 230 kV substation		PECO 100%
b0280.2	Install 161 MVAR capacitor at Bradford 230 kV substation		PECO 100%
b0280.3	Install 28.8 MVAR capacitor at Warrington 34 kV substation		PECO 100%
b0280.4	Install 18 MVAR capacitor at Waverly 13.8 kV substation		PECO 100%

* Neptune Regional Transmission System, LLC

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

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

PECO Energy Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0287	Install 600 MVAR Dynamic Reactive Device in Whitpain 500 kV vicinity		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (6.06%) / DPL (8.20%) / JCPL (21.17%) / PECO (64.56%) / PSEG (0.01%)
b0351	Reconductor Tunnel – Grays Ferry 230 kV		PECO (100%)
b0352	Reconductor Tunnel – Parrish 230 kV		PECO (100%)
b0353.1	Install 2% reactors on both lines from Eddystone – Llanerch 138 kV		PECO (100%)
b0353.2	Install identical second 230/138 kV transformer in parallel with existing 230/138 kV transformer at Plymouth Meeting		PECO 100%
b0353.3	Replace Whitpain 230 kV breaker 135		PECO (100%)
b0353.4	Replace Whitpain 230 kV breaker 145		PECO (100%)
b0354	Eddystone – Island Road Upgrade line terminal equipment		PECO 100%

* Neptune Regional Transmission System, LLC
††Cost allocations associated with below 500 kV elements of the project

PECO Energy Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0355	Reconductor Master – North Philadelphia 230 kV line		PECO 100%
b0357	Reconductor Buckingham – Pleasant Valley 230 kV		JCPL (*37.89*%) / Neptune* (*4.55*%) / PSEG (*55.19*%) / RE (*2.37*%)
b0359	Reconductor North Philadelphia – Waneeta 230 kV circuit		PECO 100%
b0402.1	Replace Whitpain 230 kV breaker #245		PECO (100%)
b0402.2	Replace Whitpain 230 kV breaker #255		PECO (100%)
b0438	Spare Whitpain 500/230 kV transformer		PECO (100%)
b0443	Spare Peach Bottom 500/230 kV transformer		PECO (100%)
b0505	Reconductor the North Wales – Whitpain 230 kV circuit		AEC (8.58%) / DPL (7.76%) / PECO (83.66%)
b0506	Reconductor the North Wales – Hartman 230 kV circuit		AEC (8.58%) / DPL (7.76%) / PECO (83.66%)
b0507	Reconductor the Jarrett – Whitpain 230 kV circuit		AEC (8.58%) / DPL (7.76%) PECO (83.66%)
b0508.1	Replace station cable at Hartman on the Warrington - Hartman 230 kV circuit		PECO (100%)
b0509	Reconductor the Jarrett – Heaton 230 kV circuit		PECO (100%)

PECO Energy Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0727	Rebuild Bryn Mawr – Plymouth Meeting 138 kV line		AEC (1.25%) / DPL (3.11%) / PECO (95.64%)
b0789	Reconductor the line to provide a normal rating of 677 MVA and an emergency rating of 827 MVA		AEC (*0.73*%) / JCPL (*17.52*%) / NEPTUNE* (*1.72*%) / PECO (*44.88*%) / PSEG (*33.83*%) / RE (*1.32*%)
b0790	Reconductor the Bradford – Planebrook 230 kV Ckt. 220-31 to provide a normal rating of 677 MVA and emergency rating of 827 MVA		JCPL (*17.46*%) / NEPTUNE* (*1.71*%) / PECO (*45.51*%) / PSEG (*34.00*%) / RE (*1.32*%)
b0829.1	Replace Whitpain 230 kV breaker '155'		PECO (100%)
b1073	Install 2 new 230 kV breakers at Planebrook (on the 220-02 line terminal and on the 230 kV side of the #9 transformer)		PECO (100%)
b0829.2	Replace Whitpain 230 kV breaker '525'		PECO (100%)
b0829.3	Replace Whitpain 230 kV breaker '175'		PECO (100%)
b0829.4	Replace Plymouth Meeting 230 kV breaker '225'		PECO (100%)
b0829.5	Replace Plymouth Meeting 230 kV breaker '335'		PECO (100%)
b0841	Move the connection points for the 2nd Plymouth Meeting 230/138 kV XFMR		PECO (100%)

* Neptune Regional Transmission System, LLC

PECO Energy Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0842	Install a 2nd 230/138 kV XFMR and 35 MVAR CAP at Heaton 138 kV bus		PECO (100%)
b0842.1	Replace Heaton 138 kV breaker ‘150’		PECO (100%)
b0843	Install a 75 MVAR CAP at Llanerch 138 kV bus		PECO (100%)
b0844	Move the connection point for the Llanerch 138/69 kV XFMR		PECO (100%)
b0887	Replace Richmond-Tacony 69 kV line		PECO (100%)
b0920	Replace station cable at Whitpain and Jarrett substations on the Jarrett - Whitpain 230 kV circuit		PECO (100%)
b1014.1	Replace Circuit breaker, Station Cable, CTs and Wave Trap at Eddistone 230 kV		PECO (100%)
b1014.2	Replace Circuit breaker, Station Cable, CTs Disconnect Switch and Wave Trap at Island Rd. 230 kV		PECO (100%)
b1015	Replace Breakers #115 and #125 at Printz 230 kV substation		PECO (100%)
b1156.1	Upgrade at Richmond 230 kV breaker ‘525’		PECO (100%)
b1156.2	Upgrade at Richmond 230 kV breaker ‘415’		PECO (100%)
b1156.3	Upgrade at Richmond 230 kV breaker ‘475’		PECO (100%)
b1156.4	Upgrade at Richmond 230 kV breaker ‘575’		PECO (100%)

* Neptune Regional Transmission System, LLC

PECO Energy Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1156.5	Upgrade at Richmond 230 kV breaker '185'		PECO (100%)
b1156.6	Upgrade at Richmond 230 kV breaker '285'		PECO (100%)
b1156.7	Upgrade at Richmond 230 kV breaker '85'		PECO (100%)
b1156.8	Upgrade at Waneeta 230 kV breaker '425'		PECO (100%)
b1156.9	Upgrade at Emilie 230 kV breaker '815'		PECO (100%)
b1156.10	Upgrade at Plymouth Meeting 230 kV breaker '265'		PECO (100%)
b1156.11	Upgrade at Croydon 230 kV breaker '115'		PECO (100%)
b1156.12	Replace Emilie 138 kV breaker '190'		PECO (100%)
b1178	Add a second 230/138 kV transformer at Chichester. Add an inductor in series with the parallel transformers		JCPL (*4.17*%) / Neptune (0.44%) / PECO (*82.73*%) / PSEG (*12.18*%) / RE (0.48%)
b1179	Replace terminal equipment at Eddystone and Saville and replace underground section of the line		PECO (100%)
b1180.1	Replace terminal equipment at Chichester		PECO (100%)
b1180.2	Replace terminal equipment at Chichester		PECO (100%)
b1181	Install 230/138 kV transformer at Eddystone		PECO (100%)

* Neptune Regional Transmission System, LLC

PECO Energy Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1182	Reconductor Chichester – Saville 138 kV line and upgrade terminal equipment		JCPL (*5.12*%) / Neptune (0.54%) / PECO (*79.46*%) / PSEG (*14.31*%) / RE (*0.57*%)
b1183	Replace 230/69 kV transformer #6 at Cromby. Add two 50 MVAR 230 kV banks at Cromby		PECO (100%)
b1184	Add 138 kV breakers at Cromby, Perkiomen, and North Wales; add a 35 MVAR capacitor at Perkiomen 138 kV		PECO (100%)
b1185	Upgrade Eddystone 230 kV breaker #365		PECO (100%)
b1186	Upgrade Eddystone 230 kV breaker #785		PECO (100%)
b1197	Reconductor the PECO portion of the Burlington – Croydon circuit		PECO (100%)
b1198	Replace terminal equipments including station cable, disconnects and relay at Conowingo 230 kV station		PECO (100%)
b1338	Replace Printz 230 kV breaker ‘225’		PECO (100%)
b1339	Replace Printz 230 kV breaker ‘315’		PECO (100%)
b1340	Replace Printz 230 kV breaker ‘215’		PECO (100%)
b1398.6	Reconductor the Camden – Richmond 230 kV circuit (PECO portion) and upgrade terminal equipments at Camden substations		JCPL (*13.03*%) / NEPTUNE (*1.20*%) / PECO (*51.93*%) / PEPCO (*0.58*%) / PSEG (*31.99*%) / RE (*1.27*%)

PECO Energy Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1398.8	Reconductor Richmond – Waneeta 230 kV and replace terminal equipments at Richmond and Waneeta substations		JCPL (*13.03*%) / NEPTUNE (*1.20*%) / PECO (*51.93*%) / PEPCO (*0.58*%) / PSEG (*31.99*%) / RE (*1.27*%)
b1398.12	Replace Graysferry 230 kV breaker '115'		PECO (100%)
b1398.13	Upgrade Peach Bottom 500 kV breaker '225'		AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)†
b1398.14	Replace Whitpain 230 kV breaker '105'		PECO (100%)
b1590.1	Upgrade the PECO portion of the Camden – Richmond 230 kV to a six wire conductor and replace terminal equipment at Richmond.		BGE (*3.06*%) / ME (0.83%) / PECO (*91.70*%) / PEPCO (*1.94*%) / PPL (*2.47*%)
b1591	Reconductor the underground portion of the Richmond – Waneeta 230 kV and replace terminal equipment		BGE (4.54%) / DL (0.27%) / ME (1.04%) / PECO (*88.11*%) / PEPCO (2.79%) / PPL (3.25%)

* Neptune Regional Transmission System, LLC

PECO Energy Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1717	Install a second Waneeta 230/138 kV transformer on a separate bus section		PECO (*100*%)
b1718	Reconductor the Crescentville - Foxchase 138 kV circuit		PECO (100%)
b1719	Reconductor the Foxchase - Bluegrass 138 kV circuit		PECO (100%)
b1720	Increase the effective rating of the Eddystone 230/138 kV transformer by replacing a circuit breaker at Eddystone		PECO (100%)
b1721	Increase the rating of the Waneeta - Tuna 138 kV circuit by replacing two 138 kV CTs at Waneeta		PECO (100%)
b1722	Increase the normal rating of the Cedarbrook - Whitemarsh 69 kV circuit by changing the CT ratio and replacing station cable at Whitemarsh 69 kV		PECO (100%)
b1768	Install 39 MVAR capacitor at Cromby 138 kV bus		PECO (100%)
b1900	Add a 3rd 230 kV transmission line between Chichester and Linwood substations and remove the Linwood SPS		PECO (*70.24*%) / JCPL (*6.07*%) / ATSI (*1.24*%) / PSEG (*21.01*%) / RE (*0.84*%) / NEPTUNE* (*0.60*%)
b2140	Install a 3rd Emilie 230/138 kV transformer		PECO (*100*%)
b2145	Replace two sections of conductor inside Richmond substation		PECO (100%)

* Neptune Regional Transmission System, LLC

SCHEDULE 12 – APPENDIX A

(8) PECO Energy Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2130	Replace Waneeta 138 kV breaker '15' with 63 kA rated breaker		PECO (100%)
b2131	Replace Waneeta 138 kV breaker '35' with 63 kA rated breaker		PECO (100%)
b2132	Replace Waneeta 138 kV breaker '875' with 63 kA rated breaker		PECO (100%)
b2133	Replace Waneeta 138 kV breaker '895' with 63 kA rated breaker		PECO (100%)
b2134	Plymouth Meeting 230 kV breaker '115' with 63 kA rated breaker		PECO (100%)
b2222	Install a second Eddystone 230/138 kV transformer		PECO (100%)
b2222.1	Replace the Eddystone 138 kV #205 breaker with 63kA breaker		PECO (100%)
b2222.2	Increase Rating of Eddystone #415 138kV Breaker		PECO (100%)
b2236	50 MVAR reactor at Buckingham 230 kV		PECO (100%)
b2527	Replace Whitpain 230 kV breaker ‘155’ with 80kA breaker		PECO (100%)
b2528	Replace Whitpain 230 kV breaker ‘525’ with 80kA breaker		PECO (100%)
b2529	Replace Whitpain 230 kV breaker ‘175’ with 80 kA breaker		PECO (100%)
b2549	Replace terminal equipment inside Chichester substation on the 220-36 (Chichester – Eddystone) 230 kV line		PECO (100%)

PECO Energy Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2550	Replace terminal equipment inside Nottingham substation on the 220-05 (Nottingham – Daleville- Bradford) 230 kV line		PECO (100%)
b2551	Replace terminal equipment inside Llanerch substation on the 130-45 (Eddystone to Llanerch) 138 kV line		PECO (100%)
b2572	Replace the Peach Bottom 500 kV '#225' breaker with a 63kA breaker		PECO (100%)
b2694	Increase ratings of Peach Bottom 500/230 kV transformer to 1479 MVA normal/1839 MVA emergency		AEC (*4.04*%) / AEP (*5.87*%) / APS (*4.34*%) / ATSI (*6.25*%) / BGE (*1.66*%) / ComEd (*0.73*%) / Dayton (*1.08*%) / DEOK (*2.01*%) / DL (*2.29*%) / Dominion (0.35%) / DPL (*14.53*%) / EKPC (*0.40*%) / JCPL (*6.95*%) / MetEd (*3.34*%) / Neptune (*2.18*%) / PECO (*16.69*%) / PENELEC (*4.01*%) / PPL (*8.46*%) / PSEG (*14.37*%) / RECO (*0.45*%)
b2752.2	Tie in new Furnace Run substation to Peach Bottom – TMI 500 kV		AEP (6.46%) / APS (8.74%) / BGE (19.74%) / ComEd (2.16%) / Dayton (0.59%) / DEOK (1.02%) / DL (0.01%) / Dominion (39.95%) / EKPC (0.45%) / PEPCO (20.88%)
b2752.3	Upgrade terminal equipment and required relay communication at Peach Bottom 500 kV: on the Beach Bottom – TMI 500 kV circuit		AEP (6.46%) / APS (8.74%) / BGE (19.74%) / ComEd (2.16%) / Dayton (0.59%) / DEOK (1.02%) / DL (0.01%) / Dominion (39.95%) / EKPC (0.45%) / PEPCO (20.88%)

PECO Energy Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2766.2	Upgrade substation equipment at Peach Bottom 500 kV to increase facility rating to 2826 MVA normal and 3525 MVA emergency		**Load-Ratio Share Allocation:** AEC (*1.66*%) / AEP (*14.16*%) / APS (*5.73*%) / ATSI (*7.88*%) / BGE (*4.22*%) / ComEd (*13.31*%) / Dayton (*2.11*%) / DEOK (*3.29*%) / DL (*1.75*%) / DPL (*2.50*%) / Dominion (*12.86*%) / EKPC (*1.87*%) / JCPL (*3.74*%) / ME (*1.90*%) / NEPTUNE* (*0.44*%) / PECO (*5.34*%) / PENELEC (*1.89*%) / PEPCO (*3.99*%) / PPL (*4.84*%) / PSEG (*6.26*%) / RE (*0.26*%)
			DFAX Allocation: AEC (0.05%) / APS (*11.40*%) / BGE (*22.83*%) / Dayton (*2.23*%) / DEOK (*4.28*%) / DPL (0.20%) / EKPC (*1.98*%) / JCPL (*11.06*%) / NEPTUNE* (*1.17*%) / POSEIDON**** (*0.64*%) / PENELEC (0.06%) / PEPCO (*19.38*%) / PSEG (*23.77*%) / RECO (*0.95*%)

*Neptune Regional Transmission System, LLC
****Poseidon Transmission 1, LLC

PECO Energy Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2774	Reconductor the Emilie - Falls 138 kV line, and replace station cable and relay		PECO (100%)
b2775	Reconductor the Falls - U.S. Steel 138 kV line		PECO (100%)
b2850	Replace the Waneeta 230 kV "285" with 63kA breaker		PECO (100%)
b2852	Replace the Chichester 230 kV "195" with 63kA breaker		PECO (100%)
b2854	Replace the North Philadelphia 230 kV "CS 775" with 63kA breaker		PECO (100%)
b2855	Replace the North Philadelphia 230 kV "CS 885" with 63kA breaker		PECO (100%)
b2856	Replace the Parrish 230 kV "CS 715" with 63kA breaker		PECO (100%)
b2857	Replace the Parrish 230 kV "CS 825" with 63kA breaker		PECO (100%)
b2858	Replace the Parrish 230 kV "CS 935" with 63kA breaker		PECO (100%)
b2859	Replace the Plymouth Meeting 230 kV "215" with 63kA breaker		PECO (100%)
b2860	Replace the Plymouth Meeting 230 kV "235" with 63kA breaker		PECO (100%)
b2861	Replace the Plymouth Meeting 230 kV "325" with 63kA breaker		PECO (100%)
b2862	Replace the Grays Ferry 230 kV "705" with 63kA breaker		PECO (100%)

PECO Energy Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2863	Replace the Grays Ferry 230 kV "985" with 63kA breaker		PECO (100%)
b2864	Replace the Grays Ferry 230 kV "775" with 63kA breaker		PECO (100%)
b2923	Replace the China Tap 230 kV ‘CS 15’ breaker with a 63 kA breaker		PECO (100%)
b2924	Replace the Emilie 230 kV ‘CS 15’ breaker with 63 kA breaker		PECO (100%)
b2925	Replace the Emilie 230 kV ‘CS 25’ breaker with 63 kA breaker		PECO (100%)
b2926	Replace the Chichester 230 kV ‘215’ breaker with 63 kA breaker		PECO (100%)
b2927	Replace the Plymouth Meeting 230 kV ‘125’ breaker with 63 kA breaker		PECO (100%)
b2985	Replace the 230 kV CB #225 at Linwood Substation (PECO) with a double circuit breaker (back to back circuit breakers in one device)		PECO (100%)

Attachment 7m (AEP OATT)

SCHEDULE 12 – APPENDIX

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0318	Install a 765/138 kV transformer at Amos		AEP (99.00%) / PEPCO (1.00%)
b0324	Replace entrance conductors, wave traps, and risers at the Tidd 345 kV station on the Tidd – Canton Central 345 kV circuit		AEP (100%)
b0447	Replace Cook 345 kV breaker M2		AEP (100%)
b0448	Replace Cook 345 kV breaker N2		AEP (100%)
b0490	Construct an Amos – Bedington 765 kV circuit (AEP equipment)	As specified under the procedures detailed in Attachment H-19B	**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)

* Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0490.2	Replace Amos 138 kV breaker ‘B’		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)
b0490.3	Replace Amos 138 kV breaker ‘B1’		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0490.4	Replace Amos 138 kV breaker 'C'		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)
b0490.5	Replace Amos 138 kV breaker 'C1'		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)

* Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0490.6	Replace Amos 138 kV breaker 'D'		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)
b0490.7	Replace Amos 138 kV breaker 'D2'		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0490.8	Replace Amos 138 kV breaker ‘E’		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)
b0490.9	Replace Amos 138 kV breaker ‘E2’		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEC (5.01%) / AEP (4.39%) / APS (9.26%) / BGE (4.43%) / DL (0.02%) / DPL (6.91%) / Dominion (10.82%) / JCPL (11.64%) / ME (2.94%) / NEPTUNE (1.12%) / PECO (14.51%) / PEPCO (6.11%) / PPL (6.39%) / PSEG (15.86%) / RE (0.59%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0504	Add two advanced technology circuit breakers at Hanging Rock 765 kV to improve operational performance		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEP (100%)
b0570	Reconductor East Side Lima – Sterling 138 kV		AEP (41.99%) / ComEd (58.01%)
b0571	Reconductor West Millersport – Millersport 138 kV		AEP (73.83%) / ComEd (19.26%) / Dayton (6.91%)
b0748	Establish a new 69 kV circuit between the Canal Road and East Wooster stations, establish a new 69 kV circuit between the West Millersburg and Moreland Switch stations (via Shreve), add reactive support via cap banks		AEP (100%)
b0838	Hazard Area 138 kV and 69 kV Improvement Projects		AEP (100%)
b0839	Replace existing 450 MVA transformer at Twin Branch 345 / 138 kV with a 675 MVA transformer		AEP (99.73%) / Dayton (0.27%)

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

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

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

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

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

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

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

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

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

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

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

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

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

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1463	Reconductor the Bexley – Groves 138 kV circuit		AEP (100%)
b1464	Corner 138 kV upgrades		AEP (100%)
b1465.1	Add a 3rd 2250 MVA 765/345 kV transformer at Sullivan station		AEC (0.71%) / AEP (*75.17*%) / APS (1.25%) / BGE (1.81%) / ComEd (*5.92*%) / Dayton (0.86%) / DL (1.23%) / DPL (0.95%) / Dominion (*3.90*%) / JCPL (1.58%) / NEPTUNE (0.15%) / PECO (2.08%) / PEPCO (1.66%) / PSEG (*2.63*%) / RE (0.10%)
b1465.2	Replace the 100 MVAR 765 kV shunt reactor bank on Rockport – Jefferson 765 kV line with a 300 MVAR bank at Rockport Station		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1465.3	Transpose the Rockport – Sullivan 765 kV line and the Rockport – Jefferson 765 kV line		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%) **DFAX Allocation:** AEP (100%)
b1465.4	Make switching improvements at Sullivan and Jefferson 765 kV stations		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%) **DFAX Allocation:** AEP (100%)
b1466.1	Create an in and out loop at Adams Station by removing the hard tap that currently exists		AEP (100%)
b1466.2	Upgrade the Adams transformer to 90 MVA		AEP (100%)

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

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

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

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

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

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1495	Add an additional 765/345 kV transformer at Baker Station		AEC (0.41%) / AEP (*87.29*%) / BGE (1.03%) / ComEd (*3.39*%) / Dayton (1.23%) / DL (1.46%) / DPL (0.54%) / JCPL (0.90%) / NEPTUNE (0.09%) / PECO (1.18%) / PEPCO (0.94%) / PSEG (1.48%) / RE (0.06%)
b1496	Replace 138 kV bus and risers at Johnson Mountain Station		AEP (100%)
b1497	Replace 138 kV bus and risers at Leesville Station		AEP (100%)
b1498	Replace 138 kV risers at Wurno Station		AEP (100%)
b1499	Perform a sag study on Sporn A – Gavin 138 kV to determine if the emergency rating can be improved		AEP (100%)
b1500	The North East Canton – Wagenhals 138 kV circuit would need an electrical clearance study to determine if the emergency rating can be utilized		AEP (100%)
b1501	The Moseley – Reusens 138 kV circuit requires a sag study to determine if the emergency rating can be utilized to address a thermal loading issue for a category C3		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1502	Reconductor the Conesville East – Conesville Prep Plant Tap 138 kV section of the Conesville – Ohio Central to fix Reliability N-1-1 thermal overloads		AEP (100%)
b1659	Establish Sorenson 345/138 kV station as a 765/345 kV station		AEP (93.67%) / ATSI (2.99%) / ComEd (2.07%) / PENELEC (0.31%) / PSEG (0.92%) / RE (0.04%)
b1659.1	Replace Sorenson 138 kV breaker 'L1'		AEP (100%)
b1659.2	Replace Sorenson 138 kV breaker 'L2' breaker		AEP (100%)
b1659.3	Replace Sorenson 138 kV breaker 'M1'		AEP (100%)
b1659.4	Replace Sorenson 138 kV breaker 'M2'		AEP (100%)
b1659.5	Replace Sorenson 138 kV breaker 'N1'		AEP (100%)
b1659.6	Replace Sorenson 138 kV breaker 'N2'		AEP (100%)
b1659.7	Replace Sorenson 138 kV breaker 'O1'		AEP (100%)
b1659.8	Replace Sorenson 138 kV breaker 'O2'		AEP (100%)
b1659.9	Replace Sorenson 138 kV breaker 'M'		AEP (100%)
b1659.10	Replace Sorenson 138 kV breaker 'N'		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1659.11	Replace Sorenson 138 kV breaker 'O'		AEP (100%)
b1659.12	Replace McKinley 138 kV breaker 'L1'		AEP (100%)
b1659.13	Establish 765 kV yard at Sorenson and install four 765 kV breakers		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEP (73.42%) / Dayton (11.78%) / DEOK (14.80%)
b1659.14	Build approximately 14 miles of 765 kV line from existing Dumont - Marysville line		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEP (63.21%) / ATSI (18.99%) / ComEd (3.32%) / Dayton (8.73%) / DL (5.41%) / EKPC (0.34%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1660	Install a 765/500 kV transformer at Cloverdale		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (98.28%) / DEOK (0.45%) / Dominion (1.11%) / EKPC (0.16%)
b1661	Install a 765 kV circuit breaker at Wyoming station		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEP (100%)

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

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1662.2	Install three 138 kV breakers at Grandview Station (facing Cherry Creek, Hinton, and Bradley Stations)		AEP (100%)
b1662.3	Remove Sullivan Switching Station (46 kV)		AEP (100%)
b1663	Install a new 765/138 kV transformer at Jackson Ferry substation		AEP (100%)
b1663.1	Establish a new 10 mile double circuit 138 kV line between Jackson Ferry and Wythe		AEP (100%)
b1663.2	Install 2 765 kV circuit breakers, breaker disconnect switches and associated bus work for the new 765 kV breakers, and new relays for the 765 kV breakers at Jackson's Ferry		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEP (100%)
b1664	Install switched capacitor banks at Kenwood 138 kV stations		AEP (100%)
b1665	Install a second 138/69 kV transformer at Thelma station		AEP (100%)
b1665.1	Construct a single circuit 69 kV line from West Paintsville to the new Paintsville station		AEP (100%)

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

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

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

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

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

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

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

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

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

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

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

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1956	Perform a sag study of the Tillman - Dawkins 138 kV line may improve the emergency rating to 245 MVA		AEP (100%)
b1957	Terminate Transformer #2 at SW Lima in a new bay position		AEP (*69.66*%) / ATSI (*23.19*%) / PENELEC (*2.43*%) / PSEG (*4.54*%) / RE (0.18%)
b1958	Perform a sag study on the Brookside - Howard 138 kV line and replace bus and risers at AEP Howard station		AEP (100%)
b1960	Sag Study on 7.2 miles SE Canton-Canton Central 138kV ckt		AEP (100%)
b1961	Sag study on the Southeast Canton – Sunnyside 138kV line		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1962	Add four 765 kV breakers at Kammer		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEP (100%)
b1963	Build approximately 1 mile of circuit comprising of 2-954 ACSR to get the rating of Waterford-Muskinum 345 kV higher		AEP (100%)
b1970	Reconductor 13 miles of the Kammer – West Bellaire 345kV circuit		APS (*33.58*%) / ATSI (*32.28*%) / DL (*18.68*%) / Dominion (*6.02*%) / JCPL (1.68%) / Neptune* (0.18%) / PENELEC (*4.59*%) / PSEG (*2.88*%) / RE (0.11%)
b1971	Perform a sag study to improve the emergency rating on the Bridgville – Chandlersville 138 kV line		AEP (100%)
b1972	Replace disconnect switch on the South Canton 765/345 kV transformer		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1973	Perform a sag study to improve the emergency rating on the Carrollton – Sunnyside 138 kV line		AEP (100%)
b1974	Perform a sag study to improve the emergency rating on the Bethel Church – West Dover 138 kV line		AEP (100%)
b1975	Replace a switch at South Millersburg switch station		AEP (100%)
b2017	Reconductor or rebuild Sporn - Waterford - Muskingum River 345 kV line		ATSI (*37.10*%) / AEP (*34.41*%) / DL (*10.43*%) / Dominion (*6.20*%) / APS (*3.95*%) / PENELEC (*3.10*%) / JCPL (1.39%) / Dayton (1.20%) / Neptune* (0.14%) / PSEG (2.00%) / RE (0.08%)
b2018	Loop Conesville - Bixby 345 kV circuit into Ohio Central		ATSI (58.58%) / AEP (14.16%) / APS (12.88%) / DL (7.93%) / PENELEC (5.73%) / Dayton (0.72%)
b2019	Establish Burger 345/138 kV station		AEP (93.74%) / APS (4.40%) / DL (1.11%) / ATSI (0.74%) / PENELEC (0.01%)
b2020	Rebuild Amos - Kanawah River 138 kV corridor		AEP (88.39%) / APS (7.12%) / ATSI (2.89%) / DEOK (1.58%) / PEPCO (0.02%)
b2021	Add 345/138 transformer at Sporn, Kanawah River & Muskingum River stations		AEP (91.92%) / DEOK (3.60%) / APS (2.19%) / ATSI (1.14%) / DL (1.08%) / PEPCO (0.04%) / BGE (0.03%)
b2021.1	Replace Kanawah 138 kV breaker 'L'		AEP (100%)
b2021.2	Replace Muskingum 138 kV breaker 'HG'		AEP (100%)

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

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

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

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

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

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

*Neptune Regional Transmission System, LLC

SCHEDULE 12 – APPENDIX A

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1660.1	Cloverdale: install 6-765 kV breakers, incremental work for 2 additional breakers, reconfigure and relocate miscellaneous facilities, establish 500 kV station and 500 kV tie with 765 kV station		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (97.94%) / DEOK (0.54%) / Dominion (1.33%) / EKPC (0.19%)

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

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b1797.1	Reconductor the AEP portion of the Cloverdale - Lexington 500 kV line with 2-1780 ACSS		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: APS (55.05%) / ATSI (2.77%) / Dayton (0.84%) / DEOK (2.06%) / Dominion (5.76%) / EKPC (0.72%) / PEPCO (32.80%)
b2055	Upgrade relay at Brues station		AEP (100%)
b2122.3	Upgrade terminal equipment at Howard on the Howard - Brookside 138 kV line to achieve ratings of 252/291 (SN/SE)		AEP (100%)
b2122.4	Perform a sag study on the Howard - Brookside 138 kV line		AEP (100%)
b2229	Install a 300 MVAR reactor at Dequine 345 kV		AEP (100%)

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2230	Replace existing 150 MVAR reactor at Amos 765 kV substation on Amos - N. Proctorville - Hanging Rock with 300 MVAR reactor		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEP (100%)
b2231	Install 765 kV reactor breaker at Dumont 765 kV substation on the Dumont - Wilton Center line		AEP (100%)
b2232	Install 765 kV reactor breaker at Marysville 765 kV substation on the Marysville - Maliszewski line		AEP (100%)
b2233	Change transformer tap settings for the Baker 765/345 kV transformer		AEP (100%)
b2252	Loop the North Muskingum - Crooksville 138 kV line into AEP's Philo 138 kV station which lies approximately 0.4 miles from the line		AEP (100%)

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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

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

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2394	Replace the Sporn 345 kV breaker 'CC1'		AEP (100%)
b2409	Install two 56.4 MVAR capacitor banks at the Melmore 138 kV station in Ohio		AEP (100%)
b2410	Convert Hogan Mullin 34.5 kV line to 138 kV, establish 138 kV line between Jones Creek and Strawton, rebuild existing Mullin Elwood 34.5 kV and terminate line into Strawton station, retire Mullin station		AEP (100%)
b2411	Rebuild the 3/0 ACSR portion of the Hadley - Kroemer Tap 69 kV line utilizing 795 ACSR conductor		AEP (100%)
b2423	Install a 300 MVAR shunt reactor at AEP's Wyoming 765 kV station		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEP (100%)

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

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

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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

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

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

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2687.1	Install a +/- 450 MVAR SVC at Jacksons Ferry 765 kV substation		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEP (100%)

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

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2687.2	Install a 300 MVAR shunt line reactor on the Broadford end of the Broadford – Jacksons Ferry 765 kV line		**Load-Ratio Share Allocation:** AEC (1.66%) / AEP (14.16%) / APS (5.73%) / ATSI (7.88%) / BGE (4.22%) / ComEd (13.31%) / Dayton (2.11%) / DEOK (3.29%) / DL (1.75%) / DPL (2.50%) / Dominion (12.86%) / EKPC (1.87%) / JCPL (3.74%) / ME (1.90%) / NEPTUNE* (0.44%) / PECO (5.34%) / PENELEC (1.89%) / PEPCO (3.99%) / PPL (4.84%) / PSEG (6.26%) / RE (0.26%)
			DFAX Allocation: AEP (100%)
b2697.1	Mitigate violations identified by sag study to operate Fieldale-Thornton-Franklin 138 kV overhead line conductor at its max. operating temperature. 6 potential line crossings to be addressed.		AEP (100%)
b2697.2	Replace terminal equipment at AEP's Danville and East Danville substations to improve thermal capacity of Danville – East Danville 138 kV circuit		AEP (100%)

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

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2760	Perform a Sag Study of the Saltville – Tazewell 138 kV line to increase the thermal rating of the line		AEP (100%)
b2761.1	Replace the Hazard 161/138 kV transformer		AEP (100%)
b2761.2	Perform a Sag Study of the Hazard – Wooten 161 kV line to increase the thermal rating of the line		AEP (100%)
b2761.3	*Rebuild the Hazard – Wooton 161 kV line utilizing 795 26/7 ACSR conductor (300 MVA rating)*		*AEP (100%)*
b2762	Perform a Sag Study of Nagel – West Kingsport 138 kV line to increase the thermal rating of the line		AEP (100%)
b2776	Reconductor the entire Dequine – Meadow Lake 345 kV circuit #2		AEP (100%)
b2777	Reconductor the entire Dequine – Eugene 345 kV circuit #1		AEP (100%)
b2779.1	Construct a new 138 kV station, Campbell Road, tapping into the Grabill – South Hicksville138 kV line		AEP (100%)
b2779.2	Reconstruct sections of the Butler-N.Hicksville and Auburn-Butler 69 kV circuits as 138 kV double circuit and extend 138 kV from Campbell Road station		AEP (100%)

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2779.3	Construct a new 345/138 kV SDI Wilmington Station which will be sourced from Collingwood 345 kV and serve the SDI load at 345 kV and 138 kV, respectively		AEP (100%)
b2779.4	Loop 138 kV circuits in-out of the new SDI Wilmington 138 kV station resulting in a direct circuit to Auburn 138 kV and an indirect circuit to Auburn and Rob Park via Dunton Lake, and a circuit to Campbell Road; Reconductor 138 kV line section between Dunton Lake – SDI Wilmington		AEP (100%)
b2779.5	Expand Auburn 138 kV bus		AEP (100%)
b2787	Reconductor 0.53 miles (14 spans) of the Kaiser Jct. - Air Force Jct. Sw section of the Kaiser - Heath 69 kV circuit/line with 336 ACSR to match the rest of the circuit (73 MVA rating, 78% loading)		AEP (100%)
b2788	Install a new 3-way 69 kV line switch to provide service to AEP's Barnesville distribution station. Remove a portion of the #1 copper T-Line from the 69 kV through-path		AEP (100%)

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

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

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2817	Replace Delaware 138 kV breaker ‘P’ with a 40 kA breaker		AEP (100%)
b2818	Replace West Huntington 138 kV breaker ‘F’ with a 40 kA breaker		AEP (100%)
b2819	Replace Madison 138 kV breaker ‘V’ with a 63 kA breaker		AEP (100%)
b2820	Replace Sterling 138 kV breaker ‘G’ with a 40 kA breaker		AEP (100%)
b2821	Replace Morse 138 kV breakers ‘103’, ‘104’, ‘105’, and ‘106’ with 63 kA breakers		AEP (100%)
b2822	Replace Clinton 138 kV breakers ‘105’ and ‘107’ with 63 kA breakers		AEP (100%)
b2826.1	Install 300 MVAR reactor at Ohio Central 345 kV substation		AEP (100%)

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2826.2	Install 300 MVAR reactor at West Bellaire 345 kV substation		AEP (100%)
b2831.1	Upgrade the Tanner Creek – Miami Fort 345 kV circuit (AEP portion)		**DFAX Allocation:** Dayton (34.34%) / DEOK (56.45%) / EKPC (9.21%)
b2832	Six wire the Kyger Creek – Sporn 345 kV circuits #1 and #2 and convert them to one circuit		AEP (100%)
b2833	Reconductor the Maddox Creek – East Lima 345 kV circuit with 2-954 ACSS Cardinal conductor		**DFAX Allocation:** Dayton (100%)
b2834	Reconductor and string open position and sixwire 6.2 miles of the Chemical – Capitol Hill 138 kV circuit		AEP (100%)
b2872	Replace the South Canton 138 kV breaker ‘K2’ with a 80 kA breaker		AEP (100%)
b2873	Replace the South Canton 138 kV breaker “M” with a 80 kA breaker		AEP (100%)
b2874	Replace the South Canton 138 kV breaker “M2” with a 80 kA breaker		AEP (100%)
b2878	Upgrade the Clifty Creek 345 kV risers		AEP (100%)
b2880	Rebuild approximately 4.77 miles of the Cannonsburg – South Neal 69 kV line section utilizing 795 ACSR conductor (90 MVA rating)		AEP (100%)

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

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

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

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2890.1	Rebuild 23.55 miles of the East Cambridge – Smyrna 34.5 kV circuit with 795 ACSR conductor (128 MVA rating) and convert to 69 kV		AEP (100%)
b2890.2	East Cambridge: Install a 2000 A 69 kV 40 kA circuit breaker for the East Cambridge – Smyrna 69 kV circuit		AEP (100%)
b2890.3	Old Washington: Install 69 kV 2000 A two way phase over phase switch		AEP (100%)
b2890.4	Install 69 kV 2000 A two way phase over phase switch		AEP (100%)
b2891	Rebuild the Midland Switch to East Findlay 34.5 kV line (3.31 miles) with 795 ACSR (63 MVA rating) to match other conductor in the area		AEP (100%)
b2892	Install new 138/12 kV transformer with high side circuit switcher at Leon and a new 138 kV line exit towards Ripley. Establish 138 kV at the Ripley station with a new 138/69 kV 130 MVA transformer and move the distribution load to 138 kV service		AEP (100%)
b2936.1	Rebuild approximately 6.7 miles of 69 kV line between Mottville and Pigeon River using 795 ACSR conductor (129 MVA rating). New construction will be designed to 138 kV standards but operated at 69 kV		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2936.2	Pigeon River Station: Replace existing MOAB Sw. ‘W’ with a new 69 kV 3000 A 40 kA breaker, and upgrade existing relays towards HMD station. Replace CB H with a 3000 A 40 kA breaker		AEP (100%)
b2937	Replace the existing 636 ACSR 138 kV bus at Fletchers Ridge with a larger 954 ACSR conductor		AEP (100%)
b2938	Perform a sag mitigations on the Broadford – Wolf Hills 138 kV circuit to allow the line to operate to a higher maximum temperature		AEP (100%)
b2958.1	*Cut George Washington – Tidd 138 kV circuit into Sand Hill and reconfigure Brues & Warton Hill line entrances*		*AEP (100%)*
b2958.2	*Add 2 138 kV 3000 A 40 kA breakers, disconnect switches, and update relaying at Sand Hill station*		*AEP (100%)*
b2968	*Upgrade existing 345 kV terminal equipment at Tanner Creek station*		*AEP (100%)*
b2969	*Replace terminal equipment on Maddox Creek - East Lima 345 kV circuit*		*AEP (100%)*
b2976	*Upgrade terminal equipment at Tanners Creek 345 kV station. Upgrade 345 kV bus and risers at Tanners Creek for the Dearborn circuit*		*AEP (100%)*

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2988	Replace the Twin Branch 345 kV breaker “JM” with 63 kA breaker and associated substation works including switches, bus leads, control cable and new DICM		AEP (100%)

Attachment 8 (EL05-121 Settlement FERC Order)

163 FERC ¶ 61,168
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Cheryl A. LaFleur, Neil Chatterjee,
and Richard Glick.

PJM Interconnection, L.L.C. Docket No. EL05-121-009

ORDER ON CONTESTED SETTLEMENT

(Issued May 31, 2018)

1. On June 15, 2016, the Settling Parties,[1] pursuant to Rule 602 of the Commission's rules of practice and procedure,[2] submitted an offer of settlement (Settlement) in the matter set for hearing and settlement judge procedures in this proceeding.

2. In this order, we approve the Settlement, finding that the overall result of the Settlement is just and reasonable.

I. Background

3. On April 19, 2007, the Commission issued Opinion No. 494,[3] an order on an initial decision concerning the cost allocation method for existing and new transmission facilities contained in PJM Interconnection, L.L.C.'s (PJM) then-current Open Access Transmission Tariff (Tariff). In Opinion No. 494, the Commission, acting under section 206 of the Federal Power Act,[4] found PJM's existing cost allocation method, which used a violation-based distribution factor (DFAX) method[5] to allocate 100 percent of the costs

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[1] Appendix A lists the Settling and Non-Opposing Parties.

[2] 18 C.F.R. § 385.602(h) (2017).

[3] *PJM Interconnection, L.L.C.*, Opinion No. 494, 119 FERC ¶ 61,063 (2007), *order on reh'g*, Opinion No. 494-A, 122 FERC ¶ 61,082 (2008).

[4] 16 U.S.C. § 824e (2012).

[5] Under the violation-based DFAX method, to determine cost responsibility for new transmission facilities, PJM conducted studies to determine which loads contribute *(continued ...)*

of new transmission facilities that operate at or above 500 kV, unjust and unreasonable and required PJM to allocate 100 percent of the costs of such facilities on a load-ratio share basis (the 100 percent load-ratio share method),[6] to the Merchant Transmission Facilities and Zones[7] of the Responsible Customers pursuant to Schedule 12 of the PJM Tariff.[8]

4. Parties sought review of Opinion No. 494 in the U.S. Court of Appeals for the Seventh Circuit (Court). The Court granted the petition for review regarding the allocation of all of the costs of new transmission facilities that operate at or above 500 kV on a load-ratio share basis and remanded the case to the Commission for further proceedings.[9] On remand, the Commission affirmed the 100 percent load-ratio share

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to the reliability violation that caused the upgrade by examining power flows on the constrained facilities at the time of a reliability violation. The Zones that are using the constrained facilities at the time of the violation are allocated the costs of the reliability upgrades because they are considered to be the ones that "cause" the violation and "benefit from" the addition of upgrades that eliminate the violation. *See* Opinion No. 494, 119 FERC ¶ 61,063 at P 2, fn.2.

[6] Opinion No. 494, 119 FERC ¶ 61,063 at P 82 (accepting PJM's proposal "to fully allocate, on a region-wide basis, the costs of new, centrally-planned facilities that operate at or above 500 kV," noting that "lower voltage facilities that are necessary to construct a particular new project at 500 kV and above would also be rolled in to the 500 kV and above postage stamp rate").

[7] The PJM Tariff defines Zone as an area within the PJM Region, as set forth in the Tariff, Attachment J. PJM Tariff, W-X-Y-Z, OATT Definitions - W - X - Y - Z, 4.0.0. *See* PJM Tariff, ATTACHMENT J PJM Transmission Zones.

[8] Responsible Customers are those customers designated by PJM as responsible for Transmission Enhancement Charges. *See* Schedule 12 (b)(viii). Transmission Enhancement Charges are established to recover the revenue requirement with respect to a Required Transmission Enhancement. *See* PJM Tariff, Schedule 12(a)(i). The PJM Tariff defines Required Transmission Enhancements as "[e]nhancements and expansions of the Transmission System that (1) a Regional Transmission Expansion Plan developed pursuant to Schedule 6 of the Operating Agreement or (2) any joint planning or coordination agreement between PJM and another region or transmission planning authority set forth in Schedule 12-Appendix B ("Appendix B Agreement") designates one or more of the Transmission Owner(s) to construct and own or finance. PJM Tariff Definitions - R - S, OATT Definitions - R - S, 13.0.0.

[9] *See Illinois Commerce Comm'n* v. *FERC*, 576 F.3d 470 (7th Cir. 2009).

method for new transmission facilities that operate at or above 500 kV.[10] The Commission found that, while there is imprecision in valuing the benefits of new transmission facilities that operate at or above 500 kV, the benefits of such facilities are sufficiently shared across the PJM region to justify region-wide cost allocation.

5. Parties again sought review and the Court again reversed and remanded the Commission's determination that the costs of transmission facilities that operate at or above 500 kV should be allocated on a 100 percent load-ratio share basis. The Court found that the Order on Remand failed to respond to the directive "to quantify the benefits" of new transmission facilities that operate at or above 500 kV.[11] The Court stated that "[c]ost-benefit analysis is the standard method of valuation for large public or commercial projects, and it is hardly alien to the electric power industry."[12] The court concluded that Commission had not provided a quantitative estimate of the benefits of the new transmission facilities or demonstrated that "the benefits can't be quantified even roughly."[13]

6. While this second proceeding on remand was pending before the Commission, and on compliance with Order No. 1000,[14] the PJM Transmission Owners proposed and the Commission accepted a hybrid cost allocation method for Regional Facilities and Necessary Lower Voltage Facilities,[15] selected in the PJM Regional Transmission

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[10] *PJM Interconnection, L.L.C.*, 138 FERC ¶ 61,230 (2012) (Order on Remand), *order on reh'g*, 142 FERC ¶ 61,216 (2013).

[11] *Illinois Commerce Comm'n. v. FERC*, 756 F.3d 556, 562 (7th Cir. 2014).

[12] *Id.* at 561.

[13] *Id.* at 564.

[14] *See Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011) (Order No. 1000), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth.* v. *FERC*, 762 F.3d 41 (D.C. Cir. 2014).

[15] Regional Facilities are defined as Required Transmission Enhancements included in the Regional Transmission Expansion Plan that are transmission facilities that: (a) are AC facilities that operate at or above 500 kV; (b) are double-circuit AC facilities that operate at or above 345 kV; (c) are AC or DC shunt reactive resources connected to a facility from (a) or (b); or (d) are DC facilities that meet the necessary criteria as described in section (b)(i)(D). Necessary Lower Voltage Facilities are defined as Required Transmission Enhancements included in the Regional Transmission *(continued ...)*

Expansion Plan (RTEP) for purposes of cost allocation.[16] Under the cost allocation method accepted as complying with Order No. 1000, for Regional Facilities and Necessary Lower Voltage Facilities that address a reliability need,[17] 50 percent of the costs are allocated on a load-ratio share basis and the other 50 percent of the costs are allocated using the solution-based DFAX method.[18] The Commission granted a February 1, 2013 effective date for cost allocation method accepted as complying with Order No. 1000.[19] As a result, the 100 percent load-ratio share method accepted by the Commission in Opinion No. 494 and at issue in the remand proceedings was applied only

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Expansion Plan that are lower voltage facilities that must be constructed or reinforced to support new Regional Facilities. PJM Tariff, Schedule 12(b)(i). The PJM Tariff defines Required Transmission Enhancements as "[e]nhancements and expansions of the Transmission System that (1) a Regional Transmission Expansion Plan developed pursuant to Schedule 6 of the Operating Agreement or (2) any joint planning or coordination agreement between PJM and another region or transmission planning authority set forth in Schedule 12-Appendix B ("Appendix B Agreement") designates one or more of the Transmission Owner(s) to construct and own or finance. PJM Tariff Definitions - R - S, OATT Definitions - R - S, 13.0.0.

[16] *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 (2013), o*rder on reh'g and compliance*, 147 FERC ¶ 61,128 (2014), o*rder on reh'g and compliance*, 150 FERC ¶ 61,038, and o*rder on reh'g and compliance*, 151 FERC ¶ 61,250 (2015).

[17] PJM identifies reliability transmission needs and economic constraints that result from the incorporation of public policy requirements into its sensitivity analyses, and allocates the costs of the solutions to such transmission needs in accordance with the type of benefits they provide. *See PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 at P 441. *See also* PJM Tariff, Schedule 12 (b)(v) Economic Projects (assigning cost responsibility for Economic Projects).

[18] The solution-based DFAX method evaluates the projected relative use on the new facility by the load of each transmission Zone or Merchant Transmission Facility and, through this power flow analysis, identifies projected beneficiaries for individual entities in relation to power flows. *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 at P 416. The solution-based DFAX method replaced the violation-based DFAX method that assigned cost responsibility by determining which loads contribute to the reliability violation that caused the upgrade.

[19] *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 at P 1; *PJM Interconnection, L.L.C.*, 147 FERC ¶ 61,128 at PP 18, 29.

to those new transmission facilities that operate at or above 500 kV approved by the PJM Board of Directors prior to February 1, 2013.[20]

7. In the second proceeding on remand, the Commission established hearing and settlement judge procedures to determine the appropriate cost allocation for the transmission projects that remain at issue in this proceeding (i.e., those new transmission facilities that operate at or above 500 kV that PJM planned and were approved before February 1, 2013 whose costs were allocated in accordance with the 100 percent load-ratio share method established in Opinion No. 494).[21] On June 15, 2016, the Settling Parties submitted a Settlement in this proceeding. On August 16, 2016, the Settlement Judge issued a report of the contested Settlement.[22]

II. Settlement

8. The Settlement specifies the terms that will be incorporated into a new Schedule 12-C added to the PJM Tariff to be effective as of January 1, 2016. The Settlement defines Covered Transmission Enhancements as those Required Transmission Enhancements for which costs were assigned under the 100 percent load-ratio share method that was accepted by the Commission in Opinion No. 494 that the PJM Board approved prior to February 1, 2013, and that are planned to operate at or above 500 kV. This includes any Necessary Lower Voltage Facilities (as defined in the PJM Tariff) associated with those Required Transmission Enhancements.[23] The Covered Transmission Enhancements, including those Covered Transmission Enhancements that were canceled or abandoned before entering service (Cancelled Projects), are listed in Appendix A to new Schedule 12-C of the PJM Tariff.

9. The Settlement contains different methods for recovery of costs incurred for Covered Transmission Enhancements for the periods before and starting January 1, 2016. From January 1, 2016 onward (going-forward period), and continuing until all charges authorized by the Commission with respect to each Covered Transmission Enhancement are fully recovered, the Settlement provides that PJM shall collect a Current Recovery

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[20] Tariff, Schedule 12(a)(v).

[21] *PJM Interconnection, L.L.C.*, 149 FERC ¶ 61,233, at P 2 (2014).

[22] *PJM Interconnection, L.L.C.*, 156 FERC ¶ 63,027 (2016).

[23] As previously noted, Necessary Lower Voltage Facilities are defined as Required Transmission Enhancements included in the Regional Transmission Expansion Plan that are lower voltage facilities that must be constructed or reinforced to support new Regional Facilities. Tariff, Schedule 12(b)(i).

Charge from Responsible Customers for each Covered Transmission Enhancement. Specifically, PJM will assign cost responsibility for the revenue requirement associated with each Covered Transmission Enhancement through a hybrid method in which: (1) 50 percent of the cost responsibility shall be assigned to Responsible Customers on an annual load-ratio share basis, as set forth in section (b)(i)(A)(1) of Schedule 12 of the PJM Tariff; and (2) 50 percent of the cost responsibility shall be assigned to Responsible Customers based on the solution-based DFAX method, as set forth in subsection (b)(i)(A)(2)(a) of Schedule 12, provided that the Current Recovery Charges with respect to each Covered Transmission Enhancement reflect only the amounts that the Commission authorizes the owner(s) to recover from and after January 1, 2016.[24]

10. To address the period from 2007 to January 1, 2016 (historical period), in which the costs of the Covered Transmission Enhancements were recovered under the method approved in Opinion No. 494, the Settlement also provides for Transmission Enhancement Charge Adjustments to the billings for the Covered Transmission Enhancements through a schedule of credits and payments from Responsible Customers.[25] Specifically, effective as of January 1, 2016 and continuing through December 31, 2025, in addition to the Current Recovery Charge, PJM shall collect from or credit to Responsible Customers the Transmission Enhancement Charge Adjustments set forth in Appendix C to Schedule 12-C for each Zone and each Merchant Transmission Facility.

11. Section 2.2 (d) of the Settlement states that the total amounts credited or recovered for Covered Transmission Enhancements as Transmission Enhancement Charge Adjustments are the result of a "black box" Settlement. As a negotiated black box Settlement, the Settling Parties acknowledge that there is agreement only on the total amounts to be collected or credited by PJM from or to Responsible Customers as stated in Appendix C, with no separately stated components in the Covered Transmission Enhancements with respect to the cost of equity or debt, capital structure, regulatory asset amount, or other elements. Further, there is no separate statement of how the individual zonal and Merchant Transmission Facility monthly charges were derived.

12. The Settlement also provides for adjustments to the Transmission Enhancement Charge Adjustments to address (1) any determination that all or a portion of the costs

[24] Settlement, Section 2.2(c). Because there will be no flow over the Cancelled Projects to allow for the use of the solution-based DFAX method, 50 percent of the cost responsibility for Covered Transmission Enhancements that are not assigned on a load-ratio share basis will be assigned to Responsible Customers based on the violation-based DFAX method for the cost responsibility assignments not assigned on a load-ratio basis.

[25] Settlement, Section 2.2(d).

recovered by the Potomac Appalachian Transmission Highline (PATH) were not properly recoverable, and (2) any circumstance under which all Responsible Customers in a Zone or associated with a Merchant Transmission Facility are no longer subject to Transmission Enhancement Charges during the period in which Transmission Enhancement Charge Adjustments are collected. In the latter scenario, during the portion of the period that such Responsible Customers are not subject to Transmission Enhancement Charges, the payments from or credits to such Responsible Customers shall cease and PJM shall adjust the Transmission Enhancement Charge Adjustments to other remaining Responsible Customers on a *pro rata* basis.

13. The Settlement provides that, unless the Settling Parties and Non-Opposing Parties otherwise agree in writing, any modification to the Settlement or to the rates and charges set forth in Attachment C to the Settlement (but not including a modification that implements section 2.2(e) of the Settlement)[26] proposed by one of the Settling Parties or Non-Opposing Parties after the Effective Date shall, as between them, be subject to the public interest application of the just and reasonable standard of review set forth in *United Gas Pipe Line Co. v. Mobile Gas Serv. Corp*., 350 U.S. 332 (1956) and *Federal Power Commission v. Sierra Pacific Power Co*., 350 U.S. 348 (1956), as clarified in *Morgan Stanley Capital Group, Inc. v. Public Util. Dist. No. 1 of Snohomish County, Washington*, 554 U.S. 527 (2008) and refined in *NRG Power Mktg. v. Maine Pub. Utils. Comm'n*, 558 U.S. 165 (2010).[27] The standard of review for any modifications requested by any party other than a Settling Party, Non-Opposing Party, or initiated by the Commission acting *sua sponte* shall be the most stringent standard permissible under applicable law.[28]

14. The Settlement further provides that upon the Commission's approval of the Settlement and the satisfaction of all conditions to its effectiveness, all remaining issues in all sub-dockets of Docket No. EL05-121, including any issues raised in a request for rehearing or a petition for judicial review, shall be fully and finally resolved on the basis of the Settlement and no Settling Party or Non-Opposing Party shall retain any right to pursue any such issue.

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[26] Section 2.2(e) of the Settlement implements the Adjustments to the Transmission Enhancement Charge Adjustments.

[27] Settlement, Section 4.2.

[28] *Id*.

III. Comments

15. Comments supporting the Settlement were filed by PJM and the PJM Transmission Owners (PJM Parties),[29] Michigan Commission, Indiana Commission, Pennsylvania Commission, and Commission Trial Staff (together with PJM Parties, Supporting Parties).[30] The Illinois Municipal Electric Agency (IMEA) submitted comments not opposing the Settlement, but requesting the addition of clarifying language.

16. Linden VFT, LLC (Linden VFT) filed comments opposing the Settlement.[31] Joint comments opposing the Settlement were filed by Neptune Regional Transmission System, LLC (Neptune) and Long Island Power Authority (LIPA),[32]and Hudson Transmission Partners, LLC (Hudson) and New York Power Authority (NYPA).[33] The Retail Energy Supply Association (RESA) filed an out-of-time motion to intervene and comments requesting a modification to the Settlement.[34]

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[29] PJM and the PJM Transmission Owners included declarations from Paul F. McGlynn (McGlynn Declaration) and Raymond L. Gifford (Gifford Declaration), and exhibits supporting the PJM Transmission Owners proposed hybrid cost allocation methodology for new high voltage transmission facilities planned and approved by the PJM Board on or after February 1, 2013 in PJM's Order No. 1000 compliance proceedings.

[30] The PJM Transmission Owners indicate that their comments are supported by the Michigan Commission, Indiana Commission, and Pennsylvania Commission.

[31] Linden VFT included an affidavit of John J. Marczewski (Marczewski Affidavit).

[32] Neptune and LIPA included an affidavit of Jeffery T. Wood (Wood Affidavit).

[33] Hudson and NYPA also included the Wood Affidavit.

[34] The Chief Judge denied the RESA motion to intervene (limited to denying intervention). *See PJM Interconnection, L.L.C.*, 156 FERC ¶ 63,012 (2016). The Motions Commissioner rejected a motion for interlocutory appeal. We address the RESA comments in this order.

17. Commission Trial Staff, PJM Transmission Owners,[35] IMEA, and Linden VFT filed reply comments.[36] Neptune, Hudson, NYPA, and LIPA (Joint Opposing Parties) filed joint reply comments.

18. Linden VFT and the Joint Opposing Parties filed answers to the PJM Transmission Owners reply comments,[37] and the PJM Transmission Owners filed a response.[38] Linden VFT filed a supplemental answer.

IV. Discussion

A. Initial Comments

1. Comments Supporting Settlement

19. The PJM Parties state that the Commission should approve the Settlement because it satisfies the Commission's *Trailblazer* standard for approval of contested settlements.[39] Specifically, they argue that the Settlement meets the standard set out under the second approach set forth in *Trailblazer* because the Settlement package as a whole presents a just and reasonable result.[40] The PJM Parties contend that the Settlement implements a cost allocation method that is substantially the same as the method that the Commission has already found to be a just and reasonable method of allocating the costs of similar

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[35] The PJM Transmission Owners included the declarations of Scott W. Gass (Gass Declaration) and Michael M. Schnitzer (Schnitzer Declaration).

[36] With its reply comments, Linden VFT included an affidavit of John J. Marczewski (Marczewski Reply Affidavit).

[37] Linden VFT included an affidavit of John J. Marczewski (Marczewski Answer Affidavit). Linden VFT and the Joint Parties also filed a motion to strike both the McGlynn Declaration and Gifford Declaration. *See PJM Interconnection, L.L.C.*, 156 FERC ¶ 63,025 (denying motions to strike and granting leave to answer), 156 FERC ¶ 63,049 (2016) (denying reconsideration and granting clarification).

[38] *See PJM Interconnection, L.L.C.*, 156 FERC ¶ 63,022 (2016) (granting motions to answer).

[39] PJM Parties Comments at 5. *See Trailblazer Pipeline Co.*, 85 FERC ¶ 61,345 (1998), *order on reh'g*, 87 FERC ¶ 61,110, *reh'g denied*, 88 FERC ¶ 61,168 (1999) (*Trailblazer II*).

[40] *Id.* at 18 (citing *Trailblazer II at 9*).

transmission projects in PJM, and the likely result of litigation would not differ materially from the Settlement's proposed resolution.[41] The PJM Parties also contend that the Commission could approve the Settlement under the first approach set forth in *Trailblazer* by addressing the contesting parties' contentions on the merits because the Settlement cost allocation method is just and reasonable and supported by Commission policy and precedent.[42]

20. The Supporting Parties provide the McGlynn Declaration to support the assertion that the Settlement presents a just and reasonable result. For the going-forward period, McGlynn states that the Settlement applies the cost allocation method that the Commission accepted in PJM's Order No. 1000 compliance proceedings (hybrid cost allocation method). For the historical period, McGlynn contends that the allocation of credits and payments under the negotiated provisions of the Settlement is substantially similar to what the cost allocation would have been had it been developed based on the hybrid cost allocation method.[43] In support, McGlynn states that there is only an 11.9 percent difference between the total amount of adjustments to the credits and payments under the negotiated provisions of the Settlement and what PJM staff estimated the total amount of adjustments to the credits and payments would have been under the Settlement going-forward period method. McGlynn also states that, on a zonal load and Merchant Transmission Facility basis, the credits and payments using the negotiated amounts vary from what the credits and payments would have been under the PJM staff estimated going-forward period method in a range of only 7.5 to 13.5 percent. Therefore, McGlynn contends that the adjustments to the credits or payments under the Settlement negotiated provisions are substantially similar to what would have been credited or paid if the Settlement going-forward period method was used to allocate the costs recovered between 2007 and January 1, 2016.[44]

21. The Michigan Commission contends that the Settlement presents a fair resolution to the allocation issues before the Commission and produces just and reasonable rates. The Pennsylvania Commission contends that the Settlement precludes the possibility of further lengthy and expensive litigation, and resolves the concerns raised by the Court by implicitly adopting a cost allocation method that the Commission has previously

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[41] PJM Parties Comments at 19.

[42] PJM Parties Comments at 32.

[43] McGlynn Declaration at 6-9. The 50 percent of the cost responsibility assignments not assigned on a load-ratio basis is based on the solution-based DFAX method, using a year 2019 power flow model.

[44] McGlynn Declaration at 10.

approved as reasonable. The Indiana Commission requests that the Commission approve the Settlement as embodying a definitive resolution that will foreclose the possibility of further litigation and provide certainty to all interested parties.

22. Commission Trial Staff supports approval of the Settlement under either the first or second approach identified by *Trailblazer*. Commission Trial Staff contends that the Settlement resolves all issues set for hearing in a manner that is either supported or unopposed by a majority of PJM Transmission Owners and all of the affected state commissions, and ensures funding of the necessary transmission investments.

23. While not opposing the Settlement, IMEA requests clarifying language to ensure that the revenues from Transmission Enhancement Charge Adjustments identified in the Settlement are properly refunded by the transmission owners who receive them.

24. RESA does not contest the amounts to be exchanged under the Settlement. However, RESA objects to the implementation of the Settlement effective January 1, 2016. RESA contends that the Settlement should be effective and the rates collected effective the later of the date the Commission approves the Settlement or January 1, 2017.

2. Comments Opposing Settlement

25. Parties opposing the Settlement contend that the Commission should reject the Settlement because it fails to establish a just and reasonable cost allocation method that is supported by substantial evidence.[45] Parties opposing the Settlement further contend that the Settlement fails to meet the Court's requirement for a quantitative assessment of the costs and benefits of the new transmission facilities. Instead, the parties opposing the Settlement contend that the Settlement imposes significant additional costs on the Merchant Transmission Facilities without any record evidence of a cost-benefit analysis or showing that the benefits of the new transmission facilities are proportional to the increased costs.[46]

26. Parties opposing the Settlement contend that there are genuine issues of material fact in dispute related to the identification of the benefits and beneficiaries that must be answered with substantial evidence before the Commission can determine a cost allocation method that assigns costs in a manner that satisfies the Court's remand. The

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[45] Hudson and NYPA Comments at 20; Neptune and LIPA Comments at 19.

[46] The Wood Affidavit details the cost increases to Neptune and Hudson under the Settlement as compared to the existing cost responsibility assignments made pursuant to the 100 percent load-ratio share method.

parties opposing the Settlement argue that the Settlement relies on a cost allocation method for the Covered Transmission Enhancements that was accepted by the Commission to apply prospectively, which is not comparable to the fact-based scenario now before the Commission.

27. Parties opposing the Settlement also contend that the Settlement does not satisfy any of the approaches identified by *Trailblazer* for approving contested settlements, and that the Settlement infringes on their right to obtain a ruling on the merits. In the alternative, the parties opposing the Settlement state that they would not object to the Commission approving the Settlement subject to a ruling that the Settling Parties cannot recover any additional costs and charges or financial obligations imposed on the parties opposing the Settlement by the Settlement.

28. Linden VFT contends that the Settlement requires it to be responsible for significantly increased costs without its consent and without providing any quantitative evidence or estimates showing that the increased allocations reflect benefits that it receives.[47] Linden VFT argues that the use of the solution-based DFAX method as an underlying rationale for the going-forward cost allocation method assigns it costs far in excess of benefits it accrues. Linden VFT further argues that the costs for the historical period are merely re-assigned on a negotiated basis, without even the flow-based rationale supporting identification of benefits. Linden VFT states that it made its concerns known during negotiations, but was excluded from meaningful settlement discussions, and has no knowledge of how the bargain was struck.[48]

29. Linden VFT contends that, under traditional cost-benefit analysis it does not receive any specific benefits from the Covered Transmission Enhancements, and that the Settlement was negotiated by the Settling Parties in their own interests. Linden VFT argues that the solution-based DFAX method does not accurately or commensurately

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[47] The Marczewski Affidavit details the cost responsibility assignment increases for Linden VFT as compared to the existing cost responsibility assignments made pursuant to the 100 percent load-ratio share cost allocation method. According to Marczewski, for the historical period, Linden VFT will be required to pay on average $59,000 per month over the ten-year period; its going-forward period costs will increase by 49 percent; and costs for the Cancelled Projects will approximately double. Marczewski Affidavit at 6.

[48] Linden VFT notes that the confidentiality requirements of the Commission Rules of Practice and Procedures preclude discussion of the negotiations. 18 C.F.R. § 385.601, *et seq*. (2017).

match costs and benefits as closely as possible, citing various deficiencies and modeling conventions related to the method's implementation.[49]

B. Reply Comments

30. The PJM Transmission Owners contend that the cost allocation method upon which the Settlement is founded is a just and reasonable approach for allocating the costs of high-voltage regional reliability projects and appropriately measures the benefits of these transmission projects for customers in the region. The PJM Transmission Owners state that the Commission approved the solution-based DFAX method component of the hybrid cost allocation method as a just and reasonable method of identifying the specific benefits and beneficiaries of such projects, and that the method evaluates the relative use of a facility by individual entities, including withdrawals by Merchant Transmission Facilities. The PJM Transmission Owners contend that this method can be applied to support the finding in this proceeding that the Settlement results in a just and reasonable cost allocation, and that the Merchant Transmission Facility parties' arguments lack merit.

31. In support, the PJM Transmission Owners reiterate that the Transmission Enhancement Charge Adjustments result in a cost allocation that is substantially similar to that which would have resulted if the hybrid cost allocation method had been in place since 2007. The PJM Transmission Owners further note that, because a significant portion of the costs of the Covered Transmission Enhancements remains unrecovered, over the life of the facilities covered by the Settlement, there will be very little difference between the cost allocations made pursuant to the Settlement and the cost allocations that would have been made pursuant to the hybrid cost allocation method.

32. The PJM Transmission Owners, citing the Gass Declaration, state that the increased costs to the Merchant Transmission Facility parties under the Settlement are primarily driven by their use of the Susquehanna-Roseland transmission facility, as well as their proportionate use of the other Covered Transmission Enhancements.[50] Therefore, the PJM Transmission Owners contend that the Merchant Transmission Facilities benefit from their use of the Covered Transmission Facilities to obtain deliveries from the PJM system in proportion to the costs assigned to them.

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[49] The Marczewski Affidavit details Linden VFT's concerns with the solution-based DFAX method provisions and implementation. Marczewski Affidavit at 8-16.

[50] PJM Transmission Owner Reply Comments at 16 (citing Gass Declaration at 14-16, Schnitzer Declaration at 4).

33. The PJM Transmission Owners support use of the violation-based DFAX method to allocate 50 percent of the costs of the Cancelled Projects because there will be no flow over the facilities to allow for use of the solution-based DFAX method. The PJM Transmission Owners note that, while in Opinion No. 494 the Commission rejected a violation-based DFAX method as the sole method for allocating the costs of transmission facilities operating at 500 kV and above, the Settlement employs a hybrid cost allocation method that combines an allocation based on the violation-based DFAX method with an allocation based on load-ratio share.

34. With respect to IMEA, the PJM Transmission Owners answer that the premise of IMEA's concern is incorrect, and that credits or payments pursuant to the Transmission Enhancement Charge Adjustments provisions are handled by the normal functioning of the PJM Tariff and billing processes. The PJM Transmission Owners contend that no modification to the Settlement is necessary. Commission Trial Staff further contends that modification to the Settlement to address IMEA's concerns is not necessary because Transmission Enhancement Charge Adjustments apply only to Responsible Customers, and because transmission owners only receive credits or make payments as Responsible Customers, they would not have revenues to credit.

35. In reply comments, Linden VFT contends that the inclusion by the Supporting Parties (PJM and the PJM Transmission Owners) of the McGlynn Declaration and Gifford Declaration is an attempt to create a record, using self-serving and conclusory statements that provide no evidentiary support. Linden VFT argues that the McGlynn Declaration's conclusions that the cost allocations in the Settlement are substantially similar to what the cost allocations would have been using the hybrid cost allocation method are not supported by data and cannot be tested. As a result, Linden VFT also contends that the differences between the credits and payments under the negotiated Transmission Enhancement Charge Adjustments and what would have been under the hybrid cost allocation method, on either an aggregate or zonal basis, is meaningless and not supported. Linden VFT further contends that, given the changing system topology, the use of year 2019 modeling as a basis of comparison would not produce accurate results.

36. The Joint Opposing Parties reiterate that the Settlement is not supported by substantial evidence, and that the Settling Parties have failed to provide any quantitative assessment of the benefits of the Covered Transmission Enhancements. Accordingly, the Joint Opposing Parties contend that the Settlement cannot be approved under either the first or second *Trailblazer* approaches. The Joint Opposing Parties further contend that the violation-based DFAX analysis, under which cost allocation is based on the cause of the project, is improper for the allocation of the costs of the Cancelled Projects under the Settlement. The Joint Opposing Parties contend that just because Merchant Transmission Facilities had been allocated some RTEP costs based on a violation-based DFAX analysis does not support that the Merchant Transmission Facilities should be subject to the

hybrid cost allocation method on which the Settlement is based, and that a quantitative assessment of the benefits is necessary.

37. IMEA replies that, while it understands the intention of the Settlement, specific provisions related to the crediting of Transmission Enhancement Charge Adjustments may be read ambiguously.

C. Determination

38. We approve the Settlement. Under Rule 602 of the Commission's Rules of Practice, the Commission may decide the merits of a contested settlement if the record contains substantial evidence upon which to base a reasoned decision or the Commission determines that there is no genuine issue of material fact.[51] In *Trailblazer*, the Commission identified four approaches it can use to approve contested settlements.[52] We find analysis under the second *Trailblazer* approach relevant to the circumstances of this proceeding. Under the second *Trailblazer* approach, the Commission may approve a contested settlement as a package if the overall result of the settlement is just and reasonable.[53] Under this approach, the Commission does not need to render a merits decision on whether each element of a settlement package is just and reasonable, so long as the overall package falls within a broad ambit of various rates which may be just and reasonable.[54] As the Commission explained, this approach may involve some analysis of the specific issues raised by a settlement in order to determine whether the result under the settlement is no worse for the contesting party than the likely result of continued litigation.[55] The Commission clarified that this approach "focuses on the end result of the

[51] 18 C.F.R. § 602 (2017).

[52] The four approaches laid out in Trailblazer are: (1) the Commission renders a binding merits decision on each contested issue, (2) the Commission approves the settlement based on a finding that the overall settlement as a package is just and reasonable, (3) the Commission determines that the benefits of the settlement outweigh the nature of the objections and the interests of the contesting party are too attenuated, and (4) the Commission approves the settlement as uncontested for the consenting parties, and severs the contesting parties to allow them to litigate the issues raised. *See Trailblazer II*, 85 FERC ¶ 61,345 at 62,342-62,345.

[53] *Trailblazer II,* 85 FERC ¶ 61,345 at 62,342-62,343.

[54] *Id*.

[55] *Trailblazer Pipeline Co*., 87 FERC ¶ 61,110, at 61439 (1999) (*Trailblazer III*).

overall settlement, and involves a balancing of the benefits of a settlement against the costs and potential effect of continued litigation."[56]

39. We find that the overall result of the Settlement is just and reasonable as applied to the contesting parties. In the Settlement, the Settling Parties applied the existing just and reasonable cost allocation method, subject to several simplifying assumptions and a black box adjustment.[57] For the going-forward period (the period after January 1, 2016), the Settlement Tariff references Schedule 12 of the PJM Tariff to apply the currently effective PJM Tariff without modification (i.e., 50 percent of the costs of Covered Transmission Enhancements will be allocated on a load-ratio share basis and 50 percent of the costs of Covered Transmission Enhancements will be allocated according to the solution-based DFAX method). We find that using the currently effective PJM Tariff to establish the cost responsibility assignments for the Covered Transmission Enhancements during the going-forward period is just and reasonable because the hybrid cost allocation method allocates the costs of these transmission facilities in a manner that is at least roughly commensurate with the benefits that they provide.[58]

40. For the historical period (the period prior to January 1, 2016), in which the Settlement provides credits or payments based on a negotiated schedule, the Settling Parties supported the allocations using a comparison to the currently effective PJM Tariff based on a proxy 2019 test year.[59] The Settling Parties then explained the negotiated changes in that allocation, such that the rates for the individual load Zones vary in a 7.5 – 13.5 percent range from what the cost responsibility assignments would have been had they been based solely on the application of the hybrid cost allocation method to the proxy 2019 test year. As explained in the McGlynn Declaration, the adjustments to the credits or payments for the historical period under the Settlement negotiated provisions are substantially similar to what would have been credited or paid if the Settlement going-forward period method was used to allocate the costs recovered between 2007 and January 1, 2016.[60] We find that these proposed cost responsibility assignments for the

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[56] *Trailblazer III*, 87 FERC at 61,110 at 61,439.

[57] As discussed above, these adjustments include changes to the cost allocations for the Cancelled Projects because the just and reasonable hybrid cost allocation method (which has a flow-based component) could not be applied.

[58] *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 at P 420.

[59] The parties state that they chose a single year for the comparison due to the difficulty of re-running the allocation for every intermediate year. McGlynn Declaration at 8.

[60] McGlynn Declaration at 10.

historical period are just and reasonable, as the negotiated adjustments to the cost responsibility assignments that would have resulted if the currently effective PJM Tariff were applied to the historical period result in an allocation of costs that is roughly commensurate with benefits. Specifically, we find persuasive Settling Parties' representation that the rates for individual load Zones vary by at most 13.5 percent from what they would have been had the currently effective PJM Tariff been used to establish the rates without any subsequent adjustments.[61]

41. We note that, under the Settlement, the contesting parties receive lower cost responsibility assignments for all Covered Transmission Enhancements (with the exception of the Susquehanna-Roseland project) than they received under the 100 percent load-ratio share method established in Opinion No. 464 and remanded by the Seventh Circuit Court. Specifically:

		$ Allocation Based on Load Ratio Share			**$ Allocation Based on Settlement Agreement**		
RTEP Project	**RTEP Cost Estimate (MM)**	**Hudson (0.2%)**	**Neptune (0.4%)**	**Linden (0.2%)**	**Hudson**	**Neptune**	**Linden**
Total Cost (All Projects except S-R	$2,700	$5.4	$10.8	$5.4	$3.5	$9.1	$4.3
PSEG S-R	$746	$1.5	$3.0	$1.5	$12.6	$11.3	$10
PPL S-R	$622	$1.2	$2.5	$1.2	$8.3	$10.2	$7.7
Total Cost	$4,068	$8	$16	$8	$24	$31	$23

PJM Transmission Owners Reply Comments, Exhibit No. PTO-5 (Gass Declaration) at P 15.

42. While the contesting parties do receive higher cost responsibility assignments for the Susquehanna-Roseland project than they received under the 100 percent load-ratio share method, we find that the allocation of costs to the contesting parties for the Susquehanna-Roseland project is just and reasonable and their resulting allocation is no worse for the contesting parties than continued litigation. As noted above, the Commission's approval of PJM's use of the 100 percent load-ratio share method for the projects at issue here has twice been remanded by the Court. Therefore, we believe that it

[61] *Id.*

is reasonable to assume that the existing just and reasonable PJM Tariff, which allocates 50 percent of the costs pursuant to the load-ratio share method and 50 percent of the costs pursuant to the solution-based DFAX method, and which has previously been approved by the Commission,[62] would be the method that would likely prevail in continued litigation.

43. First, we note that the Susquehanna-Roseland project went into service in 2015 and most of the cost of the project will be recovered under the going-forward period method (the period after January 1, 2016), using the currently effective PJM Tariff. Second, even for the historical period (which was subject to the black box adjustment of the Settlement), the cost responsibility assignments to the contesting parties are no higher than they would have been under the current just and reasonable rate. We find the data submitted by the Settling Parties in their declarations persuasive. The following chart shows the costs allocated to each contesting party for the Susquehanna-Roseland project under the hybrid cost allocation method versus the Settlement.[63] Specifically:

1		**Neptune**	**Hudson**	**Linden**
2	Total Cost Susquehanna-Roseland (MM) (PTO-5, at P15)	$1,368.00	$1,368.00	$1,368.00
3	DFAX (PTO-5, at P 18)	2.80%	2.90%	2.50%
4	Load-Ratio Share (PTO-5, at P 15)	0.40%	0.20%	0.20%
5	% Allocation under Settlement (PTO-5, at P 18)	1.60%	1.50%	1.30%
6	DFAX Allocation (line 2/2 * line3)	$19.15	$19.84	$17.10
7	Load-Ratio Share (line2/2 * line 4)	$2.74	$1.37	$1.37
8	Total Hybrid (total line 6 and 7)	$21.89	$21.20	$18.47
9	Allocation under Settlement (line 2* line 4)	$21.89	$20.52	$17.78

[62] *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 at P 412.

[63] This analysis is based on the data in the Gass Declaration. PJM Transmission Owners Reply Comments, Exhibit No. PTO-5 at P 15, 18.

As this chart shows, the three contesting parties are allocated the same or lower costs under the Settlement black box allocation (line 9) than they would have had under the currently effective PJM Tariff (line 8). Accordingly, where the Settlement approximates the cost that would have been assigned under the currently effective PJM Tariff, we find that the contesting parties would be in no worse position under the Settlement than if the current just and reasonable rate were applied.[64]

44. The contesting parties also question the use of the currently effective PJM Tariff in the Settlement, and maintain that the Commission should remand the Settlement to the Presiding Judge for a determination of which parties benefit from each of the transmission projects in question.[65] The Court remanded the cost allocation method for the transmission projects at issue in this Settlement, concluding that the Commission had not justified using a 100 percent load-ratio share cost allocation method for all 500 kV and above transmission projects. Subsequent to the Court's remand, the Commission adopted as just and reasonable the current hybrid cost allocation method as satisfying the cost allocation requirements of Order No. 1000, which just like the remand order, required costs to be allocated in a manner that is at least "roughly commensurate" with estimated benefits.[66] We therefore find that application of the currently effective PJM Tariff in the Settlement is just and reasonable. We recognize that, more recently, the concerns raised by the contesting parties, are pending in complaint proceedings,[67] regarding the justness and reasonableness of the hybrid cost allocation method for the 50 percent cost responsibility assigned pursuant to the solution-based DFAX method (at least in certain circumstances). To the extent that the contesting parties were to prevail in those separate proceedings and the determination affects the Covered Transmission Enhancements in the Settlement, Section 2.2(c)(ii) of the Settlement provides that "nothing in this Settlement shall prevent the Commission from adjusting the Current Recovery Charges, as necessary, if the Commission modifies the charges that the owner(s) of a Covered Transmission Enhancement are authorized to recover."[68] This

[64] *Id.*

[65] Significantly, other than alleging that they do not receive benefits commensurate with the costs allocated to them, the contesting parties do not present an alternative cost allocation mechanism.

[66] *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 at PP 414-416.

[67] *See, e.g. Linden VFT. LLC v. PJM Interconnection, L.L.C.*, 155 FERC ¶ 61,089 (2016), *reh'g pending*.

[68] Settlement, Section 2.2(c)(ii).

provision should protect the contesting parties if they succeed in their complaint proceedings.

45. The contesting parties also object to the allocation for the Cancelled Projects. The Settlement allocates 50 percent of the costs of these transmission projects pursuant to the violation-based DFAX method while the other 50 percent is assigned on a load-ratio share basis. The Settlement utilizes violation-based DFAX method because the solution-based DFAX method cannot be used given that the Cancelled Projects are not in service and thus do not support any power flows. The contesting parties claim that this allocation has not been shown to be just and reasonable as the Commission had previously raised concerns with assignment of cost responsibility pursuant to the violation-based DFAX method. While the Commission did question the use of the violation-based DFAX cost allocation method as the sole method for allocating the costs of transmission facilities operating at or above 500 kV (and any lower voltage facilities that are necessary to construct a particular new project at 500 kV and above),[69] we note that the Commission supported the identification of beneficiaries through the violation-based DFAX method for Lower Voltage Facilities at the time when the Covered Transmission Enhancements, including the Cancelled Projects,[70] were planned.[71] Thus, while the Commission has raised concerns about the use of violation-based DFAX method to allocate costs under particular circumstances, the use of the violation-based DFAX method, where there are no flows in which to assign a portion of the cost responsibility pursuant to the solution-based DFAX method,[72] is consistent with our prior orders. Here, the Settling Parties do not propose to use violation-based DFAX method as the sole cost allocation method for allocating the costs of the Cancelled Projects. Rather, the Settlement would apply a hybrid cost allocation method to the Cancelled Projects, under which 50 percent of the costs would be allocated on a load-ratio share basis and 50 percent of the costs would be

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[69] *See PJM Interconnection, L.L.C.*, 119 FERC ¶ 61,063, at P 82 (2007).

[70] The Cancelled Project were all either Regional Facilities or Necessary Lower Voltage Facilities.

[71] *Id.* (recognizing that it would be possible to allocate the cost of 500 kV and above facilities through a more discrete modeling methodology, such as the one set for hearing for facilities below 500 kV). *See PJM Interconnection, L.L.C.*, 124 FERC ¶ 61,112 (2008) (accepting settlement to assign cost responsibility for Lower Voltage Facilities based on the violation-based DFAX method).

[72] *See PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 at P 427 (recognizing that the solution-based DFAX method is an improvement over the violation-based DFAX method).

allocated based on the violation-based DFAX method.[73] We therefore find the use of the violation-based DFAX method for 50 percent of the costs of the Cancelled Projects reasonable where the relevant facilities are not in service and thus do not support any power flows.

46. RESA does not contest the amounts to be exchanged under the Settlement. However, RESA objects to the implementation of the Settlement effective January 1, 2016. RESA contends that it could not adjust its contracts retroactively and suggests that the Settlement should be effective January 1, 2017. We find January 1, 2016 date establishes a reasonable date for dividing the going-forward period from the historical period and that such a date is not an impermissibly retroactive date. As a result of the remand, the Commission would be able to make adjustments to correct the legal error.[74] The only issue here is whether the assignment of cost responsibility pursuant to the Settlement for the Covered Transmission Enhancements should be made as part of the going-forward or historical period. The parties were able to calculate the cost responsibility assignments for 2016 based on actual data rather than negotiated amounts based on the black box allocations of the Settlement as an approximation (based on the use of a 2019 proxy year) of the current just and reasonable rate applicable to the historical period. We therefore find the January 1, 2016 date for dividing the historical from the going-forward period under the Settlement reasonable.

47. IMEA, in its reply comments, notes that its concerns reflect only potential ambiguity regarding billing processes, and in response, the PJM Transmission Owners clarify that the normal PJM billing processes will be followed. Accordingly, we find IMEA's requested clarification unnecessary.

48. Because the Settlement appears to provide that the standard of review applicable to modifications to the Settlement proposed by third parties and the Commission acting *sua sponte* is to be "the most stringent standard permissible under applicable law," we clarify the framework that would apply if the Commission were required to determine the standard of review in a later challenge to the Settlement by a third party or by the Commission acting *sua sponte*. The *Mobile-Sierra* "public interest" presumption applies to an agreement only if the agreement has certain characteristics that justify the presumption. In ruling on whether the characteristics necessary to justify a *Mobile-Sierra* presumption are present, the Commission must determine whether the agreement at issue

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[73] *See PJM Interconnection, L.L.C.*, 138 FERC ¶ 61,230 (2012). And, in fact, the violation-based DFAX method was used for all lower voltage facilities.

[74] *Natural Gas Clearinghouse v. FERC*, 965 F.2d at 1073-74 (D.C. Cir. 1992) (holding the Commission has "broad discretion" in its remedial authority to "correct errors resulting from orders overturned by a reviewing court").

embodies either: (1) individualized rates, terms, or conditions that apply only to sophisticated parties who negotiated them freely at arm's length; or (2) rates, terms, or conditions that are generally applicable or that arose in circumstances that do not provide the assurance of justness and reasonableness associated with arm's-length negotiations. Unlike the latter, the former constitutes contract rates, terms, or conditions that necessarily qualify for a *Mobile-Sierra* presumption. In *New England Power Generators Association v. FERC*,[75] however, the D.C. Circuit determined that the Commission is legally authorized to impose a more rigorous application of the statutory "just and reasonable" standard of review on future changes to agreements that fall within the second category described above.

49. PJM is directed to make a compliance filing with revised tariff records in eTariff format,[76] within 30 days of this order, to reflect the Commission's action in this order.

<u>The Commission orders</u>:

(A) The Settlement is hereby approved, as discussed in the body of this order.

(B) PJM is directed to make a compliance filing, as discussed in the body of this order.

By the Commission. Chairman McIntyre and Commissioner Powelson are not participating.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

[75] *New England Power Generators Ass'n v. FERC*, 707 F.3d 364, 370-71 (D.C. Cir. 2013).

[76] *See Electronic Tariff Filings*, Order No. 714, FERC Stats. & Regs. ¶ 31,276 (2008).

Appendix A

Settling Parties

American Electric Power Service Corporation;[77]
Dayton Power and Light Company;
Delaware Municipal Electric Corporation, Inc.;
Duke Energy Business Services, LLC;[78]
Duquesne Light Company;
East Kentucky Power Cooperative, Inc.;
Exelon Corporation;[79]
FirstEnergy Utilities;[80]
PPL Electric Utilities Corporation;
UGI Utilities, Inc.;
PJM Interconnection, L.L.C.;
Public Service Commission of West Virginia;
Public Utilities Commission of Ohio;
Illinois Commerce Commission;
Indiana Utility Regulatory Commission (Indiana Commission);
Michigan Public Service Commission (Michigan Commission); and
Pennsylvania Public Utility Commission (Pennsylvania Commission).

Non-Opposing Parties

Delaware Public Service Commission; Maryland Public Service Commission; New Jersey Board of Public Utilities; Public Service Commission of the District of Columbia;

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[77] On behalf of its operating companies: Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company); Blue Ridge Power Agency, Inc.

[78] On behalf of Duke Energy Ohio, Inc. and Duke Energy Kentucky, Inc.

[79] For Commonwealth Edison Company and PECO Energy Company (with Baltimore Gas and Electric Company, Pepco Holdings, LLC, Potomac Electric Power Company, Delmarva Power & Light Company and Atlantic City Electric Company).

[80] On behalf of affiliates: American Transmission Systems, Incorporated, Cleveland Electric Illuminating Company, Jersey Central Power & Light Company, Metropolitan Edison Company, Ohio Edison Company, Monongahela Power Company, Pennsylvania Electric Company, Pennsylvania Power Company, Potomac Edison Company, Toledo Edison Company, and West Penn Power Company.

Consolidated Edison Company of New York, Inc. (Con Edison); Old Dominion Electric Cooperative; PSEG Energy Resources & Trade LLC; Public Power Association of New Jersey; Public Service Electric and Gas Company; Rockland Electric Company; Virginia Electric and Power Company, and the Virginia State Corporation Commission are listed in the Settlement as not opposing the Settlement. American Municipal Power, Inc. filed comments noting is neither supports nor opposes the Settlement, but should be considered as a non-opposing party.

Document Content(s)

Attachment 8

Attachment 9 (PSE&G FERC Formula Rate Filing)

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PSEG Services Corporation

January 9, 2018

VIA EFILING

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

Re: Public Service Electric and Gas Company
Docket No. ER09-1257-000
Informational Filing of 2018 Formula Rate Annual Update (Revision)

Dear Secretary Bose:

On behalf of Public Service Electric and Gas Company ("PSE&G"), attached please find a revised informational filing of PSE&G's 2018 Transmission Formula Rate Annual Update. On October 16, 2017, PSE&G filed with the Federal Energy Regulatory Commission in the above-captioned docket a 2018 Formula Rate Annual Update ("Annual Update"). The Annual Update filing was revised by an errata filing made by PSE&G on October 27, 2017.

This revised informational filing is being made to implement the recent reduction in the federal corporate income tax rate pursuant to the Tax Cuts and Jobs Act of 2017 ("TCJA"), *Public Law No. 115-97*. More specifically, in this informational filing PSE&G has updated the Federal Income Tax Rate value posted in Excel Row 206 of Appendix A to the Annual Update from 35% to 21%.

Also, enclosed please find an updated version of Exhibit 1 of the Annual Update, which includes a revised version of PSEG's 2018 Formula Rate Annual Update. Any other aspects of the TCJA that impact the 2018 annual revenue requirement will be incorporated in the true-up filing of the 2018 rate.

The October 27, 2017 Annual Update filing remains unchanged in all other respects. This revised informational filing reduces the 2018 annual revenue requirement forecasted in the Annual Update by $148,235,120.

The revised formula rate template in Exhibit 1 is also being provided to PJM Interconnection, L.L.C. for posting on its website. Consistent with the Commission

Staff's Guidance on Formula Rate Updates, PSE&G is submitting the updated formula rate template in Microsoft Excel format.

Thank you for your attention to this matter and please advise the undersigned of any questions.

Respectfully submitted,

Hesser G. McBride, Jr.

Hesser G. McBride, Jr.

Attachments

Public Service Electric and Gas Company

ATTACHMENT H-10A

Formula Rate -- Appendix A

Shaded cells are input cells

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

Public Service Electric and Gas Company

ATTACHMENT H-10A

Formula Rate -- Appendix A

Shaded cells are input cells

Line	Description	Notes	FERC Form 1 Page # or Instruction	12 Months Ended 12/31/2018
	Adjustment To Rate Base			
	Accumulated Deferred Income Taxes			
44	**ADIT net of FASB 106 and 109**	(Note Q)	Attachment 1	-2,502,792,692
	CWIP for Incentive Transmission Projects			
45	CWIP Balances for Current Rate Year	(Note B & H)	Attachment 6	102,222,422
	Abandoned Transmission Projects			
45a	Unamortized Abandoned Transmission Projects	(Note R)	Attachment 5	0
46	**Plant Held for Future Use**	(Note C & Q)	Attachment 5	18,085,194
	Prepayments			
47	Prepayments	(Note A & Q)	Attachment 5	0
	Materials and Supplies			
48	Undistributed Stores Expense	(Note Q)	Attachment 5	0
49	Wage & Salary Allocator		(Line 5)	16.0000%
50	Total Undistributed Stores Expense Allocated to Transmission		(Line 48 * Line 49)	0
51	Transmission Materials & Supplies	(Note N & Q))	Attachment 5	48,632,000
52	Total Materials & Supplies Allocated to Transmission		(Line 50 + Line 51)	48,632,000
	Cash Working Capital			
53	Operation & Maintenance Expense		(Line 80)	133,933,189
54	1/8th Rule		1/8	12.5%
55	Total Cash Working Capital Allocated to Transmission		(Line 53 * Line 54)	16,741,649
	Network Credits			
56	Outstanding Network Credits	(Note N & Q))	Attachment 5	0
57	**Total Adjustment to Rate Base**		**(Lines 44 + 45 + 45a + 46 + 47 + 52 + 55 - 56)**	**(2,317,111,428)**
58	**Rate Base**		(Line 43 + Line 57)	**7,917,997,903**
	Operations & Maintenance Expense			
	Transmission O&M			
59	Transmission O&M	(Note O)	Attachment 5	107,887,010
60	Plus Transmission Lease Payments	(Note O)	Attachment 5	0
61	**Transmission O&M**		(Lines 59 + 60)	**107,887,010**
	Allocated Administrative & General Expenses			
62	Total A&G	(Note O)	Attachment 5	172,512,000
63	Plus: Actual PBOP expense	(Note J)	Attachment 5	26,864,000
64	Less: Actual PBOP expense	(Note O)	Attachment 5	37,487,000
65	Less Property Insurance Account 924	(Note O)	Attachment 5	3,032,000
66	Less Regulatory Commission Exp Account 928	(Note E & O)	Attachment 5	10,400,000
67	Less General Advertising Exp Account 930.1	(Note O)	Attachment 5	2,125,000
68	Less EPRI Dues	(Note D & O)	Attachment 5	0
69	**Administrative & General Expenses**		Sum (Lines 62 to 63) - Sum (Lines 64 to 68)	146,332,000
70	Wage & Salary Allocator		(Line 5)	16.0000%
71	**Administrative & General Expenses Allocated to Transmission**		(Line 69 * Line 70)	**23,413,179**
	Directly Assigned A&G			
72	Regulatory Commission Exp Account 928	(Note G & O)	Attachment 5	835,000
73	General Advertising Exp Account 930.1	(Note K & O)	Attachment 5	0
74	Subtotal - Accounts 928 and 930.1 - Transmission Related		(Line 72 + Line 73)	835,000
75	Property Insurance Account 924		(Line 65)	3,032,000
76	General Advertising Exp Account 930.1	(Note F & O)	Attachment 5	0
77	Total Accounts 928 and 930.1 - General		(Line 75 + Line 76)	3,032,000
78	Net Plant Allocator		(Line 18)	59.3008%
79	**A&G Directly Assigned to Transmission**		(Line 77 * Line 78)	**1,798,000**
80	**Total Transmission O&M**		**(Lines 61 + 71 + 74 + 79)**	**133,933,189**

Public Service Electric and Gas Company

ATTACHMENT H-10A

Formula Rate -- Appendix A		Notes	FERC Form 1 Page # or Instruction	12 Months Ended 12/31/2018
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	266,279,924
81a	Amortization of Abandoned Plant Projects	(Note R)	Attachment 5	0
82	General Depreciation Expense Including Amortization of Limited Term Plant	(Note J & O)	Attachment 5	27,729,088
83	Less: Amount of General Depreciation Expense Associated with Acct. 397	(Note J & O)	Attachment 5	7,252,148
84	Balance of General Depreciation Expense		(Line 82 - Line 83)	20,476,940
85	Intangible Amortization	(Note A & O)	Attachment 5	11,136,699
86	Total		(Line 84 + Line 85)	31,613,639
87	Wage & Salary Allocator		(Line 5)	16.00%
88	General Depreciation & Intangible Amortization Allocated to Transmission		(Line 86 * Line 87)	5,058,195
89	General Depreciation Expense for Acct. 397 Directly Assigned to Transmission	(Note J & O)	Attachment 5	1,908,451
90	**General Depreciation and Intangible Amortization Functionalized to Transmission**		(Line 88 + Line 89)	**6,966,646**
91	**Total Transmission Depreciation & Amortization**		**(Lines 81 + 81a + 90)**	**273,246,570**
Taxes Other than Income Taxes				
92	Taxes Other than Income Taxes	(Note O)	Attachment 2	10,432,800
93	**Total Taxes Other than Income Taxes**		(Line 92)	**10,432,800**
Return \ Capitalization Calculations				
94	**Long Term Interest**		p117.62.c through 67.c	299,596,596
95	**Preferred Dividends**	enter positive	p118.29.d	0
	Common Stock			
96	Proprietary Capital	(Note P)	Attachment 5	8,201,697,087
97	Less Accumulated Other Comprehensive Income Account 219	(Note P)	Attachment 5	1,021,739
98	Less Preferred Stock		(Line 106)	0
99	Less Account 216.1	(Note P)	Attachment 5	3,331,169
100	**Common Stock**		(Line 96 - 97 - 98 - 99)	8,197,344,179
	Capitalization			
101	Long Term Debt	(Note P)	Attachment 5	7,362,278,245
102	Less Loss on Reacquired Debt	(Note P)	Attachment 5	63,934,374
103	Plus Gain on Reacquired Debt	(Note P)	Attachment 5	0
104	Less ADIT associated with Gain or Loss	(Note P)	Attachment 5	16,982,115
105	Total Long Term Debt		(Line 101 - 102 + 103 - 104)	7,281,361,756
106	Preferred Stock	(Note P)	Attachment 5	0
107	Common Stock		(Line 100)	8,197,344,179
108	**Total Capitalization**		(Sum Lines 105 to 107)	15,478,705,935
109	Debt % — Total Long Term Debt		(Line 105 / Line 108)	47.04%
110	Preferred % — Preferred Stock		(Line 106 / Line 108)	0.00%
111	Common % — Common Stock		(Line 107 / Line 108)	52.96%
112	Debt Cost — Total Long Term Debt		(Line 94 / Line 105)	0.0411
113	Preferred Cost — Preferred Stock		(Line 95 / Line 106)	0.0000
114	Common Cost — Common Stock	(Note J)	Fixed	0.1168
115	Weighted Cost of Debt — Total Long Term Debt (WCLTD)		(Line 109 * Line 112)	0.0194
116	Weighted Cost of Preferred — Preferred Stock		(Line 110 * Line 113)	0.0000
117	Weighted Cost of Common — Common Stock		(Line 111 * Line 114)	0.0619
118	**Rate of Return on Rate Base (ROR)**		(Sum Lines 115 to 117)	**0.0812**
119	**Investment Return = Rate Base * Rate of Return**		**(Line 58 * Line 118)**	**643,031,192**

Public Service Electric and Gas Company

ATTACHMENT H-10A

	Formula Rate -- Appendix A		**Notes**	**FERC Form 1 Page # or Instruction**	**12 Months Ended 12/31/2018**
	Shaded cells are input cells				
	Composite Income Taxes				
	Income Tax Rates				
120	FIT=Federal Income Tax Rate		(Note I)		21.00%
121	SIT=State Income Tax Rate or Composite				9.00%
122	p	(percent of federal income tax deductible for state purposes)		Per State Tax Code	0.00%
123	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			28.11%
124	T / (1-T)				39.10%
	ITC Adjustment				
125	Amortized Investment Tax Credit	enter negative	(Note O)	Attachment 5	-561,000
126	1/(1-T)			1 / (1 - Line 123)	139.10%
127	Net Plant Allocation Factor			(Line 18)	59.30%
128	**ITC Adjustment Allocated to Transmission**			(Line 125 * Line 126 * Line 127)	**-462,759**
129	**Income Tax Component =**	(T/1-T) * Investment Return * (1-(WCLTD/ROR)) =		[Line 124 * Line 119 * (1- (Line 115 / Line 118))]	**191,508,964**
130	**Total Income Taxes**			**(Line 128 + Line 129)**	**191,046,205**
	Revenue Requirement				
	Summary				
131	Net Property, Plant & Equipment			(Line 43)	10,235,109,330
132	Total Adjustment to Rate Base			(Line 57)	-2,317,111,428
133	**Rate Base**			(Line 58)	**7,917,997,903**
134	Total Transmission O&M			(Line 80)	133,933,189
135	Total Transmission Depreciation & Amortization			(Line 91)	273,246,570
136	Taxes Other than Income			(Line 93)	10,432,800
137	Investment Return			(Line 119)	643,031,192
138	Income Taxes			(Line 130)	191,046,205
139	**Gross Revenue Requirement**			**(Sum Lines 134 to 138)**	**1,251,689,957**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
140	Transmission Plant In Service			(Line 19)	11,162,840,225
141	Excluded Transmission Facilities		(Note B & M)	Attachment 5	0
142	Included Transmission Facilities			(Line 140 - Line 141)	11,162,840,225
143	Inclusion Ratio			(Line 142 / Line 140)	100.00%
144	Gross Revenue Requirement			(Line 139)	1,251,689,957
145	**Adjusted Gross Revenue Requirement**			(Line 143 * Line 144)	**1,251,689,957**
	Revenue Credits & Interest on Network Credits				
146	**Revenue Credits**		(Note O)	Attachment 3	21,251,492
147	**Interest on Network Credits**		(Note N & O)	Attachment 5	0
148	**Net Revenue Requirement**			**(Line 145 - Line 146 + Line 147)**	**1,230,438,464**
	Net Plant Carrying Charge				
149	Gross Revenue Requirement			(Line 144)	**1,251,689,957**
150	Net Transmission Plant, CWIP and Abandoned Plant			(Line 19 - Line 32 + Line 45 + Line 45a)	**10,296,207,758**
151	Net Plant Carrying Charge			(Line 149 / Line 150)	**12.1568%**
152	Net Plant Carrying Charge without Depreciation			(Line 149 - Line 81) / Line 150	**9.5706%**
153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes			(Line 149 - Line 81 - Line 119 - Line 130) / Line 15(	**1.4698%**
	Net Plant Carrying Charge Calculation per 100 Basis Point increase in ROE				
154	Gross Revenue Requirement Less Return and Taxes			(Line 144 - Line 137 - Line 138)	**417,612,559**
155	Increased Return and Taxes			Attachment 4	**892,406,517**
156	Net Revenue Requirement per 100 Basis Point increase in ROE			(Line 154 + Line 155)	**1,310,019,076**
157	Net Transmission Plant, CWIP and Abandoned Plant			(Line 19 - Line 32 + Line 45 + Line 45a)	**10,296,207,758**
158	Net Plant Carrying Charge per 100 Basis Point increase in ROE			(Line 156 / Line 157)	**12.7233%**
159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation			(Line 156 - Line 81) / Line 157	**10.1371%**
160	**Net Revenue Requirement**			(Line 148)	**1,230,438,464**
161	True-up amount			Attachment 6	**12,591,534**
162	Plus any increased ROE calculated on Attachment 7 other than PJM Sch. 12 projects not paid by other PJM transmission ;			Attachment 7	**5,789,354**
163	Facility Credits under Section 30.9 of the PJM OATT			Attachment 5	**0**
164	**Net Zonal Revenue Requirement**			(Line 160 + 161 + 162 + 163)	**1,248,819,352**
	Network Zonal Service Rate				
165	1 CP Peak		(Note L)	Attachment 5	**9,566.9**
166	Rate ($/MW-Year)			(Line 164 / 165)	**130,535.22**
167	**Network Service Rate ($/MW/Year)**			**(Line 166)**	**130,535.22**

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

Shaded cells are input cells

Notes

A Electric portion only

B Calculated using 13-month average balances

C Includes Transmission portion only. At each annual informational filing, Company will identify for each parcel of land an intended use within a 15 year period

D Includes all EPRI Annual Membership Dues

E Includes all Regulatory Commission Expenses

F Includes Safety related advertising included in Account 930.1

G Includes Regulatory Commission Expenses directly related to transmission service, RTO filings, or transmission siting itemized in Form 1 at 351.h

H CWIP can only be included if authorized by the Commission

I The currently effective income tax rate where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = the percentage of federal income tax deductible for state income taxes

J ROE will be supported in the original filing and no change in ROE will be made absent a filing at FERC
PBOP expense shall be based upon the Company's Actual Annual PBOP Expense until changed by a filing at FERC
The actual Annual PBOP Expense to be included in the Formula Rate Annual Update that is required to be filed on or before October 15 of each year shall be based upon the Actual Annual PBOP Expense as charged to FERC Account 926 on behalf of electric employees for PBOP and as included by the Company in its most recent True-up Adjustment filing.
PSEG will provide, in connection with each annual True-Up Adjustment filing a confidential copy of relevant pages from annual actuarial valuation report supporting the derivation of the Actual Annual PBOP Expense as charged to FERC Account 926 on behalf of electric employees
Depreciation rates shown in Attachment 8 are fixed until changed as the result of a filing at FERC
If book depreciation rates are different than the Attachment 8 rates, PSE&G will provide workpapers at the annual update to reconcile formula depreciation expense and depreciation accruals to FERC Form 1 amounts

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

L As provided for in Section 34.1 of the PJM OATT; the PJM established billing determinants will not be revised or updated in the annual rate reconciliations

M Amount of transmission plant excluded from rates per Attachment 5

N Outstanding Network Credits is the balance of Network Facilities Upgrades Credits due Transmission Customers who have made lump-sum payments towards the construction of Network Transmission Facilities consistent with Paragraph 657 of Order 2003-A
Interest on the Network Credits as booked each year is added to the revenue requirement to make the Transmission Owner whole on Line "&A248&"."

O Expenses reflect full year plan

P The projected capital structure shall reflect the capital structure from the FERC Form 1 data. For all other formula rate calculations, the projected capital structure and actual capital structure shall reflect the capital structure from the most recent FERC Form 1 data available.
Calculated using the average of the prior year and current year balances

Q Calculated using beginning and year end projected balances

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

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

	Only Transmission Related	Plant Related	Labor Related	Total ADIT	
ADIT- 282	(2,597,832,425)	0	(36,267,968)		From Acct. 282 total, below
ADIT-283	0	(14,192,780)	0		From Acct. 283 total, below
ADIT-190	0	0	12,168,870		From Acct. 190 total, below
Subtotal	(2,597,832,425)	(14,192,780)	(24,099,098)		
Wages & Salary Allocator			16.0000%		
Net Plant Allocator		59.3008%			
End of Year ADIT	(2,597,832,425)	(8,416,431)	(3,855,865)	**(2,610,104,721)**	
End of Previous Year ADIT (from Sheet 1A-ADIT (3))	(2,383,691,531)	(8,797,786)	(2,991,346)	**(2,395,480,663)**	
Average Beginning and End of Year ADIT	(2,490,761,978)	(8,607,109)	(3,423,606)	**(2,502,792,692)**	Appendix A, Line 44

Note: ADIT associated with Gain or Loss on Reacquired Debt is included in Column A here and included in Cost of Debt on Appendix A, Line 108
(14,192,780) < From Acct 283, below

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

A	B	C	D	E	F	G
ADIT-190	*Total*	*Gas, Prod Or Other Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
ADIT - Contribution In Aid of Construction	33,971,473	33,971,473	-	-	-	Represents the estimated IRC 118 amount (CIAC)
Vacation Pay	631,750	-	-	-	631,750	Vacation pay earned and expensed for books, tax deduction when paid - employees in all functions
OPEB	180,153,245	-	-	-	180,153,245	FASB 106 - Post Retirement Obligation, labor related.
Deferred Dividend Equivalents	3,105,261	-	-	-	3,105,261	Book accrual of dividends on employee stock options affecting all functions
Deferred Compensation	395,586	-	-	-	395,586	Book estimate accrued and expensed, tax deduction when paid - employees in all functions
ADIT - Unallowable PIP Accrual	-	-	-	-	-	Book estimate accrued and expensed, tax deduction when paid - employees in all functions
Bankruptcies $ Acfc	189,384	189,384	-	-	-	Book estimate accrued and expensed, tax deduction when paid - Generation Related
Federal Taxes Deferred	5,554,630	-	-	5,554,630	-	FASB 109 - deferred tax asset primarily associated with items previously flowed through due to regulation
Miscellaneous	(1,631,739)	(9,668,012)	-	-	8,036,273	-
Subtotal - p234	**222,369,590**	**24,492,845**		**5,554,630**	**192,322,115**	
Less FASB 109 Above if not separately removed	5,554,630			5,554,630		
Less FASB 106 Above if not separately removed	180,153,245				180,153,245	
Total	**36,661,715**	**24,492,845**		**0**	**12,168,870**	

Instructions for Account 190:

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

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

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

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

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

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

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

A	B	C	D	E	F	G
ADIT- 282	***Total***	***Gas, Prod Or Other Related***	***Only Transmission Related***	***Plant Related***	***Labor Related***	***Justification***
Depreciation - Liberalized Depreciation (Federal)	(4,004,267,788)	(1,595,753,854)	(2,375,774,816)	-	(32,739,118)	For federal - Column D represents the direct assignment of prorated ADIT associated with Transmission assets,, column F represents ADIT associated with the allocation of common plant and column C represents estimated electrical distribution ADIT
Depreciation - Liberalized Depreciation (State)	(412,147,501)	(186,561,043)	(222,057,608)	-	(3,528,850)	For state - Column D represents the direct assignment of prorated ADIT associated with Transmission assets,, column F represents ADIT associated with the allocation of common plant and column C represents estimated electrical distribution ADIT
Accounting for Income Taxes	(317,127,352)	(267,274,356)	(49,588,141)	-	(264,855)	FASB 109 - deferred tax liability primarily associated with plant related items previously flowed through due to regulation
Subtotal - p275	**(4,733,542,641)**	**(2,049,589,252)**	**(2,647,420,566)**	**0**	**(36,532,823)**	
Less FASB 109 Above if not separately removed	(49,852,996)		(49,588,141)	0	(264,855)	
Less FASB 106 Above if not separately removed						
Total	**(4,683,689,644)**	**(2,049,589,252)**	**(2,597,832,425)**	**0**	**(36,267,968)**	

Instructions for Account 282:

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

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

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

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

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

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

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

Instructions for Account 283:

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

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

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

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

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

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

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

Note: ADIT associated with Gain or Loss on Reacquired Debt is included in Column A here and included in Cost of Debt on Appendix A, Line 108
(14,835,865) < From Acct 283, below

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

A *ADIT-190*	B *Total*	C *Gas, Prod Or Other Related*	D *Only Transmission Related*	E *Plant Related*	F *Labor Related*	G *Justification*
ADIT - Contribution In Aid of Construction	37,748,575	37,748,575	-	-	-	Represents the estimated IRC 118 amount (CIAC)
Vacation Pay	631,750	-	-	-	631,750	Vacation pay earned and expensed for books, tax deduction when paid - employees in all functions
OPEB	179,879,275	-	-	-	179,879,275	FASB 106 - Post Retirement Obligation, labor related.
Deferred Dividend Equivalents	3,105,261	-	-	-	3,105,261	Book accrual of dividends on employee stock options affecting all functions
Deferred Compensation	395,586	-	-	-	395,586	Book estimate accrued and expensed, tax deduction when paid - employees in all functions
ADIT - Unallowable PIP Accrual	-	-	-	-	-	Book estimate accrued and expensed, tax deduction when paid - employees in all functions
Bankruptcies $ Acfc	189,384	189,384	-	-	-	Book estimate accrued and expensed, tax deduction when paid - Generation Related
Federal Taxes Deferred	5,554,630	-	-	5,554,630	-	FASB 109 - deferred tax asset primarily associated with items previously flowed through due to regulation
Miscellaneous	(1,631,739)	(9,668,012)	-	-	8,036,273	0
Subtotal - p234	**225,872,721**	**28,269,947**		**5,554,630**	**192,048,144**	
Less FASB 109 Above if not separately removed	5,554,630			5,554,630		
Less FASB 106 Above if not separately removed	179,879,275				179,879,275	
Total	**40,438,817**	**28,269,947**		**0**	**12,168,870**	

Instructions for Account 190:

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

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

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

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

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

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

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

A	B	C	D	E	F	G
ADIT- 282	*Total*	*Gas, Prod Or Other Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
Depreciation - Liberalized Depreciation (Federal)	(3,710,135,516)	(1,484,577,833)	(2,198,221,800)	-	(27,335,883)	For Federal - Column D represents the direct assignment of ADIT, unprorated, associated with Transmission assets, column F represents ADIT associated with the allocation of common plant and column C represents estimated electrical distribution ADIT
Depreciation - Liberalized Depreciation (State)	(360,901,871)	(171,903,290)	(185,469,731)	-	(3,528,850)	For State - Column D represents the direct assignment of ADIT, unprorated, associated with Transmission assets, column F represents ADIT associated with the allocation of common plant and column C represents estimated electrical distribution ADIT
Accounting for Income Taxes	(49,852,996)	-	(49,588,141)	-	(264,855)	FASB 109 - deferred tax liability primarily associated with plant related items previously flowed through due to regulation
Subtotal - p275	**(4,120,890,383)**	**(1,656,481,123)**	**(2,433,279,672)**	**0**	**(31,129,588)**	
Less FASB 109 Above if not separately removed	(49,852,996)		(49,588,141)	0	(264,855)	
Less FASB 106 Above if not separately removed						
Total	**(4,071,037,387)**	**(1,656,481,123)**	**(2,383,691,531)**	**0**	**(30,864,733)**	

Instructions for Account 282:

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

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

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

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

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

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

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

Instructions for Account 283:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C

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

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

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

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

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 2 - Taxes Other Than Income Worksheet - December 31, 2018

	Other Taxes	*Page 263 Col (i)*	*Allocator*	*Allocated Amount*	
	Plant Related				
1	Real Estate	21,308,000			Attachment #5
2	***Total Plant Related***	21,308,000	N/A	7,881,000	
	Labor Related		***Wages & Salary Allocator***		
3	FICA	14,264,750			
4	Federal Unemployment Tax	322,070			
5	New Jersey Unemployment Tax	687,790			
6	New Jersey Workforce Development	674,100			
7					
8	***Total Labor Related***	15,948,710	16.0000%	2,551,800	
	Other Included		***Net Plant Allocator***		
9					
10					
11					
12					
13	***Total Other Included***	0	59.3008%	0	
14	***Total Included (Lines 8 + 14 + 19)***	37,256,710		10,432,800	
	Currently Excluded				
15	Corporate Business Tax	0			
16	TEFA	0			
17	Use & Sales Tax	0			
18	Local Franchise Tax	0			
19	PA Corporate Income Tax	0			
20	Municipal Utility	0			
21	Public Utility Fund	0			
22	**Subtotal, Excluded**	0			
23	**Total, Included and Excluded (Line 20 + Line 28)**	37,256,710			
24	**Total Other Taxes from p114.14.g - Actual**	37,256,710			
25	Difference (Line 29 - Line 30)	-			

Criteria for Allocation:

A Other taxes that are incurred through ownership of plant including transmission plant will be allocated based on the Net Plant Allocator. If the taxes are 100% recovered at retail they shall not be included. Real Estate taxes are directly assigned to Transmission.

B Other taxes that are incurred through ownership of only general or intangible plant will be allocated based on the Wages and Salary Allocator. If the taxes are 100% recovered at retail they shall not be included.

C Other taxes that are assessed based on labor will be allocated based on the Wages and Salary Allocator.

D Other taxes except as provided for in A, B and C above, that are incurred and (1) are not fully recovered at retail or (2) are directly or indirectly related to transmission service will be allocated based on the Net Plant Allocator; provided, however, that overheads shall be treated as in footnote B above.

E Excludes prior period adjustments in the first year of the formula's operation and reconciliation for the first year.

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 3 - Revenue Credit Workpaper - December 31, 2018

	Accounts 450 & 451		
1	Late Payment Penalties Allocated to Transmission		0
	Account 454 - Rent from Electric Property		
2	Rent from Electric Property - Transmission Related (Note 2)		600,000
	Account 456 - Other Electric Revenues		
3	Transmission for Others		0
4	Schedule 1A		4,665,000
5	Net revenues associated with Network Integration Transmission Service (NITS) for which the load is not included in the divisor (difference between NITS credits from PJM and PJM NITS charges paid by Transmission Owner)		
6	Point to Point Service revenues for which the load is not included in the divisor received by Transmission Owner		6,650,000
7	Professional Services (Note 2)		45,000
8	Revenues from Directly Assigned Transmission Facility Charges (Note 1)		7,962,979
9	Rent or Attachment Fees associated with Transmission Facilities (Note 2)		4,845,371
10	Gross Revenue Credits	(Sum Lines 1-9)	24,768,349
11	Less line 18	- line 18	(3,516,857)
12	Total Revenue Credits	line 10 + line 11	21,251,492
13	Revenues associated with lines 2, 7, and 9 (Note 2)		5,490,371
14	Income Taxes associated with revenues in line 13		1,543,343
15	One half margin (line 13 - line 14)/2		1,973,514
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		1,973,514
18	Line 13 less line 17		3,516,857

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	892,406,517
B	100 Basis Point increase in ROE			1.00%

Return Calculation

			Appendix A Line or Source Reference	
1	**Rate Base**		(Line 43 + Line 57)	7,917,997,903
2	**Long Term Interest**		p117.62.c through 67.c	299,596,596
3	**Preferred Dividends**	enter positive	p118.29.d	0
	Common Stock			
4	Proprietary Capital		Attachment 5	8,201,697,087
5	Less Accumulated Other Comprehensive Income Account 219		p112.15.c	1,021,739
6	Less Preferred Stock		(Line 106)	0
7	Less Account 216.1		Attachment 5	3,331,169
8	Common Stock		(Line 96 - 97 - 98 - 99)	8,197,344,179
	Capitalization			
9	Long Term Debt		Attachment 5	7,362,278,245
10	Less Loss on Reacquired Debt		Attachment 5	63,934,374
11	Plus Gain on Reacquired Debt		Attachment 5	0
12	Less ADIT associated with Gain or Loss		Attachment 5	16,982,115
13	Total Long Term Debt		(Line 101 - 102 + 103 - 104)	7,281,361,756
14	Preferred Stock		Attachment 5	0
15	Common Stock		(Line 100)	8,197,344,179
16	Total Capitalization		(Sum Lines 105 to 107)	15,478,705,935
17	Debt %	Total Long Term Debt	(Line 105 / Line 108)	47.0%
18	Preferred %	Preferred Stock	(Line 106 / Line 108)	0.0%
19	Common %	Common Stock	(Line 107 / Line 108)	53.0%
20	Debt Cost	Total Long Term Debt	(Line 94 / Line 105)	0.0411
21	Preferred Cost	Preferred Stock	(Line 95 / Line 106)	0.0000
22	Common Cost	Common Stock	(Line 114 + 100 basis points)	0.1268
23	Weighted Cost of Debt	Total Long Term Debt (WCLTD)	(Line 109 * Line 112)	0.0194
24	Weighted Cost of Preferred	Preferred Stock	(Line 110 * Line 113)	0.0000
25	Weighted Cost of Common	Common Stock	(Line 111 * Line 114)	0.0672
26	**Rate of Return on Rate Base (ROR)**		**(Sum Lines 115 to 117)**	**0.0865**
27	**Investment Return = Rate Base * Rate of Return**		**(Line 58 * Line 118)**	**684,963,996**

Composite Income Taxes

	Income Tax Rates			
28	FIT=Federal Income Tax Rate			21.00%
29	SIT=State Income Tax Rate or Composite			9.00%
30	p = percent of federal income tax deductible for state purposes		Per State Tax Code	0.00%
31	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		28.11%
35	CIT = T / (1-T)			39.10%
36	1 / (1-T)			139.10%
	ITC Adjustment			
37	Amortized Investment Tax Credit	enter negative	Attachment 5	-561,000
38	1/(1-T)		1 / (1 - Line 123)	139%
39	Net Plant Allocation Factor		(Line 18)	59.3008%
40	**ITC Adjustment Allocated to Transmission**		(Line 125 * Line 126 * Line 127)	**-462,759**
41	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		207,905,280
42	**Total Income Taxes**			**207,442,521**

Public Service Electric and Gas Company

ATTACHMENT H-10A

Attachment 5 - Cost Support - December 31, 2018

Attachment 9

Electric / Non-electric Cost Support

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

Wages & Salary

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

Transmission / Non-transmission Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Beginning Year Balance	End of Year	Average
	Plant Held for Future Use (Including Land)	(Note C & Q)	p214.47.d	20,440,107	27,940,107	24,190,107
46	Transmission Only			17,076,194	19,094,194	18,085,194

Prepayments

Line #s	Descriptions	Notes	Page #'s & Instructions	Previous Year	Electric Beginning Year Balance	Electric End of Year Balance	Average Balance	Wage & Salary Allocator	To Line 47
	Prepayments								
47	Prepayments	(Note A & Q)	p111.57c	0	0	0	0	16.000%	-

Materials and Supplies

Line #s	Descriptions	Notes	Page #'s & Instructions	Beginning Year Balance	End of Year	Average
	Materials and Supplies					
48	Undistributed Stores Exp	(Note Q)	p227.16.b,c	0	0	0
51	Transmission Materials & Supplies	(Note N & Q))	p227.8.b,c	48,632,000	48,632,000	48,632,000

Outstanding Network Credits Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Beginning Year Balance	End of Year	Average
	Network Credits					
56	**Outstanding Network Credits**	(Note N & Q))	From PJM	0	0	0

O&M Expenses

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
59	Transmission O&M	(Note O)	p.321.112.b	107,887,010
60	Transmission Lease Payments		p321.96.b	-

Property Insurance Expenses

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
65	Property Insurance Account 924	(Note O)	p323.185b	3,032,000

Adjustments to A & G Expense

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

Regulatory Expense Related to Transmission Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year	Transmission Related
	Allocated General & Common Expenses				
66	Regulatory Commission Exp Account 928	(Note E & O)	p323.189b	10,400,000	-
	Directly Assigned A&G				
72	Regulatory Commission Exp Account 928	(Note G & O)	p351.11-13h	835,000	835,000

General & Common Expenses

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

Safety Related Advertising Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year	Safety Related	Non-safety Related
	Directly Assigned A&G					
73	General Advertising Exp Account 930.1	(Note K & O)	p323.191b	2,125,000	-	2,125,000

Education and Out Reach Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year	Education & Outreach	Other
	Directly Assigned A&G					
76	General Advertising Exp Account 930.1	(Note K & O)	p323.191b	2,125,000	-	2,125,000

Depreciation Expense

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

Direct Assignment of Transmission Real Estate Taxes

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year	Transmission Related	Non-Transmission
92	Real Estate Taxes - Directly Assigned to Transmission		p263.33i	21,308,000	7,881,000	13,427,000

PSE&G's real estate taxes detail is in an access database which contains a list of the towns PSE&G pays taxes to, which are billed on a quarterly basis for various parcels of property by major classification.
Every parcel is associated with a Lot & Block number. These Lot & Blocks are identified to a particular type of property and are labeled. This is the breakout of transmission real estate taxes from total electric.

Return \ Capitalization

Line #s	Descriptions	Notes	Page #'s & Instructions	2015 End of Year	2016 End of Year	Average
96	Proprietary Capital	(Note P)	p112.16.c,d	7,629,005,378	8,774,388,796	8,201,697,087
97	Accumulated Other Comprehensive Income Account 219	(Note P)	p112.15.c,d	1,227,004	816,474	1,021,739
99	Account 216.1	(Note P)	p119.53.c&d	3,474,616	3,187,722	3,331,169
101	Long Term Debt	(Note P)	p112.18.c,d thru 23.c,d	6,861,859,145	7,862,697,345	7,362,278,245
102	Loss on Reacquired Debt	(Note P)	p111.81.c,d	66,774,576	61,094,172	63,934,374
103	Gain on Reacquired Debt	(Note P)	p113.61.c,d	-	-	0
104	ADIT associated with Gain or Loss on Reacquired Debt	(Note P)	p277.3.k (footnote)	16,982,115	16,982,115	16,982,115
106	Preferred Stock	(Note P)	p112.3.c,d	-	-	0

MultiState Workpaper

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

Amortized Investment Tax Credit

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
125	Amortized Investment Tax Credit	(Note O)	p266.8.f	561,000

Excluded Transmission Facilities

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

Interest on Outstanding Network Credits Cost Support

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

Facility Credits under Section 30.9 of the PJM OATT

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

PJM Load Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	1 CP Peak
	Network Zonal Service Rate			
165	1 CP Peak	(Note L)	PJM Data	9,566.9

Abandoned Transmission Projects

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

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6 - True-up Adjustment for Network Integration Transmission Service - December 31, 2018

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

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

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

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

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

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

Summary of Formula Rate Process including True-Up Adjustment

Month	Year	Action
July	2008	TO populates the formula with Year 2008 estimated data
October	2008	TO populates the formula with Year 2009 estimated data
June	2009	TO populates the formula with Year 2008 actual data and calculates the 2008 True-Up Adjustment Before Interest
October	2009	TO calculates the Interest to include in the 2008 True-Up Adjustment
October	2009	TO populates the formula with Year 2010 estimated data and 2008 True-Up Adjustment
June	2010	TO populates the formula with Year 2009 actual data and calculates the 2009 True-Up Adjustment Before Interest
October	2010	TO calculates the Interest to include in the 2009 True-Up Adjustment
October	2010	TO populates the formula with Year 2011 estimated data and 2009 True-Up Adjustment
June	2011	TO populates the formula with Year 2010 actual data and calculates the 2010 True-Up Adjustment Before Interest
October	2011	TO calculates the Interest to include in the 2010 True-Up Adjustment
October	2011	TO populates the formula with Year 2012 estimated data and 2010 True-Up Adjustment
June	2012	TO populates the formula with Year 2011 actual data and calculates the 2011 True-Up Adjustment Before Interest
October	2012	TO calculates the Interest to include in the 2011 True-Up Adjustment
October	2012	TO populates the formula with Year 2013 estimated data and 2011 True-Up Adjustment
June	2013	TO populates the formula with Year 2012 actual data and calculates the 2012 True-Up Adjustment Before Interest
October	2013	TO calculates the Interest to include in the 2012 True-Up Adjustment
October	2013	TO populates the formula with Year 2014 estimated data and 2012 True-Up Adjustment
June	2014	TO populates the formula with Year 2013 actual data and calculates the 2013 True-Up Adjustment Before Interest
October	2014	TO calculates the Interest to include in the 2013 True-Up Adjustment
October	2014	TO populates the formula with Year 2015 estimated data and 2013 True-Up Adjustment
June	2015	TO populates the formula with Year 2014 actual data and calculates the 2014 True-Up Adjustment Before Interest
October	2015	TO calculates the Interest to include in the 2014 True-Up Adjustment
October	2015	TO populates the formula with Year 2016 estimated data and 2014 True-Up Adjustment
June	2016	TO populates the formula with Year 2015 actual data and calculates the 2015 True-Up Adjustment Before Interest
October	2016	TO calculates the Interest to include in the 2015 True-Up Adjustment
October	2016	TO populates the formula with Year 2017 estimated data and 2015 True-Up Adjustment
June	2017	TO populates the formula with Year 2016 actual data and calculates the 2016 True-Up Adjustment Before Interest
October	2017	TO calculates the Interest to include in the 2016 True-Up Adjustment
October	2017	TO populates the formula with Year 2018 estimated data and 2016 True-Up Adjustment

Formula Rate was not in effect for 2006 or 2007.

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

Calendar Year — Complete for Each Calendar Year beginning in 2009

A	ATRR based on actual costs included for the previous calendar year but excludes the true-up adjustment.	1,075,953,704	
B	ATRR based on projected costs included for the previous calendar year but excludes the true-up adjustment.	1,064,228,952	
C	Difference (A-B)	11,724,752	<Note: for the first rate year, divide this reconciliation amount by 12 and multiply by the number of months and fractional months the rate was in effect.
D	Future Value Factor (1+i)^24	1.07393	
E	True-up Adjustment (C*D)	12,591,534	

Where:
i = average interest rate as calculated below

Interest on Amount of Refunds or Surcharges

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

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

	Estimated Additions - 2018												
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	Other Projects PIS (monthly additions)	Ridge Road 69kV Breaker Station (B1255) (monthly additions)	Reconfigure Kearny- Loop in P2216 Ckt (B1589) (monthly additions)	Reconfigure Brunswick Sw-New 69kVCkt-T (B2146) (monthly additions)	350 MVAR Reactor Hopatcong 500kV (B2702) (monthly additions)	Mickleton-Gloucester-Camden(B1398-B1398.7) (monthly additions)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (monthly additions)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (monthly additions)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (monthly additions)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33) (monthly additions)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34) (monthly additions)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50) (monthly additions)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (monthly additions)
		(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)
Dec-17	9,222,677,668	33,382,127	1,530,376	74,949,196	-	438,784,743	174,641,754	43,133,750	24,754,173	15,218,118	-	-	15,218,118
Jan	22,521,913	191,572	-	-	-	5,000	16,938	1,137	1,137	200,524	-	-	200,524
Feb	39,984,029	190,217	-	-	-	5,000	72,474	13,156,649	13,156,649	141,962,430	13,155,532	-	43,884
Mar	48,273,703	594,143	-	-	-	5,000	60,637	430,421	430,421	799,071	386,938	26,103,784	22,171
Apr	55,032,865	223,817	-	-	-	5,000	17,253	8,786,110	581,716	843,679	105,436,138	36,175,259	33,149,302
May	123,826,918	129,299	19,584,758	1,947,000	-	80,000	18,211	687,981	420,170	701,225	711,485	298,021	316,633
Jun	150,159,437	18,565	106,000	9,641,161	21,224,080	100,000	19,771	562,066	8,535,382	614,707	729,092	390,579	378,065
Jul	4,051,043	-	35,000	-	18,000	100,000	23,267	260,922	387,476	345,990	93,225	51,796	22,392
Aug	3,662,511	-	88,000	-	18,000	100,000	18,258	259,612	363,825	367,208	125,010	24,657	681
Sep	30,948,506	-	37,000	-	15,000	100,000	23,797	252,489	308,420	321,919	73,336	20,202	888
Oct	8,829,690	-	36,000	-	9,000	100,000	25,867	254,326	302,616	310,929	75,766	20,349	-
Nov	14,165,647	-	35,000	59,287,359	9,000	-	16,108	257,297	306,151	310,860	66,590	14,480	-
Dec	465,669,098	-	35,000	426,000	8,000	-	15,017	277,237	66,677	332,611	69,412	13,262	-
Total	**10,189,803,028**	**34,729,740**	**21,487,134**	**146,250,715**	**21,301,080**	**439,384,743**	**174,969,351**	**68,319,997**	**49,614,813**	**162,329,270**	**120,922,525**	**63,112,389**	**49,352,658**

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

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

Total Projects	Branchburg (B0130)	Kittatinny (B0134)	Essex Aldene (B0145)	New Freedom Trans.(B0411)	New Freedom Loop (B0498)	Metuchen Transformer (B0161)	Branchburg-Flagtown-Somerville (B0169)	Flagtown-Somerville-Bridgewater (B0170)	Roseland Transformers (B0274)	Wave Trap Branchburg (B0172.2)	Reconductor Hudson - South Waterfront (B0813)	Reconductor South Mahwah J-3410 Circuit (B1017)
511,849,690	**1,901,999**	**772,843**	**8,279,691**	**2,099,946**	**2,665,229**	**2,568,254**	**1,570,839**	**686,810**	**2,101,858**	**2,697**	**946,750**	**2,154,499**

Actual Transmission Enhancement Charges - 2016

Total Projects	Branchburg (B0130)	Kittatinny (B0134)	Essex Aldene (B0145)	New Freedom Trans.(B0411)	New Freedom Loop (B0498)	Metuchen Transformer (B0161)	Branchburg-Flagtown-Somerville (B0169)	Flagtown-Somerville-Bridgewater (B0170)	Roseland Transformers (B0274)	Wave Trap Branchburg (B0172.2)	Reconductor Hudson - South Waterfront (B0813)	Reconductor South Mahwah J-3410 Circuit (B1017)
549,724,505	**2,293,690**	**930,448**	**9,968,442**	**2,528,394**	**3,208,097**	**3,110,954**	**1,890,650**	**826,705**	**2,529,913**	**3,247**	**1,139,246**	**2,592,387**

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

Reconciliation by Project (without interest)

	Total Projects	Branchburg (B0130)	Kittatinny (B0134)	Essex Aldene (B0145)	New Freedom Trans.(B0411)	New Freedom Loop (B0498)	Metuchen Transformer (B0161)	Branchburg-Flagtown-Somerville (B0169)	Flagtown-Somerville-Bridgewater (B0170)	Roseland Transformers (B0274)	Wave Trap Branchburg (B0172.2)	Reconductor Hudson - South Waterfront (B0813)	Reconductor South Mahwah J-3410 Circuit (B1017)
	28,517,873	**(22,848)**	**(8,620)**	**(106,012)**	**(23,351)**	**(29,948)**	**(30,044)**	**(17,700)**	**(7,717)**	**(31,969)**	**(30)**	**(10,755)**	**(24,532)**
Interest		1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393

True Up by Project (with interest) -2016

Total Projects	Branchburg (B0130)	Kittatinny (B0134)	Essex Aldene (B0145)	New Freedom Trans.(B0411)	New Freedom Loop (B0498)	Metuchen Transformer (B0161)	Branchburg-Flagtown-Somerville (B0169)	Flagtown-Somerville-Bridgewater (B0170)	Roseland Transformers (B0274)	Wave Trap Branchburg (B0172.2)	Reconductor Hudson - South Waterfront (B0813)	Reconductor South Mahwah J-3410 Circuit (B1017)
30,626,128	**(24,537)**	**(9,257)**	**(113,849)**	**(25,077)**	**(32,162)**	**(32,265)**	**(19,009)**	**(8,287)**	**(34,332)**	**(32)**	**(11,550)**	**(26,346)**

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

Total Projects	Branchburg (B0130)	Kittatinny (B0134)	Essex Aldene (B0145)	New Freedom Trans.(B0411)	New Freedom Loop (B0498)	Metuchen Transformer (B0161)	Branchburg-Flagtown-Somerville (B0169)	Flagtown-Somerville-Bridgewater (B0170)	Roseland Transformers (B0274)	Wave Trap Branchburg (B0172.2)	Reconductor Hudson - South Waterfront (B0813)	Reconductor South Mahwah J-3410 Circuit (B1017)
542,475,818	**1,877,462**	**763,586**	**8,165,842**	**2,074,869**	**2,633,067**	**2,535,989**	**1,551,830**	**678,523**	**2,067,526**	**2,664**	**935,200**	**2,128,153**

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

Estimated Additions - 2018													
(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)
Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70) (monthly additions)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81) (monthly additions	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83) (monthly additions)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) (monthly additions)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (monthly additions)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (monthly additions)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91) (monthly additions)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (monthly additions)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (monthly additions)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20) (monthly additions)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (monthly additions)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (monthly additions)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33) (monthly additions)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (monthly additions)
(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(CWIP)
15,218,118	30,700,815	30,700,815	44,419,189	44,419,189	29,425,776	24,754,173	26,818,736	26,818,736	15,218,118	15,218,118	17,350,419	-	704,837
200,524	14,291,067	14,291,067	321,453	321,453	23,885	1,137	-	-	200,524	200,524	117,832	-	-
43,884	264,809	264,809	255,631	255,631	29,038	1,117	-	-	43,884	43,884	208,810	13,155,532	(50,196)
71,111,339	32,666	32,666	46,245	46,245	147,489	43,483	1,100	1,100	22,171	22,171	(1,607)	386,938	-
239,947	141,110	141,110	84,275	84,275	354,519	1,159	-	-	31,610	31,610	1,789,753	580,558	-
251,153	139,928	139,928	69,727	69,727	344,120	1,223	-	-	45,975	45,975	143,322	418,947	-
221,639	17,158	17,158	13,175	13,175	5,112,642	1,328	-	-	9,958	9,958	166,226	343,014	(654,641)
237,835	4,654	4,654	4,654	4,654	212,487	1,562	-	-	868	868	179,989	49,997	-
201,868	3,652	3,652	3,652	3,652	1,993,527	1,226	-	-	681	681	122,848	105,132	-
308,736	4,760	4,760	4,760	4,760	189,367	1,598	-	-	888	888	160,123	51,137	-
310,087	3,900	3,900	3,900	3,900	190,744	1,610	-	-	-	-	153,239	51,509	-
307,603	3,946	3,946	3,946	3,946	184,830	1,628	-	-	-	-	146,887	52,111	-
329,102	3,438	3,438	3,438	3,438	192,764	1,755	-	-	-	-	140,496	56,149	-
88,981,836	**45,611,902**	**45,611,902**	**45,234,044**	**45,234,044**	**38,401,188**	**24,812,999**	**26,819,837**	**26,819,837**	**15,574,675**	**15,574,675**	**20,678,337**	**15,251,024**	**0**

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

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

Reconductor South Mahwah K-3411 Circuit (B1018)	Branchburg 400 MVAR Capacitor (B0290)	Saddle Brook - Athenia Upgrade Cable (B0472)	Branchburg-Sommerville-Flagtown Reconductor (B0664 & B0665)	Somerville-Bridgewater Reconductor (B0668)	New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie (B0814)	Salem 500 kV breakers (B1410-B1415)	230kV Lawrence Switching Station Upgrade (B1228)	Branchburg-Middlesex Switch Rack (B1155)	Aldene-Springfield Rd. Conversion (B1399)	Upgrade Camden-Richmond 230kV Circuit (B1590)	Susquehanna Roseland Breakers (b0489.5-B0489.15)	Susquehanna Roseland < 500KV (B0489.4)	Susquehanna Roseland > 500KV (B0489)
2,237,137	**8,216,634**	**1,537,343**	**1,987,742**	**685,500**	**4,966,854**	**1,730,197**	**2,373,909**	**6,919,796**	**8,103,744**	**1,267,230**	**642,820**	**4,713,850**	**84,864,454**

Actual Transmission Enhancement Charges - 2016

Reconductor South Mahwah K-3411 Circuit (B1018)	Branchburg 400 MVAR Capacitor (B0290)	Saddle Brook - Athenia Upgrade Cable (B0472)	Branchburg-Sommerville-Flagtown Reconductor (B0664 & B0665)	Somerville-Bridgewater Reconductor (B0668)	New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie (B0814)	Salem 500 kV breakers (B1410-B1415)	230kV Lawrence Switching Station Upgrade (B1228)	Branchburg-Middlesex Switch Rack (B1155)	Aldene-Springfield Rd. Conversion (B1399)	Upgrade Camden-Richmond 230kV Circuit (B1590)	Susquehanna Roseland Breakers (b0489.5-B0489.15)	Susquehanna Roseland < 500KV (B0489.4)	Susquehanna Roseland > 500KV (B0489)
2,691,625	**9,901,291**	**1,849,551**	**2,391,449**	**824,687**	**5,978,667**	**2,083,057**	**2,856,436**	**9,096,222**	**9,746,523**	**1,524,089**	**776,124**	**5,688,534**	**102,755,603**

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

Reconciliation by Project (without interest)

Reconductor South Mahwah K-3411 Circuit (B1018)	Branchburg 400 MVAR Capacitor (B0290)	Saddle Brook - Athenia Upgrade Cable (B0472)	Branchburg-Sommerville-Flagtown Reconductor (B0664 & B0665)	Somerville-Bridgewater Reconductor (B0668)	New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie (B0814)	Salem 500 kV breakers (B1410-B1415)	230kV Lawrence Switching Station Upgrade (B1228)	Branchburg-Middlesex Switch Rack (B1155)	Aldene-Springfield Rd. Conversion (B1399)	Upgrade Camden-Richmond 230kV Circuit (B1590)	Susquehanna Roseland Breakers (b0489.5-B0489.15)	Susquehanna Roseland < 500KV (B0489.4)	Susquehanna Roseland > 500KV (B0489)
(25,540)	**(517,088)**	**(17,589)**	**(22,732)**	**(7,964)**	**(59,384)**	**(80,284)**	**(69,701)**	**(147,778)**	**(85,367)**	**6,830**	**(7,274)**	**(53,963)**	**(1,059,483)**
1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393

True Up by Project (with interest) -2016

Reconductor South Mahwah K-3411 Circuit (B1018)	Branchburg 400 MVAR Capacitor (B0290)	Saddle Brook - Athenia Upgrade Cable (B0472)	Branchburg-Sommerville-Flagtown Reconductor (B0664 & B0665)	Somerville-Bridgewater Reconductor (B0668)	New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie (B0814)	Salem 500 kV breakers (B1410-B1415)	230kV Lawrence Switching Station Upgrade (B1228)	Branchburg-Middlesex Switch Rack (B1155)	Aldene-Springfield Rd. Conversion (B1399)	Upgrade Camden-Richmond 230kV Circuit (B1590)	Susquehanna Roseland Breakers (b0489.5-B0489.15)	Susquehanna Roseland < 500KV (B0489.4)	Susquehanna Roseland > 500KV (B0489)
(27,428)	**(555,315)**	**(18,890)**	**(24,412)**	**(8,553)**	**(63,774)**	**(86,219)**	**(74,854)**	**(158,703)**	**(91,678)**	**7,335**	**(7,811)**	**(57,952)**	**(1,137,808)**

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

Reconductor South Mahwah K-3411 Circuit (B1018)	Branchburg 400 MVAR Capacitor (B0290)	Saddle Brook - Athenia Upgrade Cable (B0472)	Branchburg-Sommerville-Flagtown Reconductor (B0664 & B0665)	Somerville-Bridgewater Reconductor (B0668)	New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie (B0814)	Salem 500 kV breakers (B1410-B1415)	230kV Lawrence Switching Station Upgrade (B1228)	Branchburg-Middlesex Switch Rack (B1155)	Aldene-Springfield Rd. Conversion (B1399)	Upgrade Camden-Richmond 230kV Circuit (B1590)	Susquehanna Roseland Breakers (b0489.5-B0489.15)	Susquehanna Roseland < 500KV (B0489.4)	Susquehanna Roseland > 500KV (B0489)
2,209,709	**7,661,319**	**1,518,454**	**1,963,330**	**676,947**	**4,903,080**	**1,643,978**	**2,299,056**	**6,761,094**	**8,012,066**	**1,274,565**	**635,009**	**4,655,898**	**83,726,646**

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

Estimated Additions - 2018

(AB)	(AC)	(AD)	(AE)	(AF)	(AG)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)	(AN)	(AO)	(AP)	(AQ)	(AR)	(AS)	(AT)		(AU)
Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (monthly additions)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (monthly additions)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33) (monthly additions)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34) (monthly additions)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50) (monthly additions)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (monthly additions)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70) (monthly additions)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81) (monthly additions	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83) (monthly additions)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (monthly additions)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91) (monthly additions)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (monthly additions)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (monthly additions)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20) (monthly additions)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (monthly additions)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (monthly additions)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33) (monthly additions)				Ridge Road 69kV Breaker Station (B1255)
(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)				(in service)
15,873,514	14,614,183	133,132,128	103,234,243	53,061,761	27,376,832	59,546,744	1,074,767	1,034,193	1,703,883	13,549	763,249	763,249	16,545	16,545	25,613,549	12,374,116		**Dec-17**	9,222,677,668	33,382,127
652,831	(1,557,054)	1,815,939	1,055,192	509,173	686,858	657,991	(1,074,767)	(1,034,193)	330,990	-	-	-	-	-	(22,742,030)	85,192		**Jan**	22,521,913	33,573,699
(11,470,385)	(10,596,791)	(134,948,067)	(10,669,451)	1,210,747	1,145,475	319,400	-	-	131,819	1,113	(58,480)	(58,480)	(1,199)	(1,199)	264,924	(12,459,152)		**Feb**	39,984,029	33,763,916
1,295,284	1,599,104	-	288,524	(22,682,892)	312,521	(60,524,135)	-	-	754,485	-	-	-	-	-	(1,558,855)	-		**Mar**	48,273,703	34,358,059
(6,351,243)	624,357	-	(93,908,509)	(32,098,788)	(29,521,685)	-	-	-	804,726	-	-	-	-	-	(1,577,588)	-		**Apr**	55,032,865	34,581,876
-	307,672	-	-	-	-	-	-	-	710,942	-	-	-	-	-	-	-		**May**	123,826,918	34,711,175
-	(4,991,470)	-	-	-	-	-	-	-	(4,436,845)	(14,662)	(704,769)	(704,769)	(15,346)	(15,346)	-	(156)		**Jun**	150,159,437	34,729,740
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		**Jul**	4,051,043	34,729,740
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		**Aug**	3,662,511	34,729,740
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		**Sep**	30,948,506	34,729,740
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		**Oct**	8,829,690	34,729,740
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		**Nov**	14,165,647	34,729,740
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		**Dec**	465,669,098	34,729,740
(0)	**(0)**	**(0)**	**0**	**0**	**(0)**	**(0)**	**0**	**(0)**	**(0)**	**0**	**0**	**0**	**(0)**	**(0)**	**0**	**(0)**		**Total**	**10,189,803,028**	**447,479,030**
																		13 Month Average CWIP to Appendix A, line 45	**783,831,002**	**34,421,464** **12.88**

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

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

Burlington - Camden 230kV Conversion (B1156)	Mickleton-Gloucester-Camden(B1398-B1398.7)	North Central Reliability (West Orange Conversion) (B1154)	Northeast Grid Reliability Project (B1304.1-B1304.4)	Northeast Grid Reliability Project (B1304.5-B1304.21)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11)
39,257,924	**49,741,703**	**40,364,207**	**71,935,992**	**-**	**20,262,866**	**7,311,454**	**4,948,493**	**16,480,496**	**10,206,715**	**5,445,790**	**4,618,938**	**8,471,130**	**5,266,819**	**5,266,819**	**5,340,569**	**5,340,569**	**3,949,660**	**2,932,429**	**3,107,951**	**3,107,951**

Actual Transmission Enhancement Charges - 2016

Burlington - Camden 230kV Conversion (B1156)	Mickleton-Gloucester-Camden(B1398-B1398.7)	North Central Reliability (West Orange Conversion) (B1154)	Northeast Grid Reliability Project (B1304.1-B1304.4)	Northeast Grid Reliability Project (B1304.5-B1304.21)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11)
47,233,422	**60,066,502**	**48,529,997**	**74,236,857**	**49,268,709**	**14,148,115**	**1,874,846**	**1,874,846**	**47,577**	**-**	**-**	**47,577**	**47,577**	**71,227**	**71,227**	**71,227**	**71,227**	**2,252,189**	**1,874,846**	**2,363,328**	**2,363,328**

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

Reconciliation by Project (without interest)

Burlington - Camden 230kV Conversion (B1156)	Mickleton-Gloucester-Camden(B1398-B1398.7)	North Central Reliability (West Orange Conversion) (B1154)	Northeast Grid Reliability Project (B1304.1-B1304.4)	Northeast Grid Reliability Project (B1304.5-B1304.21)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11)
(241,416)	**1,274,783**	**(244,661)**	**(29,570,588)**	**49,268,709**	**2,507,949**	**394,617**	**394,617**	**47,577**	**-**	**-**	**47,577**	**47,577**	**71,227**	**71,227**	**71,227**	**71,227**	**204,949**	**394,615**	**464,535**	**464,535**
1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393

True Up by Project (with interest) -2016

Burlington - Camden 230kV Conversion (B1156)	Mickleton-Gloucester-Camden(B1398-B1398.7)	North Central Reliability (West Orange Conversion) (B1154)	Northeast Grid Reliability Project (B1304.1-B1304.4)	Northeast Grid Reliability Project (B1304.5-B1304.21)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11)
(259,263)	**1,369,024**	**(262,749)**	**(31,756,668)**	**52,911,022**	**2,693,356**	**423,790**	**423,790**	**51,095**	**-**	**-**	**51,095**	**51,095**	**76,493**	**76,493**	**76,493**	**76,493**	**220,101**	**423,788**	**498,877**	**498,877**

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

Burlington - Camden 230kV Conversion (B1156)	Mickleton-Gloucester-Camden(B1398-B1398.7)	North Central Reliability (West Orange Conversion) (B1154)	Northeast Grid Reliability Project (B1304.1-B1304.4)	Northeast Grid Reliability Project (B1304.5-B1304.21)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11)
38,998,661	**51,110,727**	**40,101,459**	**40,179,324**	**52,911,022**	**22,956,222**	**7,735,244**	**5,372,283**	**16,531,590**	**10,206,715**	**5,445,790**	**4,670,033**	**8,522,224**	**5,343,312**	**5,343,312**	**5,417,062**	**5,417,062**	**4,169,761**	**3,356,217**	**3,606,828**	**3,606,828**

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

Estimated Additions - 2018													
(AV)	(AW)	(AX)	(AY)	(AZ)	(BA)	(BB)	(BC)	(BD)	(BE)	(BF)	(BG)	(BH)	(BI)
Reconfigure Kearny- Loop in P2216 Ckt (B1589)	Reconfigure Brunswick Sw-New 69kVCkt-T (B2146)	350 MVAR Reactor Hopatcong 500kV (B2702)	Mickleton-Gloucester-Camden(B1398-B1398.7)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83)
(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)
1,530,376	74,949,196	-	438,784,743	174,641,754	43,133,750	24,754,173	15,218,118	-	-	15,218,118	15,218,118	30,700,815	30,700,815
1,530,376	74,949,196	-	438,789,743	174,658,692	43,134,887	24,755,311	15,418,642	-	-	15,418,642	15,418,642	44,991,882	44,991,882
1,530,376	74,949,196	-	438,794,743	174,731,166	56,291,536	37,911,960	157,381,072	13,155,532	-	15,462,526	15,462,526	45,256,691	45,256,691
1,530,376	74,949,196	-	438,799,743	174,791,803	56,721,957	38,342,381	158,180,143	13,542,470	26,103,784	15,484,696	86,573,865	45,289,358	45,289,358
1,530,376	74,949,196	-	438,804,743	174,809,056	65,508,067	38,924,097	159,023,821	118,978,608	62,279,043	48,633,998	86,813,812	45,430,467	45,430,467
21,115,134	76,896,196	-	438,884,743	174,827,266	66,196,048	39,344,267	159,725,046	119,690,093	62,577,064	48,950,631	87,064,965	45,570,395	45,570,395
21,221,134	86,537,356	21,224,080	438,984,743	174,847,038	66,758,114	47,879,648	160,339,753	120,419,185	62,967,643	49,328,697	87,286,605	45,587,553	45,587,553
21,256,134	86,537,356	21,242,080	439,084,743	174,870,305	67,019,036	48,267,125	160,685,743	120,512,411	63,019,439	49,351,089	87,524,440	45,592,207	45,592,207
21,344,134	86,537,356	21,260,080	439,184,743	174,888,562	67,278,648	48,630,949	161,052,951	120,637,420	63,044,096	49,351,770	87,726,308	45,595,858	45,595,858
21,381,134	86,537,356	21,275,080	439,284,743	174,912,360	67,531,137	48,939,370	161,374,870	120,710,757	63,064,298	49,352,658	88,035,044	45,600,618	45,600,618
21,417,134	86,537,356	21,284,080	439,384,743	174,938,226	67,785,463	49,241,985	161,685,799	120,786,523	63,084,647	49,352,658	88,345,131	45,604,518	45,604,518
21,452,134	145,824,715	21,293,080	439,384,743	174,954,334	68,042,760	49,548,136	161,996,659	120,853,113	63,099,127	49,352,658	88,652,734	45,608,464	45,608,464
21,487,134	146,250,715	21,301,080	439,384,743	174,969,351	68,319,997	49,614,813	162,329,270	120,922,525	63,112,389	49,352,658	88,981,836	45,611,902	45,611,902
178,325,947	**1,176,404,387**	**148,879,560**	**5,707,551,661**	**2,272,839,913**	**803,721,399**	**546,154,215**	**1,794,411,887**	**1,110,208,636**	**592,351,530**	**504,610,798**	**923,104,026**	**576,440,730**	**576,440,730**
13,717,381 **8.30**	**90,492,645** **8.04**	**11,452,274** **6.99**	**439,042,435** **12.99**	**174,833,839** **12.99**	**61,824,723** **11.76**	**42,011,863** **11.01**	**138,031,684** **11.05**	**85,400,664** **9.18**	**45,565,502** **9.39**	**38,816,215** **10.22**	**71,008,002** **10.37**	**44,341,595** **12.64**	**44,341,595** **12.64**

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

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

New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33)	Upgrade Eagle Point-Gloucester 230kV Circuit (B1588)	Mickleton-Gloucester 230kV Circuit (B2139)	Ridge Road 69kV Breaker Station (B1255)	Cox's Corner-Lumberton 230kV Circuit (B1787)	Install Conemaugh 250MVAR Cap Bank (B0376)	Reconfigure Kearny-Loop in P2216 Ckt (B1589)	Reconfigure Brunswick Sw-New 69kVCkt-T (B2146)	350 MVAR Reactor Hopatcong 500kV (B2702)	Susquehanna Roseland < 500KV (B0489.4) (CWIP)	Susquehanna Roseland >= 500KV (B0489) (CWIP)
1,835,238	1,835,212	2,226,613	1,479,264	1,368,849	2,193,902	4,116,007	3,664,036	129,905	1,639,441	10,815,286	1,368,726	-	-

Actual Transmission Enhancement Charges - 2016

New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33)	Upgrade Eagle Point-Gloucester 230kV Circuit (B1588)	Mickleton-Gloucester 230kV Circuit (B2139)	Ridge Road 69kV Breaker Station (B1255)	Cox's Corner-Lumberton 230kV Circuit (B1787)	Install Conemaugh 250MVAR Cap Bank (B0376)	Reconfigure Kearny-Loop in P2216 Ckt (B1589)	Reconfigure Brunswick Sw-New 69kVCkt-T (B2146)	350 MVAR Reactor Hopatcong 500kV (B2702)	Susquehanna Roseland < 500KV (B0489.4) (CWIP)	Susquehanna Roseland >= 500KV (B0489) (CWIP)
25,899	27,513	141,823	-	1,646,241	2,637,556	556,391	4,451,390	153,181	-	-	-	-	-

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

Reconciliation by Project (without interest)

New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33)	Upgrade Eagle Point-Gloucester 230kV Circuit (B1588)	Mickleton-Gloucester 230kV Circuit (B2139)	Ridge Road 69kV Breaker Station (B1255)	Cox's Corner-Lumberton 230kV Circuit (B1787)	Install Conemaugh 250MVAR Cap Bank (B0376)	Reconfigure Kearny-Loop in P2216 Ckt (B1589)	Reconfigure Brunswick Sw-New 69kVCkt-T (B2146)	350 MVAR Reactor Hopatcong 500kV (B2702)	Susquehanna Roseland < 500KV (B0489.4) (CWIP)	Susquehanna Roseland >= 500KV (B0489) (CWIP)
25,899	**27,513**	**141,823**	**-**	**(7,964)**	**112,364**	**(2,251,480)**	**325,597**	**153,181**	**-**	**-**	**-**	**-**	**-**
1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393

True Up by Project (with interest) -2016

New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33)	Upgrade Eagle Point-Gloucester 230kV Circuit (B1588)	Mickleton-Gloucester 230kV Circuit (B2139)	Ridge Road 69kV Breaker Station (B1255)	Cox's Corner-Lumberton 230kV Circuit (B1787)	Install Conemaugh 250MVAR Cap Bank (B0376)	Reconfigure Kearny-Loop in P2216 Ckt (B1589)	Reconfigure Brunswick Sw-New 69kVCkt-T (B2146)	350 MVAR Reactor Hopatcong 500kV (B2702)	Susquehanna Roseland < 500KV (B0489.4) (CWIP)	Susquehanna Roseland >= 500KV (B0489) (CWIP)
27,813	**29,547**	**152,308**	**-**	**(8,552)**	**120,671**	**(2,417,927)**	**349,668**	**164,506**	**-**	**-**	**-**	**-**	**-**

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

New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33)	Upgrade Eagle Point-Gloucester 230kV Circuit (B1588)	Mickleton-Gloucester 230kV Circuit (B2139)	Ridge Road 69kV Breaker Station (B1255)	Cox's Corner-Lumberton 230kV Circuit (B1787)	Install Conemaugh 250MVAR Cap Bank (B0376)	Reconfigure Kearny-Loop in P2216 Ckt (B1589)	Reconfigure Brunswick Sw-New 69kVCkt-T (B2146)	350 MVAR Reactor Hopatcong 500kV (B2702)	Susquehanna Roseland < 500KV (B0489.4) (CWIP)	Susquehanna Roseland >= 500KV (B0489) (CWIP)
1,863,051	**1,864,759**	**2,378,921**	**1,479,264**	**1,360,297**	**2,314,572**	**1,698,080**	**4,013,704**	**294,411**	**1,639,441**	**10,815,286**	**1,368,726**	**-**	**-**

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

Estimated Additions - 2018													
(BJ)	(BK)	(BL)	(BM)	(BN)	(BO)	(BP)	(BQ)	(BR)	(BS)	(BT)	(BU)	(BV)	(BW)
Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33)
(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(CWIP)	(CWIP)	(CWIP)	(CWIP)
44,419,189	44,419,189	29,425,776	24,754,173	26,818,736	26,818,736	15,218,118	15,218,118	17,350,419	-	704,837	15,873,514	14,614,183	133,132,128
44,740,642	44,740,642	29,449,661	24,755,311	26,818,736	26,818,736	15,418,642	15,418,642	17,468,251	-	704,837	16,526,345	13,057,129	134,948,067
44,996,273	44,996,273	29,478,699	24,756,428	26,818,736	26,818,736	15,462,526	15,462,526	17,677,062	13,155,532	654,641	5,055,960	2,460,338	(0)
45,042,518	45,042,518	29,626,188	24,799,911	26,819,837	26,819,837	15,484,696	15,484,696	17,675,454	13,542,470	654,641	6,351,244	4,059,442	(0)
45,126,793	45,126,793	29,980,708	24,801,069	26,819,837	26,819,837	15,516,306	15,516,306	19,465,207	14,123,028	654,641	(0)	4,683,799	(0)
45,196,520	45,196,520	30,324,827	24,802,292	26,819,837	26,819,837	15,562,281	15,562,281	19,608,529	14,541,974	654,641	(0)	4,991,471	(0)
45,209,694	45,209,694	35,437,469	24,803,620	26,819,837	26,819,837	15,572,239	15,572,239	19,774,755	14,884,989	0	(0)	(0)	(0)
45,214,348	45,214,348	35,649,956	24,805,182	26,819,837	26,819,837	15,573,107	15,573,107	19,954,744	14,934,986	0	(0)	(0)	(0)
45,218,000	45,218,000	37,643,482	24,806,408	26,819,837	26,819,837	15,573,788	15,573,788	20,077,592	15,040,118	0	(0)	(0)	(0)
45,222,759	45,222,759	37,832,849	24,808,006	26,819,837	26,819,837	15,574,675	15,574,675	20,237,715	15,091,255	0	(0)	(0)	(0)
45,226,660	45,226,660	38,023,594	24,809,616	26,819,837	26,819,837	15,574,675	15,574,675	20,390,954	15,142,764	0	(0)	(0)	(0)
45,230,605	45,230,605	38,208,424	24,811,244	26,819,837	26,819,837	15,574,675	15,574,675	20,537,842	15,194,875	0	(0)	(0)	(0)
45,234,044	45,234,044	38,401,188	24,812,999	26,819,837	26,819,837	15,574,675	15,574,675	20,678,337	15,251,024	0	(0)	(0)	(0)
586,078,044	**586,078,044**	**439,482,822**	**322,326,260**	**348,654,574**	**348,654,574**	**201,680,405**	**201,680,405**	**250,896,862**	**160,903,014**	**4,028,239**	**43,807,061**	**43,866,358**	**268,080,194**
45,082,926	**45,082,926**	**33,806,371**	**24,794,328**	**26,819,583**	**26,819,583**	**15,513,877**	**15,513,877**	**19,299,759**	**12,377,155**				
12.96	**12.96**	**11.44**	**12.99**	**13.00**	**13.00**	**12.95**	**12.95**	**12.13**	**10.55**	**13.00**	**13.00**	**13.00**	**13.00**
										309,865	**3,369,774**	**3,374,335**	**20,621,553**

Attachment 9

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

Estimated Transmission Enhancement Charges (Before True-Up) - 2018													
North Central Reliability (West Orange Conversion) (B1154) (CWIP)	Mickleton-Gloucester-Camden (B1398-B1398.7) (CWIP)	Mickleton-Gloucester-Camden Breakers (B1398.15-B1398.19) (CWIP)	Burlington - Camden 230kV Conversion (B1156) (CWIP)	Burlington - Camden 230kV Conversion (B1156.13-B1156.20) (CWIP)	Northeast Grid Reliability Project (B1304.1-B1304.4) (CWIP)	Northeast Grid Reliability Project (B1304.5-B1304.21) (CWIP)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (CWIP)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (CWIP)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (CWIP)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33) (CWIP)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34) (CWIP)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50) (CWIP)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (CWIP)
-	-	-	-	-	-	-	31,344	322,857	419,841	1,976,705	2,908,909	1,425,414	841,713

							Actual Transmission Enhancement Charges - 2016						
North Central Reliability (West Orange Conversion) (B1154) (CWIP)	Mickleton-Gloucester-Camden (B1398-B1398.7) (CWIP)	Mickleton-Gloucester-Camden Breakers (B1398.15-B1398.19) (CWIP)	Burlington - Camden 230kV Conversion (B1156) (CWIP)	Burlington - Camden 230kV Conversion (B1156.13-B1156.20) (CWIP)	Northeast Grid Reliability Project (B1304.1-B1304.4) (CWIP)	Northeast Grid Reliability Project (B1304.5-B1304.21) (CWIP)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (CWIP)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (CWIP)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (CWIP)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33) (CWIP)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34) (CWIP)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50) (CWIP)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (CWIP)
-	-	-	-	-	11,982,038	4,104,014	5,126,158	857,240	921,870	3,473,891	1,695,242	1,011,439	749,927

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

Reconciliation by Project (without interest)

North Central Reliability (West Orange Conversion) (B1154) (CWIP)	Mickleton-Gloucester-Camden (B1398-B1398.7) (CWIP)	Mickleton-Gloucester-Camden Breakers (B1398.15-B1398.19) (CWIP)	Burlington - Camden 230kV Conversion (B1156) (CWIP)	Burlington - Camden 230kV Conversion (B1156.13-B1156.20) (CWIP)	Northeast Grid Reliability Project (B1304.1-B1304.4) (CWIP)	Northeast Grid Reliability Project (B1304.5-B1304.21) (CWIP)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (CWIP)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (CWIP)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (CWIP)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33) (CWIP)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34) (CWIP)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50) (CWIP)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (CWIP)
-	-	-	-	-	3,522,083	3,748,178	(700,564)	(569,315)	(143,008)	586,708	59,227	(538,073)	(257,986)

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

True Up by Project (with interest) -2016

North Central Reliability (West Orange Conversion) (B1154) (CWIP)	Mickleton-Gloucester-Camden (B1398-B1398.7) (CWIP)	Mickleton-Gloucester-Camden Breakers (B1398.15-B1398.19) (CWIP)	Burlington - Camden 230kV Conversion (B1156) (CWIP)	Burlington - Camden 230kV Conversion (B1156.13-B1156.20) (CWIP)	Northeast Grid Reliability Project (B1304.1-B1304.4) (CWIP)	Northeast Grid Reliability Project (B1304.5-B1304.21) (CWIP)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (CWIP)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (CWIP)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (CWIP)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33) (CWIP)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34) (CWIP)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50) (CWIP)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (CWIP)
-	-	-	-	-	3,782,462	4,025,272	(752,355)	(611,403)	(153,580)	630,082	63,605	(577,852)	(277,058)

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

North Central Reliability (West Orange Conversion) (B1154) (CWIP)	Mickleton-Gloucester-Camden (B1398-B1398.7) (CWIP)	Mickleton-Gloucester-Camden Breakers (B1398.15-B1398.19) (CWIP)	Burlington - Camden 230kV Conversion (B1156) (CWIP)	Burlington - Camden 230kV Conversion (B1156.13-B1156.20) (CWIP)	Northeast Grid Reliability Project (B1304.1-B1304.4) (CWIP)	Northeast Grid Reliability Project (B1304.5-B1304.21) (CWIP)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (CWIP)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (CWIP)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (CWIP)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33) (CWIP)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34) (CWIP)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50) (CWIP)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (CWIP)
-	-	-	-	-	3,782,462	4,025,272	(721,012)	(288,547)	266,261	2,606,787	2,972,515	847,562	564,655

Attachment 9

(BX)	(BY)	(BZ)	(CA)	(CB)	(CC)	(CD)	(CE)	(CF)	(CG)	(CH)	(CI)	(CJ)	(CK)
Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (monthly additions)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (monthly additions)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20) (monthly additions)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (monthly additions)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (monthly additions)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33) (monthly additions)
(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)	(CWIP)
103,234,243	53,061,761	27,376,832	59,546,744	1,074,767	1,034,193	1,703,883	13,549	763,249	763,249	16,545	16,545	25,613,549	12,374,116
104,289,435	53,570,934	28,063,690	60,204,735	0	(0)	2,034,872	13,549	763,249	763,249	16,545	16,545	2,871,520	12,459,308
93,619,985	54,781,681	29,209,165	60,524,134	0	(0)	2,166,691	14,662	704,769	704,769	15,346	15,346	3,136,443	156
93,908,509	32,098,788	29,521,686	(0)	0	(0)	2,921,177	14,662	704,769	704,769	15,346	15,346	1,577,588	156
0	0	(0)	(0)	0	(0)	3,725,903	14,662	704,769	704,769	15,346	15,346	0	156
0	0	(0)	(0)	0	(0)	4,436,845	14,662	704,769	704,769	15,346	15,346	0	156
0	0	(0)	(0)	0	(0)	(0)	0	0	0	(0)	(0)	0	(0)
0	0	(0)	(0)	0	(0)	(0)	0	0	0	(0)	(0)	0	(0)
0	0	(0)	(0)	0	(0)	(0)	0	0	0	(0)	(0)	0	(0)
0	0	(0)	(0)	0	(0)	(0)	0	0	0	(0)	(0)	0	(0)
0	0	(0)	(0)	0	(0)	(0)	0	0	0	(0)	(0)	0	(0)
0	0	(0)	(0)	0	(0)	(0)	0	0	0	(0)	(0)	0	(0)
0	0	(0)	(0)	0	(0)	(0)	0	0	0	(0)	(0)	0	(0)
395,052,176	**193,513,166**	**114,171,370**	**180,275,609**	**1,074,771**	**1,034,189**	**16,989,371**	**85,746**	**4,345,571**	**4,345,571**	**94,474**	**94,474**	**33,199,102**	**24,834,045**
13.00	**13.00**	**13.00**	**13.00**	**13.00**	**13.00**	**13.00**	**13.00**	**13.00**	**13.00**	**13.00**	**13.00**	**13.00**	**13.00**
30,388,629	**14,885,628**	**8,782,413**	**13,867,355**	**82,675**	**79,553**	**1,306,875**	**6,596**	**334,275**	**334,275**	**7,267**	**7,267**	**2,553,777**	**1,910,311**

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

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

Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70) (CWIP)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81) (CWIP)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83) (CWIP)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) (CWIP)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (CWIP)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (CWIP)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91) (CWIP)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (CWIP)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (CWIP)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20) (CWIP)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (CWIP)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (CWIP)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33) (CWIP)
1,328,392	**8,046**	**7,738**	**-**	**-**	**136,075**	**702**	**33,744**	**33,744**	**735**	**735**	**160,162**	**183,255**

Actual Transmission Enhancement Charges - 2016

Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70) (CWIP)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81) (CWIP)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83) (CWIP)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) (CWIP)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (CWIP)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (CWIP)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91) (CWIP)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (CWIP)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (CWIP)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20) (CWIP)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (CWIP)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (CWIP)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33) (CWIP)
2,311,095	**1,295,020**	**1,295,020**	**1,342,797**	**1,342,797**	**868,195**	**704,952**	**908,856**	**915,296**	**597,380**	**597,124**	**2,125,894**	**157,609**

Attachment 9

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

Reconciliation by Project (without interest)

Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70) (CWIP)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81) (CWIP)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83) (CWIP)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) (CWIP)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (CWIP)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (CWIP)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91) (CWIP)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (CWIP)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (CWIP)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20) (CWIP)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (CWIP)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (CWIP)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33) (CWIP)
517,581	**175,506**	**175,506**	**66,363**	**66,363**	**(213,626)**	**(158,798)**	**(417,851)**	**(408,383)**	**(41,915)**	**(42,254)**	**1,274,130**	**11,628**
1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393	1.07393

True Up by Project (with interest) -2016

Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70) (CWIP)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81) (CWIP)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83) (CWIP)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) (CWIP)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (CWIP)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (CWIP)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91) (CWIP)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (CWIP)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (CWIP)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20) (CWIP)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (CWIP)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (CWIP)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33) (CWIP)
555,844	**188,481**	**188,481**	**71,269**	**71,269**	**(229,419)**	**(170,537)**	**(448,742)**	**(438,574)**	**(45,014)**	**(45,378)**	**1,368,323**	**12,488**

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

Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70) (CWIP)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81) (CWIP)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83) (CWIP)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) (CWIP)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (CWIP)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (CWIP)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91) (CWIP)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (CWIP)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (CWIP)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20) (CWIP)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (CWIP)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (CWIP)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33) (CWIP)
1,884,236	**196,527**	**196,218**	**71,269**	**71,269**	**(93,344)**	**(169,836)**	**(414,998)**	**(404,830)**	**(44,279)**	**(44,643)**	**1,528,485**	**195,743**

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

1 New Plant Carrying Charge

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

Line		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	9.57%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5	C		Line B less Line A	0.57%

6 **FCR if a CIAC**

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

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 **For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the**
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		Branchburg (B0130)			Kittatinny (B0134)			Essex Aldene (B0145)			New Freedom Trans.(B0411)		
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes			Yes			Yes			Yes		
12	Useful life of the project	Life		42			42			42			42		
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No			No			No			No		
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0			0			0			0		
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%			9.57%			9.57%			9.57%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%			9.57%			9.57%			9.57%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		20,645,602			8,069,022			86,467,721			22,188,863		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		491,562			192,120			2,058,755			528,306		
19	Months in service for depreciation expense from			13.00			13.00			13.00			13.00		
20	Year placed in Service (0 if CWIP)			2006			2007			2007			2007		
21			**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**
22		W 11.68 % ROE	2006	20,680,597	492,395	4,652,471									
23		W Increased ROE	2006	20,680,597	492,395	4,652,471									
24		W 11.68 % ROE	2007	20,188,202	492,395	4,553,422	8,069,022	80,050	1,703,202	86,565,629	858,786	18,272,191	22,188,863	484,281	4,947,757
25		W Increased ROE	2007	20,188,202	492,395	4,553,422	8,069,022	80,050	1,703,202	86,565,629	858,786	18,272,191	22,188,863	484,281	4,947,757
26		W 11.68 % ROE	2008	19,695,807	492,395	4,454,372	7,988,972	192,120	1,799,169	85,706,843	2,061,086	19,301,739	21,704,582	528,306	4,894,366
27		W Increased ROE	2008	19,695,807	492,395	4,454,372	7,988,972	192,120	1,799,169	85,706,843	2,061,086	19,301,739	21,704,582	528,306	4,894,366
28		W 11.68 % ROE	2009	19,203,412	492,395	4,523,234	7,796,853	192,120	1,828,696	83,645,756	2,061,086	19,618,517	21,176,276	528,306	4,973,254
29		W Increased ROE	2009	19,203,412	492,395	4,523,234	7,796,853	192,120	1,828,696	83,645,756	2,061,086	19,618,517	21,176,276	528,306	4,973,254
30		W 11.68 % ROE	2010	18,711,016	492,395	4,095,968	7,604,733	192,120	1,656,722	81,584,670	2,061,086	17,773,557	20,647,970	528,306	4,504,919
31		W Increased ROE	2010	18,711,016	492,395	4,095,968	7,604,733	192,120	1,656,722	81,584,670	2,061,086	17,773,557	20,647,970	528,306	4,504,919
32		W 11.68 % ROE	2011	18,218,621	492,395	3,746,858	7,412,613	192,120	1,516,263	79,523,584	2,061,086	16,266,692	20,119,663	528,306	4,122,360
33		W Increased ROE	2011	18,218,621	492,395	3,746,858	7,412,613	192,120	1,516,263	79,523,584	2,061,086	16,266,692	20,119,663	528,306	4,122,360
34		W 11.68 % ROE	2012	17,726,226	492,395	3,154,416	7,220,494	192,120	1,276,451	77,462,497	2,061,086	13,693,952	19,591,357	528,306	3,470,422
35		W Increased ROE	2012	17,726,226	492,395	3,154,416	7,220,494	192,120	1,276,451	77,462,497	2,061,086	13,693,952	19,591,357	528,306	3,470,422
36		W 11.68 % ROE	2013	17,233,831	492,395	2,886,756	7,028,374	192,120	1,168,598	75,401,411	2,061,086	12,536,886	19,063,051	528,306	3,176,807
37		W Increased ROE	2013	17,233,831	492,395	2,886,756	7,028,374	192,120	1,168,598	75,401,411	2,061,086	12,536,886	19,063,051	528,306	3,176,807
38		W 11.68 % ROE	2014	16,741,436	492,395	2,555,172	6,836,255	192,120	1,034,441	73,340,324	2,061,086	11,097,629	18,534,745	528,306	2,812,043
39		W Increased ROE	2014	16,741,436	492,395	2,555,172	6,836,255	192,120	1,034,441	73,340,324	2,061,086	11,097,629	18,534,745	528,306	2,812,043
40		W 11.68 % ROE	2015	16,249,041	492,395	2,397,208	6,644,135	192,120	970,986	71,279,238	2,061,086	10,416,881	18,006,439	528,306	2,639,133
41		W Increased ROE	2015	16,249,041	492,395	2,397,208	6,644,135	192,120	970,986	71,279,238	2,061,086	10,416,881	18,006,439	528,306	2,639,133
42		W 11.68 % ROE	2016	15,743,650	492,086	2,293,690	6,452,016	192,120	930,448	69,120,244	2,058,755	9,968,442	17,478,132	528,306	2,528,394
43		W Increased ROE	2016	15,743,650	492,086	2,293,690	6,452,016	192,120	930,448	69,120,244	2,058,755	9,968,442	17,478,132	528,306	2,528,394
44		W 11.68 % ROE	2017	15,264,250	492,395	2,176,785	6,259,896	192,120	882,891	67,157,065	2,061,086	9,471,779	16,949,826	528,306	2,398,697
45		W Increased ROE	2017	15,264,250	492,395	2,176,785	6,259,896	192,120	882,891	67,157,065	2,061,086	9,471,779	16,949,826	528,306	2,398,697
46		W 11.68 % ROE	2018	14,737,169	491,562	1,901,999	6,067,776	192,120	772,843	65,000,402	2,058,755	8,279,691	16,421,520	528,306	2,099,946
47		W Increased ROE	2018	14,737,169	491,562	1,901,999	6,067,776	192,120	772,843	65,000,402	2,058,755	8,279,691	16,421,520	528,306	2,099,946

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

1 New Plant Carrying Charge

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

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4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5	C		Line B less Line A	0.57%

6 **FCR if a CIAC**

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

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Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		New Freedom Loop (B0498)	Metuchen Transformer (B0161)	Branchburg-Flagtown-Somerville (B0169)	Flagtown-Somerville-Bridgewater (B0170)
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%	9.57%	9.57%	9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%	9.57%	9.57%	9.57%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		27,005,248	25,654,455	15,731,554	6,961,495
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		642,982	610,820	374,561	165,750
19	Months in service for depreciation expense from			13.00	13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)			2008	2009	2009	2008

Line		Invest Yr	New Freedom Loop (B0498) Ending	Depreciation or Amortization	Revenue	Metuchen Transformer (B0161) Ending	Depreciation or Amortization	Revenue	Branchburg-Flagtown-Somerville (B0169) Ending	Depreciation or Amortization	Revenue	Flagtown-Somerville-Bridgewater (B0170) Ending	Depreciation or Amortization	Revenue
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008	24,921,237	88,646	837,584							6,961,495	25,372	239,734
27	W Increased ROE	2008	24,921,237	88,646	837,584							6,961,495	25,372	239,734
28	W 11.68 % ROE	2009	26,916,602	642,982	6,292,837	19,700,217	288,478	2,831,673	15,773,880	234,561	2,302,423	6,936,122	165,750	1,621,657
29	W Increased ROE	2009	26,916,602	642,982	6,292,837	19,700,217	288,478	2,831,673	15,773,880	234,561	2,302,423	6,936,122	165,750	1,621,657
30	W 11.68 % ROE	2010	26,273,620	642,982	5,703,044	25,488,527	613,738	5,522,598	15,539,319	375,568	3,368,301	6,770,372	165,750	1,469,662
31	W Increased ROE	2010	26,273,620	642,982	5,703,044	25,488,527	613,738	5,522,598	15,539,319	375,568	3,368,301	6,770,372	165,750	1,469,662
32	W 11.68 % ROE	2011	25,630,832	642,987	5,221,521	24,896,838	614,263	5,061,682	15,121,425	374,561	3,075,759	6,604,623	165,750	1,345,559
33	W Increased ROE	2011	25,630,832	642,987	5,221,521	24,896,838	614,263	5,061,682	15,121,425	374,561	3,075,759	6,604,623	165,750	1,345,559
34	W 11.68 % ROE	2012	24,987,652	642,982	4,395,482	24,282,576	614,263	4,260,879	14,746,864	374,561	2,589,159	6,438,873	165,750	1,132,702
35	W Increased ROE	2012	24,987,652	642,982	4,395,482	24,282,576	614,263	4,260,879	14,746,864	374,561	2,589,159	6,438,873	165,750	1,132,702
36	W 11.68 % ROE	2013	24,344,669	642,982	4,025,278	23,668,312	614,263	3,902,590	14,372,303	374,561	2,371,359	6,273,123	165,750	1,037,298
37	W Increased ROE	2013	24,344,669	642,982	4,025,278	23,668,312	614,263	3,902,590	14,372,303	374,561	2,371,359	6,273,123	165,750	1,037,298
38	W 11.68 % ROE	2014	23,701,687	642,982	3,563,358	23,054,049	614,263	3,454,841	13,997,743	374,561	2,099,276	6,107,373	165,750	918,263
39	W Increased ROE	2014	23,701,687	642,982	3,563,358	23,054,049	614,263	3,454,841	13,997,743	374,561	2,099,276	6,107,373	165,750	918,263
40	W 11.68 % ROE	2015	23,058,705	642,982	3,346,067	22,439,786	614,263	3,244,794	13,623,182	374,561	1,971,555	5,941,623	165,750	862,264
41	W Increased ROE	2015	23,058,705	642,982	3,346,067	22,439,786	614,263	3,244,794	13,623,182	374,561	1,971,555	5,941,623	165,750	862,264
42	W 11.68 % ROE	2016	22,415,723	642,982	3,208,097	21,819,123	614,111	3,110,954	13,248,621	374,561	1,890,650	5,775,874	165,750	826,705
43	W Increased ROE	2016	22,415,723	642,982	3,208,097	21,819,123	614,111	3,110,954	13,248,621	374,561	1,890,650	5,775,874	165,750	826,705
44	W 11.68 % ROE	2017	21,772,741	642,982	3,045,575	21,211,259	614,263	2,954,897	12,874,060	374,561	1,795,196	5,610,124	165,750	784,820
45	W Increased ROE	2017	21,772,741	642,982	3,045,575	21,211,259	614,263	2,954,897	12,874,060	374,561	1,795,196	5,610,124	165,750	784,820
46	W 11.68 % ROE	2018	21,129,759	642,982	2,665,229	20,452,549	610,820	2,568,254	12,499,499	374,561	1,570,839	5,444,374	165,750	686,810
47	W Increased ROE	2018	21,129,759	642,982	2,665,229	20,452,549	610,820	2,568,254	12,499,499	374,561	1,570,839	5,444,374	165,750	686,810

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

1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if if not a CIAC**			
		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	9.57%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5	C		Line B less Line A	0.57%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		Roseland Transformers (B0274)			Wave Trap Branchburg (B0172.2)			Reconductor Hudson - South Waterfront (B0813)			Reconductor South Mahwah J-3410 Circuit (B1017)		
10		Details		**Roseland Transformers (B0274)**			**Wave Trap Branchburg (B0172.2)**			**Reconductor Hudson - South Waterfront (B0813)**			**Reconductor South Mahwah J-3410 Circuit (B1017)**		
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes			Yes			Yes			Yes		
12	Useful life of the project	Life		42			42			42			42		
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No			No			No			No		
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0			0			0			0		
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%			9.57%			9.57%			9.57%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%			9.57%			9.57%			9.57%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		21,014,433			27,988			9,158,918			20,626,991		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		500,344			666			218,069			491,119		
19	Months in service for depreciation expense from			13.00			13.00			13.00			13.00		
20	Year placed in Service (0 if CWIP)			2009			2008			2010			2011		
21			**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**
22		W 11.68 % ROE	2006												
23		W Increased ROE	2006												
24		W 11.68 % ROE	2007												
25		W Increased ROE	2007												
26		W 11.68 % ROE	2008				36,369	577	5,114						
27		W Increased ROE	2008				36,369	577	5,114						
28		W 11.68 % ROE	2009	21,092,458	268,347	2,634,066	35,792	866	8,379						
29		W Increased ROE	2009	21,092,458	268,347	2,634,066	35,792	866	8,379						
30		W 11.68 % ROE	2010	20,797,967	501,579	4,507,079	27,122	666	5,890	8,806,222	18,700	169,959			
31		W Increased ROE	2010	20,797,967	501,579	4,507,079	27,122	666	5,890	8,806,222	18,700	169,959			
32		W 11.68 % ROE	2011	20,302,520	501,725	4,128,443	25,878	666	5,289	9,140,218	218,069	1,850,822	20,623,951	300,198	2,435,793
33		W Increased ROE	2011	20,302,520	501,725	4,128,443	25,878	666	5,289	9,140,218	218,069	1,850,822	20,623,951	300,198	2,435,793
34		W 11.68 % ROE	2012	19,802,055	501,755	3,475,512	25,212	666	4,453	8,922,149	218,069	1,557,946	20,326,793	491,119	3,543,678
35		W Increased ROE	2012	19,802,055	501,755	3,475,512	25,212	666	4,453	8,922,149	218,069	1,557,946	20,326,793	491,119	3,543,678
36		W 11.68 % ROE	2013	19,300,300	501,755	3,183,218	24,546	666	4,077	8,704,079	218,069	1,427,360	19,835,674	491,119	3,246,963
37		W Increased ROE	2013	19,300,300	501,755	3,183,218	24,546	666	4,077	8,704,079	218,069	1,427,360	19,835,674	491,119	3,246,963
38		W 11.68 % ROE	2014	18,798,545	501,755	2,817,996	23,880	666	3,609	8,486,010	218,069	1,263,663	19,344,555	491,119	2,874,636
39		W Increased ROE	2014	18,798,545	501,755	2,817,996	23,880	666	3,609	8,486,010	218,069	1,263,663	19,344,555	491,119	2,874,636
40		W 11.68 % ROE	2015	18,296,790	501,755	2,646,618	23,213	666	3,388	8,267,940	218,069	1,187,289	18,853,437	491,119	2,701,236
41		W Increased ROE	2015	18,296,790	501,755	2,646,618	23,213	666	3,388	8,267,940	218,069	1,187,289	18,853,437	491,119	2,701,236
42		W 11.68 % ROE	2016	17,735,762	500,344	2,529,913	22,547	666	3,247	8,049,871	218,069	1,139,246	18,362,318	491,119	2,592,387
43		W Increased ROE	2016	17,735,762	500,344	2,529,913	22,547	666	3,247	8,049,871	218,069	1,139,246	18,362,318	491,119	2,592,387
44		W 11.68 % ROE	2017	17,293,281	501,755	2,410,045	21,880	666	3,081	7,831,801	218,069	1,082,298	17,871,199	491,119	2,463,182
45		W Increased ROE	2017	17,293,281	501,755	2,410,045	21,880	666	3,081	7,831,801	218,069	1,082,298	17,871,199	491,119	2,463,182
46		W 11.68 % ROE	2018	16,733,664	500,344	2,101,858	21,214	666	2,697	7,613,732	218,069	946,750	17,380,080	491,119	2,154,499
47		W Increased ROE	2018	16,733,664	500,344	2,101,858	21,214	666	2,697	7,613,732	218,069	946,750	17,380,080	491,119	2,154,499

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

1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if if not a CIAC**			
		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	9.57%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5	C		Line B less Line A	0.57%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		Reconductor South Mahwah K-3411 Circuit (B1018)	Branchburg 400 MVAR Capacitor (B0290)	Saddle Brook - Athenia Upgrade Cable (B0472)	Branchburg-Sommerville-Flagtown Reconductor (B0664 & B0665)
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%	9.57%	9.57%	9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%	9.57%	9.57%	9.57%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		21,170,273	77,352,830	14,404,842	18,664,931
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		504,054	1,841,734	342,972	444,403
19	Months in service for depreciation expense from			13.00	13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)			2011	2012	2012	2012

21		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011	20,511,158	37,566	284,735									
33	W Increased ROE	2011	20,511,158	37,566	284,735									
34	W 11.68 % ROE	2012	21,132,707	504,054	3,677,641	79,937,194	1,240,233	9,062,770	14,401,477	210,412	1,537,549	19,820,557	318,342	2,326,229
35	W Increased ROE	2012	21,132,707	504,054	3,677,641	79,937,194	1,240,233	9,062,770	14,401,477	210,412	1,537,549	19,820,557	318,342	2,326,229
36	W 11.68 % ROE	2013	20,628,652	504,054	3,370,070	79,195,082	1,915,127	12,917,996	14,194,429	342,972	2,315,058	18,294,505	443,163	2,984,887
37	W Increased ROE	2013	20,628,652	504,054	3,370,070	79,195,082	1,915,127	12,917,996	14,194,429	342,972	2,315,058	18,294,505	443,163	2,984,887
38	W 11.68 % ROE	2014	20,124,598	504,054	2,983,683	77,279,955	1,915,127	11,437,086	13,851,457	342,972	2,049,664	17,903,425	444,403	2,650,353
39	W Increased ROE	2014	20,124,598	504,054	2,983,683	77,279,955	1,915,127	11,437,086	13,851,457	342,972	2,049,664	17,903,425	444,403	2,650,353
40	W 11.68 % ROE	2015	19,620,544	504,054	2,804,096	75,364,829	1,915,127	10,749,859	13,508,484	342,972	1,926,521	17,459,022	444,403	2,491,058
41	W Increased ROE	2015	19,620,544	504,054	2,804,096	75,364,829	1,915,127	10,749,859	13,508,484	342,972	1,926,521	17,459,022	444,403	2,491,058
42	W 11.68 % ROE	2016	19,116,490	504,054	2,691,625	70,419,117	1,842,970	9,901,291	13,165,512	342,972	1,849,551	17,014,619	444,403	2,391,449
43	W Increased ROE	2016	19,116,490	504,054	2,691,625	70,419,117	1,842,970	9,901,291	13,165,512	342,972	1,849,551	17,014,619	444,403	2,391,449
44	W 11.68 % ROE	2017	18,612,436	504,054	2,557,912	71,534,576	1,915,127	9,808,871	12,822,540	342,972	1,757,923	16,570,216	444,403	2,272,904
45	W Increased ROE	2017	18,612,436	504,054	2,557,912	71,534,576	1,915,127	9,808,871	12,822,540	342,972	1,757,923	16,570,216	444,403	2,272,904
46	W 11.68 % ROE	2018	18,108,382	504,054	2,237,137	66,609,121	1,841,734	8,216,634	12,479,567	342,972	1,537,343	16,125,813	444,403	1,987,742
47	W Increased ROE	2018	18,108,382	504,054	2,237,137	66,609,121	1,841,734	8,216,634	12,479,567	342,972	1,537,343	16,125,813	444,403	1,987,742

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

1 New Plant Carrying Charge

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

Line		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	9.57%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5	C		Line B less Line A	0.57%

6 **FCR if a CIAC**

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

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		Somerville-Bridgewater Reconductor (B0668)	New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie (B0814)	Salem 500 kV breakers (B1410-B1415)	230kV Lawrence Switching Station Upgrade (B1228)
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%	9.57%	9.57%	9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%	9.57%	9.57%	9.57%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		6,390,403	46,035,637	15,865,267	21,736,918
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		152,152	1,096,087	377,744	517,546
19	Months in service for depreciation expense from			13.00	13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)			2012	2012	2011	2013

Line		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011							2,640,253	9,537	73,000			
33	W Increased ROE	2011							2,640,253	9,537	73,000			
34	W 11.68 % ROE	2012	4,404,012	57,853	422,751	22,800,866	123,008	898,857	7,275,941	108,279	790,336			
35	W Increased ROE	2012	4,404,012	57,853	422,751	22,800,866	123,008	898,857	7,275,941	108,279	790,336			
36	W 11.68 % ROE	2013	6,291,725	151,180	1,025,313	45,385,800	1,083,543	7,389,162	9,926,683	192,972	1,305,797	22,127,065	248,542	1,698,840
37	W Increased ROE	2013	6,291,725	151,180	1,025,313	45,385,800	1,083,543	7,389,162	9,926,683	192,972	1,305,797	22,127,065	248,542	1,698,840
38	W 11.68 % ROE	2014	6,181,332	152,152	913,777	44,747,660	1,094,148	6,607,679	15,445,872	289,093	1,755,636	21,792,104	524,777	3,209,866
39	W Increased ROE	2014	6,181,332	152,152	913,777	44,747,660	1,094,148	6,607,679	15,445,872	289,093	1,755,636	21,792,104	524,777	3,209,866
40	W 11.68 % ROE	2015	6,029,218	152,152	858,935	43,772,546	1,096,982	6,228,271	15,276,916	378,019	2,168,874	21,267,327	524,777	3,017,865
41	W Increased ROE	2015	6,029,218	152,152	858,935	43,772,546	1,096,982	6,228,271	15,276,916	378,019	2,168,874	21,267,327	524,777	3,017,865
42	W 11.68 % ROE	2016	5,877,066	152,152	824,687	42,662,264	1,096,665	5,978,667	14,899,633	378,036	2,083,057	20,438,822	517,546	2,856,436
43	W Increased ROE	2016	5,877,066	152,152	824,687	42,662,264	1,096,665	5,978,667	14,899,633	378,036	2,083,057	20,438,822	517,546	2,856,436
44	W 11.68 % ROE	2017	5,724,913	152,152	783,889	41,578,581	1,096,982	5,685,123	14,510,533	378,022	1,979,240	20,217,772	524,777	2,755,781
45	W Increased ROE	2017	5,724,913	152,152	783,889	41,578,581	1,096,982	5,685,123	14,510,533	378,022	1,979,240	20,217,772	524,777	2,755,781
46	W 11.68 % ROE	2018	5,572,761	152,152	685,500	40,444,309	1,096,087	4,966,854	14,131,308	377,744	1,730,197	19,396,499	517,546	2,373,909
47	W Increased ROE	2018	5,572,761	152,152	685,500	40,444,309	1,096,087	4,966,854	14,131,308	377,744	1,730,197	19,396,499	517,546	2,373,909

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

1 New Plant Carrying Charge

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

Line		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	9.57%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5	C		Line B less Line A	0.57%

6 **FCR if a CIAC**

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

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		Branchburg-Middlesex Switch Rack (B1155)	Aldene-Springfield Rd. Conversion (B1399)	Upgrade Camden-Richmond 230kV Circuit (B1590)	Susquehanna Roseland Breakers (b0489.5-B0489.15)
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	125
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%	9.57%	9.57%	9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%	9.57%	9.57%	10.28%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		62,937,256	72,380,453	11,276,183	5,857,687
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		1,498,506	1,723,344	268,481	139,469
19	Months in service for depreciation expense from			13.00	13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)			2013	2014	2014	2010

Line		Invest Yr	B1155 Ending	B1155 Depreciation or Amortization	B1155 Revenue	B1399 Ending	B1399 Depreciation or Amortization	B1399 Revenue	B1590 Ending	B1590 Depreciation or Amortization	B1590 Revenue	B0489 Ending	B0489 Depreciation or Amortization	B0489 Revenue
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010										2,662,585	7,802	70,915
31	W Increased ROE	2010										2,662,585	7,802	70,915
32	W 11.68 % ROE	2011										5,849,885	116,061	966,188
33	W Increased ROE	2011										5,849,885	116,061	1,014,845
34	W 11.68 % ROE	2012										5,733,823	139,469	1,000,541
35	W Increased ROE	2012										5,733,823	139,469	1,051,531
36	W 11.68 % ROE	2013	20,876,286	101,812	695,908							5,594,354	139,469	916,713
37	W Increased ROE	2013	20,876,286	101,812	695,908							5,594,354	139,469	967,047
38	W 11.68 % ROE	2014	60,374,269	1,439,907	8,878,852	68,405,611	556,909	3,438,903	7,389,782	37,992	234,599	5,454,886	139,469	811,586
39	W Increased ROE	2014	60,374,269	1,439,907	8,878,852	68,405,611	556,909	3,438,903	7,389,782	37,992	234,599	5,454,886	139,469	859,361
40	W 11.68 % ROE	2015	61,346,085	1,497,329	8,688,697	71,213,315	1,708,815	10,056,881	11,126,578	265,823	1,570,150	5,315,417	139,469	762,575
41	W Increased ROE	2015	61,346,085	1,497,329	8,688,697	71,213,315	1,708,815	10,056,881	11,126,578	265,823	1,570,150	5,315,417	139,469	808,174
42	W 11.68 % ROE	2016	65,275,261	1,626,531	9,096,222	70,112,484	1,723,291	9,746,523	10,972,368	268,481	1,524,089	5,175,948	139,469	731,772
43	W Increased ROE	2016	65,275,261	1,626,531	9,096,222	70,112,484	1,723,291	9,746,523	10,972,368	268,481	1,524,089	5,175,948	139,469	776,124
44	W 11.68 % ROE	2017	63,648,517	1,626,495	8,650,024	68,474,262	1,724,855	9,280,898	10,705,213	268,300	1,449,606	5,036,479	139,469	695,238
45	W Increased ROE	2017	63,648,517	1,626,495	8,650,024	68,474,262	1,724,855	9,280,898	10,705,213	268,300	1,449,606	5,036,479	139,469	737,976
46	W 11.68 % ROE	2018	56,645,182	1,498,506	6,919,796	66,666,584	1,723,344	8,103,744	10,435,588	268,481	1,267,230	4,897,011	139,469	608,143
47	W Increased ROE	2018	56,645,182	1,498,506	6,919,796	66,666,584	1,723,344	8,103,744	10,435,588	268,481	1,267,230	4,897,011	139,469	642,820

Attachment 9

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

1 New Plant Carrying Charge

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

		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	9.57%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5	C		Line B less Line A	0.57%

6 **FCR if a CIAC**

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

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

				Susquehanna Roseland < 500KV (B0489.4)	Susquehanna Roseland > 500KV (B0489)	Burlington - Camden 230kV Conversion (B1156)	Mickleton-Gloucester-Camden(B1398-B1398.7)
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)		125	125	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%	9.57%	9.57%	9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		10.28%	10.28%	9.57%	9.57%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		40,538,248	720,620,844	356,333,540	439,384,743
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		965,196	17,157,639	8,484,132	10,461,542
19	Months in service for depreciation expense from			13.00	13.00	13.00	12.99
20	Year placed in Service (0 if CWIP)			2011	2012	2011	2013

			Susquehanna Roseland < 500KV (B0489.4)			Susquehanna Roseland > 500KV (B0489)			Burlington - Camden 230kV Conversion (B1156)			Mickleton-Gloucester-Camden(B1398-B1398.7)		
21		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011	7,844,331	111,778	905,525				19,902,939	147,204	1,150,144			
33	W Increased ROE	2011	7,844,331	111,778	952,449				19,902,939	147,204	1,150,144			
34	W 11.68 % ROE	2012	7,628,074	184,491	1,331,330	4,694,511	8,598	62,828	19,848,511	475,501	3,452,558			
35	W Increased ROE	2012	7,628,074	184,491	1,399,243	4,694,511	8,598	66,040	19,848,511	475,501	3,452,558			
36	W 11.68 % ROE	2013	6,391,895	159,242	1,047,292	25,426,870	605,606	4,138,257	118,115,741	2,827,106	19,237,368	777,714	1,424	9,736
37	W Increased ROE	2013	6,391,895	159,242	1,104,801	25,426,870	605,606	4,367,027	118,115,741	2,827,106	19,237,368	777,714	1,424	9,736
38	W 11.68 % ROE	2014	40,082,737	717,210	4,387,056	666,963,000	10,160,548	62,692,814	333,325,376	6,107,990	37,392,933	83,696,796	854,944	5,279,191
39	W Increased ROE	2014	40,082,737	717,210	4,647,913	666,963,000	10,160,548	66,426,879	333,325,376	6,107,990	37,392,933	83,696,796	854,944	5,279,191
40	W 11.68 % ROE	2015	39,365,526	965,196	5,579,868	711,440,230	16,714,518	97,780,708	346,271,067	8,256,393	47,814,854	436,685,203	6,739,741	39,857,912
41	W Increased ROE	2015	39,365,526	965,196	5,917,569	711,440,230	16,714,518	103,713,135	346,271,067	8,256,393	47,814,854	436,685,203	6,739,741	39,857,912
42	W 11.68 % ROE	2016	38,400,330	965,196	5,359,489	694,520,844	17,213,677	96,796,429	338,712,254	8,485,957	47,233,422	430,951,154	10,495,692	60,066,502
43	W Increased ROE	2016	38,400,330	965,196	5,688,534	694,520,844	17,213,677	102,755,603	338,712,254	8,485,957	47,233,422	430,951,154	10,495,692	60,066,502
44	W 11.68 % ROE	2017	37,435,134	965,196	5,096,113	678,154,289	17,211,186	92,044,606	330,265,484	8,488,706	44,933,061	421,661,646	10,462,931	56,992,730
45	W Increased ROE	2017	37,435,134	965,196	5,413,780	678,154,289	17,211,186	97,799,286	330,265,484	8,488,706	44,933,061	421,661,646	10,462,931	56,992,730
46	W 11.68 % ROE	2018	36,469,937	965,196	4,455,592	658,706,710	17,157,639	80,199,899	321,544,683	8,484,132	39,257,924	410,830,010	10,453,391	49,741,703
47	W Increased ROE	2018	36,469,937	965,196	4,713,850	658,706,710	17,157,639	84,864,454	321,544,683	8,484,132	39,257,924	410,830,010	10,453,391	49,741,703

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

1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if if not a CIAC**			
		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	9.57%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5	C		Line B less Line A	0.57%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

				North Central Reliability (West Orange Conversion (B1154)			**Northeast Grid Reliability Project (B1304.1-B1304.4)**			**Northeast Grid Reliability Project (B1304.5-B1304.21)**			**Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)**		
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			25			25			0		
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%			9.57%			9.57%			9.57%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%			9.71%			9.71%			9.57%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		370,006,995			625,390,228			-			174,969,351		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		8,809,690			14,890,244			-			4,165,937		
19	Months in service for depreciation expense from			13.00			13.00						12.99		
20	Year placed in Service (0 if CWIP)			2012			2013			2016			2016		
21			**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**
22		W 11.68 % ROE	2006												
23		W Increased ROE	2006												
24		W 11.68 % ROE	2007												
25		W Increased ROE	2007												
26		W 11.68 % ROE	2008												
27		W Increased ROE	2008												
28		W 11.68 % ROE	2009												
29		W Increased ROE	2009												
30		W 11.68 % ROE	2010												
31		W Increased ROE	2010												
32		W 11.68 % ROE	2011												
33		W Increased ROE	2011												
34		W 11.68 % ROE	2012	16,441,748	30,113	220,046									
35		W Increased ROE	2012	16,441,748	30,113	220,046									
36		W 11.68 % ROE	2013	257,640,264	6,135,009	41,929,935	23,466,022	86,647	592,253						
37		W Increased ROE	2013	257,640,264	6,135,009	41,929,935	23,466,022	86,647	598,801						
38		W 11.68 % ROE	2014	360,673,484	7,742,354	47,135,528	274,113,325	2,382,627	14,708,781						
39		W Increased ROE	2014	360,673,484	7,742,354	47,135,528	274,113,325	2,382,627	14,884,013						
40		W 11.68 % ROE	2015	355,885,266	8,777,921	50,370,637	433,597,024	7,852,675	46,296,391				-	-	-
41		W Increased ROE	2015	355,885,266	8,777,921	50,370,637	433,597,024	7,852,675	46,859,053				-	-	-
42		W 11.68 % ROE	2016	347,072,992	8,805,472	48,529,997	615,905,487	12,804,341	73,330,415	352,027,464	8,381,606	48,665,417	178,685,539	2,436,719	14,148,115
43		W Increased ROE	2016	347,072,992	8,805,472	48,529,997	615,905,487	12,804,341	74,236,857	352,027,464	8,381,606	49,268,709	178,685,539	2,436,719	14,148,115
44		W 11.68 % ROE	2017	338,731,158	8,813,920	46,192,451	597,948,245	14,904,549	80,887,339	351,791,077	8,375,978	47,195,653	173,780,513	4,177,297	23,318,838
45		W Increased ROE	2017	338,731,158	8,813,920	46,192,451	597,948,245	14,904,549	81,902,152	351,791,077	8,375,978	47,792,699	173,780,513	4,177,297	23,318,838
46		W 11.68 % ROE	2018	329,702,206	8,809,690	40,364,207	587,359,389	14,890,244	71,104,128	-	-	-	168,355,336	4,162,710	20,262,866
47		W Increased ROE	2018	329,702,206	8,809,690	40,364,207	587,359,389	14,890,244	71,935,992	-	-	-	168,355,336	4,162,710	20,262,866

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

1 New Plant Carrying Charge

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

Line		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	9.57%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5	C		Line B less Line A	0.57%

6 **FCR if a CIAC**

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

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

				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)**
10		Details					
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%	9.57%	9.57%	9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%	9.57%	9.57%	9.57%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		68,319,997	49,614,813	162,329,270	120,922,525
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		1,626,667	1,181,305	3,864,983	2,879,108
19	Months in service for depreciation expense from			11.76	11.01	11.05	9.18
20	Year placed in Service (0 if CWIP)			2016	2016	2015	2018

21		**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011												
33	W Increased ROE	2011												
34	W 11.68 % ROE	2012												
35	W Increased ROE	2012												
36	W 11.68 % ROE	2013												
37	W Increased ROE	2013												
38	W 11.68 % ROE	2014												
39	W Increased ROE	2014												
40	W 11.68 % ROE	2015							225,037	412	2,441			
41	W Increased ROE	2015							225,037	412	2,441			
42	W 11.68 % ROE	2016	23,849,835	322,903	1,874,846	23,849,835	322,903	1,874,846	349,923	8,202	47,577			
43	W Increased ROE	2016	23,849,835	322,903	1,874,846	23,849,835	322,903	1,874,846	349,923	8,202	47,577			
44	W 11.68 % ROE	2017	24,121,486	572,715	3,199,550	24,121,486	572,715	3,199,550	15,071,025	193,511	1,090,341			
45	W Increased ROE	2017	24,121,486	572,715	3,199,550	24,121,486	572,715	3,199,550	15,071,025	193,511	1,090,341			
46	W 11.68 % ROE	2018	67,424,378	1,472,017	7,311,454	48,719,195	1,000,282	4,948,493	162,127,145	3,286,469	16,480,496	120,922,525	2,033,349	10,206,715
47	W Increased ROE	2018	67,424,378	1,472,017	7,311,454	48,719,195	1,000,282	4,948,493	162,127,145	3,286,469	16,480,496	120,922,525	2,033,349	10,206,715

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

1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if if not a CIAC**			
		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	9.57%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5	C		Line B less Line A	0.57%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

		Details		Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81)
10							
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%	9.57%	9.57%	9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%	9.57%	9.57%	9.57%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		63,112,389	49,352,658	88,981,836	45,611,902
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		1,502,676	1,175,063	2,118,615	1,085,998
19	Months in service for depreciation expense from			9.39	10.22	10.37	12.64
20	Year placed in Service (0 if CWIP)			2018	2015	2015	2015

21		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011												
33	W Increased ROE	2011												
34	W 11.68 % ROE	2012												
35	W Increased ROE	2012												
36	W 11.68 % ROE	2013												
37	W Increased ROE	2013												
38	W 11.68 % ROE	2014												
39	W Increased ROE	2014												
40	W 11.68 % ROE	2015				225,037	412	2,441	225,037	412	2,441	225,037	412	2,441
41	W Increased ROE	2015				225,037	412	2,441	225,037	412	2,441	225,037	412	2,441
42	W 11.68 % ROE	2016				349,923	8,202	47,577	349,923	8,202	47,577	723,468	12,273	71,227
43	W Increased ROE	2016				349,923	8,202	47,577	349,923	8,202	47,577	723,468	12,273	71,227
44	W 11.68 % ROE	2017				48,229,026	259,831	1,464,046	15,071,025	193,511	1,090,341	24,740,340	338,724	1,908,566
45	W Increased ROE	2017				48,229,026	259,831	1,464,046	15,071,025	193,511	1,090,341	24,740,340	338,724	1,908,566
46	W 11.68 % ROE	2018	63,112,389	1,084,893	5,445,790	49,084,212	924,196	4,618,938	88,779,710	1,690,667	8,471,130	45,260,492	1,055,752	5,266,819
47	W Increased ROE	2018	63,112,389	1,084,893	5,445,790	49,084,212	924,196	4,618,938	88,779,710	1,690,667	8,471,130	45,260,492	1,055,752	5,266,819

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

1	New Plant Carrying Charge				
2	**Fixed Charge Rate (FCR) if if not a CIAC**				
		Formula Line			
3	A	152	Net Plant Carrying Charge without Depreciation	9.57%	
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%	
5	C		Line B less Line A	0.57%	
6	**FCR if a CIAC**				
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%	

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

		Details		**Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83)**	**Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84)**	**Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85)**	**Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90)**
10							
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%	9.57%	9.57%	9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%	9.57%	9.57%	9.57%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		45,611,902	45,234,044	45,234,044	38,401,188
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		1,085,998	1,077,001	1,077,001	914,314
19	Months in service for depreciation expense from			12.64	12.96	12.96	11.44
20	Year placed in Service (0 if CWIP)			2015	2015	2015	2016

21		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011												
33	W Increased ROE	2011												
34	W 11.68 % ROE	2012												
35	W Increased ROE	2012												
36	W 11.68 % ROE	2013												
37	W Increased ROE	2013												
38	W 11.68 % ROE	2014												
39	W Increased ROE	2014												
40	W 11.68 % ROE	2015	225,037	412	2,441	225,037	412	2,441	225,037	412	2,441			
41	W Increased ROE	2015	225,037	412	2,441	225,037	412	2,441	225,037	412	2,441			
42	W 11.68 % ROE	2016	723,468	12,273	71,227	723,468	12,273	71,227	723,468	12,273	71,227	28,441,681	387,893	2,252,189
43	W Increased ROE	2016	723,468	12,273	71,227	723,468	12,273	71,227	723,468	12,273	71,227	28,441,681	387,893	2,252,189
44	W 11.68 % ROE	2017	24,740,340	338,724	1,908,566	36,209,684	485,767	2,737,100	36,209,684	485,767	2,737,100	28,907,314	688,967	3,843,966
45	W Increased ROE	2017	24,740,340	338,724	1,908,566	36,209,684	485,767	2,737,100	36,209,684	485,767	2,737,100	28,907,314	688,967	3,843,966
46	W 11.68 % ROE	2018	45,260,492	1,055,752	5,266,819	44,735,591	1,073,403	5,340,569	44,735,591	1,073,403	5,340,569	37,324,329	804,914	3,949,660
47	W Increased ROE	2018	45,260,492	1,055,752	5,266,819	44,735,591	1,073,403	5,340,569	44,735,591	1,073,403	5,340,569	37,324,329	804,914	3,949,660

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

1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if if not a CIAC**			
		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	9.57%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5	C		Line B less Line A	0.57%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

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

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

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

10		Details		**Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91)**			**New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10)**			**New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11)**			**New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20)**	
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes			Yes			Yes			Yes		
12	Useful life of the project	Life		42			42			42			42		
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No			No			No			No		
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0			0			0			0		
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%			9.57%			9.57%			9.57%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%			9.57%			9.57%			9.57%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		24,812,999			26,819,837			26,819,837			15,574,675		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		590,786			638,568			638,568			370,826		
19	Months in service for depreciation expense from			12.99			13.00			13.00			12.95		
20	Year placed in Service (0 if CWIP)			2016			2016			2016			2015		
21			**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**
22		W 11.68 % ROE	2006												
23		W Increased ROE	2006												
24		W 11.68 % ROE	2007												
25		W Increased ROE	2007												
26		W 11.68 % ROE	2008												
27		W Increased ROE	2008												
28		W 11.68 % ROE	2009												
29		W Increased ROE	2009												
30		W 11.68 % ROE	2010												
31		W Increased ROE	2010												
32		W 11.68 % ROE	2011												
33		W Increased ROE	2011												
34		W 11.68 % ROE	2012												
35		W Increased ROE	2012												
36		W 11.68 % ROE	2013												
37		W Increased ROE	2013												
38		W 11.68 % ROE	2014												
39		W Increased ROE	2014												
40		W 11.68 % ROE	2015										225,037	412	2,441
41		W Increased ROE	2015										225,037	412	2,441
42		W 11.68 % ROE	2016	23,849,835	322,903	1,874,846	27,523,727	407,034	2,363,328	27,523,727	407,034	2,363,328	349,923	4,465	25,899
43		W Increased ROE	2016	23,849,835	322,903	1,874,846	27,523,727	407,034	2,363,328	27,523,727	407,034	2,363,328	349,923	4,465	25,899
44		W 11.68 % ROE	2017				25,328,064	610,761	3,405,679	25,328,064	610,761	3,405,679	15,071,025	193,511	1,090,341
45		W Increased ROE	2017				25,328,064	610,761	3,405,679	25,328,064	610,761	3,405,679	15,071,025	193,511	1,090,341
46		W 11.68 % ROE	2018	24,490,096	590,341	2,932,429	25,802,041	638,561	3,107,951	25,802,041	638,561	3,107,951	15,376,287	369,378	1,835,238
47		W Increased ROE	2018	24,490,096	590,341	2,932,429	25,802,041	638,561	3,107,951	25,802,041	638,561	3,107,951	15,376,287	369,378	1,835,238

Attachment 9

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

1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if if not a CIAC**			
		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	9.57%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5	C		Line B less Line A	0.57%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

				New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21)			New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30)			New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33)			Upgrade Eagle Point-Gloucester 230kV Circuit (B1588)		
10		Details													
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes			Yes			Yes			Yes		
12	Useful life of the project	Life		42			42			42			42		
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No			No			No			No		
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0			0			0			0		
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%			9.57%			9.57%			9.57%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%			9.57%			9.57%			9.57%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		15,574,675			20,678,337			15,251,024			12,087,537		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		370,826			492,341			363,120			287,798		
19	Months in service for depreciation expense from			12.95			12.13			10.55			13.00		
20	Year placed in Service (0 if CWIP)			2015			2017			2018			2015		
21			Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
22		W 11.68 % ROE	2006												
23		W Increased ROE	2006												
24		W 11.68 % ROE	2007												
25		W Increased ROE	2007												
26		W 11.68 % ROE	2008												
27		W Increased ROE	2008												
28		W 11.68 % ROE	2009												
29		W Increased ROE	2009												
30		W 11.68 % ROE	2010												
31		W Increased ROE	2010												
32		W 11.68 % ROE	2011												
33		W Increased ROE	2011												
34		W 11.68 % ROE	2012												
35		W Increased ROE	2012												
36		W 11.68 % ROE	2013												
37		W Increased ROE	2013												
38		W 11.68 % ROE	2014												
39		W Increased ROE	2014												
40		W 11.68 % ROE	2015	225,037	412	2,441							11,980,348	216,491	1,282,387
41		W Increased ROE	2015	225,037	412	2,441							11,980,348	216,491	1,282,387
42		W 11.68 % ROE	2016	349,923	4,743	27,513	2,241,267	24,426	141,823				11,871,005	287,798	1,646,241
43		W Increased ROE	2016	349,923	4,743	27,513	2,241,267	24,426	141,823				11,871,005	287,798	1,646,241
44		W 11.68 % ROE	2017	15,071,025	193,511	1,090,341	58,015,888	871,281	4,909,357				11,583,195	287,722	1,565,912
45		W Increased ROE	2017	15,071,025	193,511	1,090,341	58,015,888	871,281	4,909,357				11,583,195	287,722	1,565,912
46		W 11.68 % ROE	2018	15,376,009	369,378	1,835,212	19,782,631	459,518	2,226,613	15,251,024	294,694	1,479,264	11,295,526	287,798	1,368,849
47		W Increased ROE	2018	15,376,009	369,378	1,835,212	19,782,631	459,518	2,226,613	15,251,024	294,694	1,479,264	11,295,526	287,798	1,368,849

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

1	New Plant Carrying Charge				
2	**Fixed Charge Rate (FCR) if if not a CIAC**				
		Formula Line			
3	A	152	Net Plant Carrying Charge without Depreciation	9.57%	
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%	
5	C		Line B less Line A	0.57%	
6	**FCR if a CIAC**				
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%	

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

		Details		**Mickleton-Gloucester 230kV Circuit (B2139)**	**Ridge Road 69kV Breaker Station (B1255)**	**Cox's Corner-Lumberton 230kV Circuit (B1787)**	**Sewaren Switch 230kV Conversion (B2276)**
10							
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%	9.57%	9.57%	9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%	9.57%	9.57%	9.57%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		19,272,633	34,729,740	32,027,160	-
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		458,872	826,899	762,551	-
19	Months in service for depreciation expense from			13.00	13.00	13.00	-
20	Year placed in Service (0 if CWIP)			2015	2016	2015	2015

21		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011												
33	W Increased ROE	2011												
34	W 11.68 % ROE	2012												
35	W Increased ROE	2012												
36	W 11.68 % ROE	2013												
37	W Increased ROE	2013												
38	W 11.68 % ROE	2014												
39	W Increased ROE	2014												
40	W 11.68 % ROE	2015	18,260,361	232,128	1,375,013	-	-	-	17,370,246	185,057	1,096,185	13,591,177	156,762	928,580
41	W Increased ROE	2015	18,260,361	232,128	1,375,013	-	-	-	17,370,246	185,057	1,096,185	13,591,177	156,762	928,580
42	W 11.68 % ROE	2016	19,039,119	458,839	2,637,556	4,024,723	95,827	556,391	32,167,824	770,307	4,451,390	118,288,759	2,820,131	16,356,354
43	W Increased ROE	2016	19,039,119	458,839	2,637,556	4,024,723	95,827	556,391	32,167,824	770,307	4,451,390	118,288,759	2,820,131	16,356,354
44	W 11.68 % ROE	2017	18,357,357	452,946	2,478,656	35,212,643	267,164	1,488,600	30,829,183	755,191	4,157,150	116,563,457	2,815,636	15,669,479
45	W Increased ROE	2017	18,357,357	452,946	2,478,656	35,212,643	267,164	1,488,600	30,829,183	755,191	4,157,150	116,563,457	2,815,636	15,669,479
46	W 11.68 % ROE	2018	18,128,720	458,872	2,193,902	34,366,749	826,899	4,116,007	30,316,606	762,551	3,664,036	-	-	-
47	W Increased ROE	2018	18,128,720	458,872	2,193,902	34,366,749	826,899	4,116,007	30,316,606	762,551	3,664,036	-	-	-

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

1	New Plant Carrying Charge				
2	**Fixed Charge Rate (FCR) if if not a CIAC**				
			Formula Line		
3		A	152	Net Plant Carrying Charge without Depreciation	9.57%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5		C		Line B less Line A	0.57%
6	**FCR if a CIAC**				
7		D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		**Install Conemaugh 250MVAR Cap Bank (B0376)**	**Reconfigure Kearny- Loop in P2216 Ckt (B1589)**	**Reconfigure Brunswick Sw-New 69kVCkt-T (B2146)**	**350 MVAR Reactor Hopatcong 500kV (B2702)**
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%	9.57%	9.57%	9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%	9.57%	9.57%	9.57%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		1,108,058	21,487,134	146,250,715	21,301,080
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		26,382	511,598	3,482,160	507,169
19	Months in service for depreciation expense from			13.00	8.30	8.04	6.99
20	Year placed in Service (0 if CWIP)			2016	2018	2017	2018

Line		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011												
33	W Increased ROE	2011												
34	W 11.68 % ROE	2012												
35	W Increased ROE	2012												
36	W 11.68 % ROE	2013												
37	W Increased ROE	2013												
38	W 11.68 % ROE	2014												
39	W Increased ROE	2014												
40	W 11.68 % ROE	2015												
41	W Increased ROE	2015												
42	W 11.68 % ROE	2016	1,108,058	26,382	153,181									
43	W Increased ROE	2016	1,108,058	26,382	153,181									
44	W 11.68 % ROE	2017												
45	W Increased ROE	2017												
46	W 11.68 % ROE	2018	1,081,675	26,382	129,905	21,487,134	326,604	1,639,441	146,250,715	2,154,587	10,815,286	21,301,080	272,673	1,368,726
47	W Increased ROE	2018	1,081,675	26,382	129,905	21,487,134	326,604	1,639,441	146,250,715	2,154,587	10,815,286	21,301,080	272,673	1,368,726

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

1	New Plant Carrying Charge				
2	**Fixed Charge Rate (FCR) if if not a CIAC**				
			Formula Line		
3		A	152	Net Plant Carrying Charge without Depreciation	9.57%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5		C		Line B less Line A	0.57%
6	**FCR if a CIAC**				
7		D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		Susquehanna Roseland < 500KV (B0489.4) (CWIP)	Susquehanna Roseland >= 500kV (B0489) (CWIP)	North Central Reliability (West Orange Conversion) (B1154) (CWIP)	Mickleton-Gloucester-Camden(B1398-B1398.7) (CWIP)
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		125	125	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%	9.57%	9.57%	9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		10.28%	10.28%	9.57%	9.57%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		-	-	-	-
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		-	-	-	-
19	Months in service for depreciation expense from						
20	Year placed in Service (0 if CWIP)						

21		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008				8,927,082		819,421						
27	W Increased ROE	2008				8,927,082		858,682						
28	W 11.68 % ROE	2009	8,601,534		794,647	33,993,795		3,927,226						
29	W Increased ROE	2009	8,601,534		833,737	33,993,795		4,120,411						
30	W 11.68 % ROE	2010	10,121,290		1,719,499	83,961,998		10,780,919						
31	W Increased ROE	2010	10,121,290		1,811,185	83,961,998		11,355,769						
32	W 11.68 % ROE	2011	30,831,150		3,376,923	133,618,838		19,674,374	19,588,655		1,299,846	1,648,851		56,106
33	W Increased ROE	2011	30,831,150		3,565,874	133,618,838		20,775,227	19,588,655		1,299,846	1,648,851		56,106
34	W 11.68 % ROE	2012	38,077,851		5,359,127	264,235,891		27,190,938	139,052,337		10,137,161	22,706,717		1,587,335
35	W Increased ROE	2012	38,077,851		5,676,479	264,235,891		28,801,108	139,052,337		10,137,161	22,706,717		1,587,335
36	W 11.68 % ROE	2013	40,538,248		5,381,625	567,928,477		56,420,758	79,292,223		21,408,869	117,558,986		7,924,475
37	W Increased ROE	2013	40,538,248		5,730,133	567,928,477		60,074,507	79,292,223		21,408,869	117,558,986		7,924,475
38	W 11.68 % ROE	2014	12,476,737		1,537,307	34,481,067		28,945,163	31,617,517		3,895,715	160,260,925		16,099,944
39	W Increased ROE	2014	12,476,737		1,646,580	34,481,067		31,002,624	31,617,517		3,895,715	160,260,925		16,099,944
40	W 11.68 % ROE	2015	-		-	15,544,417		1,822,213	-		-	81,558,947		9,560,846
41	W Increased ROE	2015	-		-	15,544,417		1,955,563	-		-	81,558,947		9,560,846
42	W 11.68 % ROE	2016	-		-	-		-	-		-	-		-
43	W Increased ROE	2016	-		-	-		-	-		-	-		-
44	W 11.68 % ROE	2017	-		-	-		-	-		-	-		-
45	W Increased ROE	2017	-		-	-		-	-		-	-		-
46	W 11.68 % ROE	2018	-		-	-		-	-		-	-		-
47	W Increased ROE	2018	-		-	-		-	-		-	-		-

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

1 New Plant Carrying Charge

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

Line		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	9.57%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5	C		Line B less Line A	0.57%

6 **FCR if a CIAC**

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

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		Mickleton-Gloucester-Camden Breakers (B1398.15-B1398.19) (CWIP)	Burlington - Camden 230kV Conversion (B1156) (CWIP)	Burlington - Camden 230kV Conversion (B1156.13-B1156.20) (CWIP)	Northeast Grid Reliability Project (B1304.1-B1304.4) (CWIP)
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	25
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%	9.57%	9.57%	9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%	9.57%	9.57%	9.71%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		-	-	-	-
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		-	-	-	-
19	Months in service for depreciation expense from						
20	Year placed in Service (0 if CWIP)						

21		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011				22,089,378		1,874,440						
33	W Increased ROE	2011				22,089,378		1,874,440						
34	W 11.68 % ROE	2012	532,375		24,600	128,653,138		10,501,318	9,231,712		791,084	81,587,177		6,341,372
35	W Increased ROE	2012	532,375		24,600	128,653,138		10,501,318	9,231,712		791,084	81,587,177		6,416,475
36	W 11.68 % ROE	2013	532,375		73,965	155,344,760		22,819,788	8,854,018		1,275,855	184,611,449		18,512,179
37	W Increased ROE	2013	532,375		73,965	155,344,760		22,819,788	8,854,018		1,275,855	184,611,449		18,751,945
38	W 11.68 % ROE	2014	532,375		65,596	56,976,438		7,020,285	3,745,932		461,551	211,553,988		28,743,491
39	W Increased ROE	2014	532,375		65,596	56,976,438		7,020,285	3,745,932		461,551	211,553,988		29,152,116
40	W 11.68 % ROE	2015	204,760		24,003	-		-	-		-	232,789,181		31,313,982
41	W Increased ROE	2015	204,760		24,003	-		-	-		-	232,789,181		31,772,294
42	W 11.68 % ROE	2016	-		-	-		-	-		-	103,162,268		11,805,242
43	W Increased ROE	2016	-		-	-		-	-		-	103,162,268		11,982,038
44	W 11.68 % ROE	2017	-		-	-		-	-		-	-		-
45	W Increased ROE	2017	-		-	-		-	-		-	-		-
46	W 11.68 % ROE	2018	-		-	-		-	-		-	-		-
47	W Increased ROE	2018	-		-	-		-	-		-	-		-

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

1	New Plant Carrying Charge				
2	**Fixed Charge Rate (FCR) if if not a CIAC**				
			Formula Line		
3		A	152	Net Plant Carrying Charge without Depreciation	9.57%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5		C		Line B less Line A	0.57%
6	**FCR if a CIAC**				
7		D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		Northeast Grid Reliability Project (B1304.5-B1304.21) (CWIP)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (CWIP)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (CWIP)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (CWIP)
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)		25	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%	9.57%	9.57%	9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.71%	9.57%	9.57%	9.57%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		-	327,500	3,373,416	4,386,778
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		-	7,798	80,319	104,447
19	Months in service for depreciation expense from				13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)						

Line		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
21														
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011												
33	W Increased ROE	2011												
34	W 11.68 % ROE	2012	5,537,185		457,198									
35	W Increased ROE	2012	5,537,185		462,613									
36	W 11.68 % ROE	2013	18,052,410		1,627,531									
37	W Increased ROE	2013	18,052,410		1,648,610									
38	W 11.68 % ROE	2014	33,293,621		3,699,551	9,496,612		391,383	1,589,541		61,526	1,531,032		58,653
39	W Increased ROE	2014	33,293,621		3,752,145	9,496,612		391,383	1,589,541		61,526	1,531,032		58,653
40	W 11.68 % ROE	2015	31,157,349		2,302,742	79,833,944		3,818,309	14,281,935		836,684	14,081,213		819,896
41	W Increased ROE	2015	31,157,349		2,336,445	79,833,944		3,818,309	14,281,935		836,684	14,081,213		819,896
42	W 11.68 % ROE	2016	35,334,506		4,043,459	518,235		5,126,158	11,570,665		857,240	2,658,598		921,870
43	W Increased ROE	2016	35,334,506		4,104,014	518,235		5,126,158	11,570,665		857,240	2,658,598		921,870
44	W 11.68 % ROE	2017	-		-	2,271,018		519,803	23,927,668		2,300,724	13,263,928		1,087,121
45	W Increased ROE	2017	-		-	2,271,018		519,803	23,927,668		2,300,724	13,263,928		1,087,121
46	W 11.68 % ROE	2018	-		-	327,500		31,344	3,373,416		322,857	4,386,778		419,841
47	W Increased ROE	2018	-		-	327,500		31,344	3,373,416		322,857	4,386,778		419,841

Attachment 9

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

1 New Plant Carrying Charge

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

Line		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	9.57%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5	C		Line B less Line A	0.57%

6 **FCR if a CIAC**

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

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		**Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33) (CWIP)**	**Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34) (CWIP)**	**Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50) (CWIP)**	**Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (CWIP)**
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%	9.57%	9.57%	9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%	9.57%	9.57%	9.57%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		20,653,909	30,394,186	14,893,653	8,794,765
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		491,760	723,671	354,611	209,399
19	Months in service for depreciation expense from Year placed in Service (0 if CWIP)			13.00	13.00	13.00	13.00
20							

Line			Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
22		W 11.68 % ROE	2006												
23		W Increased ROE	2006												
24		W 11.68 % ROE	2007												
25		W Increased ROE	2007												
26		W 11.68 % ROE	2008												
27		W Increased ROE	2008												
28		W 11.68 % ROE	2009												
29		W Increased ROE	2009												
30		W 11.68 % ROE	2010												
31		W Increased ROE	2010												
32		W 11.68 % ROE	2011												
33		W Increased ROE	2011												
34		W 11.68 % ROE	2012												
35		W Increased ROE	2012												
36		W 11.68 % ROE	2013												
37		W Increased ROE	2013												
38		W 11.68 % ROE	2014	2,114,342		74,197	1,476,460		58,912	838,906		41,991	433,918		21,259
39		W Increased ROE	2014	2,114,342		74,197	1,476,460		58,912	838,906		41,991	433,918		21,259
40		W 11.68 % ROE	2015	7,520,100		530,656	1,567,639		105,699	3,286,307		178,025	3,386,828		209,207
41		W Increased ROE	2015	7,520,100		530,656	1,567,639		105,699	3,286,307		178,025	3,386,828		209,207
42		W 11.68 % ROE	2016	65,119,433		3,473,891	36,960,137		1,695,242	24,980,240		1,011,439	14,073,743		749,927
43		W Increased ROE	2016	65,119,433		3,473,891	36,960,137		1,695,242	24,980,240		1,011,439	14,073,743		749,927
44		W 11.68 % ROE	2017	103,139,173		8,457,930	100,004,406		7,165,306	50,261,443		4,476,177	4,257,610		1,981,744
45		W Increased ROE	2017	103,139,173		8,457,930	100,004,406		7,165,306	50,261,443		4,476,177	4,257,610		1,981,744
46		W 11.68 % ROE	2018	20,653,909		1,976,705	30,394,186		2,908,909	14,893,653		1,425,414	8,794,765		841,713
47		W Increased ROE	2018	20,653,909		1,976,705	30,394,186		2,908,909	14,893,653		1,425,414	8,794,765		841,713

Attachment 9

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

1 New Plant Carrying Charge

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

Line		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	9.57%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5	C		Line B less Line A	0.57%

6 **FCR if a CIAC**

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

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70) (CWIP)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81) (CWIP)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83) (CWIP)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) (CWIP)
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%	9.57%	9.57%	9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%	9.57%	9.57%	9.57%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		13,879,908	84,069	80,847	(0)
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		330,474	2,002	1,925	(0)
19	Months in service for depreciation expense from			13.00	13.00	13.00	
20	Year placed in Service (0 if CWIP)						

Line		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
21														
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011												
33	W Increased ROE	2011												
34	W 11.68 % ROE	2012												
35	W Increased ROE	2012												
36	W 11.68 % ROE	2013												
37	W Increased ROE	2013												
38	W 11.68 % ROE	2014	1,370,003		56,093	597,317		24,145	597,317		24,145	569,297		24,114
39	W Increased ROE	2014	1,370,003		56,093	597,317		24,145	597,317		24,145	569,297		24,114
40	W 11.68 % ROE	2015	7,110,556		414,795	4,018,145		249,912	4,018,145		249,912	3,852,871		236,839
41	W Increased ROE	2015	7,110,556		414,795	4,018,145		249,912	4,018,145		249,912	3,852,871		236,839
42	W 11.68 % ROE	2016	45,554,419		2,311,095	21,015,450		1,295,020	21,015,450		1,295,020	22,912,843		1,342,797
43	W Increased ROE	2016	45,554,419		2,311,095	21,015,450		1,295,020	21,015,450		1,295,020	22,912,843		1,342,797
44	W 11.68 % ROE	2017	55,639,039		5,480,161	53,134		937,564	53,134		937,564	11,129,698		1,228,147
45	W Increased ROE	2017	55,639,039		5,480,161	53,134		937,564	53,134		937,564	11,129,698		1,228,147
46	W 11.68 % ROE	2018	13,879,908		1,328,392	84,069		8,046	80,847		7,738	(0)		-
47	W Increased ROE	2018	13,879,908		1,328,392	84,069		8,046	80,847		7,738	(0)		-

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

1 New Plant Carrying Charge

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

Line		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	9.57%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5	C		Line B less Line A	0.57%

6 **FCR if a CIAC**

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

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		**Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (CWIP)**	**Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (CWIP)**	**Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91) (CWIP)**	**New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (CWIP)**
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%	9.57%	9.57%	9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%	9.57%	9.57%	9.57%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		(0)	1,421,804	7,334	352,578
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		(0)	33,852	175	8,395
19	Months in service for depreciation expense from Year placed in Service (0 if CWIP)				13.00	13.00	13.00
20							

Line		Invest Yr	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011												
33	W Increased ROE	2011												
34	W 11.68 % ROE	2012												
35	W Increased ROE	2012												
36	W 11.68 % ROE	2013												
37	W Increased ROE	2013												
38	W 11.68 % ROE	2014	569,297		24,114	1,581,597		63,898	1,286,903		48,434	4,799,334		220,160
39	W Increased ROE	2014	569,297		24,114	1,581,597		63,898	1,286,903		48,434	4,799,334		220,160
40	W 11.68 % ROE	2015	3,852,871		236,839	14,750,089		849,382	13,603,685		780,003	20,855,739		1,506,352
41	W Increased ROE	2015	3,852,871		236,839	14,750,089		849,382	13,603,685		780,003	20,855,739		1,506,352
42	W 11.68 % ROE	2016	22,912,843		1,342,797	946,989		868,195	34,036		704,952	210,981		908,856
43	W Increased ROE	2016	22,912,843		1,342,797	946,989		868,195	34,036		704,952	210,981		908,856
44	W 11.68 % ROE	2017	11,129,698		1,228,147	2,422,164		197,896	777,902		85,840	1,212,870		130,718
45	W Increased ROE	2017	11,129,698		1,228,147	2,422,164		197,896	777,902		85,840	1,212,870		130,718
46	W 11.68 % ROE	2018	(0)		-	1,421,804		136,075	7,334		702	352,578		33,744
47	W Increased ROE	2018	(0)		-	1,421,804		136,075	7,334		702	352,578		33,744

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

1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if if not a CIAC**			
		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	9.57%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5	C		Line B less Line A	0.57%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (CWIP)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20) (CWIP)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (CWIP)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (CWIP)
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%	9.57%	9.57%	9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%	9.57%	9.57%	9.57%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		352,578	7,678	7,678	1,673,479
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		8,395	183	183	39,845
19	Months in service for depreciation expense from			13.00	13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)						

Line		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011												
33	W Increased ROE	2011												
34	W 11.68 % ROE	2012												
35	W Increased ROE	2012												
36	W 11.68 % ROE	2013												
37	W Increased ROE	2013												
38	W 11.68 % ROE	2014	5,002,105		223,171	123,509		4,946	124,051		4,952	337,481		13,854
39	W Increased ROE	2014	5,002,105		223,171	123,509		4,946	124,051		4,952	337,481		13,854
40	W 11.68 % ROE	2015	21,058,511		1,530,122	2,601,853		148,281	2,602,395		148,345	2,972,226		101,157
41	W Increased ROE	2015	21,058,511		1,530,122	2,601,853		148,281	2,602,395		148,345	2,972,226		101,157
42	W 11.68 % ROE	2016	96,330		915,296	9,752,687		597,380	9,750,168		597,124	35,618,949		2,125,894
43	W Increased ROE	2016	96,330		915,296	9,752,687		597,380	9,750,168		597,124	35,618,949		2,125,894
44	W 11.68 % ROE	2017	1,241,892		133,921	4,472,474		493,532	4,472,773		493,565	15,327,955		1,691,419
45	W Increased ROE	2017	1,241,892		133,921	4,472,474		493,532	4,472,773		493,565	15,327,955		1,691,419
46	W 11.68 % ROE	2018	352,578		33,744	7,678		735	7,678		735	1,673,479		160,162
47	W Increased ROE	2018	352,578		33,744	7,678		735	7,678		735	1,673,479		160,162

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

1	New Plant Carrying Charge			
2	**Fixed Charge Rate (FCR) if if not a CIAC**			
		Formula Line		
3	A	152	Net Plant Carrying Charge without Depreciation	9.57%
4	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.14%
5	C		Line B less Line A	0.57%
6	**FCR if a CIAC**			
7	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.47%

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

10		Details		**New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33) (CWIP)**
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes
12	Useful life of the project	Life		42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.57%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.57%
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		1,914,773
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		45,590
19	Months in service for depreciation expense from			13.00
20	Year placed in Service (0 if CWIP)			

21		Invest Yr	Ending	Depreciation or Amortization	Revenue	Total	Incentive Charged	Revenue Credit	
22	W 11.68 % ROE	2006				$ 4,652,471		$ 4,652,471	
23	W Increased ROE	2006				$ 4,652,471	$ 4,652,471		$ -
24	W 11.68 % ROE	2007				$ 29,476,571		$ 29,476,571	
25	W Increased ROE	2007				$ 29,476,571	$ 29,476,571		$ -
26	W 11.68 % ROE	2008				$ 32,346,385		$ 32,346,385	
27	W Increased ROE	2008				$ 32,385,646	$ 32,385,646		$ 39,261
28	W 11.68 % ROE	2009				$ 51,356,608		$ 51,356,608	
29	W Increased ROE	2009				$ 51,588,883	$ 51,588,883		$ 232,275
30	W 11.68 % ROE	2010				$ 61,349,032		$ 61,349,032	
31	W Increased ROE	2010				$ 62,015,568	$ 62,015,568		$ 666,536
32	W 11.68 % ROE	2011				$ 78,438,322		$ 78,438,322	$ -
33	W Increased ROE	2011				$ 79,823,709	$ 79,823,709		$ 1,385,386
34	W 11.68 % ROE	2012				$ 129,728,618		$ 129,728,618	
35	W Increased ROE	2012				$ 131,858,773	$ 131,858,773		$ 2,130,155
36	W 11.68 % ROE	2013				$ 279,708,533		$ 279,708,533	
37	W Increased ROE	2013				$ 284,314,797	$ 284,314,797		$ 4,606,265
38	W 11.68 % ROE	2014	133,460		5,677	$ 342,977,142		$ 342,977,142	
39	W Increased ROE	2014	133,460		5,677	$ 349,823,024	$ 349,823,024		$ 6,845,883
40	W 11.68 % ROE	2015	258,129		20,804	$ 434,110,713		$ 434,110,713	
41	W Increased ROE	2015	258,129		20,804	$ 441,614,467	$ 441,614,467		$ 7,503,754
42	W 11.68 % ROE	2016	2,173,541		157,609	$ 558,001,204		$ 558,001,204	
43	W Increased ROE	2016	2,173,541		157,609	$ 566,080,859	$ 566,080,859		$ 8,079,655
44	W 11.68 % ROE	2017	14,065,098		934,008	$ 576,209,051		576,209,051	
45	W Increased ROE	2017	14,065,098		934,008	$ 583,935,997	$ 583,935,997		$ 7,726,945
46	W 11.68 % ROE	2018	1,914,773		183,255	$ 506,060,336		$ 506,060,336	
47	W Increased ROE	2018	1,914,773		183,255	$ 511,849,690	$ 511,849,690		$ 5,789,354

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

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

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

Required Transmission Enhancements

Upgrade ID	RTEP Baseline Project Description	Estimated/Actual Project Cost (thru 2018) *	Anticipated/Actual In-Service Date *
b0130	Replace all derated Branchburg 500/230 kv transformers	$ 20,645,602	Jan-06
b0134	Reconductor Kittatinny - Newtown 230 kV with 1590 ACSS	$ 8,069,022	Aug-07
b0145	Build new Essex - Aldene 230 kV cable connected through phase angle regulator at Essex	$ 86,467,721	Aug-07
b0411	Install 4th 500/230 kV transformer at New Freedom	$ 22,188,863	May-09
b0498	Loop the 5021 circuit into New Freedom 500 kV substation	$ 27,005,248	May-09
b0161	Install 230-138kV transformer at Metuchen substation	$ 25,654,455	Nov-08
b0169	Build a new 230 kV section from Branchburg - Flagtown and move the Flagtown - Somerville 230 kV circuit to the new section	$ 15,731,554	May-08
b0170	Reconductor the Flagtown-Somerville-Bridgewater 230 kV circuit with 1590 ACSS	$ 6,961,495	May-09
b0274	Replace both 230/138 kV transformers at Roseland	$ 21,014,433	Apr-12
b0172.2	Replace wave trap at Branchburg 500kV substation	$ 27,988	Feb-07
b0813	Reconductor Hudson - South Waterfront 230kV circuit	$ 9,158,918	May-12
b1017	Reconductor South Mahwah 345 kV J-3410 Circuit	$ 20,626,991	Dec-12
b1018	Reconductor South Mahwah 345 kV K-3411 Circuit	$ 21,170,273	May-11
b0290	Branchburg 400 MVAR Capacitor	$ 77,352,830	Nov-10
b0472	Saddle Brook - Athenia Upgrade Cable	$ 14,404,842	Nov-08
b0664-b0665	Branchburg-Somerville-Flagtown Reconductor	$ 18,664,931	Apr-12
b0668	Somerville -Bridgewater Reconductor	$ 6,390,403	Apr-12
b0814	New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie	$ 46,035,637	Dec-10
b1410-b1415	Replace Salem 500 kV breakers	$ 15,865,267	Oct-12
b1228	230kV Lawrence Switching Station Upgrade	$ 21,736,918	May-11
b1155	Branchburg-Middlesex Swich Rack	$ 62,937,256	Dec-11
b1399	Aldene-Springfield Rd. Conversion	$ 72,380,453	Dec-12
b1590	Upgrade Camden-Richmond 230kV Circuit (B1590)	$ 11,276,183	Apr-13
b1588	Uprate EaglePoint-Gloucester 230kV Circuit	$ 12,087,537	May-11
b2139	Build Mickleton-Gloucester Corridor Ultimate Design	$ 19,272,633	Dec-13
b1255	Ridge Road 69kV Breaker Station	$ 34,729,740	Jun-16
b1787	New Cox's Corner-Lumberton 230kV Circuit	$ 32,027,160	Nov-13
b0376	Install Conemaugh 250MVAR Cap Bank (B0376)	$ 1,108,058	Mar-16
b1589	Reconfigure Kearny- Loop in P2216 Ckt (B1589)	$ 21,487,134	May-18
b2146	Reconfigure Brunswick Sw-New 69kVCkt-T (B2146)	$ 146,250,715	Oct-17
b2702	350 MVAR Reactor Hopatcong 500kV (B2702)	$ 21,301,080	Jun-18
b0489.5-b0489.15	Susquehanna Roseland Breakers(In-Service)	$ 5,857,687	Jun-14
b0489.4	Build new 500 kV transmission facilities from Pennsylvania - New Jersey border at Bushkill to Roseland (Below 500 kV elements of the project) (In-Service)	$ 40,538,248	Nov-11
b0489	Build new 500 kV transmission facilities from Pennsylvania - New Jersey border at Bushkill to Roseland (500kV and above elements of the project) (In-Service)	$ 720,620,844	Mar-15
b1156	Burlington - Camden 230kV Conversion (In-Service)	$ 356,333,540	Oct-14
b1398 - b1398.7	Mickleton-Gloucester-Camden(In-Service)	$ 439,384,743	Jun-15
b1154	North Central Reliability (West Orange Conversion) (In-Service)	$ 370,006,995	Jun-15
b1304.1-b1304.4	Northeast Grid Reliability Project (In-Service)	$ 625,390,228	Jun-15
b2436.10	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)	$ 174,969,351	Jan-16
b2436.21	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades	$ 68,319,997	May-16
b2436.22	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades	$ 49,614,813	May-16
b2436.33	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades	$ 162,329,270	Dec-15
b2436.34	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34)	$ 120,922,525	Feb-18
b2436.50	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50)	$ 63,112,389	Mar-18
b2436.60	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60)	$ 49,352,658	Dec-15
b2437.10	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10)	$ 26,819,837	May-16
b2437.11	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11)	$ 26,819,837	May-16
b2437.20	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20)	$ 15,574,675	Dec-15
b2437.21	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21)	$ 15,574,675	Dec-15
b2437.30	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30)	$ 20,678,337	Jul-16
	Total	**$ 4,581,326,904**	

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

Public Service Electric and Gas Company

Accumulated Deferred Income Taxes Using The Proration Methodology - Tax Basis

Amounts reflected in Annual Update Filing

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

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

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	
Line	Year	Month	Projected Monthly (Increase) In ADIT - Depreciable Tax Basis	Days Outstanding During the Year	Proration Percentage	Monthly Prorated Amount	Cumulative "prorated" ADIT	Beginning & Ending ADIT Balance	
1	2017	Dec						(2,383,691,531)	A
2	2018	Jan	(23,167,070)	335	91.78%	(21,262,928)	(2,404,954,459)		
3	2018	Feb	(23,640,412)	307	84.11%	(19,883,853)	(2,424,838,312)		
4	2018	Mar	(24,080,123)	276	75.62%	(18,208,531)	(2,443,046,843)		
5	2018	Apr	(25,252,039)	246	67.40%	(17,019,182)	(2,460,066,025)		
6	2018	May	(24,392,170)	215	58.90%	(14,367,991)	(2,474,434,016)		
7	2018	Jun	(24,900,952)	185	50.68%	(12,621,031)	(2,487,055,047)		
8	2018	Jul	(23,470,852)	154	42.19%	(9,902,771)	(2,496,957,818)		
9	2018	Aug	(23,044,552)	123	33.70%	(7,765,698)	(2,504,723,516)		
10	2018	Sep	(23,177,202)	93	25.48%	(5,905,424)	(2,510,628,940)		
11	2018	Oct	(23,569,552)	62	16.99%	(4,003,595)	(2,514,632,535)		
12	2018	Nov	(23,121,902)	32	8.77%	(2,027,126)	(2,516,659,661)		
13	2018	Dec	(23,576,902)	1	0.27%	(64,594)	(2,516,724,255)		
		Total	(285,393,730)			(133,032,724)			

14	Projected 2018 Liberalized Depreciation based on ADIT Proration Methodology:	(133,032,724)	
15	Plus: Projected 2018 ADIT associated with Liberalized Deprecation not subject to Proration Methodology:	(81,108,169)	
16	Projected 2018 EOY Federal and State Liberalized Depreciation ADIT included in the FERC Formula Filing:	(2,597,832,425)	B

Explanations:

Col. 8, Line 1	Represents the estimated beginning plant-related Liberalized Depreciation ADIT balance as of 1/1/2018.
Lines 2 - 13	Represents the Forecasted Rate period (e.g. 2018).
Col. 3	Represents the monthly (increase) additions to the ADIT balance associated with depreciatable tax basis before proration.
Col. 4	Number of days remaining in the year as of and including the last day of the month.
Col. 5	Col. 4 divided by the number of days in the year, 365.
Col. 6	Col. 3 multiplied by Col. 5.
Col. 7	Col. 6 of previous month plus Col. 7; represents the cumulative balance.
Col. 8, Line 14	Total projected plant-related Liberalized Depreciation ADIT related to depreciable tax basis.
Col. 8, Line 15	Projected plant-related Liberalized Depreciation ADIT that is not subjected to the proration rules.
Col. 8, Line 16	Projected Total EOY balance of plant-related Liberalized Depreciation ADIT that is included in the formula rate.

Public Service Electric and Gas Company

Accumulated Deferred Income Taxes Using The Proration Methodology - Tax Basis

Amounts reflected in Annual Update Filing

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

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

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

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

Explanations:

Col. 8, Line 1	Represents the estimated beginning plant-related Liberalized Depreciation ADIT balance as of 1/1/2018.
Lines 2 - 13	Represents the Forecasted Rate period (e.g. 2018).
Col. 3	Represents the monthly (increase) additions to the ADIT balance associated with depreciatable tax basis before proration.
Col. 4	Number of days remaining in the year as of and including the last day of the month.
Col. 5	Col. 4 divided by the number of days in the year, 365.
Col. 6	Col. 3 multiplied by Col. 5.
Col. 7	Col. 6 of previous month plus Col. 7; represents the cumulative balance.
Col. 8, Line 14	Total projected plant-related Liberalized Depreciation ADIT related to depreciable tax basis.
Col. 8, Line 15	Projected plant-related Liberalized Depreciation ADIT that is not subjected to the proration rules.
Col. 8, Line 16	Projected Total EOY balance of plant-related Liberalized Depreciation ADIT that is included in the formula rate.

Attachment 10 (JCP&L Formula Rate Offer of Settlement)

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TORONTO

December 21, 2017

By eTariff

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

Re: PJM Interconnection, L.L.C., Docket No. ER17-217-003
Offer of Settlement

Dear Secretary Bose:

Pursuant to Rule 602 of the Commission's Rules of Practice and Procedure, Jersey Central Power & Light Company ("JCP&L") hereby submits an Offer of Settlement ("Settlement") in the above-referenced proceeding. This Settlement is intended to resolve all issues set for hearing in the above-captioned proceeding involving JCP&L's transmission formula rate under the PJM Interconnection, L.L.C. ("PJM") Open Access Transmission Tariff.[1]

In accordance with Rule 602(c)(1), this Settlement filing consists of the following documents:

1. This transmittal letter;

2. An Explanatory Statement; and

3. The Settlement, including copies of *pro forma* tariff records and other appendices.

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[1] This filing is being submitted by PJM on behalf of JCP&L as part of an XML filing package that conforms with the Commission's regulations. PJM has agreed to make all filings on behalf of the PJM Transmission Owners in order to retain administrative control over the PJM Tariff. JCP&L requested that PJM submit this filing in the eTariff system as part of PJM's electronic Intra-PJM Tariff.

JCP&L certifies that it is serving a complete copy of the Settlement on all parties to the above-referenced proceeding. In accordance with Commission regulations, comments on the settlement package are due twenty (20) days from the date of filing, making comments due January 10, 2018. Reply comments are due January 22, 2018.

Respectfully submitted,

/s/ Matthew W.S. Estes

Counsel for
Jersey Central Power & Light Company

cc: All parties
Enclosures

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	**Docket No. ER17-217-003**
Jersey Central Power & Light Co.	)	

EXPLANATORY STATEMENT

Pursuant to Rule 602 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or "Commission"), 18 C.F.R. § 385.602 (2017), Jersey Central Power & Light Co. ("JCP&L"), on behalf of the Settling Parties,[1] submits this explanatory statement in support of the Offer of Settlement ("Settlement") to resolve the issues set for hearing and settlement judge procedures in the above-captioned docket. It is the Settling Parties' understanding that no other participants in these proceedings oppose the Settlement.

This Explanatory Statement is provided solely to comply with Rule 602(c)(1)(ii) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.602(c)(1)(ii). Except as otherwise defined herein, the capitalized terms used in this Explanatory Statement have the meanings set forth in the related Settlement. This Explanatory Statement is not intended to, and does not alter any of the provisions of the Settlement. In the event of an inconsistency between the Explanatory Statement and the Settlement, the Settlement shall control.

I. PROCEDURAL HISTORY

On October 28, 2016, in Docket No. ER17-217-000, PJM Interconnection, L.L.C. ("PJM"), on behalf of JCP&L, filed under section 205 of the Federal Power Act ("FPA") for approval of a transmission formula rate template ("Template") and formula rate protocols

---

[1] The Settling Parties are JCP&L and New Jersey Division of the Rate Counsel ("NJ Rate Counsel"); New Jersey Board of Public Utilities ("NJ BPU"), the Public Power Association of New Jersey ("PPANJ"), and the U.S. Department of Defense/Federal Executive Agencies ("DOD").

("Protocols") to establish transmission rates for the JCPL zone under the PJM Open Access Transmission Tariff ("PJM Tariff"). JCP&L's filing included a revised Exhibit H-4 and new Attachments H-4A (Template) and H-4B (Protocols) to the PJM Tariff. JCP&L requested an effective date for its filing of January 1, 2017.

Motions to intervene and comments, protests, and motions for suspension and hearing were filed in this proceeding by certain parties, including, among others, all Settling Parties. On December 5, 2016, JCP&L submitted an answer to the protests and motions, and certain parties filed answers to JCP&L's answer.

On December 28, 2016, the Commission issued a letter finding JCP&L's filing to be deficient and requesting additional information. PJM Interconnection, L.L.C., Docket No. ER17-217-000, Deficiency Letter (issued Dec. 28, 2016) ("December 28 Letter"). On January 10, 2017, JCP&L submitted its response providing the additional information requested in the December 28 Letter, as well as certain revisions to the Template required in the December 28 Letter. Several parties submitted comments and protests to JCP&L's response, and JCP&L filed an answer to those pleadings.

On March 10, 2017, the Commission issued a letter order accepting JCP&L's filing subject to refund, suspending the filing for five months to be effective on June 1, 2017, and setting the proceeding for hearing and settlement judge procedures. *Jersey Cent. Power & Light Co.*, 158 FERC ¶ 62,186 (2017) ("March 10 Order"). On April 10, 2017, JCP&L filed a motion for reconsideration or, in the alternative, request for rehearing of the March 10 Order, asking for reconsideration or rehearing of the decision to suspend the filing for five months.

On March 16, 2017, the Chief Administrative Law Judge ("ALJ") appointed ALJ Philip C. Baten as the Settlement Judge. In-person settlement proceedings were held with Judge Baten on April 11, 2017, June 6, 2017, July 14, 2017, August 17, 2017, September 21, 2017, and October 26, 2017. In addition, numerous telephonic technical conferences were held among JCP&L, the parties, and FERC Trial Staff; and the parties and FERC Trial Staff submitted, and JCP&L responded to, several sets of data requests seeking information on JCP&L's filing.

During the settlement proceedings, the parties and FERC Trial Staff submitted several settlement proposals and counterproposals.

As a result of these settlement efforts, during a settlement call held on November 9, 2017, an agreement-in-principle to resolve all issues in this proceeding was reached among FERC Trial Staff and the Settling Parties. The agreement-in-principle has resulted in the Offer of Settlement and Settlement Agreement that is being filed today.

II. SUMMARY OF SETTLEMENT

The provisions of the Settlement are summarized below.

Article 1 is an introductory section, identifying the parties to the Settlement and stating that it will be filed with the Commission.

Article 2 provides that the Settlement resolves all issues raised in this proceeding and sets forth the terms and conditions of the Settlement.

> Section 2.1 provides that the filed formula rate Template and Protocols will be replaced by a black box stated rate with revenue requirements ("Settlement Revenue Requirements"). JCP&L's stated revenue requirement for its Network Integration Transmission Service ("NITS") shall be $135 million/year and JCP&L's stated revenue requirement for its projects listed on Schedule 12 of the PJM OATT shall be an average of $20 million/year aggregating $51.67 million over the 31 months from June 1, 2017 through December 31, 2019. JCP&L's stated total aggregate revenue requirement for its

projects listed on Schedule 12 will be allocated over three periods as specified in the Settlement. The Settlement Revenue Requirements fully reflect the Settling Parties' view of the impact of any potential legislative tax reform and the Settling Parties agree that no future adjustment to those revenue requirements is necessary if any Federal tax reform is enacted.

Section 2.2 provides that the Template and Protocols that were accepted, subject to refund, in the March 10 Order as Attachments H-4A and H-4B respectively, shall be withdrawn as of the date that the Settlement is approved by the Commission and shall have no effect thereafter.

Section 2.3 establishes a rate moratorium, and provides that, with limited exceptions, no Settling Party (individually or collectively) shall seek an effective date earlier than January 1, 2020 in any filing made under sections 205 or 206 of the FPA proposing any changes to, or challenging the justness and reasonableness of, this Settlement Agreement or the Settlement Revenue Requirements. The exceptions are that: (a) JCP&L may file for adders to the Settlement Revenue Requirements for certain large projects placed in service with a January 1, 2019 or later in-service date; (b) JCP&L may file pursuant to FPA section 205 solely to recover the costs of an Extraordinary Storm (as defined in the Settlement) in addition to recovering the Settlement Revenue Requirements; and (c) in the event the Commission or any non-Settling Party files under section 206 of the FPA to re-open the stated rate to seek changes to reflect the impact of legislative tax reform, JCP&L shall be entitled, at its discretion, to make a filing under FPA section 205 to change its rates during the moratorium period. The other Settling Parties shall have full rights under FPA section 205 to oppose any such filings by JCP&L as not being just and reasonable.

Section 2.4 provides that the rates to existing NITS customers for transmission over low voltage facilities (*i.e.*, at voltages below 34.5 kv delta) ("Low Voltage Customers") shall be fixed at the existing levels for the duration of the transmission stated rate moratorium. In addition, a new Attachment H-4A shall be added to the PJM Tariff that addresses rates charged for the provision of transmission service over JCP&L's low voltage transmission facilities

Section 2.5 provides that, as of December 31, 2019, the account balances of the three regulatory assets for (a) storm costs, (b) vegetation management costs, and (c) formula rate development costs that JCP&L included in its filed Formula Rate Template will be deemed to be $0.00 for FERC accounting purposes and deemed fully recovered for ratemaking purposes.

Section 2.6 establishes JCP&L's depreciation rates.

Section 2.7 provides that the effective date of the Settlement Revenue Requirements shall be June 1, 2017. An amount equal to the difference between the rates charged by PJM and the rates that would have been charged under the Settlement, plus interest calculated pursuant to section 35.19a(a)(2) of the Commission's regulations, for the period from June 1, 2017 through the date the Settlement Revenue Requirements as reflected in PJM billings for NITS and Schedule 12 charges (the "Settlement Billing Date") will be ratably credited against the revenue requirements for NITS and Schedule 12 for the remaining months in the calendar year in which the Settlement Billing Date occurs.

Section 2.8 provides that, within thirty days of the Commission's approval of the Settlement, JCP&L will withdraw its April 10, 2017 Motion for Reconsideration or, in the Alternative, Request for Rehearing.

Section 2.9 provides that JCP&L shall file a motion with the Chief Administrative Law Judge requesting that the Settlement Revenue Requirements be accepted as interim rates pursuant to 18 C.F.R. § 375.307(a)(1)(iv), effective January 1, 2018, pending the Commission's approval of the Settlement. In the event the Settlement is withdrawn, then JCP&L's existing revenue requirements shall go into effect and the difference between the amounts collected under the Interim Rate and the amounts that would have been collected under the existing revenue requirements for such period that the Interim Rate was in effect shall be reflected in JCP&L's revenue requirements.

Article 3 sets forth miscellaneous provisions. Notably, Article 3 provides that the Settlement is an integrated package and that the individual provisions thereof are non-severable. However, if any party submits comments opposing specific aspects of the Settlement, if all the Settling Parties agree and so inform the Commission, the Commission may sever some or all of the issues raised in the comments. Further, Article 3 provides that the standard of review for modifications to the Settlement proposed by any Settling Party thereto after it is approved by the Commission is the public interest standard and that the standard of review for any changes proposed by third parties and the Commission acting *sua sponte* shall be the just and reasonable standard.

III. INFORMATION REQUIRED BY THE CHIEF ADMINISTRATIVE LAW JUDGE'S DECEMBER 15, 2016 NOTICE REGARDING SETTLEMENT AGREEMENTS

1. Does the settlement affect other pending cases?

The Settling Parties are not aware of any pending cases that would be affected by the Settlement.

2. Does the settlement involve issues of first impression?

The Settling Parties are not aware of any issues of first impression raised by the Settlement.

3. Does the settlement depart from Commission precedent?

The Settling Parties are not aware of any departures from Commission precedent.

4. Does the settlement seek to impose a standard of review other than the ordinary just and reasonable standard with respect to any changes to the settlement that might be sought by either a third party or the Commission acting sua sponte?

Upon the Commission's approval of the Settlement, the applicable standard of review for any changes proposed by the Settling Parties shall be the public interest standard and the standard of review for any changes proposed by third parties and the Commission acting *sua sponte* shall be the just and reasonable standard.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	Docket No. ER17-217-003
Jersey Central Power & Light Co.	)	

SETTLEMENT AGREEMENT
AND
OFFER OF SETTLEMENT

This Settlement Agreement (“Settlement” or “Agreement”), submitted to the Federal Energy Regulatory Commission (“FERC” or the “Commission”) for approval as an Offer of Settlement pursuant to Rule 602 of the Commission’s Rules of Practice and Procedure, 18 C.F.R. § 385.602 (2017), is entered into as of December 19, 2017 by Jersey Central Power & Light Company (“JCP&L), New Jersey Division of the Rate Counsel (“NJ Rate Counsel”); New Jersey Board of Public Utilities (“NJ BPU”), the Public Power Association of New Jersey (“PPANJ”), and the U.S. Department of Defense/Federal Executive Agencies (“DOD”) (each a “Settling Party” and collectively, the “Settling Parties”).

This Settlement Agreement is submitted as an Offer of Settlement to resolve completely, upon the Commission’s acceptance of this Settlement without condition or modification unacceptable to the Settling Parties, all issues in this proceeding. Subject to the conditions set forth in this Settlement, including the acceptance by the Commission of this Settlement in its entirety without condition or modification unacceptable to the Settling Parties, and with the understanding that each term of this Settlement is in consideration and support of every other term, the Settling Parties agree as follows.

ARTICLE I

Background

1.1. On October 28, 2016, in Docket No. ER17-217-000, PJM Interconnection, L.L.C. ("PJM"), on behalf of JCP&L, filed under section 205 of the Federal Power Act ("FPA") for approval of a transmission formula rate template ("Template") and formula rate protocols ("Protocols") to establish transmission rates for the JCPL zone under the PJM Open Access Transmission Tariff ("PJM Tariff"). JCP&L's filing included a revised Exhibit H-4 and new Attachments H-4A (Template) and H-4B (Protocols) to the PJM Tariff. JCP&L requested an effective date for its filing of January 1, 2017.

1.2. Motions to intervene and comments, protests, and motions for suspension and hearing were filed in this proceeding by certain parties, including, among others, all Settling Parties. On December 5, 2016, JCP&L submitted an answer to the protests and motions, and certain parties filed answers to JCP&L's answer.

1.3. On December 28, 2016, the Commission issued a letter finding JCP&L's filing to be deficient and requesting additional information. *PJM Interconnection, L.L.C.*, Docket No. ER17-217-000, Deficiency Letter (issued Dec. 28, 2016) ("December 28 Letter"). On January 10, 2017, JCP&L submitted its response providing the additional information requested in the December 28 Letter, as well as certain revisions to the Template required in the December 28 Letter. Several parties submitted comments and protests to JCP&L's response, and JCP&L filed an answer to those pleadings.

1.4. On March 10, 2017, the Commission issued a letter order accepting JCP&L's filing subject to refund, suspending the filing for five months to be effective on June 1, 2017, and setting the proceeding for hearing and settlement judge procedures. *Jersey Cent. Power & Light Co.*, 158 FERC ¶ 62,186 (2017) ("March 10 Order"). On

April 10, 2017, JCP&L filed a motion for reconsideration or, in the alternative, request for rehearing of the March 10 Order, asking for reconsideration or rehearing of the decision to suspend the filing for five months.

1.5. On March 16, 2017, the Chief Administrative Law Judge ("ALJ") appointed ALJ Philip C. Baten as the Settlement Judge. In-person settlement proceedings were held with Judge Baten on April 11, 2017, June 6, 2017, July 14, 2017, August 17, 2017, September 21, 2017, and October 26, 2017. In addition, numerous telephonic technical conferences were held among JCP&L, the parties, and FERC Trial Staff; and the parties and FERC Trial Staff submitted, and JCP&L responded to, several sets of data requests seeking information on JCP&L's filing.

1.6 During the settlement proceedings, the parties and FERC Trial Staff submitted several settlement proposals and counterproposals.

1.7. As a result of these settlement efforts, during a settlement call held on November 9, 2017, an agreement-in-principle to resolve all issues in this proceeding was reached among FERC Trial Staff and the Settling Parties. The agreement-in-principle has resulted in the Offer of Settlement and Settlement Agreement that is being filed today.

1.8. No party indicated that it would oppose the Offer of Settlement, either on the November 9, 2017 settlement call or thereafter. Consequently, to the knowledge of the Settling Parties, this Offer of Settlement is uncontested.

NOW, THEREFORE, in consideration of the promises and the mutual covenants and agreements contained herein, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Settling Parties, intending to be legally bound, agree as follows:

ARTICLE II

Terms of the Settlement Agreement

The Settling Parties hereby settle and resolve all issues between them involving the matters raised in Docket No. ER17-217, on the terms set forth below.

2.1 Black Box Stated Revenue Requirement. The Settling Parties agree that JCP&L's proposed Formula Rate shall be replaced by a black box stated rate with revenue requirements, as follows:

(a) JCP&L's stated revenue requirement for its Network Integration Transmission Service ("NITS") shall be $135 million/year.

(b) JCP&L's stated revenue requirement for its projects listed on Schedule 12 of the PJM OATT shall be an average of $20 million/year aggregating $51.67 million over the 31 months from June 1, 2017 through December 31, 2019. JCP&L's stated total aggregate revenue requirement for TEC will be allocated over three periods:

(i) For rates effective from June 1, 2017 through December 31, 2017, JCP&L's stated revenue requirement collected for TEC will be $7,433,693 based on an annual revenue requirement of $12,743,474.
(ii) For rates effective from January 1, 2018 through December 31, 2018, JCP&L's stated annual revenue requirement for TEC will be $21,605,928.
(iii) For rates effective from January 1, 2019, JCP&L's stated annual revenue requirement for TEC will be $22,627,046.

(c) The revenue requirements provided for in parts (a) and (b) of this Section 2.1 (the "Settlement Revenue Requirements") are the product of a black box settlement, and they are not based on any agreed-upon assumptions about the elements of the rate, including return on equity, recovery of regulatory assets, or the functionalization of JCP&L's costs or plant. Nothing in this

Settlement Agreement is intended to establish any principle or precedent with respect to any issue in these proceedings except as explicitly set forth herein. Accordingly, neither this Settlement Agreement nor JCP&L's performance in accordance herewith shall be deemed to constitute an admission or concession as to (i) the justness of any cost, charge, cost-of-service component, or ratemaking method, or (ii) any contention or position that was asserted, or that could have been asserted, in this docket. The Commission's approval of this Settlement Agreement shall not constitute a determination by the Commission as to the merits of any allegation or contention that was made or that could have been made in these proceedings.

(d) The Settlement Revenue Requirements fully reflect the Settling Parties' view of the impact of any potential legislative tax reform and the Settling Parties agree that no future adjustment to those revenue requirements is necessary if any Federal tax reform is enacted. Therefore, there shall be no re-opener or adjustment to the Settlement Agreement or the Settlement Revenue Requirements effective prior to January 1, 2020 to reflect the recently introduced Tax Cuts and Jobs Act, or any other legislation reducing the corporate income tax rate or otherwise affecting the amount of Federal taxes owed by JCP&L.

(e) Attached as Exhibit 1 is the revised version of the tariff sheets affected by this Settlement Agreement, and attached as Exhibit 2 is a marked version of those tariff sheets showing the changes made to the currently-effective tariff.

2.2 Withdrawal of Template and Protocols. The Settling Parties agree that the Template and Protocols that were accepted, subject to refund, in the March 10 Order as Attachments H-4A and H-4B respectively, shall be withdrawn as of the date that this Settlement Agreement is approved by the Commission and shall have no effect thereafter.

2.3. Rate Moratorium.

(a) Except as provided in Sections 2.3(b), (c) and (d) below, no Settling Party (individually or collectively) shall seek an effective date earlier than January 1, 2020 in any filing made under sections 205 or 206 of the FPA proposing any changes to, or challenging the justness and reasonableness of, this Settlement Agreement or the Settlement Revenue Requirements. Nor shall any Settling Party support such a request by another entity.

(b) JCP&L may make limited filings pursuant to FPA section 205, and the other Settling Parties shall have full rights under FPA section 205 to oppose JCP&L's rate filing as not being just and reasonable, for adders to the Settlement Revenue Requirements for projects with a January 1, 2019 or later in-service date that would take effect during the period of the rate moratorium, as follows: (1) filings pursuant to FERC Order No. 679 for incentives associated with a project with a projected cost of $100 million or more; or (2) filings associated with PJM Regional Transmission Expansion Planning ("RTEP") project(s) (costing $50 million or more in the aggregate) to the extent that, prior to January 1, 2020, JCP&L is required to construct and place such projects in service.

(c) In the event of an Extraordinary Storm (defined below) during the period in which the Settlement Revenue Requirements are in effect, JCP&L may file pursuant to FPA section 205 solely to recover the costs of an Extraordinary Storm in addition to recovering the Settlement Revenue Requirements. For purposes of this Agreement, an Extraordinary Storm shall be defined as a single event (wind, tornado, hurricane, tropical storm, tropical depression, rain, snow, hail, sleet, ice, lightning, flood, fire resulting from any of these natural perils, and similar causes) that results in JCP&L incurring costs of greater than $1,500,000 (net of any insurance receipts from third-party coverage) to remediate storm damage to the JCP&L transmission system.[1] The other Settling Parties shall have full rights under FPA section 205 to oppose JCP&L's rate filing as not being just and reasonable. Any Extraordinary Storm costs below this $1,500,000 threshold are deemed to be recovered through the Settlement Revenue Requirements.

(d) No Party may support any action initiated during the moratorium period by the Commission or any non-Settling Party under section 206 of the FPA to re-open the stated rate to seek changes to reflect the impact of legislative tax reform, nor shall any Party be entitled to initiate its own section 206 action or otherwise take any action during the moratorium period to support any change to Settlement Revenue Requirements; except that only if the Commission and/or any non-Settling Party initiates an action to re-open the

[1] The definition of Extraordinary Storm as used herein does not incorporate the definition of an "Extraordinary Item" as defined in General Instruction No. 7 of the Commission's Uniform System of Accounts.

stated rate shall JCP&L be entitled, at its discretion, to make a filing under FPA section 205 to change its rates during the moratorium period. The other Settling Parties shall have full rights under FPA section 205 to oppose JCP&L's rate filing as not being just and reasonable.

(e) Notwithstanding paragraph 2.3(d), Settling Parties are free to take any position in generic Commission proceedings not specifically applicable to JCP&L regarding the effect of legislative tax reform on existing transmission rates, provided that no Settling Party may take a position in such generic proceeding specifically as to the Settlement Revenue Requirements during the moratorium period.

2.4 Rates for Transmission Over Low Voltage Facilities.

(a) The rates to existing NITS customers for transmission over low voltage facilities (*i.e.*, at voltages below 34.5 kv delta) ("Low Voltage Customers") shall be fixed at the existing levels for the duration of the transmission stated rate moratorium. Such Low Voltage Customers include the New Jersey Boroughs of Butler, Lavallette, Madison, Pemberton and Seaside Heights. These rates are already fixed pursuant to individual PJM NITS (Attachment F) agreements through May 31, 2019.

(b) A new Attachment H-4A shall be added to the PJM Tariff that addresses rates charged for the provision of transmission service over JCP&L's low voltage transmission facilities, as reflected on Exhibits 1 and 2 to this Settlement Agreement.

2.5. Regulatory Assets. As of December 31, 2019, the account balances of the three regulatory assets for (a) storm costs, (b) vegetation management costs, and (c) formula rate development costs that JCP&L included in its filed Formula Rate Template will be deemed to be $0.00 for FERC accounting purposes and deemed fully recovered for ratemaking purposes.

2.6. Depreciation. The Settling Parties agree to the depreciation and amortization rates filed in this proceeding by JCP&L and shown in Exhibit 3 to this Settlement Agreement, which shall be deemed accepted for use by JCP&L in setting rates in this and all other JCP&L rate filings unless and until the Commission approves a change in the depreciation and/or amortization rates pursuant to FPA section 205 or 206.

2.7. Effective Date and Refunds. The effective date of the Settlement Revenue Requirements shall be June 1, 2017. Within 60 days of the issuance of a Final Order approving this Settlement Agreement, JCP&L shall coordinate with PJM to revise the monthly billing amounts for NITS and TEC to reflect the settlement. An amount equal to the difference between the rates charged by PJM and the rates that would have been charged under this Settlement Agreement, plus interest calculated pursuant to section 35.19a(a)(2) of the Commission's regulations, for the period from June 1, 2017 through the date the Settlement Revenue Requirements as reflected in PJM billings for NITS and Schedule 12 charges (the "Settlement Billing Date") will be ratably credited against the revenue requirements for NITS and Schedule 12 for the remaining months in the calendar year in which the Settlement Billing Date occurs. For purposes of this Settlement Agreement, an order shall be deemed to be a "Final Order" as of the date rehearing is denied by the Commission, or if rehearing is not sought, as of the date on which the right to seek Commission rehearing expires.

2.8 Withdrawal of Request for Reconsideration/Rehearing. Within thirty days of the issuance of a Final Order approving this Agreement, JCP&L will withdraw its April 10, 2017 Motion for Reconsideration or, in the Alternative, Request for Rehearing.

2.9 Motion for Interim Rates. Concurrently with the filing of this Settlement Agreement with the Commission, JCP&L shall file a motion with the Chief Administrative Law Judge requesting that the Settlement Revenue Requirements be accepted as interim rates pursuant to 18 C.F.R. § 375.307(a)(1)(iv), effective January 1, 2018, pending the Commission's approval. The Settling Parties agree that, in the event this Settlement Agreement is withdrawn pursuant to Section 3.4, then JCP&L's existing revenue requirements shall go into effect and the difference between the amounts collected under the Interim Rate and the amounts that would have been collected under the existing revenue requirements for such period that the Interim Rate was in effect shall be reflected in JCP&L's revenue requirements.

ARTICLE III
Miscellaneous Provisions

3.1. *Scope of the Agreement.* This Settlement Agreement, including the exhibits hereto, constitutes the entire agreement among the Settling Parties with respect to the subject matter addressed herein, and supersedes any and all prior or contemporaneous representations, agreements, instruments and understandings between them, whether written or oral. There are no other oral understandings, terms or conditions, and none of the Settling Parties has relied upon any representation, express or implied, not contained in this Settlement.

3.2. *Non-Severability*. The Settling Parties agree and understand that the various provisions of this Settlement Agreement are not severable and, and except for Article 3 of this Settlement Agreement, shall not become operative unless and until the Commission issues a Final Order accepting or approving this Settlement Agreement as to all its terms and conditions without modification.

3.3. *Effectiveness of Settlement.* Except for Article 3 of this Settlement Agreement, the provisions hereof shall become effective when accepted or approved by the Commission without modification or condition through a Final Order. Article 3 of this Settlement Agreement shall go into effect upon the execution of the Settlement Agreement by all of the Settling Parties.

3.4 *Reservations.* No Settling Party shall be bound or prejudiced by any part of this Settlement Agreement unless and until it becomes effective in the manner provided by Section 3.3 hereof. If this Settlement Agreement is not accepted or approved in its entirety without modification or conditions it shall be deemed withdrawn, shall not be considered to be part of the record in this proceeding, and shall be null and void and of no force and effect, unless all of the Settling Parties otherwise agree in writing to such modification or condition.

3.5. *No Admissions or Precedent.* This Settlement Agreement is submitted pursuant to Rule 602, and is inadmissible as evidence in any proceeding, and of no effect unless it is approved and made effective as to all of its terms and conditions without modification. Further, the making of this Settlement Agreement and its acceptance or approval by the Commission shall not in any respect constitute an admission by any Settling Party, or a determination by the Commission, that any allegation or contention in these proceedings, or concerning any of the foregoing matters, is true or valid. In consideration of all elements of this negotiated settlement, no element of this Settlement Agreement constitutes precedent or should be deemed to be a "settled practice" as that term was interpreted and applied in *Public Service Commission of New York v. FERC*, 642 F.2d 1335 (D.C. Cir. 1980).

3.6. *Settlement Discussions.* The discussions between and among the Settling Parties that have produced this Settlement Agreement have been conducted with the explicit understanding, pursuant to Rule 602 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.602, that all offers of settlement and discussions relating thereto shall be privileged and confidential, shall be without prejudice to the position of any Settling Party or participant presenting any such offer or participating in any such discussion, and are not to be used in any manner in connection with this proceeding, any other proceeding, or otherwise, except to the extent necessary to enforce its terms.

3.7. *Further Assurances*. Each Settling Party shall cooperate with and support, and shall not take any action inconsistent with: (i) the filing of this Settlement Agreement with the Commission, and (ii) efforts to obtain Commission acceptance or approval of the Settlement Agreement. No Settling Party shall take any actions that are inconsistent with the provisions of this Settlement Agreement.

3.8. *Waiver*. No provision of this Settlement Agreement may be waived except through a writing signed by an authorized representative of the waiving Settling Party. Waiver of any provisions of this Settlement Agreement shall not be deemed to waive any other provision.

3.9. *Modifications/Standard of Review*. The standard of review for any modifications to this Settlement Agreement, set forth in a written amendment executed by all of the Settling Parties shall be the just and reasonable standard. The standard of review for any modifications to this Settlement Agreement requested by a Settling Party other than those set forth in a written amendment executed by all of the Settling Parties shall be the "public interest" standard set forth in *United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 332 (1956) and *Federal Power Commission v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956), as clarified in *Morgan Stanley Capital Group Inc. v. Public Utility District No. 1 of Snohomish County, Washington*, 554 U.S. 527 (2008), and refined in *NRG Power Marketing, LLC v. Maine Public Utilities Commission*, 558 U.S. 165, 174-75 (2010). The standard of review for any changes proposed by third parties and the Commission acting *sua sponte* shall be the just and reasonable standard.

3.10. *Successors and Assigns.* This Settlement Agreement is binding upon and for the benefit of the Settling Parties and their successors and assigns.

3.11. *Captions.* The captions in this Settlement Agreement are for convenience only and are not a part of this Settlement Agreement and do not in any way limit or amplify the terms and provisions of this Settlement Agreement and shall have no effect on its interpretation.

3.12. *Ambiguities Neutrally Construed*. This Settlement Agreement is the result of negotiations among, and has been reviewed by, each Settling Party and its respective counsel. Accordingly, this Settlement Agreement shall be deemed to be the product of each Settling Party, and no ambiguity shall be construed in favor of or against any Settling Party.

3.13. *Authorization*. Each person executing this Settlement Agreement on behalf of a Settling Party represents and warrants that he or she is duly authorized and empowered to act on behalf of, and to authorize this Settlement to be executed on behalf of, the Settling Party that he or she represents.

3.14. *Notices*. All notices, demands, and other communications hereunder shall be in writing and shall be delivered to each Settling Party's "Corporate Official" as found on the Commission's website at http://www.ferc.gov/docs-filing/corp-off.asp or the representatives of each Settling Party on the official service list in Docket No. ER17-211.

3.15. *Counterparts.* This Settlement Agreement may be executed in one or more counterparts, each of which shall be deemed to be an original and all of which together shall be deemed to be one and the same instrument.

[SIGNATURES ON NEXT PAGE]

IN WITNESS WHEREOF, the Settling Parties have caused this Settlement to be duly executed.

JERSEY CENTRAL POWER & LIGHT COMPANY

By: ______________________ Date: Dec. 19, 2017

Counsel for JCP+L

NEW JERSEY DIVISION OF THE RATE COUNSEL

By: ______________________ Date: __________

NEW JERSEY BOARD OF PUBLIC UTILITIES

By: ______________________ Date: __________

U.S. DEPARTMENT OF DEFENSE/FEDERAL EXECUTIVE AGENCIES

By: ______________________ Date: __________

PUBLIC POWER ASSOCIATION OF NEW JERSEY

By: ______________________ Date: __________

IN WITNESS WHEREOF, the Settling Parties have caused this Settlement to be duly executed.

JERSEY CENTRAL POWER & LIGHT COMPANY

By: ______________________ Date: __________

NEW JERSEY DIVISION OF THE RATE COUNSEL

By: ______________________ Date: 19-Dec-2017

Stephen C. Pearson
Attorney for Rate Counsel

NEW JERSEY BOARD OF PUBLIC UTILITIES

By: ______________________ Date: __________

U.S. DEPARTMENT OF DEFENSE/FEDERAL EXECUTIVE AGENCIES

By: ______________________ Date: __________

PUBLIC POWER ASSOCIATION OF NEW JERSEY

By: ______________________ Date: __________

IN WITNESS WHEREOF, the Settling Parties have caused this Settlement to be duly executed.

JERSEY CENTRAL POWER & LIGHT COMPANY

By: ______________________ Date: __________

NEW JERSEY DIVISION OF THE RATE COUNSEL

By: ______________________ Date: __________

NEW JERSEY BOARD OF PUBLIC UTILITIES

CHRISTOPHER S. PORRINO
ATTORNEY GENERAL OF NEW JERSEY

By: Carol Mc Date: 12/19/17
Carolyn A. McIntosh
Deputy Attorney General

U.S. DEPARTMENT OF DEFENSE/FEDERAL EXECUTIVE AGENCIES

By: ______________________ Date: __________

PUBLIC POWER ASSOCIATION OF NEW JERSEY

By: ______________________ Date: __________

IN WITNESS WHEREOF, the Settling Parties have caused this Settlement to be duly executed.

JERSEY CENTRAL POWER & LIGHT COMPANY

By: ____________________________ Date: ____________

NEW JERSEY DIVISION OF THE RATE COUNSEL

By: ____________________________ Date: ____________

NEW JERSEY BOARD OF PUBLIC UTILITIES

By: ____________________________ Date: ____________

U.S. DEPARTMENT OF DEFENSE/FEDERAL EXECUTIVE AGENCIES

By: ____________________________ Date: ____________

PUBLIC POWER ASSOCIATION OF NEW JERSEY

By: ____________________________ Date: ____________

IN WITNESS WHEREOF, the Settling Parties have caused this Settlement to be duly executed.

JERSEY CENTRAL POWER & LIGHT COMPANY

By: ________________________ Date: ___________

NEW JERSEY DIVISION OF THE RATE COUNSEL

By: ________________________ Date: ___________

NEW JERSEY BOARD OF PUBLIC UTILITIES

By: ________________________ Date: ___________

U.S. DEPARTMENT OF DEFENSE/FEDERAL EXECUTIVE AGENCIES

By: ________________________ Date: ___________

PUBLIC POWER ASSOCIATION OF NEW JERSEY

By: Geri M. Barker Date: 12/18/17

EXHIBIT 1

Pro Forma Settlement Tariff Sheets
JCP&L's PJM Tariff Attachments H-4, H-4A, and H-4B, and Schedule 12-Appendix
(Clean Format)

ATTACHMENT H-4

Annual Transmission Rates -- Jersey Central Power & Light Company for Network Integration Transmission Service

1. The annual transmission revenue requirement for Network Integration Transmission Service is $135,000,000. Attachment H-4A sets forth the rates for deliveries that utilize Jersey Central Power & Light Company ("JCP&L") distribution facilities at voltages below 34.5 kV delta. The transmission revenue requirement reflects the cost of providing transmission service over the 34.5 kV delta and higher transmission facilities of JCP&L.

2. The revenue requirements in this attachment shall be effective until amended by JCP&L or modified by the Commission.

3. In addition to the revenue requirement set forth in paragraph 1 above, a Network Customer purchasing Network Integration Transmission Service shall pay for transmission congestion charges, in accordance with the provisions of the Tariff, and any amounts necessary to reimburse JCP&L for applicable sales, excise, "Btu," carbon, value-added or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.

ATTACHMENT H-4A
Other Supporting Facilities -- Jersey Central Power & Light Company

As provided in Attachment H-4, section 1, service utilizing facilities at voltages below 34.5 kV delta to serve certain New Jersey municipal utilities will be provided at rates determined on a case-by-case basis and stated in existing NITS Agreements under Attachment F through the expiration of such agreements on May 31, 2019. Commencing on June 1, 2019, the rates for such service shall be as follows:

Borough of Butler, New Jersey: $0.1121/kW-Month

Borough of Lavallette, New Jersey: $2.3784/kW-Month

Borough of Madison, New Jersey: $0.0570/kW-Month

Borough of Pemberton, New Jersey: $1.1081/kW-Month

Borough of Seaside Heights, New Jersey: $1.2459/kW-Month

The above rates will be applied to the each of the New Jersey boroughs' monthly sixty (60) minute coincident billing demands measured at the time of JCP&L's system peak each month.

ATTACHMENT H-4B

[Reserved]

SCHEDULE 12 – APPENDIX

(4) Jersey Central Power & Light Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0123	Add 180 MVAR of distributed capacitors. 65 MVAR in northern JCPL and 115 MVAR in southern JCPL		JCPL (100%)
b0124.1	Add a 72 MVAR capacitor at Kittatinny 230 kV		JCPL (100%)
b0124.2	Add a 130 MVAR capacitor at Manitou 230 kV		JCPL (100%)
b0132	Reconductor Portland – Kittatinny 230 kV with 1590 ACSS		JCPL (100%)
b0132.1	Replace terminal equipment on the Portland – Kittatinny 230 kV and CB at the Kittatinny bus		JCPL (100%)
b0132.2	Replace terminal equipment on the Portland – Kittatinny 230 kV and CB at the Portland bus		JCPL (100%)
b0173	Replace a line trap at Newton 230kV substation for the Kittatinny-Newton 230kV circuit		JCPL (100%)
b0174	Upgrade the Portland – Greystone 230kV circuit	The following rates are consistent with the settlement agreement filed in and approved by the Commission in Docket No. ER17-217, 2017: $1,442,372 2018: $1,273,748 2019: $1,235,637	JCPL (35.40%) / Neptune* (5.67%) / PSEG (54.37%) RE (2.94%) / ECP** (1.62%)
b0199	Greystone 230kV substation: Change Tap of limiting CT and replace breaker on the Greystone Whippany (Q1031) 230kV line		JCPL (100%)
b0200	Greystone 230kV substation: Change Tap of limiting CT on the West Wharton Greystone (E1045) 230kV line		JCPL (100%)

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

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0202	Kittatinny 230kV substation: Replace line trap on Kittatinny Pohatcong (L2012) 230kV line; Pohatcong 230kV substation: Change Tap of limiting CT on Kittatinny Pohatcong (L2012) 230kV line		JCPL (100%)
b0203	Smithburg 230kV Substation: Replace line trap on the East Windsor Smithburg (E2005) 230kV line; East Windsor 230kV substation: Replace line trap on the East Windsor Smithburg (E2005) 230kV line		JCPL (100%)
b0204	Install 72Mvar capacitor at Cookstown 230kV substation		JCPL (100%)
b0267	Reconductor JCPL 2 mile portion of Kittatinny – Newton 230 kV line		JCPL (100%)
b0268	Reconductor the 8 mile Gilbert – Glen Gardner 230 kV circuit	The following rates are consistent with the settlement agreement filed in and approved by the Commission in Docket No. ER17-217, 2017: $734,194 2018: $646,180 2019: $628,066	JCPL (61.77%) / Neptune* (3%) / PSEG (32.73%) / RE (1.45%) / ECP** (1.05%)

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

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0279.1	Install 100 MVAR capacitor at Glen Gardner substation		JCPL (100%)
b0279.2	Install MVAR capacitor at Kittatinny 230 kV substation		JCPL (100%)
b0279.3	Install 17.6 MVAR capacitor at Freneau 34.5 kV substation		JCPL (100%)
b0279.4	Install 6.6 MVAR capacitor at Waretown #1 bank 34.5 kV substation		JCPL (100%)
b0279.5	Install 10.8 MVAR capacitor at Spottswood #2 bank .4.5 kV substation		JCPL (100%)
b0279.6	Install 6.6 MVAR capacitor at Pequannock N bus 34.5 kV substation		JCPL (100%)
b0279.7	Install 6.6 MVAR capacitor at Haskell P bus 34.5 kV substation		JCPL (100%)
b0279.8	Install 6.6 MVAR capacitor at Pinewald #2 Bank 34.5 kV substation		JCPL (100%)
b0279.9	Install 6.6 MVAR capacitor at Matrix 34.5 kV substation		JCPL (100%)
b0279.10	Install 6.6 MVAR capacitor at Hamburg Boro Q Bus 34.5 kV substation		JCPL (100%)
b0279.11	Install 6.6 MVAR capacitor at Newburg Q Bus 34.5 kV substation		JCPL (100%)
b0286	Install 130 MVAR capacitor at Whippany 230 kV		JCPL (100%)
b0289	Install 600 MVAR Dynamic Reactive Device in the Whippany 230 kV vicinity		AEC (0.65%) / JCPL (30.37%) / Neptune* (4.96%) / PSEG (59.65%) / RE (2.66%) / ECP** (1.71%)
b0289.1	Install additional 130 MVAR capacitor at West Wharton 230 kV substation		JCPL (100%)

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

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0292	Replace a 1600A line trap at Atlantic Larrabee 230 kV substation		JCPL (100%)
b0350	Implement Operating Procedure of closing the Glendon – Gilbert 115 kV circuit		JCPL (100%)
b0356	Replace wave trap on the Portland – Greystone 230 kV		JCPL (100%)
b0361	Change tap of limiting CT at Morristown 230 kV		JCPL (100%)
b0362	Change tap setting of limiting CT at Pohatcong 230 kV		JCPL (100%)
b0363	Change tap setting of limiting CT at Windsor 230 kV		JCPL (100%)
b0364	Change tap setting of CT at Cookstown 230 kV		JCPL (100%)
b0423.1	Upgrade terminal equipment at Readington (substation conductor)		JCPL (100%)
b0520	Replace Gilbert circuit breaker 12A		JCPL (100%)
b0657	Construct Boston Road 34.5 kV stations, construct Hyson 34.5 stations, add a 7.2 MVAR capacitor at Boston Road 34.5 kV		JCPL (100%)
b0726	Add a 2nd Raritan River 230/115 kV transformer	The following rates are consistent with the settlement agreement filed in and approved by the Commission in Docket No. ER17-217, 2017: $950,666 2018: $846,872 2019: $827,854	AEC (2.45%) / JCPL (97.55%)
b1020	Replace wave trap at Englishtown on the Englishtown - Manalapan circuit		JCPL (100%)

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1075	Replace the West Wharton - Franklin - Vermont D931 and J932 115 kV line conductors with 1590 45/7 ACSR wire between the tower structures 78 and 78-B		JCPL (100%)
b1154.1	Upgrade the Whippany 230 kV breaker 'JB'		JCPL (100%)
b1155.1	Upgrade the Red Oak 230 kV breaker 'G1047'		JCPL (100%)
b1155.2	Upgrade the Red Oak 230 kV breaker 'T1034'		JCPL (100%)
b1345	Install Martinsville 4-breaker 34.5 rink bus		JCPL (100%)
b1346	Reconductor the Franklin – Humburg (R746) 4.7 miles 34.5 kV line with 556 ACSR and build 2.7 miles 55 ACSR line extension to Sussex		JCPL (100%)
b1347	Replace 500 CU substation conductor with 795 ACSR on the Whitesville – Asbury Tap 34.5 kV (U47) line		JCPL (100%)
b1348	Upgrade the Newton – North Newton 34.5 kV (F708) line by adding a second underground 1250 CU egress cable		JCPL (100%)
b1349	Reconductor 5.2 miles of the Newton – Woodruffs Gap 34.5 kV (A703) line with 556 ACSR		JCPL (100%)
b1350	Upgrade the East Flemington – Flemington 34.5 kV (V724) line by adding second underground 1000 AL egress cable and replacing 4/0		JCPL (100%)

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1351	Add 34.5 kV breaker on the Larrabee A and D bus tie		JCPL (100%)
b1352	Upgrade the Smithburg – Centerstate Tap 34.5 kV (X752) line by adding second 200 ft underground 1250 CU egress cable		JCPL (100%)
b1353	Upgrade the Larrabee – Laurelton 34.5 kV (Q43) line by adding second 700 ft underground 1250 CU egress cable		JCPL (100%)

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1354	Add four 34.5 kV breakers and re-configure A/B bus at Rockaway		JCPL (100%)
b1355	Build a new section 3.3 miles 34.5 kV 556 ACSR line from Riverdale to Butler		JCPL (100%)
b1357	Build 10.2 miles new 34.5 kV line from Larrabee – Howell		JCPL (100%)
b1359	Install a Troy Hills 34.5 kV by-pass switch and reconfigure the Montville – Whippany 34.5 kV (D4) line		JCPL (100%)
b1360	Reconductor 0.7 miles of the Englishtown – Freehold Tap 34.5 kV (L12) line with 556 ACSR		JCPL (100%)
b1361	Reconductor the Oceanview – Neptune Tap 34.5 kV (D130) line with 795 ACSR		JCPL (100%)
b1362	Install a 23.8 MVAR capacitor at Wood Street 69 kV		JCPL (100%)
b1364	Upgrade South Lebanon 230/69 kV transformer #1 by replacing 69 kV substation conductor with 1590 ACSR		JCPL (100%)
b1399.1	Upgrade the Whippany 230 kV breaker 'QJ'		JCPL (100%)
b1673	Rocktown - Install a 230/34.5 kV transformer by looping the Pleasant Valley - E Flemington 230 kV Q-2243 line (0.4 miles) through the Rocktown Substation		JCPL (100%)

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1674	Build a new Englishtown - Wyckoff St 15 mile, 115 kV line and install 115/34.5 kV transformer at Wyckoff St		JCPL (100%)
b1689	Atlantic Sub - 230 kV ring bus reconfiguration. Put a “source” between the Red Bank and Oceanview “loads”		JCPL (100%)
b1690	Build a new third 230 kV line into the Red Bank 230 kV substation		JCPL (100%)
b1853	Install new 135 MVA 230/34.5 kV transformer with one 230 kV CB at Eaton Crest and create a new 34.5 kV CB straight bus to feed new radial lines to Locust Groove and Interdata/Woodbine		JCPL (100%)
b1854	Readington I737 34.5 kV Line - Parallel existing 1250 CU UG cable (440 feet)		JCPL (100%)
b1855	Oceanview Substation - Relocate the H216 breaker from the A bus to the B bus		JCPL (100%)
b1856	Madison Tp to Madison (N14) line - Upgrade limiting 250 Cu substation conductor with 795 ACSR at Madison sub		JCPL (100%)
b1857	Montville substation - Replace both the 397 ACSR and the 500 Cu substation conductor with 795 ACSR on the 34.5 kV (M117) line		JCPL (100%)

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1858	Reconductor the Newton - Mohawk (Z702) 34.5 kV line with 1.9 miles of 397 ACSR		JCPL (100%)
b2003	Construct a Whippany to Montville 230 kV line (6.4 miles)		JCPL (100%)
b2015	Build a new 230 kV circuit from Larrabee to Oceanview	The following rates are consistent with the settlement agreement filed in and approved by the Commission in Docket No. ER17-217, 2017: $9,616,241 2018: $18,839,128 2019: $19,935,489	JCPL (35.83%) / NEPTUNE* (23.61%) / HTP (1.77%) / ECP** (1.49%) / PSEG (35.87%) / RE (1.43%)
b2147	At Deep Run, install 115 kV line breakers on the B2 and C3 115 kV lines		JCPL (100%)

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

EXHIBIT 2

Pro Forma Settlement Tariff Sheets
JCP&L's PJM Tariff Attachments H-4, H-4A, and H-4B, and Schedule 12-Appendix
(Marked / Redline Format)

ATTACHMENT H-4

Annual Transmission Rates -- Jersey Central Power & Light Company for Network Integration Transmission Service

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1. The annual transmission revenue requirement ~~and the rate~~ for Network Integration Transmission Service is $135,000,000. Attachment H-4A sets forth the rates for deliveries that utilize Jersey Central Power & Light Company ("JCP&L") distribution facilities at voltages below 34.5 kV delta~~are equal to the results of the formula shown in Attachment H- 4A, and will be posted on the PJM website pursuant to Attachment H-4B (Formula Rate Protocols)~~. The transmission revenue requirement ~~and the rate~~ reflects the cost of providing transmission service over the 34.5 kV delta and higher transmission facilities of ~~Jersey Central Power & Light Company ("~~JCP&L~~"). Service utilizing facilities at voltages below 34.5 kV delta will be provided at rates determined on a case-by-case basis and stated in service agreements with affected customers.~~

~~2. The formula rate set forth in Attachment H-4A shall be calculated on the basis of projections, subject to true-up to actual data in accordance with the adjustment mechanism described in Attachment H-4B (Formula Rate Protocols).~~

~~3~~2. The ~~rate and~~ revenue requirements in this attachment shall be effective until amended by JCP&L or modified by the Commission.

~~4~~3. In addition to the ~~rate~~revenue requirement set forth in paragraph 1 above, a Network Customer purchasing Network Integration Transmission Service shall pay for transmission congestion charges, in accordance with the provisions of the Tariff, and any amounts necessary to reimburse JCP&L for applicable sales, excise, "Btu," carbon, value-added or similar taxes (other than taxes based upon or measured by net income) with respect to the amounts payable pursuant to the Tariff.

ATTACHMENT H-4A
Other Supporting Facilities -- Jersey Central Power & Light Company

As provided in Attachment H-4, section 1, service utilizing facilities at voltages below 34.5 kV delta to serve certain New Jersey municipal utilities will be provided at rates determined on a case-by-case basis and stated in existing NITS Agreements under Attachment F through the expiration of such agreements on May 31, 2019. Commencing on June 1, 2019, the rates for such service shall be as follows:

Borough of Butler, New Jersey: $0.1121/kW-Month

Borough of Lavallette, New Jersey: $2.3784/kW-Month

Borough of Madison, New Jersey: $0.0570/kW-Month

Borough of Pemberton, New Jersey: $1.1081/kW-Month

Borough of Seaside Heights, New Jersey: $1.2459/kW-Month

The above rates will be applied to the each of the New Jersey boroughs' monthly sixty (60) minute coincident billing demands measured at the time of JCP&L's system peak each month.

~~Formula Rate - Non-Levelized~~ ~~For the 12 months ended 12/31/2017~~

~~Rate Formula Template~~
~~Utilizing FERC Form 1 Data~~

~~Jersey Central Power & Light~~

~~Line No.~~						~~Allocated Amount~~
~~1~~	~~GROSS REVENUE REQUIREMENT [page 3, line 43, col 5]~~					
	~~REVENUE CREDITS~~	~~(Note T)~~	~~Total~~	~~Allocator~~		
~~2~~	~~Account No. 451~~	~~(page 4, line 29)~~		~~TP~~	~~1.00000~~	
~~3~~	~~Account No. 454~~	~~(page 4, line 30)~~		~~TP~~	~~1.00000~~	
~~4~~	~~Account No. 456~~	~~(page 4, line 31)~~		~~TP~~	~~1.00000~~	
~~5~~	~~Revenues from Grandfathered Interzonal Transactions~~			~~TP~~	~~1.00000~~	
~~6~~	~~Revenues from service provided by the ISO at a discount~~			~~TP~~	~~1.00000~~	
~~7~~	~~TEC Revenue~~	~~Attachment 11, Page 2, Line 3, Col. 12~~		~~TP~~	~~1.00000~~	
~~8~~	~~TOTAL REVENUE CREDITS (sum lines 2-7)~~					
~~9~~	~~True-up Adjustment with Interest~~	~~Attachment 13, Line 28~~				
~~10~~	~~NET REVENUE REQUIREMENT~~	~~(Line 1 - Line 8 + Line 9)~~				
	~~DIVISOR~~					~~Total~~
~~11~~	~~1 Coincident Peak (CP) (MW)~~				~~(Note A)~~	
~~12~~	~~Average 12 CPs (MW)~~				~~(Note CC)~~	
			~~Total~~			
~~13~~	~~Annual Rate ($/MW/Yr)~~	~~(line 10 / line 11)~~				
			~~Peak Rate Total~~			~~Off-Peak Rate Total~~
~~14~~	~~Point-to-Point Rate ($/MW/Year)~~	~~(line 10 / line 12)~~				
~~15~~	~~Point-to-Point Rate ($/MW/Month)~~	~~(line 14/12)~~				
~~16~~	~~Point-to-Point Rate ($/MW/Week)~~	~~(line 14/52)~~				
~~17~~	~~Point-to-Point Rate ($/MW/Day)~~	~~(line 16/5; line 16/7)~~				
~~18~~	~~Point-to-Point Rate ($/MWh)~~	~~(line 14/4,160; line 14/8,760)~~				

~~Attachment H-4A~~
~~page 2 of 5~~

~~Formula Rate - Non-Levelized~~ ~~Rate Formula Template~~ ~~For the 12 months ended 12/31/2017~~

~~Utilizing FERC Form 1 Data~~

~~Jersey Central Power & Light~~

	~~(1)~~	~~(2)~~	~~(3)~~	~~(4)~~		~~(5)~~
~~Line No.~~	~~**RATE BASE:**~~	~~**Source**~~	~~**Company Total**~~	~~**Allocator**~~		~~**Transmission**~~ ~~(Col 3 times Col 4)~~
	~~GROSS PLANT IN SERVICE~~					
~~1~~	~~Production~~	~~Attachment 3, Line 14, Col. 1 (Notes U & X)~~		~~NA~~		
~~2~~	~~Transmission~~	~~Attachment 3, Line 14, Col. 2 (Notes U & X)~~		~~TP~~	~~1.00000~~	
~~3~~	~~Distribution~~	~~Attachment 3, Line 14, Col. 3 (Notes U & X)~~		~~NA~~		
~~4~~	~~General & Intangible~~	~~Attachment 3, Line 14, Col. 4 & 5 (Notes U & X)~~		~~GP~~	~~1.00000~~	
~~5~~	~~Common~~	~~Attachment 3, Line 14, Col. 6 (Notes U & X)~~		~~CE~~	~~1.00000~~	
~~6~~	~~TOTAL GROSS PLANT (sum lines 1-5)~~			~~GP=~~	~~100.00%~~	
	~~ACCUMULATED DEPRECIATION~~					
~~7~~	~~Production~~	~~Attachment 4, Line 14, Col. 1 (Notes U & X)~~		~~NA~~		
~~8~~	~~Transmission~~	~~Attachment 4, Line 14, Col. 2 (Notes U & X)~~		~~TP~~	~~1.00000~~	
~~9~~	~~Distribution~~	~~Attachment 4, Line 14, Col. 3 (Notes U & X)~~		~~NA~~		
~~10~~	~~General & Intangible~~	~~Attachment 4, Line 14, Col. 4 & 5 (Notes U & X)~~		~~GP~~	~~1.00000~~	
~~11~~	~~Common~~	~~Attachment 4, Line 14, Col. 6 (Notes U & X)~~		~~CE~~	~~1.00000~~	
~~12~~	~~TOTAL ACCUM. DEPRECIATION (sum lines 7-11)~~					
	~~NET PLANT IN SERVICE~~					
~~13~~	~~Production~~	~~(line 1 - line 7)~~				
~~14~~	~~Transmission~~	~~(line 2 - line 8)~~		-		
~~15~~	~~Distribution~~	~~(line 3 - line 9)~~				
~~16~~	~~General & Intangible~~	~~(line 4 - line 10)~~				
~~17~~	~~Common~~	~~(line 5 - line 11)~~				
~~18~~	~~TOTAL NET PLANT (sum lines 13-17)~~			~~NP=~~	~~100.00%~~	
	~~ADJUSTMENTS TO RATE BASE~~					
~~19~~	~~Account No. 281 (enter negative)~~	~~Attachment 5, Line 3, Col. 1 (Notes C, F, Y)~~		~~NA~~		
~~20~~	~~Account No. 282 (enter negative)~~	~~Attachment 5, Line 3, Col. 2 (Note C, F, Y)~~		~~DA~~	~~1.00000~~	
~~21~~	~~Account No. 283 (enter negative)~~	~~Attachment 5, Line 3, Col. 3 (Notes C, F, Y)~~		~~DA~~	~~1.00000~~	
~~22~~	~~Account No. 190~~	~~Attachment 5, Line 3, Col. 4 (Notes C, F, Y)~~		~~DA~~	~~1.00000~~	
~~23~~	~~Account No. 255 (enter negative)~~	~~Attachment 5, Line 3, Col. 5 (Notes C, F, Y)~~		~~DA~~	~~1.00000~~	
~~24~~	~~Unfunded Reserve Plant-related (enter negative)~~	~~Attachment 14, Line 6, Col. 6 (Notes C & Y)~~		~~DA~~	~~1.00000~~	
~~25~~	~~Unfunded Reserve Labor-related (enter negative)~~	~~Attachment 14, Line 9, Col. 6 (Notes C & Y)~~		~~DA~~	~~1.00000~~	
~~26~~	~~CWIP~~	~~216.b (Notes X & Z)~~		~~DA~~	~~1.00000~~	
~~27~~	~~Unamortized Regulatory Asset~~	~~Attachment 16a, 16b, 16c, Line 15, Col. 7 (Note X)~~		~~DA~~	~~1.00000~~	
~~28~~	~~Unamortized Abandoned Plant~~	~~Attachment 17, Line 15, Col. 7 (Notes X & BB)~~		~~DA~~	~~1.00000~~	
~~29~~	~~TOTAL ADJUSTMENTS (sum lines 19-28)~~					
~~30~~	~~LAND HELD FOR FUTURE USE~~	~~214.x.d (Attachment 14, Line 3, Col. 1) (Notes G & Y)~~		~~TP~~	~~1.00000~~	
~~31~~	~~WORKING CAPITAL (Note H)~~					
~~32~~	~~CWC~~	~~1/8*(Page 3, Line 15 minus Page 3, Lines 11 & 12)~~				
~~33~~	~~Materials & Supplies (Note G)~~	~~227.8.c & .16.c (Attachment 14, Line 3, Col. 2) (Note Y)~~		~~TE~~	~~1.00000~~	
~~34~~	~~Prepayments (Account 165)~~	~~111.57.c (Attachment 14, Line 3, Col. 3) (Notes B & Y)~~		~~GP~~	~~1.00000~~	
~~35~~	~~TOTAL WORKING CAPITAL (sum lines 32 - 34)~~					
~~36~~	~~RATE BASE (sum lines 18, 29, 30, & 35)~~					

Formula Rate - Non-Levelized | Rate Formula Template | For the 12 months ended 12/31/2017

Utilizing FERC Form 1 Data

Jersey Central Power & Light

Line No.	(1) RATE BASE:	(2) Source	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	321.112.b		TE	1.00000	
2	Less LSE Expenses Included in Transmission O&M Accounts (Note W)			DA	1.00000	
3	Less Account 565	321.96.b		DA	1.00000	
4	Less Account 566	321.97.b		DA	1.00000	
5	A&G	323.197.b		W/S	1.00000	
6	Less FERC Annual Fees			W/S	1.00000	
7	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)			W/S	1.00000	
8	Plus Transmission Related Reg. Comm. Exp. (Note I)			TE	1.00000	
9	PBOP Expense Adjustment in Year	Attachment 6, Line 9 (Note C)		DA	1.00000	
10	Common	356.1		CE	1.00000	
11	Account 407.3 Amortization of Regulatory Assets	Attachment 16a, 16b, 16c, Line 15, Col. 5		DA	1.00000	
12	Account 566 Amortization of Regulatory Assets			DA	1.00000	
13	Acct. 566 Miscellaneous Transmission Expense (less amortization of regulatory asset) 321.97.b - line 12			DA	1.00000	
14	Total Account 566 (sum lines 12 & 13, ties to 321.97.b)					
15	TOTAL O&M (sum lines 1, 5,8, 9, 10, 11, 14 less 2, 3, 4, 6, 7)					
	DEPRECIATION AND AMORTIZATION EXPENSE					
16	Transmission	336.7.b (Note U)		TP	1.00000	
17	General & Intangible	336.1.f & 336.10.f (Note U)		GP	1.00000	
18	Common	336.11.b (Note U)		CE	1.00000	
19	Amortization of Abandoned Plant	Attachment 17, Line 15, Col. 5 (Note BB)		DA	1.00000	
20	TOTAL DEPRECIATION (sum lines 16 - 19)					
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
21	Payroll	263.i (Attachment 7, line 1z)		W/S	1.00000	
22	Highway and vehicle	263.i (Attachment 7, line 2z)		W/S	1.00000	
23	PLANT RELATED					
24	Property	263.i (Attachment 7, line 3z)		GP	1.00000	
25	Gross Receipts	263.i (Attachment 7, line 4z)		NA		
26	Other	263.i (Attachment 7, line 5z)		GP	1.00000	
27	Payments in lieu of taxes	Attachment 7, line 6z		GP	1.00000	
28	TOTAL OTHER TAXES (sum lines 21 - 27)					
	INCOME TAXES	(Note K)				
29	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =					
30	CIT=(T/1-T) * (1-(WCLTD/R)) =					
	where WCLTD=(page 4, line 22) and R= (page 4, line 25)					
	and FIT, SIT & p are as given in footnote K.					
31	1 / (1 - T) = (from line 30)					
32	Amortized Investment Tax Credit (266.8.f) (enter negative)					
33	Tax Effect of Permanent Differences and AFUDC Equity (Attachment 15, Line 1, Col. 3) [Notes D & Y]					
34	(Excess)/Deficient Deferred Income Taxes (Attachment 15, Lines 2 & 3, Col. 3) [Notes E & Y]					
35	Income Tax Calculation = line 30 * line 40			NA		
36	ITC adjustment (line 31 * line 32)			NP	1.00000	
37	Permanent Differences and AFUDC Equity Tax Adjustment (line 31 * line 33)			DA	1.00000	
38	(Excess)/Deficient Deferred Income Tax Adjustment (line 31 * line 34)			DA	1.00000	
39	Total Income Taxes	sum lines 35 through 38				
40	RETURN			NA		
	[Rate Base (page 2, line 36) * Rate of Return (page 4, line 25, col. 6)]					
41	GROSS REV. REQUIREMENT (WITHOUT INCENTIVE)					
	(sum lines 15, 20, 28, 39, 40)					
42	ADDITIONAL INCENTIVE REVENUE	Attachment 11, Line 4 (Note AA)				
43	GROSS REV. REQUIREMENT					
	(line 41 + line 42)					

Formula Rate - Non-Levelized — Rate Formula Template — For the 12 months ended 12/31/2017

Utilizing FERC Form 1 Data

Jersey Central Power & Light

SUPPORTING CALCULATIONS AND NOTES

Line No.	(1)	(2)	(3)	(4)	(5)	(6)	
	TRANSMISSION PLANT INCLUDED IN ISO RATES						
1	Total transmission plant (page 2, line 2, column 3)						
2	Less transmission plant excluded from ISO rates (Note M)						
3	Less transmission plant included in OATT Ancillary Services (Note N)						
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)						
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)				TP=		
	TRANSMISSION EXPENSES						
6	Total transmission expenses (page 3, line 1, column 3)						
7	Less transmission expenses included in OATT Ancillary Services (Note L)						
8	Included transmission expenses (line 6 less line 7)						
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)						
10	Percentage of transmission plant included in ISO Rates (line 5)				TP		
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)				TE=		
	WAGES & SALARY ALLOCATOR (W&S)						
		Form 1 Reference	$	TP	Allocation		
12	Production	354.20.b	-	0.00	-		
13	Transmission	354.21.b		1.00			
14	Distribution	354.23.b		0.00	-	W&S Allocator	
15	Other	354.24,25,26.b		0.00	-	($ / Allocation)	
16	Total (sum lines 12-15)	-			=	1.00000	= WS
	COMMON PLANT ALLOCATOR (CE) (Note O)						
			$		% Electric	W&S Allocator	
17	Electric	200.3.c	-		(line 17 / line 20)	(line 16, col. 6)	= CE
18	Gas	201.3.d	-		1.00000 *	1.00000	= 1.00000
19	Water	201.3.e	-				
20	Total (sum lines 17 - 19)		-				
	RETURN (R)					$	
21		Preferred Dividends (118.29c) (positive number)				-	
			$	%	Cost (Note P)	Weighted	
22	Long Term Debt (112.24.c) (Attachment 8, Line 14, Col. 7) (Note X)						=WCLTD
23	Preferred Stock (112.3d) (Attachment 8, Line 14, Col. 2) (Note X)						
24	Common Stock Attachment 8, Line 14, Col. 6) (Note X)						
25	Total (sum lines 22-24)						=R
	REVENUE CREDITS						
	ACCOUNT 447 (SALES FOR RESALE)		(310-311)	(Note Q)			
26	a. Bundled Non-RQ Sales for Resale (311.x.h)						
27	b. Bundled Sales for Resale included in Divisor on page 1						
28	Total of (a)-(b)						
29	ACCOUNT 451 (MISCELLANEOUS SERVICE REVENUE) (Note S)			(300.17.b)			
30	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)			(300.19.b)			
31	ACCOUNT 456 (OTHER ELECTRIC REVENUE) (Note V)			(330.x.n)			

~~Formula Rate - Non-Levelized~~ ~~Rate Formula Template~~ ~~For the 12 months ended 12/31/2017~~
~~Utilizing FERC Form 1 Data~~

~~Jersey Central Power & Light~~

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

~~Note Letter~~	
~~A~~	~~As provided by PJM and in effect at the time of the annual rate calculations pursuant to Section 34.1 of the PJM OATT.~~
~~B~~	~~Prepayments shall exclude prepayments of income taxes.~~
~~C~~	~~Transmission-related only~~
~~D~~	~~Includes the annual income tax cost or benefits due to permanent differences or differences between the amounts of expenses or revenues recognized in one period for ratemaking purposes and the amounts recognized for income tax purposes which do not reverse in one or more other periods, including the cost of income taxes on the Allowance for Other Funds Used During Construction~~
~~E~~	~~Upon enactment of changes in tax law, income tax rates (including changes in apportionment) and other actions taken by a taxing authority, deferred taxes are re-measured and adjusted in the Company's books of account, resulting in excess or deficient accumulated deferred taxes. Such excess or deficient deferred taxes attributed to the transmission function will be based upon tax records and calculated in the calendar year in which the excess or deficient amount was measured and recorded for financial reporting purposes. Amounts to be included will be January 1, 2017 and thereafter.~~
~~F~~	~~The balances in Accounts 190, 281, 282 and 283, should exclude all FASB 106 or 109 related amounts. For example, any and all amounts in contra accounts identified as regulatory assets or liabilities related to FASB 106 or 109 should be excluded. The balance of Account 255 is reduced by prior flow throughs and excluded if the utility chose to utilize amortization of tax credits against taxable income as discussed in Note K. Account 281 is not allocated.~~
~~G~~	~~Identified in Form 1 as being only transmission related.~~
~~H~~	~~Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 15, column 5 minus amortization of regulatory assets (page 3, lines 11 & 12, col. 5). Prepayments are the electric related prepayments booked to Account No. 165 and reported on Page 111, line 57 in the Form 1.~~
~~I~~	~~Line 7 - EPRI Annual Membership Dues listed in Form 1 at 353.f, all Regulatory Commission Expenses itemized at 351.h, and non-safety related advertising included in Account 930.1. Line 8 - Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h.~~
~~J~~	~~Includes only FICA, unemployment, highway, property, gross receipts, and other assessments charged in the current year. Taxes related to income are excluded. Gross receipts taxes are not included in transmission revenue requirement in the Rate Formula Template, since they are recovered elsewhere.~~
~~K~~	~~The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility is taxed in more than one state it must attach a work paper showing the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by (1/1-T) (page 3, line 31).~~
	~~Inputs Required:~~ ~~FIT =~~
	~~SIT=~~ ~~(State Income Tax Rate or Composite SIT)~~
	~~p =~~ ~~(percent of federal income tax deductible for state purposes)~~
~~L~~	~~Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1 - 561.3, and 561.BA.~~
~~M~~	~~Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test.~~
~~N~~	~~Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.~~
~~O~~	~~Enter dollar amounts~~
~~P~~	~~Debt cost rate = Attachment 10, Column (j) total. Preferred cost rate = preferred dividends (line 21) / preferred outstanding (line 23). ROE will be supported in the original filing and no change in ROE may be made absent a filing with FERC.~~
~~Q~~	~~Line 28 must equal zero since all short-term power sales must be unbundled and the transmission component reflected in Account No. 456.1 and all other uses are to be included in the divisor.~~
~~R~~	~~Includes income related only to transmission facilities, such as pole attachments, rentals and special use.~~
~~S~~	~~Excludes revenues unrelated to transmission services.~~
~~T~~	~~The revenues credited on page 1, lines 2-6 shall include only the amounts received directly (in the case of grandfathered agreements) or from the ISO (for service under this tariff) reflecting the Transmission Owner's integrated transmission facilities. They do not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, or facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template. The revenue on line 7 is supported by it own reference.~~
~~U~~	~~Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC.~~
~~V~~	~~On Line 31, enter revenues from RTO settlements that are associated with NITS and firm Point-to-Point Service for which the load is not included in the divisor to derive JCP&L's zonal rates. Exclude non-firm Point-to-Point revenues and revenues related to RTEP projects.~~
~~W~~	~~Account Nos. 561.4, 561.8, and 575.7 consist of RTO expenses billed to load-serving entities and are not included in Transmission Owner revenue requirements.~~
~~X~~	~~Calculate using a 13 month average balance.~~
~~Y~~	~~Calculate using average of beginning and end of year balance.~~
~~Z~~	~~Includes only CWIP authorized by the Commission for inclusion in rate base.~~
~~AA~~	~~Any actual ROE incentive must be approved by the Commission; therefore, line will remain zero until a project(s) is granted an ROE incentive adder.~~
~~BB~~	~~Unamortized Abandoned Plant and Amortization of Abandoned Plant will be zero until the Commission accepts or approves recovery of the cost of abandoned plant. Utility must submit a Section 205 filing to recover the cost of abandoned plant.~~
~~CC~~	~~Peak as would be reported on page 401, column d of Form 1 at the time of the zonal peak for the twelve month period ending October 31 of the calendar year used to calculate rates. The projection year will utilize the most recent preceding 12-month period at the time of the filing.~~

~~Schedule 1A Rate Calculation~~

~~1~~	~~$~~	~~Attachment H-4A, Page 4, Line 7~~
~~2~~	~~$~~	~~Revenue Credits for Sched 1A -- Note A~~
~~3~~	~~$~~	~~Net Schedule 1A Expenses (Line 1 - Line 2)~~
~~4~~		~~Annual MWh in JCP&L Zone - Note B~~
~~5~~	~~$~~	~~Schedule 1A rate $/MWh (Line 3/ Line 4)~~

~~Note:~~

~~A~~ ~~Revenues received pursuant to PJM Schedule 1A revenue allocation procedures for transmission service outside of JCP&L's zone during the year used to calculate rates under Attachment H-4A.~~

~~B~~ ~~Load expressed in MWh consistent with load used for billing under Schedule 1A for the JCP&L zone. Data from RTO settlement systems for the calendar year prior to the rate year.~~

~~Incentive ROE Calculation~~

~~Return Calculation~~

			Source Reference
~~1~~	~~Rate Base~~		~~Attachment H-4A, page 2, Line 36, Col. 5~~
~~2~~	~~Preferred Dividends~~	~~enter positive~~	~~Attachment H-4A, page 4, Line 21, Col. 6~~
	~~Common Stock~~		
~~3~~	~~Proprietary Capital~~		~~Attachment 8, Line 14, Col. 1~~
~~4~~	~~Less Preferred Stock~~		~~Attachment 8, Line 14, Col. 2~~
~~5~~	~~Less Accumulated Other Comprehensive Income Account 219~~		~~Attachment 8, Line 14, Col. 4~~
~~6~~	~~Less Account 216.1 & Goodwill~~		~~Attachment 8, Line 14, Col. 3&5~~
~~7~~	~~Common Stock~~		~~Attachment 8, Line 14, Col. 6~~
	~~Capitalization~~		
~~8~~	~~Long Term Debt~~		~~Attachment H-4A, page 4, Line 22, Col. 3~~
~~9~~	~~Preferred Stock~~		~~Attachment H-4A, page 4, Line 23, Col. 3~~
~~10~~	~~Common Stock~~		~~Attachment H-4A, page 4, Line 24, Col. 3~~
~~11~~	~~Total Capitalization~~		~~Attachment H-4A, page 4, Line 25, Col. 3~~
~~12~~	~~Debt %~~	~~Total Long Term Debt~~	~~Attachment H-4A, page 4, Line 22, Col. 4~~
~~13~~	~~Preferred %~~	~~Preferred Stock~~	~~Attachment H-4A, page 4, Line 23, Col. 4~~
~~14~~	~~Common %~~	~~Common Stock~~	~~Attachment H-4A, page 4, Line 24, Col. 4~~
~~15~~	~~Debt Cost~~	~~Total Long Term Debt~~	~~Attachment H-4A, page 4, Line 22, Col. 5~~
~~16~~	~~Preferred Cost~~	~~Preferred Stock~~	~~Attachment H-4A, page 4, Line 23, Col. 5~~
~~17~~	~~Common Cost~~	~~Common Stock~~	
~~18~~	~~Weighted Cost of Debt~~	~~Total Long Term Debt (WCLTD)~~	~~(Line 12*Line 15)~~
~~19~~	~~Weighted Cost of Preferred~~	~~Preferred Stock~~	~~(Line 13*Line 16)~~
~~20~~	~~Weighted Cost of Common~~	~~Common Stock~~	~~(Line 14*Line 17)~~
~~21~~	~~Rate of Return on Rate Base (ROR)~~		~~(Sum Lines 18 to 20)~~
~~22~~	~~Investment Return = Rate Base * Rate of Return~~		**~~(Line 1*Line 21)~~**

	~~Income Tax Rates~~	
~~23~~	~~T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =~~	~~Attachment H-4A, page 3, Line 29, Col. 3~~
~~24~~	~~CIT=(T/1-T) * (1-(WCLTD/R)) =~~	~~Calculated~~
~~25~~	~~1 / (1 - T) = (from line 23)~~	~~Calculated~~
~~26~~	~~Amortized Investment Tax Credit (266.8.f) (enter negative)~~	~~Attachment H-4A, page 3, Line 32, Col. 3~~
~~27~~	~~Tax Effect of Permanent Differences and AFUDC Equity~~	~~Attachment H-4A, page 3, Line 33, Col. 3~~
~~28~~	~~(Excess)/Deficient Deferred Income Taxes~~	~~Attachment H-4A, page 3, Line 34, Col. 3~~
~~29~~	~~Income Tax Calculation~~	~~(Line 22*Line 24)~~
~~30~~	~~ITC adjustment~~	~~Attachment H-4A, page 3, Line 36, Col. 5~~
~~31~~	~~Permanent Differences and AFUDC Equity Tax Adjustment~~	~~Attachment H-4A, page 3, Line 37, Col. 5~~
~~32~~	~~(Excess)/Deficient Deferred Income Tax Adjustment~~	~~Attachment H-4A, page 3, Line 38, Col. 5~~
~~33~~	~~Total Income Taxes~~	~~Sum Lines 29 to 32~~
~~34~~	~~Return and Income taxes with increase in ROE~~	~~(Line 22 + Line 33)~~
~~35~~	~~Return without incentive adder~~	~~Attachment H-4A, Page 3, Line 40, Col. 5~~
~~36~~	~~Income Tax without incentive adder~~	~~Attachment H-4A, Page 3, Line 39, Col. 5~~
~~37~~	~~Return and Income taxes without increase in ROE~~	~~Line 35 + Line 36~~
~~38~~	~~Return and Income taxes with increase in ROE~~	~~Line 34~~
~~39~~	~~Incremental Return and incomes taxes for increase in ROE~~	~~Line 38 - Line 37~~
~~40~~	~~Rate Base~~	~~Line 1~~
~~41~~	~~Incremental Return and incomes taxes for increase in ROE divided by rate base~~	~~Line 39 / Line 40~~

~~Notes:~~
~~Line 17 to include an incentive ROE that is used only to determine the increase in return and incomes taxes associated with a specific increase in ROE. Any actual ROE incentive must be approved by the Commission. Until an ROE incentive is approved, line 17 will reflect the current ROE.~~

~~Gross Plant Calculation~~

~~For the 12 months ended 12/31/2017~~

			~~[1]~~ ~~Production~~	~~[2]~~ ~~Transmission~~	~~[3]~~ ~~Distribution~~	~~[4]~~ ~~Intangible~~	~~[5]~~ ~~General~~	~~[6]~~ ~~Common~~	~~[7]~~ ~~Total~~
~~1~~	~~December~~	~~2016~~							
~~2~~	~~January~~	~~2017~~							
~~3~~	~~February~~	~~2017~~							
~~4~~	~~March~~	~~2017~~							
~~5~~	~~April~~	~~2017~~							
~~6~~	~~May~~	~~2017~~							
~~7~~	~~June~~	~~2017~~							
~~8~~	~~July~~	~~2017~~							
~~9~~	~~August~~	~~2017~~							
~~10~~	~~September~~	~~2017~~							
~~11~~	~~October~~	~~2017~~							
~~12~~	~~November~~	~~2017~~							
~~13~~	~~December~~	~~2017~~							
~~14~~	~~13-month Average [A] [C]~~								

			~~Production~~	~~Transmission~~	~~Distribution~~	~~Intangible~~	~~General~~	~~Common~~	~~Total~~
		~~[B]~~	~~205.46.g~~	~~207.58.g~~	~~207.75.g~~	~~205.5.g~~	~~207.99.g~~	~~356.1~~	
~~15~~	~~December~~	~~2016~~							
~~16~~	~~January~~	~~2017~~							
~~17~~	~~February~~	~~2017~~							
~~18~~	~~March~~	~~2017~~							
~~19~~	~~April~~	~~2017~~							
~~20~~	~~May~~	~~2017~~							
~~21~~	~~June~~	~~2017~~							
~~22~~	~~July~~	~~2017~~							
~~23~~	~~August~~	~~2017~~							
~~24~~	~~September~~	~~2017~~							
~~25~~	~~October~~	~~2017~~							
~~26~~	~~November~~	~~2017~~							
~~27~~	~~December~~	~~2017~~							
~~28~~	~~13-month Average~~								

~~Asset Retirement Costs~~

			~~Production~~	~~Transmission~~	~~Distribution~~	~~Intangible~~	~~General~~	~~Common~~
		~~[B]~~		~~207.57.g~~	~~207.74.g~~		~~207.98.g~~	
~~29~~	~~December~~	~~2016~~						
~~30~~	~~January~~	~~2017~~						
~~31~~	~~February~~	~~2017~~						
~~32~~	~~March~~	~~2017~~						
~~33~~	~~April~~	~~2017~~						
~~34~~	~~May~~	~~2017~~						
~~35~~	~~June~~	~~2017~~						
~~36~~	~~July~~	~~2017~~						
~~37~~	~~August~~	~~2017~~						
~~38~~	~~September~~	~~2017~~						
~~39~~	~~October~~	~~2017~~						
~~40~~	~~November~~	~~2017~~						
~~41~~	~~December~~	~~2017~~						
~~42~~	~~13-month Average~~		–					–

~~Notes:~~
~~[A] Taken to Attachment H-4A, page 2, lines 1-6, Col. 3~~
~~[B] Reference for December balances as would be reported in FERC Form 1.~~
~~[C] Balance excludes Asset Retirements Costs~~

~~Accumulated Depreciation Calculation~~

			~~[1]~~ ~~Production~~	~~[2]~~ ~~Transmission~~	~~[3]~~ ~~Distribution~~	~~[4]~~ ~~Intangible~~	~~[5]~~ ~~General~~	~~[6]~~ ~~Common~~	~~[7]~~ ~~Total~~
~~1~~	~~December~~	~~2016~~							
~~2~~	~~January~~	~~2017~~							
~~3~~	~~February~~	~~2017~~							
~~4~~	~~March~~	~~2017~~							
~~5~~	~~April~~	~~2017~~							
~~6~~	~~May~~	~~2017~~							
~~7~~	~~June~~	~~2017~~							
~~8~~	~~July~~	~~2017~~							
~~9~~	~~August~~	~~2017~~							
~~10~~	~~September~~	~~2017~~							
~~11~~	~~October~~	~~2017~~							
~~12~~	~~November~~	~~2017~~							
~~13~~	~~December~~	~~2017~~							
~~14~~	~~13-month Average~~	~~[A] [C]~~							

				~~Production~~	~~Transmission~~	~~Distribution~~	~~Intangible~~	~~General~~	~~Common~~	~~Total~~
			~~[B]~~							
~~15~~	~~December~~	~~2016~~								
~~16~~	~~January~~	~~2017~~								
~~17~~	~~February~~	~~2017~~								
~~18~~	~~March~~	~~2017~~								
~~19~~	~~April~~	~~2017~~								
~~20~~	~~May~~	~~2017~~								
~~21~~	~~June~~	~~2017~~								
~~22~~	~~July~~	~~2017~~								
~~23~~	~~August~~	~~2017~~								
~~24~~	~~September~~	~~2017~~								
~~25~~	~~October~~	~~2017~~								
~~26~~	~~November~~	~~2017~~								
~~27~~	~~December~~	~~2017~~								
~~28~~	~~13-month Average~~									

~~Reserve for Depreciation of Asset Retirement Costs~~

				~~Production~~	~~Transmission~~	~~Distribution~~	~~Intangible~~	~~General~~	~~Common~~
			~~[B]~~		~~Company Records~~				
~~29~~	~~December~~	~~2016~~							
~~30~~	~~January~~	~~2017~~							
~~31~~	~~February~~	~~2017~~							
~~32~~	~~March~~	~~2017~~							
~~33~~	~~April~~	~~2017~~							
~~34~~	~~May~~	~~2017~~							
~~35~~	~~June~~	~~2017~~							
~~36~~	~~July~~	~~2017~~							
~~37~~	~~August~~	~~2017~~							
~~38~~	~~September~~	~~2017~~							
~~39~~	~~October~~	~~2017~~							
~~40~~	~~November~~	~~2017~~							
~~41~~	~~December~~	~~2017~~							
~~42~~	~~13-month Average~~			-		-	-	-	-

~~Notes:~~
~~[A] Taken to Attachment H-4A, page 2, lines 7-11, Col. 3~~
~~[B] Reference for December balances as would be reported in FERC Form 1.~~
~~[C] Balance excludes reserve for depreciation of asset retirement costs~~

				~~[1]~~	~~[2]~~	~~[3]~~	~~[4]~~	~~[5]~~	~~[6]~~
				~~ADIT Transmission Total (including Plant & Labor Related Transmission ADITs and applicable transmission adjustments from notes below)~~					
				~~**Acct. No. 281 (enter negative)**~~	~~**Acct. No. 282 (enter negative)**~~	~~**Acct. No. 283 (enter negative)**~~	~~**Acct. No. 190**~~	~~**Acct. No. 255 (enter negative)**~~	~~**Total**~~
					~~[B]~~	~~[C]~~	~~[D]~~	~~[E]~~	
~~1~~	~~December 31~~	~~2016~~		-					
~~2~~	~~December 31~~	~~2017~~		-					
~~3~~	~~**Begin/End Average**~~		~~[A]~~	-					
				~~ADIT Total Transmission-related only, including Plant & Labor Related Transmission ADITs (prior to adjustments from notes below)~~					
				~~**Acct. No. 281**~~	~~**Acct. No. 282**~~	~~**Acct. No. 283**~~	~~**Acct. No. 190**~~	~~**Acct. No. 255**~~	~~**Total**~~
~~4~~	~~December 31~~	~~2016~~	~~[H]~~	-					
~~5~~	~~December 31~~	~~2017~~	~~[H]~~	-					
~~6~~	~~Begin/End Average~~			-					

~~Notes:~~

~~[A] Beginning/Ending Average with adjustments for FAS143, FAS106, FAS109, CIACs and normalization to populate Appendix H-4A, page 2, lines 19-23, col. 3 for accounts 281, 282, 283, 190, and 255, respectively~~

~~[B] FERC Account No. 282 is adjusted for the following items.~~

	~~FAS 143 - ARO~~	~~FAS 106~~	~~FAS 109~~	~~CIAC~~	~~Normalization [G]~~
~~2016~~					
~~2017~~					
~~Begin/End Average~~					

~~[C] FERC Account No. 283 is adjusted for the following items.~~

	~~FAS 143 - ARO~~	~~FAS 106~~	~~FAS 109~~	~~CIAC~~	~~Normalization [G]~~
~~2016~~					
~~2017~~					
~~Begin/End Average~~					

~~[D] FERC Account No. 190 is adjusted for the following items:~~

	~~FAS 143 - ARO~~	~~FAS 106~~	~~FAS 109~~	~~CIAC~~	~~Normalization [G]~~
~~2016~~					
~~2017~~					
~~Begin/End Average~~					

~~[E] "Based on prior elections and IRS rulings, the 3% Investment Tax Credit ("ITC") and the 4% ITC may be used to reduce rate base as well as utilizing amortization of the tax credits against taxable income.~~
~~As a result, only the 3% and 4% values in FERC Form 1 column (h) on page 267 should be reported under Acct. No. 255.~~

~~[G] Sourced from Attachment 5b, page 2, col. 4~~

~~[H] Sourced from Attachment 5a, page 1, lines 1-5, col. 6 for beginning balance and page 1, lines 1-5, col. 7 for ending balance~~

~~**Jersey Central Power & Light**~~
~~**Summary of Transmission ADIT (prior to adjusted items)**~~

~~Line~~	~~1~~	~~2~~	~~3~~	~~4~~	~~5~~	~~6~~	~~7~~
		~~Transmission Beginning~~ (~~Note F~~)	~~Transmission Ending~~ (~~Note F~~)	~~Beg Plant & Labor Related Allocated to Transmission~~ (~~page 1, col. K~~)	~~End Plant & Labor Related Allocated to Transmission~~ (~~page 1, col. L~~)	~~Total Transmission Beginning~~ (~~col. 2 + col. 4) (Note E~~)	~~Total Transmission Ending~~ (~~col. 3 + col. 5) (Note E~~)
~~1~~	~~**ADIT- 282 From Account Subtotal Below**~~						
~~2~~	~~**ADIT-283 From Account Subtotal Below**~~						
~~3~~	~~**ADIT-190 From Account Subtotal Below**~~						
~~4~~	~~**ADIT-281 From Account Subtotal Below**~~						
~~5~~	~~**ADIT-255 From Account Subtotal Below**~~						
	~~**Total (sum rows 1-5)**~~						

~~**Jersey Central Power & Light**~~
~~**Calculation of Plant & Labor Related ADIT allocated to Transmission**~~

~~Line~~		~~F1~~	~~F2~~	~~G1~~	~~G2~~	~~H~~	~~I~~	~~J~~	~~K~~	~~L~~	~~M~~
		~~Beg Plant Related~~ (~~Note A~~)	~~End Plant Related~~ (~~Note A~~)	~~Beg Labor Related~~ (~~Note B~~)	~~End Labor Related~~ (~~Note B~~)	~~Plant & Labor Subtotal~~ ~~Col. F1 + Col. F2 + Col. G1 + Col. G2~~	~~Gross Plant Allocator~~ (~~Note C~~)	~~Wages & Salary Allocator~~ (~~Note D~~)	~~Beg Plant & Labor Related ADIT~~ (~~Col. F1 * Col. I) + (Col. F2 * Col. J~~)	~~End Plant & Labor Related ADIT~~ (~~Col. F2 * Col. I) + (Col. G2 * Col. J~~)	~~Beg/End Avg Plant & Labor Total~~ (~~Col. K + Col. L) / 2~~
~~1~~	~~**ADIT- 282 From Account Total Below**~~										
~~2~~	~~**ADIT-283 From Account Total Below**~~										
~~3~~	~~**ADIT-190 From Account Total Below**~~										
~~4~~	~~**ADIT-281 From Account Total Below**~~										
~~5~~	~~**ADIT-255 From Account Total Below**~~										
~~6~~	~~**Subtotal**~~										

~~Notes~~
~~A~~ ~~From column F (beginning on page 2)~~
~~B~~ ~~From column G (beginning on page 2)~~
~~C~~ ~~Refers to Attachment H-4A, page 2, line 6, col. 4~~
~~D~~ ~~Refers to Attachment H-4A, page 4, line 16, col.6~~
~~E~~ ~~Total Transmission Beginning taken to Attachment 5, line 4 and Total Transmission Ending taken to Attachment 5, line 5~~
~~F~~ ~~From column E (beginning on page 2) by account~~

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

~~A~~	~~B1~~	~~B2~~	~~B3~~	~~C~~	~~D~~	~~E~~	~~F~~	~~G~~	
	~~Jersey Central Power & Light~~								
~~ADIT-190~~	~~Beg of Year Balance p234.18.b~~			~~Retail Related~~	~~Gas, Prod Or Other Related~~	~~Only Transmission Related~~	~~Plant Related~~	~~Labor Related~~	~~JUSTIFICATION~~
~~Subtotal~~							-	-	
~~ADIT-190~~		~~End of Year Balance p234.18.c~~		~~Retail Related~~	~~Gas, Prod Or Other Related~~	~~Only Transmission Related~~	~~Plant Related~~	~~Labor Related~~	~~JUSTIFICATION~~
~~Subtotal~~	-						-	-	

~~**Instructions for Account 190:**~~

~~1. ADIT items related only to Retail Related Operations are directly assigned to Column C.~~
~~2. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D.~~
~~3. ADIT items related only to Transmission are directly assigned to Column E.~~
~~4. ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.~~
~~5. ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.~~
~~6. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates. Therefore, if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.~~

~~A~~	~~B1~~	~~B2~~	~~B3~~	~~C~~	~~D~~	~~E~~	~~F~~	~~G~~	
	~~Jersey Central Power & Light~~								
~~ADIT- 282~~	~~Beg of Year Balance p274.9.b~~			~~Retail Related~~	~~Gas, Prod Or Other Related~~	~~Only Transmission Related~~	~~Plant Related~~	~~Labor Related~~	~~JUSTIFICATION~~
					-	-			
~~Subtotal~~							-	-	
~~ADIT- 282~~		~~End of Year Balance p275.9.k~~		~~Retail Related~~	~~Gas, Prod Or Other Related~~	~~Only Transmission Related~~	~~Plant Related~~	~~Labor Related~~	~~JUSTIFICATION~~
~~Subtotal~~							-	-	

~~Instructions for Account 282:~~
~~1. ADIT items related only to Retail Related Operations are directly assigned to Column C.~~
~~2. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D.~~
~~3. ADIT items related only to Transmission are directly assigned to Column E.~~
~~4. ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.~~
~~5. ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.~~
~~6. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates. Therefore, if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.~~

~~A~~	~~B1~~	~~B2~~	~~B3~~	~~C~~	~~D~~	~~E~~	~~F~~	~~G~~	
	~~Jersey Central Power & Light~~								
~~ADIT-283~~	~~Beg of Year Balance p276.19.b~~			~~Retail Related~~	~~Gas, Prod Or Other Related~~	~~Only Transmission Related~~	~~Plant Related~~	~~Labor Related~~	~~JUSTIFICATION~~
						-			
~~Subtotal~~							-	-	
~~ADIT-283~~		~~End of Year Balance p277.19.k~~		~~Retail Related~~	~~Gas, Prod Or Other Related~~	~~Only Transmission Related~~	~~Plant Related~~	~~Labor Related~~	~~JUSTIFICATION~~
						-			
						-			
						-			
						-			
						-			
~~Subtotal~~		-					-	-	

~~Instructions for Account 283:~~

~~1. ADIT items related only to Retail Related Operations are directly assigned to Column C.~~
~~2. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D.~~
~~3. ADIT items related only to Transmission are directly assigned to Column E.~~
~~4. ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.~~
~~5. ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.~~
~~6. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates. Therefore, if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.~~

~~PJM TRANSMISSION OWNER~~

~~A~~	~~B1~~	~~B2~~	~~B3~~	~~C~~	~~D~~	~~E~~	~~F~~	~~G~~	
	~~Jersey Central Power & Light~~								
~~ADIT-281~~	~~Beg of Year Balance~~ ~~p272.8.b~~			~~Retail Related~~	~~Gas, Prod Or Other Related~~	~~Only Transmission Related~~	~~Plant Related~~	~~Labor Related~~	~~JUSTIFICATION~~
						-			
						-			
						-			
						-			
						-			
						-			
						-			
						-			
						-			
~~Subtotal~~	-				-	-	-	-	
~~ADIT-281~~		~~End of Year Balance~~ ~~p273.8.k~~		~~Retail Related~~	~~Gas, Prod Or Other Related~~	~~Only Transmission Related~~	~~Plant Related~~	~~Labor Related~~	~~JUSTIFICATION~~
						-			
						-			
						-			
						-			
						-			
						-			
						-			
						-			
						-			
~~Subtotal~~	-				-	-	-	-	

~~Instructions for Account 281:~~
~~1. ADIT items related only to Retail Related Operations are directly assigned to Column C.~~
~~2. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D.~~
~~3. ADIT items related only to Transmission are directly assigned to Column E.~~
~~4. ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.~~
~~5. ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.~~
~~6. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates. Therefore, if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.~~

~~PJM TRANSMISSION OWNER~~

~~A~~	~~B1~~	~~B2~~	~~B3~~	~~C~~	~~D~~	~~E~~	~~F~~	~~G~~	
	~~Jersey Central Power & Light~~								
~~ADIT-255~~	~~Beg of Year Balance~~ ~~p266.b~~			~~Retail Related~~	~~Gas, Prod Or Other Related~~	~~Only Transmission Related~~	~~Plant Related~~	~~Labor Related~~	~~JUSTIFICATION~~
~~Subtotal~~							-	-	
~~ADIT-255~~		~~End of Year Balance~~ ~~p267.h~~		~~Retail Related~~	~~Gas, Prod Or Other Related~~	~~Only Transmission Related~~	~~Plant Related~~	~~Labor Related~~	~~JUSTIFICATION~~
~~Subtotal~~								-	

~~**Instructions for Account 255:**~~

~~**1. ADIT items related only to Retail Related Operations are directly assigned to Column C.**~~
~~**2. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column D.**~~
~~**3. ADIT items related only to Transmission are directly assigned to Column E.**~~
~~**4. ADIT items related to Plant and not in Columns C, D & E are directly assigned to Column F.**~~
~~**5. ADIT items related to labor and not in Columns C, D, E & F are directly assigned to Column G.**~~
~~**6. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates. Therefore, if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.**~~

~~[1]~~	~~[2]~~	~~[3]~~	~~[4]~~	~~[5]~~	~~[6]~~	~~[7]~~	~~[8]~~	~~[9]~~
	~~2017 Quarterly Activity and Balances~~							
~~Beginning 190 (including adjustments)~~	~~Q1 Activity~~	~~Ending Q1~~	~~Q2 Activity~~	~~Ending Q2~~	~~Q3 Activity~~	~~Ending Q3~~	~~Q4 Activity~~	~~Ending Q4~~
~~Beginning 190 (including adjustments)~~	~~Pro-rated Q1~~		~~Pro-rated Q2~~		~~Pro-rated Q3~~		~~Pro-rated Q4~~	
~~Beginning 282 (including adjustments)~~	~~Q1 Activity~~	~~Ending Q1~~	~~Q2 Activity~~	~~Ending Q2~~	~~Q3 Activity~~	~~Ending Q3~~	~~Q4 Activity~~	~~Ending Q4~~
~~Beginning 282 (including adjustments)~~	~~Pro-rated Q1~~		~~Pro-rated Q2~~		~~Pro-rated Q3~~		~~Pro-rated Q4~~	
~~Beginning 283 Including adjustments)~~	~~Q1 Activity~~	~~Ending Q1~~	~~Q2 Activity~~	~~Ending Q2~~	~~Q3 Activity~~	~~Ending Q3~~	~~Q4 Activity~~	~~Ending Q4~~
~~Beginning 283 Including adjustments)~~	~~Pro-rated Q1~~		~~Pro-rated Q2~~		~~Pro-rated Q3~~		~~Pro-rated Q4~~	

	~~[1]~~	~~[2]~~	~~[3]~~	~~[4]~~	~~[5]~~
~~2017 Activity~~	~~Transmission-only (including plant and labor related ADIT allocated to transmission) FERC Form 1 - Year-End 2017~~	~~Prorated year-end less FERC Form 1 Year-end~~	~~Sum of FAS143, FAS106, FAS109, and CIAC from Attachment 5 notes~~	~~Total Normalization to Attachment 5 ((col. 1 - col. 3) - page 1, col. 9)~~	~~Ending Balance for formula rate (col. 1 - col. 3. - col. 4)~~
~~Pro-rated Total~~ ~~Pro-rated Ending 190~~					
~~Pro-rated Total~~ ~~Pro-rated Ending 282~~					
~~Pro-rated Total~~ ~~Pro-rated Ending 283~~					

~~Attachment H-4A, Attachment 6~~
~~page 1 of 1~~
~~For the 12 months ended 12/31/2017~~

~~1~~	**~~Calculation of PBOP Expenses~~**	
~~2~~	**~~JCP&L~~**	
~~3~~	~~Total FirstEnergy PBOP expenses~~	
~~4~~	~~Labor dollars (FirstEnergy)~~	
~~5~~	~~cost per labor dollar (line 3 / line 4)~~	
~~6~~	~~labor (labor not capitalized) current year~~	
~~7~~	~~PBOP Expense for current year (line 5 * line 6)~~	
~~8~~	~~PBOP expense in all O&M and A&G accounts for current year~~	
~~9~~	~~PBOP Adjustment for Attachment H-4A, page 3, line 9 (line 7 - line 8)~~	
~~10~~	~~Lines 3-4 cannot change absent approval or acceptance by FERC in a separate proceeding~~	

~~For the 12 months ended 12/31/2017~~

~~Taxes Other than Income Calculation~~

		~~[A]~~	~~Dec 31, 2017~~
~~1~~	**~~Payroll Taxes~~**		
~~1a~~		~~263.i~~	
~~1b~~		~~263.i~~	
~~1c~~		~~263.i~~	
~~1d~~		~~263.i~~	
~~1z~~	**~~Payroll Taxes Total~~**		
~~2~~	**~~Highway and Vehicle Taxes~~**		
~~2a~~		~~263.i~~	
~~2z~~	**~~Highway and Vehicle Taxes~~**		
~~3~~	**~~Property Taxes~~**		
~~3a~~		~~263.i~~	
~~3b~~		~~263.i~~	
~~3c~~		~~263.i~~	
~~3d~~		~~263.i~~	
~~3z~~	**~~Property Taxes~~**		
~~4~~	**~~Gross Receipts Tax~~**		
~~4a~~		~~263.i~~	
~~4z~~	**~~Gross Receipts Tax~~**		
~~5~~	**~~Other Taxes~~**		
~~5a~~		~~263.i~~	
~~5b~~		~~263.i~~	
~~5c~~		~~263.i~~	
~~5d~~			
~~5z~~	**~~Other Taxes~~**		
~~6z~~	**~~Payments in lieu of taxes~~**		
~~7~~	~~Total other than income taxes (sum lines 1z, 2z, 3z, 4z, 5z, 6z) [tie to 114.14c]~~		

~~Notes:~~

~~[A]~~ ~~Reference for December balances as would be reported in FERC Form 1.~~

~~Attachment H-4A, Attachment 8~~
~~page 1 of 1~~
~~For the 12 months ended 12/31/2017~~

~~Capital Structure Calculation~~

				~~[1]~~ ~~Proprietary Capital~~	~~[2]~~ ~~Preferred Stock~~	~~[3]~~ ~~Account 216.1~~	~~[4]~~ ~~Account 219~~	~~[5]~~ ~~Goodwill~~	~~[6]~~ ~~Common Stock~~	~~[7]~~ ~~Long Term Debt~~
			~~[A]~~	~~112.16.c~~	~~112.3.c~~	~~112.12.c~~	~~112.15.c~~	~~233.5.f~~	~~(1) - (2) - (3) - (4) - (5)~~	~~112.24.c~~
~~1~~	~~December~~	~~2016~~								
~~2~~	~~January~~	~~2017~~								
~~3~~	~~February~~	~~2017~~								
~~4~~	~~March~~	~~2017~~								
~~5~~	~~April~~	~~2017~~								
~~6~~	~~May~~	~~2017~~								
~~7~~	~~June~~	~~2017~~								
~~8~~	~~July~~	~~2017~~								
~~9~~	~~August~~	~~2017~~								
~~10~~	~~September~~	~~2017~~								
~~11~~	~~October~~	~~2017~~								
~~12~~	~~November~~	~~2017~~								
~~13~~	~~December~~	~~2017~~								
~~14~~	~~13-month Average~~									

~~Notes:~~

~~[A] Reference for December balances as would be reported in FERC Form 1.~~

~~Stated Value Inputs~~

~~Formula Rate Protocols~~
~~Section VIII.A~~

~~1. Rate of Return on Common Equity ("ROE")~~

~~JCP&L's stated ROE is set to: 11.0%~~

~~2. Postretirement Benefits Other Than Pension ("PBOP")~~
~~*sometimes referred to as Other Post Employment Benefits, or "OPEB"~~*

~~Total FirstEnergy PBOP expenses~~	~~-$108,686,300~~
~~Labor dollars (FirstEnergy)~~	~~$2,024,261,894~~

~~3. Depreciation Rates~~

~~FERC Account~~	~~Depr %~~
~~350.2~~	~~1.44%~~
~~352~~	~~1.33%~~
~~353~~	~~2.21%~~
~~354~~	~~1.29%~~
~~355~~	~~1.93%~~
~~356~~	~~2.60%~~
~~356.1~~	~~1.22%~~
~~357~~	~~1.53%~~
~~358~~	~~1.76%~~
~~359~~	~~1.21%~~
~~303~~	~~14.29%~~
~~390.1~~	~~1.61%~~
~~390.2~~	~~0.46%~~
~~391~~	~~10.91%~~
~~391.15~~	~~0.96%~~
~~391.2~~	~~6.39%~~
~~392~~	~~11.29%~~
~~393~~	~~3.13%~~
~~394~~	~~6.17%~~
~~395~~	~~16.27%~~
~~396~~	~~2.35%~~
~~397~~	~~5.13%~~
~~398~~	~~1.36%~~

~~Attachment H-4A, Attachment 10~~
~~page 1 of 1~~
~~For the 12 months ended 12/31/2017~~

~~Debt Cost Calculation~~

~~TABLE 1: Summary Cost of Long Term Debt~~

~~CALCULATION OF COST OF DEBT~~

~~YEAR ENDED 12/31/2017~~

~~Long Term Debt Cost at Year Ended:~~	~~t=N 12/31/2017~~	~~(a) Issue Date~~	~~(b) Maturity Date~~	~~(c) ORIGINAL ISSUANCE (table 2, col. cc)~~	~~(d) Net Proceeds At Issuance (table 2, col. hh)~~	~~(e) Net Amount Outstanding at t=N~~	~~(f) Months Outstanding at t=N~~	~~(g) Average Net Outstanding in Year* z* ((col e. * col. F)/12)~~	~~(h) Weighted Outstanding Ratios (col. g/col. g total)~~	~~(i) Effective Cost Rate (Table 2, Col. II)~~	~~(j) Weighted Debt Cost at t = N (h) * (i)~~	
~~First Mortgage Bonds:~~												
~~(1)~~												
~~(2)~~												
~~(3)~~												
~~(4)~~												
~~(5)~~												
~~(6)~~												
~~(7)~~												
												~~**~~

~~t = time~~
~~The current portion of long term debt is included in the Net Amount Outstanding at t = N in these calculations.~~
~~The outstanding amount (column (e)) for debt retired during the year is the outstanding amount at the last month it was outstanding.~~
~~* z = Average of monthly balances for months outstanding during the year (average of the balances for the 12 months of the year, with zero in months that the issuance is not outstanding in a month.).~~
~~Interim (individual debenture) debt cost calculations shall be taken to four decimals in percentages (7.2300%, 5.2582%); Final Total Weighted Average Debt Cost for the Formula Rate shall be rounded to two decimals of a percent (7.03%).~~
~~** This Total Weighted Average Debt Cost will be shown on page 4, line 27, column 5 of formula rate Attachment H-4A.~~

~~TABLE 2: Effective Cost Rates For Traditional Front-Loaded Debt Issuances:~~

~~YEAR ENDED 12/31/2017~~

~~Long Term Debt Issuances~~	~~Affiliate~~	~~(aa) Issue Date~~	~~(bb) Maturity Date~~	~~(cc) Amount Issued~~	~~(dd) (Discount) Premium at Issuance~~	~~(ee) Issuance Expense~~	~~(ff) Loss/Gain on Reacquired Debt~~	~~(gg) Less Related ADIT~~	~~(hh) Net Proceeds (col. cc + col. dd + col. ee + col. ff)~~	~~(ii) Net Proceeds Ratio ((col. cc / col. hh) *100)~~	~~(jj) Coupon Rate~~	~~(kk) Annual Interest (col. cc *col. jj)~~	~~(ll) Effective Cost Rate* (Yield to Maturity at Issuance, t = 0)~~
~~(1)~~													
~~(2)~~													
~~(3)~~													
~~(4)~~													
~~(5)~~													
~~(6)~~													
~~(7)~~													

~~* YTM at issuance calculated from an acceptable bond table or from YTM = Internal Rate of Return (IRR) calculation~~
~~Effective Cost Rate of Individual Debenture (YTM at issuance): the t=0 Cashflow C_0 equals Net Proceeds column (gg); Semi-annual (or other) interest cashflows ($C_{t=1}$, $C_{t=2}$, etc.).~~

~~Attachment H-4A, Attachment 11~~
~~page 1 of 2~~
~~For the 12 months ended 12/31/2017~~

~~Transmission Enhancement Charge (TEC) Worksheet~~
~~To be completed in conjunction with Attachment H-4~~

~~Columns 5-9 (page 1) only applies with incentive ROE project(s) (Note F)~~

	~~(1)~~	~~(2)~~	~~(3)~~	~~(4)~~	~~(5)~~	~~(6)~~	~~(7)~~	~~(8)~~	~~(9)~~
~~Line No.~~		**~~Reference~~**	**~~Transmission~~**	**~~Allocator~~**	~~Line No.~~		**~~Reference~~**	**~~Transmission~~**	**~~Allocator~~**
~~1~~	~~Gross Transmission Plant - Total~~	~~Attach. H-4A, p. 2, line 2, col. 5 (Note A)~~							
~~2~~	~~Net Transmission Plant - Total~~	~~Attach. H-4A, p. 2, line 14, col. 5 (Note B)~~							
	~~O&M EXPENSE~~								
~~3~~	~~Total O&M Allocated to Transmission~~	~~Attach. H-4A, p. 3, line 15, col. 5~~							
~~4~~	~~Annual Allocation Factor for O&M~~	~~(line 3 divided by line 1, col. 3)~~							
	~~GENERAL, INTANGIBLE, AND COMMON (G,I, & C) DEPRECIATION EXPENSE~~								
~~5~~	~~Total G, I, & C depreciation expense~~	~~Attach. H-4A, p. 3, lines 17 & 18, col. 5~~							
~~6~~	~~Annual allocation factor for G, I, & C depreciation expense~~	~~(line 5 divided by line 1, col. 3)~~							
		~~TAXES OTHER THAN INCOME TAXES~~							
~~7~~	~~Total Other Taxes~~	~~Attach. H-4A, p. 3, line 28, col. 5~~							
~~8~~	~~Annual Allocation Factor for Other Taxes~~	~~(line 7 divided by line 1, col. 3)~~							
~~9~~	**~~Annual Allocation Factor for Expense~~**	**~~Sum of line 4, 6, & 8~~**							
	~~INCOME TAXES~~					~~INCOME TAXES~~			
~~10~~	~~Total Income Taxes~~	~~Attach. H-4A, p. 3, line 39, col. 5~~			~~10b~~	~~Total Income Taxes~~	~~Attachment 2, line 33~~		
~~11~~	~~Annual Allocation Factor for Income Taxes~~	~~(line 12 divided by line 2, col. 3)~~			~~11b~~	~~Annual Allocation Factor for Income Taxes~~	~~(line 10b divided by line 2, col. 3)~~		
	~~RETURN~~					~~RETURN~~			
~~12~~	~~Return on Rate Base~~	~~Attach. H-4A, p. 3, line 40, col. 5~~			~~12b~~	~~Return on Rate Base~~	~~Attachment 2, line 22~~		
~~13~~	~~Annual Allocation Factor for Return on Rate Base~~	~~(line 14 divided by line 2, col. 3)~~			~~13b~~	~~Annual Allocation Factor for Return on Rate Base~~	~~(line 12b divided by line 2, col. 3)~~		
~~14~~	**~~Annual Allocation Factor for Return~~**	**~~Sum of line 11 and 13~~**			**~~14b~~**	**~~Annual Allocation Factor for Return~~**	**~~Sum of line 11b and 13b~~**		
					~~15~~	**~~Additional Annual Allocation Factor for Return~~**	**~~Line 14 b, col. 9 less line 14, col. 4~~**		

~~Transmission Enhancement Charge (TEC) Worksheet~~
~~To be completed in conjunction with Attachment H-4~~

	~~(1)~~	~~(2)~~	~~(3)~~	~~(4)~~	~~(5)~~	~~(6)~~	~~(7)~~	~~(8)~~	~~(9)~~	~~(10)~~	~~(11)~~	~~(12)~~	~~(13)~~	~~(14)~~
~~Line No.~~	~~Project Name~~	~~RTEP Project Number~~	~~Project Gross Plant~~	~~Annual Allocation Factor for Expense~~	~~Annual Expense Charge~~	~~Project Net Plant~~	~~Annual Allocation Factor for Return~~	~~Annual Return Charge~~	~~Project Depreciation Expense~~	~~Annual Revenue Requirement~~	~~Additional Incentive Annual Allocation Factor for Return (Note F)~~	~~Total Annual Revenue Requirement~~	~~True-up Adjustment~~	~~Net Revenue Requirement with True-up~~
			~~(Note C & H)~~	~~(Page 1, line 9)~~	~~(Col. 3 * Col. 4)~~	~~(Note D & H)~~	~~Page 1, line 14~~	~~(Col. 6 * Col. 7)~~	~~(Note E)~~	~~(Sum Col. 5, 8, & 9)~~	~~(Col. 6 * Page 1, line 15, Col. 9)~~	~~(Sum Col. 10 & 11)~~	~~(Note G)~~	~~(Sum Col. 12 & 13)~~
~~2a~~														
~~2b~~														
~~2c~~														
~~2d~~														
~~2e~~														
~~2f~~														
~~2g~~														

~~3~~ ~~Transmission Enhancement Credit taken to Attachment H-4A Page 1, Line 7~~
~~4~~ ~~Additional Incentive Revenue taken to Attachment H-4A, Page 3, Line 42~~

~~Notes~~

~~A~~ ~~Gross Transmission Plant is that identified on page 2 line 2 of Attachment H-4A.~~
~~B~~ ~~Net Transmission Plant is that identified on page 2 line 14 of Attachment H-4A.~~
~~C~~ ~~Project Gross Plant is the total capital investment for the project calculated in the same method as the gross plant value in line 1 above. This value includes subsequent capital investments required to maintain the project in-service.~~
~~D~~ ~~Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation.~~
~~E~~ ~~Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H-4A, page 3, line 16.~~
~~F~~ ~~Any actual ROE incentive must be approved by the Commission~~
~~G~~ ~~True-up adjustment is calculated on the project true-up schedule, attachment 12 column j~~
~~H~~ ~~Based on a 13-month average~~

~~Attachment H-4A, Attachment 11a~~
~~page 1 of 2~~
~~For the 12 months ended 12/31/2017~~

~~Transmission Enhancement Charge (TEC) Worksheet~~
~~To be completed in conjunction with Attachment H-4A~~

~~Line No.~~	~~Project Name~~	~~RTEP Project Number~~	~~Project Gross Plant~~	~~Dec-16~~	~~Jan-17~~	~~Feb-17~~	~~Mar-17~~	~~Apr-17~~	~~May-17~~	~~Jun-17~~	~~Jul-17~~	~~Aug-17~~	~~Sep-17~~	~~Oct-17~~	~~Nov-17~~	~~Dec-17~~
			~~(Note A)~~													
~~2a~~																
~~2b~~																
~~2c~~																
~~2d~~																
~~2e~~																
~~2f~~																
~~2g~~																

~~NOTE:~~
~~[A] Project Gross Plant is the total capital investment for the project, including subsequent capital investments required to maintain the project in-service. Utilizing a 13-month average.~~

~~**Transmission Enhancement Charge (TEC) Worksheet**~~

~~To be completed in conjunction with Attachment H-4A~~

~~For the 12 months ended 12/31/2017~~

~~**Accumulated Depreciation**~~	~~**Dec-16**~~	~~**Jan-17**~~	~~**Feb-17**~~	~~**Mar-17**~~	~~**Apr-17**~~	~~**May-17**~~	~~**Jun-17**~~	~~**Jul-17**~~	~~**Aug-17**~~	~~**Sep-17**~~	~~**Oct-17**~~	~~**Nov-17**~~	~~**Dec-17**~~	[redacted]	~~**Project Net Plant**~~
~~(Note B)~~															~~(Note B & C)~~

~~NOTE~~

~~[B] Utilizing a 13-month average.~~ ~~[C] Taken to Attachment 11, Page 2, Col. 6~~

~~Attachment H-4A, Attachment 12~~
~~page 1 of 1~~
~~For the 12 months ended 12/31/2017~~

~~Transmission Enhancement Charge (TEC) Worksheet~~

~~To be completed in conjunction with Attachment H-4A~~

	~~(a)~~	~~(b)~~	~~(c)~~	~~(d)~~	~~(e)~~	~~(f)~~	~~(g)~~	~~(h)~~	~~(i)~~	~~(j)~~
~~Line No.~~	~~Project Name~~	~~RTEP Project Number~~	~~Actual Revenues for Attachment 11~~	~~Projected Annual Revenue Requirement~~	~~% of Total Revenue Requirement~~	~~Revenue Received~~	~~Actual Annual Revenue Requirement~~	~~True-up Adjustment Principal Over/(Under)~~	~~Applicable Interest Rate on Over/(Under)~~	~~Total True-up Adjustment with Interest Over/(Under)~~
				~~Projected Attachment 11 p 2 of 2, col. 14~~	~~Col d, line 2 / col. d, line 3~~	~~Col c, line 1 * Col e~~	~~Actual Attachment 11 p 2 of 2, col. 14~~	~~Col. f - Col. G~~	~~Col. H line 2x / Col. H line 3* Col. J line 4~~	~~Col. h + Col. i~~
~~1~~	~~[A] Actual RTEP Credit Revenues for true-up year~~		~~0~~							
~~2a~~	~~Project 1~~			~~-~~	~~-~~	~~-~~	~~-~~	~~-~~	~~#DIV/0!~~	~~#DIV/0!~~
~~2b~~	~~Project 2~~				~~-~~	~~-~~		~~-~~	~~#DIV/0!~~	~~#DIV/0!~~
~~2c~~	~~Project 3~~				~~-~~	~~-~~		~~-~~	~~#DIV/0!~~	~~#DIV/0!~~
~~3~~	~~Subtotal~~			~~-~~			~~-~~	~~-~~		~~#DIV/0!~~
4	~~Total Interest (Sourced from Attachment 13a, line 30)~~									~~-~~

~~NOTE~~

~~[A] Amount included in revenues reported on pages 328-330 of FERC Form 1.~~

~~Net Revenue Requirement True-up with Interest~~

	~~Reconciliation Revenue Requirement For Year 2015 Available May 1, 2016~~		~~2015 Revenue Requirement Collected by PJM Based on Forecast filed on Oct 31, 2014~~		~~True-up Adjustment - Over (Under) Recovery~~
~~1~~	~~$0~~	-	~~$0~~	=	~~$0~~

			~~Over (Under) Recovery Plus Interest~~	~~Average Monthly Interest Rate~~	~~Months~~	~~Calculated Interest~~	~~Amortization~~	~~Surcharge (Refund) Owed~~
~~2~~	~~Interest Rate on Amount of Refunds or Surcharges from 35.19a~~			~~%~~				
	~~An over or under collection will be recovered prorata over 2015, held for 2016 and returned prorate over 2017~~							
	~~Calculation of Interest~~					**~~Monthly~~**		
~~3~~	~~January~~	~~Year 2015~~	-	~~%~~	~~12~~	-		-
~~4~~	~~February~~	~~Year 2015~~	-	~~%~~	~~11~~	-		-
~~5~~	~~March~~	~~Year 2015~~	-	~~%~~	~~10~~	-		-
~~6~~	~~April~~	~~Year 2015~~	-	~~%~~	~~9~~	-		-
~~7~~	~~May~~	~~Year 2015~~	-	~~%~~	~~8~~	-		-
~~8~~	~~June~~	~~Year 2015~~	-	~~%~~	~~7~~	-		-
~~9~~	~~July~~	~~Year 2015~~	-	~~%~~	~~6~~	-		-
~~10~~	~~August~~	~~Year 2015~~	-	~~%~~	~~5~~	-		-
~~11~~	~~September~~	~~Year 2015~~	-	~~%~~	~~4~~	-		-
~~12~~	~~October~~	~~Year 2015~~	-	~~%~~	~~3~~	-		-
~~13~~	~~November~~	~~Year 2015~~	-	~~%~~	~~2~~	-		-
~~14~~	~~December~~	~~Year 2015~~	-	~~%~~	~~1~~	-		-
						-		-
						~~Annual~~		
~~15~~	~~January through December~~	~~Year 2016~~	-	~~%~~	~~12~~	-		-
	~~Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months~~					**~~Monthly~~**		
~~16~~	~~January~~	~~Year 2017~~	-	~~%~~		-	-	-
~~17~~	~~February~~	~~Year 2017~~	-	~~%~~		-	-	-
~~18~~	~~March~~	~~Year 2017~~	-	~~%~~		-	-	-
~~19~~	~~April~~	~~Year 2017~~	-	~~%~~		-	-	-
~~20~~	~~May~~	~~Year 2017~~	-	~~%~~		-	-	-
~~21~~	~~June~~	~~Year 2017~~	-	~~%~~		-	-	-
~~22~~	~~July~~	~~Year 2017~~	-	~~%~~		-	-	-
~~23~~	~~August~~	~~Year 2017~~	-	~~%~~		-	-	-
~~24~~	~~September~~	~~Year 2017~~	-	~~%~~		-	-	-
~~25~~	~~October~~	~~Year 2017~~	-	~~%~~		-	-	-
~~26~~	~~November~~	~~Year 2017~~	-	~~%~~		-	-	-
~~27~~	~~December~~	~~Year 2017~~	-	~~%~~		-	-	-
						-		

~~28~~	~~True-Up with Interest~~	~~$~~
~~29~~	~~Less Over (Under) Recovery~~	~~$~~
~~30~~	~~Total Interest~~	~~$~~

Attachment H-4A, Attachment 13a
page 1 of 1
For the 12 months ended 12/31/2017

TEC Revenue Requirement True-up with Interest

	TEC Reconciliation Revenue Requirement For Year 2015 Available May 1, 2016		TEC 015 Revenue Requirement Collected by PJM Based on Forecast filed on Oct 31, 2014		True-up Adjustment - Over (Under) Recovery
1	$0	-	$0	=	$0

			Over (Under) Recovery Plus Interest	Average Monthly Interest Rate	Months	Calculated Interest	Amortization	Surcharge (Refund) Owed
2	Interest Rate on Amount of Refunds or Surcharges from 35.19a			%				
	An over or under collection will be recovered prorata over 2015, held for 2016 and returned prorate over 2017							
	Calculation of Interest					**Monthly**		
3	January	Year 2015	-	%	12	-		-
4	February	Year 2015	-	%	11	-		-
5	March	Year 2015	-	%	10	-		-
6	April	Year 2015	-	%	9	-		-
7	May	Year 2015	-	%	8	-		-
8	June	Year 2015	-	%	7	-		-
9	July	Year 2015	-	%	6	-		-
10	August	Year 2015	-	%	5	-		-
11	September	Year 2015	-	%	4	-		-
12	October	Year 2015	-	%	3	-		-
13	November	Year 2015	-	%	2	-		-
14	December	Year 2015	-	%	1	-		-
						-		-
						Annual		
15	January through December	Year 2016	-	%	12	-		-
	Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					**Monthly**		
16	January	Year 2017	-	%		-	-	-
17	February	Year 2017	-	%		-	-	-
18	March	Year 2017	-	%		-	-	-
19	April	Year 2017	-	%		-	-	-
20	May	Year 2017	-	%		-	-	-
21	June	Year 2017	-	%		-	-	-
22	July	Year 2017	-	%		-	-	-
23	August	Year 2017	-	%		-	-	-
24	September	Year 2017	-	%		-	-	-
25	October	Year 2017	-	%		-	-	-
26	November	Year 2017	-	%		-	-	-
27	December	Year 2017	-	%		-	-	-
						-		

28	True-Up with Interest	$ -
29	Less Over (Under) Recovery	$ -
30	Total Interest	$ -

~~Attachment H-4A, Attachment 14~~
~~page 1 of 1~~
~~For the 12 months ended 12/31/2017~~

~~Other Rate Base Items~~

				~~[1]~~	~~[2]~~	~~[3]~~	~~[4]~~	~~[5]~~	~~[6]~~
				~~Land Held for Future Use~~	**~~Materials & Supplies~~**	**~~Prepayments (Account 165)~~**		**~~Total~~**	
			~~[A]~~	~~214.x.d~~	~~227.8.c&.16.c~~	~~111.57.c[C]~~			
~~1~~	~~December 31~~	~~2016~~		-	-				
~~2~~	~~December 31~~	~~2017~~		-	-				
~~3~~	~~Begin/End Average~~			-	-				

				~~Unfunded Reserve - Plant Related~~					**~~Total~~**
		~~FERC Acct No.~~		**~~228.1~~**	**~~228.2~~**	**~~228.3~~**	**~~228.4~~**	**~~242~~**	
		~~[A]~~	~~[D]~~	~~112.27.c~~	~~112.28.c~~	~~112.29.c~~	~~112.30.c~~	~~113.48.c~~	
~~4~~	~~December 31~~	~~2016~~		-	-	-	-	-	-
~~5~~	~~December 31~~	~~2017~~		-	-	-	-	-	-
~~6~~	~~Begin/End Average~~			-	-	-	-	-	-

				~~Unfunded Reserve - Labor Related~~						**~~Total~~**
		~~FERC Acct No.~~		**~~228.1~~**	**~~228.2~~**	**~~228.3~~**	**~~228.4~~**	**~~242~~**		
		~~[A]~~	~~[D]~~	~~112.27.c~~	~~112.28.c~~	~~112.29.c~~	~~112.30.c~~	~~113.48.c [B]~~		
~~7~~	~~December 31~~	~~2016~~		-	-	-	-	-	-	-
~~8~~	~~December 31~~	~~2017~~		-	-	-	-	-	-	-
~~9~~	~~Begin/End Average~~			-	-	-	-	-	-	-

~~Notes:~~
~~[A] Reference for December balances as would be reported in FERC Form 1.~~
~~[B] Values entered under FERC Account No. 242, classified as Unfunded Reserve - Labor Related, are limited to Vacation Accruals and Employee Incentive Compensation.~~
~~[C] Prepayments shall exclude prepayments of income taxes.~~
~~[D] Includes transmission-related balance only~~

~~Income Tax Adjustments~~

	~~[1]~~	~~[2]~~	~~[3]~~	~~[4]~~	~~[5]~~
				~~Dec 31,~~	~~Dec 31,~~
			~~Beg/End Average [C]~~	~~2016~~	~~2017~~
~~1~~	~~Tax adjustment for Permanent Differences & AFUDC Equity~~	~~[A]~~			
~~2~~	~~Amortized Excess Deferred Taxes (enter negative)~~	~~[B]~~			
~~3~~	~~Amortized Deficient Deferred Taxes~~	~~[B]~~			

~~Notes:~~

~~[A]~~ ~~AFUDC equity component is the gross cumulative annual amount based upon tax records of capitalized AFUDC equity embedded in the gross plant attributable to the transmission function.~~

~~[B]~~ ~~Upon enactment of changes in tax law, income tax rates (including changes in apportionment) and other actions taken by a taxing authority, deferred taxes are re-measured and adjusted in the Company's books of account, resulting in excess or deficient accumulated deferred taxes. Such excess or deficient deferred taxes attributed to the transmission function will be based upon tax records and calculated in the calendar year in which the excess or deficient amount was measured and recorded for financial reporting purposes. Amounts to be included will be January 1, 2017 and thereafter.~~

~~[C]~~ ~~Beg/End Average for line 1 taken to Attachment H-4A, page 3, line 33; Beg/End Average for lines 2-3 taken to Attachment H-4A, page 3, line 34~~

~~Regulatory Asset - Storms~~

	~~[1]~~		~~[2]~~	~~[3]~~	~~[4]~~	~~[5]~~	~~[6]~~	~~[7]~~
~~1~~	**~~Monthly Balance~~**		~~Source~~	~~Months Remaining In Amortization Period~~	~~Beginning Balance~~	~~Amortization Expense (Company Records)~~	~~Additions (Deductions)~~	~~Ending Balance~~
~~2~~	~~December~~	~~2016~~	~~p232 (and Notes)~~					
~~3~~	~~January~~	~~2017~~	~~company records~~					
~~4~~	~~February~~		~~company records~~					
~~5~~	~~March~~		~~company records~~					
~~6~~	~~April~~		~~company records~~					
~~7~~	~~May~~		~~company records~~					
~~8~~	~~June~~		~~company records~~					
~~9~~	~~July~~		~~company records~~					
~~10~~	~~August~~		~~company records~~					
~~11~~	~~September~~		~~company records~~					
~~12~~	~~October~~		~~company records~~					
~~13~~	~~November~~		~~company records~~					
~~14~~	~~December~~	~~2017~~	~~p232 (and Notes)~~					
~~15~~	**~~Ending Balance 13-Month Average~~**		~~(sum lines 2-14) /13~~					
						~~Attachment H-4A, page 3, line 12~~		~~Attachment H-4A, page 2, Line 27~~

~~Regulatory Asset - Vegetation Management~~

	~~[1]~~		~~[2]~~	~~[3]~~	~~[4]~~	~~[5]~~	~~[6]~~	~~[7]~~
~~1~~	**~~Monthly Balance~~**		~~Source~~	~~Months Remaining In Amortization Period~~	~~Beginning Balance~~	~~Amortization Expense (Company Records)~~	~~Additions (Deductions)~~	~~Ending Balance~~
~~2~~	~~December~~	~~2016~~	~~p232 (and Notes)~~					
~~3~~	~~January~~	~~2017~~	~~company records~~					
~~4~~	~~February~~		~~company records~~					
~~5~~	~~March~~		~~company records~~					
~~6~~	~~April~~		~~company records~~					
~~7~~	~~May~~		~~company records~~					
~~8~~	~~June~~		~~company records~~					
~~9~~	~~July~~		~~company records~~					
~~10~~	~~August~~		~~company records~~					
~~11~~	~~September~~		~~company records~~					
~~12~~	~~October~~		~~company records~~					
~~13~~	~~November~~		~~company records~~					
~~14~~	~~December~~	~~2017~~	~~p232 (and Notes)~~					
~~15~~	**~~Ending Balance 13-Month Average~~**		~~(sum lines 2-14) /13~~					
						~~Attachment H-4A, page 3, line 12~~		~~Attachment H-4A, page 2, Line 27~~

~~For the 12 months ended 12/31/2017~~

~~Regulatory Asset – Formula Rate Development Costs~~

	~~[1]~~		~~[2]~~	~~[3]~~	~~[4]~~	~~[5]~~	~~[6]~~	~~[7]~~
~~1~~	~~**Monthly Balance**~~		~~Source~~	~~Months Remaining In Amortization Period~~	~~Beginning Balance~~	~~Amortization Expense (Company Records)~~	~~Additions (Deductions)~~	~~Ending Balance~~
~~2~~	~~December~~	~~2016~~	~~p232 (and Notes)~~					
~~3~~	~~January~~	~~2017~~	~~company records~~					
~~4~~	~~February~~		~~company records~~					
~~5~~	~~March~~		~~company records~~					
~~6~~	~~April~~		~~company records~~					
~~7~~	~~May~~		~~company records~~					
~~8~~	~~June~~		~~company records~~					
~~9~~	~~July~~		~~company records~~					
~~10~~	~~August~~		~~company records~~					
~~11~~	~~September~~		~~company records~~					
~~12~~	~~October~~		~~company records~~					
~~13~~	~~November~~		~~company records~~					
~~14~~	~~December~~	~~2017~~	~~p232 (and Notes)~~					
~~15~~	~~**Ending Balance 13-Month Average**~~		~~(sum lines 2-14) /13~~					
						~~Attachment H-4A, page 3, line 12~~		~~Attachment H-4A, page 2, Line 27~~

~~Abandoned Plant~~

	~~[1]~~		~~[2]~~	~~[3]~~	~~[4]~~	~~[5]~~	~~[6]~~	~~[7]~~
~~1~~	**~~Monthly Balance~~**		~~Source~~	~~Months Remaining In Amortization Period~~	~~Beginning Balance~~	~~Amortization Expense (p114.10.c)~~	~~Additions (Deductions)~~	~~Ending Balance~~
~~2~~	~~December~~	~~2016~~	~~p111.71.d (and Notes)~~					
~~3~~	~~January~~	~~2017~~	~~company records~~					
~~4~~	~~February~~		~~company records~~					
~~5~~	~~March~~		~~company records~~					
~~6~~	~~April~~		~~company records~~					
~~7~~	~~May~~		~~company records~~					
~~8~~	~~June~~		~~company records~~					
~~9~~	~~July~~		~~company records~~					
~~10~~	~~August~~		~~company records~~					
~~11~~	~~September~~		~~company records~~					
~~12~~	~~October~~		~~company records~~					
~~13~~	~~November~~		~~company records~~					
~~14~~	~~December~~	~~2017~~	~~p111.71.c (and Notes) Detail on p230b~~					
~~15~~	**~~Ending Balance 13-Month Average~~**		~~(sum lines 2-14) /13~~					
						~~Attachment H-4A, page 3, Line 19~~		~~Attachment H-4A, page 2, Line 28~~

~~Note:~~
~~Recovery of abandoned plant is limited to any abandoned plant recovery authorized by FERC and will be zero until the Commission accepts or approves recovery of the cost of abandoned plant~~

		~~CWIP~~	
		~~[A]~~	
		~~216.b~~	
~~1~~	~~December~~	~~2016~~	
~~2~~	~~January~~	~~2017~~	
~~3~~	~~February~~	~~2017~~	
~~4~~	~~March~~	~~2017~~	
~~5~~	~~April~~	~~2017~~	
~~6~~	~~May~~	~~2017~~	
~~7~~	~~June~~	~~2017~~	
~~8~~	~~July~~	~~2017~~	
~~9~~	~~August~~	~~2017~~	
~~10~~	~~September~~	~~2017~~	
~~11~~	~~October~~	~~2017~~	
~~12~~	~~November~~	~~2017~~	
~~13~~	~~December~~	~~2017~~	
~~14~~	~~13-month Average~~		-

~~Notes:~~
~~[A] Includes only CWIP authorized by the Commission for inclusion in rate base.~~

~~Federal Income Tax Rate~~

~~Nominal Federal Income Tax Rate (entered on Attachment H-4A, page 5 of 5, Note K)~~

~~State Income Tax Rate~~

	~~New Jersey~~	~~Combined Rate (entered on Attachment H-4A, page 5 of 5, Note K)~~
~~Nominal State Income Tax Rate~~		
~~Times Apportionment Percentage~~		
~~Combined State Income Tax Rate~~		

ATTACHMENT H-4B

[Reserved]

~~Jersey Central Power & Light Company~~

~~Formula Rate Implementation Protocols~~

~~ANNUAL TRUE-UP, INFORMATION EXCHANGE, AND CHALLENGE PROCEDURES~~

~~Definitions~~

~~"Actual Transmission Revenue Requirement" or "ATRR" means the actual net transmission revenue requirement calculated and posted on the PJM website no later than June 1 of each year subsequent to calendar year 2017 for the immediately preceding calendar year in accordance with JCP&L's Formula Rate and based upon JCP&L's actual costs and expenditures.~~

~~"Annual Update" means JCP&L's ATRR for the preceding calendar year, as well as the True-up for the prior Rate Year, as posted on or before June 1 of each year.~~

~~"Formal Challenge" means a written challenge to an Annual Update or Projected Transmission Revenue Requirement submitted to the Federal Energy Regulatory Commission (the "Commission" or "FERC") as provided in Section IV below.~~

~~"Formula Rate" means these protocols (to be included as Attachment H-4B of the PJM Interconnection, L.L.C. ("PJM"), FERC Electric Tariff ("PJM Tariff")) and the Formula Rate Template.~~

~~"Formula Rate Template" means the collection of formulas and worksheets, unpopulated with any data, to be included as Attachment H-4A of the PJM Tariff.~~

~~"Interested Parties" include, but are not limited to, customers under the PJM Tariff, state utility regulatory commissions, the Organization of PJM States, Inc., consumer advocacy agencies, and state attorneys general.~~

~~"Preliminary Challenge" means a written challenge to the Annual Update or Projected Transmission Revenue Requirement submitted to JCP&L as provided in Section IV below.~~

~~"Projected Transmission Revenue Requirement" or "PTRR" means the projected net transmission revenue requirement calculated for the forthcoming Rate Year, as well as, where applicable, the most recently calculated True-up, with interest, to be posted on the PJM website no later than October 31 of each year for rates effective the next calendar year starting January 1.~~

~~"Publication Date" means the date on which the Annual Update is posted.~~

~~"Rate Year" means the twelve consecutive month period that begins on January 1 and continues through~~

~~December 31.~~

~~"True-up" means the difference between the revenues collected by PJM based on the PTRR (net of the True-up from the prior year) and the ATRR for the same Rate Year, which shall be provided in the Annual Update on or before June 1 of the year subsequent to the Rate Year. The True-up will be a component of the PTRR.~~

~~Section I. Applicability~~

~~The following procedures shall apply to the Jersey Central Power & Light Company ("JCP&L") calculation of its Actual Transmission Revenue Requirement, True-up, and Projected Transmission Revenue Requirement.~~

~~Section II. Annual Update and Projected Transmission Revenue Requirement~~

~~A. On or before June 1 of each year subsequent to calendar year 2017, JCP&L shall determine its Annual Update for the immediately preceding calendar year under Attachment H-4A and Section VII of these protocols, including calculation of the True-up to be included in JCP&L's PTRR for the subsequent Rate Year.~~

~~B. On or before June 1 of each year subsequent to calendar year 2017, JCP&L shall provide its Annual Update for the immediately preceding calendar year to PJM and cause such information to be posted on the PJM website. Within two (2) days of such posting, PJM shall provide notice of such posting via an e-mail exploder list.~~

~~C. On or before October 31, 2017, and on or before each subsequent October 31, JCP&L shall provide the PTRR to PJM and cause such information to be posted on the PJM website, in both a Portable Document Format ("PDF") and fully-functioning Excel file, and within two (2) days of posting of the PTRR, PJM shall provide notice of such posting via an e-mail exploder list.~~

~~D. If the date for posting the Annual Update or PTRR falls on a weekend or a holiday recognized by FERC, then the posting shall be due on the next business day. The date on which posting of the Annual Update occurs shall be that year's Publication Date. Any delay in the Publication Date or in the posting of the PTRR will result in an equivalent extension of time for the submission of information requests discussed in Section III of these protocols.~~

~~E. The ATRR shall:~~

~~1. Include a workable data-populated Formula Rate Template and underlying work papers in native format with all formulas and links intact;~~

~~2. Be based on JCP&L's FERC Form No. 1 for the prior calendar year;~~

~~3. Provide the Formula Rate calculations and all inputs thereto, as well as supporting documentation and work papers for data that are used in the ATRR that are not otherwise~~

~~available in the FERC Form No. 1, subject to the protection of any confidential information, as needed, under non-disclosure agreements that are based on FERC's Model Protective Order;~~

~~4. Provide sufficient information to enable Interested Parties to replicate the calculation of the ATRR results from the FERC Form No. 1;~~

~~5. Identify any changes in the formula references (page and line numbers) to the FERC Form No. 1;~~

~~6. Identify and, to the extent not explained in a worksheet included in the ATRR, explain, all material adjustments made to the FERC Form No. 1 data in determining formula inputs, including relevant footnotes to the FERC Form No. 1 and any adjustments not shown in the FERC Form No. 1;~~

~~7. Provide underlying data for Formula Rate inputs that provide greater granularity than is required for the FERC Form No. 1;~~

~~8. With respect to any change in accounting that affects inputs to the Formula Rate or the resulting charges billed under the Formula Rate ("Accounting Change"):~~

~~a. Identify any Accounting Change, including:~~

~~i. the initial implementation of an accounting standard or policy;~~

~~ii. the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;~~

~~iii. correction of errors and prior period adjustments that affect the ATRR and True-up calculation;~~

~~iv. the implementation of new estimation methods or policies that change prior estimates; and~~

~~v. changes to income tax elections;~~

~~b. Identify items included in the ATRR at an amount other than on a historic cost basis (e.g., fair value adjustments);~~

~~c. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the ATRR;~~

~~d. Provide, for each item identified pursuant to items II.E.8.a - II.E.8.c above, a narrative explanation of the individual impact of such change on the ATRR.~~

~~9. Include for the applicable Rate Year the following information related to affiliate cost allocation: (A) a detailed description of the methodologies used to allocate and directly~~

~~assign costs between JCP&L and its affiliates by service category and function, including any changes to such cost allocation methodologies from the prior year, and the reasons and justification for those changes; and (B) the magnitude of such costs that have been allocated or directly assigned between JCP&L and each affiliate by service category or function.~~

~~F. The Projected Transmission Revenue Requirement shall:~~

~~1. Include a workable data-populated Formula Rate Template and underlying work papers in native format with all formulas and links intact;~~

~~2. Provide the Formula Rate calculations and all inputs thereto, as well as supporting documentation and work papers for data that are used in the PTRR;~~

~~3. Provide sufficient information to enable Interested Parties to replicate the calculation of the PTRR;~~

~~4. With respect to any Accounting Change:~~

~~a. Identify any Accounting Change, including:~~

~~i. the initial implementation of an accounting standard or policy;~~

~~ii. the initial implementation of accounting practices for unusual or unconventional items where FERC has not provided specific accounting direction;~~

~~iii. correction of errors and prior period adjustments that affect the PTRR calculation;~~

~~iv. the implementation of new estimation methods or policies that change prior estimates; and~~

~~v. changes to income tax elections.~~

~~b. Identify items included in the PTRR at an amount other than on a historic cost basis (e.g., fair value adjustments);~~

~~c. Identify any reorganization or merger transaction during the previous year and explain the effect of the accounting for such transaction(s) on inputs to the PTRR; and~~

~~d. Provide, for each item identified pursuant to items II.F.4.a – II.F.4.c of these protocols, a narrative explanation of the individual impact of such change on the PTRR.~~

~~G. JCP&L shall hold an open meeting among Interested Parties ("Annual Update Meeting"), to be conducted via Internet webcast, no earlier than ten (10) business days following the Publication Date and no later than June 25. No fewer than seven (7) days prior to such Annual Update~~

~~Meeting, JCP&L shall provide notice on PJM's website of the time and date of the Annual Update Meeting, and PJM shall provide notice of the posting via an e-mail exploder list. The Annual Update Meeting shall: (i) permit JCP&L to explain and clarify its ATRR and True-up; and (ii) provide Interested Parties an opportunity to seek information and clarifications from JCP&L about the ATRR and True-up.~~

~~H. JCP&L shall hold an open meeting among Interested Parties ("Annual Projected Rate Meeting"), to be conducted via Internet webcast, no earlier than five (5) business days following the posting of the PTRR (as described in Section II.C of these protocols) and no later than November 30. No fewer than five (5) days prior to such Annual Projected Rate Meeting, JCP&L shall provide notice on PJM's website of the time and date of the Annual Projected Rate Meeting, and PJM shall provide notice of the posting via an e-mail exploder list. The Annual Projected Rate Meeting shall: (i) permit JCP&L to explain and clarify its PTRR and (ii) provide Interested Parties an opportunity to seek information and clarifications from JCP&L about the PTRR.~~

~~I. Each year JCP&L shall endeavor to (a) coordinate with other Transmission Owners in PJM using formula rates to establish revenue requirements for recovery of the costs of transmission projects that utilize the same regional cost sharing mechanism and (b) hold a joint informational meeting to enable all Interested Parties to understand how those transmission owners are implementing their formula rates for recovering the costs of such projects..~~

~~Section III. Information Exchange Procedures~~

~~Each Annual Update and PTRR shall be subject to the following information exchange procedures ("Information Exchange Procedures"):~~

~~A. Interested Parties shall have until January 15 following the Publication Date (unless such period is extended with the written consent of JCP&L or by FERC order) to serve reasonable information and document requests on JCP&L ("Information Exchange Period"). If January 15 falls on a weekend or a holiday recognized by FERC, the deadline for submitting all information and document requests shall be extended to the next business day. Such information and document requests shall be limited to what is necessary to determine:~~

~~1. the extent or effect of an Accounting Change;~~

~~2. whether the ATRR or PTRR fails to include data properly recorded in accordance with these protocols;~~

~~3. the proper application of the Formula Rate and procedures in these protocols;~~

~~4. the accuracy of data and consistency with the Formula Rate of the calculations shown in the ATRR or PTRR;~~

~~5. the prudence of actual costs and expenditures;~~

~~6. the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or~~

7. ~~any other information that may reasonably have a substantive effect on the calculation of the charge pursuant to the Formula Rate.~~

~~The information and document requests shall not otherwise be directed to ascertaining whether the Formula Rate is just and reasonable.~~

~~B. JCP&L shall make a good faith effort to respond to information and document requests within fifteen (15) business days of receipt of such requests. JCP&L shall respond to all information and document requests by no later than February 25 following the Publication Date, unless the Information Exchange Period is extended by JCP&L or FERC.~~

~~C. JCP&L will serve all information requests from Interested Parties and JCP&L's response(s) to such requests upon any Interested Party that requests such service, subject to the protection of any confidential information contained in such information requests or responses, as needed, under non-disclosure agreements that are based on FERC's Model Protective Order.~~

~~D. JCP&L shall not claim that responses to information and document requests provided pursuant to these protocols are subject to any settlement privilege in any proceeding addressing JCP&L's Annual Update or PTRR, and such responses may be included in any Formal Challenge or other submittal addressing JCP&L's Annual Update or PTRR.~~

~~Section IV. Challenge Procedures~~

~~A. Interested Parties shall have until March 31 following the Publication Date (unless such period is extended with the written consent of JCP&L or by FERC order) ("Review Period"), to review the inputs, supporting explanations, allocations and calculations and to notify JCP&L in writing, which may be made electronically, of any specific Preliminary Challenges to the Annual Update or PTRR. If the final day of the Review Period falls on a holiday recognized by FERC, the deadline for submitting all Preliminary Challenges shall be extended to the next business day. Failure to pursue an issue through a Preliminary Challenge or to lodge a Formal Challenge regarding any issue as to a given Annual Update or PTRR shall bar pursuit of such issue with respect to that Annual Update or PTRR under the challenge procedures set forth in these protocols, but shall not bar pursuit of such issue or the lodging of a Formal Challenge as to such issue as it relates to a subsequent Annual Update or PTRR.~~

~~B. Preliminary Challenges shall be subject to the resolution procedures and limitations in this Section IV and shall satisfy all of the following requirements.~~

~~1. A party submitting a Preliminary Challenge to JCP&L must specify the inputs, supporting explanations, allocations, calculations, or other information to which it objects, and provide an appropriate explanation and documents to support its challenge.~~

~~2. JCP&L shall make a good faith effort to respond to any Preliminary Challenge within twenty (20) business days of notification of such challenge.~~

~~3. JCP&L, and where applicable, PJM, shall appoint a senior representative to work with the party that submitted the Preliminary Challenge (or its representative) toward a~~

~~resolution of the challenge.~~

~~4. If JCP&L disagrees with such challenge, JCP&L will provide the Interested Party(ies) with an explanation supporting the inputs, supporting explanations, allocations, calculations, or other information.~~

~~5. No Preliminary Challenge may be submitted after March 31, and JCP&L must respond to all Preliminary Challenges by no later than April 30 unless the Review Period is extended by JCP&L or FERC, or as provided in Section IV.A above.~~

~~6. JCP&L will serve all Preliminary Challenges from Interested Parties and JCP&L's response(s) to such Preliminary Challenges upon any Interested Party that requests such service, subject to the protection of any confidential information contained in such Preliminary Challenges or responses, as needed, under non-disclosure agreements that are based on the FERC's Model Protective Order.~~

~~C. Formal Challenges shall be subject to the resolution procedures and limitations in this Section IV. Formal Challenges shall be filed pursuant to these protocols and shall satisfy all of the following requirements.~~

~~1. A Formal Challenge shall:~~

~~a. Clearly identify the action or inaction which is alleged to violate the filed rate formula or protocols;~~

~~b. Explain how the action or inaction violates the filed rate formula or protocols;~~

~~c. Set forth the business, commercial, economic or other issues presented by the action or inaction as such relate to or affect the party filing the Formal Challenge, including:~~

~~(i) the extent or effect of an Accounting Change;~~

~~(ii) whether the ATRR or PTRR fails to include data properly recorded in accordance with these protocols;~~

~~(iii) the proper application of the Formula Rate and procedures in these protocols;~~

~~(iv) the accuracy of data and consistency with the Formula Rate of the charges shown in the ATRR or PTRR;~~

~~(v) the prudence of actual costs and expenditures;~~

~~(vi) the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or~~

~~(vii) any other information that may reasonably have a substantive effect on the calculation of the charge pursuant to the Formula Rate.~~

~~d. Make a good faith effort to quantify the financial impact or burden (if any) created for the party filing the Formal Challenge as a result of the challenged~~

~~action or inaction;~~

~~e. State whether the issues presented are pending in an existing Commission proceeding or a proceeding in any other forum in which the filing party is a party, and if so, provide an explanation why timely resolution cannot be achieved in that forum;~~

~~f. State the specific relief or remedy requested, including any request for stay or extension of time, and the basis for that relief;~~

~~g. Include all documents that support the facts in the Formal Challenge in possession of, or otherwise attainable by, the filing party, including, but not limited to, contracts and affidavits; and~~

~~h. State whether the filing party utilized the Preliminary Challenge procedures described in these protocols to dispute the challenged action or inaction raised by the Formal Challenge, and, if not, describe why not.~~

~~2. Service. Any person filing a Formal Challenge must serve a copy of the Formal Challenge on JCP&L. Service to JCP&L must be simultaneous with filing at the Commission. Simultaneous service can be accomplished by electronic mail in accordance with 18 C.F.R. § 385.2010(f)(3), facsimile, express delivery, or messenger. The party filing the Formal Challenge shall serve the individual listed as the contact person on JCP&L's Informational Filing required under Section VI of these protocols.~~

~~D. Preliminary and Formal Challenges shall be limited to all issues that may be necessary to determine:~~

~~1. the extent or effect of an Accounting Change;~~

~~2. whether the ATRR or PTRR fails to include data properly recorded in accordance with these protocols, or includes data not properly recorded in accordance with these protocols;~~

~~3. the proper application of the Formula Rate and procedures in these protocols;~~

~~4. the accuracy of data and consistency with the formula rate of the calculations shown in the ATRR and PTRR;~~

~~5. the prudence of actual costs and expenditures;~~

~~6. the effect of any change to the underlying Uniform System of Accounts or FERC Form No. 1; or~~

~~7. any other information that may reasonably have a substantive effect on the calculation of the charge pursuant to the Formula Rate.~~

~~E. Any changes or adjustments to the ATRR and PTRR resulting from the information exchange and Preliminary Challenge processes that are agreed to by JCP&L will be reported in the Informational Filing required pursuant to Section VI of these protocols. Any such changes or adjustments agreed to by JCP&L on or before December 1 will be reflected in the PTRR for the~~

~~upcoming Rate Year. Any changes or adjustments agreed to by JCP&L after December 1 will be reflected in the following year's Annual Update, as discussed in Section V of these protocols.~~

~~F. An Interested Party shall have until June 1 following the Review Period (unless such date is extended with the written consent of JCP&L to continue efforts to resolve the Preliminary Challenge) to make a Formal Challenge with FERC, which shall be served on JCP&L on the date of such filing as specified in Section IV.C.2 above. A Formal Challenge shall be filed in the same docket as JCP&L's Informational Filing discussed in Section VI of these protocols. JCP&L shall respond to the Formal Challenge by the deadline established by FERC. An Interested Party may not pursue a Formal Challenge unless it submitted a Preliminary Challenge on some issue (which may be different from the Formal Challenge issue) during the applicable Review Period.~~

~~G. In any proceeding initiated by FERC concerning the Annual Update or PTRR or in response to a Formal Challenge, JCP&L shall bear the burden, consistent with section 205 of the Federal Power Act, of proving that it has correctly applied the terms of the Formula Rate consistent with these protocols, that it followed the applicable requirements and procedures in the Formula Rate. Nothing herein is intended to alter the burdens applied by FERC with respect to prudence challenges.~~

~~H. Except as specifically provided herein, nothing herein shall be deemed to limit in any way the right of JCP&L to file unilaterally, pursuant to Federal Power Act section 205 and the regulations thereunder, to change the Formula Rate or any of its inputs (including, but not limited to, rate of return and transmission incentive rate treatment), or to replace the Formula Rate with a stated rate, or the right of any other party to request such changes pursuant to section 206 of the Federal Power Act and the regulations thereunder.~~

~~I. No party shall seek to modify the Formula Rate under the challenge procedures set forth in these protocols and the Annual Update and PTRR shall not be subject to challenge by anyone for the purpose of modifying the Formula Rate. Any modifications to the Formula Rate will require, as applicable, a Federal Power Act section 205 or section 206 filing. JCP&L may, at its discretion and at a time of its choosing, make a limited filing pursuant to Section 205 to modify stated values in the Formula Rate for (a) amortization and depreciation rates, (b) Post-Employment Benefits Other Than Pensions rates, or (c) the weighting of the ADIT balance in rate base to ensure JCP&L's compliance with the IRS regulations for normalization under IRS Section 1.167(l)-1(h)(6). The sole issue in any such limited Section 205 proceeding shall be whether such proposed change(s) is just and reasonable, and it shall not address other aspects of the Formula Rate.~~

~~J. Any Interested Party seeking changes to the application of the Formula Rate due to a change in the Uniform System of Accounts or FERC Form No. 1 shall first raise the matter with JCP&L in accordance with this Section IV before pursuing a Formal Challenge.~~

~~**Section V. Changes to Actual Transmission Revenue Requirement or Projected Transmission Revenue Requirement**~~

~~A. Except as provided in Section IV.E of these protocols, any changes to the data inputs, including but not limited to revisions to JCP&L's FERC Form No. 1, or as the result of any FERC proceeding to consider the ATRR or PTRR, or as a result of the procedures set forth herein, shall be incorporated into the Formula Rate and the charges produced by the Formula Rate in the PTRR for the next Rate Year. This reconciliation mechanism shall apply in lieu of mid-Rate Year adjustments. Interest on any refund or surcharge shall be calculated in accordance with the procedures outlined in Section VII of these protocols.~~

~~Section VI. Informational Filings~~

~~A. By June 1 of each year, JCP&L shall submit to FERC an informational filing ("Informational Filing") of its PTRR for the Rate Year, including its ATRR and True-up. This Informational Filing must include information that is reasonably necessary to determine:~~

~~1. that input data under the Formula Rate are properly recorded in any underlying work-papers;~~

~~2. that JCP&L has properly applied the Formula Rate and these procedures;~~

~~3. the accuracy of data and the consistency with the Formula Rate of the transmission revenue requirement and rates under review;~~

~~4. the extent of Accounting Changes that affect Formula Rate inputs; and~~

~~5. the reasonableness of projected costs.~~

~~The Informational Filing must also describe any corrections or adjustments made during the period since the Publication Date, and must describe all aspects of the Formula Rate or its inputs that are the subject of an ongoing dispute under the Preliminary or Formal Challenge procedures.~~

~~Finally, the Informational Filing shall include for the applicable Rate Year the following information related to affiliate cost allocation: a detailed description of the methodologies used to allocate and directly assign costs between JCP&L and its affiliates by service category or function, including any changes to such cost allocation methodologies from the prior year, and the reasons and justification for those changes; the magnitude of such costs that have been allocated or directly assigned between JCP&L and each affiliate by service category or function; and a copy of any service agreement between JCP&L and any JCP&L affiliate that went into effect during the Rate Year.~~

~~Within five (5) days of such Informational Filing, PJM shall provide notice of the Informational Filing via an e-mail exploder list and by posting the docket number assigned to JCP&L's Informational Filing on the PJM website, subject to the protection of any confidential information contained in the Informational Filing, as needed, under nondisclosure agreements that are based on FERC's Model Protective Order.~~

~~B. Any challenges to the implementation of the formula rate must be made through the challenge procedures described in Section IV of these protocols or in a separate complaint proceeding, and~~

~~not in response to the Informational Filing.~~

~~Section VII. Calculation of True-up~~

~~The True-up will be determined in the following manner:~~

~~A. As part of the Annual Update for each Rate Year, JCP&L shall determine the difference between the revenues collected by PJM based on the PTRR for the Rate Year (net of the True-up from the prior year) and the ATRR for the same Rate Year based on actual cost data as reflected in its FERC Form No. 1. The True-up will be determined as follows:~~

~~i. The ATRR for the previous Rate Year as determined using JCP&L's completed FERC Form No. 1 report shall be compared to the revenues collected by PJM based on the PTRR (net of the True-up from the prior year) for that same Rate Year ("True-up Year") to determine any excess or shortfall in the revenues collected by PJM in the True-up Year. The revenue excess or shortfall determined by this comparison shall constitute the "True-up."~~

~~ii. Interest on any True-up shall be based on the Commission's interest rate on refunds as determined in accordance with 18 C.F.R. § 35.19a. Interest rates will be used to calculate the time value of money for the period that the True-up exists. The interest rate to be applied to the True-up will be determined using the average rate for the twenty (20) months preceding September of the current year.~~

~~B. JCP&L will post on PJM's website all information relating to the True-up as part of the Annual Update.~~

~~Section VIII. Formula Rate Inputs~~

~~A. Stated inputs to the Formula Rate Template: For (i) rate of return on common equity; (ii) "Post-Employment Benefits other than Pension" pursuant to Statement of Financial Accounting Standards No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions ("PBOP") charges; and (iii) depreciation and/or amortization rates, the values shall be stated values to be used in the Formula Rate until changed pursuant to a Federal Power Act section 205 or section 206 filing. These stated-value inputs are specified in Attachment 9, respectively, of the Formula Rate Template.~~

~~B. Unpopulated Formula Rate line items: With respect to line items in the Formula Rate that are not currently populated with non-zero numerical values because FERC policy requires prior authorization for recovery of the underlying costs or because, due to the nature of the associated functional activities, such costs are not considered part of JCP&L's transmission-related revenue requirement (but not line items that are zero values in a particular Rate Year for the sole reason that no such costs or revenues were incurred or revenues received or projected to be incurred or received during the Rate Year), such line items shall not be populated with non-zero values except as may be authorized following a Federal Power Act section 205 filing or required under~~

~~Federal Power Act section 206.~~

SCHEDULE 12 – APPENDIX

(4) Jersey Central Power & Light Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0123	Add 180 MVAR of distributed capacitors. 65 MVAR in northern JCPL and 115 MVAR in southern JCPL		JCPL (100%)
b0124.1	Add a 72 MVAR capacitor at Kittatinny 230 kV		JCPL (100%)
b0124.2	Add a 130 MVAR capacitor at Manitou 230 kV		JCPL (100%)
b0132	Reconductor Portland – Kittatinny 230 kV with 1590 ACSS		JCPL (100%)
b0132.1	Replace terminal equipment on the Portland – Kittatinny 230 kV and CB at the Kittatinny bus		JCPL (100%)
b0132.2	Replace terminal equipment on the Portland – Kittatinny 230 kV and CB at the Portland bus		JCPL (100%)
b0173	Replace a line trap at Newton 230kV substation for the Kittatinny-Newton 230kV circuit		JCPL (100%)
b0174	Upgrade the Portland – Greystone 230kV circuit	The following rates are consistent with the settlement agreement filed in and approved by the Commission in Docket No. ER17-217, 2017: $1,442,372 2018: $1,273,748 2019: $1,235,637	JCPL (35.40%) / Neptune* (5.67%) / PSEG (54.37%) RE (2.94%) / ECP** (1.62%)
b0199	Greystone 230kV substation: Change Tap of limiting CT and replace breaker on the Greystone Whippany (Q1031) 230kV line		JCPL (100%)
b0200	Greystone 230kV substation: Change Tap of limiting CT on the West Wharton Greystone (E1045) 230kV line		JCPL (100%)

* Neptune Regional Transmission System, LLC

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

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0202	Kittatinny 230kV substation: Replace line trap on Kittatinny Pohatcong (L2012) 230kV line; Pohatcong 230kV substation: Change Tap of limiting CT on Kittatinny Pohatcong (L2012) 230kV line		JCPL (100%)
b0203	Smithburg 230kV Substation: Replace line trap on the East Windsor Smithburg (E2005) 230kV line; East Windsor 230kV substation: Replace line trap on the East Windsor Smithburg (E2005) 230kV line		JCPL (100%)
b0204	Install 72Mvar capacitor at Cookstown 230kV substation		JCPL (100%)
b0267	Reconductor JCPL 2 mile portion of Kittatinny – Newton 230 kV line		JCPL (100%)
b0268	Reconductor the 8 mile Gilbert – Glen Gardner 230 kV circuit	The following rates are consistent with the settlement agreement filed in and approved by the Commission in Docket No. ER17-217, 2017: $734,194 2018: $646,180 2019: $628,066	JCPL (61.77%) / Neptune* (3%) / PSEG (32.73%) / RE (1.45%) / ECP** (1.05%)

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

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0279.1	Install 100 MVAR capacitor at Glen Gardner substation		JCPL (100%)
b0279.2	Install MVAR capacitor at Kittatinny 230 kV substation		JCPL (100%)
b0279.3	Install 17.6 MVAR capacitor at Freneau 34.5 kV substation		JCPL (100%)
b0279.4	Install 6.6 MVAR capacitor at Waretown #1 bank 34.5 kV substation		JCPL (100%)
b0279.5	Install 10.8 MVAR capacitor at Spottswood #2 bank .4.5 kV substation		JCPL (100%)
b0279.6	Install 6.6 MVAR capacitor at Pequannock N bus 34.5 kV substation		JCPL (100%)
b0279.7	Install 6.6 MVAR capacitor at Haskell P bus 34.5 kV substation		JCPL (100%)
b0279.8	Install 6.6 MVAR capacitor at Pinewald #2 Bank 34.5 kV substation		JCPL (100%)
b0279.9	Install 6.6 MVAR capacitor at Matrix 34.5 kV substation		JCPL (100%)
b0279.10	Install 6.6 MVAR capacitor at Hamburg Boro Q Bus 34.5 kV substation		JCPL (100%)
b0279.11	Install 6.6 MVAR capacitor at Newburg Q Bus 34.5 kV substation		JCPL (100%)
b0286	Install 130 MVAR capacitor at Whippany 230 kV		JCPL (100%)
b0289	Install 600 MVAR Dynamic Reactive Device in the Whippany 230 kV vicinity		AEC (0.65%) / JCPL (30.37%) / Neptune* (4.96%) / PSEG (59.65%) / RE (2.66%) / ECP** (1.71%)
b0289.1	Install additional 130 MVAR capacitor at West Wharton 230 kV substation		JCPL (100%)

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

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0292	Replace a 1600A line trap at Atlantic Larrabee 230 kV substation		JCPL (100%)
b0350	Implement Operating Procedure of closing the Glendon – Gilbert 115 kV circuit		JCPL (100%)
b0356	Replace wave trap on the Portland – Greystone 230 kV		JCPL (100%)
b0361	Change tap of limiting CT at Morristown 230 kV		JCPL (100%)
b0362	Change tap setting of limiting CT at Pohatcong 230 kV		JCPL (100%)
b0363	Change tap setting of limiting CT at Windsor 230 kV		JCPL (100%)
b0364	Change tap setting of CT at Cookstown 230 kV		JCPL (100%)
b0423.1	Upgrade terminal equipment at Readington (substation conductor)		JCPL (100%)
b0520	Replace Gilbert circuit breaker 12A		JCPL (100%)
b0657	Construct Boston Road 34.5 kV stations, construct Hyson 34.5 stations, add a 7.2 MVAR capacitor at Boston Road 34.5 kV		JCPL (100%)
b0726	Add a 2nd Raritan River 230/115 kV transformer	The following rates are consistent with the settlement agreement filed in and approved by the Commission in Docket No. ER17-217, 2017: $950,666 2018: $846,872 2019: $827,854	AEC (2.45%) / JCPL (97.55%)
b1020	Replace wave trap at Englishtown on the Englishtown - Manalapan circuit		JCPL (100%)

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1075	Replace the West Wharton - Franklin - Vermont D931 and J932 115 kV line conductors with 1590 45/7 ACSR wire between the tower structures 78 and 78-B		JCPL (100%)
b1154.1	Upgrade the Whippany 230 kV breaker 'JB'		JCPL (100%)
b1155.1	Upgrade the Red Oak 230 kV breaker 'G1047'		JCPL (100%)
b1155.2	Upgrade the Red Oak 230 kV breaker 'T1034'		JCPL (100%)
b1345	Install Martinsville 4-breaker 34.5 rink bus		JCPL (100%)
b1346	Reconductor the Franklin – Humburg (R746) 4.7 miles 34.5 kV line with 556 ACSR and build 2.7 miles 55 ACSR line extension to Sussex		JCPL (100%)
b1347	Replace 500 CU substation conductor with 795 ACSR on the Whitesville – Asbury Tap 34.5 kV (U47) line		JCPL (100%)
b1348	Upgrade the Newton – North Newton 34.5 kV (F708) line by adding a second underground 1250 CU egress cable		JCPL (100%)
b1349	Reconductor 5.2 miles of the Newton – Woodruffs Gap 34.5 kV (A703) line with 556 ACSR		JCPL (100%)
b1350	Upgrade the East Flemington – Flemington 34.5 kV (V724) line by adding second underground 1000 AL egress cable and replacing 4/0		JCPL (100%)

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1351	Add 34.5 kV breaker on the Larrabee A and D bus tie		JCPL (100%)
b1352	Upgrade the Smithburg – Centerstate Tap 34.5 kV (X752) line by adding second 200 ft underground 1250 CU egress cable		JCPL (100%)
b1353	Upgrade the Larrabee – Laurelton 34.5 kV (Q43) line by adding second 700 ft underground 1250 CU egress cable		JCPL (100%)

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1354	Add four 34.5 kV breakers and re-configure A/B bus at Rockaway		JCPL (100%)
b1355	Build a new section 3.3 miles 34.5 kV 556 ACSR line from Riverdale to Butler		JCPL (100%)
b1357	Build 10.2 miles new 34.5 kV line from Larrabee – Howell		JCPL (100%)
b1359	Install a Troy Hills 34.5 kV by-pass switch and reconfigure the Montville – Whippany 34.5 kV (D4) line		JCPL (100%)
b1360	Reconductor 0.7 miles of the Englishtown – Freehold Tap 34.5 kV (L12) line with 556 ACSR		JCPL (100%)
b1361	Reconductor the Oceanview – Neptune Tap 34.5 kV (D130) line with 795 ACSR		JCPL (100%)
b1362	Install a 23.8 MVAR capacitor at Wood Street 69 kV		JCPL (100%)
b1364	Upgrade South Lebanon 230/69 kV transformer #1 by replacing 69 kV substation conductor with 1590 ACSR		JCPL (100%)
b1399.1	Upgrade the Whippany 230 kV breaker 'QJ'		JCPL (100%)
b1673	Rocktown - Install a 230/34.5 kV transformer by looping the Pleasant Valley - E Flemington 230 kV Q-2243 line (0.4 miles) through the Rocktown Substation		JCPL (100%)

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1674	Build a new Englishtown - Wyckoff St 15 mile, 115 kV line and install 115/34.5 kV transformer at Wyckoff St		JCPL (100%)
b1689	Atlantic Sub - 230 kV ring bus reconfiguration. Put a “source” between the Red Bank and Oceanview “loads”		JCPL (100%)
b1690	Build a new third 230 kV line into the Red Bank 230 kV substation		JCPL (100%)
b1853	Install new 135 MVA 230/34.5 kV transformer with one 230 kV CB at Eaton Crest and create a new 34.5 kV CB straight bus to feed new radial lines to Locust Groove and Interdata/Woodbine		JCPL (100%)
b1854	Readington I737 34.5 kV Line - Parallel existing 1250 CU UG cable (440 feet)		JCPL (100%)
b1855	Oceanview Substation - Relocate the H216 breaker from the A bus to the B bus		JCPL (100%)
b1856	Madison Tp to Madison (N14) line - Upgrade limiting 250 Cu substation conductor with 795 ACSR at Madison sub		JCPL (100%)
b1857	Montville substation - Replace both the 397 ACSR and the 500 Cu substation conductor with 795 ACSR on the 34.5 kV (M117) line		JCPL (100%)

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1858	Reconductor the Newton - Mohawk (Z702) 34.5 kV line with 1.9 miles of 397 ACSR		JCPL (100%)
b2003	Construct a Whippany to Montville 230 kV line (6.4 miles)		JCPL (100%)
b2015	Build a new 230 kV circuit from Larrabee to Oceanview	The following rates are consistent with the settlement agreement filed in and approved by the Commission in Docket No. ER17-217, 2017: $9,616,241 2018: $18,839,128 2019: $19,935,489	JCPL (35.83%) / NEPTUNE* (23.61%) / HTP (1.77%) / ECP** (1.49%) / PSEG (35.87%) / RE (1.43%)
b2147	At Deep Run, install 115 kV line breakers on the B2 and C3 115 kV lines		JCPL (100%)

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

EXHIBIT 3

Depreciation Rates

Jersey Central Power & Light Company
ER17-217

Depreciation Rates

FERC Account	Depr %
350.2	1.44%
352	1.33%
353	2.21%
354	1.29%
355	1.93%
356	2.60%
356.1	1.22%
357	1.53%
358	1.76%
359	1.21%
303	14.29%
390.1	1.61%
390.2	0.46%
391	10.91%
391.15	0.96%
391.2	6.39%
392	11.29%
393	3.13%
394	6.17%
395	16.27%
396	2.35%
397	5.13%
398	1.36%

Attachment 11 (ACE 2018 Formula Rate Petition)

Philip J. Passanante
Assistant General Counsel

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atlantic city electric
An Exelon Company

July 11, 2018

VIA FEDERAL EXPRESS and
ELECTRONIC MAIL
aida.camacho@bpu.nj.gov
board.secretary@bpu. nj.gov

Aida Camacho-Welch
Secretary of the Board
Board of Public Utilities
44 South Clinton Avenue, 3rd Floor, Suite 314
P.O. Box 350
Trenton, New Jersey 08625-0350

RE: I/M/O the Petition of Atlantic City Electric Company for Approval to Implement FERC-Approved Changes to ACE's Retail Transmission (Formula) Rate Pursuant to Paragraphs 15.9 of the BGS-RSCP and BGS-CIEP Supplier Master Agreements and Tariff Filing Reflecting Changes to Schedule 12 Charges in PJM Open Access Transmission Tariff (2018)
BPU Docket No. ______________________

Dear Secretary Camacho-Welch:

The undersigned is Assistant General Counsel to Atlantic City Electric Company ("ACE" or the "Company") in connection with the above referenced matter.

Enclosed herewith for filing are three conformed copies of a Verified Petition and supporting Exhibits seeking Board approval to implement changes to ACE's retail transmission rates charged to suppliers of Residential Small Commercial Pricing and Commercial and Industrial Basic Generation Service.[1] Tariff pages reflecting changes to Schedule 12 charges in the PJM Open Access Transmission Tariff have also been provided.

Kindly file this submission and advise ACE of the assigned docket number at your earliest convenience. Please note that the Company has requested action on this filing by the Board meeting currently scheduled for August 29, 2018.

[1] This filing has been made consistent with the Board's Order Waiving Provisions of N.J.A.C. 14:4-2, N.J.A.C. 14:17-4.2(a), N.J.A.C. 14:1-1.6(c), and N.J.A.C. 14:17-1.6(d), issued on July 29, 2016, in connection with *In the Matter of the Board's E-Filing Program*, BPU Docket No. AX16020100.

Thank you for your consideration and courtesies. Feel free to contact me with any questions or if I can be of further assistance.

Respectfully submitted,

/jpr

Philip J. Passanante
An Attorney at Law of the
State of New Jersey

Enclosure

cc: Service List

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL TO IMPLEMENT FERC-APPROVED CHANGES TO ACE'S RETAIL TRANSMISSION (FORMULA) RATE PURSUANT TO PARAGRAPHS 15.9 OF THE BGS-RSCP AND BGS-CIEP SUPPLIER MASTER AGREEMENTS (2018)	STATE OF NEW JERSEY BOARD OF PUBLIC UTILITIES BPU Docket No. ________________ VERIFIED PETITION

ATLANTIC CITY ELECTRIC COMPANY (hereinafter referred to as "Petitioner," "ACE" or the "Company"), a public utility corporation of the State of New Jersey, respectfully requests that the Board of Public Utilities ("BPU" or the "Board") approve implementation of changes to the Company's retail transmission (formula) rates filed with the Federal Energy Regulatory Commission ("FERC"), as proposed and outlined herein. In support thereof, Petitioner states as follows:

1. The Company is engaged in the purchase, transmission, distribution, and sale of electric energy to residential, commercial, and industrial customers. ACE's service territory comprises eight counties located in southern New Jersey, and includes approximately 550,000 customers.

2. As part of a settlement approved by FERC on or about August 9, 2004, certain transmission owners in PJM Interconnection, L.L.C. ("PJM"), including ACE, agreed to reexamine their existing rates and propose a method (such as a formula rate) to harmonize new and existing transmission investments by January 31, 2005. It was anticipated that such new rate (if any) would go into effect on or by June 1, 2005.[1] On January 31, 2005, Petitioner, among others, filed a formula rate for determining the wholesale transmission revenue requirements

[1] *See Allegheny Power System Operating Companies, et al.*, 108 FERC ¶61,167 (2004).

applicable in its PJM rate zone pursuant to the PJM tariff, to be effective on or about June 1, 2005.

3. The objective of the formula rate filing was to establish a just and reasonable method for determining transmission revenue requirements for the affected transmission pricing zones which would reflect existing and new investment on a current basis. The formula rate tracks increases and decreases in costs such that no under-recovery and no over-recovery of actual costs will occur. In the formula rate filing, ACE committed to populate the formula with actual data from its filed FERC Form 1 for calendar year 2004, and to post that information on the PJM website no later than May 1, 2004.

4. On March 20, 2006, certain transmission owners within PJM filed an uncontested settlement in Docket No. ER04-515-000 (the "Settlement").[2] The Settlement was approved by FERC on or about April 19, 2006. FERC also accepted the revised tariff sheets for filing effective June 1, 2005. The formula rate implementation protocols included provisions for an annual update to the Annual Transmission Revenue Requirements (the "Transmission Rate") based on current levels of costs and the reconciliation of prior period costs and revenues.

5. The Settlement also provided that, "[o]n or before May 15 of each year [ACE] shall recalculate its [Transmission Rate], produce an "Annual Update" for the upcoming year, and;

(i) post such Annual Update on PJM's Internet website… and

(ii) file such Annual Update with the FERC as an informational filing."[3]

[2] The transmission owners included Baltimore Gas and Electric Company and Pepco Holdings, Inc. ("PHI") and its operating affiliates. The Petitioner is an operating affiliate of PHI, which is now known as Pepco Holdings LLC.

[3] *See* Settlement Agreement, Exhibit B-1 containing PJM Tariff Attachment H1-B, Section 1.b.

6. Pursuant to the implementation protocols established in the Settlement, the Company filed an update to the formula rate at FERC on May 15, 2018, to be effective June 1, 2018. The formula rate update also incorporated a number of transmission enhancement projects that are included in Schedule 12 of the PJM Open Access Transmission Tariff ("OATT"). A copy of that update is included as **Exhibit A**.

7. Schedule 12 of the PJM OATT details Transmission Enhancement Charges ("TECs"), which 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. By Order dated January 25, 2017 (BPU Docket No. ER16121153), the Board approved and authorized ACE and the other New Jersey electric distribution companies ("EDCs") to recover the FERC-approved TECs found in Schedule 12 of the OATT for the Potomac Appalachian Transmission Highline, L.L.P. ("PATH") project, and for certain projects of Virginia Electric and Power Company ("VEPCo").

8. Commencing on or about April 27, 2018, formula rate update filings were made by Baltimore Gas and Electric Company (May 4, 2018), PPL Electric Utilities Corporation (April 27, 2018), Trans-Allegheny Interstate Line Company (also referred to as "TrAILCo") (May 15, 2018), PECO Energy (May 11, 2018), Delmarva Power & Light Company (May 15, 2018), and Potomac Electric Power Company (May 15, 2018), to be effective June 1, 2018. Each formula rate update filing includes TECs that are applicable to customers in the ACE

service territory. Copies of all formula rate updates can be found on the PJM website at http://www.pjm.com/markets-and-operations/billing-settlements-and-credit/formula-rates.aspx.

9. By Order dated October 22, 2003 (BPU Docket No. EO03050394), the Board authorized the EDCs to recover FERC-approved changes in firm transmission service-related charges. The Board has also authorized recovery of FERC-approved changes in firm transmission service-related charges in subsequent orders approving the Basic Generation Service ("BGS") supply procurement process and the associated Supplier Master Agreement(s) ("SMAs"). Pursuant to these Board Orders, the Company has recovered the TECs as part of its Basic Generation Service-Residential Small Commercial Pricing ("BGS-RSCP") and Basic Generation Service-Commercial and Industrial Energy Pricing ("BGS-CIEP").

10. Through this filing, the Company respectfully requests approval to implement the new transmission rates and TECs effective as of Saturday, September 1, 2018. Proposed tariffs containing the revised rates for transmission service are attached as **Exhibit B**. Also included in **Exhibit B** are tariff pages showing additions and deletions to the current tariff pages. The revised tariff sheets reflect changes in BGS-RSCP and BGS-CIEP charges to customers resulting from a change in FERC-approved Transmission Rates.

11. **Exhibit C** provides the proposed adjustment to the overall retail transmission rate to incorporate the TECs for projects outside of the ACE Zone in PJM. Additionally, as indicated previously, a number of TEC-related projects have been approved within the ACE Zone. The revenue requirements associated with these projects are delineated in Attachment 7 to the Company's formula rate filing. Note that these allocations incorporate changes to the PJM OATT pursuant to FERC Orders issued on December 15, 2017, in Docket Nos. EL17-84-000 and EL17-90-000 (the HTP and Linden VFT Orders). PJM implemented these changes in the

OATT effective January 1, 2018. The allocations also incorporate changes to the OATT pursuant to a FERC Order issued on April 25, 2017, in Docket Nos. ER17-950-000 and ER17-940-001 (the ConEd Wheel Order). **Exhibit D** to this filing provides the treatment for incorporating the cost responsibilities and revenue credits for these projects in the development of the ACE retail transmission rates. The Company's work papers, which set forth the details of the rate design calculations, are provided as **Exhibit E**.

12. The Transmission Rates reported herein have been modified in accordance with the Board-approved methodology contained in the Company-Specific Addenda provided pursuant to the BGS proceedings referenced in this Petition.

13. For an average residential customer using approximately 679 kWh per month, this filing, once implemented, represents an increase of approximately $0.55 or 0.45 percent on a total monthly bill as shown in **Exhibit F** included herewith.

14. Petitioner further respectfully requests that the effected BGS suppliers receive the appropriate compensation for the rate adjustment(s) detailed herein, subject to the terms and conditions of the appropriate BGS-RSCP and/or BGS-CIEP SMAs.

15. This Petition satisfies the requirements of ¶¶ 15.9(a)(i) and (ii) of the BGS-RSCP SMAs and ¶¶ 15.9(a)(i) and (ii) of the BGS-CIEP SMAs, which mandate that BGS suppliers be notified of rate increases or decreases in the Transmission Rate, and that the Company file for and obtain the Board's approval to implement changes in retail rates commensurate with the FERC-implemented Transmission Rate change. An adjustment to BGS supplier accounts for the period June 1, 2018 through May 31, 2019 will be made upon the Board's approval of this request. For the period beginning June 1, 2018, Petitioner will track amounts associated with the rate change to BGS suppliers in accordance with ¶¶ 15.9(a)(iii) and (iv) of the BGS-RSCP and

BGS-CIEP SMAs until receipt of final FERC action on the informational filing referenced in Paragraph 6 above.

16. Communications and correspondence regarding this matter should be sent to Petitioner and its counsel at the following addresses:

Philip J. Passanante, Esquire
Assistant General Counsel
Atlantic City Electric Company
92DC42
500 North Wakefield Drive
Newark, Delaware 19702

P.O. Box 6066
Newark, Delaware 19714-6066

with copies to the following representatives of the Company:

Joseph F. Janocha
Manager, Retail Rates
Atlantic City Electric Company - 63ML38
5100 Harding Highway
Mays Landing, New Jersey 08330

Alison Regan
Senior Rate Analyst
500 N. Wakefield Drive
Newark, Delaware 19702

and

Daniel A. Tudor
Manager, Energy Acquisition Operations
Pepco Holdings LLC/Atlantic City Electric Company
701 Ninth Street, N.W.
Washington, DC 20068-0001

WHEREFORE, the Petitioner, **ATLANTIC CITY ELECTRIC COMPANY**, respectfully requests that the Board of Public Utilities:

A. permit the Company to implement changes to Petitioner's retail transmission (formula) rates as detailed in this filing, including any TEC updates referenced in the Petition and the Exhibits thereto;

B. authorize appropriate adjustments to BGS suppliers subject to the terms and conditions of the BGS-RSCP and/or BGS-CIEP SMAs; and

C. grant such other or further relief as may be just and appropriate.

Respectfully submitted,

ATLANTIC CITY ELECTRIC COMPANY

Dated: July 11, 2018

Passanante /jpr

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Assistant General Counsel to
Atlantic City Electric Company

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL TO IMPLEMENT FERC-APPROVED CHANGES TO ACE'S RETAIL TRANSMISSION (FORMULA) RATE PURSUANT TO PARAGRAPHS 15.9 OF THE BGS-RSCP AND BGS-CIEP SUPPLIER MASTER AGREEMENTS (2018)	STATE OF NEW JERSEY BOARD OF PUBLIC UTILITIES

AFFIDAVIT OF VERIFICATION

KEVIN M. McGOWAN, being duly sworn, upon his oath deposes and says:

1. I am the Vice President of Regulatory Policy and Strategy of Atlantic City Electric Company ("ACE"), the Petitioner named in the foregoing Verified Petition. I am duly authorized to make this Affidavit of Verification on ACE's behalf.

2. I have read the contents of the foregoing Verified Petition by ACE for Approval to Implement FERC-Approved Changes to Its Retail Transmission (Formula) Rate Pursuant to Paragraphs 15.9 of the BGS-RSCP and BGS-CIEP Supplier Master Agreements. I verify that the statements of fact and other information contained therein are true and correct to the best of my knowledge, information, and belief.

JAMIELA LANE
NOTARY PUBLIC
EXP.
5-14-21
DISTRICT OF COLUMBIA

KEVIN M. McGOWAN

SWORN TO AND SUBSCRIBED before me this 9 day of July, 2018.

District of Columbia: SS
Subscribed and sworn to before me, in my presence,
this 9 day of July 2018
Jamiela Lane, Notary Public, D.C.
My commission expires May 14, 2021.

Notary Public
My Commission Expires: 5/14/21

Exhibit A

ATTACHMENT H-1A

Atlantic City Electric Company

Formula Rate - Appendix A

Shaded cells are input cells

Line	Description		Notes	FERC Form 1 Page # or Instruction	2017
	Allocators				
	Wages & Salary Allocation Factor				
1	Transmission Wages Expense			p354.21.b	$ 2,295,571
2	Total Wages Expense			p354.28b	$ 36,223,095
3	Less A&G Wages Expense			p354.27b	$ 1,243,809
4	Total			(Line 2 - 3)	34,979,286
5	Wages & Salary Allocator			(Line 1 / 4)	6.5627%
	Plant Allocation Factors				
6	Electric Plant in Service		(Note B)	p207.104g (see Attachment 5)	$ 3,605,589,602
7	Common Plant In Service - Electric			(Line 24)	0
8	Total Plant In Service			(Sum Lines 6 & 7)	3,605,589,602
9	Accumulated Depreciation (Total Electric Plant)			p219.29c (see Attachment 5)	$ 752,843,799
10	Accumulated Intangible Amortization		(Note A)	p200.21c (see Attachment 5)	$ 15,279,562
11	Accumulated Common Amortization - Electric		(Note A)	p356	$ -
12	Accumulated Common Plant Depreciation - Electric		(Note A)	p356	$ -
13	Total Accumulated Depreciation			(Sum Lines 9 to 12)	768,123,361
14	Net Plant			(Line 8 - 13)	2,837,466,241
15	Transmission Gross Plant			(Line 29 - Line 28)	1,283,293,498
16	Gross Plant Allocator			(Line 15 / 8)	35.5918%
17	Transmission Net Plant			(Line 39 - Line 28)	1,035,003,451
18	Net Plant Allocator			(Line 17 / 14)	36.4763%
	Plant Calculations				
	Plant In Service				
19	Transmission Plant In Service		(Note B)	p207.58.g	$ 1,274,493,121
20	For Reconciliation only - remove New Transmission Plant Additions for Current Calendar Year		For Reconciliation Only	Attachment 6 - Enter Negative	$ -
21	New Transmission Plant Additions for Current Calendar Year (weighted by months in service)			Attachment 6	-
22	Total Transmission Plant In Service			(Line 19 - 20 + 21)	1,274,493,121
23	General & Intangible			p205.5.g & p207.99.g (see Attachment 5)	$ 134,097,754
24	Common Plant (Electric Only)		(Notes A & B)	p356	$ -
25	Total General & Common			(Line 23 + 24)	134,097,754
26	Wage & Salary Allocation Factor			(Line 5)	6.56266%
27	General & Common Plant Allocated to Transmission			(Line 25 * 26)	8,800,377
28	Plant Held for Future Use (Including Land)		(Note C)	p214	782,029
29	TOTAL Plant In Service			(Line 22 + 27 + 28)	1,284,075,527
	Accumulated Depreciation				
30	Transmission Accumulated Depreciation		(Note B)	p219.25.c	$ 245,046,572
31	Accumulated General Depreciation			p219.28.c (see Attachment 5)	$ 34,143,635
32	Accumulated Intangible Amortization			(Line 10)	15,279,562
33	Accumulated Common Amortization - Electric			(Line 11)	0
34	Common Plant Accumulated Depreciation (Electric Only)			(Line 12)	0
35	Total Accumulated Depreciation			(Sum Lines 31 to 34)	49,423,197
36	Wage & Salary Allocation Factor			(Line 5)	6.56266%
37	General & Common Allocated to Transmission			(Line 35 * 36)	3,243,476
38	TOTAL Accumulated Depreciation			(Line 30 + 37)	248,290,048
39	TOTAL Net Property, Plant & Equipment			(Line 29 - 38)	1,035,785,480
	Adjustment To Rate Base				
	Accumulated Deferred Income Taxes				
40	ADIT net of FASB 106 and 109			Attachment 1	-329,243,425
41	Accumulated Investment Tax Credit Account No. 255	Enter Negative	(Notes A & I)	p266.h	0
42	Net Plant Allocation Factor			(Line 18)	36.48%
43	Accumulated Deferred Income Taxes Allocated To Transmission			(Line 41 * 42) + Line 40	-329,243,425
43a	Transmission Related CWIP (Current Year 12 Month weighted average balances)		(Note B)	p216.43.b as Shown on Attachment 6	0
	Transmission O&M Reserves				
44	Total Balance Transmission Related Account 242 Reserves		Enter Negative	Attachment 5	-2,046,990
	Prepayments				
45	Prepayments		(Note A)	Attachment 5	4,876,221
46	Total Prepayments Allocated to Transmission			(Line 45)	4,876,221
	Materials and Supplies				
47	Undistributed Stores Exp		(Note A)	p227.6c & 16.c	0
48	Wage & Salary Allocation Factor			(Line 5)	6.56%
49	Total Transmission Allocated			(Line 47 * 48)	0
50	Transmission Materials & Supplies			p227.8c	$ 1,857,041
51	Total Materials & Supplies Allocated to Transmission			(Line 49 + 50)	1,857,041
	Cash Working Capital				
52	Operation & Maintenance Expense			(Line 85)	27,124,788
53	1/8th Rule			x 1/8	12.5%
54	Total Cash Working Capital Allocated to Transmission			(Line 52 * 53)	3,390,598
	Network Credits				
55	Outstanding Network Credits		(Note N)	From PJM	0
56	Less Accumulated Depreciation Associated with Facilities with Outstanding Network Credits		(Note N)	From PJM	0
57	Net Outstanding Credits			(Line 55 - 56)	0
58	TOTAL Adjustment to Rate Base			(Line 43 + 43a + 44 + 46 + 51 + 54 - 57)	-321,166,555
59	Rate Base			(Line 39 + 58)	714,618,924

O&M

	Transmission O&M			
60	Transmission O&M		p321.112.b (see Attachment 5)	$ 21,706,703
61	Less extraordinary property loss		Attachment 5	0
62	Plus amortized extraordinary property loss		Attachment 5	0
63	Less Account 565		p321.96.b	$ -
64	Plus Schedule 12 Charges billed to Transmission Owner and booked to Account 565	(Note O)	PJM Data	$ -
65	Plus Transmission Lease Payments	(Note A)	p200.3c	$ -
66	Transmission O&M		(Lines 60 - 63 + 64 + 65)	21,706,703
	Allocated General & Common Expenses			
67	Common Plant O&M	(Note A)	p356	$ -
68	Total A&G		p323.197.b (see Attachment 5)	$ 83,679,206
68a	For informational purposes: PBOB expense in FERC Account 926	(Note S)	Attachment 5	$ 773,511
69	Less Property Insurance Account 924		p323.185b	$ 469,686
70	Less Regulatory Commission Exp Account 928	(Note E)	p323.189b	$ 4,783,058
71	Less General Advertising Exp Account 930.1		p323.191b	$ 286,452
72	Less DE Enviro & Low Income and MD Universal Funds		p335.b	$ -
73	Less EPRI Dues	(Note D)	p352-353	$ 220,349
74	General & Common Expenses		(Lines 67 + 68) - Sum (69 to 73)	77,919,661
75	Wage & Salary Allocation Factor		(Line 5)	6.5627%
76	General & Common Expenses Allocated to Transmission		(Line 74 * 75)	5,113,601
	Directly Assigned A&G			
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b	133,159
78	General Advertising Exp Account 930.1	(Note F)	p323.191b	0
79	Subtotal - Transmission Related		(Line 77 + 78)	133,159
80	Property Insurance Account 924		p323.185b	$ 469,686
81	General Advertising Exp Account 930.1	(Note K)	p323.191b	0
82	Total		(Line 80 + 81)	469,686
83	Net Plant Allocation Factor		(Line 18)	36.48%
84	A&G Directly Assigned to Transmission		(Line 82 * 83)	171,324
85	Total Transmission O&M		(Line 66 + 76 + 79 + 84)	27,124,788

Depreciation & Amortization Expense

	Depreciation Expense			
86	Transmission Depreciation Expense		p336.7b&c	29,624,450
87	General Depreciation		p336.10b&c (see Attachment 5)	6,449,388
88	Intangible Amortization	(Note A)	p336.1d&e (see Attachment 5)	159,633
89	Total		(Line 87 + 88)	6,609,021
90	Wage & Salary Allocation Factor		(Line 5)	6.5627%
91	General Depreciation Allocated to Transmission		(Line 89 * 90)	433,727
92	Common Depreciation - Electric Only	(Note A)	p336.11.b	0
93	Common Amortization - Electric Only	(Note A)	p356 or p336.11d	0
94	Total		(Line 92 + 93)	0
95	Wage & Salary Allocation Factor		(Line 5)	6.5627%
96	Common Depreciation - Electric Only Allocated to Transmission		(Line 94 * 95)	0
97	Total Transmission Depreciation & Amortization		(Line 86 + 91 + 96)	30,058,177

Taxes Other than Income

98	Taxes Other than Income		Attachment 2	1,053,584
99	Total Taxes Other than Income		(Line 98)	1,053,584

Return / Capitalization Calculations

	Long Term Interest				
100	Long Term Interest			p117.62c through 67c	62,992,469
101	Less LTD Interest on Securitization Bonds		(Note P)	Attachment 8	5,670,914
102	Long Term Interest			"(Line 100 - line 101)"	57,321,555
103	Preferred Dividends		enter positive	p118.29c	$ -
	Common Stock				
104	Proprietary Capital			p112.16c	$ 1,042,601,119
105	Less Preferred Stock		enter negative	(Line 114)	0
106	Less Account 216.1		enter negative	p112.12c	$ -
107	Common Stock			(Sum Lines 104 to 106)	1,042,601,119
	Capitalization				
108	Long Term Debt			p112.17c through 21c	$ 1,077,521,230
109	Less Loss on Reacquired Debt		enter negative	p111.81.c	$ (5,278,948)
110	Plus Gain on Reacquired Debt		enter positive	p113.61.c	$ -
111	Less ADIT associated with Gain or Loss		enter negative	Attachment 1	1,483,912
112	Less LTD on Securitization Bonds	(Note P)	enter negative	Attachment 8	-40,506,230
113	Total Long Term Debt			(Sum Lines Lines 108 to 112)	1,033,219,964
114	Preferred Stock			p112.3c	$ -
115	Common Stock			(Line 107)	1,042,601,119
116	Total Capitalization			(Sum Lines 113 to 115)	2,075,821,083
117	Debt %	Total Long Term Debt	(Note Q)	(Line 113 / 116)	50%
118	Preferred %	Preferred Stock	(Note Q)	(Line 114 / 116)	0%
119	Common %	Common Stock	(Note Q)	(Line 115 / 116)	50%
120	Debt Cost	Total Long Term Debt		(Line 102 / 113)	0.0555
121	Preferred Cost	Preferred Stock		(Line 103 / 114)	0.0000
122	Common Cost	Common Stock	(Note J)	Fixed	0.1050
123	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Line 117 * 120)	0.0277
124	Weighted Cost of Preferred	Preferred Stock		(Line 118 * 121)	0.0000
125	Weighted Cost of Common	Common Stock		(Line 119 * 122)	0.0525
126	Total Return (R)			(Sum Lines 123 to 125)	0.0802
127	Investment Return = Rate Base * Rate of Return			(Line 59 * 126)	57,340,508

	Composite Income Taxes				
	Income Tax Rates				
128	FIT=Federal Income Tax Rate				21.00%
129	SIT=State Income Tax Rate or Composite		(Note I)		9.00%
130	p	(percent of federal income tax deductible for state purposes)		Per State Tax Code	0.00%
131	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			28.11%
132	T/ (1-T)				39.10%
	ITC Adjustment		(Note I)		
133	Amortized Investment Tax Credit		enter negative	p266.8f	$ (363,377)
134	T/(1-T)			(Line 132)	39.10%
135	Net Plant Allocation Factor			(Line 18)	36.4763%
136	ITC Adjustment Allocated to Transmission			(Line 133 * (1 + 134) * 135)	-184,374
137	Income Tax Component =	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		[Line 132 * 127 * (1-(123 / 126))]	14,669,867
138	Total Income Taxes			(Line 136 + 137)	14,485,493
	REVENUE REQUIREMENT				
	Summary				
139	Net Property, Plant & Equipment			(Line 39)	1,035,785,480
140	Adjustment to Rate Base			(Line 58)	-321,166,555
141	Rate Base			(Line 59)	714,618,924
142	O&M			(Line 85)	27,124,788
143	Depreciation & Amortization			(Line 97)	30,058,177
144	Taxes Other than Income			(Line 99)	1,053,584
145	Investment Return			(Line 127)	57,340,508
146	Income Taxes			(Line 138)	14,485,493
147	Gross Revenue Requirement			(Sum Lines 142 to 146)	130,062,550
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
148	Transmission Plant In Service			(Line 19)	1,274,493,121
149	Excluded Transmission Facilities		(Note M)	Attachment 5	0
150	Included Transmission Facilities			(Line 148 - 149)	1,274,493,121
151	Inclusion Ratio			(Line 150 / 148)	100.00%
152	Gross Revenue Requirement			(Line 147)	130,062,550
153	Adjusted Gross Revenue Requirement			(Line 151 * 152)	130,062,550
	Revenue Credits & Interest on Network Credits				
154	Revenue Credits			Attachment 3	2,245,360
155	Interest on Network Credits		(Note N)	PJM Data	-
156	Net Revenue Requirement			(Line 153 - 154 + 155)	127,817,189
	Net Plant Carrying Charge				
157	Net Revenue Requirement			(Line 156)	127,817,189
158	Net Transmission Plant			(Line 19 - 30)	1,029,446,549
159	Net Plant Carrying Charge			(Line 157 / 158)	12.4161%
160	Net Plant Carrying Charge without Depreciation			(Line 157 - 86) / 158	9.5384%
161	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes			(Line 157 - 86 - 127 - 138) / 158	2.5613%
	Net Plant Carrying Charge Calculation per 100 Basis Point increase in ROE				
162	Net Revenue Requirement Less Return and Taxes			(Line 156 - 145 - 146)	55,991,189
163	Increased Return and Taxes			Attachment 4	76,796,225
164	Net Revenue Requirement per 100 Basis Point increase in ROE			(Line 162 + 163)	132,787,414
165	Net Transmission Plant			(Line 19 - 30)	1,029,446,549
166	Net Plant Carrying Charge per 100 Basis Point increase in ROE			(Line 164 / 165)	12.8989%
167	Net Plant Carrying Charge per 100 Basis Point increase in ROE without Depreciation			(Line 163 - 86) / 165	10.0212%
168	Net Revenue Requirement			(Line 156)	127,817,189
169	True-up amount			Attachment 6	8,525,952
170	Plus any increased ROE calculated on Attachment 7 other than PJM Sch. 12 projects			Attachment 7	289,177
171	Facility Credits under Section 30.9 of the PJM OATT and Facility Credits paid to Vineland per settlement in ER05-515 (Note R)			Attachment 5	-
172	Net Zonal Revenue Requirement			(Line 168 - 169 + 171)	136,632,319
	Network Zonal Service Rate				
173	1 CP Peak		(Note L)	PJM Data	2,541
174	Rate ($/MW-Year)			(Line 172 / 173)	53,775
175	Network Service Rate ($/MW/Year)			(Line 174)	53,775

Notes

A Electric portion only
B Exclude Construction Work In Progress and leases that are expensed as O&M (rather than amortized). New Transmission plant that is expected to be placed in service in the current calendar year weighted by number of months it is expected to be in-service. New Transmission plant expected to be placed in service in the current calendar year that is not included in the PJM Regional Transmission Plan (RTEP) must be separately detailed on Attachment 5. For the Reconciliation, new transmission plant that was actually placed in service weighted by the number of months it was actually in service CWIP will be linked to Attachment 6 which shows detail support by project (incentive and non-incentive).
C Transmission Portion Only
D All EPRI Annual Membership Dues
E All Regulatory Commission Expenses
F Safety related advertising included in Account 930.1
G Regulatory Commission Expenses directly related to transmission service, RTO filings, or transmission siting itemized in Form 1 at 351.h.
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 The ROE is 10.5% which includes a base ROE of 10.0% ROE per FERC order in Docket No. EL13-48 and a 50 basis point RTO membership adder as authorized by FERC: provided, that the projects identified in Docket Nos. ER08-686 and ER08-1423 have been awarded an additional 150 basis point adder and, thus, their ROE is 12.0%.
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 and the PJM established billing determinants will not be revised or updated in the annual rate reconciliations per settlement in ER05-515.
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) towards the construction of Network Transmission Facilities consistent with Paragraph 657 of Order 2003-A. Interest on the Network Credits as booked each year is added to the revenue requirement to make the Transmisison Owner whole on Line 155.
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 in on line 64
P Securitization bonds may be included in the capital structure per settlement in ER05-515.
Q ACE capital structure is initially fixed at 50% common equity and 50% debt per settlement in ER05-515 subject to moratorium provisions in the settlement.
R Per the settlement in ER05-515, the facility credits of $15,000 per month paid to Vineland will increase to $37,500 per month (prorated for partial months) effective on the date FERC approves the settlement in ER05-515.
S See Attachment 5 - Cost Support, section entitled "PBOP Expense in FERC Account 926" for additional information per FERC orders in Docket Nos. EL13-48 , EL15-27 and ER16-456.

Atlantic City Electric Company

Attachment 1- Accumulated Deferred Income Taxes (ADIT) Worksheet

	Only Transmission Related	*Plant Related*	*Labor Related*	*Total ADIT*
ADIT- 282	-	(942,450,108)	-	
ADIT-283	(4,331,250)	48,279	(34,109,695)	
ADIT-190	-	34,472,927	7,228,456	
Subtotal	(4,331,250)	(907,928,901)	(26,881,239)	
Wages & Salary Allocator			6.5627%	
Gross Plant Allocator		35.5918%		
ADIT	(4,331,250)	(323,148,052)	(1,764,124)	(329,243,425)

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 111.
Amount (1,483,912)

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

	A	B Total	C	D	E	F	G
ADIT-190			Gas, Prod or Other Related	Only Transmission Related	Plant	Labor	Justifications
190	1999 AMT	443,467	-	-	443,467	-	Reflects the deferred tax asset related to New Jersey Alternative Minimum Assessment (AMA) credit. Relates to both Transmission and Distribution.
190	Accrual Labor Related	5,077,299	-	-	-	5,077,299	Represents deferred income taxes on labor related book accruals that are only deductible for tax purposes as economic performance occurs. The deferred taxes are related to Company personnel across all functions.
190	Accrued Liab - Auto	70,036	-	-	-	70,036	These deferred taxes are the result of a deduction taken for book purposes to set aside a reserve for Auto liability claims. For tax, no deduction is permitted until the "all events" test is met, typically when payment is made. The deferred taxes related to Company personnel across all functions.
190	Accrued Liab - Misc.	3,178,991	2,352,122	-	826,869	-	Represents accrued book liabilities that can not be deducted for tax purposes until the "all events" test is met. Amounts in Gas, Production or Other Related represent deferred taxes on Unbilled Revenues which are retail related. Deferred taxes on Other Miscellaneous Accrued Liabilities relate to both Transmission and Distribution and are being allocated using both the Plant and Labor allocators.
190	Accrued Liability - General	3,102,873	2,161,580	-	941,293	-	Amounts in Gas, Production or Other Related represent deferred income taxes on Accrued Merger Commitments made as part of the 2016 merger with Exelon that have not been paid to date. These amounts are excluded from Rate Base. Other General Accrued liabilities are related to both Transmission and Distribution and are being allocated using the Plant Allocator.
190	Accumulated Deferred Investment Tax Credit	1,039,304	-	-	1,039,304	-	Pursuant to the requirements of FAS 109, ACE's accumulated deferred income taxes must encompass all timing differences regardless of whether the difference is normalized or flowed-through. These balances represent the deferred taxes on the Investment Tax Credit regulatory liability. Related to all plant. These amounts are removed below.
190	BAD DEBT RESERVE	4,995,180	4,995,180	-	-	-	Under the Tax Reform Act of 1986, taxpayers were required to account for bad debts using the specific write-off method. The reserve method is used for book purposes. The amount represents the deferred tax asset related to the add-back of book reserves for tax purposes.. The deferred tax asset is retail related.
190	Charitable Contribution Limit	582,061	582,061	-	-	-	ACE accrued Charitable Contribution Commitments made as part of the 2016 merger with Exelon that have not been paid to date. In addition, ACE has deducted Charitable Contributions for book purposes that could not be used in ACE's federal income tax return because of limitations caused by its tax net operating losses. Charitable Contributions are not included in Operating Income and any related deferred income taxes are excluded from Rate Base.
190	ENVIRONMENTAL EXPENSE	176,796	176,796	-	-	-	These deferred taxes are the result of a deduction taken for book purposes to set aside a reserve for environmental site clean-up expenses. For tax, no deduction is permitted until the "all events" test is met, typically when economic performance has occurred. This book reserve is primarily related to Deepwater and BL England sites which should not be in transmission service. It is Generation related.
190	OPEB	4,162,474	-	-	-	4,162,474	FAS No. 106 requires accrual basis instead of cash basis accounting for post retirement health care and life insurance benefits for book purposes. Amounts paid to participants or funded through the VEBA or 401(h) accounts are currently deductible for tax purposes. Affects Company personnel across all functions.
190	SERP	247,791	-	-	-	247,791	Represents deferred taxes for supplemental executive retirement plan ("SERP"). Accrued SERP expense is included on book but is not deductible for tax until economic performance is met.
190	Stranded Costs	1,218,428	1,218,428	-	-	-	Stranded Costs incurred when Generation was deregulated were deferred for book purposes pending collection from/refund to customers in the future. These amounts were included for tax purposes when incurred. The deferred tax asset is Generation related.
190	Use Tax Reserve	784,569	784,569	-	-	-	Represents deferred taxes for FAS 5/ASC 450 Use Tax Reserves which are not fixed and determinable and therefore not deductible for income tax purposes.
190	Federal NOL	13,246,763	-	-	13,246,763	-	Represents the deferred tax asset related to federal net operating loss carryforwards (offset by the federal benefit of state NOL carryforwards) available to offset future federal taxable income. Related to both Transmission and Distribution.
190	State NOL	21,234,578	7,304,705	-	13,929,873	-	Represents the deferred tax asset related to state net operating loss carryforwards available to offset future state taxable income. Related to both Transmission and Distribution.
190	FAS 109 Deferred Taxes - 190	406,383	-	-	406,383	-	Pursuant to the requirements of FAS 109, ACE's accumulated deferred income taxes must encompass all timing differences regardless of whether the difference is normalized or flowed-through. These balances represent the tax gross-up necessary for full recovery of unamortized ITC. These amoutns are removed from rate base below.
190	Gross up on TCJA FAS 109 Excess Deferred Taxes	5,770,244	-	459,854	2,712,088	2,598,303	Pursuant to the requirements of FAS 109, ACE's accumulated deferred income taxes must encompass all timing differences regardless of whether the difference is normalized or flowed-through. These balances represent the tax gross-up necessary for full recovery of the 2017 Tax Cuts and Jobs Act (2017) Federal Tax Rate reduction. These amounts are removed from rate base below.
190	Gross up on FAS 109 Deferred Taxes	109,423,708	-	-	109,423,708	-	Pursuant to the requirements of FAS 109, ACE's accumulated deferred income taxes must encompass all timing differences regardless of whether the difference is normalized or flowed-through. These balances represent the tax gross-up necessary for full recovery of the prior flow-through amounts. Related to all plant. These amounts are removed from rate base below.
190	Subtotal - p234	175,160,945	19,575,441	459,854	142,969,747	12,155,903	
	Less FASB 109 Above if not separately removed	102,712,541	(7,009,106)	459,854	108,496,820	764,973	
190	Less FASB 106 Above if not separately removed	4,162,474	-	-	-	4,162,474	FAS No. 106 requires accrual basis instead of cash basis accounting for post retirement health care and life insurance benefits for book purposes. Amounts paid to participants or funded through the VEBA or 401(h) accounts are currently deductible for tax purposes. Affects company personnel across all functions.
190	Total	68,285,930	26,584,547	-	34,472,927	7,228,456	

Instructions for Account 190:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.
6. Re: Form 1-F filer: Sum of subtotals for Accounts 282 and 283 should tie to Form No. 1-F, p.113.57.c

	A	B	C	D	E	F	G
ADIT-282		Total	Gas, Prod or Other Related	Only Transmission Related	Plant	Labor	Justifications
282	Plant Related - APB 11 Deferred Taxes	(942,450,108)			(942,450,108)		This deferred tax balance relates to our plant and results from life and method differences. Related to both T & D plant.
282	CIAC	50,313,891	50,313,891				Contributions in Aid of Construction (CIAC) are a reduction to Plant for book accounting purposes, but are included in taxable income and depreciated for income tax purposes. This different book/tax treatment results in deferred income taxes which must be recorded in accordance with SFAS 109. The Company collects an income tax gross-up from the customer which is reimbursement for the time value of money on the additional tax liability incurred until such time as the amounts are fully depreciated for tax purposes. The deferred income tax asset on CIAC's is excluded from Rate Base because the underlying plant is not included in Rate Base.
282	Leased Vehicles	11,277,468	11,277,468				The Company leases its vehicles under arrangements that are treated as Operating Leases for book purposes, but financing leases for tax purposes. The differing income tax treatment between Rent Expense deducted for book purposes and tax depreciation expense deducted for income tax purposes, results in deferred income taxes being recorded on the books. Since Leased Vehicles are not included in Rate Base, the deferred income taxes are being excluded as well.
282	Plant Related - FAS109 Deferred Taxes	279,845,977	(12,427,784)	-	292,273,761		Pursuant to the requirements of FAS 109, ACE's accumulated deferred income taxes must encompass all timing differences regardless of whether the difference is normalized or flowed-through. These balances represent the deferred taxes on prior flow-through items. Related to all plant. These amounts are removed below.
	Subtotal - p275	(601,012,772)	49,163,575	-	(650,176,347)	-	
	Less FASB 109 Above if not separately removed	279,845,977	(12,427,784)	-	292,273,761	-	
	Less FASB 106 Above if not separately removed	-					
282	Total	(880,858,749)	61,591,359	-	(942,450,108)	-	

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

	A	B	C	D	E	F	G
ADIT-283		Total	Gas, Prod or Other Related	Only Transmission Related	Plant	Labor	Justifications
283	Accrual Labor Related	(1,458,050)	-	-	-	(1,458,050)	Represents deferred income tax liability on Vacation Accrual Regulatory Asset. The deferred taxes are related to Company personnel across all functions.
283	BGS Deferred Related - Retail	(2,615,558)	(2,615,558)	-	-	-	Relates to deferred costs associated with Basic Generation Service. Retail related.
283	Interest on Contingent Taxes	48,279	-	-	48,279	-	Estimated book interest income on prior year taxes not included in taxable income for tax purposes. Related to both Transmission and Distribution.
283	Loss on Reacquired Debt	(1,483,912)	(1,483,912)	-	-	-	The cost of bond redemption is deductible currently for tax purposes and is amortized over the life of the new bond issue for book purposes. Excluded here since included in Cost of Debt
283	Misc. Deferred Debits - Retail	(484,545)	(484,545)	-	-	-	Represents deferred taxes on miscellaneous deferred debits deducted for tax purposes in advance of book purposes. Retail related.
283	NUG BUYOUT	(6,627,894)	(6,627,894)	-	-	-	These deferred taxes relate to Regulatory Assets created during Generation deregulation. The underlying costs were deducted for tax purposes as incurred. Amortization Expense recorded for book purposes as amounts are collected from customers is reversed for tax purposes. It is Generation related.
	Other- 283	(432,517)	(432,517)				Represents deferred taxes realted to income on books not included for tax.
283	PENSION PAYMENT RESERVE	(22,468,488)	-	-	-	(22,468,488)	The Company claims tax deductions for payments made to fund its Retirement Income Plan to the extent permitted under the IRC Section 415 contribution limitations. For book purposes, Pension Plan expense is recorded in accordance with SFAS 158. This deferred tax liability reflects the difference between the tax versus book deductions. It affects Company personnel across all functions.
283	Reg Asset - FERC Formula Rate Adj. Trans. Svc	(2,980,451)	-	(2,980,451)	-	-	When a regulatory asset/liability is established, books credit/debit income, which for tax purposes needs to be reversed along with the associated amortization. The deferred tax asset is 100% Transmission related.
283	Reg Asset-NJ Rec-Base	(7,770,512)	(7,770,512)	-	-	-	When a regulatory asset/liability is established, books credit/debit income, which for tax purposes needs to be reversed along with the associated amortization. This deferred tax liability is retail related.
283	Regulatory Asset - General	2,814,050	2,814,050				For book purposes, regulatory assets are established with an increase to book income. For tax purposes the regulatory assets are not recognized and book income is reversed.
283	Regulatory Asset - NJ RGGI	(1)	(1)	-	-	-	When a regulatory asset/liability is established, books credit/debit income, which for tax purposes needs to be reversed along with the associated amortization. This deferred tax liability is retail related.
283	Regulatory Asset - SREC Program	(178,463)	(178,463)	-	-	-	Represents deferred income tax liability on the Solar Renewable Energy Certificate Program. Retail related.
283	Stranded Costs	(19,844,720)	(19,844,720)	-	-	-	These deferred taxes relate to Regulatory Assets created during Generation deregulation. The underlying costs were deducted for tax purposes as incurred. Amortization Expense recorded for book purposes as amounts are collected from customers is reversed for tax purposes. It is Generation related.
283	Subtotal - p277 (Form 1-F filer: see note 6, below)	(63,482,782)	(36,624,072)	(2,980,451)	48,279	(23,926,538)	
283	Less FASB 109 Above if not separately removed	28,684,225	17,150,270	1,350,799	-	10,183,157	
283	Less FASB 106 Above if not separately removed	-					
283	Total	(92,167,007)	(53,774,342)	(4,331,250)	48,279	(34,109,695)	

check

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

ADITC-255			Balance	Amortization
1	Rate Base Treatment			
2	Balance to line 41 of Appendix A	Total		
3	Amortization			
4	Amortization to line 133 of Appendix A	Total	3,697,280	363,377
5	Total		3,697,280	363,377
6	Form No. 1 balance (p.266) for amortization	Total Form No. 1 (p 266 & 267	3,697,280	363,377
7	Difference /1		-	-

/1 Difference must be zero

Atlantic City Electric Company

Attachment 2 - Taxes Other Than Income Worksheet

	Other Taxes	Page 263 Col (i)	Allocator	Allocated Amount
	Plant Related		***Gross Plant Allocator***	
1	Real property (State, Municipal or Local)	2,444,578		
2	Personal property	-		
3	City License	-		
4	Federal Excise	14,173		
	Total Plant Related	2,458,751	35.5918%	875,113
	Labor Related		***Wages & Salary Allocator***	
5	Federal FICA & Unemployment	2,487,661		
6	Unemployment(State)	214,003		
	Total Labor Related	2,701,664	6.5627%	177,301
	Other Included		***Gross Plant Allocator***	
7	Miscellaneous	3,286		
	Total Other Included	3,286	35.5918%	1,170
	Total Included			1,053,584
	Excluded			
8	State Franchise tax	-		
9	TEFA	-		
10	Use & Sales Tax	1,140,217		
10	Excluded merger costs in line 5	15		
11	Total "Other" Taxes (included on p. 263)	6,303,933		
12	Total "Taxes Other Than Income Taxes" - acct 408.10 (p. 114.14)	6,303,933		
13	Difference	-		

Criteria for Allocation:

A Other taxes that are incurred through ownership of plant including transmission plant will be 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

E Excludes prior period adjustments in the first year of the formula's operation and reconciliation for the first year

Atlantic City Electric Company

Attachment 3 - Revenue Credit Workpaper

	Account 454 - Rent from Electric Property		
1	Rent from Electric Property - Transmission Related (Note 3)		966,076
2	Total Rent Revenues	(Sum Line 1)	966,076
	Account 456 - Other Electric Revenues (Note 1)		
3	Schedule 1A		$ 816,004
4	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) (Note 4)		-
5	Point to Point Service revenues for which the load is not included in the divisor received by Transmission Owner (Note 4)		462,720
6	PJM Transitional Revenue Neutrality (Note 1)		-
7	PJM Transitional Market Expansion (Note 1)		-
8	Professional Services (Note 3)		-
9	Revenues from Directly Assigned Transmission Facility Charges (Note 2)		619,380
10	Rent or Attachment Fees associated with Transmission Facilities (Note 3)		-
11	Gross Revenue Credits	(Sum Lines 2-10)	2,864,180
12	Less line 17g		(618,820)
13	Total Revenue Credits		2,245,360

<u>Revenue Adjustment to determine Revenue Credit</u>

14 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 173 of Appendix A.

15 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.

16 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). Company will retain 50% of net revenues consistent with Pacific Gas and Electric Company, 90 FERC ¶ 61,314. Note: in order to use lines 17a - 17g, 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).

17a	Revenues included in lines 1-11 which are subject to 50/50 sharing.		966,076
17b	Costs associated with revenues in line 17a	Attachment 5 - Cost Support	271,564
17c	Net Revenues (17a - 17b)		694,512
17d	50% Share of Net Revenues (17c / 2)		347,256
17e	Costs associated with revenues in line 17a 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.		-
17f	Net Revenue Credit (17d + 17e)		347,256
17g	Line 17f less line 17a		(618,820)
18	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 is 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.		9,741,348
19	Amount offset in line 4 above		133,095,697
20	Total Account 454, 456 and 456.1		145,701,225
21	Note 4: SECA revenues booked in Account 447.		

Atlantic City Electric Company

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 127 + Line 138)	76,796,225
B	100 Basis Point increase in ROE			1.00%

Return Calculation				
59	Rate Base		(Line 39 + 58)	714,618,924
	Long Term Interest			
100	Long Term Interest		p117.62c through 67c	62,992,469
101	Less LTD Interest on Securitization E (Note P)		Attachment 8	5,670,914
102	**Long Term Interest**		"(Line 100 - line 101)"	57,321,555
103	**Preferred Dividends**	enter positive	p118.29c	0
	Common Stock			
104	Proprietary Capital		p112.16c	1,042,601,119
105	Less Preferred Stock	enter negative	(Line 114)	0
106	Less Account 216.1	enter negative	p112.12c	0
107	**Common Stock**		(Sum Lines 104 to 106)	1,042,601,119
	Capitalization			
108	Long Term Debt		p112.17c through 21c	1,077,521,230
109	Less Loss on Reacquired Debt	enter negative	p111.81.c	-5,278,948
110	Plus Gain on Reacquired Debt	enter positive	p113.61.c	0
111	Less ADIT associated with Gain or Loss	enter negative	Attachment 1	1,483,912
112	Less LTD on Securitization Bonds	enter negative	Attachment 8	-40,506,230
113	Total Long Term Debt		(Sum Lines Lines 108 to 112)	1,033,219,964
114	Preferred Stock		p112.3c	0
115	Common Stock		(Line 107)	1,042,601,119
116	**Total Capitalization**		(Sum Lines 113 to 115)	2,075,821,083
117	Debt % (Note Q from Appendix A)	Total Long Term Debt	(Line 113 / 116)	50%
118	Preferred % (Note Q from Appendix A)	Preferred Stock	(Line 114 / 116)	0%
119	Common % (Note Q from Appendix A)	Common Stock	(Line 115 / 116)	50%
120	Debt Cost	Total Long Term Debt	(Line 102 / 113)	0.0555
121	Preferred Cost	Preferred Stock	(Line 103 / 114)	0.0000
122	Common Cost (Note J from Appendix A)	Common Stock	Appendix A % plus 100 Basis Pts	0.1150
123	Weighted Cost of Debt	Total Long Term Debt (WCLTD)	(Line 117 * 120)	0.0277
124	Weighted Cost of Preferred	Preferred Stock	(Line 118 * 121)	0.0000
125	Weighted Cost of Common	Common Stock	(Line 119 * 122)	0.0575
126	Total Return (R)		**(Sum Lines 123 to 125)**	**0.0852**
127	Investment Return = Rate Base * Rate of Return		**(Line 59 * 126)**	**60,913,602**

Composite Income Taxes			(Note L)	
	Income Tax Rates			
128	FIT=Federal Income Tax Rate			21.00%
129	SIT=State Income Tax Rate or Composite			9.00%
130	p = percent of federal income tax deductible for state purposes		Per State Tax Code	0.00%
131	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		28.11%
132	T/ (1-T)			39.10%
	ITC Adjustment			
133	Amortized Investment Tax Credit	enter negative	p266.8f	-363,377
134	T/(1-T)		(Line 132)	39.10%
135	Net Plant Allocation Factor		(Line 18)	36.4763%
136	**ITC Adjustment Allocated to Transmission**	(Note I from Appendix A)	(Line 133 * (1 + 134) * 135)	**-184,374**
137	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		16,066,997
138	**Total Income Taxes**			**15,882,623**

Atlantic City Electric Company

Attachment 5 - Cost Support

Electric / Non-electric Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Form 1 Amount	Electric Portion	Non-electric Portion	Details
	Plant Allocation Factors						
10	Accumulated Intangible Amortization	(Note A)	p200.21c (see Attachm	15,293,580	15,293,580	0	Respondent is Electric Utility only.
11	Accumulated Common Amortization - Electric	(Note A)	p356	0	0	0	
12	Accumulated Common Plant Depreciation - Electric	(Note A)	p356	0	0	0	
	Plant In Service						
24	Common Plant (Electric Only)	(Notes A & B)	p356	0	0	0	
	Accumulated Deferred Income Taxes						
41	Accumulated Investment Tax Credit Account No. 255	(Notes A & I)	p266.h	3,697,280	3,697,280	0	Respondent is Electric Utility only.
	Materials and Supplies						
47	Undistributed Stores Exp	(Note A)	p227.6c & 16.c	0	0	0	Respondent is Electric Utility only.
	Allocated General & Common Expenses						
65	Plus Transmission Lease Payments	(Note A)	p200.3c	0			
67	Common Plant O&M	(Note A)	p356	0	0	0	
	Depreciation Expense						
88	Intangible Amortization	(Note A)	p336.1d&e	173,651	173,651	0	Respondent is Electric Utility only.
92	Common Depreciation - Electric Only	(Note A)	p336.11.b	0	0	0	
93	Common Amortization - Electric Only	(Note A)	p356 or p336.11d	0	0	0	

Transmission / Non-transmission Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Form 1 Amount	Transmission Related	Non-transmission Related	Details
28	Plant Held for Future Use (Including Land)	(Note C)	p214	12,883,207	782,029	12,101,178	Transmission Right of Way - Carll's Corner to Landis

CWIP & Expensed Lease Worksheet

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Form 1 Amount	CWIP In Form 1 Amount	Expensed Lease in Form 1 Amount	Details
	Plant Allocation Factors						
6	Electric Plant in Service	(Note B)	p207.104g	3,607,191,404	0	0	See ARO Exclusion - Cost Support section below for Electric Plant in Servie without AROs
	Plant In Service						
19	Transmission Plant In Service	(Note B)	p207.58.g	1,274,493,121	0	0	See Form 1
24	Common Plant (Electric Only)	(Notes A & B)	p356	0	0	0	
	Accumulated Depreciation						
30	Transmission Accumulated Depreciation	(Note B)	p219.25.c	245,046,572	0	0	See Form 1

EPRI Dues Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Form 1 Amount	EPRI Dues	Details
	Allocated General & Common Expenses					
73	Less EPRI Dues	(Note D)	p352-353	220,349	220,349	See Form 1

Atlantic City Electric Company

Attachment 5 - Cost Support

Regulatory Expense Related to Transmission Cost Support

Line	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Note	Form 1 Page	Form 1 Amount	Transmission Related	Non-transmission Related	Details
	Allocated General & Common Expenses						
70	Less Regulatory Commission Exp Account 928	(Note E)	p323.189b	4,783,058	133,159	4,649,899	FERC Form 1 page 351 line 6 (h) and 7 (h)
	Directly Assigned A&G						
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b	4,783,058	133,159	4,649,899	FERC Form 1 page 351 line 6 (h) and 7 (h)

Safety Related Advertising Cost Support

Line	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Note	Form 1 Page	Form 1 Amount	Safety Related	Non-safety Related	Details
	Directly Assigned A&G						
81	General Advertising Exp Account 930.1	(Note K)	p323.191b	286,452	-	286,452	None

MultiState Workpaper

Line	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Note	Rate	State 1	State 2	State 3	State 4	State 5	Details
	Income Tax Rates								
				NJ	PA				Enter Calculation
129	SIT=State Income Tax Rate or Composite	(Note I)	9.0000%	9.00%	9.990%				Apportioned: NJ 100.0000%, PA 0.0000%

Education and Out Reach Cost Support

Line	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Note	Form 1 Page	Form 1 Amount	Education & Outreach	Other	Details
	Directly Assigned A&G						
78	General Advertising Exp Account 930.1	(Note F)	p323.191b	286,452	-	286,452	None

Excluded Plant Cost Support

Line	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Example	Note	Reference	Excluded Transmission Facilities	Description of the Facilities
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities					
149	Excluded Transmission Facilities		(Note M)	Attachment 5	-	General Description of the Facilities
	Instructions:				Enter $	None
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,				Or	
	the following formula will be used:	Example			Enter $	
A	Total investment in substation	1,000,000				
B	Identifiable investment in Transmission (provide workpapers)	500,000				
C	Identifiable investment in Distribution (provide workpapers)	400,000				
D	Amount to be excluded (A x (C / (B + C)))	444,444				
						Add more lines if necessary

Atlantic City Electric Company

Attachment 5 - Cost Support

Outstanding Network Credits Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Outstanding Network Credits	Description of the Credits
	Network Credits			Enter $	
55	Outstanding Network Credits	(Note N)	From PJM	0	General Description of the Credits
					None
56	Less Accumulated Depreciation Associated with Facilities with Outstanding Network Credits	(Note N)	From PJM	0	
					None
					Add more lines if necessary

Transmission Related Account 242 Reserves

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions	Total	Allocation	Transmission Related	Details
44	Transmission Related Account 242 Reserves (exclude current year environmental site related reserves)	Enter $		Amount	
	Directly Assignable to Transmission	0	100%	-	
	Labor Related, General plant related or Common Plant related	15,238,358	6.56%	1,000,041	
	Plant Related	2,941,546	35.59%	1,046,949	
	Other		0.00%	-	
	Total Transmission Related Reserves	18,179,904		2,046,990	

Prepayments

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions					Description of the Prepayments
45	Prepayments					
5	Wages & Salary Allocator			6.563%	To Line 45	
	Pension Liabilities, if any, in Account 242		-	6.563%	-	
	Prepayments	$	371,936	6.563%	24,409	
	Prepaid Pensions if not included in Prepayments	$	73,930,586	6.563%	4,851,812	Prepaid Pension is recorded in FERC account 186 (see FERC Form 1 page 233).
			74,302,522		4,876,221	
						Add more lines if necessary

Extraordinary Property Loss

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Amount	Number of years	Amortization	w/ interest
61	Less extraordinary property loss	Attachment 5	$ -			
62	Plus amortized extraordinary property loss	Attachment 5		5	$ -	$ -

Atlantic City Electric Company

Attachment 5 - Cost Support

Interest on Outstanding Network Credits Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Interest on Network Credits	Description of the Interest on the Credits
	Revenue Credits & Interest on Network Credits				
155	Interest on Network Credits	(Note N)	PJM Data	0	General Description of the Credits
				Enter $	None
					Add more lines if necessary

Facility Credits under Section 30.9 of the PJM OATT and Facility Credits paid to Vineland per settlement in ER05-515 (Note R)

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Amount	Description & PJM Documentation
	Net Revenue Requirement		
171	Facility Credits under Section 30.9 of the PJM OATT and Facility Credits paid to Vineland per settlement in ER05-515 (Note R)	-	Settelement agreement.

PJM Load Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				1 CP Peak	Description & PJM Documentation
	Network Zonal Service Rate				
173	1 CP Peak	(Note L)	PJM Data	2,540.8	See Form 1

Statements BG/BH (Present and Proposed Revenues)

Customer	Billing Determinants	Current Rate	Proposed Rate	Current Revenues	Proposed Revenues	Change in Revenues
ACE zone						
Total						

Supporting documentation for FERC Form 1 reconciliation

Compliance with FERC Order on the Exelon Merger

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	Merger Costs	Non Merger Related	
6	Electric Plant in Service	p207.104g	3,607,191,404	157,222	3,607,034,182	
9	Accumulated Depreciation (Total Electric Plant)	p219.29c	753,019,802	198	753,019,604	
10	Accumulated Intangible Amortization	p200.21c	15,293,580	14,018	15,279,562	
23	General & Intangible	p205.5.g & p207.99.g	134,744,748	157,222	134,587,526	
60	Transmission O&M	p321.112.b	21,789,347	82,644	21,706,703	
68	Total A&G	p323.197.b	79,823,542	(3,855,664)	83,679,206	Removal of $4,315,518 of 2017 merger related costs, offset by establishment of regulatory asset of $8,171,182 in A&G accounts.
87	General Depreciation	p336.10b&c	6,449,586	198	6,449,388	
88	Intangible Amortization	p336.1d&e	173,651	14,018	159,633	

ARO Exclusion - Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	ARO's	Non-ARO's	
6	Electric Plant in Service	p207.104g	3,607,191,404	1,444,581	3,605,746,823	Distribution ARO-$954,809 and General & Intangible ARO-$489,772
9	Accumulated Depreciation (Total Electric Plant)	p219.29c	753,019,802	175,805	752,843,997	Distribution ARO-$113,267 and General ARO-$62,538

Atlantic City Electric Company

Attachment 5 - Cost Support

23	General & Intangible	p205.5.g & p207.99.g	134,744,748	489,772	134,254,976		General & Intangible ARO-$489,772
31	Accumulated General Depreciation	p219.28.c	34,206,372	62,538	34,143,834		General ARO-$62,538

ARO & Merger Related Exclusion - Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Form 1 Amount	ARO's	Merger Costs	Non-ARO's & Non Merger Related	
6	Electric Plant in Service	p207.104g	3,607,191,404	1,444,581	157,222	3,605,589,602	Distribution ARO-$954,809, General & Intangible ARO-$489,772 and Intangible Merger Cost $157,222
9	Accumulated Depreciation (Total Electric Plant)	p219.29c	753,019,802	175,805	198	752,843,799	Distribution ARO-$113,267 and General ARO-$62,538 and General Merger Cost $198
23	General & Intangible	p205.5.g & p207.99.g	134,744,748	489,772	157,222	134,097,754	General & Intangible ARO-$489,772 and Intangible Merger Cost $157,222
31	Accumulated General Depreciation	p219.28.c	34,206,372	62,538	198	34,143,635	General ARO-$62,538 and General Merger Cost $198

PBOP Expense in FERC 926

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions		Total A&G Form 1 Amount	Account 926 Form 1 Amount	PBOP in FERC 926 current rate year	PBOP in FERC 926 prior rate year	Explanation of change in PBOP in FERC 926
68	Total A&G	Total: p.323.197.b Account 926: p.323.187.b and c	79,823,542	14,039,705	773,511	1,000,545	The actuarially determined amount of OPEB expense in FERC 926 decreased $.227 million from the prior year; the decrease primarily represents a ($0.2 million) decrease in service cost primarily due to (i) change in the discount rate from 3.80% in 2016 to 4.0% in 2017 and (ii) updated census data, ($0.3 million) increase in expected return on plan assets due to year over year assets growth, offset by $0.1 million increase in amortization of unregonized gain/loss. This decrease was offset by a $0.183 million decrease in OPEB costs directly charged to capital or other income deduction accounts (i.e. below the line).

Attachment 3 - Revenue Credit Workpaper

17b	Costs associated with revenues in line 17a	$	271,564
	Revenue Subject to 50/50 sharing (Attachment 3 - line 17a)	$	966,076
	Federal Income Tax Rate		21.00%
	Federal Tax on Revenue subject to 50/50 sharing		202,876
	Net Revenue subject to 50/50 sharing		763,200
	Composite State Income Tax Rate		9.000%
	State Tax on Revenue subject to 50/50 sharing		68,688
	Total Tax on Revenue subject to 50/50 sharing	$	271,564

Atlantic City Electric Company

Attachment 5a - Allocations of Costs to Affiliate

	Delmarva Power	Atlantic City	Pepco	Non - Regulated	Total
Executive Management	6,721,922	6,040,279	11,559,004	2,731,918	27,053,123
Procurement & Administrative Services	5,753,548	4,160,116	8,276,756	3,721,474	21,911,894
Financial Services & Corporate Expenses	16,768,656	13,558,856	23,867,875	15,207,024	69,402,411
Insurance Coverage and Services	292,642	563,869	(390,363)	(5,012)	461,136
Human Resources	(1,116,564)	(1,258,037)	(540,100)	5,485,522	2,570,821
Legal Services	2,170,665	1,000,599	4,150,743	6,816,457	14,138,464
Customer Services	52,746,755	47,419,527	45,717,038	2,626	145,885,946
Information Technology	17,257,383	13,248,946	32,727,761	10,871,056	74,105,146
External Affairs	3,411,728	2,935,223	5,190,824	626,833	12,164,608
Environmental Services	2,358,711	2,065,133	2,509,472	346	6,933,662
Safety Services	481,504	493,828	775,837		1,751,169
Regulated Electric & Gas T&D	44,391,825	35,785,749	58,175,755	2,973,981	141,327,310
Internal Consulting Services	241,911	194,452	414,624		850,987
Interns	174,619	133,726	128,150		436,495
Cost of Benefits	13,261,385	8,972,178	22,145,832		44,379,395
Building Services	146,800	96,476	4,309,323	849,170	5,401,769
Total	**$ 165,063,490**	**$ 135,410,920**	**$ 219,018,531**	**$ 49,281,395**	**$ 568,774,336**

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
PHI Service Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2017

Schedule XVII - Analysis of Billing – Associate Companies (Account 457)

1. For services rendered to associate companies (Account 457), list all of the associate companies.

Line No.	Name of Associate Company (a)	Account 457.1 Direct Costs Charged (b)	Account 457.2 Indirect Costs Charged (c)	Account 457.3 Compensation For Use of Capital (d)	Total Amount Billed (e)
1	Potomac Electric Company	54,658,874	164,339,096	20,561	219,018,531
2	Delmarva Power & Light Company	43,878,996	121,169,503	14,991	165,063,490
3	Atlantic City Electric Company	29,283,609	106,115,313	11,998	135,410,920
4	Exelon Business Services Company, LLC	47,134,513			47,134,513
5	Pepco Energy Services, Inc	415,765	1,111,189		1,526,954
6	Pepco Holdings LLC	45,859	490,907	268	537,034
7	Atlantic Southern Properties, Inc	2,419	39,576		41,995
8	Conectiv Properties & Investments, Inc	250	29,336		29,586
9	Atlantic City Electric Transition Funding, LLC	2,895	2,847	4	5,746
10	Conectiv Holding Company, Inc.	3,279			3,279
11	Potomac Capital Investments Corporation	1,623	255		1,878
12	Conectiv Thermal Systems, Inc.		410		410
13					
14					
15					
16					
17					
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29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	Total	175,428,082	393,298,432	47,822	568,774,336

Service Company Billing Analysis by Utility FERC Account
YTD Dec 2017
Total PHI

FERC Accounts	FERC Account Name	DPL	ACE	PEPCO	Non-Utility	Total	Inclusion in ATRR
107	Constr Work In Progress	26,393,027	20,238,001	36,545,201	-	83,176,229	Not included
182.3	Other Regulatory Assets	2,372,237	217,458	7,097,229	-	9,686,924	Not included
184	Clearing Accounts - Other	290,866	240,842	743,443	(623,559)	651,592	Not included
408.1	Taxes other than inc taxes, utility operating inc	1,821	705	1,742	-	4,268	Wage & Salary Factor
416-421.2	Other Income -Below the Line	791,529	668,026	953,108	49,904,954	52,317,617	Not included
426.1-426.5	Other Income Deductions - Below the Line	793,436	612,278	1,127,607	-	2,533,321	Not included
430	Interest-Debt to Associated Companies	33,667	27,028	45,561	-	106,256	Not included
431	Interest-Short Term Debt	(16,005)	(12,879)	(21,440)	-	(50,324)	Not included
556	System cont & load dispatch	1,762,459	1,397,736	1,967,404	-	5,127,599	Not included
557	Other expenses	1,289,456	1,123,936	1,209,338	-	3,622,730	Not included
560	Operation Supervision & Engineering	3,383,115	3,135,496	4,630,184	-	11,148,795	100% included
561.1	Load Dispatching - Reliability	14,659	9,981	-	-	24,640	100% included
561.2	Load Dispatch - Monitor & Operate Transmission Sys	67,228	19,453	727,609	-	814,290	100% included
561.3	Load Dispatch - Transmission Service & Scheduling	33,317	44,911	29,401	-	107,629	100% included
561.5	Reliability, Planning and Standards	348,426	219,013	131,562	-	699,001	100% included
563	Overhead line expenses	-	-	225	-	225	100% included
562	Station expenses	-	-	6,587	-	6,587	100% included
564	Underground Line Expenses - Transmission	-	-	525	-	525	100% included
566	Miscellaneous transmission expenses	964,413	829,555	916,409	-	2,710,377	100% included
568	Maintenance Supervision & Engineering	131,952	100,446	465,203	-	697,601	100% included
569	Maint of structures	6,463	6,993	7,169	-	20,625	100% included
569.2	Maintenance of Computer Software	646,321	311,341	457,266	-	1,414,928	100% included
569.4	Maintenance of Transmission Plant	-	-	4	-	4	100% included
570	Maintenance of station equipment	177,361	64,923	367,252	-	609,536	100% included
571	Maintenance of overhead lines	393,340	286,999	590,906	-	1,271,245	100% included
572	Maintenance of underground lines	194	172	1,137	-	1,503	100% included
573	Maintenance of miscellaneous transmission plant	15,358	28,110	145,477	-	188,945	100% included
575.5	Ancillary services market administration	-	-	8,945	-	8,945	Not included
580	Operation Supervision & Engineering	1,205,549	900,876	1,342,800	-	3,449,225	Not included
581	Load dispatching	1,088,271	408,220	1,622,032	-	3,118,523	Not included
582	Station expenses	519,935	-	127,953	-	647,888	Not included
583	Overhead line expenses	79,339	179,386	37,971	-	296,696	Not included
584	Underground line expenses	35,984	-	181,498	-	217,482	Not included
585	Street lighting	1,575	-	27	-	1,602	Not included
586	Meter expenses	709,279	447,257	1,114,080	-	2,270,616	Not included
587	Customer installations expenses	345,833	349,544	1,003,345	-	1,698,722	Not included
588	Miscellaneous distribution expenses	3,807,435	4,244,289	6,809,195	-	14,860,919	Not included
589	Rents	80,562	409	77,296	-	158,267	Not included
590	Maintenance Supervision & Engineering	948,744	573,387	499,410	-	2,021,541	Not included
591	Maintain structures	7,013	6,792	6,974	-	20,779	Not included
592	Maintain equipment	353,360	427,768	916,673	-	1,697,801	Not included
593	Maintain overhead lines	1,754,068	1,231,469	1,850,015	-	4,835,552	Not included
594	Maintain underground line	129,627	69,299	728,487	-	927,413	Not included
595	Maintain line transformers	2,257	-	150,585	-	152,842	Not included
596	Maintain street lighting & signal systems	41,343	36,511	6,306	-	84,160	Not included
597	Maintain meters	164,705	34,459	132,584	-	331,748	Not included
598	Maintain distribution plant	44,155	20,222	574,205	-	638,582	Not included
800-894	Total Gas Accounts	2,355,199	-	-	-	2,355,199	Not included
902	Meter reading expenses	144,273	36,799	129,651	-	310,723	Not included
903	Customer records and collection expenses	50,866,226	47,660,833	48,331,246	-	146,858,305	Not included
907	Supervision - Customer Svc & Information	88	156,520	42,124	-	198,732	Not included
908	Customer assistance expenses	1,897,100	652,072	545,344	-	3,094,516	Not included
909	Informational & instructional advertising	524,046	539,891	834,890	-	1,898,827	Not included
912	Demonstrating and selling expense	161,461	-	-	-	161,461	Not included
913	Advertising expense	40,738	-	-	-	40,738	Not included
920	Administrative & General salaries	339,115	100,744	689,110	-	1,128,969	Wage & Salary Factor
921	Office supplies & expenses	240	712	361	-	1,313	Wage & Salary Factor
923	Outside services employed	46,996,640	42,150,533	75,985,080	-	165,132,253	Wage & Salary Factor
924	Property insurance	113	91	154	-	358	Net Plant Factor
926	Employee pensions & benefits	7,809,871	4,323,683	12,245,344	-	24,378,898	Wage & Salary Factor
928	Regulatory commission expenses	1,470,858	492,412	2,686,522	-	4,649,792	Direct Transmission Only
929	Duplicate charges-Credit	422,348	150,426	1,117,064	-	1,689,838	Wage & Salary Factor
930.1	General ad expenses	208	186	356	-	750	Direct Transmission Only
930.2	Miscellaneous general expenses	518,497	510,021	999,424	-	2,027,942	Wage & Salary Factor
935	Maintenance of general plant	302,795	135,585	75,371	-	513,751	Wage & Salary Factor
	Total	**165,063,490**	**135,410,920**	**219,018,531**	**49,281,395**	**568,774,336**	

Atlantic City Electric Company

Attachment 6 - Estimate and Reconciliation Worksheet

Step	Month	Year	Action
Exec Summary			
1	April	Year 2	TO populates the formula with Year 1 data from FERC Form 1 data for Year 1 (e.g., 2004)
2	April	Year 2	TO estimates all transmission Cap Adds and CWIP for Year 2 weighted based on Months expected to be in service in Year 2 (e.g., 2005)
3	April	Year 2	TO adds weighted Cap Adds to plant in service in Formula
4	May	Year 2	Post results of Step 3 on PJM web site
5	June	Year 2	Results of Step 3 go into effect for the Rate Year 1 (e.g., June 1, 2005 - May 31, 2006)
6	April	Year 3	TO populates the formula with Year 2 data from FERC Form 1 for Year 2 (e.g., 2005)
7	April	Year 3	Reconciliation - TO calculates Reconciliation by removing from Year 2 data - the total Cap Adds placed in service in Year 2 and adding weighted average in Year 2 actual Cap Adds and CWIP in Reconciliation (adjusted to include any Reconciliation amount from prior year)
8	April	Year 3	TO estimates Cap Adds and CWIP during Year 3 weighted based on Months expected to be in service in Year 3 (e.g., 2006)
9	April	Year 3	Reconciliation - TO adds the difference between the Reconciliation in Step 7 and the forecast in Line 5 with interest to the result of Step 7 (this difference is also added to Step 8 in the subsequent year)
10	May	Year 3	Post results of Step 9 on PJM web site
11	June	Year 3	Results of Step 9 go into effect for the Rate Year 2 (e.g., June 1, 2006 - May 31, 2007)

1 April Year 2 TO populates the formula with Year 1 data from FERC Form 1 data for Year 1 (e.g., 2004)

134,969,330 Rev Req based on Year 1 data — Must run Appendix A to get this number (without inputs in lines 20, 21 or 43a of Appendix A)

2 April Year 2 TO estimates all transmission Cap Adds and CWIP for Year 2 weighted based on Months expected to be in service in Year 2 (e.g., 2005)

	(A) Monthly Additions Other Plant In Service	(B) Monthly Additions Other Plant In Service	(C) Monthly Additions MAPP CWIP	(D) Monthly Additions MAPP In Service	(E) Weighting	(F) Other Plant In Service Amount (A x E)	(G) Other Plant In Service Amount (B x E)	(H) MAPP CWIP Amount (C x E)	(I) MAPP In Service Amount (D x E)	(J) Other Plant In Service (F / 12)	(K) Other Plant In Service (G / 12)	(L) MAPP CWIP (H / 12)	(M) MAPP In Service (I / 12)	
Jan					11.5	-	-	-	-	-	-	-	-	
Feb					10.5	-	-	-	-	-	-	-	-	
Mar	6,321,892				9.5	60,057,974	-	-	-	5,004,831	-	-	-	
Apr	4,268,041				8.5	36,278,349	-	-	-	3,023,196	-	-	-	
May					7.5	-	-	-	-	-	-	-	-	
Jun	11,688,559				6.5	75,975,634	-	-	-	6,331,303	-	-	-	
Jul					5.5	-	-	-	-	-	-	-	-	
Aug					4.5	-	-	-	-	-	-	-	-	
Sep					3.5	-	-	-	-	-	-	-	-	
Oct					2.5	-	-	-	-	-	-	-	-	
Nov					1.5	-	-	-	-	-	-	-	-	
Dec					0.5	-	-	-	-	-	-	-	-	
Total	22,278,492	-	-	-		172,311,956	-	-	-	14,359,330	-	-	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										14,359,330	-	-	-	
								Input to Line 21 of Appendix A		14,359,330	-		-	14,359,330
								Input to Line 43a of Appendix A				-		-
								Month In Service or Month for CWIP		4.27	#DIV/0!	#DIV/0!	#DIV/0!	

3 April Year 2 TO adds weighted Cap Adds to plant in service in Formula

$ 14,359,330 Input to Formula Line 21

4 May Year 2 Post results of Step 3 on PJM web site

136,237,027 — Must run Appendix A to get this number (with inputs on lines 21 and 43a of Attachment A)

5 June Year 2 Results of Step 3 go into effect for the Rate Year 1 (e.g., June 1, 2005 - May 31, 2006)

$ 136,237,027

6 April Year 3 TO populates the formula with Year 2 data from FERC Form 1 for Year 2 (e.g., 2005)

139,451,889 Rev Req based on Prior Year data — Must run Appendix A to get this number (without inputs in lines 20, 21 or 43a of Appendix A)

7 April Year 3 Reconciliation - TO calculates Reconciliation by removing from Year 2 data - the total Cap Adds placed in service in Year 2 and adding weighted average in Year 2 actual Cap Adds and CWIP in Reconciliation
(adjusted to include any Reconciliation amount from prior year)

Remove all Cap Adds placed in service in Year 2
For Reconciliation only - remove actual New Transmission Plant Additions for Year 2 $ 165,916,002 Input to Formula Line 20

Add weighted Cap Adds actually placed in service in Year 2

	(A) Monthly Additions Other Plant In Service	(B) Monthly Additions Other Plant In Service	(C) Monthly Additions MAPP CWIP	(D) Monthly Additions MAPP In Service	(E) Weighting	(F) Other Plant In Service Amount (A x E)	(G) Other Plant In Service Amount (B x E)	(H) MAPP CWIP Amount (C x E)	(I) MAPP In Service Amount (D x E)	(J) Other Plant In Service (F / 12)	(K) Other Plant In Service (G / 12)	(L) MAPP CWIP (H / 12)	(M) MAPP In Service (I / 12)	
Jan	511,099				11.5	5,877,635	-	-	-	489,803	-	-	-	
Feb	23,017,869				10.5	241,687,625	-	-	-	20,140,635	-	-	-	
Mar	12,390,468				9.5	117,709,450	-	-	-	9,809,121	-	-	-	
Apr	3,126,413				8.5	26,574,509	-	-	-	2,214,542	-	-	-	
May	43,195,708				7.5	323,967,808	-	-	-	26,997,317	-	-	-	
Jun	19,857,062				6.5	129,070,901	-	-	-	10,755,908	-	-	-	
Jul	1,066,553				5.5	5,866,044	-	-	-	488,837	-	-	-	
Aug	(1,192,298)				4.5	(5,365,340)	-	-	-	(447,112)	-	-	-	
Sep	16,096,775				3.5	56,338,711	-	-	-	4,694,893	-	-	-	
Oct	21,329,923				2.5	53,324,807	-	-	-	4,443,734	-	-	-	
Nov	1,960,383				1.5	2,940,575	-	-	-	245,048	-	-	-	
Dec	24,556,048				0.5	12,278,024	-	-	-	1,023,169	-	-	-	
Total	165,916,002	-	-	-		970,270,749	-	-	-	80,855,896	-	-	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										80,855,896	-	-	-	
								Input to Line 21 of Appendix A		80,855,896	-		-	80,855,896
								Input to Line 43a of Appendix A				-		-
								Month In Service or Month for CWIP		6.15	#DIV/0!	#DIV/0!	#DIV/0!	

131,992,058 Result of Formula for Reconciliation Must run Appendix A with cap adds in line 21 & line 20
(Year 2 data with total of Year 2 Cap Adds removed and monthly weighted average of Year 2 actual Cap Adds added in)

8 April Year 3 TO estimates Cap Adds and CWIP during Year 3 weighted based on Months expected to be in service in Year 3 (e.g., 2006)

	(A) Monthly Additions Other Plant In Service	(B) Monthly Additions Other Plant In Service	(C) Monthly Additions MAPP CWIP	(D) Monthly Additions MAPP In Service	(E) Weighting	(F) Other Plant In Service Amount (A x E)	(G) Other Plant In Service Amount (B x E)	(H) MAPP CWIP Amount (C x E)	(I) MAPP In Service Amount (D x E)	(J) Other Plant In Service (F / 12)	(K) Other Plant In Service (G / 12)	(L) MAPP CWIP (H / 12)	(M) MAPP In Service (I / 12)	
Jan					11.5	-	-	-	-	-	-	-	-	
Feb					10.5	-	-	-	-	-	-	-	-	
Mar	-				9.5	-	-	-	-	-	-	-	-	
Apr	-				8.5	-	-	-	-	-	-	-	-	
May					7.5	-	-	-	-	-	-	-	-	
Jun	-				6.5	-	-	-	-	-	-	-	-	
Jul					5.5	-	-	-	-	-	-	-	-	
Aug					4.5	-	-	-	-	-	-	-	-	
Sep					3.5	-	-	-	-	-	-	-	-	
Oct					2.5	-	-	-	-	-	-	-	-	
Nov					1.5	-	-	-	-	-	-	-	-	
Dec					0.5	-	-	-	-	-	-	-	-	
Total	-	-	-	-		-	-	-	-	-	-	-	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										-	-	-	-	
128,106,367								Input to Line 21 of Appendix A		-	-		-	-
								Input to Line 43a of Appendix A				-		-
								Month In Service or Month for CWIP		#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	

9 April Year 3 Reconciliation - TO adds the difference between the Reconciliation in Step 7 and the forecast in Line 5 with interest to the result of Step 7 (this difference is also added to Step 8 in the subsequent year)

The Reconciliation in Step 7		The forecast in Prior Year		
131,992,058	-	123,838,425	=	8,153,633

Interest on Amount of Refunds or Surcharges

Interest rate pursuant to 35.19a for March c 0.3600%

Month	Yr	1/12 of Step 9	Interest rate for March of the Current Yr	Months	Interest	Surcharge (Refund) Owed
Jun	Year 1	679,469	0.3600%	11.5	28,130	707,599
Jul	Year 1	679,469	0.3600%	10.5	25,684	705,153
Aug	Year 1	679,469	0.3600%	9.5	23,238	702,707
Sep	Year 1	679,469	0.3600%	8.5	20,792	700,261
Oct	Year 1	679,469	0.3600%	7.5	18,346	697,815
Nov	Year 1	679,469	0.3600%	6.5	15,900	695,369
Dec	Year 1	679,469	0.3600%	5.5	13,453	692,923
Jan	Year 2	679,469	0.3600%	4.5	11,007	690,477
Feb	Year 2	679,469	0.3600%	3.5	8,561	688,031
Mar	Year 2	679,469	0.3600%	2.5	6,115	685,585
Apr	Year 2	679,469	0.3600%	1.5	3,669	683,139
May	Year 2	679,469	0.3600%	0.5	1,223	680,692
Total		8,153,633				8,329,752

		Balance	Interest rate from above	Amortization over Rate Year	Balance
Jun	Year 2	8,329,752	0.3600%	710,496	7,649,243
Jul	Year 2	7,649,243	0.3600%	710,496	6,966,284
Aug	Year 2	6,966,284	0.3600%	710,496	6,280,867
Sep	Year 2	6,280,867	0.3600%	710,496	5,592,982
Oct	Year 2	5,592,982	0.3600%	710,496	4,902,621
Nov	Year 2	4,902,621	0.3600%	710,496	4,209,774
Dec	Year 2	4,209,774	0.3600%	710,496	3,514,433
Jan	Year 3	3,514,433	0.3600%	710,496	2,816,589
Feb	Year 3	2,816,589	0.3600%	710,496	2,116,233
Mar	Year 3	2,116,233	0.3600%	710,496	1,413,355
Apr	Year 3	1,413,355	0.3600%	710,496	707,947
May	Year 3	707,947	0.3600%	710,496	(0)
Total with interest				8,525,952	

The difference between the Reconciliation in Step 7 and the forecast in Prior Year with interest	8,525,952
Rev Req based on Year 2 data with estimated Cap Adds and CWIP for Year 3 (Step 8)	$ 128,106,367
Revenue Requirement for Year 3	136,632,319

10 May Year 3 ılts of Step 9 on PJM web site

$ 136,632,319

11 June Year 3 r the Rate Year 2 (e.g., June 1, 2006 - May 31, 2007)

$ 136,632,319

Atlantic City Electric Company

Attachment 7 - Transmission Enhancement Charge Worksheet

1 New Plant Carrying Charge

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

Line		Formula Line		
3		Formula Line		
4	A	160	Net Plant Carrying Charge without Depreciation	9.5384%
5	B	167	Net Plant Carrying Charge per 100 Basis Point increase in ROE without Depreciation	10.0212%
6	C		Line B less Line A	0.4828%

7 **FCR if a CIAC**

Line		Formula Line		
8	D	161	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	2.5613%

9 **The FCR resulting from Formula in a given year is used for that year only.**
10 **Therefore actual revenues collected in a year do not change based on cost data for subsequent years**

11 **The ROE is 10.5% which includes a base ROE of 10.0% ROE per FERC order in Docket No. EL13-48 and a 50 basis point RTO membership adder as authorized by FERC: provided, that the projects ic**

Line		Details		B0265 Mickelton		B0276 Monroe	B0211 Union-Corson
12	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes		Yes	Yes
13	Useful life of project	Life		35		35	35
14	"Yes" if the customer has paid a lump sum payment in the amount of the investment on line 18, Otherwise "No"	CIAC	(Yes or No)	No		No	No
15	Input the allowed ROE Incentive	Increased ROE (Basis Points)		150		0	0
16	From line 4 above if "No" on line 14 and From line 8 above if "Yes" on line 14	Base FCR		9.5384%		9.5384%	9.5384%
17	Line 6 times line 15 divided by 100 basis points	FCR for This Project		10.2626%		9.5384%	9.5384%
18	Columns A, B or C from Attachment 6	Investment		4,854,660	may be weighted average of small projects	7,878,071	13,722,120
19	Line 18 divided by line 13	Annual Depreciation Exp		138,705		225,088	392,061
20	From Columns H, I or J from Attachment 6	Month In Service or Month for CWIP		6.00		6.00	9.00

Line		Invest Yr	Mickelton Beginning	Depreciation	Ending	Revenue	Monroe Beginning	Depreciation	Ending	Revenue	Union-Corson Beginning	Depreciation	Ending	Revenue
41	Base FCR	2018	3,675,671	138,705	3,536,967	476,075	5,964,825	225,088	5,739,737	772,567	10,095,560	392,061	9,703,499	1,317,619
42	W Increased ROE	2018	3,675,671	138,705	3,536,967	501,690	5,964,825	225,088	5,739,737	772,567	10,095,560	392,061	9,703,499	1,317,619
43	Base FCR	2019	3,536,967	138,705	3,398,262	462,844	5,739,737	225,088	5,514,650	751,097	9,703,499	392,061	9,311,439	1,280,223
44	W Increased ROE	2019	3,536,967	138,705	3,398,262	487,455	5,739,737	225,088	5,514,650	751,097	9,703,499	392,061	9,311,439	1,280,223
45	Base FCR	2020	3,398,262	138,705	3,259,557	449,614	5,514,650	225,088	5,289,562	729,627	9,311,439	392,061	8,919,378	1,242,827
46	W Increased ROE	2020	3,398,262	138,705	3,259,557	473,220	5,514,650	225,088	5,289,562	729,627	9,311,439	392,061	8,919,378	1,242,827
47	Base FCR	2021	3,259,557	138,705	3,120,853	436,384	5,289,562	225,088	5,064,474	708,158	8,919,378	392,061	8,527,317	1,205,430
48	W Increased ROE	2021	3,259,557	138,705	3,120,853	458,986	5,289,562	225,088	5,064,474	708,158	8,919,378	392,061	8,527,317	1,205,430
49	Base FCR	2022	3,120,853	138,705	2,982,148	423,154	5,064,474	225,088	4,839,386	686,688	8,527,317	392,061	8,135,257	1,168,034
50	W Increased ROE	2022	3,120,853	138,705	2,982,148	444,751	5,064,474	225,088	4,839,386	686,688	8,527,317	392,061	8,135,257	1,168,034
51	Base FCR	2023	2,982,148	138,705	2,843,444	409,924	4,839,386	225,088	4,614,299	665,218	8,135,257	392,061	7,743,196	1,130,638
52	W Increased ROE	2023	2,982,148	138,705	2,843,444	430,516	4,839,386	225,088	4,614,299	665,218	8,135,257	392,061	7,743,196	1,130,638
53	Base FCR	2024	2,843,444	138,705	2,704,739	396,693	4,614,299	225,088	4,389,211	643,748	7,743,196	392,061	7,351,136	1,093,241
54	W Increased ROE	2024	2,843,444	138,705	2,704,739	416,281	4,614,299	225,088	4,389,211	643,748	7,743,196	392,061	7,351,136	1,093,241
55	Base FCR	2025	2,704,739	138,705	2,566,035	383,463	4,389,211	225,088	4,164,123	622,279	7,351,136	392,061	6,959,075	1,055,845
56	W Increased ROE	2025	2,704,739	138,705	2,566,035	402,047	4,389,211	225,088	4,164,123	622,279	7,351,136	392,061	6,959,075	1,055,845
57	Base FCR	2026	2,566,035	138,705	2,427,330	370,233	4,164,123	225,088	3,939,035	600,809	6,959,075	392,061	6,567,015	1,018,449
58	W Increased ROE	2026	2,566,035	138,705	2,427,330	387,812	4,164,123	225,088	3,939,035	600,809	6,959,075	392,061	6,567,015	1,018,449
59	Base FCR	2027	2,427,330	138,705	2,288,625	357,003	3,939,035	225,088	3,713,948	579,339	6,567,015	392,061	6,174,954	981,052
60	W Increased ROE	2027		138,705	(138,705)	124,470	3,939,035	225,088	3,713,948	579,339	6,567,015	392,061	6,174,954	981,052
61		....		....	.....	....	....	....	.....	....	....	....	.....	....
62		....	....	.....	.....	....	....	.....	.....	....	....	.....	.....	....
63														

dentified in Docket Nos. ER08-686 and ER08-1423 have been awarded an additional 150 basis point adder and, thus, their ROE is 12.0%.

B0210 Orchard-500kV	B0210 Orchard-Below 500kV	B0277 Cumberland Sub:2nd Xfmr	B1398.5 Reconductor Mickleton - Depford - 230 Kv line
Yes	Yes	No	Yes
35	35	35	35
No	No	No	No
150	150	150	0
9.5384%	9.5384%	9.5384%	9.5384%
10.2626%	10.2626%	10.2626%	9.5384%
26,046,638	18,572,212	6,759,777	4,045,398
744,190	530,635	193,136	115,583
7.00	7	2	5

B0210 Orchard-500kV

Beginning	Depreciation	Ending	Revenue
19,038,852	744,190	18,294,662	2,489,208
19,038,852	744,190	18,294,662	2,621,699
18,294,662	744,190	17,550,473	2,418,224
18,294,662	744,190	17,550,473	2,545,326
17,550,473	744,190	16,806,283	2,347,240
17,550,473	744,190	16,806,283	2,468,953
16,806,283	744,190	16,062,093	2,276,257
16,806,283	744,190	16,062,093	2,392,580
16,062,093	744,190	15,317,904	2,205,273
16,062,093	744,190	15,317,904	2,316,206
15,317,904	744,190	14,573,714	2,134,289
15,317,904	744,190	14,573,714	2,239,833
14,573,714	744,190	13,829,524	2,063,305
14,573,714	744,190	13,829,524	2,163,460
13,829,524	744,190	13,085,335	1,992,321
13,829,524	744,190	13,085,335	2,087,086
13,085,335	744,190	12,341,145	1,921,338
13,085,335	744,190	12,341,145	2,010,713
12,341,145	744,190	11,596,955	1,850,354
12,341,145	744,190	11,596,955	1,934,340
....	....	.....	....
....	.....	.....	....

B0210 Orchard-Below 500kV

Beginning	Depreciation	Ending	Revenue
13,575,403	530,635	13,044,768	1,774,897
13,575,403	530,635	13,044,768	1,869,368
13,044,768	530,635	12,514,133	1,724,283
13,044,768	530,635	12,514,133	1,814,911
12,514,133	530,635	11,983,499	1,673,669
12,514,133	530,635	11,983,499	1,760,454
11,983,499	530,635	11,452,864	1,623,055
11,983,499	530,635	11,452,864	1,705,997
11,452,864	530,635	10,922,229	1,572,441
11,452,864	530,635	10,922,229	1,651,540
10,922,229	530,635	10,391,595	1,521,827
10,922,229	530,635	10,391,595	1,597,083
10,391,595	530,635	9,860,960	1,471,213
10,391,595	530,635	9,860,960	1,542,626
9,860,960	530,635	9,330,326	1,420,598
9,860,960	530,635	9,330,326	1,488,169
9,330,326	530,635	8,799,691	1,369,984
9,330,326	530,635	8,799,691	1,433,713
8,799,691	530,635	8,269,056	1,319,370
8,799,691	530,635	8,269,056	1,379,256
....	....	.....	....
....	.....	.....	....

B0277 Cumberland Sub:2nd Xfmr

Beginning	Depreciation	Ending	Revenue
5,246,875	193,136	5,053,738	675,182
5,246,875	193,136	5,053,738	711,782
5,053,738	193,136	4,860,602	656,760
5,053,738	193,136	4,860,602	691,961
4,860,602	193,136	4,667,465	638,338
4,860,602	193,136	4,667,465	672,140
4,667,465	193,136	4,474,329	619,916
4,667,465	193,136	4,474,329	652,319
4,474,329	193,136	4,281,192	601,494
4,474,329	193,136	4,281,192	632,499
4,281,192	193,136	4,088,056	583,072
4,281,192	193,136	4,088,056	612,678
4,088,056	193,136	3,894,919	564,649
4,088,056	193,136	3,894,919	592,857
3,894,919	193,136	3,701,783	546,227
3,894,919	193,136	3,701,783	573,036
3,701,783	193,136	3,508,646	527,805
3,701,783	193,136	3,508,646	553,215
3,508,646	193,136	3,315,510	509,383
3,508,646	193,136	3,315,510	533,394
....	....	.....	....
....	.....	.....	....

B1398.5 Reconductor Mickleton - Depford - 230 Kv line

Beginning	Depreciation	Ending	Revenue
3,827,154	115,583	3,711,571	469,607
3,827,154	115,583	3,711,571	469,607
3,711,571	115,583	3,595,988	458,583
3,711,571	115,583	3,595,988	458,583
3,595,988	115,583	3,480,405	447,558
3,595,988	115,583	3,480,405	447,558
3,480,405	115,583	3,364,823	436,533
3,480,405	115,583	3,364,823	436,533
3,364,823	115,583	3,249,240	425,508
3,364,823	115,583	3,249,240	425,508
3,249,240	115,583	3,133,657	414,484
3,249,240	115,583	3,133,657	414,484
3,133,657	115,583	3,018,074	403,459
3,133,657	115,583	3,018,074	403,459
3,018,074	115,583	2,902,491	392,434
3,018,074	115,583	2,902,491	392,434
2,902,491	115,583	2,786,909	381,409
2,902,491	115,583	2,786,909	381,409
2,786,909	115,583	2,671,326	370,385
2,786,909	115,583	2,671,326	370,385
....	....	.....	....
....	.....	.....	....

Attachment 11

B1398.3.1 Mickleton Deptford 230kv terminal	B1600 Upgrade Mill T2 138/69 kV Transformer
Yes	Yes
35	35
No	No
0	0
9.5384%	9.5384%
9.5384%	9.5384%
13,176,210	14,841,978
376,463	424,057
5	6

Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Total	Incentive Charged	Revenue Credit
11,828,392	376,463	11,451,929	1,468,794	14,223,334	424,057	13,799,277	1,740,287	$ 11,184,236		$ 11,184,236
11,828,392	376,463	11,451,929	1,468,794	14,223,334	424,057	13,799,277	1,740,287	$ 11,473,413	$ 11,473,413	
11,451,929	376,463	11,075,466	1,432,885	13,799,277	424,057	13,375,221	1,699,839	$ 10,884,738		$ 10,884,738
11,451,929	376,463	11,075,466	1,432,885	13,799,277	424,057	13,375,221	1,699,839	$ 11,162,280	$ 11,162,280	
11,075,466	376,463	10,699,003	1,396,977	13,375,221	424,057	12,951,164	1,659,390	$ 10,585,241		$ 10,585,241
11,075,466	376,463	10,699,003	1,396,977	13,375,221	424,057	12,951,164	1,659,390	$ 10,851,147	$ 10,851,147	
10,699,003	376,463	10,322,539	1,361,068	12,951,164	424,057	12,527,107	1,618,942	$ 10,285,743		$ 10,285,743
10,699,003	376,463	10,322,539	1,361,068	12,951,164	424,057	12,527,107	1,618,942	$ 10,540,013	$ 10,540,013	
10,322,539	376,463	9,946,076	1,325,160	12,527,107	424,057	12,103,051	1,578,494	$ 9,986,245		$ 9,986,245
10,322,539	376,463	9,946,076	1,325,160	12,527,107	424,057	12,103,051	1,578,494	$ 10,228,880	$ 10,228,880	
9,946,076	376,463	9,569,613	1,289,251	12,103,051	424,057	11,678,994	1,538,046	$ 9,686,747		$ 9,686,747
9,946,076	376,463	9,569,613	1,289,251	12,103,051	424,057	11,678,994	1,538,046	$ 9,917,746	$ 9,917,746	
9,569,613	376,463	9,193,150	1,253,343	11,678,994	424,057	11,254,938	1,497,598	$ 9,387,249		$ 9,387,249
9,569,613	376,463	9,193,150	1,253,343	11,678,994	424,057	11,254,938	1,497,598	$ 9,606,613	$ 9,606,613	
9,193,150	376,463	8,816,687	1,217,434	11,254,938	424,057	10,830,881	1,457,149	$ 9,087,752		$ 9,087,752
9,193,150	376,463	8,816,687	1,217,434	11,254,938	424,057	10,830,881	1,457,149	$ 9,295,480	$ 9,295,480	
8,816,687	376,463	8,440,224	1,181,526	10,830,881	424,057	10,406,825	1,416,701	$ 8,788,254		$ 8,788,254
8,816,687	376,463	8,440,224	1,181,526	10,830,881	424,057	10,406,825	1,416,701	$ 8,984,346	$ 8,984,346	
8,440,224	376,463	8,063,761	1,145,617	10,406,825	424,057	9,982,768	1,376,253	$ 8,488,756		$ 8,488,756
8,440,224	376,463	8,063,761	1,145,617	10,406,825	424,057	9,982,768	1,376,253	$ 8,424,106	$ 8,424,106	
....	....	.....	....	....	....	.....	....			$ -
....	.....	.....	....	....	.....	.....	....		$ -	
									$ 207,459,487	$ 201,047,950

Atlantic City Electric Company

Attachment 8 - Company Exhibit - Securitization Workpaper

Line #		
	Long Term Interest	
101	**Less LTD Interest on Securitization Bonds**	5,670,914
	Capitalization	
112	**Less LTD on Securitization Bonds**	40,506,230

Calculation of the above Securitization Adjustments

Inputs from Atlantic City Electric Company 2017 FERC Form 1
Pages 256-257 "Long Term Debt (Account 221, 222, 223, and 224)"
Line 17 "Note Payable to ACE Transition Funding - variable"
LTD Interest on Securitization Bonds in column (i)
LTD on Securitization Bonds in column (h)

Exhibit B

Tariff Sheets

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV Revised Sheet Replaces Revised Sheet No. 5

RATE SCHEDULE RS
(Residential Service)

AVAILABILITY
Available for full domestic service to individually metered residential customers, including rural domestic customers, engaged principally in agricultural pursuits.

	SUMMER June Through September	WINTER October Through May
Delivery Service Charges:		
Customer Charge ($/Month)	$4.83	$4.83
Distribution Rates ($/kWH)		
First Block	$0.055619	$0.051319
(Summer <= 750 kWh; Winter<= 500kWh)		
Excess kWh	$0.063942	$0.051319
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC	
Societal Benefits Charge ($/kWh)		
Clean Energy Program	See Rider SBC	
Universal Service Fund	See Rider SBC	
Lifeline	See Rider SBC	
Uncollectible Accounts	See Rider SBC	
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC	
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC	
Transmission Service Charges ($/kWh):		
Transmission Rate	$0.020355	$0.020355
Reliability Must Run Transmission Surcharge	$0.003737	$0.003737
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI	

CORPORATE BUSINESS TAX (CBT)
Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)
Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

Date of Issue: **Effective Date:**

Issued by:

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

RATE SCHEDULE MGS-SECONDARY
(Monthly General Service)

AVAILABILITY

Available at any point within the Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer delivered at one point and metered at or compensated to the voltage of delivery. This schedule is not available to residential customers.

	SUMMER	WINTER
	June Through September	October Through May
Delivery Service Charges:		
Customer Charge		
Single Phase	$8.35	$8.35
Three Phase	$9.72	$9.72
Distribution Demand Charge (per kW)	$2.07	$1.70
Reactive Demand Charge	$0.48	$0.48
(For each kvar over one-third of kW demand**)**		
Distribution Rates ($/kWh)	$0.049365	$0.044591
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC	
Societal Benefits Charge ($/kWh)		
Clean Energy Program	See Rider SBC	
Universal Service Fund	See Rider SBC	
Lifeline	See Rider SBC	
Uncollectible Accounts	See Rider SBC	
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC	
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC	
CIEP Standby Fee ($/kWh)	See Rider BGS	
Transmission Demand Charge ($/kW for each kW in excess of 3 kW)	$3.43	$3.05
Reliability Must Run Transmission Surcharge ($/kWh)	$0.003737	$0.003737
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI	

The minimum monthly bill will be $8.35 per month plus any applicable adjustment.

Date of Issue: **Effective Date:**

Issued by:

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV Revised Sheet Replaces Revised Sheet No. 14

RATE SCHEDULE MGS-PRIMARY
(Monthly General Service)

AVAILABILITY

Available at any point within the Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer delivered at one point and metered at or compensated to the voltage of delivery. This schedule is not available to residential customers.

	SUMMER	**WINTER**
	June Through September	October Through May
Delivery Service Charges:		
Customer Charge		
Single Phase	$14.80	$14.80
Three Phase	$16.08	$16.08
Distribution Demand Charge (per kW)	$1.58	$1.23
Reactive Demand Charge	$0.44	$0.44
(For each kvar over one-third of kW demand)		
Distribution Rates ($/kWh)	$0.044522	$0.043240
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC	
Societal Benefits Charge ($/kWh)		
Clean Energy Program	See Rider SBC	
Universal Service Fund	See Rider SBC	
Lifeline	See Rider SBC	
Uncollectible Accounts	See Rider SBC	
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC	
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC	
CIEP Standby Fee ($/kWh)	See Rider BGS	
Transmission Demand Charge ($/kW for each kW in excess of 3 kW)	$2.42	$2.08
Reliability Must Run Transmission Surcharge ($/kWh)	$0.003650	$0.003650
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI	

The minimum monthly bill will be $14.80 per month plus any applicable adjustment.

Date of Issue: **Effective Date:**

Issued by:

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV Revised Sheet Replaces Revised Sheet No. 17

RATE SCHEDULE AGS-SECONDARY
(Annual General Service)

AVAILABILITY

Available at any point within the Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer contracting for annual service delivered at one point and metered at or compensated to the voltage of delivery.

MONTHLY RATE

Delivery Service Charges:

Customer Charge	$161.98
Distribution Demand Charge ($/kW)	$9.44
Reactive Demand (for each kvar over one-third of kW demand)	$0.73
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC
Societal Benefits Charge ($/kWh)	
Clean Energy Program	See Rider SBC
Universal Service Fund	See Rider SBC
Lifeline	See Rider SBC
Uncollectible Accounts	See Rider SBC
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC
CIEP Standby Fee ($/kWh)	See Rider BGS
Transmission Demand Charge ($/kW)	$3.68
Reliability Must Run Transmission Surcharge ($/kWh)	$0.003737
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI

Date of Issue: **Effective Date:**

Issued by:

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV Revised Sheet Replaces Revised Sheet No. 19

RATE SCHEDULE AGS-PRIMARY
(Annual General Service)

AVAILABILITY
Available at any point within the Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer contracting for annual service delivered at one point and metered at or compensated to the voltage of delivery.

MONTHLY RATE

Delivery Service Charges:

Customer Charge	$585.08
Distribution Demand Charge ($/kW)	$7.56
Reactive Demand (for each kvar over one-third of kW demand)	$0.56
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC
Societal Benefits Charge ($/kWh)	
Clean Energy Program	See Rider SBC
Universal Service Fund	See Rider SBC
Lifeline	See Rider SBC
Uncollectible Accounts	See Rider SBC
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC
CIEP Standby Fee ($/kWh)	See Rider BGS
Transmission Demand Charge ($/kW)	$3.80
Reliability Must Run Transmission Surcharge ($/kWh)	$0.003650
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI

Date of Issue: **Effective Date:**

Issued by:

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV Revised Sheet Replaces Revised Sheet No. 29

RATE SCHEDULE TGS
(Transmission General Service)
(Sub Transmission Service Taken at 23kV and 34.5 kV)

AVAILABILITY
Available at any point within the Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer contracting for annual service delivered at one point and metered at or compensated to the voltage subtransmission level (23 or 34.5 kV).

MONTHLY RATE

Delivery Service Charges:

Customer Charge

Maximum billed demand within the most recent 12 billing months.	
Less than 5,000 kW	$132.67
5,000 – 9,000 kW	$4,393.94
Greater than 9,000 kW	$7,976.15

Distribution Demand Charge ($/kW)

Maximum billed demand within the most recent 12 billing months.	
Less than 5,000 kW	$3.81
5,000 – 9,000 kW	$2.93
Greater than 9,000 kW	$1.46

Reactive Demand (for each kvar over one-third of kW demand)	$0.52
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC
Societal Benefits Charge ($/kWh)	
Clean Energy Program	See Rider SBC
Universal Service Fund	See Rider SBC
Lifeline	See Rider SBC
Uncollectible Accounts	See Rider SBC
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC
CIEP Standby Fee ($/kWh)	See Rider BGS
Transmission Demand Charge ($/kW)	$2.03
Reliability Must Run Transmission Surcharge ($/kWh)	$0.003570
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI

Date of Issue: **Effective Date:**

Issued by:

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV Revised Sheet Replaces Revised Sheet No. 29a

RATE SCHEDULE TGS
(Transmission General Service)
(Transmission Service Taken at or above 69kV)

AVAILABILITY
Available at any point within the Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer contracting for annual service delivered at one point and metered at or compensated to the voltage at transmission level (69 kV or higher).

MONTHLY RATE

Delivery Service Charges:

Customer Charge

Maximum billed demand within the most recent 12 billing months.		
Less than 5,000 kW	$129.11	
5,000 – 9,000 kW	$4,275.98	
Greater than 9,000 kW	$19,450.62	
Distribution Demand Charge ($/kW)		
Maximum billed demand within the most recent 12 billing months.		
Less than 5,000 kW	$2.96	
5,000 – 9,000 kW	$2.29	
Greater than 9,000 kW	$0.15	
Reactive Demand (for each kvar over one-third of kW demand)	$0.50	
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC	
Societal Benefits Charge ($/kWh)		
Clean Energy Program	See Rider SBC	
Universal Service Fund	See Rider SBC	
Lifeline	See Rider SBC	
Uncollectible Accounts	See Rider SBC	
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC	
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC	
CIEP Standby Fee ($/kWh)	See Rider BGS	
Transmission Demand Charge ($/kW)	$2.13	
Reliability Must Run Transmission Surcharge ($/kWh)	$0.003570	$0.003570
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI	

Date of Issue: **Effective Date:**
Issued by:

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service – Section IV Revised Sheet Replaces Revised Sheet No. 31

RATE SCHEDULE DDC
(Direct Distribution Connection)

AVAILABILITY

Available at any point within the Company's existing distribution system where facilities of adequate character exist for the connection of fixed, constant and predictable non-residential loads not to exceed one kilowatt

MONTHLY RATES

Distribution:

Service and Demand (per day per connection)	$0.162252
Energy (per day for each kW of effective load)	$0.781508
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC
Societal Benefits Charge ($/kWh)	
Clean Energy Program	See Rider SBC
Universal Service Fund	See Rider SBC
Lifeline See Rider SBC	
Uncollectible Accounts	See Rider SBC
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC
Transmission Rate ($/kWh)	$0.007659
Reliability Must Run Transmission Surcharge ($/kWh)	$0.003737
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI

CORPORATE BUSINESS TAX (CBT)

Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)

Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

LOAD CONSUMPTION

Effective load shall be determined by the Company and be specified in the contract. Effective load is defined as the sum of the products of the connected load in kilowatts times the percent load on at one time. No changes in attached load may be made by the customer without the permission of the Company and customer shall allow the Company access to his premises to assure conformance with this provision.

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV Revised Sheet Replaces Revised Sheet No. 44

RIDER STB-STANDBY SERVICE
(Applicable to MGS, AGS, TGS and SPP Rate Schedules)

AVAILABILITY
This rider is available to customers having other sources of electrical energy supply, but who desire to purchase Standby Service from the Company. The terms of this rider shall not be available in any month when the customer's Generation Availability for the current and preceding five (5) months does not exceed 50%.

DEFINITIONS

Standby Service:
Standby Service is defined as the additional electrical capacity available to a customer in the event of a forced outage and during a mutually agreed upon customer's scheduled maintenance shutdown of the customer owned electrical energy source.

Standby Service Capacity:
The Standby Service Capacity shall be the maximum electrical capacity in kW supplied by the customer owned electrical energy source during the current and preceding five (5) months. Such Standby Service Capacity may be revised with the Company's approval as changes in the customer's load conditions warrant.

Generation Availability:
Generation Availability is defined as the availability of the customer owned electrical energy source during the current and preceding five (5) months and shall be determined by dividing the Kwhrs produced during this period by the product of the Standby Service Capacity times 4380 hours.

MODIFICATION OF DEMAND DETERMINATION
The monthly billing demand shall be as defined under the "Demand Determination" section of the applicable rate schedule.

The Standby Service Demand shall be the "Standby Service Capacity" as defined above.

During the billing months in which a forced outage or mutually agreed upon customer's scheduled maintenance shutdown occurs, the billing demand will be determined by subtracting the Standby Service Capacity from the total demand and waives the minimum charge provision of the applicable rate schedule. Electric service is provided under the terms of the applicable rate schedule. Total demand is defined as the sum of the Company's demand meter plus demand supplied by the other sources of electrical energy, all computed to the nearest whole kilowatt during a fifteen minute period.

STANDBY SERVICE CHARGE
This rider imposes a Standby Service Charge at the following voltage levels:

Tariff	Transmission Stand By Rate ($/kW)	Distribution Stand By Rate ($/kW)
MGS-Secondary	$0.35	$0.11
MGS Primary	$0.25	$0.14
AGS Secondary	$0.37	$0.96
AGS Primary	$0.39	$0.77
TGS Sub Transmission	$0.22	$0.00
TGS Transmission	$0.22	$0.00

Date of Issue: **Effective Date:**

Issued by:

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

RIDER (BGS) continued
Basic Generation Service (BGS)

CIEP Standby Fee $0.000160 per kWh
This charge recovers the costs associated with the winning BGS-CIEP bidders maintaining the availability of the hourly priced default electric supply service plus administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT. This charge is assessed on all kWhs delivered to all CIEP- eligible customers on Rate Schedules MGS Secondary, MGS Primary, AGS Secondary, AGS Primary or TGS.

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

	Rate Class							
	RS	MGS Secondary	MGS Primary	AGS Secondary	AGS Primary	TGS	SPL/ CSL	DDC
VEPCo	0.000437	0.000361	0.000293	0.000242	0.000194	0.000187	-	0.000147
TrAILCo	0.000448	0.000372	0.000368	0.000257	0.000209	0.000187	-	0.000179
PSE&G	0.000582	0.000482	0.000391	0.000323	0.000259	0.000251	-	0.000197
PATH	(0.000050)	(0.000042)	(0.000034)	(0.000028)	(0.000022)	(0.000021)	-	(0.000017)
PPL	0.000213	0.000177	0.000176	0.000123	0.000100	0.000090	-	0.000085
Pepco	0.000018	0.000015	0.000015	0.000011	0.000009	0.000007	-	0.000007
PECO	0.000223	0.000186	0.000183	0.000128	0.000104	0.000094	-	0.000090
MAIT	0.000031	0.000026	0.000028	0.000017	0.000014	0.000013		0.000011
JCP&L	0.000003	0.000003	0.000002	0.000002	0.000001	0.000001	-	0.000001
Delmarva	0.000001	0.000001	0.000001	0.000001	0.000001	0.000001	-	0.000001
BG&E	0.000039	0.000033	0.000032	0.000022	0.000018	0.000016	-	0.000016
AEP - East	0.000131	0.000108	0.000087	0.000073	0.000058	0.000055	-	0.000044
Total	0.002076	0.001722	0.001542	0.001171	0.000945	0.000881	-	0.000761

Date of Issue: **Effective Date:**
Issued by:

Exhibit B

Redlined Tariff Sheets

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV ~~Forty-First~~ Revised Sheet Replaces Revised ~~Fortieth~~ Sheet No. 5

RATE SCHEDULE RS
(Residential Service)

AVAILABILITY
Available for full domestic service to individually metered residential customers, including rural domestic customers, engaged principally in agricultural pursuits.

	SUMMER June Through September	WINTER October Through May
Delivery Service Charges:		
Customer Charge ($/Month)	$4.83	$4.83
Distribution Rates ($/kWH)		
First Block	$0.055619	$0.051319
(Summer <= 750 kWh; Winter<= 500kWh)		
Excess kWh	$0.063942	$0.051319
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC	
Societal Benefits Charge ($/kWh)		
Clean Energy Program	See Rider SBC	
Universal Service Fund	See Rider SBC	
Lifeline	See Rider SBC	
Uncollectible Accounts	See Rider SBC	
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC	
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC	
Transmission Service Charges ($/kWh):		
Transmission Rate	$0.~~019377~~020355	$0.~~019377~~020355
Reliability Must Run Transmission Surcharge	$0.003737	$0.003737
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI	

CORPORATE BUSINESS TAX (CBT)
Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)
Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

Date of Issue: ~~March 29, 2018~~ **Effective Date:** ~~April 1, 2018~~

~~**Issued by: David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company**~~
~~**Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the**~~
~~**BPU Docket Nos. AX18010001 and ER18030241**~~
Issued by:

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV ~~Forty-Second~~ Revised Sheet Replaces ~~Forty-First~~ Revised Sheet No. 11

RATE SCHEDULE MGS-SECONDARY
(Monthly General Service)

AVAILABILITY
Available at any point within the Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer delivered at one point and metered at or compensated to the voltage of delivery. This schedule is not available to residential customers.

	SUMMER June Through September	WINTER October Through May
Delivery Service Charges:		
Customer Charge		
Single Phase	$8.35	$8.35
Three Phase	$9.72	$9.72
Distribution Demand Charge (per kW)	$2.07	$1.70
Reactive Demand Charge	$0.48	$0.48
(For each kvar over one-third of kW demand**)**		
Distribution Rates ($/kWh)	$0.049365	$0.044591
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC	
Societal Benefits Charge ($/kWh)		
Clean Energy Program	See Rider SBC	
Universal Service Fund	See Rider SBC	
Lifeline	See Rider SBC	
Uncollectible Accounts	See Rider SBC	
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC	
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC	
CIEP Standby Fee ($/kWh)	See Rider BGS	
Transmission Demand Charge ($/kW for each kW in excess of 3 kW)	$3.~~26~~43	$~~2.88~~3.05
Reliability Must Run Transmission Surcharge ($/kWh)	$0.003737	$0.003737
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI	

The minimum monthly bill will be $8.35 per month plus any applicable adjustment.

Date of Issue: ~~**March 29, 2018**~~ **Effective Date:** ~~**April 1, 2018**~~

~~**Issued by: David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company**~~
~~**Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket Nos. AX18010001 and ER18030241**~~

Issued by:

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV ~~Forty-Second~~ Revised Sheet Replaces ~~Forty-First~~ Revised Sheet No. 14

RATE SCHEDULE MGS-PRIMARY
(Monthly General Service)

AVAILABILITY

Available at any point within the Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer delivered at one point and metered at or compensated to the voltage of delivery. This schedule is not available to residential customers.

	SUMMER June Through September	WINTER October Through May
Delivery Service Charges:		
Customer Charge		
Single Phase	$14.80	$14.80
Three Phase	$16.08	$16.08
Distribution Demand Charge (per kW)	$1.58	$1.23
Reactive Demand Charge	$0.44	$0.44
(For each kvar over one-third of kW demand)		
Distribution Rates ($/kWh)	$0.044522	$0.043240
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC	
Societal Benefits Charge ($/kWh)		
Clean Energy Program	See Rider SBC	
Universal Service Fund	See Rider SBC	
Lifeline	See Rider SBC	
Uncollectible Accounts	See Rider SBC	
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC	
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC	
CIEP Standby Fee ($/kWh)	See Rider BGS	
Transmission Demand Charge ($/kW for each kW in excess of 3 kW)	$~~3.16~~2.42	~~–~~$2.~~81~~08
Reliability Must Run Transmission Surcharge ($/kWh)	$0.003650	$0.003650
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI	

The minimum monthly bill will be $14.80 per month plus any applicable adjustment.

Date of Issue: ~~**March 29, 2018**~~ **Effective Date:** ~~**April 1, 2018**~~

~~**Issued by: David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company**~~
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ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV ~~Forty-First~~ Revised Sheet Replaces ~~Fortieth~~ Revised Sheet No. 17

RATE SCHEDULE AGS-SECONDARY
(Annual General Service)

AVAILABILITY

Available at any point within the Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer contracting for annual service delivered at one point and metered at or compensated to the voltage of delivery.

MONTHLY RATE

Delivery Service Charges:

Customer Charge	$161.98
Distribution Demand Charge ($/kW)	$9.44
Reactive Demand (for each kvar over one-third of kW demand)	$0.73
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC
Societal Benefits Charge ($/kWh)	
Clean Energy Program	See Rider SBC
Universal Service Fund	See Rider SBC
Lifeline	See Rider SBC
Uncollectible Accounts	See Rider SBC
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC
CIEP Standby Fee ($/kWh)	See Rider BGS
Transmission Demand Charge ($/kW)	$3.~~56~~68
Reliability Must Run Transmission Surcharge ($/kWh)	$0.003737
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI

Date of Issue: ~~**March 29, 2018**~~ **Effective Date:** ~~**April 1, 2018**~~

~~**Issued by: David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company**~~
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ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV ~~Forty-First~~ Revised Sheet Replaces ~~Fortieth~~ Revised Sheet No. 19

RATE SCHEDULE AGS-PRIMARY
(Annual General Service)

AVAILABILITY

Available at any point within the Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer contracting for annual service delivered at one point and metered at or compensated to the voltage of delivery.

MONTHLY RATE

Delivery Service Charges:

Customer Charge	$585.08
Distribution Demand Charge ($/kW)	$7.56
Reactive Demand (for each kvar over one-third of kW demand)	$0.56
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC
Societal Benefits Charge ($/kWh)	
Clean Energy Program	See Rider SBC
Universal Service Fund	See Rider SBC
Lifeline	See Rider SBC
Uncollectible Accounts	See Rider SBC
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC
CIEP Standby Fee ($/kWh)	See Rider BGS
Transmission Demand Charge ($/kW)	$3.~~57~~80
Reliability Must Run Transmission Surcharge ($/kWh)	$0.003650
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI

Date of Issue: ~~**March 29, 2018**~~ **Effective Date:** ~~**April 1, 2018**~~

~~**Issued by: David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company**~~
~~**Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket Nos. AX18010001 and ER18030241**~~
Issued by:

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV ~~Fortieth~~ Revised Sheet Replaces ~~Thirty-Ninth~~ Revised Sheet No. 29

RATE SCHEDULE TGS
(Transmission General Service)
(Sub Transmission Service Taken at 23kV and 34.5 kV)

AVAILABILITY
Available at any point within the Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer contracting for annual service delivered at one point and metered at or compensated to the voltage subtransmission level (23 or 34.5 kV).

MONTHLY RATE

Delivery Service Charges:

Customer Charge

Maximum billed demand within the most recent 12 billing months.	
Less than 5,000 kW	$132.67
5,000 – 9,000 kW	$4,393.94
Greater than 9,000 kW	$7,976.15
Distribution Demand Charge ($/kW)	
Maximum billed demand within the most recent 12 billing months.	
Less than 5,000 kW	$3.81
5,000 – 9,000 kW	$2.93
Greater than 9,000 kW	$1.46
Reactive Demand (for each kvar over one-third of kW demand)	$0.52
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC
Societal Benefits Charge ($/kWh)	
Clean Energy Program	See Rider SBC
Universal Service Fund	See Rider SBC
Lifeline	See Rider SBC
Uncollectible Accounts	See Rider SBC
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC
CIEP Standby Fee ($/kWh)	See Rider BGS
Transmission Demand Charge ($/kW)	$~~1.67~~2.03
Reliability Must Run Transmission Surcharge ($/kWh)	$0.003570
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV ~~Ninth~~ Revised Sheet Replaces ~~Eighth~~ Revised Sheet No. 29a

RATE SCHEDULE TGS
(Transmission General Service)
(Transmission Service Taken at or above 69kV)

AVAILABILITY
Available at any point within the Company's system where facilities of adequate character and capacity exist for the entire electric service requirements of any customer contracting for annual service delivered at one point and metered at or compensated to the voltage at transmission level (69 kV or higher).

MONTHLY RATE

Delivery Service Charges:

Customer Charge

Maximum billed demand within the most recent 12 billing months.		
Less than 5,000 kW	$129.11	
5,000 – 9,000 kW	$4,275.98	
Greater than 9,000 kW	$19,450.62	
Distribution Demand Charge ($/kW)		
Maximum billed demand within the most recent 12 billing months.		
Less than 5,000 kW	$2.96	
5,000 – 9,000 kW	$2.29	
Greater than 9,000 kW	$0.15	
Reactive Demand (for each kvar over one-third of kW demand)	$0.50	
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC	
Societal Benefits Charge ($/kWh)		
Clean Energy Program	See Rider SBC	
Universal Service Fund	See Rider SBC	
Lifeline	See Rider SBC	
Uncollectible Accounts	See Rider SBC	
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC	
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC	
CIEP Standby Fee ($/kWh)	See Rider BGS	
Transmission Demand Charge ($/kW)	$~~1.84~~2.13	
Reliability Must Run Transmission Surcharge ($/kWh)	$0.003570	$0.003570
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI	

Date of Issue: ~~**March 29, 2018**~~ **Effective Date:** ~~**April 1, 2018**~~

~~**Issued by: David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company**~~
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Issued by:

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service – Section IV ~~Sixty-Fifth~~ Revised Sheet Replaces ~~Sixty-Fourth~~ Revised Sheet No. 31

RATE SCHEDULE DDC
(Direct Distribution Connection)

AVAILABILITY
Available at any point within the Company's existing distribution system where facilities of adequate character exist for the connection of fixed, constant and predictable non-residential loads not to exceed one kilowatt

MONTHLY RATES

Distribution:

Service and Demand (per day per connection)	$0.162252
Energy (per day for each kW of effective load)	$0.781508
Non-Utility Generation Charge (NGC) ($/kWH)	See Rider NGC
Societal Benefits Charge ($/kWh)	
Clean Energy Program	See Rider SBC
Universal Service Fund	See Rider SBC
Lifeline See Rider SBC	
Uncollectible Accounts	See Rider SBC
Transition Bond Charge (TBC) ($/kWh)	See Rider SEC
Market Transition Charge Tax (MTC-Tax) ($/kWh)	See Rider SEC
Transmission Rate ($/kWh)	$0.~~006465~~007659
Reliability Must Run Transmission Surcharge ($/kWh)	$0.003737
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI

CORPORATE BUSINESS TAX (CBT)
Charges under this rate schedule include a component for Corporate Business Taxes as set forth in Rider CBT.

NEW JERSEY SALES AND USE TAX (SUT)
Charges under this rate schedule include a component for New Jersey Sales and Use Tax as set forth in Rider SUT.

LOAD CONSUMPTION
Effective load shall be determined by the Company and be specified in the contract. Effective load is defined as the sum of the products of the connected load in kilowatts times the percent load on at one time. No changes in attached load may be made by the customer without the permission of the Company and customer shall allow the Company access to his premises to assure conformance with this provision.

Date of Issue: ~~**March 29, 2018**~~ **Effective Date:** ~~**April 1, 2018**~~

~~**Issued by: David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company**~~
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ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV ~~Twenty-First~~ Revised Sheet Replaces ~~Twentieth~~ Revised Sheet No. 44

RIDER STB-STANDBY SERVICE
(Applicable to MGS, AGS, TGS and SPP Rate Schedules)

AVAILABILITY

This rider is available to customers having other sources of electrical energy supply, but who desire to purchase Standby Service from the Company. The terms of this rider shall not be available in any month when the customer's Generation Availability for the current and preceding five (5) months does not exceed 50%.

DEFINITIONS

Standby Service:
Standby Service is defined as the additional electrical capacity available to a customer in the event of a forced outage and during a mutually agreed upon customer's scheduled maintenance shutdown of the customer owned electrical energy source.

Standby Service Capacity:
The Standby Service Capacity shall be the maximum electrical capacity in kW supplied by the customer owned electrical energy source during the current and preceding five (5) months. Such Standby Service Capacity may be revised with the Company’s approval as changes in the customer's load conditions warrant.

Generation Availability:
Generation Availability is defined as the availability of the customer owned electrical energy source during the current and preceding five (5) months and shall be determined by dividing the Kwhrs produced during this period by the product of the Standby Service Capacity times 4380 hours.

MODIFICATION OF DEMAND DETERMINATION

The monthly billing demand shall be as defined under the "Demand Determination" section of the applicable rate schedule.

The Standby Service Demand shall be the "Standby Service Capacity" as defined above.

During the billing months in which a forced outage or mutually agreed upon customer's scheduled maintenance shutdown occurs, the billing demand will be determined by subtracting the Standby Service Capacity from the total demand and waives the minimum charge provision of the applicable rate schedule. Electric service is provided under the terms of the applicable rate schedule. Total demand is defined as the sum of the Company's demand meter plus demand supplied by the other sources of electrical energy, all computed to the nearest whole kilowatt during a fifteen minute period.

STANDBY SERVICE CHARGE

This rider imposes a Standby Service Charge at the following voltage levels:

Tariff	Transmission Stand By Rate ($/kW)	Distribution Stand By Rate ($/kW)
MGS-Secondary	$0.~~33~~35	$0.11
MGS Primary	$0.~~32~~25	$0.14
AGS Secondary	$0.~~36~~37	$0.96
AGS Primary	$0.~~36~~39	$0.77
TGS Sub Transmission	$0.~~19~~22	$0.00
TGS Transmission	$0.~~19~~22	$0.00

Date of Issue: ~~**March 29, 2018**~~ **Effective Date:** ~~**April 1, 2018**~~
~~**Issued by: David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company**~~
~~**Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket Nos. AX18010001 and ER18030241**~~
Issued by:

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

RIDER (BGS) continued
Basic Generation Service (BGS)

CIEP Standby Fee $0.000160 per kWh
This charge recovers the costs associated with the winning BGS-CIEP bidders maintaining the availability of the hourly priced default electric supply service plus administrative charges pursuant to N.J.S.A. 48:2-60 and New Jersey Sales and Use Tax as set forth in Rider SUT. This charge is assessed on all kWhs delivered to all CIEP- eligible customers on Rate Schedules MGS Secondary, MGS Primary, AGS Secondary, AGS Primary or TGS.

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

Rate Class

	RS	MGS Secondary	MGS Primary	AGS Secondary	AGS Primary	TGS	SPL/ CSL	DDC
VEPCo	0.000437	0.000361	0.000293	0.000242	0.000194	0.000187	-	0.000147
TrAILCo	0.~~000587~~ 000448	~~0.000491~~ 0.000372	0.~~000530~~ 000368	~~0.000324~~ 0.000257	0.~~000260~~ 000209	0.~~000249~~ 000187	-	0.~~000206~~ 000179
PSE&G	0.000582	0.000482	0.000391	0.000323	0.000259	0.000251	-	0.000197
PATH	(0.000050)	(0.000042)	(0.000034)	(0.000028)	(0.000022)	(0.000021)	-	(0.000017)
PPL	0.~~000237~~000213	0.~~000199~~000177	0.~~000214~~000176	0.~~000131~~000123	0.~~000105~~000100	0.~~000102~~000090	-	0.~~000083~~000085
Pepco	0.~~000021~~000018	0.~~000018~~000015	0.~~000019~~000015	0.~~000012~~000011	0.~~000010~~000009	0.~~000010~~000007	-	0.000007
PECO	0.~~000194~~000223	~~0.000160~~ 0.000186	0.~~000130~~000183	~~0.000108~~ 0.000128	0.~~000086~~000104	0.~~000083~~000094	-	0.~~000066~~000090
MAIT	0.000031	0.000026	0.000028	0.000017	0.000014	0.000013		0.000011
JCP&L	0.000003	0.000003	0.000002	0.000002	0.000001	0.000001	-	0.000001
Delmarva	0.000001	0.000001	0.000001	0.000001	0.000001	0.000001	-	0.000001
BG&E	0.~~000073~~000039	0.~~000061~~000033	0.~~000066~~000032	0.~~000041~~000022	0.~~000032~~000018	0.~~000031~~000016	-	0.~~000026~~000016
AEP - East	0.000131	0.000108	0.000087	0.000073	0.000058	0.000055	-	0.000044
Total	0.~~002247~~002076	0.~~001867~~001722	0.~~001727~~001542	0.~~001246~~001171	0.~~000998~~000945	0.~~000962~~000881	-	0.~~000772~~000761

Date of Issue: ~~May 29, 2018~~ **Effective Date: ~~June 1, 2018~~**
~~Issued by: David M. Velazquez, President and Chief Executive Officer – Atlantic City Electric Company~~
~~Filed pursuant to Board of Public Utilities of the State of New Jersey directives associated with the BPU Docket No. ER17040335~~
Issued by:

Exhibit C

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

Transmission Enhancement Costs Allocated to ACE Zone (2018)	$	22,082
	$	22,082
2018 ACE Zone Transmission Peak Load (MW)		2,541
Transmission Enhancement Rate ($/MW-Month)	$	8.69

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2018 - May 2019 (kWh)		Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)		Col. 5 = Col. 4 x 1/(1-Effective Rate) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)		Col. 6 = Col. 5 x 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,439	$	150,118	4,059,095,046	$	0.000037	$	0.000037	$	0.000039
MGS Secondary	357	$	37,188	1,208,290,228	$	0.000031	$	0.000031	$	0.000033
MGS Primary	9	$	917	30,079,842	$	0.000030	$	0.000030	$	0.000032
AGS Secondary	382	$	39,797	1,873,810,489	$	0.000021	$	0.000021	$	0.000022
AGS Primary	96	$	9,993	576,381,592	$	0.000017	$	0.000017	$	0.000018
TGS	132	$	13,757	888,340,177	$	0.000015	$	0.000015	$	0.000016
SPL/CSL	0	$	-	69,443,692	$	-	$	-	$	-
DDC	2	$	194	13,058,581	$	0.000015	$	0.000015	$	0.000016
	2,416	$	251,963	8,718,499,648						

Attachment 2B PJM Schedule 12 - Transmission Enhancement Charges for June 2018 - May 2019
Calculation of costs and monthly PJM charges for BG&E

		(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*	**June 2018 - May 2019 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share[1]** *per PJM Open Access Transmission Tariff*	**JCP&L Zone Share[1]**	**PSE&G Zone Share[1]**	**RE Zone Share[1]**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
Install a second Conastone – Graceton 230 kV circuit	b0497	$ 2,934,126	9.03%	9.67%	14.11%	0.52%	$264,952	$283,730	$414,005	$15,257	$977,944
install new 500 kV transmission from Possum Point to Calvert Cliffs	b0512	$ 1,687	1.66%	3.74%	6.26%	0.26%	$28	$63	$106	$4	$201
		$ -					$0	$0	$0	$0	$0
Totals							**$264,980**	**$283,793**	**$414,111**	**$15,262**	**$978,145**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

	(k)	(l)	(m)	(n)	(o)	(p)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 18/19**	**2018TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2018 Impact (7 months)**	**2019 Impact (5 months)**	**2018-2019 Impact (12 months)**
PSE&G	$ 34,509.23	9,566.9	$ 3.61	$ 241,565	$ 172,546	$ 414,111
JCP&L	$ 23,649.42	5,721.0	$ 4.13	$ 165,546	$ 118,247	$ 283,793
ACE	$ 22,081.63	2,540.8	$ 8.69	$ 154,571	$ 110,408	$ 264,980
RE	$ 1,271.82	401.7	$ 3.17	$ 8,903	$ 6,359	$ 15,262
Total Impact on NJ Zones	**$ 81,512.11**			**$ 570,585**	**$ 407,561**	**$ 978,145**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

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

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

Transmission Enhancement Costs Allocated to ACE Zone (2018)	$	250,122
	$	250,122
2018 ACE Zone Transmission Peak Load (MW)		2,541
Transmission Enhancement Rate ($/MW)	$	98.44

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2018 - May 2019 (kWh)		Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)		Col. 5 = Col. 4 x 1/(1-Effective Rate) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)		Col. 6 = Col. 5 x 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,439	$	1,700,404	4,059,095,046	$	0.000419	$	0.000420	$	0.000448
MGS Secondary	357	$	421,232	1,208,290,228	$	0.000349	$	0.000349	$	0.000372
MGS Primary	9	$	10,382	30,079,842	$	0.000345	$	0.000345	$	0.000368
AGS Secondary	382	$	450,789	1,873,810,489	$	0.000241	$	0.000241	$	0.000257
AGS Primary	96	$	113,187	576,381,592	$	0.000196	$	0.000196	$	0.000209
TGS	132	$	155,826	888,340,177	$	0.000175	$	0.000175	$	0.000187
SPL/CSL	0	$	-	69,443,692	$	-	$	-	$	-
DDC	2	$	2,195	13,058,581	$	0.000168	$	0.000168	$	0.000179
	2,416	$	2,854,016	8,718,499,648						

Attachment 2A PJM Schedule 12 - Transmission Enhancement Charges for June 2018 - May 2019
Calculation of costs and monthly PJM charges for Allegheny TrAILCo 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**	**June 2018-May 2019 Annual Revenue Requirement**	**ACE Zone Share[1]**	**JCP&L Zone Share[1]**	**PSE&G Zone Share[1]**	**RE Zone Share[1]**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
per PJM website	*per PJM spreadsheet*	*per PJM website*	*per PJM Open Access Transmission Tariff*								
502 Junction-Mt Storm-Meadowbrook (>=500kV) - CWIP[1]	b0328.1; b0328.2; b0347.1; b0347.2; b0347.3; b0347.4	$ 116,390,367.10	1.66%	3.74%	6.26%	0.26%	$1,932,080	$4,353,000	$7,286,037	$302,615	$13,873,732
Wylie Ridge [2]	b0218	$ 2,327,769.14	11.83%	15.56%	0.00%	0.00%	$275,375	$362,201	$0	$0	$637,576
Black Oak	b0216	$ 4,809,312.08	1.66%	3.74%	6.26%	0.26%	$79,835	$179,868	$301,063	$12,504	$573,270
Meadowbrook 200 MVAR capacitor	b0559	$ 653,969.56	1.66%	3.74%	6.26%	0.26%	$10,856	$24,458	$40,938	$1,700	$77,953
Replace Kammer 765/500 kV TXfmr	b0495	$ 3,959,496.93	1.66%	3.74%	6.26%	0.26%	$65,728	$148,085	$247,865	$10,295	$471,972
Doubs TXfmr 2	b0343	$ 521,436.22	1.85%	0.00%	0.00%	0.00%	$9,647	$0	$0	$0	$9,647
Doubs TXfmr 3	b0344	$ 477,541.75	1.86%	0.00%	0.00%	0.00%	$8,882	$0	$0	$0	$8,882
Doubs TXfmr 4	b0345	$ 591,741.74	1.85%	0.00%	0.00%	0.00%	$10,947	$0	$0	$0	$10,947
New Osage 138KV Ckt	b0674	$ 2,021,189.84	0.00%	0.00%	0.25%	0.01%	$0	$0	$5,053	$202	$5,255
Cap at Grover 230	b0556	$ 93,468.58	8.64%	18.30%	26.32%	0.98%	$8,076	$17,105	$24,601	$916	$50,697
Upgrade transformer 500/230	b1153	$ 3,063,019.33	3.86%	12.95%	21.15%	0.74%	$118,233	$396,661	$647,829	$22,666	$1,185,388
Build a 300 MVAR Switched Shunt at Doubs 500kV	b1803	$ 547,995.64	1.66%	3.74%	6.26%	0.26%	$9,097	$20,495	$34,305	$1,425	$65,321
Install 500 MVAR svc at Hunterstown 500kV Sub	b1800	$ 4,824,064.07	1.66%	3.74%	6.26%	0.26%	$80,079	$180,420	$301,986	$12,543	$575,028
Install a new 600 MVAR SVC at Meadowbrook 500 kV	b1804	$ 6,713,546.77	1.66%	3.74%	6.26%	0.26%	$111,445	$251,087	$420,268	$17,455	$800,255
Build 250 MVAR svc at Altoona 230kV	b1801	$ 3,979,083.16	6.48%	8.15%	8.19%	0.33%	$257,845	$324,295	$325,887	$13,131	$921,158
Convert Moshannon sub to 4 breaker 230 kv ring bus	b1964	$ 856,936.63	0.00%	5.48%	0.00%	0.00%	$0	$46,960	$0	$0	$46,960
Build a 100 MVAR Fast Switched Shunt and 200 MVAR Switched Shunt at Mansfield 345 kV	b1802	$ 155,919.37	6.48%	8.15%	8.19%	0.33%	$10,104	$12,707	$12,770	$515	$36,095
Install 100 MVAR capacitor at Johnstown 230 kV substation	b0555	$ 153,191.13	8.64%	18.30%	26.32%	0.98%	$13,236	$28,034	$40,320	$1,501	$83,091
Install 300 MVAR capacitor at Conemaugh 500 kV substation	b0376	$ -	1.66%	3.74%	6.26%	0.26%	$0	$0	$0	$0	$0
							$3,001,463	**$6,345,377**	**$9,688,921**	**$397,468**	**$19,433,228**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

	(k)	(l)	(m)	(n)	(o)	(p)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 18/19**	**2018TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2018 Impact (7 months)**	**2019 Impact (5 months)**	**2018-2019 Impact (12 months)**
PSE&G	$ 807,410.08	9,566.9	$ 84.40	$ 5,651,871	$ 4,037,050	$ 9,688,921
JCP&L	$ 528,781.40	5,721.0	$ 92.43	$ 3,701,470	$ 2,643,907	$ 6,345,377
ACE	$ 250,121.88	2,540.8	$ 98.44	$ 1,750,853	$ 1,250,609	$ 3,001,463
RE	$ 33,122.33	401.7	$ 82.46	$ 231,856	$ 165,612	$ 397,468
Total Impact on NJ Zones	**$ 1,619,435.69**			**$ 11,336,050**	**$ 8,097,178**	**$ 19,433,228**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

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

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

Transmission Enhancement Costs Allocated to ACE Zone (2018)	$	124,958
	$	124,958
2018 ACE Zone Transmission Peak Load (MW)		2,541
Transmission Enhancement Rate ($/MW)	$	49.18

Rate Class	Col. 1 Transmission Obligation (MW)	Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales Jun 2018 - May 2019 (kWh)	Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)	Col. 5 = Col. 4 x 1/(1-Effective Rate) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)	Col. 6 = Col. 5 x 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,439	$ 849,500	4,059,095,046	$ 0.000209	$ 0.000209	$ 0.000223
MGS Secondary	357	$ 210,442	1,208,290,228	$ 0.000174	$ 0.000174	$ 0.000186
MGS Primary	9	$ 5,187	30,079,842	$ 0.000172	$ 0.000172	$ 0.000183
AGS Secondary	382	$ 225,208	1,873,810,489	$ 0.000120	$ 0.000120	$ 0.000128
AGS Primary	96	$ 56,547	576,381,592	$ 0.000098	$ 0.000098	$ 0.000104
TGS	132	$ 77,849	888,340,177	$ 0.000088	$ 0.000088	$ 0.000094
SPL/CSL	-	$ -	69,443,692	$ -	$ -	$ -
DDC	2	$ 1,096	13,058,581	$ 0.000084	$ 0.000084	$ 0.000090
	2,416	$ 1,425,829	8,718,499,648			

Attachment 2G - Transmission Enhancement Charges for June 2018 - May 2019
Calculation of costs and monthly PJM charges for PECO Energy Company Transmission Projects

Required Transmission Enhancement *per PJM website*	PJM Upgrade ID *per PJM spreadsheet*	(a) 2018/2019 Annual Revenue Requirement *per PJM website*	(b) ACE Zone Share[1]	(c) JCP&L Zone Share[1]	(d) PSE&G Zone Share[1]	(e) RE Zone Share[1]	(f) ACE Zone Charges	(g) JCP&L Zone Charges	(h) PSE&G Zone Charges	(i) RE Zone Charges	(j) Total NJ Zones Charges
			Responsible Customers - Schedule 12 Appendix *per PJM Open Access Transmission Tariff*				Estimated New Jersey EDC Zone Charges by Project				
Install a new 500 kV Center Point substation in PECO by tapping the Elroy – Whitpain 500 kV circuit.	b0269	$ 3,834,453.99	1.66%	3.74%	6.26%	0.26%	$63,652	$143,409	$240,037	$9,970	$457,067
Add a new 230 kV circuit between Whitpain and Heaton substations	b0269.1	$ 4,852,276.34	8.25%	0.00%	0.00%	0.00%	$400,313	$0	$0	$0	$400,313
Add a new 500kV brkr. at Whitpain bet. #3 transfmr. and 5029 line	b0269.6	$ 539,744.43	1.66%	3.74%	6.26%	0.26%	$8,960	$20,186	$33,788	$1,403	$64,338
Replace 2-500 kV circt brkrs and 2 wave traps at Elroy subs to increase rating of Elroy - Hosensack 500kV	b0171.1	$ 726,651.74	1.66%	3.74%	6.26%	0.26%	$12,062	$27,177	$45,488	$1,889	$86,617
Increase the rating of lines 220-39 and 220-43 (Linwood-Chicester 230kV lines) and install reactors.	b1900	$ 3,515,277.26	0.00%	6.07%	21.01%	0.84%	$0	$213,377	$738,560	$29,528	$981,465
Rebuild Bryn Mawr-Plymouth Meeting 138 kV line (130-35 Line)	b0727	$ 3,379,204.64	1.25%	0.00%	0.00%	0.00%	$42,240	$0	$0	$0	$42,240
Recndr Chichester - Saville 138 kV line and upgrade term equip	b1182	$ 3,137,518.20	0.00%	5.12%	14.31%	0.57%	$0	$160,641	$448,979	$17,884	$627,504
Add a second 230/138 kV trans at Chichester. Add an inductor in series with the parallel tranfmrs	b1178	$ 1,425,743.54	0.00%	4.17%	12.18%	0.48%	$0	$59,454	$173,656	$6,844	$239,953
Increase Bradford - Planebrook 230 kV Ckt.220-31 line rating. Replace terminal equipment	b0790	$ 302,838.57	0.00%	17.46%	34.00%	1.32%	$0	$52,876	$102,965	$3,997	$159,838
Reconductor the North Wales - Hartman 230 kV circuit	b0506	$ 378,009.12	8.58%	0.00%	0.00%	0.00%	$32,433	$0	$0	$0	$32,433
Reconductor the North Wales - Whitpain 230 kV circuit	b0505	$ 422,393.72	8.58%	0.00%	0.00%	0.00%	$36,241	$0	$0	$0	$36,241
Increase Bradford - Planebrook 230 kV Ckt.220-02 line rating. Replace terminal equipment	b0789	$ 414,363.33	0.73%	17.52%	33.83%	1.32%	$3,025	$72,596	$140,179	$5,470	$221,270
Install 161MVAR capacitor at Planebrook 230kV substation	b0206	$ 560,607.56	14.20%	0.00%	3.47%	0.00%	$79,606	$0	$19,453	$0	$99,059
Install 161MVAR capacitor at Newlinville 230kV substation	b0207	$ 756,164.56	14.20%	0.00%	3.47%	0.00%	$107,375	$0	$26,239	$0	$133,614
Install 2% series reactor at Chichester substation on the Chichester - Mickleton 230kV circuit	b0209	$ 428,681.01	65.23%	25.87%	6.35%	0.00%	$279,629	$110,900	$27,221	$0	$417,750
Upgrade Chichester - Delco Tap 230kV and the PECO portion of the Delco Tap - Mickleton 230kV cicuit	b0264	$ 358,865.79	89.87%	9.48%	0.00%	0.00%	$322,513	$34,020	$0	$0	$356,533
Reconductor Buckingham - Pleasant Valley 230kV; same impedance as existing line; ratings of 760MVA normal/882MVA emergency	b0357	$ 366,372.73	0.00%	37.89%	55.19%	2.37%	$0	$138,819	$202,201	$8,683	$349,703
Reconductor Richmond-Waneeta kv and replace terminal equipment at Waneeta Substation	b1398.8	$ 280,237.30	0.00%	13.03%	31.99%	1.27%	$0	$36,515	$89,648	$3,559	$129,722
Install 600 MVAR cap banks at Elroy 500kv Substation	b0287	$ 912,611.66	1.66%	3.74%	6.26%	0.26%	$15,149	$34,132	$57,129	$2,373	$108,783
Install 161 MVAR capcitor at Heaton 230kV Substation	b0208	$ 678,119.35	14.20%	0.00%	3.47%	0.00%	$96,293	$0	$23,531	$0	$119,824
							$1,499,492	**$1,104,101**	**$2,369,074**	**$91,600**	**$5,064,267**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

Zonal Cost Allocation for New Jersey Zones	(k) Average Monthly Impact on Zone Customers in 18/19	(l) 2018TX Peak Load *per PJM website*	(m) Rate in $/MW-mo.	(n) 2018 Impact (7 months)	(o) 2019 Impact (5 months)	(n) 2018 Impact (12 months)
PSE&G	$ 197,422.84	9,566.9	$ 20.64	$ 1,381,960	$ 987,114	$ 2,369,074
JCP&L	$ 92,008.43	5,721.0	$ 16.08	$ 644,059	$ 460,042	$ 1,104,101
ACE	$ 124,957.64	2,540.8	$ 49.18	$ 874,703	$ 624,788	$ 1,499,492
RE	$ 7,633.32	401.7	$ 19.00	$ 53,433	$ 38,167	$ 91,600
Total Impact on NJ Zones	**$ 422,022.23**			**$ 2,954,156**	**$ 2,110,111**	**$ 5,064,267**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (k) *12

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

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

Transmission Enhancement Costs Allocated to ACE Zone (2018)	$	10,337
	$	10,337
2018 ACE Zone Transmission Peak Load (MW)		2,541
Transmission Enhancement Rate ($/MW-Month)	$	4.07

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2018 - May 2019 (kWh)		Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)		Col. 5 = Col. 4 x 1/(1-Effective Rate) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)		Col. 6 = Col. 5 x 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,439	$	70,277	4,059,095,046	$	0.000017	$	0.000017	$	0.000018
MGS Secondary	357	$	17,409	1,208,290,228	$	0.000014	$	0.000014	$	0.000015
MGS Primary	9	$	429	30,079,842	$	0.000014	$	0.000014	$	0.000015
AGS Secondary	382	$	18,631	1,873,810,489	$	0.000010	$	0.000010	$	0.000011
AGS Primary	96	$	4,678	576,381,592	$	0.000008	$	0.000008	$	0.000009
TGS	132	$	6,440	888,340,177	$	0.000007	$	0.000007	$	0.000007
SPL/CSL	0	$	-	69,443,692	$	-	$	-	$	-
DDC	2	$	91	13,058,581	$	0.000007	$	0.000007	$	0.000007
	2,416	$	117,955	8,718,499,648						

Attachment 2F PJM Schedule 12 - Transmission Enhancement Charges for June 2018 to May 2019
Calculation of costs and monthly PJM charges for PEPCO 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*	**June 2018-May 2019 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share[1]**	**JCP&L Zone Share[1]**	**PSE&G Zone Share[1]**	**RE Zone Share[1]**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
			per PJM Open Access Transmission Tariff								
Reconductor 23035 for Dickerson-Quince	b0367.1-2	$ 2,686,508	1.78%	2.67%	3.82%	0.00%	$47,820	$71,730	$102,625	$0	$222,174
Replace 230 1A breaker	b0512.7	$ 256,343	1.66%	3.74%	6.26%	0.26%	$4,255	$9,587	$16,047	$666	$30,556
Replace 230 1B breaker	b0512.8	$ 256,343	1.66%	3.74%	6.26%	0.26%	$4,255	$9,587	$16,047	$666	$30,556
Replace 230 2A breaker	b0512.9	$ 256,343	1.66%	3.74%	6.26%	0.26%	$4,255	$9,587	$16,047	$666	$30,556
Replace 230 3A breaker	b0512.12	$ 258,743	1.66%	3.74%	6.26%	0.26%	$4,295	$9,677	$16,197	$673	$30,842
Ritchie-Benning 230 lines	b0526	$ 7,684,181	0.77%	1.39%	2.10%	0.08%	$59,168	$106,810	$161,368	$6,147	$333,493
Totals							**$124,049**	**$216,979**	**$328,331**	**$8,820**	**$678,178**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

		(k)	(l)	(m)	(n)	(o)	(p)
	Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 18/19**	**2018TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2018 Impact (7 months)**	**2019 Impact (5 months)**	**2018-2019 Impact (12 months)**
	PSE&G	$ 27,360.91	9,566.9	$ 2.86	$ 191,526	$ 136,805	$ 328,331
	JCP&L	$ 18,081.55	5,721.0	$ 3.16	$ 126,571	$ 90,408	$ 216,979
	ACE	$ 10,337.42	2,540.8	$ 4.07	$ 72,362	$ 51,687	$ 124,049
	RE	$ 734.96	401.7	$ 1.83	$ 5,145	$ 3,675	$ 8,820
	Total Impact on NJ Zones	**$ 56,514.84**			**$ 395,604**	**$ 282,574**	**$ 678,178**
Notes on calculations >>>				= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

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

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

Transmission Enhancement Costs Allocated to ACE Zone (2018)	$	814
	$	814
2018 ACE Zone Transmission Peak Load (MW)		2,541
Transmission Enhancement Rate ($/MW-Month)	$	0.32

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2017 - May 2018 (kWh)		Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)		Col. 5 = Col. 4 x 1/(1-Effective Rate) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)		Col. 6 = Col. 5 x 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,439	$	5,536	4,059,095,046	$	0.000001	$	0.000001	$	0.000001
MGS Secondary	357	$	1,371	1,208,290,228	$	0.000001	$	0.000001	$	0.000001
MGS Primary	9	$	34	30,079,842	$	0.000001	$	0.000001	$	0.000001
AGS Secondary	382	$	1,468	1,873,810,489	$	0.000001	$	0.000001	$	0.000001
AGS Primary	96	$	368	576,381,592	$	0.000001	$	0.000001	$	0.000001
TGS	132	$	507	888,340,177	$	0.000001	$	0.000001	$	0.000001
SPL/CSL	0	$	-	69,443,692	$	-	$	-	$	-
DDC	2	$	7	13,058,581	$	0.000001	$	0.000001	$	0.000001
	2,416	$	9,291	8,718,499,648						

Attachment 2E PJM Schedule 12 - Transmission Enhancement Charges for June 2018 - May 2019
Calculation of costs and monthly PJM charges for Delmarva Projects

Required Transmission Enhancement *per PJM website*	PJM Upgrade ID *per PJM spreadsheet*	(a) June 2018-May 2019 Annual Revenue Requirement *per PJM website*	(b) Responsible Customers - Schedule 12 Appendix: ACE Zone Share[1]	(c) JCP&L Zone Share[1]	(d) PSE&G Zone Share[1]	(e) RE Zone Share[1] *per PJM Open Access Transmission Tariff*	(f) Estimated New Jersey EDC Zone Charges by Project: ACE Zone Charges	(g) JCP&L Zone Charges	(h) PSE&G Zone Charges	(i) RE Zone Charges	(j) Total NJ Zones Charges
Replace line trap-Keeney	b0272.1	$ 24,299	1.66%	3.74%	6.26%	0.26%	$403	$909	$1,521	$63	$2,896
Add two breakers-Keeney	b0751	$ 564,319	1.66%	3.74%	6.26%	0.26%	$9,368	$21,106	$35,326	$1,467	$67,267
Totals							**$9,771**	**$22,014**	**$36,847**	**$1,530**	**$70,163**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

Zonal Cost Allocation for New Jersey Zones	(k) Average Monthly Impact on Zone Customers in 18/19	(l) 2018TX Peak Load *per PJM website*	(m) Rate in $/MW-mo.	(n) 2018 Impact (7 months)	(o) 2019 Impact (5 months)	(p) 2018-2019 Impact (12 months)
PSE&G	$ 3,070.62	9,566.9	$ 0.32	$ 21,494	$ 15,353	$ 36,847
JCP&L	$ 1,834.53	5,721.0	$ 0.32	$ 12,842	$ 9,173	$ 22,014
ACE	$ 814.25	2,540.8	$ 0.32	$ 5,700	$ 4,071	$ 9,771
RE	$ 127.53	401.7	$ 0.32	$ 893	$ 638	$ 1,530
Total Impact on NJ Zones	**$ 5,846.94**			**$ 40,929**	**$ 29,235**	**$ 70,163**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

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

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

Transmission Enhancement Costs Allocated to ACE Zone (2018)	$	119,289
	$	119,289
2018 ACE Zone Transmission Peak Load (MW)		2,541
Transmission Enhancement Rate ($/MW-Month)	$	46.95

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2018 - May 2019 (kWh)		Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)		Col. 5 = Col. 4 x 1/(1-Effective Rate) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)		Col. 6 = Col. 5 x 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,439	$	810,965	4,059,095,046	$	0.000200	$	0.000200	$	0.000213
MGS Secondary	357	$	200,896	1,208,290,228	$	0.000166	$	0.000166	$	0.000177
MGS Primary	9	$	4,952	30,079,842	$	0.000165	$	0.000165	$	0.000176
AGS Secondary	382	$	214,993	1,873,810,489	$	0.000115	$	0.000115	$	0.000123
AGS Primary	96	$	53,982	576,381,592	$	0.000094	$	0.000094	$	0.000100
TGS	132	$	74,317	888,340,177	$	0.000084	$	0.000084	$	0.000090
SPL/CSL	-	$	-	69,443,692	$	-	$	-	$	-
DDC	2	$	1,047	13,058,581	$	0.000080	$	0.000080	$	0.000085
	2,416	$	1,361,152	8,718,499,648						

Attachment 2C PJM Schedule 12 - Transmission Enhancement Charges for June 2018 - May 2019
Calculation of costs and monthly PJM charges for PPL 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*	**June 2018- May 2019 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share[1]**	**JCP&L Zone Share[1]**	**PSE&G Zone Share[1]** *per PJM Open Access Transmission Tariff*	**RE Zone Share[1]**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
New 500 KV Susquehana-Roseland Line	b0487	$ 73,470,886.00	1.66%	3.74%	6.26%	0.26%	$1,219,617	$2,747,811	$4,599,277	$191,024	$8,757,730
Replace wave trap at Alburtus 500 kV Sub	b0171.2	$ 8,381.00	1.66%	3.74%	6.26%	0.26%	$139	$313	$525	$22	$999
Replace wavetrap at Hosensack 500KV Sub	b0172.1	$ 6,010.00	1.66%	3.74%	6.26%	0.26%	$100	$225	$376	$16	$716
Replace wavetraps at Juniata 500KV Sub	b0284.2	$ 12,153.00	1.66%	3.74%	6.26%	0.26%	$202	$455	$761	$32	$1,449
New S-R additions < 500kV[2]	b0487.1	$ 1,756,533.00	0.00%	0.00%	5.14%	0.19%	$0	$0	$90,286	$3,337	$93,623
New substation and transformers Middletown	b0468	$ 2,408,736.00	0.00%	4.56%	5.94%	0.22%	$0	$109,838	$143,079	$5,299	$258,216
Install Lauschtown 500/230 kV Sub below 500kv portion	b2006	$ 2,618,100.00	1.11%	9.68%	11.43%	0.45%	$29,061	$253,432	$299,249	$11,781	$593,523
Install Lauschtown 500/230 kV Sub 500kv portion tie line	b2006.1	$ 8,698,675.00	1.66%	3.74%	6.26%	0.26%	$144,398	$325,330	$544,537	$22,617	$1,036,882
200 MVAR shunt reactor at Alburtis 500kv	b2237	$ 2,286,532.50	1.66%	3.74%	6.26%	0.26%	$37,956	$85,516	$143,137	$5,945	$272,555
Totals							**$1,431,473**	**$3,522,921**	**$5,821,227**	**$240,073**	**$11,015,693**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

	(k)	(l)	(m)	(n)	(o)	(p)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 18/19**	**2018 Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2018 Impact (7 months)**	**2019 Impact (5 months)**	**2018-2019 Impact (12 months)**
PSE&G	$ 485,102.22	9,566.9	$ 50.71	$ 3,395,716	$ 2,425,511	$ 5,821,227
JCP&L	$ 293,576.76	5,721.0	$ 51.32	$ 2,055,037	$ 1,467,884	$ 3,522,921
ACE	$ 119,289.39	2,540.8	$ 46.95	$ 835,026	$ 596,447	$ 1,431,473
RE	$ 20,006.08	401.7	$ 49.80	$ 140,043	$ 100,030	$ 240,073
Total Impact on NJ Zones	**$ 917,974.45**			**$ 6,425,821**	**$ 4,589,872**	**$ 11,015,693**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

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

Exhibit D

ATLANTIC CITY ELECTRIC COMPANY
Proposed Transmission Rate Design
Formula Rate Effective June 1, 2018

Line			
1	Transmission Service Annual Revenue Requirement	$	136,632,319
2	Less Total Schedule 12 TEC Included in Line (1)	$	(10,761,631)
3	ACE Customer Share of Schedule 12 TEC included in Line 2	$	4,832,360
4	Total Transmission Costs Borne by ACE Customers	$	130,703,048
5	2018 ACE Newtwork Service Peak		2,541
6	2018 Network Integration Transmission Service Rate (per MW Per Year)	**$**	**51,441.69**

PJM Schedule 12 - Transmission Enhancement Charges for June 2018 - May 2019
Calculation of costs and monthly PJM charges for ACE Projects

	Required Transmission Enhancement *per PJM website*	**PJM Upgrade ID** *per PJM spreadsheet*		**June 2018 - May 2019 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share** *per PJM Open Access Transmission Tariff*		**ACE Zone Charges**
7	Upgrade AE portion of Delco Tap	b0265	$	501,690	89.87%	$	450,869
8	Replace Monroe 230/69 kV TXfmrs	b0276	$	772,567	91.46%	$	706,590
9	Reconductor Union - Corson 138 kV	b0211	$	1,317,619	65.23%	$	859,483
10	New 500/230 Kv Sub on Salem-East Windsor (>500 kV portion)	b0210.A	$	2,621,699	1.66%	$	43,520
11	New 500/230kV Sub on Salem-East Windsor (< 500kV) portion[2]	b0210.B	$	1,869,368	65.23%	$	1,219,389
12	Reconductor the existing Mickleton - Goucestr 230 kV circuit (AE portion)	b1398.5	$	469,607	0.00%	$	-
13	Build second 230kV parallel from Mickelton to Gloucester	b1398.3.1	$	1,468,794	0.00%	$	-
14	Upgrade to Mill T2 138/69 kV transformer	b1600	$	1,740,287	89.21%	$	1,552,510
	Total			**$10,761,631**			**$4,832,360**

Exhibit E

Atlantic City Electric Company
Proposed Transmission Rate Design
Formula Rate Effective June 1, 2018
Change in FERC Formual Based Rate

	2017 Booked Total Revenue ($)	Annualized Transmission Revenue based on Current Billing Determinants ($)	Transmission Peak Load Share (kW)	Transmission Revenue based on Peak Load Share ($)	Increase/(Decrease) ($)	Increase/(Decrease) (%)
Residential						
Residential	$ 619,204,272	$ 70,664,018	1,439,427	$ 74,228,572	$ 3,564,554	0.58%
Commercial and Industrial						
MGS Secondary	$ 155,662,730	$ 17,411,087	356,582	$ 18,388,260	$ 977,173	0.63%
MGS Primary	$ 5,722,594	$ 604,431	8,789	$ 453,232	$ (151,199)	-2.64%
AGS Secondary	$ 120,841,461	$ 19,062,086	381,603	$ 19,678,531	$ 616,444	0.51%
AGS Primary	$ 28,446,328	$ 4,648,160	95,815	$ 4,941,022	$ 292,862	1.03%
TGS - Subtransmission	$ 31,645,550	$ 1,603,476	83,853	$ 4,324,117	$ 2,720,642	8.60%
TGS - Transmission	$ 14,782,273	$ 2,139,866	48,058	$ 2,478,241	$ 338,375	2.29%
SPL/CSL	$ 19,130,073	$ -	-	$ -	$ -	0.00%
DDC	$ 1,015,862	$ 80,865	1,858	$ 95,803	$ 14,938	1.47%
Subtotal Commercial and Industrial	$ 377,246,871	$ 45,549,972	976,557	$ 50,359,206	$ 4,809,235	1.27%
Total Jurisdiction	$ 996,451,143	$ 116,213,990	2,415,984	$ 124,587,778	$ 8,373,789	0.84%

Wholesale Transmission Rate	$ 51.44
Rate Including Regulatory Assessment	$ 51.57

ATLANTIC CITY ELECTRIC COMPANY
Proposed Transmission Rate Design
Formula Rate Effective June 1, 2018

Residential ("RS")

	Billing Determinants	Rate	Rate w/o SUT	Annualized Present Revenue w/o SUT	Rate Adjustment	Proposed Rate w/o SUT	Proposed Rate w/SUT
kWh	3,888,406,860	$ 0.019377	$ 0.018173	$ 70,664,018	$ 0.000917	$ 0.019090	$ 0.020355
Transmission Rate Change				$ 3,564,554			

ATLANTIC CITY ELECTRIC COMPANY
Proposed Transmission Rate Design
Formula Rate Effective June 1, 2018

Monthly General Service - Secondary (MGS Secondary)

	Billing Determinants	Rate	Rate w/o SUT	Annualized Present Revenue w/o SUT	Rate Adjustment	Proposed Rate w/o SUT	Proposed Rate w/SUT
Demand							
SUM > 3 KW	2,987,112	$ 3.26	$ 3.06	$ 9,140,563	$ 0.160000	$ 3.22	$ 3.43
WIN > 3 KW	3,063,157	$ 2.88	$ 2.70	$ 8,270,524	$ 0.160000	$ 2.86	$ 3.05
TOTAL KW	6,050,269			$ 17,411,087			
Transmission Rate Change				$ 977,173			

ATLANTIC CITY ELECTRIC COMPANY
Proposed Transmission Rate Design
Formula Rate Effective June 1, 2018

Monthly General Service - Primary (MGS Primary)

	Billing Determinants	Rate	Rate w/o SUT	Annualized Present Revenue w/o SUT	Rate Adjustment	Proposed Rate w/o SUT	Proposed Rate w/SUT
Demand							
SUM > 3 KW	87,682	$ 3.16	$ 2.96	$ 259,539	$ (0.69)	$ 2.27	$ 2.42
WIN > 3 KW	130,641	$ 2.81	$ 2.64	$ 344,892	$ (0.69)	$ 1.95	$ 2.08
TOTAL KW	218,323			$ 604,431			
Transmission Rate Change				$ (151,199)			

ATLANTIC CITY ELECTRIC COMPANY
Proposed Transmission Rate Design
Formula Rate Effective June 1, 2018

Annual General Service Secondary (AGS Secondary)

	Billing Determinants	Rate	Rate w/o SUT	Annualized Present Revenue w/o SUT	Rate Adjustment	Proposed Rate w/o SUT	Proposed Rate w/SUT
Demand KW	5,707,212	$ 3.56	$ 3.34	$ 19,062,086	$ 0.11	$ 3.45	$ 3.68
Transmission Rate Change				$ 616,444			

ATLANTIC CITY ELECTRIC COMPANY
Proposed Transmission Rate Design
Formula Rate Effective June 1, 2018

Annual General Service Primary (AGS Primary)

	Billing Determinants	Rate	Rate w/o SUT	Annualized Present Revenue w/o SUT	Rate Adjustment	Proposed Rate w/o SUT	Proposed Rate w/SUT
Demand KW	1,387,511	$ 3.57	$ 3.35	$ 4,648,160	$ 0.21	$ 3.56	$ 3.80
Transmission Rate Change				$ 292,862			

ATLANTIC CITY ELECTRIC COMPANY
Proposed Transmission Rate Design
Formula Rate Effective June 1, 2018

Sub Transmission General Service (TGS)

	Billing Determinants	Rate	Rate w/o SUT	Annualized Present Revenue w/o SUT	Rate Adjustment	Proposed Rate w/o SUT	Proposed Rate w/SUT
Demand KW	1,021,322	$ 1.67	$ 1.57	$ 1,603,476	$ 0.33	$ 1.90	$ 2.03
Transmission Rate Change				$ 338,375			

ATLANTIC CITY ELECTRIC COMPANY
Proposed Transmission Rate Design
Formula Rate Effective June 1, 2018

Transmission General Service (TGS)

	Billing Determinants	Rate	Rate w/o SUT	Annualized Present Revenue w/o SUT	Rate Adjustment	Proposed Rate w/o SUT	Proposed Rate w/SUT
Demand KW	1,236,917	$ 1.84	$ 1.73	$ 2,139,866	$ 0.27	$ 2.00	$ 2.13
Transmission Rate Change				$ 338,375			

ATLANTIC CITY ELECTRIC COMPANY
Proposed Transmission Rate Design
Formula Rate Effective June 1, 2018

Street and Private Lighting (SPL)
Contributed Street Lighting (CSL)

	Billing Determinants	Rate	Rate w/o SUT	Annualized Present Revenue w/o SUT	Rate Adjustment	Proposed Rate w/o SUT	Proposed Rate w/SUT
Kilowatthour charge							
Annual	72,902,499	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Rate Change				$ -	$ -		

ATLANTIC CITY ELECTRIC COMPANY
Proposed Transmission Rate Design
Formula Rate Effective June 1, 2018

Direct Distribution Connection (DDC)

	Billing Determinants	Rate	Rate w/o SUT	Annualized Present Revenue w/o SUT	Rate Adjustment	Proposed Rate w/o SUT	Proposed Rate w/SUT
Kilowatthour charge							
Annual	13,337,433	$ 0.006465	$ 0.006063	$ 80,865	$ 0.001120	$ 0.007183	$ 0.007659
Transmission Rate Change				$ 14,938			

Atlantic City Electric Company
Standby Rate Development
Formula Rate Effective June 1, 2018

	Demand Rates ($/kW)	Standby Rates ($/kW)	Transmission Standby
Rate Schedule	**Transmission**	**Transmission**	Factor
MGS Secondary	$ 3.43	$ 0.35	0.101604278
MGS Primary	$ 2.42	$ 0.25	0.101604278
AGS Secondary	$ 3.68	$ 0.37	0.101604278
AGS Primary	$ 3.80	$ 0.39	0.101604278
TGS Transmission	$ 2.13	$ 0.22	0.101604278

Exhibit F

ATLANTIC CITY ELECTRIC COMPANY
RESIDENTIAL SERVICE ("RS")
8 WINTER MONTHS (October Through May)

Present Rates
vs.
Proposed Rates

Monthly Usage (kWh)	Present Delivery ($)	Present Supply+T ($)	Present Total ($)	New Delivery ($)	New Supply+T ($)	New Total ($)	Difference Delivery ($)	Difference Supply+T ($)	Total Difference ($)	(%)
0	$ 4.83	$ -	$ 4.83	$ 4.83	$ -	$ 4.83	$ -	$ -	$ -	0.00%
25	$ 6.75	$ 2.41	$ 9.16	$ 6.75	$ 2.43	$ 9.18	$ -	$ 0.02	$ 0.02	0.22%
50	$ 8.66	$ 4.82	$ 13.48	$ 8.66	$ 4.86	$ 13.52	$ -	$ 0.04	$ 0.04	0.30%
75	$ 10.58	$ 7.23	$ 17.81	$ 10.58	$ 7.29	$ 17.87	$ -	$ 0.06	$ 0.06	0.34%
100	$ 12.49	$ 9.64	$ 22.13	$ 12.49	$ 9.72	$ 22.21	$ -	$ 0.08	$ 0.08	0.36%
150	$ 16.32	$ 14.46	$ 30.78	$ 16.32	$ 14.58	$ 30.90	$ -	$ 0.12	$ 0.12	0.39%
200	$ 20.15	$ 19.28	$ 39.43	$ 20.15	$ 19.45	$ 39.60	$ -	$ 0.17	$ 0.17	0.43%
250	$ 23.98	$ 24.11	$ 48.09	$ 23.98	$ 24.31	$ 48.29	$ -	$ 0.20	$ 0.20	0.42%
300	$ 27.81	$ 28.93	$ 56.74	$ 27.81	$ 29.17	$ 56.98	$ -	$ 0.24	$ 0.24	0.42%
350	$ 31.64	$ 33.75	$ 65.39	$ 31.64	$ 34.03	$ 65.67	$ -	$ 0.28	$ 0.28	0.43%
400	$ 35.47	$ 38.57	$ 74.04	$ 35.47	$ 38.89	$ 74.36	$ -	$ 0.32	$ 0.32	0.43%
450	$ 39.30	$ 43.39	$ 82.69	$ 39.30	$ 43.75	$ 83.05	$ -	$ 0.36	$ 0.36	0.44%
500	$ 43.13	$ 48.21	$ 91.34	$ 43.13	$ 48.61	$ 91.74	$ -	$ 0.40	$ 0.40	0.44%
600	$ 50.79	$ 57.85	$ 108.64	$ 50.79	$ 58.34	$ 109.13	$ -	$ 0.49	$ 0.49	0.45%
679	**$ 56.85**	**$ 65.47**	**$ 122.32**	**$ 56.85**	**$ 66.02**	**$ 122.87**	**$ -**	**$ 0.55**	**$ 0.55**	**0.45%**
700	$ 58.45	$ 67.50	$ 125.95	$ 58.45	$ 68.06	$ 126.51	$ -	$ 0.56	$ 0.56	0.44%
716	$ 59.68	$ 69.04	$ 128.72	$ 59.68	$ 69.62	$ 129.30	$ -	$ 0.58	$ 0.58	0.45%
750	$ 62.28	$ 72.32	$ 134.60	$ 62.28	$ 72.92	$ 135.20	$ -	$ 0.60	$ 0.60	0.45%
800	$ 66.11	$ 77.14	$ 143.25	$ 66.11	$ 77.78	$ 143.89	$ -	$ 0.64	$ 0.64	0.45%
900	$ 73.78	$ 86.78	$ 160.56	$ 73.78	$ 87.51	$ 161.29	$ -	$ 0.73	$ 0.73	0.45%
1000	$ 81.44	$ 96.42	$ 177.86	$ 81.44	$ 97.23	$ 178.67	$ -	$ 0.81	$ 0.81	0.46%
1200	$ 96.76	$ 115.71	$ 212.47	$ 96.76	$ 116.68	$ 213.44	$ -	$ 0.97	$ 0.97	0.46%
1500	$ 119.74	$ 144.63	$ 264.37	$ 119.74	$ 145.84	$ 265.58	$ -	$ 1.21	$ 1.21	0.46%
2000	$ 158.04	$ 192.85	$ 350.89	$ 158.04	$ 194.46	$ 352.50	$ -	$ 1.61	$ 1.61	0.46%
2500	$ 196.35	$ 241.06	$ 437.41	$ 196.35	$ 243.07	$ 439.42	$ -	$ 2.01	$ 2.01	0.46%
3000	$ 234.65	$ 289.27	$ 523.92	$ 234.65	$ 291.69	$ 526.34	$ -	$ 2.42	$ 2.42	0.46%
3500	$ 272.95	$ 337.48	$ 610.43	$ 272.95	$ 340.30	$ 613.25	$ -	$ 2.82	$ 2.82	0.46%
4000	$ 311.25	$ 385.69	$ 696.94	$ 311.25	$ 388.92	$ 700.17	$ -	$ 3.23	$ 3.23	0.46%

ATLANTIC CITY ELECTRIC COMPANY
RESIDENTIAL SERVICE ("RS")
4 SUMMER MONTHS (June Through September)

Present Rates
vs.
Proposed Rates

Monthly Usage (kWh)	Present Delivery ($)	Present Supply+T ($)	Present Total ($)	New Delivery ($)	New Supply+T ($)	New Total ($)	Difference Delivery ($)	Difference Supply+T ($)	Total Difference ($)	Total Difference (%)
0	$ 4.83	$ -	$ 4.83	$ 4.83	$ -	$ 4.83	$ -	$ -	$ -	0.00%
25	$ 6.85	$ 2.21	$ 9.06	$ 6.85	$ 2.23	$ 9.08	$ -	$ 0.02	$ 0.02	0.22%
50	$ 8.88	$ 4.42	$ 13.30	$ 8.88	$ 4.46	$ 13.34	$ -	$ 0.04	$ 0.04	0.30%
75	$ 10.90	$ 6.62	$ 17.52	$ 10.90	$ 6.68	$ 17.58	$ -	$ 0.06	$ 0.06	0.34%
100	$ 12.92	$ 8.83	$ 21.75	$ 12.92	$ 8.91	$ 21.83	$ -	$ 0.08	$ 0.08	0.37%
150	$ 16.97	$ 13.25	$ 30.22	$ 16.97	$ 13.37	$ 30.34	$ -	$ 0.12	$ 0.12	0.40%
200	$ 21.01	$ 17.66	$ 38.67	$ 21.01	$ 17.82	$ 38.83	$ -	$ 0.16	$ 0.16	0.41%
250	$ 25.06	$ 22.08	$ 47.14	$ 25.06	$ 22.28	$ 47.34	$ -	$ 0.20	$ 0.20	0.42%
300	$ 29.10	$ 26.49	$ 55.59	$ 29.10	$ 26.74	$ 55.84	$ -	$ 0.25	$ 0.25	0.45%
350	$ 33.15	$ 30.91	$ 64.06	$ 33.15	$ 31.19	$ 64.34	$ -	$ 0.28	$ 0.28	0.44%
400	$ 37.19	$ 35.32	$ 72.51	$ 37.19	$ 35.65	$ 72.84	$ -	$ 0.33	$ 0.33	0.46%
450	$ 41.24	$ 39.74	$ 80.98	$ 41.24	$ 40.10	$ 81.34	$ -	$ 0.36	$ 0.36	0.44%
500	$ 45.28	$ 44.16	$ 89.44	$ 45.28	$ 44.56	$ 89.84	$ -	$ 0.40	$ 0.40	0.45%
600	$ 53.37	$ 52.99	$ 106.36	$ 53.37	$ 53.47	$ 106.84	$ -	$ 0.48	$ 0.48	0.45%
679	**$ 59.77**	**$ 59.96**	**$ 119.73**	**$ 59.77**	**$ 60.51**	**$ 120.28**	**$ -**	**$ 0.55**	**$ 0.55**	**0.46%**
700	$ 61.46	$ 61.82	$ 123.28	$ 61.46	$ 62.38	$ 123.84	$ -	$ 0.56	$ 0.56	0.45%
716	$ 62.76	$ 63.23	$ 125.99	$ 62.76	$ 63.81	$ 126.57	$ -	$ 0.58	$ 0.58	0.46%
750	$ 65.51	$ 66.23	$ 131.74	$ 65.51	$ 66.84	$ 132.35	$ -	$ 0.61	$ 0.61	0.46%
800	$ 69.97	$ 71.15	$ 141.12	$ 69.97	$ 71.80	$ 141.77	$ -	$ 0.65	$ 0.65	0.46%
900	$ 78.89	$ 80.98	$ 159.87	$ 78.89	$ 81.71	$ 160.60	$ -	$ 0.73	$ 0.73	0.46%
1000	$ 87.82	$ 90.81	$ 178.63	$ 87.82	$ 91.62	$ 179.44	$ -	$ 0.81	$ 0.81	0.45%
1200	$ 105.66	$ 110.48	$ 216.14	$ 105.66	$ 111.45	$ 217.11	$ -	$ 0.97	$ 0.97	0.45%
1500	$ 132.43	$ 139.97	$ 272.40	$ 132.43	$ 141.18	$ 273.61	$ -	$ 1.21	$ 1.21	0.44%
2000	$ 177.05	$ 189.13	$ 366.18	$ 177.05	$ 190.75	$ 367.80	$ -	$ 1.62	$ 1.62	0.44%
2500	$ 221.66	$ 238.29	$ 459.95	$ 221.66	$ 240.31	$ 461.97	$ -	$ 2.02	$ 2.02	0.44%
3000	$ 266.28	$ 287.45	$ 553.73	$ 266.28	$ 289.87	$ 556.15	$ -	$ 2.42	$ 2.42	0.44%
3500	$ 310.89	$ 336.61	$ 647.50	$ 310.89	$ 339.44	$ 650.33	$ -	$ 2.83	$ 2.83	0.44%
4000	$ 355.50	$ 385.77	$ 741.27	$ 355.50	$ 389.00	$ 744.50	$ -	$ 3.23	$ 3.23	0.44%

ATLANTIC CITY ELECTRIC COMPANY
RESIDENTIAL SERVICE ("RS")
Annual Average

Present Rates
vs.
Proposed Rates

Monthly Usage (kWh)	Present Delivery ($)	Present Supply+T ($)	Present Total ($)	New Delivery ($)	New Supply+T ($)	New Total ($)	Difference Delivery ($)	Difference Supply+T ($)	Total Difference ($)	Total Difference (%)
0	$ 4.83	$ -	$ 4.83	$ 4.83	$ -	$ 4.83	$ -	$ -	$ -	0.00%
25	$ 6.78	$ 2.34	$ 9.12	$ 6.78	$ 2.36	$ 9.14	$ -	$ 0.02	$ 0.02	0.22%
50	$ 8.73	$ 4.69	$ 13.42	$ 8.73	$ 4.73	$ 13.46	$ -	$ 0.04	$ 0.04	0.30%
75	$ 10.69	$ 7.03	$ 17.72	$ 10.69	$ 7.09	$ 17.78	$ -	$ 0.06	$ 0.06	0.34%
100	$ 12.63	$ 9.37	$ 22.00	$ 12.63	$ 9.45	$ 22.08	$ -	$ 0.08	$ 0.08	0.36%
150	$ 16.54	$ 14.06	$ 30.60	$ 16.54	$ 14.18	$ 30.72	$ -	$ 0.12	$ 0.12	0.39%
200	$ 20.44	$ 18.74	$ 39.18	$ 20.44	$ 18.91	$ 39.35	$ -	$ 0.17	$ 0.17	0.43%
250	$ 24.34	$ 23.43	$ 47.77	$ 24.34	$ 23.63	$ 47.97	$ -	$ 0.20	$ 0.20	0.42%
300	$ 28.24	$ 28.12	$ 56.36	$ 28.24	$ 28.36	$ 56.60	$ -	$ 0.24	$ 0.24	0.43%
350	$ 32.14	$ 32.80	$ 64.94	$ 32.14	$ 33.08	$ 65.22	$ -	$ 0.28	$ 0.28	0.43%
400	$ 36.04	$ 37.49	$ 73.53	$ 36.04	$ 37.81	$ 73.85	$ -	$ 0.32	$ 0.32	0.44%
450	$ 39.95	$ 42.17	$ 82.12	$ 39.95	$ 42.53	$ 82.48	$ -	$ 0.36	$ 0.36	0.44%
500	$ 43.85	$ 46.86	$ 90.71	$ 43.85	$ 47.26	$ 91.11	$ -	$ 0.40	$ 0.40	0.44%
600	$ 51.65	$ 56.23	$ 107.88	$ 51.65	$ 56.72	$ 108.37	$ -	$ 0.49	$ 0.49	0.45%
679	**$ 57.82**	**$ 63.63**	**$ 121.45**	**$ 57.82**	**$ 64.18**	**$ 122.00**	**$ -**	**$ 0.55**	**$ 0.55**	**0.45%**
700	$ 59.45	$ 65.61	$ 125.06	$ 59.45	$ 66.17	$ 125.62	$ -	$ 0.56	$ 0.56	0.45%
716	$ 60.71	$ 67.10	$ 127.81	$ 60.71	$ 67.68	$ 128.39	$ -	$ 0.58	$ 0.58	0.45%
750	$ 63.36	$ 70.29	$ 133.65	$ 63.36	$ 70.89	$ 134.25	$ -	$ 0.60	$ 0.60	0.45%
800	$ 67.40	$ 75.14	$ 142.54	$ 67.40	$ 75.79	$ 143.19	$ -	$ 0.65	$ 0.65	0.46%
900	$ 75.48	$ 84.85	$ 160.33	$ 75.48	$ 85.58	$ 161.06	$ -	$ 0.73	$ 0.73	0.46%
1000	$ 83.57	$ 94.55	$ 178.12	$ 83.57	$ 95.36	$ 178.93	$ -	$ 0.81	$ 0.81	0.45%
1200	$ 99.73	$ 113.97	$ 213.70	$ 99.73	$ 114.94	$ 214.67	$ -	$ 0.97	$ 0.97	0.45%
1500	$ 123.97	$ 143.08	$ 267.05	$ 123.97	$ 144.29	$ 268.26	$ -	$ 1.21	$ 1.21	0.45%
2000	$ 164.38	$ 191.61	$ 355.99	$ 164.38	$ 193.22	$ 357.60	$ -	$ 1.61	$ 1.61	0.45%
2500	$ 204.79	$ 240.14	$ 444.93	$ 204.79	$ 242.15	$ 446.94	$ -	$ 2.01	$ 2.01	0.45%
3000	$ 245.19	$ 288.66	$ 533.85	$ 245.19	$ 291.08	$ 536.27	$ -	$ 2.42	$ 2.42	0.45%
3500	$ 285.60	$ 337.19	$ 622.79	$ 285.60	$ 340.01	$ 625.61	$ -	$ 2.82	$ 2.82	0.45%
4000	$ 326.00	$ 385.72	$ 711.72	$ 326.00	$ 388.95	$ 714.95	$ -	$ 3.23	$ 3.23	0.45%

IN THE MATTER OF THE PETITION OF ATLANTIC CITY ELECTRIC COMPANY FOR APPROVAL TO IMPLEMENT FERC-APPROVED CHANGES TO ACE'S RETAIL TRANSMISSION (FORMULA) RATE PURSUANT TO PARAGRAPHS 15.9 OF THE BGS-RSCP AND BGS-CIEP SUPPLIER MASTER AGREEMENTS (2018)	STATE OF NEW JERSEY BOARD OF PUBLIC UTILITIES

CERTIFICATION OF SERVICE

PHILIP J. PASSANANTE, of full age, certifies as follows:

1. I am an attorney at law of the State of New Jersey and serve as Assistant General Counsel to Atlantic City Electric Company, the Petitioner in the within matter, with which I am familiar.

2. I hereby certify that, on July 11, 2018, I caused three conformed copies of the within Verified Petition of Atlantic City Electric Company for Approval to Implement FERC-Approved Changes to Its Retail Transmission (Formula) Rate Pursuant to Paragraphs 15.9 of the BGS-RSCP and BGS-CIEP Supplier Master Agreements (the "Petition") to be sent by electronic mail and overnight courier to Aida Camacho-Welch, Secretary of the Board, State of New Jersey, Board of Public Utilities, 44 South Clinton Avenue, 3rd Floor, Suite 314, Trenton, New Jersey 08625.

3. I further certify that, on July 11, 2018, I caused a complete copy of the Petition to be sent by electronic mail to each of the parties listed on the attached Service List, except for copies that were directed to the Division of Rate Counsel, which were sent by electronic mail and overnight courier.

4. I further and finally certify that the foregoing statements made by me are true. I am aware that, if any of the foregoing statements made by me are willfully false, I am subject to punishment.

Dated: July 11, 2018 By: ______________________________ /jpr

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I/M/O the Petition of Atlantic City Electric Company for Approval to Implement FERC-Approved Changes to ACE's Retail Transmission (Formula) Rate Pursuant to Paragraphs 15.9 of the BGS-RSCP and BGS-CIEP Supplier Master Agreements (2018)
BPU Docket No. _______________

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