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VIA ELECTRONIC MAIL ONLY

October 23, 2020

In the Matter of the Provision of
Basic Generation Service for Year Two of the Post-Transition Period
-and-
In the Matter of the Provision of
Basic Generation Service for the Period Beginning June 1, 2017
-and-
In the Matter of the Provision of
Basic Generation Service for the Period Beginning June 1, 2018
-and-
In the Matter of the Provision of
Basic Generation Service for the Period Beginning June 1, 2019
-and-
In the Matter of the Provision of
Basic Generation Service for the Period Beginning June 1, 2020

Docket Nos. EO03050394, ER16040337, ER17040335, ER18040356, ER19040428
++
Compliance Tariff Filing Reflecting Changes to Schedule 12 Charges in PJM Open Access Transmission Tariff

BPU Docket No. ____________

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

Dear Secretary Camacho-Welch:

Enclosed for filing on behalf of Jersey Central Power & Light Company ("JCP&L"), Atlantic City Electric Company ("ACE"), Public Service Electric and Gas Company ("PSE&G") and Rockland Electric Company ("RECO") (collectively, the "EDCs"), please find revised tariff sheets and supporting exhibits to modify the filings made by the EDCs on December 9, 2019, March 24, 2020, and June 22, 2020 in the above-captioned dockets (collectively, the "EDC Filings").[1]

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 three Federal Energy Regulatory Commission ("FERC") Orders:

(i) *Order on Compliance Filing*, Docket No. ER18-680-000 issued March 31, 2020 ("ER18-680 FERC Order"),

(ii) *Order Denying Rehearing and Granting Clarification*, Docket Nos. ER15-1387-005 and ER15-1344-006 issued April 3, 2020, and

(iii) *Order Accepting Compliance Filings*, Docket Nos. ER15-1387-006 and ER15-1344-007 issued April 3, 2020 ("Form 715 FERC Order").

The ER18-680 FERC Order allows PJM to charge Linden VFT and HTP for their share of violation-based DFAX projects and applies those credits to the other zones including NJ transmission zones and ultimately load serving entities. The cost reallocations result in re-billings going back to January 2018 and are applied on a go-forward basis. The charges and credits for the rebilling period will occur over a four month period that began in August 2020.

The Form 715 FERC Order approves cost reallocations for unique projects in the Dominion and PSE&G transmission zones that results in rebilling back to May 2015 for FERC Form 715 RTEP projects. Initially, these projects in the PSE&G transmission zone were paid for only by PSE&G customers. A similar situation occurred for unique projects in the Dominion transmission zone. The Form 715 FERC Order now allows PSE&G and Dominion to share these costs with other transmission zones. The cost reallocations result in re-billings going back to May 2015 and are also applied on a go-forward basis. The charges and credits for the rebilling period will occur over a seven month period that began in September 2020.

Consistent with the Order issued by the New Jersey Board of Public Utilities (the "Board" or "BPU") in connection with *In the Matter of the New Jersey Board of Public Utilities' Response to the COVID-19 Pandemic for a Temporary Waiver of Requirements for Certain Non-Essential Obligations*, BPU Docket No. EO20030254, Order dated March 19, 2020, this document and all attachments are being electronically filed with the Secretary of the Board and the New Jersey Division of Rate Counsel. No paper copies will follow.

[1] Philadelphia Electric Company ("PECO") has updated its formula rate revenue requirements after the EDCs filed jointly on June 22, 2020 and these costs have been included in this filing as well.

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 Transmission Enhancement Charge ("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 TrailCo TEC into Customer Rates)
- Attachment 2g (PSE&G Translation of PEPCO TEC into Customer Rates)
- Attachment 2h (PSE&G Translation of PPL TEC into Customer Rates)
- Attachment 2I (PSE&G Translation of BG&E TEC into Customer Rates)
- Attachment 2j (PSE&G Translation of MAIT TEC into Customer Rates)
- Attachment 2k (PSE&G Translation of PECO TEC into Customer Rates)
- Attachment 2l (PSE&G Translation of AEP East TEC into Customer Rates)
- Attachment 2m (PSE&G Translation of ER18-680 and Form 715 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)
- Attachment 3f (JCP&L Translation of TrailCo TEC into Customer Rates)
- Attachment 3g (JCP&L Translation of PEPCO TEC into Customer Rates)
- Attachment 3h (JCP&L Translation of PPL TEC into Customer Rates)
- Attachment 3i (JCP&L Translation of BG&E TEC into Customer Rate)
- Attachment 3j (JCP&L Translation of MAIT TEC into Customer Rates)
- Attachment 3k (JCP&L Translation of PECO TEC into Customer Rates)
- Attachment 3l (JCP&L Translation of AEP East TEC into Customer Rates)
- Attachment 3m (JCP&L Translation of ER18-680 and Form 715 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 TrailCo TEC into Customer Rates)
- Attachment 4g (ACE Translation of PEPCO TEC into Customer Rates)
- Attachment 4h(ACE Translation of PPL TEC into Customer Rates)
- Attachment 4i (ACE Translation of BG&E TEC into Customer Rates)
- Attachment 4j (ACE Translation of MAIT TEC into Customer Rates)
- Attachment 4k (ACE Translation of PECO TEC into Customer Rates)
- Attachment 4l (ACE Translation of AEP East TEC into Customer Rates)
- Attachment 4m (ACE Translation of ER18-680 and Form 715 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)
- Attachment 5f (RECO Translation of TrailCo TEC into Customer Rates)
- Attachment 5g (RECO Translation of PEPCO TEC into Customer Rates)
- Attachment 5h (RECO Translation of PPL TEC into Customer Rates)
- Attachment 5i (RECO Translation of BG&E TEC into Customer Rates)
- Attachment 5j (RECO Translation of MAIT TEC into Customer Rates)
- Attachment 5k (RECO Translation of PECO TEC TEC into Customer Rates)
- Attachment 5l (RECO Translation of AEP East TEC into Customer Rates)
- Attachment 5m (RECO Translation of ER18-680 and Form 715 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 (TrailCo Transmission Enhancement Charges)
- Attachment 6f (PEPCO Transmission Enhancement Charges)
- Attachment 6g (PPL Transmission Enhancement Charges)
- Attachment 6h (BG&E Transmission Enhancement Charges)
- Attachment 6i (MAIT Transmission Enhancement Charges)

- Attachment 6j(PECO Transmission Enhancement Charges)
- Attachment 6k (AEP East Transmission Enhancement Charges)
- Attachment 6l (ER18-680 and Form 715 Charges/Credits)

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

- Attachment 8a *Order on Compliance Filing*, Docket No. ER18-680-000 issued March 31, 2020
- Attachment 8b *Order Denying Rehearing and Granting Clarification*, Docket Nos. ER15-1387-005 and ER15-1344-006 issued April 3, 2020
- Attachment 8c *Order Accepting Compliance Filings*, Docket Nos. ER15-1387-006 and ER15-1344-007 issued April 3, 2020

- Attachment 9 (PSE&G FERC Formula Rate filing)
- Attachment 10 (JCP&L FERC Formula Rate filing)
- Attachment 11 (ACE FERC Formula Rate filing)
- Attachment 12 (PECO FERC Formula Rate filing)

B. <u>Request for Authority to Collect/Refund Adjusted Rate and to Pay/Charge Suppliers</u>

The EDCs respectfully reiterate the request for approval set forth in the EDC Filings as if incorporated herein. More specifically, the EDCs request approval to implement the attached tariff sheets effective November 1, 2020.

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 receiving these credits for transmission service effective September 2020 pursuant to the PJM OATT changes implementing the ER18-680 FERC Order and paying these charges/receiving credits in September 2020 pursuant to the implementation of the Form

715 FERC Order. The EDCs also seek authority from the Board to charge or credit BGS customers over a 12-month period depending on the specific EDC rate design while paying or charging suppliers as they incur these charges or credits. The EDCs also seek authority from the Board for the flexibility to net the charges and credits for a supplier at the end of the rebilling period where it makes practical sense to do so.

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, 2020, BPU Docket No. ER19040428).

We also note that the FERC-ordered rate adjustments in the attached tariffs are intended to implement adjustments to 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 or credit due to these cost reallocations, the EDCs be authorized to remit or charge to BGS suppliers the cost increases or credits collected due to the cost reallocations and that the EDCs will accrue the charges or credits to or from the BGS suppliers and amortize them over the same 12 month period matching the BGS customer rates in order to minimize the timing differences impact on the EDC's BGS Reconciliation Charge. Beyond that, any difference between the payments or charges to the BGS suppliers and charges or credits to BGS 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 where applicable for these reallocation orders 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.

C. Conclusion

For the foregoing reasons, the EDCs respectfully request that the Board accept the tariff revisions proposed herein and the Board authorize the EDCs to remit payment to suppliers as set forth above.

We thank the Board for all courtesies extended.

Respectfully submitted,

Attachments

C Stacy Peterson, NJBPU
Stefanie Brand, Division of Rate Counsel
Attached Service List (email only)

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
BGS TRANSMISSION ENHANCEMENT CHARGE

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BGS TRANSMISSION ENHANCEMENT CHARGE

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

Attachment 1a PSE&G Network Integration Service Calculation.

Derived Network Integration Service Rate Applicable to PSE&G customers - Effective January 1, 2020 through December 31, 2020

Line #	Description	Rate			Source
(1)	Transmission Service Annual Revenue Requirement	$	1,526,297,807.55		Page 4 of Attachment 9 -Line 164
(2)	Total Schedule 12 TEC Included in above	$	(476,469,695.00)		Attachment 6a Column (a)
(3)	PSE&G Customer Share of Schedule 12 TEC	$	286,678,056.86		Attachment 6a Column (h)
(4)	Total Transmission Costs Borne by PSE&G customers	$	1,336,506,169.41		=(1) +(2) +(3)
(5)	2020 PSE&G Network Service Peak		9,752.5	MW	Page 4 of Attachment 9 - -Line 165
(6)	2020 Derived Network Integration Transmission Service Rate	$	137,042.42	per MW-year	
	Resulting 2020 BGS Firm Transmission Service Supplier Rate	$	374.43	per MW-day	= (6)/366

Attachment 1b JCP&L Network Integration Transmission Service Calculation

Derived Network Integration Transmission Service Rate Applicable to JCP&L Customers - Effective January 1, 2020 through December 31, 2020

Line #	Description	Rate		Source
(1)	Network Integration Transmission Service	$147,518,299		Attachment 10
(2)	JCP&L Customer Share of Schedule 12 TEC	$8,580,782		Attachment 6b
(3)	Total Transmission Costs Borne by JCP&L Customers	$156,099,081		=(1) + (2)
(4)	2020 JCP&L Network Service Peak	6,057.1	MW	PJM network service peak loads for 2020
(5)	2020 Derived Network Integration Transmission Service Rate	$25,771.26	per MW-year	
	Resulting 2020 BGS Firm Transmission Service Supplier Rate	$70.41	per MW-day	= (6)/366

ATLANTIC CITY ELECTRIC
Proposed Transmission Rate Design
Formula Rate Effective November 1, 2020

Line			
1	Transmission Service Annual Revenue Requirement	$	125,075,638
2	Less Total Schedule 12 TEC Included in Line (1)	$	(10,807,727)
3	ACE Customer Share of Schedule 12 TEC included in Line 2	$	6,252,344
4	Total Transmission Costs Borne by ACE Customers	$	120,520,255
5	2020 ACE Newtwork Service Peak		2,737
6	2020 Network Integration Transmission Service Rate (per MW Per Year)	**$**	**44,028.88**

PJM Schedule 12 - Transmission Enhancement Charges for June 2020 - May 2021
Calculation of costs and monthly PJM charges for ACE Projects

	Required Transmission Enhancement *per PJM website*	**PJM Upgrade ID** *per PJM spreadsheet*	**June 2020 - May 2021 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	$ 443,088	89.87%	$ 398,203
8	Replace Monroe 230/69 kV TXfmrs	b0276	$ 677,713	91.28%	$ 618,616
9	Reconductor Union - Corson 138 kV	b0211	$ 1,155,287	65.23%	$ 753,594
10	New 500/230 Kv Sub on Salem-East Windsor (>500 kV portion)	b0210.A	$ 1,156,794	1.72%	$ 19,897
11	New 500/230 Kv Sub on Salem-East Windsor (>500 kV portion)	b0210.A_dfax	$ 1,156,794	100.00%	$ 1,156,794
12	New 500/230kV Sub on Salem-East Windsor (< 500kV) portion[2]	b0210.B	$ 1,649,674	65.23%	$ 1,076,082
13	Reconductor the existing Mickleton - Goucestr 230 kV circuit (AE portion)	b1398.5	$ 413,399	0.00%	$ -
14	Build second 230kV parallel from Mickelton to Gloucester	b1398.3.1	$ 1,291,971	0.00%	$ -
15	Upgrade to Mill T2 138/69 kV transformer	b1600	$ 1,532,281	88.83%	$ 1,361,125
16	Orchard-Cumberland Install 2nd 230 kV line	b0210.1	$ 1,324,917	65.23%	$ 864,243
17	Corson Upgrade 138kV Line trap	b0212	$ 5,808	65.23%	$ 3,789
	Total		**$10,807,727**		**$6,252,344**

- 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)
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- Attachment 2l (PSE&G Translation of AEP East TEC into Customer Rates)
- Attachment 2m (PSE&G Translation of ER18-680 and Form 715 TEC into Customer Rates)

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

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

APPLICABLE TO:

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

BGS ENERGY CHARGES:

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

Charges per kilowatt-hour:

Rate Schedule	For usage in each of the months of October through May: Charges	Charges Including SUT	For usage in each of the months of June through September: Charges	Charges Including SUT
RS – first 600 kWh	$0.122723	$0.130853	$0.120884	$0.128893
RS – in excess of 600 kWh	0.122723	0.130853	0.129840	0.138442
RHS – first 600 kWh	0.091111	0.097147	0.085527	0.091193
RHS – in excess of 600 kWh	0.091111	0.097147	0.097503	0.103963
RLM On-Peak	0.215098	0.229348	0.223878	0.238710
RLM Off-Peak	0.055501	0.059178	0.050607	0.053960
WH	0.049048	0.052297	0.046716	0.049811
WHS	0.049903	0.053209	0.046816	0.049918
HS	0.112361	0.119805	0.112671	0.120135
BPL	0.047907	0.051081	0.043293	0.046161
BPL-POF	0.047907	0.051081	0.043293	0.046161
PSAL	0.047907	0.051081	0.043293	0.046161

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

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

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 79**
Superseding
B.P.U.N.J. No. 16 ELECTRIC **XXX Revised Sheet No. 79**

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

BGS CAPACITY CHARGES:

Applicable to Rate Schedules GLP and LPL-Sec.

Charges per kilowatt of Generation Obligation:

Charge applicable in the months of June through September.. $ 5.2965
Charge including New Jersey Sales and Use Tax (SUT).. $ 5.6474

Charge applicable in the months of October through May .... $ 5.2965
Charge including New Jersey Sales and Use Tax (SUT).. $ 5.6474

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 .... $137,042.42 per MW per year
EL05-121…….. $ 80.67 per MW per month
FERC 680 & 715 Reallocation…... ($ 788.13) per MW per month
PJM Seams Elimination Cost Assignment Charges.. $ 0.00 per MW per month
PJM Reliability Must Run Charge.. $ 0.00 per MW per month
PJM Transmission Enhancements
Trans-Allegheny Interstate Line Company .... $ 50.00 per MW per month
Virginia Electric and Power Company... $ 51.62 per MW per month
Potomac-Appalachian Transmission Highline L.L.C. ....($ 0.65) per MW per month
PPL Electric Utilities Corporation .... $ 212.68 per MW per month
American Electric Power Service Corporation .... $ 13.01 per MW per month
Atlantic City Electric Company. .... $ 8.67 per MW per month
Delmarva Power and Light Company... $ 1.00 per MW per month
Potomac Electric Power Company.. $ 2.86 per MW per month
Baltimore Gas and Electric Company .... $ 2.39 per MW per month
Jersey Central Power and Light .... $ 67.07 per MW per month
Mid Atlantic Interstate Transmission .... $ 21.93 per MW per month
PECO Energy Company……………………………….............................. $ 20.97 per MW per month
Silver Run Electric, Inc.……………………………… .... $ 24.35 per MW per month
Northern Indiana Public Service Company………………………. .... $ 0.46 per MW per month
Commonwealth Edison Company... $ 0.28 per MW per month

Above rates converted to a charge per kW of Transmission
Obligation, applicable in all months.. $ 11.1896
Charge including New Jersey Sales and Use Tax (SUT).. $ 11.9309

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

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

BGS TRANSMISSION CHARGES

Charges per kilowatt of Transmission Obligation:

Currently effective Annual Transmission Rate for
Network Integration Transmission Service for the
Public Service Transmission Zone as derived from the
FERC Electric Tariff of the PJM Interconnection, LLC ....$137,042.42 per MW per year
EL05-121……. ....$ 80.67 per MW per month
FERC 680 & 715 Reallocation……. .... ($ 788.13) per MW per month
PJM Seams Elimination Cost Assignment Charges..................................$ 0.00 per MW per month
PJM Reliability Must Run Charge..$ 0.00 per MW per month
PJM Transmission Enhancements
Trans-Allegheny Interstate Line Company .... $ 50.00 per MW per month
Virginia Electric and Power Company ....$ 51.62 per MW per month
Potomac-Appalachian Transmission Highline L.L.C. .... ($ 0.65) per MW per month
PPL Electric Utilities Corporation...$ 212.68 per MW per month
American Electric Power Service Corporation ....$ 13.01 per MW per month
Atlantic City Electric Company. ....$ 8.67 per MW per month
Delmarva Power and Light Company...$ 1.00 per MW per month
Potomac Electric Power Company. ....$ 2.86 per MW per month
Baltimore Gas and Electric Company...$ 2.39 per MW per month
Jersey Central Power and Light ....$ 67.07 per MW per month
Mid Atlantic Interstate Transmission...$ 21.93 per MW per month
PECO Energy Company………………………………..................$ 20.97 per MW per month
Silver Run Electric, Inc.…………………………………. ....$ 24.35 per MW per month
Northern Indiana Public Service Company………………………… .$ 0.46 per MW per month
Commonwealth Edison Company ....$ 0.28 per MW per month

Above rates converted to a charge per kW of Transmission
Obligation, applicable in all months..$ 11.1896
Charge including New Jersey Sales and Use Tax (SUT) ....$ 11.9309

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

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

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

PSE&G Annual Transmission Service Revenue Requirement	$	1,526,297,807.55						
Total Schedule 12 TEC Included in above	$	(476,469,695.00)						
PSE&G Customer Share of Schedule 12 NITS	$	286,678,056.86						
NITS Charges for Jan 2020 - Dec 2020	$	1,336,506,169.41						
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,752.50						
Term (Months)		12						
OATT rate	$	11,420.20	/MW/month		all values show w/o NJ SUT			
converted to $/MW/yr =	$	137,042.42	/MW/yr	**Jan 20 - Dec 20 NITS Charge**				
	$	102,309.43	/MW/yr	**2017- 2019 Weighted Average of:**		**$ 91,224.18**	**$ 110,695.46**	**$ 104,709.15**
	$	117,402.50	/MW/yr	**2018- 2020 Weighted Average of:**		**$ 110,695.46**	**$ 104,709.15**	**$ 137,042.42**
	$	111,113.72	/MW/yr	**Jan 20 - Dec 20 Weighted Average**				
Resulting Increase in Transmission Rate	$	25,928.70	/MW/yr					
Resulting Increase in Transmission Rate	$	2,160.72	/MW/month					

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4,409.3	20.0	69.4	0.0	0.0	3.3	0.0	0.0
Total Annual Energy - MWh	12,156,072.0	100,394.3	180,143.8	766.0	16.0	11,410.5	147,904.0	298,956.0
Change in energy charge								
in $/MWh	$ 9.4050	$ 5.1654	$ 9.9890	$ -	$ -	$ 7.4987	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.009405**	**$ 0.005165**	**$ 0.009989**	**$ -**	**$ -**	**$ 0.007499**	**$ -**	**$ -**

Line #					
1	Total BGS-RSCP Trans Obl	6,901.0 MW			= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust	23,970,724 MWh			= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes	25,302,921 MWh		unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 178,933,931		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl adjusted for migration
5	Change in Average Supplier Payment Rate	$ 7.0717	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ 7.07	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ 178,891,654		unrounded	= (6) * (3)
8	Difference due to rounding	$ (42,277)		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges for January 2020 - December 2020
Calculation of costs and monthly PJM charges for JCP&L

TEC Charges for Jan 2020 - Dec 2020	$ 7,848,977.22		
PSE&G Zonal Transmission Load for Effective Yr. (MW)	9,752.50		
Term (Months)	12		
OATT rate	$ 67.07	/MW/month	all values show w/o NJ SUT
converted to $/MW/yr =	$ 804.84	/MW/yr	

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4,409.3	20.0	69.4	0.0	0.0	3.3	0.0	0.0
Total Annual Energy - MWh	12,156,072.0	100,394.3	180,143.8	766.0	16.0	11,410.5	147,904.0	298,956.0
Energy Charge								
in $/MWh	$ 0.2919	$ 0.1603	$ 0.3101	$ -	$ -	$ 0.2328	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000292**	**$ 0.000160**	**$ 0.000310**	**$ -**	**$ -**	**$ 0.000233**	**$ -**	**$ -**

Line #					
1	Total BGS-RSCP Trans Obl	6,901.0	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust	23,970,724.3	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes	25,302,921.3	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 5,554,201		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$ 0.2195	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ 0.22	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ 5,566,643		unrounded	= (6) * (3)
8	Difference due to rounding	$ 12,442		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges for June 2020 - May 2021
Calculation of costs and monthly PJM charges for ACE Projects

TEC Charges for June 2020 - May 2021	$ 1,015,016.57	
PSE&G Zonal Transmission Load for Effective Yr. (MW)	9,752.5	
Term (Months)	12	
OATT rate	$ 8.67	/MW/month
converted to $/MW/yr =	$ 104.04	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4,409.3	20.0	69.4	0.0	0.0	3.3	0.0	0.0
Total Annual Energy - MWh	12,156,072.0	100,394.3	180,143.8	766.0	16.0	11,410.5	147,904.0	298,956.0
Energy Charge								
in $/MWh	$ 0.037738	$ 0.020726	$ 0.040081	$ -	$ -	$ 0.030089	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000038**	**$ 0.000021**	**$ 0.000040**	**$ -**	**$ -**	**$ 0.000030**	**$ -**	**$ -**

Line #					
1	Total BGS-RSCP Trans Obl	6,901.0 MW			= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust	23,970,724.3 MWh			= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes	25,302,921.3 MWh		unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 717,980		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$ 0.0284	/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	$ 759,088		unrounded	= (6) * (3)
8	Difference due to rounding	$ 41,108		unrounded	= (7) - (4)

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

TEC Charges for Jan 2020 - Dec 2020	$ 6,040,625.63		
PSE&G Zonal Transmission Load for Effective Yr. (MW)	9,752.5		
Term (Months)	12		
OATT rate	$ 51.62	/MW/month	all values show w/o NJ SUT
converted to $/MW/yr =	$ 619.44	/MW/yr	

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4,409.3	20.0	69.4	0.0	0.0	3.3	0.0	0.0
Total Annual Energy - MWh	12,156,072.0	100,394.3	180,143.8	766.0	16.0	11,410.5	147,904.0	298,956.0
Energy Charge								
in $/MWh	$ 0.2247	$ 0.1234	$ 0.2386	$ -	$ -	$ 0.1791	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000225**	**$ 0.000123**	**$ 0.000239**	**$ -**	**$ -**	**$ 0.000179**	**$ -**	**$ -**

Line #					
1	Total BGS-RSCP Trans Obl	6,901.0	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust	23,970,724.3	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes	25,302,921.3	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 4,274,755		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$ 0.1689	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ 0.17	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ 4,301,497		unrounded	= (6) * (3)
8	Difference due to rounding	$ 26,741		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges for June 2020 - May 2021
Calculation of costs and monthly PJM charges for Allegheny TrAILCo Projects

TEC Charges for June 2020 - May 2021	$ 5,852,026.23	
PSE&G Zonal Transmission Load for Effective Yr. (MW)	9,752.5	
Term (Months)	12	
OATT rate	$ 50.00	/MW/month
converted to $/MW/yr =	$ 600.00	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4,409.3	20.0	69.4	0.0	0.0	3.3	0.0	0.0
Total Annual Energy - MWh	12,156,072.0	100,394.3	180,143.8	766.0	16.0	11,410.5	147,904.0	298,956.0
Energy Charge								
in $/MWh	$ 0.217634	$ 0.119529	$ 0.231149	$ -	$ -	$ 0.173524	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000218**	**$ 0.000120**	**$ 0.000231**	**$ -**	**$ -**	**$ 0.000174**	**$ -**	**$ -**

Line #					
1	Total BGS-RSCP Trans Obl	6,901.0 MW			= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust	23,970,724.3 MWh			= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes	25,302,921.3 MWh		unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 4,140,600		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$ 0.1636	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ 0.16	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ 4,048,467		unrounded	= (6) * (3)
8	Difference due to rounding	$ (92,133)		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges for June 2020 - May 2021
Calculation of costs and monthly PJM charges for PEPCO Projects

TEC Charges for June 2020 - May 2021	$	334,924.60	
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,752.5	
Term (Months)		12	
OATT rate	$	2.86	/MW/month
converted to $/MW/yr =	$	34.32	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4,409.3	20.0	69.4	0.0	0.0	3.3	0.0	0.0
Total Annual Energy - MWh	12,156,072.0	100,394.3	180,143.8	766.0	16.0	11,410.5	147,904.0	298,956.0
Energy Charge								
in $/MWh	$ 0.012449	$ 0.006837	$ 0.013222	$ -	$ -	$ 0.009926	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000012**	**$ 0.000007**	**$ 0.000013**	**$ -**	**$ -**	**$ 0.000010**	**$ -**	**$ -**

Line #					
1	Total BGS-RSCP Trans Obl	6,901.0 MW			= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust	23,970,724.3 MWh			= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes	25,302,921.3 MWh		unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 236,842		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$ 0.0094	/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	$ 253,029		unrounded	= (6) * (3)
8	Difference due to rounding	$ 16,187		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges for June 2020 - May 2021
Calculation of costs and monthly PJM charges for PPL Projects

TEC Charges for June 2020 - May 2021	$24,890,178.97	
PSE&G Zonal Transmission Load for Effective Yr. (MW)	9,752.5	
Term (Months)	12	
OATT rate	$ 212.68	/MW/month
converted to $/MW/yr =	$ 2,552.16	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4,409.3	20.0	69.4	0.0	0.0	3.3	0.0	0.0
Total Annual Energy - MWh	12,156,072.0	100,394.3	180,143.8	766.0	16.0	11,410.5	147,904.0	298,956.0
Energy Charge								
in $/MWh	$ 0.925730	$ 0.508427	$ 0.983214	$ -	$ -	$ 0.738101	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000926**	**$ 0.000508**	**$ 0.000983**	**$ -**	**$ -**	**$ 0.000738**	**$ -**	**$ -**

Line #					
1	Total BGS-RSCP Trans Obl	6,901.0 MW			= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust	23,970,724.3 MWh			= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes	25,302,921.3 MWh		unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 17,612,456		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$ 0.6961	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ 0.70	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ 17,712,045		unrounded	= (6) * (3)
8	Difference due to rounding	$ 99,589		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges for June 2020 - May 2021
Calculation of costs and monthly PJM charges for BG&E

TEC Charges for June 2020 - May 2021	$	280,178.02	
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,752.5	
Term (Months)		12	
OATT rate	$	2.39	/MW/month
converted to $/MW/yr =	$	28.68	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4,409.3	20.0	69.4	0.0	0.0	3.3	0.0	0.0
Total Annual Energy - MWh	12,156,072.0	100,394.3	180,143.8	766.0	16.0	11,410.5	147,904.0	298,956.0
Energy Charge								
in $/MWh	$ 0.010403	$ 0.005713	$ 0.011049	$ -	$ -	$ 0.008294	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000010**	**$ 0.000006**	**$ 0.000011**	**$ -**	**$ -**	**$ 0.000008**	**$ -**	**$ -**

Line #					
1	Total BGS-RSCP Trans Obl	6,901.0 MW			= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust	23,970,724.3 MWh			= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes	25,302,921.3 MWh		unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 197,921		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$ 0.0078	/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	$ 253,029		unrounded	= (6) * (3)
8	Difference due to rounding	$ 55,109		unrounded	= (7) - (4)

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

TEC Charges for Jan 2020 - Dec 2020	$ 2,566,679.33		
PSE&G Zonal Transmission Load for Effective Yr. (MW)	9,752.5		
Term (Months)	12		
OATT rate	$ 21.93	/MW/month	all values show w/o NJ SUT
converted to $/MW/yr =	$ 263.16	/MW/yr	

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4,409.3	20.0	69.4	0.0	0.0	3.3	0.0	0.0
Total Annual Energy - MWh	12,156,072.0	100,394.3	180,143.8	766.0	16.0	11,410.5	147,904.0	298,956.0
Energy Charge								
in $/MWh	$ 0.0955	$ 0.0524	$ 0.1014	$ -	$ -	$ 0.0761	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000095**	**$ 0.000052**	**$ 0.000101**	**$ -**	**$ -**	**$ 0.000076**	**$ -**	**$ -**

Line #					
1	Total BGS-RSCP Trans Obl	6,901.0	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust	23,970,724.3	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes	25,302,921.3	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 1,816,067		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$ 0.0718	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ 0.07	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ 1,771,204		unrounded	= (6) * (3)
8	Difference due to rounding	$ (44,863)		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges for June 2020 - May 2021
Calculation of costs and monthly PJM charges for PECO Energy Company Transmission Projects

TEC Charges for June 2020 - May 2021	$ 2,454,222.08	
PSE&G Zonal Transmission Load for Effective Yr. (MW)	9,752.5	
Term (Months)	12	
OATT rate	$ 20.97	/MW/month
converted to $/MW/yr =	$ 251.64	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4,409.3	20.0	69.4	0.0	0.0	3.3	0.0	0.0
Total Annual Energy - MWh	12,156,072.0	100,394.3	180,143.8	766.0	16.0	11,410.5	147,904.0	298,956.0
Energy Charge								
in $/MWh	$ 0.091276	$ 0.050130	$ 0.096944	$ -	$ -	$ 0.072776	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000091**	**$ 0.000050**	**$ 0.000097**	**$ -**	**$ -**	**$ 0.000073**	**$ -**	**$ -**

Line #					
1	Total BGS-RSCP Trans Obl	6,901.0	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust	23,970,724.3	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes	25,302,921.3	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 1,736,568		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$ 0.0686	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ 0.07	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ 1,771,204		unrounded	= (6) * (3)
8	Difference due to rounding	$ 34,637		unrounded	= (7) - (4)

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

TEC Charges for Jan 2020 - Dec 2020	$ 1,522,376.41	
PSE&G Zonal Transmission Load for Effective Yr. (MW)	9,752.5	
Term (Months)	12	
OATT rate	$ 13.01	/MW/month
converted to $/MW/yr =	$ 156.12	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4,409.3	20.0	69.4	0.0	0.0	3.3	0.0	0.0
Total Annual Energy - MWh	12,156,072.0	100,394.3	180,143.8	766.0	16.0	11,410.5	147,904.0	298,956.0
Energy Charge								
in $/MWh	$ 0.0566	$ 0.0311	$ 0.0601	$ -	$ -	$ 0.0452	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000057**	**$ 0.000031**	**$ 0.000060**	**$ -**	**$ -**	**$ 0.000045**	**$ -**	**$ -**

Line #					
1	Total BGS-RSCP Trans Obl	6,901.0 MW			= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust	23,970,724.3 MWh			= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes	25,302,921.3 MWh		unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 1,077,384		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$ 0.0426	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ 0.04	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ 1,012,117		unrounded	= (6) * (3)
8	Difference due to rounding	$ (65,267)		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges for January 2020 - December 2020
Calculation of costs and monthly PJM charges for FERC-Approved ER18-680 and Form 715 Projects

TEC Charges for Jan 2020 - Dec 2020	($92,235,403.63)	
PSE&G Zonal Transmission Load for Effective Yr. (MW)	9,752.5	
Term (Months)	12	
OATT rate	$ (788.13) /MW/month	all values show w/o NJ SUT
converted to $/MW/yr =	$ (9,457.56) /MW/yr	

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4,409.3	20.0	69.4	0.0	0.0	3.3	0.0	0.0
Total Annual Energy - MWh	12,156,072.0	100,394.3	180,143.8	766.0	16.0	11,410.5	147,904.0	298,956.0
Energy Charge								
in $/MWh	$ (3.4305)	$ (1.8841)	$ (3.6435)	$ -	$ -	$ (2.7352)	$ -	$ -
in $/kWh - rounded to 6 places	**$ (0.003430)**	**$ (0.001884)**	**$ (0.003644)**	**$ -**	**$ -**	**$ (0.002735)**	**$ -**	**$ -**

Line #				
1	Total BGS-RSCP Trans Obl	6,901.0 MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust	23,970,724.3 MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes	25,302,921.3 MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ (65,266,622)	unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$ (2.5794) /MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ (2.58) /MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ (65,281,537)	unrounded	= (6) * (3)
8	Difference due to rounding	$ (14,915)	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 TrailCo TEC into Customer Rates)
- Attachment 3g (JCP&L Translation of PEPCO TEC into Customer Rates)
- Attachment 3h (JCP&L Translation of PPL TEC into Customer Rates)
- Attachment 3i (JCP&L Translation of BG&E TEC into Customer Rate)
- Attachment 3j (JCP&L Translation of MAIT TEC into Customer Rates)
- Attachment 3k (JCP&L Translation of PECO TEC into Customer Rates)
- Attachment 3l (JCP&L Translation of AEP East TEC into Customer Rates)
- Attachment 3m (JCP&L Translation of ER18-680 and Form 715 TEC into Customer Rates)

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: $0.009020** 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: $2.78** per month
Supplemental Customer Charge: $1.45 per month Off-Peak/Controlled Water Heating

2) **Distribution Charge:**

June through September:
$0.015108 per KWH for the first 600 KWH (except Water Heating)
$0.059743 per KWH for all KWH over 600 KWH (except Water Heating)

October through May:
$0.024749 per KWH for all KWH (except Water Heating)

Water Heating Service:
$0.016517 per KWH for all KWH for Off-Peak Water Heating
$0.021756 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: $0.009020** 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: $5.19** per month
Solar Water Heating Credit: $1.30 per month

2) **Distribution Charge:**
$0.046298 per KWH for all KWH on-peak for June through September
$0.034008 per KWH for all KWH on-peak for October through May
$0.021627 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)**
$0.000114 per KWH for all KWH on-peak and off-peak

4) **Societal Benefits Charge (Rider SBC):**
$0.007178 per KWH for all KWH on-peak and off-peak

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

6) **Zero Emission Certificate Recovery Charge (Rider ZEC):**
See Rider ZEC for rate per KWH for all KWH on-peak and off-peak

7) **Tax Act Adjustment (Rider TAA):**
See Rider TAA for rate per KWH for all KWH on-peak and off-peak

8) **JCP&L Reliability Plus Charge (Rider RP):**
See Rider RP for rate per KWH for all KWH on-peak and off-peak

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:
$0.009020 per KWH for all KWH on-peak and off-peak for June through September
$0.009020 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: $5.19 per month

2) Distribution Charge:

June through September:
$0.046298 per KWH for all KWH on-peak
$0.021627 per KWH for all KWH off-peak

October through May:
$0.024749 per KWH for all KWH

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 12 ELECTRIC - PART III **XX Rev. Sheet No. 10**
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:**
$0.009020 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:** **$ 3.10** per month single-phase
$11.13 per month three-phase

Supplemental Customer Charge: **$ 1.45** per month Off-Peak/Controlled Water Heating
$ 2.54 per month Day/Night Service
$11.57 per month Traffic Signal Service

2) **Distribution Charge:**

KW Charge: (Demand Charge)
$ 6.63 per maximum KW during June through September, in excess of 10 KW
$ 6.17 per maximum KW during October through May, in excess of 10 KW
$ 3.01 per KW Minimum Charge, in excess of 10 KW

JERSEY CENTRAL POWER & LIGHT COMPANY

BPU No. 12 ELECTRIC - PART III **XX Rev. Sheet No. 14**
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: $0.009020** 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: $29.86** per month single-phase
$42.61 per month three-phase

2) **Distribution Charge:**

KW Charge: (Demand Charge)
$ 7.02 per maximum KW during June through September
$ 6.56 per maximum KW during October through May
$ 3.06 per KW Minimum Charge

KWH Charge:
$0.004661 per KWH for all KWH on-peak
$0.004661 per KWH for all KWH off-peak

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: $0.006303** per KWH for all KWH

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

1) **Customer Charge: $52.56** per month

2) **Distribution Charge:**

KW Charge: (Demand Charge)
$ 5.48 per maximum KW during June through September
$ 5.09 per maximum KW during October through May
$ 1.86 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:
$0.003358 per KWH for all KWH on-peak and off-peak

3) **Non-utility Generation Charge (Rider NGC):**
$0.000109 per KWH for all KWH on-peak and off-peak

4) **Societal Benefits Charge (Rider SBC)**:
$0.007178 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) **RGGI Recovery Charge (Rider RRC):**
See Rider RRC for rate per KWH for all KWH on-peak and off-peak

7) **Zero Emission Certificate Recovery Charge (Rider ZEC):**
See Rider ZEC for rate per KWH for all KWH on-peak and off-peak

8) **Tax Act Adjustment (Rider TAA):**
See Rider TAA for rate per KWH for all KWH on-peak and off-peak

9) **JCP&L Reliability Plus Charge (Rider RP):**
See Rider RP for rate per KW for all KW

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: $0.005522** per KWH for all KWH
$0.001209 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: $225.70** per month

2) **Distribution Charge:**

KW Charge: (Demand Charge)
$ 3.52 per maximum KW
$ 0.94 per KW High Tension Service Credit
$ 2.34 per KW DOD Service Credit

KW Minimum Charge: (Demand Charge)
$ 1.07 per KW Minimum Charge
$ 0.70 per KW DOD Service Credit
$ 0.45 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:
$0.002595 per KWH for all KWH on-peak and off-peak
$0.000921 per KWH High Tension Service Credit
$0.001687 per KWH DOD Service Credit

3) **Non-utility Generation Charge (Rider NGC):**
$ 0.000107 per KWH for all KWH on-peak and off-peak – excluding High Tension Service
$ 0.000104 per KWH for all KWH on-peak and off-peak – High Tension Service

4) **Societal Benefits Charge (Rider SBC)**:
$0.007178 per KWH for all KWH on-peak and off-peak

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

2) BGS Transmission Charge per KWH: As provided in the respective tariff for Service Classifications RS, RT, RGT, GS, GST, OL, SVL, MVL, ISL and LED. Effective September 1, 2019, a RMR surcharge of **$0.000000** per KWH (includes Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage.

Effective **February 1, 2020**, the following TEC surcharges (include Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage, except lighting under Service Classifications OL, SVL, MVL, ISL and LED:

PATH-TEC surcharge of (**$0.000003)** per KWH
EL05-121-TEC surcharge of **$0.000228** per KWH

Effective **September 1, 2020**, the following TEC surcharges (include Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage, except lighting under Service Classifications OL, SVL, MVL, ISL and LED:

Delmarva-TEC surcharge of **$0.000004** per KWH
SRE-TEC surcharge of **$0.000107** per KWH
NIPSCO-TEC surcharge of **$0.000001** per KWH
COMED-TEC surcharge of **$0.000001** Per KWH

Effective **November 1, 2020**, the following TEC surcharges (include Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage, except lighting under Service Classifications OL, SVL, MVL, ISL and LED:

PSEG-TEC surcharge of **$0.002768** per KWH
ACE-TEC surcharge of **$0.000084** per KWH
VEPCO-TEC surcharge of **$0.000219** per KWH
TRAILCO-TEC surcharge of **$0.000245** per KWH
PEPCO-TEC surcharge of **$0.000014** per KWH
PPL-TEC surcharge of **$0.000805** per KWH
BG&E-TEC surcharge of **$0.000011** per KWH
MAIT-TEC surcharge of **$0.000100** per KWH
PECO-TEC surcharge of **$0.000067** per KWH
AEP-East-TEC surcharge of **$0.000051** per KWH
EL18-680FM715-TEC surcharge of (**$0.000002)** per KWH

3) BGS Reconciliation Charge per KWH: ($0.002637) (includes Sales and Use Tax as provided in Rider SUT)

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

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 **February 1, 2020**, the following TEC surcharges (include Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage:

	PATH-TEC	EL05-121-TEC
GS and GST	**($0.000003)**	**$0.000228**
GP	**($0.000002)**	**$0.000149**
GT	**($0.000002)**	**$0.000131**
GT – High Tension Service	**($0.000000)**	**$0.000030**

Effective **September 1, 2020**, the following TEC surcharges (include Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage:

	Delmarva-TEC	SRE-TEC	NIPSCO-TEC	COMED-TEC
GS and GST	**$0.000004**	**$0.000107**	**$0.000001**	**$0.000001**
GP	**$0.000003**	**$0.000069**	**$0.000001**	**$0.000000**
GT	**$0.000002**	**$0.000061**	**$0.000001**	**$0.000000**
GT – High Tension Service	**$0.000001**	**$0.000014**	**$0.000000**	**$0.000000**

Effective **November 1, 2020**, the following TEC surcharges (include Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage:

	PSEG-TEC	ACE-TEC	VEPCO-TEC	TRAILCO-TEC
GS and GST	**$0.002768**	**$0.000084**	**$0.000219**	**$0.000245**
GP	**$0.001751**	**$0.000053**	**$0.000139**	**$0.000156**
GT	**$0.001582**	**$0.000048**	**$0.000125**	**$0.000141**
GT – High Tension Service	**$0.000496**	**$0.000015**	**$0.000039**	**$0.000044**

	PEPCO-TEC	PPL-TEC	BG&E-TEC	MAIT-TEC
GS and GST	**$0.000014**	**$0.000805**	**$0.000011**	**$0.000100**
GP	**$0.000009**	**$0.000510**	**$0.000007**	**$0.000064**
GT	**$0.000007**	**$0.000461**	**$0.000006**	**$0.000058**
GT – High Tension Service	**$0.000002**	**$0.000144**	**$0.000002**	**$0.000018**

	PECO-TEC	AEP-East-TEC	EL18-680Fm715-TEC
GS and GST	**$0.000067**	**$0.000051**	**($0.000002)**
GP	**$0.000043**	**$0.000032**	**($0.000001)**
GT	**$0.000038**	**$0.000029**	**($0.000001)**
GT – High Tension Service	**$0.000012**	**$0.000010**	**($0.000000)**

4) BGS Reconciliation Charge per KWH: $0.002170 (includes Sales and Use Tax as provided in Rider SUT)
The above BGS Reconciliation Charge recovers the difference between the payments to BGS suppliers and the revenues from BGS customers for Basic Generation Service and is subject to quarterly true-ups.

Attachment 3b - JCP&L Translation of NITS Charge into BGS Customer Rates (Riders RSCP and CIEP)

NITS Charges for January 2020 through December 2020 -

JCP&L Annual NITS Revenue Requirement	147,518,299	
JCP&L Customer Share of Schedule 12 TEC	8,580,782	
NITS Charges for January 2020 - December 2020	156,099,081	
JCP&L Zonal Transmission Load for 2020	6,057.10	(MW)
2020 NITS Rate	$25,771.26	(per MW-yr)
Resulting BGS Firm Transmission Service Supplier Rate	$70.41	(per MW-day)
Change in BGS Firm Transmission Service Supplier Rate	-$0.11	(per MW-day)

Effective November 1, 2020:

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)	5,230.8	$ 134,804,208	15,933,921,417	$0.008460	$0.009020
Primary	364.5	$ 9,393,039	1,589,192,784	$0.005911	$0.006303
Transmission @ 34.5 kV	293.2	$ 7,556,747	1,459,178,627	$0.005179	$0.005522
Transmission @ 230 kV	15.1	$ 389,200	343,139,121	$0.001134	$0.001209
Total	5,903.6	$ 152,143,193	19,325,431,948		

BGS-RSCP Supplier Payment Adjustment

Line No.			
1	BGS-RSCP Eligible Sales January through December @ Customer	14,746,643	MWH
2	BGS-RSCP Eligible Sales January through December @ Transmission Node	16,356,493	MWH
3	BGS-RSCP Eligible Transmission Obligation	4,981	MW
4	Change in Transmission Payment to RSCP Suppliers	($194,589)	= Line 3 x -$0.11 x 366
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	($0.01)	= Line 4 / Line 2

Attachment 3c

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

2020/2021 Average Monthly PSEG-TEC Costs Allocated to JCP&L Zone	$3,958,054.95	(1)
2020 JCP&L Zone Transmission Peak Load (MW)	6,057.10	
PSEG-Transmission Enhancement Rate ($/MW-month)	$653.46	

				Effective November 1, 2020	
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	PSEG-TEC Surcharge ($/kWh)	PSEG-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5,274.3	$41,357,963	15,933,921,417	$0.002596	$0.002768
Primary	332.7	$2,608,874	1,589,192,784	$0.001642	$0.001751
Transmission @ 34.5 kV	276.2	$2,165,947	1,459,178,627	$0.001484	$0.001582
Transmission @ 230 kV	20.3	$159,422	343,139,121	$0.000465	$0.000496
Total	5,903.5	$46,292,207	19,325,431,948		

(1) Cost Allocation of PSEG Project Schedule 12 Charges to JCP&L Zone for 2020
(2) Based on 12 months PSEG Project costs from January 2020 through December 2020
(3) November 2020 through October 2021

BGS-RSCP Supplier Payment Adjustment

Line No.			
1	BGS-RSCP Eligible Sales June through May @ Customer	14,746,643	MWH
2	BGS-RSCP Eligible Sales June through May @ Transmission Node	16,356,493	MWH
3	BGS-RSCP Eligible Transmission Obligation	4,981.42	MW
4	PSEG-Transmission Enhancement Costs to RSCP Suppliers	$39,061,904	= Line 3 x $653.46 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$2.39	= Line 4 / Line 2

Attachment 3d

Jersey Central Power & Light Company
Proposed ACE Project Transmission Enhancement Charge (ACE-TEC Surcharge) effective November 1, 2020
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 2020 - May 2021

2020/2021 Average Monthly ACE-TEC Costs Allocated to JCP&L Zone	$120,612.90	(1)
2020 JCP&L Zone Transmission Peak Load (MW)	6,057.10	
ACE-Transmission Enhancement Rate ($/MW-month)	$19.91	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	**Effective November 1, 2020** ACE-TEC Surcharge ($/kWh)	ACE-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5,274.3	$1,260,292	15,933,921,417	$0.000079	$0.000084
Primary	332.7	$79,500	1,589,192,784	$0.000050	$0.000053
Transmission @ 34.5 kV	276.2	$66,002	1,459,178,627	$0.000045	$0.000048
Transmission @ 230 kV	20.3	$4,858	343,139,121	$0.000014	$0.000015
Total	5,903.5	$1,410,652	19,325,431,948		

(1) Cost Allocation of ACE Project Schedule 12 Charges to JCP&L Zone for 2020/2021
(2) Based on 12 months ACE Project costs from June 2020 through May 2021
(3) November 2020 through October 2021

BGS-RSCP Supplier Payment Adjustment

Line No.			
1	BGS-RSCP Eligible Sales June through May @ Customer	14,746,643	MWH
2	BGS-RSCP Eligible Sales June through May @ Transmission Node	16,356,493	MWH
3	BGS-RSCP Eligible Transmission Obligation	4,981.42	MW
4	ACE-Transmission Enhancement Costs to RSCP Suppliers	$1,190,161	= Line 3 x $19.91 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$0.07	= Line 4 / Line 2

Attachment 3e

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

2020/2021 Average Monthly VEPCO-TEC Costs Allocated to JCP&L Zone	$313,303.02	(1)
2020 JCP&L Zone Transmission Peak Load (MW)	6,057.10	
VEPCO-Transmission Enhancement Rate ($/MW-month)	$51.72	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	**Effective November 1, 2020** VEPCO-TEC Surcharge ($/kWh)	VEPCO-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5,274.3	$3,273,723	15,933,921,417	$0.000205	$0.000219
Primary	332.7	$206,508	1,589,192,784	$0.000130	$0.000139
Transmission @ 34.5 kV	276.2	$171,447	1,459,178,627	$0.000117	$0.000125
Transmission @ 230 kV	20.3	$12,619	343,139,121	$0.000037	$0.000039
Total	5,903.5	$3,664,297	19,325,431,948		

(1) Cost Allocation of VEPCO Project Schedule 12 Charges to JCP&L Zone for 2020
(2) Based on 12 months VEPCO Project costs from January 2020 through December 2020
(3) November 2020 through October 2021

BGS-RSCP Supplier Payment Adjustment

Line No.			
1	BGS-RSCP Eligible Sales June through May @ Customer	14,746,643	MWH
2	BGS-RSCP Eligible Sales June through May @ Transmission Node	16,356,493	MWH
3	BGS-RSCP Eligible Transmission Obligation	4,981.42	MW
4	VEPCO-Transmission Enhancement Costs to RSCP Suppliers	$3,091,668	= Line 3 x $51.72 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$0.19	= Line 4 / Line 2

Attachment 3f

Jersey Central Power & Light Company
Proposed TRAILCO Project Transmission Enhancement Charge (TRAILCO-TEC Surcharge) effective November 1, 2020
To reflect FERC-approved TRAILCO Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 2020 - May 2021

2020/2021 Average Monthly TRAILCO-TEC Costs Allocated to JCP&L Zone	$351,286.75	(1)
2020 JCP&L Zone Transmission Peak Load (MW)	6,057.10	
TRAILCO-Transmission Enhancement Rate ($/MW-month)	$58.00	

				Effective November 1, 2020	
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)	5,274.3	$3,670,617	15,933,921,417	$0.000230	$0.000245
Primary	332.7	$231,544	1,589,192,784	$0.000146	$0.000156
Transmission @ 34.5 kV	276.2	$192,233	1,459,178,627	$0.000132	$0.000141
Transmission @ 230 kV	20.3	$14,149	343,139,121	$0.000041	$0.000044
Total	5,903.5	$4,108,543	19,325,431,948		

(1) Cost Allocation of TRAILCO Project Schedule 12 Charges to JCP&L Zone for 2020/2021
(2) Based on 12 months TRAILCO Project costs from June 2020 through May 2021
(3) November 2020 through October 2021

BGS-RSCP Supplier Payment Adjustment

Line No.			
1	BGS-RSCP Eligible Sales June through May @ Customer	14,746,643	MWH
2	BGS-RSCP Eligible Sales June through May @ Transmission Node	16,356,493	MWH
3	BGS-RSCP Eligible Transmission Obligation	4,981.42	MW
4	TRAILCO-Transmission Enhancement Costs to RSCP Suppliers	$3,467,068	= Line 3 x $58 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$0.21	= Line 4 / Line 2

Attachment 3g

Jersey Central Power & Light Company
Proposed PEPCO Project Transmission Enhancement Charge (PEPCO-TEC Surcharge) effective November 1, 2020
To reflect FERC-approved PEPCO Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 2020 - May 2021

2020/2021 Average Monthly PEPCO-TEC Costs Allocated to JCP&L Zone	$19,171.47	(1)
2020 JCP&L Zone Transmission Peak Load (MW)	6,057.10	
PEPCO-Transmission Enhancement Rate ($/MW-month)	$3.17	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	**Effective November 1, 2020** PEPCO-TEC Surcharge ($/kWh)	PEPCO-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5,274.3	$200,324	15,933,921,417	$0.000013	$0.000014
Primary	332.7	$12,636	1,589,192,784	$0.000008	$0.000009
Transmission @ 34.5 kV	276.2	$10,491	1,459,178,627	$0.000007	$0.000007
Transmission @ 230 kV	20.3	$772	343,139,121	$0.000002	$0.000002
Total	5,903.5	$224,224	19,325,431,948		

(1) Cost Allocation of PEPCO Project Schedule 12 Charges to JCP&L Zone for 2020/2021
(2) Based on 12 months PEPCO Project costs from June 2020 through May 2021
(3) November 2020 through October 2021

BGS-RSCP Supplier Payment Adjustment

Line No.			
1	BGS-RSCP Eligible Sales June through May @ Customer	14,746,643	MWH
2	BGS-RSCP Eligible Sales June through May @ Transmission Node	16,356,493	MWH
3	BGS-RSCP Eligible Transmission Obligation	4,981.42	MW
4	PEPCO-Transmission Enhancement Costs to RSCP Suppliers	$189,493	= Line 3 x $3.17 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$0.01	= Line 4 / Line 2

Attachment 3h

Jersey Central Power & Light Company
Proposed PPL Project Transmission Enhancement Charge (PPL-TEC Surcharge) effective November 1, 2020
To reflect FERC-approved PPL Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 2020 - May 2021

2020/2021 Average Monthly PPL-TEC Costs Allocated to JCP&L Zone	$1,151,754.28	(1)
2020 JCP&L Zone Transmission Peak Load (MW)	6,057.10	
PPL-Transmission Enhancement Rate ($/MW-month)	$190.15	

				Effective November 1, 2020	
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	PPL-TEC Surcharge ($/kWh)	PPL-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5,274.3	$12,034,752	15,933,921,417	$0.000755	$0.000805
Primary	332.7	$759,156	1,589,192,784	$0.000478	$0.000510
Transmission @ 34.5 kV	276.2	$630,269	1,459,178,627	$0.000432	$0.000461
Transmission @ 230 kV	20.3	$46,390	343,139,121	$0.000135	$0.000144
Total	5,903.5	$13,470,568	19,325,431,948		

(1) Cost Allocation of PPL Project Schedule 12 Charges to JCP&L Zone for 2020/2021
(2) Based on 12 months PPL Project costs from June 2020 through May 2021
(3) November 2020 through October 2021

BGS-RSCP Supplier Payment Adjustment

Line No.			
1	BGS-RSCP Eligible Sales June through May @ Customer	14,746,643	MWH
2	BGS-RSCP Eligible Sales June through May @ Transmission Node	16,356,493	MWH
3	BGS-RSCP Eligible Transmission Obligation	4,981.42	MW
4	PPL-Transmission Enhancement Costs to RSCP Suppliers	$11,366,604	= Line 3 x $190.15 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$0.69	= Line 4 / Line 2

Attachment 3i

Jersey Central Power & Light Company
Proposed BG&E Project Transmission Enhancement Charge (BG&E-TEC Surcharge) effective November 1, 2020
To reflect FERC-approved BG&E Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 2020 - May 2021

2020/2021 Average Monthly BG&E-TEC Costs Allocated to JCP&L Zone	$15,996.90	(1)
2020 JCP&L Zone Transmission Peak Load (MW)	6,057.10	
BG&E-Transmission Enhancement Rate ($/MW-month)	$2.64	

				Effective November 1, 2020	
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)	5,274.3	$167,153	15,933,921,417	$0.000010	$0.000011
Primary	332.7	$10,544	1,589,192,784	$0.000007	$0.000007
Transmission @ 34.5 kV	276.2	$8,754	1,459,178,627	$0.000006	$0.000006
Transmission @ 230 kV	20.3	$644	343,139,121	$0.000002	$0.000002
Total	5,903.5	$187,095	19,325,431,948		

(1) Cost Allocation of BG&E Project Schedule 12 Charges to JCP&L Zone for 2020/2021
(2) Based on 12 months BG&E Project costs from June 2020 through May 2021
(3) November 2020 through October 2021

BGS-RSCP Supplier Payment Adjustment

Line No.			
1	BGS-RSCP Eligible Sales June through May @ Customer	14,746,643	MWH
2	BGS-RSCP Eligible Sales June through May @ Transmission Node	16,356,493	MWH
3	BGS-RSCP Eligible Transmission Obligation	4,981.42	MW
4	BG&E-Transmission Enhancement Costs to RSCP Suppliers	$157,811	= Line 3 x $2.64 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 MAIT Project Transmission Enhancement Charge (MAIT-TEC Surcharge) effective November 1, 2020

To reflect FERC-approved MAIT Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 2020 - December 2020

2020/2021 Average Monthly MAIT-TEC Costs Allocated to JCP&L Zone	$143,943.29	(1)
2020 JCP&L Zone Transmission Peak Load (MW)	6,057.10	
MAIT-Transmission Enhancement Rate ($/MW-month)	$23.76	

				Effective November 1, 2020	
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	MAIT-TEC Surcharge ($/kWh)	MAIT-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5,274.3	$1,504,072	15,933,921,417	$0.000094	$0.000100
Primary	332.7	$94,877	1,589,192,784	$0.000060	$0.000064
Transmission @ 34.5 kV	276.2	$78,769	1,459,178,627	$0.000054	$0.000058
Transmission @ 230 kV	20.3	$5,798	343,139,121	$0.000017	$0.000018
Total	5,903.5	$1,683,517	19,325,431,948		

(1) Cost Allocation of MAIT Project Schedule 12 Charges to JCP&L Zone for 2020
(2) Based on 12 months MAIT Project costs from January 2020 through December 2020
(3) November 2020 through October 2021

BGS-RSCP Supplier Payment Adjustment

Line No.			
1	BGS-RSCP Eligible Sales June through May @ Customer	14,746,643	MWH
2	BGS-RSCP Eligible Sales June through May @ Transmission Node	16,356,493	MWH
3	BGS-RSCP Eligible Transmission Obligation	4,981.42	MW
4	MAIT-Transmission Enhancement Costs to RSCP Suppliers	$1,420,302	= Line 3 x $23.76 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$0.09	= Line 4 / Line 2

Attachment 3k

Jersey Central Power & Light Company
Proposed PECO Project Transmission Enhancement Charge (PECO-TEC Surcharge) effective November 1, 2020
To reflect FERC-approved PECO Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective June 2020 - May 2021

2020/2021 Average Monthly PECO-TEC Costs Allocated to JCP&L Zone	$95,606.55	(1)
2020 JCP&L Zone Transmission Peak Load (MW)	6,057.10	
PECO-Transmission Enhancement Rate ($/MW-month)	$15.78	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	Effective November 1, 2020 PECO-TEC Surcharge ($/kWh)	Effective November 1, 2020 PECO-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5,274.3	$998,999	15,933,921,417	$0.000063	$0.000067
Primary	332.7	$63,017	1,589,192,784	$0.000040	$0.000043
Transmission @ 34.5 kV	276.2	$52,318	1,459,178,627	$0.000036	$0.000038
Transmission @ 230 kV	20.3	$3,851	343,139,121	$0.000011	$0.000012
Total	5,903.5	$1,118,185	19,325,431,948		

(1) Cost Allocation of PECO Project Schedule 12 Charges to JCP&L Zone for 2020/2021
(2) Based on 12 months PECO Project costs from June 2020 through May 2021
(3) November 2020 through October 2021

BGS-RSCP Supplier Payment Adjustment

Line No.			
1	BGS-RSCP Eligible Sales June through May @ Customer	14,746,643	MWH
2	BGS-RSCP Eligible Sales June through May @ Transmission Node	16,356,493	MWH
3	BGS-RSCP Eligible Transmission Obligation	4,981.42	MW
4	PECO-Transmission Enhancement Costs to RSCP Suppliers	$943,282	= Line 3 x $15.78 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$0.06	= Line 4 / Line 2

Attachment 3l

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

2020/2021 Average Monthly AEP-East-TEC Costs Allocated to JCP&L Zone	$72,605.27	(1)
2020 JCP&L Zone Transmission Peak Load (MW)	6,057.10	
AEP-East-Transmission Enhancement Rate ($/MW-month)	$11.99	

				Effective November 1, 2020	
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)	5,274.3	$758,657	15,933,921,417	$0.000048	$0.000051
Primary	332.7	$47,856	1,589,192,784	$0.000030	$0.000032
Transmission @ 34.5 kV	276.2	$39,731	1,459,178,627	$0.000027	$0.000029
Transmission @ 230 kV	20.3	$2,924	343,139,121	$0.000009	$0.000010
Total	5,903.5	$849,169	19,325,431,948		

(1) Cost Allocation of AEP-East Project Schedule 12 Charges to JCP&L Zone for 2020
(2) Based on 12 months AEP-East Project costs from January 2020 through December 2020
(3) November 2020 through October 2021

BGS-RSCP Supplier Payment Adjustment

Line No.			
1	BGS-RSCP Eligible Sales June through May @ Customer	14,746,643	MWH
2	BGS-RSCP Eligible Sales June through May @ Transmission Node	16,356,493	MWH
3	BGS-RSCP Eligible Transmission Obligation	4,981.42	MW
4	AEP-East-Transmission Enhancement Costs to RSCP Suppliers	$716,727	= Line 3 x $11.99 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$0.04	= Line 4 / Line 2

Attachment 3m

Jersey Central Power & Light Company

Proposed EL18-680Fm715 Project Transmission Enhancement Charge (EL18-680Fm715-TEC Surcharge) effective November 1, 2020

To reflect FERC-approved EL18-680Fm715 Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective August 2020 - March 2021

2020/2021 Average Monthly EL18-680Fm715-TEC Costs Allocated to JCP&L Zone	($2,560.58)	(1)
2020 JCP&L Zone Transmission Peak Load (MW)	6,057.10	
EL18-680Fm715-Transmission Enhancement Rate ($/MW-month)	($0.42)	

				Effective November 1, 2020	
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	EL18-680Fm715-TEC Surcharge ($/kWh)	EL18-680Fm715-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5,274.3	-$26,756	15,933,921,417	($0.000002)	($0.000002)
Primary	332.7	-$1,688	1,589,192,784	($0.000001)	($0.000001)
Transmission @ 34.5 kV	276.2	-$1,401	1,459,178,627	($0.000001)	($0.000001)
Transmission @ 230 kV	20.3	-$103	343,139,121	$0.000000	$0.000000
Total	5,903.5	-$29,948	19,325,431,948		

(1) Cost Allocation of EL18-680Fm715 Project Schedule 12 Charges to JCP&L Zone for 2015 through 2020
(2) Based on 8 months EL18-680Fm715 Project costs from August 2020 through March 2021
(3) November 2020 through October 2021

BGS-RSCP Supplier Payment Adjustment

Line No.			
1	BGS-RSCP Eligible Sales June through May @ Customer	14,746,643	MWH
2	BGS-RSCP Eligible Sales June through May @ Transmission Node	16,356,493	MWH
3	BGS-RSCP Eligible Transmission Obligation	4,981.42	MW
4	EL18-680Fm715-Transmission Enhancement Costs to RSCP Suppliers	($25,106)	= Line 3 x $-0.42 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$0.00	= 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 Translations of JCP&L TEC into Customer Rates
- Attachment 4e (ACE Translation of VEPCo TEC into Customer Rates)
- Attachment 4f (ACE Translation of TrailCo TEC into Customer Rates)
- Attachment 4g (ACE Translation of PEPCO TEC into Customer Rates)
- Attachment 4h(ACE Translation of PPL TEC into Customer Rates)
- Attachment 4i (ACE Translation of BG&E TEC into Customer Rates)
- Attachment 4j (ACE Translation of MAIT TEC into Customer Rates)
- Attachment 4k (ACE Translation of PECO TEC into Customer Rates)
- Attachment 4l (ACE Translation of AEP East TEC into Customer Rates)
- Attachment 4m (ACE Translation of ER18-680 and Form 715 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)	$5.77	$5.77
Distribution Rates ($/kWH)		
First Block	$0.065988	$0.060436
(Summer <= 750 kWh; Winter<= 500kWh)		
Excess kWh	$0.076732	$0.060436
Non-Utility Generation Charge (NGC) ($/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	$0.018931	$0.018931
Reliability Must Run Transmission Surcharge	$0.000000	
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI	
Infrastructure Investment Program Charge	See Rider IIP	

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	**WINTER**
	June Through September	October Through May
Delivery Service Charges:		
Customer Charge		
Single Phase	$9.96	$9.96
Three Phase	$11.59	$11.59
Distribution Demand Charge (per kW)	$2.70	$2.22
Reactive Demand Charge	$0.58	$0.58
(For each kvar over one-third of kW demand**)**		
Distribution Rates ($/kWh)	$0.057810	$0.051659
Non-Utility Generation Charge (NGC) ($/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)	$4.21	$3.83
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000000	
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI	
Infrastructure Investment Program Charge	See Rider IIP	

The minimum monthly bill will be $9.96 per month plus any applicable adjustment.

Date of Issue: **Effective Date:**

Issued by:

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	$14.70	$14.70
Three Phase	$15.97	$15.97
Distribution Demand Charge (per kW)	$1.58	$1.23
Reactive Demand Charge	$0.43	$0.43
(For each kvar over one-third of kW demand)		
Distribution Rates ($/kWh)	$0.044529	$0.043256
Non-Utility Generation Charge (NGC) ($/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	$2.51	$2.16
($/kW for each kW in excess of 3 kW)		
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000000	
Transmission Enhancement Charge ($/kWh)	See Rider BGS	
Basic Generation Service Charge ($/kWh)	See Rider BGS	
Regional Greenhouse Gas Initiative		
Recovery Charge ($/kWh)	See Rider RGGI	
Infrastructure Investment Program Charge	See Rider IIP	

The minimum monthly bill will be $14.70 per month plus any applicable adjustment.

Date of Issue: **Effective Date:**

Issued by:

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	$193.22
Distribution Demand Charge ($/kW)	$11.16
Reactive Demand (for each kvar over one-third of kW demand)	$0.86
Non-Utility Generation Charge (NGC) ($/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)	$3.40
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000000
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI
Infrastructure Investment Program Charge	See Rider IIP

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.

VETERANS' ORGANIZATION SERVICE
Pursuant to N.J.S.A 48:2-21.41, when electric service is delivered to a customer that is a veterans' organization, and where the primary use of the service is dedicated to serving the needs of veterans of the armed forces, and the customer applies for and is eligible for such service.

Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this rate schedule and by qualifying as a "Veterans' Organization" as defined by N.J.S.A. 48:2-21.41 as "an organization dedicated to serving the needs of veterans of the armed forces that: is chartered under federal law, qualifies as a tax exempt organization under paragraph (19) of subsection (c) of section 501 of the federal Internal Revenue Code of 1986, 26 U.S.C. s.501 (c)(19), or that is organized as a corporation under the 'New Jersey Nonprofit Corporation Act,' N.J.S.15A:1-1 et seq." Under N.J.S.A. 48: 2-21.41, a qualified Veterans' Organization shall be charged the residential rate for service delivered to the property where the Veterans' Organization primarily operates, if the residential rate is lower than the commercial rate for service at that property. The customer shall furnish satisfactory proof of eligibility of service under this special provision to the Company, who will determine eligibility.

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	$744.15
Distribution Demand Charge ($/kW)	$8.89
Reactive Demand (for each kvar over one-third of kW demand)	$0.67
Non-Utility Generation Charge (NGC) ($/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)	$3.15
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000000
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI
Infrastructure Investment Program Charge	See Rider IIP

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.

VETERANS' ORGANIZATION SERVICE
Pursuant to N.J.S.A 48:2-21.41, when electric service is delivered to a customer that is a veterans' organization, and where the primary use of the service is dedicated to serving the needs of veterans of the armed forces, and the customer applies for and is eligible for such service.

Each customer shall be eligible for billing under this Special Provision upon submitting an Application for Veterans' Organization Service under this rate schedule and by qualifying as a "Veterans' Organization" as defined by N.J.S.A. 48:2-21.41 as "an organization dedicated to serving the needs of veterans of the armed forces that: is chartered under federal law, qualifies as a tax exempt organization under paragraph (19) of subsection (c) of section 501 of the federal Internal Revenue Code of 1986, 26 U.S.C. s.501 (c)(19), or that is organized as a corporation under the 'New Jersey Nonprofit Corporation Act,' N.J.S.15A:1-1 et seq." Under N.J.S.A. 48: 2-21.41, a qualified Veterans' Organization shall be charged the residential rate for service delivered to the property where the Veterans' Organization primarily operates, if the residential rate is lower than the commercial rate for service at that property. The customer shall furnish satisfactory proof of eligibility of service under this special provision to the Company, who will determine eligibility.

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	$131.75
5,000 – 9,000 kW	$4,363.57
Greater than 9,000 kW	$7,921.01
Distribution Demand Charge ($/kW)	
Maximum billed demand within the most recent 12 billing months.	
Less than 5,000 kW	$3.80
5,000 – 9,000 kW	$2.93
Greater than 9,000 kW	$1.47
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)	$4.78
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000000
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI
Infrastructure Investment Program Charge	See Rider IIP

Date of Issue: **Effective Date:**

Issued by:

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	$128.21
5,000 – 9,000 kW	$4,246.42
Greater than 9,000 kW	$19,316.15
Distribution Demand Charge ($/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	$0.16
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)	$2.00
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000000
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI
Infrastructure Investment Program Charge	See Rider IIP

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)	$0.162459
Energy (per day for each kW of effective load)	$0.782504
Non-Utility Generation Charge (NGC) ($/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)	$0.005962
Reliability Must Run Transmission Surcharge ($/kWh)	$0.000000
Transmission Enhancement Charge ($/kWh)	See Rider BGS
Basic Generation Service Charge ($/kWh)	See Rider BGS
Regional Greenhouse Gas Initiative Recovery Charge ($/kWh)	See Rider RGGI
Infrastructure Investment Program Charge	See Rider IIP

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: **Effective Date:**

Issued by:

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	$0.43	$0.15
MGS Primary	$0.26	$0.14
AGS Secondary	$0.35	$1.13
AGS Primary	$0.32	$0.90
TGS Sub Transmission	$0.20	$0.00
TGS Transmission	$0.20	$0.00

ATLANTIC CITY ELECTRIC COMPANY
BPU NJ No. 11 Electric Service - Section IV Forty-Seventh Revised Sheet Replaces Forty-Sixth 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	0.000279	0.000203	0.000222	0.000143	0.000110	0.000101	-	0.000088
TrAILCo	0.000338	0.000245	0.000269	0.000172	0.000133	0.000122	-	0.000107
PSE&G	0.000544	0.000396	0.000433	0.000277	0.000214	0.000196	-	0.000172
PATH	(0.000003)	(0.000002)	(0.000002)	(0.000002)	(0.000001)	(0.000001)	-	(0.000001)
PPL	0.000118	0.000085	0.000094	0.000060	0.000047	0.000043	-	0.000037
PECO	0.000134	0.000097	0.000107	0.000068	0.000053	0.000048	-	0.000043
Pepco	0.000025	0.000018	0.000019	0.000013	0.000010	0.000009	-	0.000007
MAIT	0.000026	0.000018	0.000020	0.000013	0.000010	0.000010	-	0.000009
JCP&L	0.000003	0.000002	0.000002	0.000002	0.000001	0.000001	-	0.000001
EL05-121	0.000016	0.000013	0.000010	0.000010	0.000007	0.000007	-	0.000006
Delmarva	0.000007	0.000005	0.000005	0.000003	0.000003	0.000002	-	0.000002
BG&E	0.000029	0.000021	0.000023	0.000015	0.000012	0.000011	-	0.000010
AEP-East	0.000054	0.000039	0.000044	0.000028	0.000021	0.000020	-	0.000017
Silver Run	0.000154	0.000122	0.000093	0.000088	0.000074	0.000068	-	0.000055
NIPSCO	0.000001	0.000001	0.000001	0.000001	0.000001	0.000001	-	0.000001
CW Edison	0.000001	0.000001	0.000001	-	-	-	-	-
ER18-680 & Form 715	0.000084	0.000061	0.000067	0.000043	0.000033	0.000030	-	0.000027
Total	0.001810	0.001325	0.001408	0.000934	0.000728	0.000668	-	0.000581

Date of Issue: **Effective Date:**

Issued by:

Atlantic City Electric Company

Proposed Transmission Rate Design
Formula Rate Effective November 1, 2020
Change in FERC Formual Based Rate

	2019 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	$ 660,402,817	$ 70,598,828	1,599,270	$ 70,595,404	$ (3,424)	0.00%
Commercial and Industrial						
MGS Secondary	$ 159,285,086	$ 16,781,471	380,092	$ 16,778,140	$ (3,331)	0.00%
MGS Primary	$ 3,686,046	$ 374,109	8,490	$ 374,750	$ 641	0.02%
AGS Secondary	$ 106,633,153	$ 16,358,113	371,009	$ 16,377,178	$ 19,065	0.02%
AGS Primary	$ 28,228,787	$ 4,004,379	90,600	$ 3,999,282	$ (5,098)	-0.02%
TGS - Subtransmission	$ 30,636,643	$ 4,564,067	103,411	$ 4,564,784	$ 717	0.00%
TGS - Transmission	$ 12,283,030	$ 2,304,149	52,222	$ 2,305,198	$ 1,049	0.01%
SPL/CSL	$ 19,265,225	$ -	-	$ -	$ -	0.00%
DDC	$ 913,005	$ 82,435	1,867	$ 82,431	$ (4)	0.00%
Subtotal Commercial and Industrial	$ 360,930,975	$ 44,468,723	1,007,691	$ 44,481,763	$ 13,040	0.00%
Total Jurisdiction	$ 1,021,333,792	$ 115,067,551	2,606,960	$ 115,077,167	$ 9,616	0.00%

Wholesale Transmission Rate		$ 44.03
Rate Including Regulatory Assessment		$ 44.14

ATLANTIC CITY ELECTRIC
Proposed Transmission Rate Design
Formula Rate Effective November 1, 2020

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	3,976,054,770	$ 0.018932	$ 0.017756	$ 70,598,828	$ (0.000001)	$ 0.017755	$ 0.018931
Transmission Rate Change				$ (3,424)			

ATLANTIC CITY ELECTRIC
Proposed Transmission Rate Design
Formula Rate Effective November 1, 2020

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	1,781,692	$ 4.21	$ 3.95	$ 7,037,683	$ -	$ 3.95	$ 4.21
WIN > 3 KW	2,714,147	$ 3.83	$ 3.59	$ 9,743,788	$ -	$ 3.59	$ 3.83
TOTAL KW	4,495,839			$ 16,781,471			
Transmission Rate Change				$ (3,331)			

ATLANTIC CITY ELECTRIC
Proposed Transmission Rate Design
Formula Rate Effective November 1, 2020

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	63,680	$ 2.51	$ 2.35	$ 149,648	$ -	$ 2.35	$ 2.51
WIN > 3 KW	110,572	$ 2.16	$ 2.03	$ 224,461	$ -	$ 2.03	$ 2.16
TOTAL KW	174,252			$ 374,109			
Transmission Rate Change				$ 641			

ATLANTIC CITY ELECTRIC
Proposed Transmission Rate Design
Formula Rate Effective November 1, 2020

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	5,127,935	$ 3.40	$ 3.19	$ 16,358,113	$ -	$ 3.19	$ 3.40
Transmission Rate Change				$ 19,065			
				17,434,979			

ATLANTIC CITY ELECTRIC
Proposed Transmission Rate Design
Formula Rate Effective November 1, 2020

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	1,357,417	$ 3.15	$ 2.95	$ 4,004,379	$ -	$ 2.95	$ 3.15
Transmission Rate Change				$ (5,098)			

ATLANTIC CITY ELECTRIC
Proposed Transmission Rate Design
Formula Rate Effective November 1, 2020

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	1,018,765	$ 4.78	$ 4.48	$ 4,564,067	$ -	$ 4.48	$ 4.78
Transmission Rate Change				$ 717			

ATLANTIC CITY ELECTRIC
Proposed Transmission Rate Design
Formula Rate Effective November 1, 2020

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	1,225,611	$ 2.00	$ 1.88	$ 2,304,149	$ -	$ 1.88	$ 2.00
Transmission Rate Change				$ 1,049			

ATLANTIC CITY ELECTRIC
Proposed Transmission Rate Design
Formula Rate Effective November 1, 2020

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	71,478,467	$ -	$ -	$ -	$ -	$ -	$ -
Transmission Rate Change				$ -	$ -		

ATLANTIC CITY ELECTRIC
Proposed Transmission Rate Design
Formula Rate Effective November 1, 2020

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	14,741,626	$ 0.005962	$ 0.005592	$ 82,435	$ -	$ 0.005592	$ 0.005962
Transmission Rate Change				$ (4)			

Atlantic City Electric Company
Standby Rate Development
Formula Rate Effective November 1, 2020

	Demand Rates ($/kW)		Standby Rates ($/kW)		Transmission Standby
Rate Schedule		**Transmission**		**Transmission**	Factor
MGS Secondary	$	4.21	$	0.43	0.101604278
MGS Primary	$	2.51	$	0.26	0.101604278
AGS Secondary	$	3.40	$	0.35	0.101604278
AGS Primary	$	3.15	$	0.32	0.101604278
TGS Transmission	$	2.00	$	0.20	0.101604278

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

Transmission Enhancement Costs Allocated to ACE Zone (2020)	$	280,509
	$	280,509
2020 ACE Zone Transmission Peak Load (MW)		2,737
Transmission Enhancement Rate ($/MW)	$	102.48

Rate Class	Col. 1 Transmission Obligation (MW)	Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2020 - May 2021 (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	1,599	$ 1,966,652	3,862,087,569	$ 0.000509	$ 0.000510	$ 0.000544
MGS Secondary	380	$ 467,407	1,263,645,888	$ 0.000370	$ 0.000371	$ 0.000396
MGS Primary	8	$ 10,440	25,772,485	$ 0.000405	$ 0.000406	$ 0.000433
AGS Secondary	371	$ 456,237	1,755,110,088	$ 0.000260	$ 0.000260	$ 0.000277
AGS Primary	91	$ 111,412	554,832,432	$ 0.000201	$ 0.000201	$ 0.000214
TGS	156	$ 191,384	1,039,312,955	$ 0.000184	$ 0.000184	$ 0.000196
SPL/CSL	0	$ -	67,341,732	$ -	$ -	$ -
DDC	2	$ 2,296	14,236,110	$ 0.000161	$ 0.000161	$ 0.000172
	2,607	$ 3,205,828	8,582,339,259			

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

Transmission Enhancement Costs Allocated to ACE Zone (2020)	$	1,674
	$	1,674
2020 ACE Zone Transmission Peak Load (MW)		2,737
Transmission Enhancement Rate ($/MW)	$	0.61

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2019 - May 2020 (kWh)		Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)		Col. 5 = Col. 4 x 1/(1-Effective Rate) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)		Col. 6 = Col. 5 x 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,599	$	11,735	3,862,087,569	$	0.000003	$	0.000003	$	0.000003
MGS Secondary	380	$	2,789	1,263,645,888	$	0.000002	$	0.000002	$	0.000002
MGS Primary	8	$	62	25,772,485	$	0.000002	$	0.000002	$	0.000002
AGS Secondary	371	$	2,722	1,755,110,088	$	0.000002	$	0.000002	$	0.000002
AGS Primary	91	$	665	554,832,432	$	0.000001	$	0.000001	$	0.000001
TGS	156	$	1,142	1,039,312,955	$	0.000001	$	0.000001	$	0.000001
SPL/CSL	0	$	-	67,341,732	$	-	$	-	$	-
DDC	2	$	14	14,236,110	$	0.000001	$	0.000001	$	0.000001
	2,607	$	19,129	8,582,339,259						

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

Transmission Enhancement Costs Allocated to ACE Zone (2020)	$	144,279
	$	144,279
2020 ACE Zone Transmission Peak Load (MW)		2,737
Transmission Enhancement Rate ($/MW)	$	52.71

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2019 - May 2020 (kWh)		Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)		Col. 5 = Col. 4 x 1/(1-Effective Rate) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)		Col. 6 = Col. 5 x 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,599	$	1,011,542	3,862,087,569	$	0.000262	$	0.000262	$	0.000279
MGS Secondary	380	$	240,409	1,263,645,888	$	0.000190	$	0.000190	$	0.000203
MGS Primary	8	$	5,370	25,772,485	$	0.000208	$	0.000208	$	0.000222
AGS Secondary	371	$	234,664	1,755,110,088	$	0.000134	$	0.000134	$	0.000143
AGS Primary	91	$	57,305	554,832,432	$	0.000103	$	0.000103	$	0.000110
TGS	156	$	98,438	1,039,312,955	$	0.000095	$	0.000095	$	0.000101
SPL/CSL	0	$	-	67,341,732	$	-	$	-	$	-
DDC	2	$	1,181	14,236,110	$	0.000083	$	0.000083	$	0.000088
	2,607	$	1,648,909	8,582,339,259						

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

Transmission Enhancement Costs Allocated to ACE Zone (2019)	$	174,025
	$	174,025
2020 ACE Zone Transmission Peak Load (MW)		2,737
Transmission Enhancement Rate ($/MW)	$	63.58

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2020 - May 2021 (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	1,599	$	1,220,093	3,862,087,569	$	0.000316	$	0.000317	$	0.000338
MGS Secondary	380	$	289,975	1,263,645,888	$	0.000229	$	0.000230	$	0.000245
MGS Primary	8	$	6,477	25,772,485	$	0.000251	$	0.000252	$	0.000269
AGS Secondary	371	$	283,045	1,755,110,088	$	0.000161	$	0.000161	$	0.000172
AGS Primary	91	$	69,119	554,832,432	$	0.000125	$	0.000125	$	0.000133
TGS	156	$	118,733	1,039,312,955	$	0.000114	$	0.000114	$	0.000122
SPL/CSL	-	$	-	67,341,732	$	-	$	-	$	-
DDC	2	$	1,425	14,236,110	$	0.000100	$	0.000100	$	0.000107
	2,607	$	1,988,867	8,582,339,259						

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

Transmission Enhancement Costs Allocated to ACE Zone (2019)	$	12,540
	$	12,540
2020 ACE Zone Transmission Peak Load (MW)		2,737
Transmission Enhancement Rate ($/MW-Month)	$	4.58

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2020 - May 2021 (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	1,599	$	87,917	3,862,087,569	$	0.000023	$	0.000023	$	0.000025
MGS Secondary	380	$	20,895	1,263,645,888	$	0.000017	$	0.000017	$	0.000018
MGS Primary	8	$	467	25,772,485	$	0.000018	$	0.000018	$	0.000019
AGS Secondary	371	$	20,396	1,755,110,088	$	0.000012	$	0.000012	$	0.000013
AGS Primary	91	$	4,981	554,832,432	$	0.000009	$	0.000009	$	0.000010
TGS	156	$	8,556	1,039,312,955	$	0.000008	$	0.000008	$	0.000009
SPL/CSL	0	$	-	67,341,732	$	-	$	-	$	-
DDC	2	$	103	14,236,110	$	0.000007	$	0.000007	$	0.000007
	2,607	$	143,313	8,582,339,259						

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

Transmission Enhancement Costs Allocated to ACE Zone (2020)	$	60,944
	$	60,944
2020 ACE Zone Transmission Peak Load (MW)		2,737
Transmission Enhancement Rate ($/MW-Month)	$	22.26

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2020 - May 2021 (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	1,599	$	427,280	3,862,087,569	$	0.000111	$	0.000111	$	0.000118
MGS Secondary	380	$	101,550	1,263,645,888	$	0.000080	$	0.000080	$	0.000085
MGS Primary	8	$	2,268	25,772,485	$	0.000088	$	0.000088	$	0.000094
AGS Secondary	371	$	99,123	1,755,110,088	$	0.000056	$	0.000056	$	0.000060
AGS Primary	91	$	24,206	554,832,432	$	0.000044	$	0.000044	$	0.000047
TGS	156	$	41,581	1,039,312,955	$	0.000040	$	0.000040	$	0.000043
SPL/CSL	-	$	-	67,341,732	$	-	$	-	$	-
DDC	2	$	499	14,236,110	$	0.000035	$	0.000035	$	0.000037
	2,607	$	696,506	8,582,339,259						

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

Transmission Enhancement Costs Allocated to ACE Zone (2020)	$	14,935
	$	14,935
2020 ACE Zone Transmission Peak Load (MW)		2,737
Transmission Enhancement Rate ($/MW-Month)	$	5.46

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2020 - May 2021 (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	1,599	$	104,708	3,862,087,569	$	0.000027	$	0.000027	$	0.000029
MGS Secondary	380	$	24,886	1,263,645,888	$	0.000020	$	0.000020	$	0.000021
MGS Primary	8	$	556	25,772,485	$	0.000022	$	0.000022	$	0.000023
AGS Secondary	371	$	24,291	1,755,110,088	$	0.000014	$	0.000014	$	0.000015
AGS Primary	91	$	5,932	554,832,432	$	0.000011	$	0.000011	$	0.000012
TGS	156	$	10,190	1,039,312,955	$	0.000010	$	0.000010	$	0.000011
SPL/CSL	0	$	-	67,341,732	$	-	$	-	$	-
DDC	2	$	122	14,236,110	$	0.000009	$	0.000009	$	0.000010
	2,607	$	170,685	8,582,339,259						

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

Transmission Enhancement Costs Allocated to ACE Zone (2020)	$	13,239
	$	13,239
2020 ACE Zone Transmission Peak Load (MW)		2,737
Transmission Enhancement Rate ($/MW-Month)	$	4.84

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2019 - May 2020 (kWh)		Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)		Col. 5 = Col. 4 x 1/(1-Effective Rate) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)		Col. 6 = Col. 5 x 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,599	$	92,818	3,862,087,569	$	0.000024	$	0.000024	$	0.000026
MGS Secondary	380	$	22,060	1,263,645,888	$	0.000017	$	0.000017	$	0.000018
MGS Primary	8	$	493	25,772,485	$	0.000019	$	0.000019	$	0.000020
AGS Secondary	371	$	21,533	1,755,110,088	$	0.000012	$	0.000012	$	0.000013
AGS Primary	91	$	5,258	554,832,432	$	0.000009	$	0.000009	$	0.000010
TGS	156	$	9,033	1,039,312,955	$	0.000009	$	0.000009	$	0.000010
SPL/CSL	0	$	-	67,341,732	$	-	$	-	$	-
DDC	2	$	108	14,236,110	$	0.000008	$	0.000008	$	0.000009
	2,607	$	151,303	8,582,339,259						

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

Transmission Enhancement Costs Allocated to ACE Zone (2020)	$	69,155
	$	69,155
2020 ACE Zone Transmission Peak Load (MW)		2,737
Transmission Enhancement Rate ($/MW)	$	25.26

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales Jun 2020 - May 2021 (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	1,599	$	484,845	3,862,087,569	$	0.000126	$	0.000126	$	0.000134
MGS Secondary	380	$	115,231	1,263,645,888	$	0.000091	$	0.000091	$	0.000097
MGS Primary	8	$	2,574	25,772,485	$	0.000100	$	0.000100	$	0.000107
AGS Secondary	371	$	112,477	1,755,110,088	$	0.000064	$	0.000064	$	0.000068
AGS Primary	91	$	27,467	554,832,432	$	0.000050	$	0.000050	$	0.000053
TGS	156	$	47,183	1,039,312,955	$	0.000045	$	0.000045	$	0.000048
SPL/CSL	-	$	-	67,341,732	$	-	$	-	$	-
DDC	2	$	566	14,236,110	$	0.000040	$	0.000040	$	0.000043
	2,607	$	790,342	8,582,339,259						

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

Transmission Enhancement Costs Allocated to ACE Zone (2020)	$	28,207
	$	28,207
2020 ACE Zone Transmission Peak Load (MW)		2,737
Transmission Enhancement Rate ($/MW-Month)	$	10.30

Rate Class	Col. 1 Transmission Obligation (MW)		Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2020 - May 2021 (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	1,599	$	197,762.74	3,862,087,569	$	0.000051	$	0.000051	$	0.000054
MGS Secondary	380	$	47,002	1,263,645,888	$	0.000037	$	0.000037	$	0.000039
MGS Primary	8	$	1,050	25,772,485	$	0.000041	$	0.000041	$	0.000044
AGS Secondary	371	$	45,878	1,755,110,088	$	0.000026	$	0.000026	$	0.000028
AGS Primary	91	$	11,203	554,832,432	$	0.000020	$	0.000020	$	0.000021
TGS	156	$	19,245	1,039,312,955	$	0.000019	$	0.000019	$	0.000020
SPL/CSL	0	$	-	67,341,732	$	-	$	-	$	-
DDC	2	$	231	14,236,110	$	0.000016	$	0.000016	$	0.000017
	2,607	$	322,372	8,582,339,259						

Atlantic City Electric Company
Proposed ER16-680 and Form 715 Projects Transmission Enhancement Charge (ER16-680 and Form 715 TEC Surcharge) effective November 1, 2020
To reflect FERC-approved ER 18-680 and Form 715 Projects Transmission Enhancement Charge (Schedule 12 PJM OATT) effective August 2020 - March 2021

Transmission Enhancement Costs Allocated to ACE Zone (2020)	$	43,301
	$	43,301
2020 ACE Zone Transmission Peak Load (MW)		2,737
Transmission Enhancement Rate ($/MW)	$	15.82

Rate Class	Col. 1 Transmission Obligation (MW)	Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales June 2020 - May 2021 (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	1,599	$ 303,582	3,862,087,569	$ 0.000079	$ 0.000079	$ 0.000084
MGS Secondary	380	$ 72,151	1,263,645,888	$ 0.000057	$ 0.000057	$ 0.000061
MGS Primary	8	$ 1,612	25,772,485	$ 0.000063	$ 0.000063	$ 0.000067
AGS Secondary	371	$ 70,427	1,755,110,088	$ 0.000040	$ 0.000040	$ 0.000043
AGS Primary	91	$ 17,198	554,832,432	$ 0.000031	$ 0.000031	$ 0.000033
TGS	156	$ 29,543	1,039,312,955	$ 0.000028	$ 0.000028	$ 0.000030
SPL/CSL	0	$ -	67,341,732	$ -	$ -	$ -
DDC	2	$ 354	14,236,110	$ 0.000025	$ 0.000025	$ 0.000027
	2,607	$ 494,868	8,582,339,259			

- 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 TrailCo TEC into Customer Rates)
- Attachment 5g (RECO Translation of PEPCO TEC into Customer Rates)
- Attachment 5h (RECO Translation of PPL TEC into Customer Rates)
- Attachment 5i (RECO Translation of BG&E TEC into Customer Rates)
- Attachment 5j (RECO Translation of MAIT TEC into Customer Rates)
- Attachment 5k (RECO Translation of PECO TEC TEC into Customer Rates)
- Attachment 5l (RECO Translation of AEP East TEC into Customer Rates)
- Attachment 5m (RECO Translation of ER18-680 and Form 715 TEC into Customer Rates)

SERVICE CLASSIFICATION NO. 1
RESIDENTIAL SERVICE (Continued)

RATE – MONTHLY (Continued)

(3) Transmission Charges

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

	Summer Months*	Other Months
All kWh .... @	1.515 ¢ per kWh	1.515 ¢ per kWh

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

All kWh .... @	1.167 ¢ per kWh	1.167 ¢ per kWh

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

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

* Definition of Summer Billing Months - June through September

(Continued)

SERVICE CLASSIFICATION NO. 2
GENERAL SERVICE (Continued)

RATE – MONTHLY (Continued)

(3) Transmission Charges (Continued)

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

	Summer Months*	Other Months
Secondary Voltage Service Only		
All kWh ....@	0.788 ¢ per kWh	0.788 ¢ per kWh
Primary Voltage Service Only		
All kWh ....@	0.835 ¢ per kWh	0.835 ¢ per kWh

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

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

* Definition of Summer Billing Months - June through September

(Continued)

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

RATE – MONTHLY (Continued)

(3) Transmission Charge

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

	Summer Months*	Other Months
Peak All kWh measured between 10:00 a.m. and 10:00 p.m., Monday through Friday .....@	1.515 ¢ per kWh	1.515 ¢ per kWh
Off-Peak All other kWh ......@	1.515 ¢ per kWh	1.515 ¢ per kWh

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

All kWh .....@	1.172 ¢ per kWh	1.172 ¢ per kWh

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

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

* Definition of Summer Billing Months - June through September

(Continued)

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

RATE - MONTHLY (Continued)

(3) Transmission Charge

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

	Summer Months*	Other Months
All kWh ……….. @	1.515 ¢ per kWh	1.515 ¢ per kWh

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

All kWh ……….. @	1.167 ¢ per kWh	1.167 ¢ per kWh

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

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

* Definition of Summer Billing Months - June through September

(Continued)

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

RATE– MONTHLY (Continued)

(3) Transmission Charges (Continued)

(a) (Continued)

		Primary	High Voltage Distribution
Demand Charge			
Period I	All kW @	$2.41 per kW	$2.41 per kW
Period II	All kW @	0.64 per kW	0.64 per kW
Period III	All kW @	2.41 per kW	2.41 per kW
Period IV	All kW @	0.64 per kW	0.64 per kW
Usage Charge			
Period I	All kWh @	0.404 ¢ per kWh	0.404 ¢ per kWh
Period II	All kWh @	0.404 ¢ per kWh	0.404 ¢ per kWh
Period III	All kWh @	0.404 ¢ per kWh	0.404 ¢ per kWh
Period IV	All kWh @	0.404 ¢ per kWh	0.404 ¢ per kWh

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

		Primary	High Voltage Distribution
All Periods	All kWh @	0.396 ¢ per kWh	0.396 ¢ per kWh

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

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

(Continued)

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

SPECIAL PROVISIONS

(A) Space Heating

Customers who take service under this classification for 10 kW or more of permanently installed space heating equipment may elect to have the electricity for this service billed separately. All monthly use shall be billed at a Distribution Charge of 3.520 ¢ per kWh during the billing months of October through May and 5.691 ¢ per kWh during the summer billing months, a Transmission Charge of 0.404 ¢ per kWh and a Transmission Surcharge of 0.396 ¢ 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 November 1, 2020.
To reflect FERC-approved PSE&G Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period January 2020 - December 2020.

2020 Average Monthly PSE&G-TEC Costs Allocated to RECO	$	879,524	(1)
2020 RECO Zone Transmission Peak Load (MW)		439.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	1,999.90	
SUT		6.625%	

	Col. 1	Col. 2	Col.3=Col.2 x $879,524 x 12	Col. 4	Col. 5 = Col. 3/Col. 4	Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)	Allocated Cost Recovery (1)	BGS Eligible Sales November 2020 - October 2021(kWh)	Transmission Enhancement Charge ($/kWh)	Transmission Enhancement Charge w/ SUT ($/kWh)
SC1/SC5	271.2	61.67%	$ 6,508,719	691,834,000	$ 0.00941	$ 0.01003
SC2 Secondary	120.3	27.36%	$ 2,888,015	454,521,000	$ 0.00635	$ 0.00677
SC2 Primary	16.9	3.85%	$ 405,967	59,911,000	$ 0.00678	$ 0.00723
SC3	0.1	0.02%	$ 2,594	272,000	$ 0.00954	$ 0.01017
SC4	0.0	0.00%	$ -	6,431,000	$ -	$ -
SC5		0.00%	$ -		$ 0.00941	$ 0.01003
SC6	0.0	0.00%	$ -	5,596,000	$ -	$ -
SC7	31.2	7.10%	$ 748,994	234,430,000	$ 0.00319	$ 0.00340
Total	439.8 (2)	100.00%	$ 10,554,289	1,452,995,000		

(1) Attachment 6a - Cost Allocation of PSE&G Project Schedule 12 Charges to RECO Zone for the period January 2020 - December 2020.
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales Nov - Oct @ cust (RECO Eastern Division)		1,169,558	MWH
2	BGS-RSCP Eligible Sales Nov - Oct @ trans node (RECO Eastern Division)		1,088,038	MWH
3	BGS-RSCP Eligible Transmission Obligation		409	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	9,805,299.89	= Line 3 x $1999.9 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	9.01	= Line 4/Line 2

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

2020 Average Monthly JCP&L-TEC Costs Allocated to RECO	$	26,991	(1)
2020 RECO Zone Transmission Peak Load (MW)		439.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	61.37	
SUT		6.625%	

	Col. 1	Col. 2		Col.3=Col.2 x $26,991 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales November 2020 - October 2021(kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1/SC5	271.2	61.67%	$	199,738	691,834,000	$	0.00029	$	0.00031
SC2 Secondary	120.3	27.36%	$	88,627	454,521,000	$	0.00019	$	0.00020
SC2 Primary	16.9	3.85%	$	12,458	59,911,000	$	0.00021	$	0.00022
SC3	0.1	0.02%	$	80	272,000	$	0.00029	$	0.00031
SC4	0.0	0.00%	$	-	6,431,000	$	-	$	-
SC6	0.0	0.00%	$	-	5,596,000	$	-	$	-
SC7	31.2	7.10%	$	22,985	234,430,000	$	0.00010	$	0.00011
Total	439.8 (2)	100.00%	$	323,888	1,452,995,000				

(1) Attachment 6b - Cost Allocation of JCP&L Schedule 12 Charges to RECO Zone for the period January 2020 to December 2020
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales Nov - Oct @ cust (RECO Eastern Division)		1,169,558	MWH
2	BGS-RSCP Eligible Sales Nov - Oct @ trans node (RECO Eastern Division)		1,088,038	MWH
3	BGS-RSCP Eligible Transmission Obligation		409	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	300,890.67	= Line 3 x $61.37 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.28	= Line 4/Line 2

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

2020 Average Monthly TrAILCo-TEC Costs Allocated to RECO	$	2,441	(1)
2020 RECO Zone Transmission Peak Load (MW)		439.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	5.55	
SUT		6.625%	

	Col. 1	Col. 2		Col.3=Col.2 x $2,441 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales November 2020 - October 2021(kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1/SC5	271.2	61.67%	$	18,064	691,834,000	$	0.00003	$	0.00003
SC2 Secondary	120.3	27.36%	$	8,015	454,521,000	$	0.00002	$	0.00002
SC2 Primary	16.9	3.85%	$	1,127	59,911,000	$	0.00002	$	0.00002
SC3	0.1	0.02%	$	7	272,000	$	0.00003	$	0.00003
SC4	0.0	0.00%	$	-	6,431,000	$	-	$	-
SC6	0.0	0.00%	$	-	5,596,000	$	-	$	-
SC7	31.2	7.10%	$	2,079	234,430,000	$	0.00001	$	0.00001
Total	439.8 (2)	100.00%	$	29,292	1,452,995,000				

(1) Attachment 6c- Cost Allocation of ACE Schedule 12 Charges to RECO Zone for January 2020 to December 2020
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.					
1	BGS-RSCP Eligible Sales Nov - Oct @ cust (RECO Eastern Division)		1,169,558	MWH
2	BGS-RSCP Eligible Sales Nov - Oct @ trans node (RECO Eastern Division)		1,088,038	MWH
3	BGS-RSCP Eligible Transmission Obligation		409	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	27,211.07	= Line 3 x $5.55 * 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 November 1, 2020.
To reflect FERC-approved VEPCo Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period January 2020 - December 2020.

2020 Average Monthly VEPCo-TEC Costs Allocated to RECO	$	20,167	(1)
2020 RECO Zone Transmission Peak Load (MW)		439.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	45.86	
SUT		6.625%	

	Col. 1	Col. 2		Col.3=Col.2 x $20,167 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales November 2020 - October 2021(kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1/SC5	271.2	61.67%	$	149,238	691,834,000	$	0.00022	$	0.00023
SC2 Secondary	120.3	27.36%	$	66,219	454,521,000	$	0.00015	$	0.00016
SC2 Primary	16.9	3.85%	$	9,308	59,911,000	$	0.00016	$	0.00017
SC3	0.1	0.02%	$	59	272,000	$	0.00022	$	0.00023
SC4	0.0	0.00%	$	-	6,431,000	$	-	$	-
SC6	0.0	0.00%	$	-	5,596,000	$	-	$	-
SC7	31.2	7.10%	$	17,174	234,430,000	$	0.00007	$	0.00007
Total	439.8 (2)	100.00%	$	241,998	1,452,995,000				

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

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales Nov - Oct @ cust (RECO Eastern Division)		1,169,558	MWH
2	BGS-RSCP Eligible Sales Nov - Oct @ trans node (RECO Eastern Division)		1,088,038	MWH
3	BGS-RSCP Eligible Transmission Obligation		409	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	224,846.77	= Line 3 x $45.86 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.21	= Line 4/Line 2

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

2020 Average Monthly TrAILCo-TEC Costs Allocated to RECO	$	19,451	(1)
2020 RECO Zone Transmission Peak Load (MW)		439.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	44.23	
SUT		6.625%	

	Col. 1	Col. 2	Col.3=Col.2 x $19,451 x 12	Col. 4	Col. 5 = Col. 3/Col. 4	Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)	Allocated Cost Recovery (1)	BGS Eligible Sales November 2020 - October 2021(kWh)	Transmission Enhancement Charge ($/kWh)	Transmission Enhancement Charge w/ SUT ($/kWh)
SC1/SC5	271.2	61.67%	$ 143,942	691,834,000	$ 0.00021	$ 0.00022
SC2 Secondary	120.3	27.36%	$ 63,869	454,521,000	$ 0.00014	$ 0.00015
SC2 Primary	16.9	3.85%	$ 8,978	59,911,000	$ 0.00015	$ 0.00016
SC3	0.1	0.02%	$ 57	272,000	$ 0.00021	$ 0.00022
SC4	0.0	0.00%	$ -	6,431,000	$ -	$ -
SC6	0.0	0.00%	$ -	5,596,000	$ -	$ -
SC7	31.2	7.10%	$ 16,564	234,430,000	$ 0.00007	$ 0.00007
Total	439.8 (2)	100.00%	$ 233,410	1,452,995,000		

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

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales Nov - Oct @ cust (RECO Eastern Division)		1,169,558	MWH
2	BGS-RSCP Eligible Sales Nov - Oct @ trans node (RECO Eastern Division)		1,088,038	MWH
3	BGS-RSCP Eligible Transmission Obligation		409	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	216,855.05	= Line 3 x $44.23 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.20	= Line 4/Line 2

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

2020 Average Monthly PEPCO-TEC Costs Allocated to RECO	$	767	(1)
2020 RECO Zone Transmission Peak Load (MW)		439.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	1.74	
SUT		6.625%	

	Col. 1	Col. 2		Col.3=Col.2 x $767 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales November 2020 - October 2021(kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1/SC5	271.2	61.67%	$	5,676	691,834,000	$	0.00001	$	0.00001
SC2 Secondary	120.3	27.36%	$	2,519	454,521,000	$	0.00001	$	0.00001
SC2 Primary	16.9	3.85%	$	354	59,911,000	$	0.00001	$	0.00001
SC3	0.1	0.02%	$	2	272,000	$	0.00001	$	0.00001
SC4	0.0	0.00%	$	-	6,431,000	$	-	$	-
SC6	0.0	0.00%	$	-	5,596,000	$	-	$	-
SC7	31.2	7.10%	$	653	234,430,000	$	-	$	-
Total	439.8 (2)	100.00%	$	9,204	1,452,995,000				

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

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales Nov - Oct @ cust (RECO Eastern Division)		1,169,558	MWH
2	BGS-RSCP Eligible Sales Nov - Oct @ trans node (RECO Eastern Division)		1,088,038	MWH
3	BGS-RSCP Eligible Transmission Obligation		409	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	8,531.04	= Line 3 x $1.74 * 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 November 1, 2020.
To reflect FERC-approved PPL Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period January 2020 to December 2020

2020 Average Monthly PPL-TEC Costs Allocated to RECO	$	84,894	(1)
2020 RECO Zone Transmission Peak Load (MW)		439.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	193.04	
SUT		6.625%	

	Col. 1	Col. 2		Col.3=Col.2 x $84,894 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales November 2020 - October 2021(kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1/SC5	271.2	61.67%	$	628,242	691,834,000	$	0.00091	$	0.00097
SC2 Secondary	120.3	27.36%	$	278,760	454,521,000	$	0.00061	$	0.00065
SC2 Primary	16.9	3.85%	$	39,185	59,911,000	$	0.00065	$	0.00069
SC3	0.1	0.02%	$	250	272,000	$	0.00092	$	0.00098
SC4	0.0	0.00%	$	-	6,431,000	$	-	$	-
SC6	0.0	0.00%	$	-	5,596,000	$	-	$	-
SC7	31.2	7.10%	$	72,295	234,430,000	$	0.00031	$	0.00033
Total	439.8 (2)	100.00%	$	1,018,732	1,452,995,000				

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

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales Nov - Oct @ cust (RECO Eastern Division)		1,169,558	MWH
2	BGS-RSCP Eligible Sales Nov - Oct @ trans node (RECO Eastern Division)		1,088,038	MWH
3	BGS-RSCP Eligible Transmission Obligation		409	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	946,454.87	= Line 3 x $193.04 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.87	= Line 4/Line 2

Rockland Electric Company

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

2020 Average Monthly BG&E-TEC Costs Allocated to RECO	$	863	(1)
2020 RECO Zone Transmission Peak Load (MW)		439.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	1.96	
SUT		6.625%	

	Col. 1	Col. 2		Col.3=Col.2 x $863 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales November 2020 - October 2021(kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1/SC5	271.2	61.67%	$	6,386	691,834,000	$	0.00001	$	0.00001
SC2 Secondary	120.3	27.36%	$	2,833	454,521,000	$	0.00001	$	0.00001
SC2 Primary	16.9	3.85%	$	398	59,911,000	$	0.00001	$	0.00001
SC3	0.1	0.02%	$	3	272,000	$	0.00001	$	0.00001
SC4	0.0	0.00%	$	-	6,431,000	$	-	$	-
SC6	0.0	0.00%	$	-	5,596,000	$	-	$	-
SC7	31.2	7.10%	$	735	234,430,000	$	-	$	-
Total	439.8 (2)	100.00%	$	10,355	1,452,995,000				

(1) Attachment 6h - Cost Allocation of BG&E Schedule 12 Charges to RECO Zone for January 2020 - December 2020.
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales Nov - Oct @ cust (RECO Eastern Division)		1,169,558	MWH
2	BGS-RSCP Eligible Sales Nov - Oct @ trans node (RECO Eastern Division)		1,088,038	MWH
3	BGS-RSCP Eligible Transmission Obligation		409	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	9,609.67	= Line 3 x $1.96 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.01	= Line 4/Line 2

Attachment 5j

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

2020 Average Monthly MAIT-TEC Costs Allocated to RECO	$	8,008	(1)
2020 RECO Zone Transmission Peak Load (MW)		439.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	18.21	
SUT		6.625%	

	Col. 1	Col. 2		Col.3=Col.2 x $8,008 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales November 2020 - October 2021(kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1/SC5	271.2	61.67%	$	59,258	691,834,000	$	0.00009	$	0.00010
SC2 Secondary	120.3	27.36%	$	26,294	454,521,000	$	0.00006	$	0.00006
SC2 Primary	16.9	3.85%	$	3,696	59,911,000	$	0.00006	$	0.00006
SC3	0.1	0.02%	$	24	272,000	$	0.00009	$	0.00010
SC4	0.0	0.00%	$	-	6,431,000	$	-	$	-
SC6	0.0	0.00%	$	-	5,596,000	$	-	$	-
SC7	31.2	7.10%	$	6,819	234,430,000	$	0.00003	$	0.00003
Total	439.8 (2)	100.00%	$	96,091	1,452,995,000				

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

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales Nov - Oct @ cust (RECO Eastern Division)		1,169,558	MWH
2	BGS-RSCP Eligible Sales Nov - Oct @ trans node (RECO Eastern Division)		1,088,038	MWH
3	BGS-RSCP Eligible Transmission Obligation		409	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	89,281.72	= Line 3 x $18.21 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.08	= Line 4/Line 2

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

2020 Average Monthly PECO-TEC Costs Allocated to RECO	$	7,633	(1)
2020 RECO Zone Transmission Peak Load (MW)		439.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	17.36	
SUT		6.625%	

	Col. 1	Col. 2		Col.3=Col.2 x $7,633 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales November 2020 - October 2021(kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1/SC5	271.2	61.67%	$	56,488	691,834,000	$	0.00008	$	0.00009
SC2 Secondary	120.3	27.36%	$	25,064	454,521,000	$	0.00006	$	0.00006
SC2 Primary	16.9	3.85%	$	3,523	59,911,000	$	0.00006	$	0.00006
SC3	0.1	0.02%	$	23	272,000	$	0.00008	$	0.00009
SC4	0.0	0.00%	$	-	6,431,000	$	-	$	-
SC6	0.0	0.00%	$	-	5,596,000	$	-	$	-
SC7	31.2	7.10%	$	6,500	234,430,000	$	0.00003	$	0.00003
Total	439.8 (2)	100.00%	$	91,598	1,452,995,000				

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

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales Nov - Oct @ cust (RECO Eastern Division)		1,169,558	MWH
2	BGS-RSCP Eligible Sales Nov - Oct @ trans node (RECO Eastern Division)		1,088,038	MWH
3	BGS-RSCP Eligible Transmission Obligation		409	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	85,114.26	= Line 3 x $17.36 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.08	= Line 4/Line 2

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

2020 Average Monthly AEP-East-TEC Costs Allocated to RECO	$	5,147	(1)
2020 RECO Zone Transmission Peak Load (MW)		439.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	11.70	
SUT		6.625%	

	Col. 1	Col. 2		Col.3=Col.2 x $5,147 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales November 2020 - October 2021(kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1/SC5	271.2	61.67%	$	38,091	691,834,000	$	0.00006	$	0.00006
SC2 Secondary	120.3	27.36%	$	16,901	454,521,000	$	0.00004	$	0.00004
SC2 Primary	16.9	3.85%	$	2,376	59,911,000	$	0.00004	$	0.00004
SC3	0.1	0.02%	$	15	272,000	$	0.00006	$	0.00006
SC4	0.0	0.00%	$	-	6,431,000	$	-	$	-
SC6	0.0	0.00%	$	-	5,596,000	$	-	$	-
SC7	31.2	7.10%	$	4,383	234,430,000	$	0.00002	$	0.00002
Total	439.8 (2)	100.00%	$	61,766	1,452,995,000				

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

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales Nov - Oct @ cust (RECO Eastern Division)		1,169,558	MWH
2	BGS-RSCP Eligible Sales Nov - Oct @ trans node (RECO Eastern Division)		1,088,038	MWH
3	BGS-RSCP Eligible Transmission Obligation		409	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	57,363.87	= Line 3 x $11.7 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.05	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (ER18-680 and Form 715 Projects) effective November 1, 2020.
To reflect FERC-approved ER18-680 and Form 715 Projects Schedule 12 Charges (Schedule 12 PJM OATT) for the period January 2020 - December 2020.

2020 Average Monthly ER18-680 and Form 715-TEC Costs Allocated to RECO	$	(68,197)	(1)
2020 RECO Zone Transmission Peak Load (MW)		439.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	(155.07)	
SUT		6.625%	

	Col. 1		Col. 2		Col.3=Col.2 x $-68,197 x 12	Col. 4		Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)		Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales November 2020 - October 2021(kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1/SC5	271.2		61.67%	$	(504,676)	691,834,000	$	(0.00073)	$	(0.00078)
SC2 Secondary	120.3		27.36%	$	(223,932)	454,521,000	$	(0.00049)	$	(0.00052)
SC2 Primary	16.9		3.85%	$	(31,478)	59,911,000	$	(0.00053)	$	(0.00057)
SC3	0.1		0.02%	$	(201)	272,000	$	(0.00074)	$	(0.00079)
SC4	0.0		0.00%	$	-	6,431,000	$	-	$	-
SC6	0.0		0.00%	$	-	5,596,000	$	-	$	-
SC7	31.2		7.10%	$	(58,076)	234,430,000	$	(0.00025)	$	(0.00027)
Total	439.8	(2)	100.00%	$	(818,363)	1,452,995,000				

(1) Attachment 6l - Cost Allocation of ER18-680 and Form 715 Projects Schedule 12 Charges to RECO Zone for the period January 2020 - December 2020.
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales Nov - Oct @ cust (RECO Eastern Division)		1,169,558	MWH
2	BGS-RSCP Eligible Sales Nov - Oct @ trans node (RECO Eastern Division)		1,088,038	MWH
3	BGS-RSCP Eligible Transmission Obligation		409	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	(760,291.94)	= Line 3 x $-155.07 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	(0.70)	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting proposed changes effective November 1, 2020
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) currently in RECO's rates
FERC-approved PATH Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
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 CW Edison Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved EL05-121 Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved Silver Run Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved NIPSCO Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved ER18-680 and Form 715 Projects Schedule 12 Charges (Schedule 12 PJM OATT)

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

Transmission Projects	Note	SC1	SC2 Sec	SC2 Pri	SC3	SC4	SC5[20]	SC6	SC7
Reliability Must Run	(1)	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
ACE - TEC	(2)	0.00003	0.00002	0.00002	0.00003	0.00000	0.00003	0.00000	0.00001
AEP-East - TEC	(3)	0.00006	0.00004	0.00004	0.00006	0.00000	0.00006	0.00000	0.00002
BG&E- TEC	(4)	0.00001	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00000
Delmarva - TEC	(5)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
PATH - TEC	(6)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
PEPCO - TEC	(7)	0.00001	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00000
PPL - TEC	(8)	0.00091	0.00061	0.00065	0.00092	0.00000	0.00091	0.00000	0.00031
PSE&G - TEC	(9)	0.00941	0.00635	0.00678	0.00954	0.00000	0.00941	0.00000	0.00319
TrAILCo - TEC	(10)	0.00021	0.00014	0.00015	0.00021	0.00000	0.00021	0.00000	0.00007
VEPCo - TEC	(11)	0.00022	0.00015	0.00016	0.00022	0.00000	0.00022	0.00000	0.00007
MAIT -TEC	(12)	0.00009	0.00006	0.00006	0.00009	0.00000	0.00009	0.00000	0.00003
JCP&L -TEC	(13)	0.00029	0.00019	0.00021	0.00029	0.00000	0.00029	0.00000	0.00010
PECO -TEC	(14)	0.00008	0.00006	0.00006	0.00008	0.00000	0.00008	0.00000	0.00003
CW Edison-TEC	(15)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
EL05-121	(16)	0.00030	0.00021	0.00019	0.00023	0.00000	0.00030	0.00000	0.00012
Silver RunTEC	(17)	0.00007	0.00005	0.00005	0.00005	0.00000	0.00007	0.00000	0.00003
NIPSCO TEC	(18)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
ER18-680 & Form 715	(19)	(0.00073)	(0.00049)	(0.00053)	(0.00074)	0.00000	(0.00073)	0.00000	(0.00025)
Total ($/kWh and excl SUT)		$0.01096	$0.00741	$0.00786	$0.01100	$0.00000	$0.01096	$0.00000	$0.00373
Total (¢/kWh and excl SUT)		1.096 ¢	0.741 ¢	0.786 ¢	1.100 ¢	0.000 ¢	1.096 ¢	0.000 ¢	0.373 ¢

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

Transmission Projects	Note	SC1	SC2 Sec	SC2 Pri	SC3	SC4	SC5	SC6	SC7
Reliability Must Run	(1)	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
ACE - TEC	(2)	0.00003	0.00002	0.00002	0.00003	0.00000	0.00003	0.00000	0.00001
AEP-East - TEC	(3)	0.00006	0.00004	0.00004	0.00006	0.00000	0.00006	0.00000	0.00002
BG&E- TEC	(4)	0.00001	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00000
Delmarva - TEC	(5)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
PATH - TEC	(6)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
PEPCO - TEC	(7)	0.00001	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00000
PPL - TEC	(8)	0.00097	0.00065	0.00069	0.00098	0.00000	0.00097	0.00000	0.00033
PSE&G - TEC	(9)	0.01003	0.00677	0.00723	0.01017	0.00000	0.01003	0.00000	0.00340
TrAILCo - TEC	(10)	0.00022	0.00015	0.00016	0.00022	0.00000	0.00022	0.00000	0.00007
VEPCo - TEC	(11)	0.00023	0.00016	0.00017	0.00023	0.00000	0.00023	0.00000	0.00007
MAIT -TEC	(12)	0.00010	0.00006	0.00006	0.00010	0.00000	0.00010	0.00000	0.00003
JCP&L -TEC	(13)	0.00031	0.00020	0.00022	0.00031	0.00000	0.00031	0.00000	0.00011
PECO -TEC	(14)	0.00009	0.00006	0.00006	0.00009	0.00000	0.00009	0.00000	0.00003
CW Edison-TEC	(15)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
EL05-121	(16)	0.00032	0.00022	0.00020	0.00025	0.00000	0.00032	0.00000	0.00013
Silver Run TEC	(17)	0.00007	0.00005	0.00005	0.00005	0.00000	0.00007	0.00000	0.00003
NIPSCO TEC	(18)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
ER18-680 & Form 715	(19)	(0.00078)	(0.00052)	(0.00057)	(0.00079)	0.00000	(0.00078)	0.00000	(0.00027)
Total ($/kWh and incl SUT)		$0.01167	$0.00788	$0.00835	$0.01172	$0.00000	$0.01167	$0.00000	$0.00396
Total (¢/kWh and incl SUT)		1.167 ¢	0.788 ¢	0.835 ¢	1.172 ¢	0.000 ¢	1.167 ¢	0.000 ¢	0.396 ¢

Notes:
(1) RMR rates based on allocation by transmission zone.
(2) ACE-TEC rates calculated in attachment 5d of the joint filing.
(3) AEP-East-TEC rates calculated in attachment 5l of the joint filing.
(4) BG&E-TEC rates calculated in attachment 5i of the joint filing.
(5) Delmarva-TEC rates pursuant to the Board's Order dated August 12, 2020 in Docket No. ER20060446.
(6) PATH-TEC rates pursuant to the Board's Order dated January 22, 2020 in Docket No. ER19121509.
(7) PEPCO-TEC rates calculated in attachment 5g of the joint filing.
(8) PPL-TEC rates calculated in attachment 5h of the joint filing.
(9) PSE&G-TEC rates calculated in attachment 5b of the joint filing.
(10) TrAILCo-TEC rates calculated in attachment 5f of the joint filing.
(11) VEPCo-TEC rates calculated in attachment 5e of the joint filing.
(12) MAIT-TEC rates calculated in attachment 5j of the joint filing.
(13) JCP&L-TEC rates calculated in attachment 5c of the joint filing.
(14) PECO-TEC rates calculated in attachment 5k of the joint filing.
(15) CW Edison-TEC rates pursuant to the Board's Order dated August 12, 2020 in Docket No. ER20060446.
(16) EL05-121 rates pursuant to the Board's Order dated January 22, 2020 in Docket No. ER19121509.
(17) Silver Run-TEC rates pursuant to the Board's Order dated August 12, 2020 in Docket No. ER20030263.
(18) NIPSCO-TEC rates pursuant to the Board's Order dated August 12, 2020 in Docket No. ER20030263.
(19) ER18-680 & Form 715 rates calculated in attachment 5m of the joint filing.
(20) SC5 Rates are set identical to SC1 rates, pursuant to Board's Order dated January 22, 2020 in Docket Number ER19050552

- 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 (TrailCo Transmission Enhancement Charges)
- Attachment 6f (PEPCO Transmission Enhancement Charges)
- Attachment 6g (PPL Transmission Enhancement Charges)
- Attachment 6h (BG&E Transmission Enhancement Charges)
- Attachment 6i (MAIT Transmission Enhancement Charges)
- Attachment 6j(PECO Transmission Enhancement Charges)
- Attachment 6k (AEP East Transmission Enhancement Charges)
- Attachment 6l (ER18-680 and Form 715 Charges/Credits)

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

Required Transmission Enhancement *per PJM website*	PJM Upgrade ID *per PJM spreadsheet*	(a) Jan - Dec 2020 Annual Revenue Requirement *per PJM website*	(b) Responsible Customers - Schedule 12 Appendix *per PJM Open Access Transmission Tariff* 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
Replace all derated Branchburg 500/230 kava transformers	b0130	$ 1,870,610.00	1.36%	47.76%	50.88%	0.00%	$25,440	$893,403	$951,766	$0	$1,870,610
Reconductor Kittatinny - Newtown 230 kV with 1590 ACSS	b0134	$ 761,829.00	0.00%	51.11%	45.96%	2.93%	$0	$389,371	$350,137	$22,322	$761,829
Build new Essex - Aldene 230 kV cable connected through phase angle regulator at Essex	b0145	$ 8,162,045.00	0.00%	73.45%	21.78%	4.77%	$0	$5,995,022	$1,777,693	$389,330	$8,162,045
Install 4th 500/230 kV transformer at New Freedom	b0411	$ 2,068,529.00	47.01%	7.04%	22.31%	0.00%	$972,415	$145,624	$461,489	$0	$1,579,529
Install 230-138kV transformer at Metuchen substation	b0161	$ 2,538,904.00	0.00%	0.00%	99.80%	0.20%	$0	$0	$2,533,826	$5,078	$2,538,904
Build a new 230 kV section from Branchburg - Flagtown and move the Flagtown - Somerville 230 kV circuit to the new section	b0169	$ 1,552,237.00	1.72%	25.94%	59.59%	0.00%	$26,698	$402,650	$924,978	$0	$1,354,327
Reconductor the Flagtown-Somerville-Bridgewater 230 kV circuit with 1590 ACSS	b0170	$ 678,205.00	0.00%	42.95%	38.36%	0.79%	$0	$291,289	$260,159	$5,358	$556,806
Replace wave trap at Branchburg 500kV substation	b0172.2	$ 1,329.50	1.72%	3.82%	6.15%	0.25%	$23	$51	$82	$3	$159
Replace wave trap at Branchburg 500kV substation	b0172.2_dfax	$ 1,329.50	4.49%	29.72%	48.90%	2.01%	$60	$395	$650	$27	$1,132
Branchburg 400 MVAR Capacitor	b0290	$ 4,066,304.00	1.72%	3.82%	6.15%	0.25%	$69,940	$155,333	$250,078	$10,166	$485,517
Branchburg 400 MVAR Capacitor	b0290_dfax	$ 4,066,304.00	4.49%	29.72%	48.90%	2.01%	$182,577	$1,208,506	$1,988,423	$81,733	$3,461,238
Inst Conemaugh 250 MVAR Cap	b0376	$ 62,085.50	1.72%	3.82%	6.15%	0.25%	$1,068	$2,372	$3,818	$155	$7,413
Inst Conemaugh 250 MVAR Cap	b0376_dfax	$ 62,085.50	0.00%	18.75%	24.11%	0.99%	$0	$11,641	$14,969	$615	$27,224
Saddle Brook - Athenia Upgrade Cable	b0472	$ 1,524,743.00	0.00%	0.00%	94.41%	3.53%	$0	$0	$1,439,510	$53,823	$1,493,333
Build new 500 kV transmission facilities from Pennsylvania - New Jersey border at Bushkill to Roseland (500kV and above elements of the project)	b0489	$ 42,404,941.50	1.72%	3.82%	6.15%	0.25%	$729,365	$1,619,869	$2,607,904	$106,012	$5,063,150
Build new 500 kV transmission facilities from Pennsylvania - New Jersey border at Bushkill to Roseland (500kV and above elements of the project)	b0489_dfax	$ 42,404,941.50	0.00%	39.21%	54.50%	2.24%	$0	$16,626,978	$23,110,693	$949,871	$40,687,541
Build new 500 kV transmission facilities from Pennsylvania - New Jersey border at Bushkill to Roseland (Below 500 kV elements of the project) (In Service)	b0489.4	$ 4,690,410.00	5.09%	32.73%	40.71%	1.52%	$238,742	$1,535,171	$1,909,466	$71,294	$3,754,673
Susquehanna Roseland Breakers (In-Service)	b0489.5	$ 318,812.50	1.72%	3.82%	6.15%	0.25%	$5,484	$12,179	$19,607	$797	$38,066
Susquehanna Roseland Breakers (In-Service)	b0489.5_dfax	$ 318,812.50	0.00%	39.21%	54.50%	2.24%	$0	$125,006	$173,753	$7,141	$305,901
Loop the 5021 circuit into New Freedom 500 kV substation	b0498	$ 1,315,947.00	1.72%	3.82%	6.15%	0.25%	$22,634	$50,269	$80,931	$3,290	$157,124

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

Required Transmission Enhancement *per PJM website*	PJM Upgrade ID *per PJM spreadsheet*	(a) Jan - Dec 2020 Annual Revenue Requirement *per PJM website*	(b) Responsible Customers - Schedule 12 Appendix: ACE Zone Share	(c) JCP&L Zone Share	(d) PSE&G Zone Share1,2	(e) RE Zone Share	(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	$ 1,315,947.00	8.37%	25.68%	41.36%	1.70%	$110,145	$337,935	$544,276	$22,371	$1,014,727
Branchburg-Somerville-Flagtown Reconductor	b0664-b0665	$ 1,971,224.00	0.00%	36.35%	43.24%	1.61%	$0	$716,540	$852,357	$31,737	$1,600,634
Somerville -Bridgewater Reconductor	b0668	$ 680,066.00	0.00%	39.41%	38.76%	1.45%	$0	$268,014	$263,594	$9,861	$541,469
Reconductor Hudson - South Waterfront 230kV circuit	b0813	$ 937,362.00	0.00%	9.92%	83.73%	3.12%	$0	$92,986	$784,853	$29,246	$907,085
New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie	b0814	$ 4,929,169.00	0.00%	23.49%	67.03%	2.50%	$0	$1,157,862	$3,304,022	$123,229	$4,585,113
Reconductor South Mahwah 345 kV J-3410 Circuit	b1017	$ 2,134,354.00	0.00%	29.01%	64.85%	2.53%	$0	$619,176	$1,384,129	$53,999	$2,057,304
Reconductor South Mahwah 345 kV K-3411 Circuit	b1018	$ 2,217,622.00	0.00%	29.18%	64.68%	2.53%	$0	$647,102	$1,434,358	$56,106	$2,137,566
West Orange Conversion (North Central Reliability)	b1154	$ 40,080,672.00	0.00%	0.00%	96.18%	3.82%	$0	$0	$38,549,590	$1,531,082	$40,080,672
Branchburg-Middlesex Sw Rack	b1155	$ 7,580,817.00	0.00%	4.61%	91.75%	3.64%	$0	$349,476	$6,955,400	$275,942	$7,580,817
Conversion	b1156	$ 39,002,141.00	0.00%	0.00%	96.18%	3.82%	$0	$0	$37,512,259	$1,489,882	$39,002,141
Reconf Kearny Loop in P2216	b1589	$ 2,956,038.00	0.00%	0.00%	61.59%	2.46%	$0	$0	$1,820,624	$72,719	$1,893,342
230kV Lawrence Switching Station Upgrade	b1228	$ 2,357,604.00	0.00%	0.00%	95.83%	3.81%	$0	$0	$2,259,292	$89,825	$2,349,117
Ridge Rd 69kV Breaker Station	b1255	$ 6,000,252.00	0.00%	0.00%	96.18%	3.82%	$0	$0	$5,771,042	$229,210	$6,000,252
Northeast Grid Reliability Project	b1304.1-b1304.4	$ 71,567,505.00	0.23%	1.17%	70.16%	2.78%	$164,605	$837,340	$50,211,762	$1,989,577	$53,203,283
Mickleton-Gloucester-Camden	b1398	$ 49,472,297.00	0.00%	12.82%	31.46%	1.25%	$0	$6,342,348	$15,563,985	$618,404	$22,524,737
Aldene-Springfield Rd. Conv	b1399	$ 8,056,841.00	0.00%	0.00%	96.18%	3.82%	$0	$0	$7,749,070	$307,771	$8,056,841
Replace Salem 500 kV breakers	b1410-b1415	$ 859,015.50	1.72%	3.82%	6.15%	0.25%	$14,775	$32,814	$52,829	$2,148	$102,566
Replace Salem 500 kV breakers	b1410-b1415_dfax	$ 859,015.50	0.00%	0.00%	96.06%	3.94%	$0	$0	$825,170	$33,845	$859,016
Uprate Eagle Point-Gloucester 230 kV Circuit	b1588	$ 1,361,002.00	0.00%	10.31%	54.17%	2.16%	$0	$140,319	$737,255	$29,398	$906,972
Upgrade Camden Richmon 230kV	b1590	$ 1,260,186.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
New Cox's Corner-Lumberton 230kV Circuit	b1787	$ 3,646,046.00	4.96%	44.20%	48.08%	1.92%	$180,844	$1,611,552	$1,753,019	$70,004	$3,615,419
Build Mickleton-Gloucester Corridor Ultimate Design	b2139	$ 2,240,329.00	0.00%	0.00%	61.11%	2.44%	$0	$0	$1,369,065	$54,664	$1,423,729
Reconfigure Brunswick New 69kV	b2146	$ 19,389,918.00	0.00%	0.00%	96.16%	3.84%	$0	$0	$18,645,345	$744,573	$19,389,918
Convert Bergen Marion 138 kV to double circuit 345kV and Sub	b2436.10_dfax	$ 10,668,262.00	0.00%	0.00%	100.00%	0.00%	$0	$0	$10,668,262	$0	$10,668,262
Convert Bergen Marion 138 kV to double circuit 345kV and Sub	b2436.10	$ 10,668,262.00	1.72%	3.82%	6.15%	0.25%	$183,494	$407,528	$656,098	$26,671	$1,273,790
Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.21_dfax	$ 3,805,090.00	0.00%	0.00%	100.00%	0.00%	$0	$0	$3,805,090	$0	$3,805,090
Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.21	$ 3,805,090.00	1.72%	3.82%	6.15%	0.25%	$65,448	$145,354	$234,013	$9,513	$454,328
Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.22_dfax	$ 2,656,169.50	0.00%	0.00%	96.06%	3.94%	$0	$0	$2,551,516	$104,653	$2,656,170
Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.22	$ 2,656,169.50	1.72%	3.82%	6.15%	0.25%	$45,686	$101,466	$163,354	$6,640	$317,147

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

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				Estimated New Jersey EDC Zone Charges by Project				
Required Transmission Enhancement *per PJM website*	**PJM Upgrade ID** *per PJM spreadsheet*	**Jan - Dec 2020 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share**	**JCP&L Zone Share**	**PSE&G Zone Share1,2** *per PJM Open Access Transmission Tariff*	**RE Zone Share**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
New 500 kV bay at Hope Creek (Expansion of Hope Creek sub)	b2633.4	$ 59,982.00	1.72%	3.82%	6.15%	0.25%	$1,032	$2,291	$3,689	$150	$7,162
New 500 kV bay at Hope Creek (Expansion of Hope Creek sub)	b2633.4_dfax	$ 59,982.00	8.01%	13.85%	20.79%	0.62%	$4,805	$8,308	$12,470	$372	$25,954
New 500/230 kV autotransformer at Hope Creek and a new Hope Creek 230 kV substation	b2633.5	$ 491,171.00	8.01%	13.85%	20.79%	0.62%	$39,343	$68,027	$102,114	$3,045	$212,530
Rebuild Aldene-Warinanco-Linden VFT 230kV Circuit	b2955	$ 3,820,197.00	0.00%	92.14%	0.00%	0.00%	$0	$3,519,930	$0	$0	$3,519,930
Reconductor L-2238 Cedar Grove - Jackson Rd 230kV	b2956	$ 501,301.00	0.00%	0.00%	100.00%	0.00%	$0	$0	$501,301	$0	$501,301
Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation	b2436.81_dfax	$ 3,403,094.50	0.00%	0.00%	96.06%	3.94%	$0	$0	$3,269,013	$134,082	$3,403,095
Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation	b2436.81	$ 3,403,094.50	1.72%	3.82%	6.15%	0.25%	$58,533	$129,998	$209,290	$8,508	$406,329
Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.83_dfax	$ 3,403,256.00	0.00%	0.00%	96.06%	3.94%	$0	$0	$3,269,168	$134,088	$3,403,256
Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.83	$ 3,403,256.00	1.72%	3.82%	6.15%	0.25%	$58,536	$130,004	$209,300	$8,508	$406,349
Convert Bayway-Linden "W" to 138kV circuit to 345kV	b2436.84_dfax	$ 3,198,721.00	0.00%	0.00%	96.06%	3.94%	$0	$0	$3,072,691	$126,030	$3,198,721
Convert Bayway-Linden "W" to 138kV circuit to 345kV	b2436.84	$ 3,198,721.00	1.72%	3.82%	6.15%	0.25%	$55,018	$122,191	$196,721	$7,997	$381,927
Convert Bayway-Linden "M" to 138kV circuit to 345kV	b2436.85_dfax	$ 3,198,721.00	0.00%	0.00%	96.06%	3.94%	$0	$0	$3,072,691	$126,030	$3,198,721
Convert Bayway-Linden "M" to 138kV circuit to 345kV	b2436.85	$ 3,198,721.00	1.72%	3.82%	6.15%	0.25%	$55,018	$122,191	$196,721	$7,997	$381,927
Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades	b2436.90_dfax	$ 1,607,425.00	0.00%	0.00%	100.00%	0.00%	$0	$0	$1,607,425	$0	$1,607,425
Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades	b2436.90	$ 1,607,425.00	1.72%	3.82%	6.15%	0.25%	$27,648	$61,404	$98,857	$4,019	$191,927
New Bergen 345/230 kV transformer and any associated substation upgrades	b2437.10	$ 3,303,514.00	0.00%	0.00%	100.00%	0.00%	$0	$0	$3,303,514	$0	$3,303,514
New Bayway 345/138 kV transformer #1 and any associated substation upgrades	b2437.20	$ 1,051,024.00	0.00%	0.00%	100.00%	0.00%	$0	$0	$1,051,024	$0	$1,051,024
New Bayway 345/138 kV transformer #2 and any associated substation upgrades	b2437.21	$ 1,050,975.00	0.00%	0.00%	100.00%	0.00%	$0	$0	$1,050,975	$0	$1,050,975
New Linden 345/230 kV transformer and any associated substation upgrades	b2437.30	$ 4,175,124.00	0.00%	0.00%	96.06%	3.94%	$0	$0	$4,010,624	$164,500	$4,175,124
Install two 175 MVAR Re at Hptcg	b2702_dfax	$ 1,554,283.50	0.00%	0.00%	100.00%	0.00%	$0	$0	$1,554,284	$0	$1,554,284

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

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				Estimated New Jersey EDC Zone Charges by Project				
Required Transmission Enhancement *per PJM website*	**PJM Upgrade ID** *per PJM spreadsheet*	**Jan - Dec 2020 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share** *per PJM Open Access Transmission Tariff*	**JCP&L Zone Share**	**PSE&G Zone Share1,2**	**RE Zone Share**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
Install two 175 MVAR Re at Hptcg	b2702	$ 1,554,283.50	1.72%	3.82%	6.15%	0.25%	$26,734	$59,374	$95,588	$3,886	$185,581
Convert R-1318 and Q1815 Circuits to 230kV	b2835.3	$ 953,080.00	0.00%	0.00%	57.49%	2.36%	$0	$0	$547,926	$22,493	$570,418
Convert F-1358/Z-1326 and K-1363/Y-1325 to Circuits to 230kV	b2837.4	$ 641,952.00	0.00%	0.00%	88.71%	3.64%	$0	$0	$569,476	$23,367	$592,843
Convert F-1358/Z-1326 and K-1363/Y-1325 to Circuits to 230kV	b2837.5	$ 484,283.00	0.00%	0.00%	90.12%	3.70%	$0	$0	$436,436	$17,918	$454,354
Convert F-1358/Z-1326 and K-1363/Y-1325 to Circuits to 230kV	b2837.9	$ 189,882.00	0.00%	0.00%	87.28%	3.58%	$0	$0	$165,729	$6,798	$172,527
Convert F-1358/Z-1326 and K-1363/Y-1325 to Circuits to 230kV	b2837.10	$ 450,867.00	0.00%	0.00%	88.85%	3.65%	$0	$0	$400,595	$16,457	$417,052
Convert F-1358/Z-1326 and K-1363/Y-1325 to Circuits to 230kV	b2837.11	$ 484,283.00	0.00%	0.00%	90.40%	3.71%	$0	$0	$437,792	$17,967	$455,759
Replace Transformers 203/138kV transformers at Roseland	b0274	$ 2,016,205.00	0.00%	0.00%	96.77%	0.00%	$0	$0	$1,951,082	$0	$1,951,082
Totals		**$ 476,469,695.00**					**$3,366,109**	**$47,496,659**	**$286,678,057**	**$10,554,290**	**$348,095,116**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) +

	(k)	(l)	(m)	(n)	(o)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 2020**	**2020 Trans. Peak Load [2]**	**Rate in $/MW-mo. [1]**	**2020 Impact (12 months)**	
PSE&G	$ 23,889,838.07	9,752.5	$ 2,449.61	$ 286,678,057	
JCP&L	$ 3,958,054.95	6,057.1	$ 653.46	$ 47,496,659	
ACE	$ 280,509.11	2,737.3	$ 102.48	$ 3,366,109	
RE	$ 879,524.21	393.1	$ 2,237.41	$ 10,554,290	
Total Impact on NJ Zones	**$ 29,007,926.34**	**18,940.0**		**$ 348,095,116**	
Notes on calculations >>>			= (k) / (l)	= (k) *12	

Notes:

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

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

Calculation of Costs and Monthly PJM charges for JCP&L Projects

Required Transmission Enhancement	PJM Upgrade ID *per PJM spreadsheet*	(a) Jan - Dec 2020 Annual Revenue Requirement *per PJM website*	(b) Responsible Customers - Schedule 12 Appendix: ACE Zone Share	(c) JCP&L Zone Share	(d) PSE&G Zone Share1,2	(e) RE Zone Share *per PJM Open Access Transmission Tariff*	(f) Estimated New Jersey EDC Zone Charges by Project: ACE Zone Charges	(g) JCP&L Zone Charges	(h) PSE&G Zone Charges	(i) RE Zone Charges	(j) Total NJ Zones Charges
Upgrade the Portland - Greystone 230kV circuit	b0174	$1,300,508	0.00%	35.40%	54.37%	2.94%	$0	$460,380	$707,086	$38,235	$1,205,701
Reconductor the 8 mile Gilbert - Glen Gardner 230kV circuit	b0268	$642,197	0.00%	61.77%	32.73%	1.45%	$0	$396,685	$210,191	$9,312	$616,188
Add a 2nd Raritan River 230/115 kV transformer	b0726	$819,833	2.45%	97.55%	0.00%	0.00%	$20,086	$799,747	$0	$0	$819,833
Build a new 230kV circuit from Larrabee to Oceanview	b2015	$19,324,505	0.00%	35.83%	35.87%	1.43%	$0	$6,923,970	$6,931,700	$276,340	$14,132,011
Totals		**$22,087,043**					**$20,086**	**$8,580,782**	**$7,848,977**	**$323,887**	**$16,773,732**

Zonal Cost Allocation for New Jersey Zones	(k) Average Monthly Impact on Zone Customers in 2020	(l) 2020 Trans. Peak Load [2]	(m) Rate in $/MW-mo. [1]	(n) 2020 Impact (12 months)	(o)
PSE&G	$654,081	9,752.5	$67.07	$7,848,977	
JCP&L	$715,065	6,057.1	$118.05	$8,580,782	
ACE	$1,674	2,737.3	$0.61	$20,086	
RE	$26,991	393.1	$68.66	$323,887	
Total Impact on NJ Zones	**$1,397,811**	**18,940.0**		**$16,773,732**	
			= (k) / (l)	= (k) *12	

Notes:

1) Uncompressed rate - assumes implementation on January 1, 2020

2) Data on PJM website

Attachment 6c PJM Schedule 12 - Transmission Enhancement Charges for June 2020 - May 2021
Calculation of costs and monthly PJM charges for ACE Projects

Required Transmission Enhancement *per PJM website*	PJM Upgrade ID *per PJM spreadsheet*	(a) June 2020 - May 2021 Annual Revenue Requirement *per PJM website*	(b) Responsible Customers - Schedule 12 Appendix (per PJM Open Access Transmission Tariff): ACE Zone Share[1]	(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
Upgrade AE portion of Delco Tap	b0265	$ 443,088.00	89.87%	9.48%	0.00%	0.00%	$398,203	$42,005	$0	$0	$440,208
Replace Monroe 230/69 kV TXfmrs	b0276	$ 677,713.00	91.28%	0.00%	8.29%	0.23%	$618,616	$0	$56,182	$1,559	$676,358
Reconductor Union - Corson 138 kV	b0211	$ 1,155,287.00	65.23%	25.87%	6.35%	0.00%	$753,594	$298,873	$73,361	$0	$1,125,827
New 500/230 Kv Sub on Salem-East Windsor (>500 kV portion)	b0210.A	$ 1,156,794.37	1.72%	3.82%	6.15%	0.25%	$19,897	$44,190	$71,143	$2,892	$138,121
New 500/230 Kv Sub on Salem-East Windsor (>500 kV portion)	b0210.A_dfax	$ 1,156,794.37	100.00%	0.00%	0.00%	0.00%	$1,156,794	$0	$0	$0	$1,156,794
New 500/230kV Sub on Salem-East Windsor (< 500kV) portion[2]	b0210.B	$ 1,649,674.00	65.23%	25.87%	6.35%	0.00%	$1,076,082	$426,771	$104,754	$0	$1,607,607
Reconductor the existing Mickleton – Goucester 230 kV circuit (AE portion)	b1398.5	$ 413,399.00	0.00%	12.82%	31.46%	1.25%	$0	$52,998	$130,055	$5,167	$188,221
Build second 230kV parallel from Mickelton to Gloucester	b1398.3.1	$ 1,291,971.00	0.00%	12.82%	31.46%	1.25%	$0	$165,631	$406,454	$16,150	$588,234
Upgrade the Mill T2 138/69 kV Transformer	b1600	$ 1,532,281.00	88.83%	4.74%	5.78%	0.23%	$1,361,125	$72,630	$88,566	$3,524	$1,525,845
Orchard-Cumberland Install 2nd 230 kV line	b0210.1	$ 1,324,917.00	65.23%	25.87%	6.35%	0.00%	$864,243	$342,756	$84,132	$0	$1,291,132
Corson Upgrade 138kV Line trap	b0212	$ 5,808.00	65.23%	25.87%	6.35%	0.00%	$3,789	$1,503	$369	$0	$5,660
							$6,252,344	**$1,447,355**	**$1,015,017**	**$29,292**	**$8,744,008**
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 20/21	(l) 2020TX Peak Load per PJM *website*	(m) Rate in $/MW-mo.	(n) 2020 Impact (7 months)	(o) 2021 Impact (5 months)	(p) 2020-2021 Impact (12 months)
PSE&G	$ 84,584.71	9,752.5	$ 8.67	$ 592,093	$ 422,924	$ 1,015,017
JCP&L	$ 120,612.90	6,057.1	$ 19.91	$ 844,290	$ 603,065	$ 1,447,355
ACE	$ 521,028.67	2,737.3	$ 190.34	$ 3,647,201	$ 2,605,143	$ 6,252,344
RE	$ 2,441.01	393.1	$ 6.21	$ 17,087	$ 12,205	$ 29,292
Total Impact on NJ Zones	**$ 728,667.29**			**$ 5,100,671**	**$ 3,643,336**	**$ 8,744,008**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

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

Attachment 6d - PJM Schedule 12 - Transmission Enhancement Charges for January 2020 - December 2020 **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 2020 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**
Upgrade Mt Storm - Doubs 500kV	b0217	$93,533.69	1.72%	3.82%	6.15%	0.25%	$1,609	$3,573	$5,752	$234	$11,168
Upgrade Mt Storm - Doubs 500kV	b0217_dfax	$93,533.69	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Loudoun 150 MVA capacitor @ 500 kV	b0222	$76,268.24	1.72%	3.82%	6.15%	0.25%	$1,312	$2,913	$4,690	$191	$9,106
Loudoun 150 MVA capacitor @ 500 kV	b0222_dfax	$76,268.24	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
500 kV breakers and bus work at Suffolk	b0231	$1,135,647.08	1.72%	3.82%	6.15%	0.25%	$19,533	$43,382	$69,842	$2,839	$135,596
500 kV breakers and bus work at Suffolk	b0231_dfax	$1,135,647.08	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Meadowbrook-Loudon 500kV circuit	b0328.1	$11,472,499.60	1.72%	3.82%	6.15%	0.25%	$197,327	$438,249	$705,559	$28,681	$1,369,816
Meadowbrook-Loudon 500kV circuit	b0328.1_dfax	$11,472,499.60	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Upgrade Mt. Storm 500 KV Substation	b0328.3	$708,832.49	1.72%	3.82%	6.15%	0.25%	$12,192	$27,077	$43,593	$1,772	$84,635
Upgrade Mt. Storm 500 KV Substation	b0328.3_dfax	$708,832.49	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Upgrade Loudoun 500 KV Substation	b0328.4	$158,100.97	1.72%	3.82%	6.15%	0.25%	$2,719	$6,039	$9,723	$395	$18,877
Upgrade Loudoun 500 KV Substation	b0328.4_dfax	$158,100.97	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Carson – Suffolk 500 kV, Suffolk 500/230 kV transformer & build Suffolk – Trascher 230 kV circuit	B0329.2B	$8,325,873.06	1.72%	3.82%	6.15%	0.25%	$143,205	$318,048	$512,041	$20,815	$994,109
Carson – Suffolk 500 kV, Suffolk 500/230 kV transformer & build Suffolk – Trascher 230 kV circuit	B0329.2B_dfax	$8,325,873.06	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
500/230 KV transformer at Bristers, new 230 Bristers - Gainsville circuit	b0227	$1,962,158.37	0.71%	0.00%	0.00%	0.00%	$13,931	$0	$0	$0	$13,931
Rebuild Mt Storm-Doubs 500 KV circuit	b1507	$16,763,202.31	1.72%	3.82%	6.15%	0.25%	$288,327	$640,354	$1,030,937	$41,908	$2,001,526
Rebuild Mt Storm-Doubs 500 KV circuit	b1507_dfax	$16,763,202.31	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Replace wave traps on Dooms-Lexington 500KV circuit	b0457	$5,291.19	1.72%	3.82%	6.15%	0.25%	$91	$202	$325	$13	$632
Replace wave traps on Dooms-Lexington 500KV circuit	b0457_dfax	$5,291.19	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Morrisville H1T573	b1647	$807.36	1.72%	3.82%	6.15%	0.25%	$14	$31	$50	$2	$96
Morrisville H1T573	b1647_dfax	$807.36	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Morrisville H2T545	b1648	$807.36	1.72%	3.82%	6.15%	0.25%	$14	$31	$50	$2	$96
Morrisville H2T545	b1648_dfax	$807.36	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Morrisville H1T580	b1649	$42,598.43	1.72%	3.82%	6.15%	0.25%	$733	$1,627	$2,620	$106	$5,086
Morrisville H1T580	b1649_dfax	$42,598.43	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Morrisville H2T569	b1650	$42,598.43	1.72%	3.82%	6.15%	0.25%	$733	$1,627	$2,620	$106	$5,086
Morrisville H2T569	b1650_dfax	$42,598.43	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Replace wave traps on North Anna-Ladysmith 500KV circuit	b0784	$3,671.42	1.72%	3.82%	6.15%	0.25%	$63	$140	$226	$9	$438
Replace wave traps on North Anna-Ladysmith 500KV circuit	b0784_dfax	$3,671.42	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0

Attachment 6d - PJM Schedule 12 - Transmission Enhancement Charges for January 2020 - December 2020 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 2020 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**
Reconductor the Dickerson-Pleasant View 230 KV circuit	b0467.2	$527,826.16	1.75%	0.71%	0.00%	0.00%	$9,237	$3,748	$0	$0	$12,985
Install 500/230 kV transformer and two 230 kV breakers at Brambleton	b1188.6	$1,712,199.73	0.22%	0.00%	0.00%	0.00%	$3,767	$0	$0	$0	$3,767
New Brambleton 500 kV line, 3 ring bus, to Loudon to Pleasant View 500 kV	b1188	$80,129.54	1.72%	3.82%	6.15%	0.25%	$1,378	$3,061	$4,928	$200	$9,567
New Brambleton 500 kV line, 3 ring bus, to Loudon to Pleasant View 500 kV	b1188_dfax	$80,129.54	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
500 kV breaker at Brambleton	b1698.1	$0.00	1.72%	3.82%	6.15%	0.25%	$0	$0	$0	$0	$0
500 kV breaker at Brambleton	b1698.1_dfax	$0.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Install 2 500kV breakers at Chancellor 500 kV	b0756.1	$209,449.54	1.72%	3.82%	6.15%	0.25%	$3,603	$8,001	$12,881	$524	$25,008
Install 2 500kV breakers at Chancellor 500 kV	b0756.1_dfax	$209,449.54	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Wreck and Rebuild 7 miles of Cloverdale - Lexington 500 kV Line	b1797	$929,329.01	1.72%	3.82%	6.15%	0.25%	$15,984	$35,500	$57,154	$2,323	$110,962
Wreck and Rebuild 7 miles of Cloverdale - Lexington 500 kV Line	b1797_dfax	$929,329.01	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Build 450 MVAR SVC and 300 MVAR switched shunt at Loudoun 500 kV	b1798	$5,708,973.61	1.72%	3.82%	6.15%	0.25%	$98,194	$218,083	$351,102	$14,272	$681,651
Build 450 MVAR SVC and 300 MVAR switched shunt at Loudoun 500 kV	b1798_dfax	$5,708,973.61	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Build 150 MVAR Switched Shunt at Pleasant View 500 kV Line	b1799	$1,343,490.54	1.72%	3.82%	6.15%	0.25%	$23,108	$51,321	$82,625	$3,359	$160,413
Build 150 MVAR Switched Shunt at Pleasant View 500 kV Line	b1799_dfax	$1,343,490.54	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Install 250 MVAR SVC at Mt. Storm 500 kV Substation	b1805	$1,896,144.85	1.72%	3.82%	6.15%	0.25%	$32,614	$72,433	$116,613	$4,740	$226,400
Install 250 MVAR SVC at Mt. Storm 500 kV Substation	b1805_dfax	$1,896,144.85	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
At Yadkin 500 kV, install six 500 kV Breakers	b1906.1	$525,051.64	1.72%	3.82%	6.15%	0.25%	$9,031	$20,057	$32,291	$1,313	$62,691
At Yadkin 500 kV, install six 500 kV Breakers	b1906.1_dfax	$525,051.64	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Rebuild Lexington-Dooms 500 kV Line	b1908	$6,723,598.67	1.72%	3.82%	6.15%	0.25%	$115,646	$256,841	$413,501	$16,809	$802,798
Rebuild Lexington-Dooms 500 kV Line	b1908_dfax	$6,723,598.67	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Surry 500 kV Station Work	b1905.2	$93,464.75	1.72%	3.82%	6.15%	0.25%	$1,608	$3,570	$5,748	$234	$11,160
Surry 500 kV Station Work	b1905.2_dfax	$93,464.75	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Mt Storm - Replace MOD with breaker on 500kV side of Transformer	b0837	$36,199.44	1.72%	3.82%	6.15%	0.25%	$623	$1,383	$2,226	$90	$4,322
Mt Storm - Replace MOD with breaker on 500kV side of Transformer	b0837_dfax	$36,199.44	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0

Attachment 6d - PJM Schedule 12 - Transmission Enhancement Charges for January 2020 - December 2020 **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 2020 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	$408,446.97	0.66%	0.00%	0.00%	0.00%	$2,696	$0	$0	$0	$2,696
Rebuild Loudoun - Brambleto 500kV	b1694	$2,496,438.72	1.72%	3.82%	6.15%	0.25%	$42,939	$95,364	$153,531	$6,241	$298,075
Rebuild Loudoun - Brambleto 500kV	b1694_dfax	$2,496,438.72	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
R/P Midlothian 500kV 3 breaker Ring Bus	b2471	$414,709.10	1.72%	3.82%	6.15%	0.25%	$7,133	$15,842	$25,505	$1,037	$49,516
R/P Midlothian 500kV 3 breaker Ring Bus	b2471_dfax	$414,709.10	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Surry to Skiffes Creek 500kV Line	b1905.1	$14,564,332.17	1.72%	3.82%	6.15%	0.25%	$250,507	$556,357	$895,706	$36,411	$1,738,981
Surry to Skiffes Creek 500kV Line	b1905.1_dfax	$14,564,332.17	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Install Breaker and half scheme with minimum of eight 230kV Breakers	b1696	$2,881,073.35	0.46%	0.64%	0.00%	0.00%	$13,253	$18,439	$0	$0	$31,692
Build a second Loudon - Brambleton 500kV line	b2373	$2,358,682.48	1.72%	3.82%	6.15%	0.25%	$40,569	$90,102	$145,059	$5,897	$281,627
Build a second Loudon - Brambleton 500kV line	b2373_dfax	$2,358,682.48	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Rebuild Carson Rogers 500kV Ckt	b2744	$4,649,812.66	1.72%	3.82%	6.15%	0.25%	$79,977	$177,623	$285,963	$11,625	$555,188
Rebuild Carson Rogers 500kV Ckt	b2744_dfax	$4,649,812.66	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Optimal Capacitors Configuaration	b2729	$1,199,710.25	1.96%	3.31%	7.29%	0.00%	$23,514	$39,710	$87,459	$0	$150,684
Rebuild Elmont-Cunningham 500 kV Ln	b2582	$5,713,363.00	1.72%	3.82%	6.15%	0.25%	$98,270	$218,250	$351,372	$14,283	$682,176
Rebuild Elmont-Cunningham 500 kV Ln	b2582_dfax	$5,713,363.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Rebuild Cunningham-Dooms 500 kV Ln	b2665	$4,290,020.17	1.72%	3.82%	6.15%	0.25%	$73,788	$163,879	$263,836	$10,725	$512,228
Rebuild Cunningham-Dooms 500 kV Ln	b2665_dfax	$4,290,020.17	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Rebuild Line#549 Dooms-Valley 500kV	b2758	$2,602,909.59	1.72%	3.82%	6.15%	0.25%	$44,770	$99,431	$160,079	$6,507	$310,787
Rebuild Line#549 Dooms-Valley 500kV	b2758_dfax	$2,602,909.59	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Rebuild 4 Structures Line#549	b2928	$1,999,784.83	1.72%	3.82%	6.15%	0.25%	$34,396	$76,392	$122,987	$4,999	$238,774
Rebuild 4 Structures Line#549	b2928_dfax	$1,999,784.83	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Replace Capacitors on Line#547	b2960.1	$686,439.50	1.72%	3.82%	6.15%	0.25%	$11,807	$26,222	$42,216	$1,716	$81,961
Replace Capacitors on Line#547	b2960.1_dfax	$686,439.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Replace Capacitors on Line#548	b2960.2	$647,404.00	1.72%	3.82%	6.15%	0.25%	$11,135	$24,731	$39,815	$1,619	$77,300
Replace Capacitors on Line#548	b2960.2_dfax	$647,404.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Totals		**$202,290,333.71**					**$1,731,349**	**$3,759,636**	**$6,040,626**	**$241,999**	**$11,773,609**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

(k) (l) (m) (n)

Attachment 6d - PJM Schedule 12 - Transmission Enhancement Charges for January 2020 - December 2020 **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	**PJM Upgrade ID**	**Jan - Dec 2020 Annual Revenue Requirement**	**ACE Zone Share**	**JCP&L Zone Share**	**PSE&G Zone Share1**	**RE Zone Share**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
per PJM website	*per PJM spreadsheet*	*per PJM website*	*per PJM Open Access Transmission Tariff*								

Zonal Cost Allocation for New Jersey Zones	Average Monthly Impact on Zone Customers in 2020	2020 Trans. Peak Load [2]	Rate in \$/MW-mo. [1]	2020 Impact (12 months)
PSE&G	\$ 503,385.47	9,752.5	\$ 51.62	\$ 6,040,626
JCP&L	\$ 313,303.02	6,057.1	\$ 51.72	\$ 3,759,636
ACE	\$ 144,279.07	2,737.3	\$ 52.71	\$ 1,731,349
RE	\$ 20,166.55	393.1	\$ 51.30	\$ 241,999
Total Impact on NJ Zones	**\$ 981,134.11**	**18,940.0**		**\$11,773,609**

Notes on calculations >>> = (k) / (l) = (k) *12

Attachment 6e PJM Schedule 12 - Transmission Enhancement Charges for June 2020 - May 2021
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 2020-May 2021 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
502 Junction-Mt Storm-Meadowbrook (>=500kV) - CWIP[1]	b0328.1; b0328.2; b0347.1; b0347.2; b0347.3; b0347.4	$ 64,291,222.94	1.72%	3.82%	6.15%	0.25%	$1,105,809	$2,455,925	$3,953,910	$160,728	$7,676,372
Wylie Ridge [2]	b0218	$ 2,566,265.53	11.83%	15.56%	0.00%	0.00%	$303,589	$399,311	$0	$0	$702,900
Black Oak	b0216	$ 2,646,810.20	1.72%	3.82%	6.15%	0.25%	$45,525	$101,108	$162,779	$6,617	$316,029
Meadowbrook 200 MVAR capacitor	b0559	$ 358,624.70	1.72%	3.82%	6.15%	0.25%	$6,168	$13,699	$22,055	$897	$42,820
Replace Kammer 765/500 kV TXfmr	b0495	$ 2,189,076.15	1.72%	3.82%	6.15%	0.25%	$37,652	$83,623	$134,628	$5,473	$261,376
Doubs TXfmr 2	b0343	$ 581,163.93	1.85%	0.00%	0.00%	0.00%	$10,752	$0	$0	$0	$10,752
Doubs TXfmr 3	b0344	$ 536,391.94	1.86%	0.00%	0.00%	0.00%	$9,977	$0	$0	$0	$9,977
Doubs TXfmr 4	b0345	$ 643,125.40	1.85%	0.00%	0.00%	0.00%	$11,898	$0	$0	$0	$11,898
New Osage 138KV Ckt	b0674	$ 2,810,217.08	0.00%	0.00%	0.25%	0.01%	$0	$0	$7,026	$281	$7,307
Cap at Grover 230	b0556	$ 106,838.29	8.58%	18.16%	26.13%	0.97%	$9,167	$19,402	$27,917	$1,036	$57,522
Upgrade transformer 500/230	b1153	$ 3,519,706.71	3.74%	12.57%	20.52%	0.72%	$131,637	$442,427	$722,244	$25,342	$1,321,650
Build a 300 MVAR Switched Shunt at Doubs 500kV	b1803	$ 303,938.75	1.72%	3.82%	6.15%	0.25%	$5,228	$11,610	$18,692	$760	$36,290
Install 500 MVAR svc at Hunterstown 500kV Sub	b1800	$ 2,677,677.73	1.72%	3.82%	6.15%	0.25%	$46,056	$102,287	$164,677	$6,694	$319,715
Install 500 MVAR svc at Hunterstown 500kV Sub	b1800_dfax	$ 2,677,677.73	0.00%	0.04%	0.08%	0.00%	$0	$1,071	$2,142	$0	$3,213
Install a new 600 MVAR SVC at Meadowbrook 500 kV	b1804	$ 3,739,290.99	1.72%	3.82%	6.15%	0.25%	$64,316	$142,841	$229,966	$9,348	$446,471
Build 250 MVAR svc at Altoona 230kV	b1801	$ 4,419,104.33	6.47%	8.14%	8.18%	0.33%	$285,916	$359,715	$361,483	$14,583	$1,021,697
Convert Moshannon sub to 4 breaker 230 kv ring bus	b1964	$ 939,591.98	0.00%	5.48%		0.00%	$0	$51,490	$0	$0	$51,490
Build a 100 MVAR Fast Switched Shunt and 200 MVAR Switched Shunt at Mansfield 345 kV	b1802	$ -	6.47%	8.14%	8.18%	0.33%	$0	$0	$0	$0	$0

Attachment 6e PJM Schedule 12 - Transmission Enhancement Charges for June 2020 - May 2021 **Attachment 6e**
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 2020-May 2021 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 100 MVAR capacitor at Johnstown 230 kV substation	b0555	$ 170,327.98	8.58%	18.16%	26.13%	0.97%	$14,614	$30,932	$44,507	$1,652	$91,705
Totals							**$2,088,304**	**$4,215,441**	**$5,852,026**	**$233,411**	**$12,389,182**
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 20/21**	**2020TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2020 Impact (7 months)**	**2021 Impact (5 months)**	**2020-2021 Impact (12 months)**
PSE&G	$ 487,668.85	9,752.5	$ 50.00	$ 3,413,682	$ 2,438,344	$ 5,852,026
JCP&L	$ 351,286.75	6,057.1	$ 58.00	$ 2,459,007	$ 1,756,434	$ 4,215,441
ACE	$ 174,025.30	2,737.3	$ 63.58	$ 1,218,177	$ 870,127	$ 2,088,304
RE	$ 19,450.92	393.1	$ 49.48	$ 136,156	$ 97,255	$ 233,411
Total Impact on NJ Zones	**$ 1,032,431.82**			**$ 7,227,023**	**$ 5,162,159**	**$ 12,389,182**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

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

Attachment 6f PJM Schedule 12 - Transmission Enhancement Charges for June 2020 to May 2021 **Attachment 6f**
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 2020-May 2021 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**
Reconductor 23035 for Dickerson-Quince	b0367.1-2	$ 2,434,092.00	1.78%	2.67%	3.81%	0.00%	$43,327	$64,990	$92,739	$0	$201,056
Replace 230 1A breaker	b0512.7	$ 115,507.73	1.72%	3.82%	6.15%	0.25%	$1,987	$4,412	$7,104	$289	$13,792
Replace 230 1A breaker	b0512.7_dfax	$ 115,507.73	3.94%	9.43%	14.71%	0.54%	$4,551	$10,892	$16,991	$624	$33,058
Replace 230 1B breaker	b0512.8	$ 115,507.73	1.72%	3.82%	6.15%	0.25%	$1,987	$4,412	$7,104	$289	$13,792
Replace 230 1B breaker	b0512.8_dfax	$ 115,507.73	3.94%	9.43%	14.71%	0.54%	$4,551	$10,892	$16,991	$624	$33,058
Replace 230 2A breaker	b0512.9	$ 115,507.73	1.72%	3.82%	6.15%	0.25%	$1,987	$4,412	$7,104	$289	$13,792
Replace 230 2A breaker	b0512.9_dfax	$ 115,507.73	3.94%	9.43%	14.71%	0.54%	$4,551	$10,892	$16,991	$624	$33,058
Replace 230 3A breaker	b0512.12	$ 116,636.78	1.72%	3.82%	6.15%	0.25%	$2,006	$4,456	$7,173	$292	$13,926
Replace 230 3A breaker	b0512.12_dfax	$ 116,636.78	3.94%	9.43%	14.71%	0.54%	$4,595	$10,999	$17,157	$630	$33,381
Ritchie-Benning 230 lines	b0526	$ 6,931,930.00	0.77%	1.39%	2.10%	0.08%	$53,376	$96,354	$145,571	$5,546	$300,846
Reconductor Dickerson-Pleasant View 230 kV	b0467.1	$ 1,034,489.00	1.75%	0.71%	0.00%	0.00%	$18,104	$7,345	$0	$0	$25,448
Reconductor Dickerson staion H and Upgrade Equipment	b1596	$ 1,182,124.00	0.80%	0.00%	0.00%	0.00%	$9,457	$0	$0	$0	$9,457
Totals							**$150,478**	**$230,058**	**$334,925**	**$9,205**	**$724,665**
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 20/21**	**2020TX Peak Load per PJM** *website*	**Rate in $/MW-mo.**	**2020 Impact (7 months)**	**2021 Impact (5 months)**	**2020-2021 Impact (12 months)**
PSE&G	$ 27,910.38	9,752.5	$ 2.86	$ 195,373	$ 139,552	$ 334,925
JCP&L	$ 19,171.47	6,057.1	$ 3.17	$ 134,200	$ 95,857	$ 230,058
ACE	$ 12,539.84	2,737.3	$ 4.58	$ 87,779	$ 62,699	$ 150,478
RE	$ 767.04	393.1	$ 1.95	$ 5,369	$ 3,835	$ 9,205
Total Impact on NJ Zones	**$ 60,388.74**			**$ 422,721**	**$ 301,944**	**$ 724,665**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

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

Attachment 6g PJM Schedule 12 - Transmission Enhancement Charges for June 2020 - May 2021 **Attachment 6g**
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 2020- May 2021 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	$	36,461,845.00	1.72%	3.82%	6.15%	0.25%	$627,144	$1,392,842	$2,242,403	$91,155	$4,353,544
New 500 KV Susquehana-Roseland Line	b0487_dfax	$	36,461,845.00	0.00%	32.93%	60.23%	2.47%	$0	$12,006,886	$21,960,969	$900,608	$34,868,462
Replace wave trap at Alburtus 500 kV Sub	b0171.2	$	4,113.50	1.72%	3.82%	6.15%	0.25%	$71	$157	$253	$10	$491
Replace wave trap at Alburtus 500 kV Sub	b0171.2_dfax	$	4,113.50	4.19%	19.81%	0.00%	0.00%	$172	$815	$0	$0	$987
Replace wavetrap at Hosensack 500KV Sub	b0172.1	$	2,950.00	1.72%	3.82%	6.15%	0.25%	$51	$113	$181	$7	$352
Replace wavetrap at Hosensack 500KV Sub	b0172.1_dfax	$	2,950.00	4.49%	29.72%	48.90%	2.01%	$132	$877	$1,443	$59	$2,511
Replace wavetraps at Juniata 500KV Sub	b0284.2	$	5,970.50	1.72%	3.82%	6.15%	0.25%	$103	$228	$367	$15	$713
Replace wavetraps at Juniata 500KV Sub	b0284.2_dfax	$	5,970.50	0.00%	18.75%	24.11%	0.99%	$0	$1,119	$1,439	$59	$2,618
New S-R additions < 500kV[2]	b0487.1	$	1,737,153.00	0.00%	0.00%	5.13%	0.19%	$0	$0	$89,116	$3,301	$92,417
New substation and transformers Middletown	b0468	$	2,376,503.00	0.00%	4.55%	5.93%	0.22%	$0	$108,131	$140,927	$5,228	$254,286
Install Lauschtown 500/230 kV Sub below 500kv portion	b2006	$	1,111,610.00	1.10%	9.61%	11.35%	0.45%	$12,228	$106,826	$126,168	$5,002	$250,223
Install Lauschtown 500/230 kV Sub 500kv portion tie line	b2006.1	$	2,354,590.00	1.72%	3.82%	6.15%	0.25%	$40,499	$89,945	$144,807	$5,886	$281,138
Install Lauschtown 500/230 kV Sub 500kv portion tie line	b2006.1_dfax	$	2,354,590.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
200 MVAR shunt reactor at Alburtis 500kv	b2237	$	854,374.50	1.72%	3.82%	6.15%	0.25%	$14,695	$32,637	$52,544	$2,136	$102,012
200 MVAR shunt reactor at Alburtis 500kv	b2237_dfax	$	854,374.50	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0

Attachment 6g PJM Schedule 12 - Transmission Enhancement Charges for June 2020 - May 2021 **Attachment 6g**
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 2020- May 2021 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**
200 MVAR shunt reactor at Lackawana 500kv	b2716	$ 876,872.00	1.72%	3.82%	6.15%	0.25%	$15,082	$33,497	$53,928	$2,192	$104,699
200 MVAR shunt reactor at Lackawana 500kv	b2716_dfax	$ 876,872.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Add 3rd Bay w/3 Breakers at Lackawanna 500kv	b2824	$ 1,229,811.00	1.72%	3.82%	6.15%	0.25%	$21,153	$46,979	$75,633	$3,075	$146,839
Add 3rd Bay w/3 Breakers at Lackawanna 500kv	b2824_dfax	$ 1,229,811.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Totals							**$731,330**	**$13,821,051**	**$24,890,179**	**$1,018,733**	**$40,461,293**
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 20/21**	**2020TX Peak Load per PJM** *website*	**Rate in $/MW-mo.**	**2020 Impact (7 months)**	**2021 Impact (5 months)**	**2020-2021 Impact (12 months)**
PSE&G	$ 2,074,181.58	9,752.5	$ 212.68	$ 14,519,271	$ 10,370,908	$ 24,890,179
JCP&L	$ 1,151,754.28	6,057.1	$ 190.15	$ 8,062,280	$ 5,758,771	$ 13,821,051
ACE	$ 60,944.13	2,737.3	$ 22.26	$ 426,609	$ 304,721	$ 731,330
RE	$ 84,894.45	393.1	$ 215.96	$ 594,261	$ 424,472	$ 1,018,733
Total Impact on NJ Zones	**$ 3,371,774.45**			**$ 23,602,421**	**$ 16,858,872**	**$ 40,461,293**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

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

Attachment 6h PJM Schedule 12 - Transmission Enhancement Charges for June 2020 - May 2021 **Attachment 6h**
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 2020 - May 2021 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	$ 1,991,315.00	9.00%	9.64%	14.07%	0.52%	$179,218	$191,963	$280,178	$10,355	$661,714
		$ -	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
		$ -					$0	$0	$0	$0	$0
Totals							**$179,218**	**$191,963**	**$280,178**	**$10,355**	**$661,714**
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 20/21**	**2020TX Peak Load per PJM** *website*	**Rate in $/MW-mo.**	**2020 Impact (7 months)**	**2021 Impact (5 months)**	**2020-2021 Impact (12 months)**
PSE&G	$ 23,348.17	9,752.5	$ 2.39	$ 163,437	$ 116,741	$ 280,178
JCP&L	$ 15,996.90	6,057.1	$ 2.64	$ 111,978	$ 79,984	$ 191,963
ACE	$ 14,934.86	2,737.3	$ 5.46	$ 104,544	$ 74,674	$ 179,218
RE	$ 862.90	393.1	$ 2.20	$ 6,040	$ 4,315	$ 10,355
Total Impact on NJ Zones	**$ 55,142.83**			**$ 386,000**	**$ 275,714**	**$ 661,714**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (n) * (o)

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

Attachment 6i - Transmission Enhancement Charges for January 2020 - December 2020 **Attachment 6i**
Calculation of costs and monthly PJM charges for Mid Atlantic Interstate Transmission Projects

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				Estimated New Jersey EDC Zone Charges by Project				
Required Transmission Enhancement *per PJM website*	PJM Upgrade ID *per PJM spreadsheet*	Jan-Dec 2020 Annual Revenue Requirement *per PJM website*	ACE Zone Share[1]	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 230kV series reactor and 2-100MVAR PLC switched capacitors at Hunterstown	b0215	$ 1,350,447.00	6.71%	16.85%	22.67%	0.34%	$90,615	$227,550	$306,146	$4,592	$628,903
Replace wave trap at Kestone 500kV Sub	b2688.1	$ 1,502,687.00	0.00%	0.00%	0.00%	0.12%	$0	$0	$0	$1,803	$1,803
Install 250 MVAR Capacitor at Keystone 500kV Sub	b0549	$ 175,075.00	1.72%	3.82%	6.15%	0.25%	$3,011	$6,688	$10,767	$438	$20,904
Install 250 MVAR Capacitor at Keystone 500kV Sub	b0549_dfax	$ 175,075.00	4.26%	15.53%	19.08%	0.78%	$7,458	$27,189	$33,404	$1,366	$69,417
Install 25 MVAR capacitor at Saxton 115 kV Sub	b0551	$ 143,377.00	8.58%	18.16%	26.13%	0.97%	$12,302	$26,037	$37,464	$1,391	$77,194
Install 50 MVAR capacitor at Altoona 230 kV Sub	b0552	$ 115,214.00	8.58%	18.16%	26.13%	0.97%	$9,885	$20,923	$30,105	$1,118	$62,031
Install 50 MVAR capacitor at Raystoon 230 kV Sub	b0553	$ 101,288.00	8.58%	18.16%	26.13%	0.97%	$8,691	$18,394	$26,467	$982	$54,533
Install 75 MVAR capacitor at East Towanda 230 kV Sub	b0557	$ 237,837.00	8.58%	18.16%	26.13%	0.97%	$20,406	$43,191	$62,147	$2,307	$128,051
Relocate the Erie South 345 kV Line Terminal	b1993	$ 1,205,508.00	0.00%	5.14%	12.10%	0.48%	$0	$61,963	$145,866	$5,786	$213,616
Conver Lewis Run-Farmers Valley to 230kV using 1033.5 Conductor	b1994	$ 13,956,274.00	0.00%	8.64%	13.55%	0.54%	$0	$1,205,822	$1,891,075	$75,364	$3,172,261
Loop the 2026 kV Line to Laushtown Substation	b2006.1.1	$ 377,834.00	1.72%	3.82%	6.15%	0.25%	$6,499	$14,433	$23,237	$945	$45,113
Loop the 2026 kV Line to Laushtown Substation	b2006.1.1_dfax	$ 329,649.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
	b0132.3	$ 36,465.17	0.00%	100.00%	0.00%	0.00%	$0	$36,465	$0	$0	$36,465
South Lebanon 230/69 kv Bank 1 - Upgrade 69 kv Terminal Facilities	b1364	$ 24,499.00	0.00%	100.00%	0.00%	0.00%	$0	$24,499	$0	$0	$24,499
Middletown Sub - 69 kv Capacitor Bank	b1362	$ 14,164.36	0.00%	100.00%	0.00%	0.00%	$0	$14,164	$0	$0	$14,164
							$158,867	**$1,727,320**	**$2,566,679**	**$96,091**	**$4,548,957**
		$ 19,745,394									
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

	(k)	(l)	(m)	(n)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 2020**	**2020TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2020 Impact (12 months)**
PSE&G	$ 213,889.94	9,752.5	$ 21.93	$ 2,566,679
JCP&L	$ 143,943.29	6,057.1	$ 23.76	$ 1,727,320
ACE	$ 13,238.94	2,737.3	$ 4.84	$ 158,867
RE	$ 8,007.56	393.1	$ 20.37	$ 96,091
Total Impact on NJ Zones	**$ 379,079.74**			**$ 4,548,957**
Notes on calculations >>>			= (k) * (l)	= (k) *12

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

Attachment 6j - Transmission Enhancement Charges for June 2020 - May 2021 **Attachment 6j**
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) 2020/2021 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 a new 500 kV Center Point substation in PECO by tapping the Elroy – Whitpain 500 kV circuit.	b0269	$ 1,962,315.00	1.72%	3.82%	6.15%	0.25%	$33,752	$74,960	$120,682	$4,906	$234,300
Add a new 230 kV circuit between Whitpain and Heaton substations	b0269.10	$ 517,129.00	8.25%	0.00%	0.00%	0.00%	$42,663	$0	$0	$0	$42,663
Add a new 500kV brkr. at Whitpain bet. #3 transfmr. and 5029 line	b0269.6	$ 148,924.50	1.72%	3.82%	6.15%	0.25%	$2,562	$5,689	$9,159	$372	$17,782
Replace 2-500 kV circt brkrs and 2 wave traps at Elroy subs to increase rating of Elroy - Hosensack 500kV	b0171.1	$ 198,730.50	1.72%	3.82%	6.15%	0.25%	$3,418	$7,592	$12,222	$497	$23,728
Replace 2-500 kV circt brkrs and 2 wave traps at Elroy subs to increase rating of Elroy - Hosensack 500kV	b0171.1_dfax	$ 198,730.50	4.19%	19.81%	0.00%	0.00%	$8,327	$39,369	$0	$0	$47,695
Increase the rating of lines 220-39 and 220-43 (Linwood-Chicester 230kV lines) and install reactors.	b1900	$ 5,237,707.00	0.00%	6.02%	20.83%	0.83%	$0	$315,310	$1,091,014	$43,473	$1,449,797
Rebuild Bryn Mawr-Plymouth Meeting 138 kV line (130-35 Line)	b0727	$ 1,494,006.00	1.25%	0.00%	0.00%	0.00%	$18,675	$0	$0	$0	$18,675
Recndr Chichester - Saville 138 kV line and upgrade term equip	b1182	$ 1,671,526.00	0.00%	5.08%	14.20%	0.56%	$0	$84,914	$237,357	$9,361	$331,631
Add a second 230/138 kV trans at Chichester. Add an inductor in series with the parallel tranfmrs	b1178	$ 764,192.00	0.00%	4.14%	12.10%	0.48%	$0	$31,638	$92,467	$3,668	$127,773
Increase Bradford - Planebrook 230 kV Ckt.220-31 line rating. Replace terminal equipment	b0790	$ 163,431.00	0.00%	17.30%	33.68%	1.31%	$0	$28,274	$55,044	$2,141	$85,458
Reconductor the North Wales - Hartman 230 kV circuit	b0506	$ 202,818.00	8.58%	0.00%	0.00%	0.00%	$17,402	$0	$0	$0	$17,402
Reconductor the North Wales - Whitpain 230 kV circuit	b0505	$ 230,537.00	8.58%	0.00%	0.00%	0.00%	$19,780	$0	$0	$0	$19,780
Increase Bradford - Planebrook 230 kV Ckt.220-02 line rating. Replace terminal equipment	b0789	$ 223,837.00	0.72%	17.36%	33.52%	1.31%	$1,612	$38,858	$75,030	$2,932	$118,432
Install 161MVAR capacitor at Planebrook 230kV substation	b0206	$ 313,493.00	14.20%	0.00%	3.47%	0.00%	$44,516	$0	$10,878	$0	$55,394
Install 161MVAR capacitor at Newlinville 230kV substation	b0207	$ 421,407.00	14.20%	0.00%	3.47%	0.00%	$59,840	$0	$14,623	$0	$74,463
Install 2% series reactor at Chichester substation on the Chichester - Mickleton 230kV circuit	b0209	$ 238,426.00	65.23%	25.87%	6.35%	0.00%	$155,525	$61,681	$15,140	$0	$232,346
Upgrade Chichester - Delco Tap 230kV and the PECO portion of the Delco Tap - Mickleton 230kV cicuit	b0264	$ 196,699.00	89.87%	9.48%	0.00%	0.00%	$176,773	$18,647	$0	$0	$195,420

Attachment 6j - Transmission Enhancement Charges for June 2020 - May 2021 **Attachment 6j**
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*	**2020/2021 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**
Reconductor Buckingham - Pleasant Valley 230kV; same impedance as existing line; ratings of 760MVA normal/882MVA emergency	b0357	$ 177,284.00	0.00%	37.17%	54.14%	2.32%	$0	$65,896	$95,982	$4,113	$165,991
Reconductor Richmond-Waneeta kv and replace terminal equipment at Waneeta Substation	b1398.8	$ 259,235.00	0.00%	12.82%	31.46%	1.25%	$0	$33,234	$81,555	$3,240	$118,030
Install 600 MVAR cap banks at Elroy 500kv Substation	b0287	$ 422,461.00	1.72%	3.82%	6.15%	0.25%	$7,266	$16,138	$25,981	$1,056	$50,442
Install 600 MVAR cap banks at Elroy 500kv Substation	b2087_dfax	$ 422,461.00	4.19%	19.81%	0.00%	0.00%	$17,701	$83,690	$0	$0	$101,391
Install 161 MVAR capcitor at Heaton 230kV Substation	b0208	$ 633,747.00	14.20%	0.00%	3.47%	0.00%	$89,992	$0	$21,991	$0	$111,983
Increase Ratings at Peach Bottom 500/230kV Tfmr to 1839 MVA Emgcy	b2694	$ 3,201,780.00	3.97%	6.84%	14.13%	0.44%	$127,111	$219,002	$452,412	$14,088	$812,612
Upgrade sub equipment at Peach Bottom	b2766.2	$ 103,604.50	1.72%	3.82%	6.15%	0.25%	$1,782	$3,958	$6,372	$259	$12,370
Upgrade sub equipment at Peach Bottom	b2766.2_dfax	$ 103,604.50	1.12%	17.79%	35.05%	1.44%	$1,160	$18,431	$36,313	$1,492	$57,397
							$829,857	**$1,147,279**	**$2,454,222**	**$91,598**	**$4,522,956**
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 20/21**	**2020TX Peak Load per PJM** *website*	**Rate in $/MW-mo.**	**2020 Impact (7 months)**	**2021 Impact (5 months)**	**2020-2021 Impact (12 months)**
PSE&G	$ 204,518.51	9,752.5	$ 20.97	$ 1,431,630	$ 1,022,593	$ 2,454,222
JCP&L	$ 95,606.55	6,057.1	$ 15.78	$ 669,246	$ 478,033	$ 1,147,279
ACE	$ 69,154.75	2,737.3	$ 25.26	$ 484,083	$ 345,774	$ 829,857
RE	$ 7,633.17	393.1	$ 19.42	$ 53,432	$ 38,166	$ 91,598
Total Impact on NJ Zones	**$ 376,912.98**			**$ 2,638,391**	**$ 1,884,565**	**$ 4,522,956**
Notes on calculations >>>			= (k) * (l)	= (k) * 7	= (k) * 5	= (k) *12

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

Attachment 6k PJM Schedule 12 - Transmission Enhancement Charges for January 2020 - December 2020 **Attachment 6k**
Calculation of costs and monthly PJM charges for AEP -East Projects

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				Estimated New Jersey EDC Zone Charges by Project				
Required Transmission Enhancement *per PJM website*	**PJM Upgrade ID** *per PJM spreadsheet*	**Jan - Dec 2020 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share**[1]	**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								
New 765 KV circuit breakers at Hanging Rock Sub	b0504	$ 378,611	1.72%	3.82%	6.15%	0.25%	$6,512	$14,463	$23,285	$947	$45,206
New 765 KV circuit breakers at Hanging Rock Sub	b0504_dfax	$ 378,611	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Rockport Reactor Bank	b1465.2	$ 940,352	1.72%	3.82%	6.15%	0.25%	$16,174	$35,921	$57,832	$2,351	$112,278
Rockport Reactor Bank	b1465.2_dfax	$ 940,352	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Transpose Rockport- Sullivan 765KV line	b1465.3	$ 1,107,912	1.72%	3.82%	6.15%	0.25%	$19,056	$42,322	$68,137	$2,770	$132,285
Transpose Rockport- Sullivan 765KV line	b1465.3_dfax	$ 1,107,912	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Switching changes Sullivan 765KV station	b1465.4	$ (138,876)	1.72%	3.82%	6.15%	0.25%	-$2,389	-$5,305	-$8,541	-$347	-$16,582
Switching changes Sullivan 765KV station	b1465.4_dfax	$ (138,876)	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Sullivan Inst Baker 765kV Trnsf.	b1465.5	$ 1,138,437	1.72%	3.82%	6.15%	0.25%	$19,581	$43,488	$70,014	$2,846	$135,929
Sullivan Inst Baker 765kV Trnsf.	b1465.5_dfax	$ 1,138,437	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
765kV circuit breaker at Wyoming station	b1661	$ (1,281)	1.72%	3.82%	6.15%	0.25%	-$22	-$49	-$79	-$3	-$153
765kV circuit breaker at Wyoming station	b1661_dfax	$ (1,281)	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Term Tsfmr #2 @ SW Lima - new bay position	b1957	$ 1,625,291	0.00%	0.00%	4.52%	0.18%	$0	$0	$73,463	$2,926	$76,389
Reconductor/Rebuild Sporn-Waterford-Muskingham River 345 kV Line	b2017	$ 11,540,442	0.00%	1.39%	2.00%	0.08%	$0	$160,412	$230,809	$9,232	$400,453
Add four 765 kV Breakers at Kammar	b1962	$ 1,422,508	1.72%	3.82%	6.15%	0.25%	$24,467	$54,340	$87,484	$3,556	$169,847
Add four 765 kV Breakers at Kammar	b1962_dfax	$ 1,422,508	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Ft. Wayne Relocate	b1659.14	$ 2,309,000	1.72%	3.82%	6.15%	0.25%	$39,715	$88,204	$142,004	$5,773	$275,695
Ft. Wayne Relocate	b1659.14_dfax	$ 2,309,000	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Sorenson 765/500kV Transformer	b1659	$ 7,952,328	0.00%	0.00%	0.92%	0.04%	$0	$0	$73,161	$3,181	$76,342
Sorenson Work 765kV	b1659.13	$ 3,214,938	1.72%	3.82%	6.15%	0.25%	$55,297	$122,811	$197,719	$8,037	$383,864
Sorenson Work 765kV	b1659.13_dfax	$ 3,214,938	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Baker Station 765/500kV Transformer	b1495	$ 4,771,714	0.41%	0.90%	1.48%	0.06%	$19,564	$42,945	$70,621	$2,863	$135,994
Cloverdale 765/500kV Transformer	b1660	$ (588,304)	1.72%	3.82%	6.15%	0.25%	($10,119)	($22,473)	($36,181)	($1,471)	($70,243)
Cloverdale 765/500kV Transformer	b1660_dfax	$ (588,304)	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Cloverdale 500kV Station	b1660.1	$ 1,496,129	1.72%	3.82%	6.15%	0.25%	$25,733	$57,152	$92,012	$3,740	$178,638
Cloverdale 500kV Station	b1660.1_dfax	$ 1,496,129	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Jacksons-Ferry 765kV Breakers	b1663.2	$ 306,069	1.72%	3.82%	6.15%	0.25%	$5,264	$11,692	$18,823	$765	$36,545
Jacksons-Ferry 765kV Breakers	b1663.2_dfax	$ 306,069	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Reconductor Cloverdale-Lexington 500kV	b1797.1	$ 2,898,729	1.72%	3.82%	6.15%	0.25%	$49,858	$110,731	$178,272	$7,247	$346,108

Attachment 6k PJM Schedule 12 - Transmission Enhancement Charges for January 2020 - December 2020 **Attachment 6k**
Calculation of costs and monthly PJM charges for AEP -East Projects

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				Estimated New Jersey EDC Zone Charges by Project				
Required Transmission Enhancement *per PJM website*	**PJM Upgrade ID** *per PJM spreadsheet*	**Jan - Dec 2020 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share**[1]	**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**
Reconductor Cloverdale-Lexington 500kV	b1797.1_dfax	$ 2,898,729	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Reconductor West Bellaire	b1970	$ (2,413,072)	0.00%	1.68%	2.88%	0.11%	$0	-$40,540	-$69,496	-$2,654	-$112,690
Add a 3rd 2250 MVA 765/345 kV transformer at Sullivan station	b1465.1	$ 4,271,272	0.71%	1.58%	2.62%	0.10%	$30,326	$67,486	$111,907	$4,271	$213,991
Replace existing 150 MVAR reactor at Amos 765 kV sub	b2230	$ 860,412	1.72%	3.82%	6.15%	0.25%	$14,799	$32,868	$52,915	$2,151	$102,733
Replace existing 150 MVAR reactor at Amos 765 kV sub	b2230_dfax	$ 860,412	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Install a 300 MVAR shunt reactor at AEP's Wyoming 765 kV station	b2423	$ 1,275,003	1.72%	3.82%	6.15%	0.25%	$21,930	$48,705	$78,413	$3,188	$152,235
Install a 300 MVAR shunt reactor at AEP's Wyoming 765 kV station	b2423_dfax	$ 1,275,003	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Install a 450 MVAR SVC Jackson's Ferry 765kV Substation	b2687.1	$ (378,019)	1.72%	3.82%	6.15%	0.25%	-$6,502	-$14,440	-$23,248	-$945	-$45,135
Install a 450 MVAR SVC Jackson's Ferry 765kV Substation	b2687.1_dfax	$ (378,019)	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Install a 450 MVAR SVC Jackson's Ferry 765kV Substation	b2687.2	$ 537,419	1.72%	3.82%	6.15%	0.25%	$9,244	$20,529	$33,051	$1,344	$64,168
Install 300 MVAR shunt line reactor	b2687.2_dfax	$ 537,419	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Totals							**$338,489**	**$871,263**	**$1,522,376**	**$61,766**	**$2,793,895**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

	(k)	(l)	(m)	(n)
Zonal Cost Allocation for New Jersey Zones	**Average Monthly Impact on Zone Customers in 2020**	**2020Tx Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2020 Impact (12 months)**
PSE&G	$ 126,864.70	9,752.5	$ 13.01	$ 1,522,376
JCP&L	$ 72,605.27	6,057.1	$ 11.99	$ 871,263
ACE	$ 28,207.46	2,737.3	$ 10.30	$ 338,489
RE	$ 5,147.19	393.1	$ 13.09	$ 61,766
Total Impact on NJ Zones	**$ 232,824.62**			**$ 2,793,895**
Notes on calculations >>>			= (k) * (l)	= (k) *12

Notes:

Attachment 6k PJM Schedule 12 - Transmission Enhancement Charges for January 2020 - December 2020
Calculation of costs and monthly PJM charges for AEP -East Projects

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				Estimated New Jersey EDC Zone Charges by Project				
Required Transmission Enhancement	**PJM Upgrade ID**	**Jan - Dec 2020 Annual Revenue Requirement**	**ACE Zone Share[1]**	**JCP&L Zone Share[1]**	**PSE&G Zone Share[1]**	**RE Zone Share[1]**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
per PJM website	*per PJM spreadsheet*	*per PJM website*	*per PJM Open Access Transmission Tariff*								

1) 2019 allocation share percentages are from PJM OATT

Attachment 6I - Summary of Charges and Credits for ER18-680 and Form 715 Projects

Total 715 Dollars	August 20	September 20	October 20	November 20	December 20	January 20	February 20	March 20	Total	Per Month Over 6	Per Month Over 12
AECO	$ -	$ -	$ -	$ 55,957.97	$ 161,400.25	$ 226,139.04	$ 198,342.22	$ -	$ 641,839.49	$ 106,973.25	$ 53,486.62
JCPL	$ -	$ -	$ -	$ 124,456.54	$ 363,659.45	$ 521,135.59	$ 440,531.78	$ -	$ 1,449,783.35	$ 241,630.56	$ 120,815.28
PSEG	$ -	$ -	($619,323.39)	($12,015,658.70)	($16,987,032.74)	$699,451.34	($6,356,239.53)	($30,938,705.88)	($66,217,508.91)	($11,036,251.48)	($5,518,125.74)
RECO	$ -	$ -	$ -	$ 8,250.01	$ 25,294.07	$ 70,590.89	$ 102,172.15	$ -	$ 206,307.13	$ 34,384.52	$ 17,192.26

Total 680 Dollars	August 20	September 20	October 20	November 20	December 20	January 20	February 20	March 20	Total	Per Month Over 3	Per Month Over 12
AECO	$ -	($40,961.25)	($49,529.60)	($31,739.26)	$ -	$ -	$ -	$ -	($122,230.11)	($40,743.37)	($10,185.84)
JCPL	$ -	($535,157.75)	($584,204.50)	($361,148.07)	$ -	$ -	$ -	$ -	($1,480,510.32)	($493,503.44)	($123,375.86)
PSEG	$ -	($7,858,527.96)	($10,941,311.02)	($7,218,055.74)	$ -	$ -	$ -	$ -	($26,017,894.72)	($8,672,631.57)	($2,168,157.89)
RECO	$ -	($308,563.34)	($431,553.16)	($284,554.15)	$ -	$ -	$ -	$ -	($1,024,670.64)	($341,556.88)	($85,389.22)

Total 680 and 715 Dollars	August 20	September 20	October 20	November 20	December 20	January 20	February 20	March 20	Total	Per Month Over 12
AECO	$ -	($40,961.25)	($49,529.60)	$24,218.70	$161,400.25	$226,139.04	$ 198,342.22	$ -	$519,609.38	$43,300.78
JCPL	$ -	($535,157.75)	($584,204.50)	($236,691.53)	$363,659.45	$521,135.59	$440,531.78	$ -	($30,726.96)	($2,560.58)
PSEG	$ -	($7,858,527.96)	($11,560,634.41)	($19,233,714.44)	($16,987,032.74)	$699,451.34	($6,356,239.53)	($30,938,705.88)	($92,235,403.63)	($7,686,283.64)
RECO	$ -	($308,563.34)	($431,553.16)	($276,304.14)	$25,294.07	$70,590.89	$102,172.15	$ -	($818,363.52)	($68,196.96)

Attachment 6I - Summary of Charges and Credits for ER18-680 and Form 715 Projects

DOCKET NO. ER18-680 ESTIMATES	2018	2019	2020(Jan-July)	TOTAL
AECO	($40,961.25)	($49,529.60)	($31,739.26)	($122,230.11)
AEP	($25,579.53)	($23,130.56)	($14,614.74)	($63,324.83)
APS	($10,561.17)	($35,323.96)	($30,008.76)	($75,893.90)
ATSI	($42,511.75)	($55,409.40)	($40,600.29)	($138,521.44)
BGE	($110,700.27)	($151,114.35)	($99,515.39)	($361,330.01)
ComEd	($225,275.20)	($323,884.91)	($213,514.12)	($762,674.23)
Dayton	($13,188.54)	($19,082.27)	($12,670.89)	($44,941.69)
DEOK	$0.00	($127.10)	($219.86)	($346.96)
DUQ	($2,842.20)	($2,687.57)	($1,840.50)	($7,370.27)
DOM	($2,066.43)	($1,988.32)	($2,727.25)	($6,782.01)
DPL	($5,343.59)	($5,539.53)	($4,430.04)	($15,313.16)
ECP	$2,201,021.53	$2,573,785.24	$1,643,521.74	$6,418,328.51
EKPC	$0.00	($42.37)	($73.29)	($115.65)
HTP	$8,274,027.65	$11,523,455.19	$7,596,802.04	$27,394,284.89
JCPL	($535,157.75)	($584,204.50)	($361,148.07)	($1,480,510.32)
MetEd	($10,510.44)	($15,032.45)	($10,329.30)	($35,872.19)
Neptune	($180,153.28)	($191,411.83)	($111,386.74)	($482,951.86)
PECO	($626,461.36)	($577,380.11)	($340,175.42)	($1,544,016.89)
PENELEC	($335,730.61)	($503,912.92)	($342,947.97)	($1,182,591.49)
PEPCO	($108,555.67)	($152,282.62)	($101,126.55)	($361,964.84)
PPL	($32,358.85)	($32,291.89)	($18,645.45)	($83,296.18)
PSEG	($7,858,527.96)	($10,941,311.02)	($7,218,055.74)	($26,017,894.72)
RECO	($308,563.34)	($431,553.16)	($284,554.15)	($1,024,670.64)

FERC FORM 715 DOMINION ESTIMATES	2015	2016	2017	2018	2019	2020(Jan-Aug)	INTEREST	TOTAL
AECO	$ -	$ -	$ 51,566.79	$ 148,734.73	$ 208,393.29	$ 182,777.76	$ 50,366.92	$ 641,839.49
AEP	$ -	$ -	$ 432,289.77	$ 1,268,725.17	$ 1,825,059.23	$ 1,506,853.87	$ 430,254.00	$ 5,463,182.04
APS	$ -	$ -	$ 167,769.36	$ 513,403.62	$ 1,306,033.08	$ 997,557.73	$ 229,932.81	$ 3,214,696.60
ATSI	$ -	$ -	$ 245,372.82	$ 706,041.97	$ 1,029,022.76	$ 841,627.83	$ 241,407.42	$ 3,063,472.80
BGE	$ -	$ -	$ 127,042.74	$ 378,108.77	$ 531,985.35	$ 449,505.77	$ 127,004.98	$ 1,613,647.61
ComEd	$ -	$ -	$ 407,367.51	$ 1,192,565.82	$ 1,713,743.56	$ 1,402,713.05	$ 404,008.24	$ 5,120,398.18
ConEd	$ -	$ -	$ 5,774.67	$ -	$ -	$ -	$ 998.22	$ 6,772.89
Dayton	$ -	$ -	$ 64,331.85	$ 189,054.39	$ 267,934.23	$ 217,845.59	$ 63,561.51	$ 802,727.56
DEOK	$ -	$ -	$ 102,221.79	$ 294,781.48	$ 416,786.58	$ 494,141.39	$ 104,545.17	$ 1,412,476.41
DPL	$ -	$ -	$ 79,427.04	$ 223,998.09	$ 321,003.33	$ 274,166.64	$ 76,677.78	$ 975,272.87
DUQ	$ -	$ -	$ 53,694.30	$ 156,798.66	$ 223,947.69	$ 179,047.70	$ 52,854.79	$ 666,343.14
ECP	$ -	$ -	$ 6,078.60	$ -	$ -	$ -	$ 1,050.75	$ 7,129.35
EKPC	$ -	$ -	$ 55,315.26	$ 167,550.57	$ 275,700.44	$ 260,694.34	$ 61,275.82	$ 820,536.42
HTP	$ -	$ -	$ 6,078.60	$ -	$ -	$ -	$ 1,050.75	$ 7,129.35
JCPL	$ -	$ -	$ 114,682.92	$ 335,101.14	$ 480,210.62	$ 405,936.65	$ 113,852.02	$ 1,449,783.35
MetEd	$ -	$ -	$ 56,733.60	$ 170,238.55	$ 243,341.23	$ 199,780.34	$ 57,311.11	$ 727,404.83
Neptune	$ -	$ -	$ 12,765.06	$ 39,423.66	$ 54,363.47	$ 44,631.78	$ 12,998.31	$ 164,182.28
OVEC	$ -	$ -	$ -	$ -	$ -	$ 8,501.29	$ 285.27	$ 8,786.57
PECO	$ -	$ -	$ 160,778.97	$ 478,459.91	$ 691,192.65	$ 564,273.20	$ 161,962.10	$ 2,056,666.83
PENELEC	$ -	$ -	$ 55,923.12	$ 169,342.55	$ 240,752.49	$ 201,905.67	$ 56,926.06	$ 724,849.89
PEPCO	$ -	$ -	$ 334,626.93	$ 620,972.58	$ 515,158.56	$ 414,437.95	$ 191,664.46	$ 2,076,860.48
PPL	$ -	$ -	$ 135,248.85	$ 433,660.30	$ 616,119.29	$ 531,330.70	$ 144,849.97	$ 1,861,209.10
PSEG	$ -	$ -	$ 188,639.22	$ 560,891.21	$ 801,213.95	$ 653,536.76	$ 188,923.28	$ 2,393,204.42
RECO	$ -	$ -	$ 7,598.25	$ 23,295.80	$ 33,653.57	$ 26,566.54	$ 7,815.60	$ 98,929.76
DOM REFUND			($2,871,328.02)	($8,071,148.97)	($11,795,615.36)	$ (9,857,832.53)	($2,781,577.33)	($35,377,502.22)

FERC FORM 715 PSEG ESTIMATES	2015(May - Dec)	2016	2017	2018	2019	2020(Jan-Aug)	INTEREST	TOTAL
ConEd	$ 284,157.46	$ 7,381,095.06	$ 3,414,358.91	$ -	$ -	$ -	$ 2,265,543.00	$ 13,345,154.43
ECP	$ 274,987.49	$ 3,651,931.94	$ 12,454,079.09	$ -	$ -	$ -	$ 2,945,857.67	$ 19,326,856.18
Neptune	$ -	$ -	$ 17,790.00	$ 153,872.00	$ 6,346,714.78	$ 16,601,997.02	$ 1,072,632.46	$ 24,193,006.25
PECO	$ -	$ -	$ -	$ -	$ -	$ 11,260,455.75	$ 377,863.35	$ 11,638,319.09
RECO	$ -	$ -	$ -	$ -	$ 32,505.58	$ 69,999.69	$ 4,872.10	$ 107,377.37
PSEG REFUND	($559,144.95)	($11,033,027.00)	($15,886,228.00)	($153,872.00)	($6,379,220.35)	($27,932,452.45)	($6,666,768.58)	($68,610,713.33)

- 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 (1.72%) / JCPL (25.94%) / Neptune* (10.62%) / PSEG (59.59%) / ECP** (2.13%)
b0170	Reconductor the Flagtown-Somerville-Bridgewater 230 kV circuit with 1590 ACSS		JCLP (42.95%) / Neptune* (17.90%) / PSEG (38.36%) RE (0.79%)

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0172.2	Replace wave trap at Branchburg 500kV substation		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: AEC (4.49%) / JCPL (29.72%) / NEPTUNE (4.97%) / PECO (9.91%) / PSEG (48.90%) / RE (2.01%)
b0184	Replace Hudson 230kV circuit breakers #1-2		PSEG (100%)
b0185	Replace Deans 230kV circuit breakers #9-10		PSEG (100%)
b0186	Replace Essex 230kV circuit breaker #5-6		PSEG (100%)
b1082	Install 230/138 kV transformer at Bergen substation		PENELEC (16.52%) / PSEG (80.29%) / RE (3.19%)

* Neptune Regional Transmission System, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0201	Branchburg substation: replace wave trap on Branchburg – Readington 230 kV circuit		PSEG (100%)
b0213.1	Replace New Freedom 230 kV breaker BS2-6		PSEG (100%)
b0213.3	Replace New Freedom 230 kV breaker BS2-8		PSEG (100%)
b0274	Replace both 230/138 kV transformers at Roseland		PSEG (96.77%) / ECP** (3.23%)
b0275	Upgrade the two 138 kV circuits between Roseland and West Orange		PSEG (100%)
b0278	Install 228 MVAR capacitor at Roseland 230 kV substation		PSEG (100%)
b0290	Install 400 MVAR capacitor in the Branchburg 500 kV vicinity		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: AEC (4.49%) / JCPL (29.72%) / NEPTUNE (4.97%) / PECO (9.91%) / PSEG (48.90%) / RE (2.01%)
b0358	Reconductor the PSEG portion of Buckingham – Pleasant Valley 230 kV, replace wave trap and metering transformer		PSEG (100%)

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

Public Service Electric and Gas Company (cont.)

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0401.8	Replace W. Orange 138 kV breaker 132-4		PSEG (100%)
b0411	Install 4th 500/230 kV transformer at New Freedom		AEC (47.01%) / JCPL (7.04%) / Neptune* (0.28%) / PECO (23.36%) / PSEG (22.31%)
b0423	Reconductor Readington (2555) – Branchburg (4962) 230 kV circuit w/1590 ACSS		PSEG (100%)
b0424	Replace Readington wavetrap on Readington (2555) – Roseland (5017) 230 kV circuit		PSEG (100%)
b0425	Reconductor Linden (4996) – Tosco (5190) 230 kV circuit w/1590 ACSS (Assumes operating at 220 degrees C)		PSEG (100%)
b0426	Reconductor Tosco (5190) – G22_MTX5 (90220) 230 kV circuit w/1590 ACSS (Assumes operation at 220 degrees C)		PSEG (100%)
b0427	Reconductor Athenia (4954) – Saddle Brook (5020) 230 kV circuit river section		PSEG (100%)
b0428	Replace Roseland wavetrap on Roseland (5019) – West Caldwell "G" (5089) 138 kV circuit		PSEG (100%)
b0429	Reconductor Kittatinny (2553) – Newton (2535) 230 kV circuit w/1590 ACSS		JCPL (41.91%) / Neptune* (3.59%) / PSEG (50.59%) / RE (2.23%) / ECP** (1.68%)
b0439	Spare Deans 500/230 kV transformer		PSEG (100%)
b0446.1	Upgrade Bayway 138 kV breaker #2-3		PSEG (100%)
b0446.2	Upgrade Bayway 138 kV breaker #3-4		PSEG (100%)
b0446.3	Upgrade Bayway 138 kV breaker #6-7		PSEG (100%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0446.4	Upgrade the breaker associated with TX 132-5 on Linden 138 kV		PSEG (100%)
b0470	Install 138 kV breaker at Roseland and close the Roseland 138 kV buses		PSEG (100%)
b0471	Replace the wave traps at both Lawrence and Pleasant Valley on the Lawrence – Pleasant Vallen 230 kV circuit		PSEG (100%)
b0472	Increase the emergency rating of Saddle Brook – Athenia 230 kV by 25% by adding forced cooling		ECP (2.06%) / PSEG (94.41%) / RE (3.53%)
b0473	Move the 150 MVAR mobile capacitor from Aldene 230 kV to Lawrence 230 kV substation		PSEG (100%)
b0489	Build new 500 kV transmission facilities from Pennsylvania – New Jersey border at Bushkill to Roseland		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)†
			DFAX Allocation: JCPL (39.21%) / NEPTUNE (4.05%) / PSEG (54.50%) / RE (2.24%)

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

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b489.1	Replace Athenia 230 kV breaker 31H		PSEG (100%)
b489.2	Replace Bergen 230 kV breaker 10H		PSEG (100%)
b489.3	Replace Saddlebrook 230 kV breaker 21P		PSEG (100%)
b0489.4	Install two Roseland 500/230 kV transformers as part of the Susquehanna – Roseland 500 kV project		AEC (5.09%) / ComEd (0.29%) / Dayton (0.03%) / DPL (1.76%) / JCPL (32.73%) / Neptune* (6.32%) / PECO (10.04%) / PENELEC (0.56%) / ECP** (0.95%) / PSEG (40.71%) / RE (1.52%) ††
b0489.5	Replace Roseland 230 kV breaker '42H' with 80 kA		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: JCPL (39.21%) / NEPTUNE (4.05%) / PSEG (54.50%) / RE (2.24%)

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0489.6	Replace Roseland 230 kV breaker '51H' with 80 kA		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: JCPL (39.21%) / NEPTUNE (4.05%) / PSEG (54.50%) / RE (2.24%)
b0489.7	Replace Roseland 230 kV breaker '71H' with 80 kA		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: JCPL (39.21%) / NEPTUNE (4.05%) / PSEG (54.50%) / RE (2.24%)

* Neptune Regional Transmission System, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0489.8	Replace Roseland 230 kV breaker '31H' with 80 kA		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: JCPL (39.21%) / NEPTUNE (4.05%) / PSEG (54.50%) / RE (2.24%)

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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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: JCPL (39.21%) / NEPTUNE (4.05%) / PSEG (54.50%) / RE (2.24%)
b0489.10	Replace Roseland 230 kV breaker '21H'		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: JCPL (39.21%) / NEPTUNE (4.05%) / PSEG (54.50%) / RE (2.24%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0489.11	Replace Roseland 230 kV breaker '32H'		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: JCPL (39.21%) / NEPTUNE (4.05%) / PSEG (54.50%) / RE (2.24%)
b0489.12	Replace Roseland 230 kV breaker '12H'		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: JCPL (39.21%) / NEPTUNE (4.05%) / PSEG (54.50%) / RE (2.24%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0489.13	Replace Roseland 230 kV breaker '52H'		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: JCPL (39.21%) / NEPTUNE (4.05%) / PSEG (54.50%) / RE (2.24%)
b0489.14	Replace Roseland 230 kV breaker '41H'		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: JCPL (39.21%) / NEPTUNE (4.05%) / PSEG (54.50%) / RE (2.24%)

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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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: JCPL (39.21%) / NEPTUNE (4.05%) / PSEG (54.50%) / RE (2.24%)
b0498	Loop the 5021 circuit into New Freedom 500 kV substation		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: AEC (8.37%) / JCPL (25.68%) / NEPTUNE (3.11%) / PECO (19.78%) / PSEG (41.36%) / RE (1.70%)

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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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
b0565	Install 100 MVAR capacitor at Cox's Corner 230 kV substation		PSEG (100%)

* Neptune Regional Transmission System, LLC

Public Service Electric and Gas Company (cont.)

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

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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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
b0829.6	Replace Branchburg 500 kV breaker 91X		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%) **DFAX Allocation:** PSEG (96.06%) / RE (3.94%)
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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
b0830.1	Replace Roseland 230 kV breaker '82H' with 80 kA		PSEG (100%
b0830.2	Replace Roseland 230 kV breaker '91H' with 80 kA		PSEG (100%)
b0830.3	Replace Roseland 230 kV breaker '22H' with 80 kA		PSEG (100%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0831	Replace 138/13 kV transformers with 230/13 kV units as part of Branchburg – Hudson 500 kV project		ComEd (2.51%) / Dayton (0.09%) / PENELEC (2.75%) / ECP** (2.45%) / PSEG (88.74%) / RE (3.46%)
b0832	Build Hudson 500 kV switching station as part of Branchburg – Hudson 500 kV project		AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
b0833	Build Roseland 500 kV switching station as part of Branchburg – Hudson 500 kV project		AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)

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

Public Service Electric and Gas Company (cont.)

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

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1013	Replace Linden 138 kV breaker '7PB'		PSEG (100%)
b1017	Reconductor South Mahwah - Waldwick 345 kV J-3410 circuit		JCPL (29.01%) / NEPTUNE* (2.74%) / PSEG (64.85%) / RE (2.53%) / ECP** (0.87%)
b1018	Reconductor South Mahwah - Waldwick 345 kV K-3411 circuit		JCPL (29.18%) / NEPTUNE* (2.74%) / PSEG (64.68%) / RE (2.53%) / ECP** (0.87%)
b1019.1	Replace wave trap, line disconnect and ground switch at Roseland on the F-2206 circuit		PSEG (100%)
b1019.2	Replace wave trap, line disconnect and ground switch at Roseland on the B-2258 circuit		PSEG (100%)
b1019.3	Replace 1-2 and 2-3 section disconnect and ground switches at Cedar Grove on the F-2206 circuit		PSEG (100%)
b1019.4	Replace 1-2 and 2-3 section disconnect and ground switches at Cedar Grove on the B-2258 circuit		PSEG (100%)
b1019.5	Replace wave trap, line disconnect and ground switch at Cedar Grove on the F-2206 circuit		PSEG (100%)
b1019.6	Replace line disconnect and ground switch at Cedar Grove on the K-2263 circuit		PSEG (100%)

Public Service Electric and Gas Company (cont.)

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

Public Service Electric and Gas Company (cont.)

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

Public Service Electric and Gas Company (cont.)

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

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1156.16	Replace New Freedom 230 kV breaker '50H' with 63 kA		PSEG (100%)
b1156.17	Replace New Freedom 230 kV breaker '41H' with 63 kA		PSEG (100%)
b1156.18	Replace New Freedom 230 kV breaker '51H' with 63 kA		PSEG (100%)
b1156.19	Rebuild Camden 230 kV to 80 kA		PSEG (100%)
b1156.20	Rebuild Burlington 230 kV to 80 kA		PSEG (100%)
b1197.1	Reconductor the PSEG portion of the Burlington – Croydon circuit with 1590 ACSS		PSEG (100%)
b1228	Re-configure the Lawrence 230 kV substation to breaker and half		HTP (0.14%) / ECP (0.22%) / PSEG (95.83%) / RE (3.81%)
b1255	Build a new 69 kV substation (Ridge Road) and build new 69 kV circuits from Montgomery – Ridge Road – Penns Neck/Dow Jones		PSEG (96.18%) / RE (3.82%)
b1304.1	Convert the existing ‘D1304’ and ‘G1307’ 138 kV circuits between Roseland – Kearny – Hudson to 230 kV operation		AEC (0.23%) / BGE (0.97%) / ComEd (2.32%) / Dayton (0.13%) / JCPL (1.17%) / Neptune (0.07%) / HTP (16.05%) / PENELEC (2.97%) / PEPCO (1.04%) / ECP (2.11%) / PSEG (70.16%) / RE (2.78%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1304.2	Expand existing Bergen 230 kV substation and reconfigure the Athenia 230 kV substation to breaker and a half scheme		AEC (0.23%) / BGE (0.97%) / ComEd (2.32%) / Dayton (0.13%) / JCPL (1.17%) / Neptune (0.07%) / HTP (16.05%) / PENELEC (2.97%) / PEPCO (1.04%) / ECP (2.11%) / PSEG (70.16%) / RE (2.78%)
b1304.3	Build second 230 kV underground cable from Bergen to Athenia		AEC (0.23%) / BGE (0.97%) / ComEd (2.32%) / Dayton (0.13%) / JCPL (1.17%) / Neptune (0.07%) / HTP (16.05%) / PENELEC (2.97%) / PEPCO (1.04%) / ECP (2.11%) / PSEG (70.16%) / RE (2.78%)
b1304.4	Build second 230 kV underground cable from Hudson to South Waterfront		AEC (0.23%) / BGE (0.97%) / ComEd (2.32%) / Dayton (0.13%) / JCPL (1.17%) / Neptune (0.07%) / HTP (16.05%) / PENELEC (2.97%) / PEPCO (1.04%) / ECP (2.11%) / PSEG (70.16%) / RE (2.78%)

Public Service Electric and Gas Company (cont.)

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1304.15	Replace Essex 230 kV breaker '21H' with 80 kA		PSEG (100%)
b1304.16	Replace Essex 230 kV breaker '10H' with 80 kA		PSEG (100%)
b1304.17	Replace Essex 230 kV breaker '11H' with 80 kA		PSEG (100%)
b1304.18	Replace Essex 230 kV breaker '11HL' with 80 kA		PSEG (100%)
b1304.19	Replace Newport R 230 kV breaker '23H' with 63 kA		PSEG (100%)
b1304.20	Rebuild Athenia 230 kV substation to 80 kA		PSEG (100%)
b1304.21	Rebuild Bergen 230 kV substation to 80 kA		PSEG (100%)
b1398	Build two new parallel underground circuits from Gloucester to Camden		JCPL (12.82%) / NEPTUNE (1.18%) / HTP (0.79%) / PECO (51.08%) / PEPCO (0.57%) / ECP** (0.85%) / PSEG (31.46%) / RE (1.25%)
b1398.1	Install shunt reactor at Gloucester to offset cable charging		JCPL (12.82%) / NEPTUNE (1.18%) / HTP (0.79%) / PECO (51.08%) / PEPCO (0.57%) / ECP** (0.85%) / PSEG (31.46%) / RE (1.25%)
b1398.2	Reconfigure the Cuthbert station to breaker and a half scheme		JCPL (12.82%) / NEPTUNE (1.18%) / HTP (0.79%) / PECO (51.08%) / PEPCO (0.57%) / ECP** (0.85%) / PSEG (31.46%) / RE (1.25%)
b1398.3	Build a second 230 kV parallel overhead circuit from Mickelton – Gloucester		JCPL (12.82%) / NEPTUNE (1.18%) / HTP (0.79%) / PECO (51.08%) / PEPCO (0.57%) / ECP** (0.85%) / PSEG (31.46%) / RE (1.25%)

Public Service Electric and Gas Company (cont.)

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

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1410	Replace Salem 500 kV breaker '11X'		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: PSEG (96.06%) / RE (3.94%)
b1411	Replace Salem 500 kV breaker '12X'		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: PSEG (96.06%) / RE (3.94%)

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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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: PSEG (96.06%) / RE (3.94%)
b1413	Replace Salem 500 kV breaker '21X'		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: PSEG (96.06%) / RE (3.94%)

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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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: PSEG (96.06%) / RE (3.94%)
b1415	Replace Salem 500 kV breaker ‘32X’		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: PSEG (96.06%) / RE (3.94%)

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Public Service Electric and Gas Company (cont.)

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

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1752	Advance n0666.10 (Replace Hudson 230 kV breaker '2HB' with 80 kA (without TRV cap, so actually 63 kA))		PSEG (100%)
b1753	Marion 138 kV breaker '7PM' - delay the relay time to increase the contact parting time to 2.5 cycles		PSEG (100%)
b1754	Marion 138 kV breaker '3PM' - delay the relay time to increase the contact parting time to 2.5 cycles		PSEG (100%)
b1755	Marion 138 kV breaker '6PM' - delay the relay time to increase the contact parting time to 2.5 cycles		PSEG (100%)
b1787	Build a second 230 kV circuit from Cox's Corner - Lumberton		AEC (4.96%) / JCPL (44.20%) / NEPTUNE* (0.53%) / HTP (0.15%) / ECP** (0.16%) / PSEG (48.08%) / RE (1.92%)
b2034	Install a reactor along the Kearny - Essex 138 kV line		PSEG (100%)
b2035	Replace Sewaren 138 kV breaker '11P'		PSEG (100%)
b2036	Replace Sewaren 138 kV breaker '21P'		PSEG (100%)
b2037	Replace PVSC 138 kV breaker '452'		PSEG (100%)
b2038	Replace PVSC 138 kV breaker '552'		PSEG (100%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2039	Replace Bayonne 138 kV breaker '11P'		PSEG (100%)
b2139	Reconductor the Mickleton - Gloucester 230 kV parallel circuits with double bundle conductor		PSEG (61.11%) / PECO (36.45%) / RE (2.44%)
b2146	Re-configure the Brunswick 230 kV and 69 kV substations		PSEG (96.16%) / RE (3.84%)
b2151	Construct Jackson Rd. 69 kV substation and loop the Cedar Grove - Hinchmans Ave into Jackson Rd. and construct Hawthorne 69 kV substation and build 69 kV circuit from Hinchmans Ave - Hawthorne - Fair Lawn		PSEG (100%)
b2159	Reconfigure the Linden, Bayway, North Ave, and Passaic Valley S.C. 138 kV substations. Construct and loop new 138 kV circuit to new airport station		PSEG (72.61%) / HTP (24.49%) / RE (2.90%)

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SCHEDULE 12 – APPENDIX A

(12) Public Service Electric and Gas Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2218	Rebuild 4 miles of overhead line from Edison - Meadow Rd - Metuchen (Q 1317)		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%)

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

Public Service Electric and Gas Company (cont.)

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

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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 (*1.72*%) / AEP (*14.18*%) / APS (*6.05*%) / ATSI (*7.92*%) / BGE (*4.23*%) / ComEd (*13.20*%) / Dayton (*2.05*%) / DEOK (*3.18*%) / DL (*1.68*%) / DPL (*2.58*%) / Dominion (*12.56*%) / EKPC (*1.94*%) / JCPL (*3.82*%) / ME (1.88%) / NEPTUNE* (0.42%) / *OVEC (0.08%) /* PECO (*5.31*%) / PENELEC (*1.90*%) / PEPCO (*3.90*%) / PPL (*5.00*%) / PSEG (*6.15*%) / RE (*0.25*%)
			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 (*1.72*%) / AEP (*14.18*%) / APS (*6.05*%) / ATSI (*7.92*%) / BGE (*4.23*%) / ComEd (*13.20*%) / Dayton (*2.05*%) / DEOK (*3.18*%) / DL (*1.68*%) / DPL (*2.58*%) / Dominion (*12.56*%) / EKPC (*1.94*%) / JCPL (*3.82*%) / ME (1.88%) / NEPTUNE* (0.42%) / *OVEC (0.08%) /* PECO (*5.31*%) / PENELEC (*1.90*%) / PEPCO (*3.90*%) / PPL (*5.00*%) / PSEG (*6.15*%) / RE (*0.25*%)
			DFAX Allocation: PSEG (100%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2436.22	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades		**Load-Ratio Share Allocation:** AEC (*1.72*%) / AEP (*14.18*%) / APS (*6.05*%) / ATSI (*7.92*%) / BGE (*4.23*%) / ComEd (*13.20*%) / Dayton (*2.05*%) / DEOK (*3.18*%) / DL (*1.68*%) / DPL (*2.58*%) / Dominion (*12.56*%) / EKPC (*1.94*%) / JCPL (*3.82*%) / ME (1.88%) / NEPTUNE* (0.42%) / *OVEC (0.08%) /* PECO (*5.31*%) / PENELEC (*1.90*%) / PEPCO (*3.90*%) / PPL (*5.00*%) / PSEG (*6.15*%) / RE (*0.25*%) **DFAX Allocation:** PSEG (*96.06*%) */ RE (3.94%)*
b2436.33	Construct a new Bayway – Bayonne 345 kV circuit and any associated substation upgrades		PSEG (*96.06*%) */ RE (3.94%)*
b2436.34	Construct a new North Ave – Bayonne 345 kV circuit and any associated substation upgrades		PSEG (*96.06*%) */ RE (3.94%)*

*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 (*96.06*%) / *RE (3.94%)*
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 (*1.72*%) / AEP (*14.18*%) / APS (*6.05*%) / ATSI (*7.92*%) / BGE (*4.23*%) / ComEd (*13.20*%) / Dayton (*2.05*%) / DEOK (*3.18*%) / DL (*1.68*%) / DPL (*2.58*%) / Dominion (*12.56*%) / EKPC (*1.94*%) / JCPL (*3.82*%) / ME (1.88%) / NEPTUNE* (0.42%) / *OVEC (0.08%)* / PECO (*5.31*%) / PENELEC (*1.90*%) / PEPCO (*3.90*%) / PPL (*5.00*%) / PSEG (*6.15*%) / RE (*0.25*%)
			DFAX Allocation: PSEG (*96.06*%) / RE (*3.94*%)

*Neptune Regional Transmission System, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2436.83	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades		**Load-Ratio Share Allocation:** AEC (*1.72*%) / AEP (*14.18*%) / APS (*6.05*%) / ATSI (*7.92*%) / BGE (*4.23*%) / ComEd (*13.20*%) / Dayton (*2.05*%) / DEOK (*3.18*%) / DL (*1.68*%) / DPL (*2.58*%) / Dominion (*12.56*%) / EKPC (*1.94*%) / JCPL (*3.82*%) / ME (1.88%) / NEPTUNE* (0.42%) / *OVEC (0.08%) /* PECO (*5.31*%) / PENELEC (*1.90*%) / PEPCO (*3.90*%) / PPL (*5.00*%) / PSEG (*6.15*%) / RE (*0.25*%)
			DFAX Allocation: PSEG (*96.06*%) / RE (*3.94*%)
b2436.84	Convert the Bayway – Linden “W” 138 kV circuit to 345 kV and any associated substation upgrades		**Load-Ratio Share Allocation:** AEC (*1.72*%) / AEP (*14.18*%) / APS (*6.05*%) / ATSI (*7.92*%) / BGE (*4.23*%) / ComEd (*13.20*%) / Dayton (*2.05*%) / DEOK (*3.18*%) / DL (*1.68*%) / DPL (*2.58*%) / Dominion (*12.56*%) / EKPC (*1.94*%) / JCPL (*3.82*%) / ME (1.88%) / NEPTUNE* (0.42%) / *OVEC (0.08%) /* PECO (*5.31*%) / PENELEC (*1.90*%) / PEPCO (*3.90*%) / PPL (*5.00*%) / PSEG (*6.15*%) / RE (*0.25*%)
			DFAX Allocation: PSEG (*96.06*%) / RE (*3.94*%)

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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 (*1.72*%) / AEP (*14.18*%) / APS (*6.05*%) / ATSI (*7.92*%) / BGE (*4.23*%) / ComEd (*13.20*%) / Dayton (*2.05*%) / DEOK (*3.18*%) / DL (*1.68*%) / DPL (*2.58*%) / Dominion (*12.56*%) / EKPC (*1.94*%) / JCPL (*3.82*%) / ME (1.88%) / NEPTUNE* (0.42%) / *OVEC (0.08%) /* PECO (*5.31*%) / PENELEC (*1.90*%) / PEPCO (*3.90*%) / PPL (*5.00*%) / PSEG (*6.15*%) / RE (*0.25*%)
			DFAX Allocation: PSEG (*96.06*%) / RE (*3.94*%)
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 (*1.72*%) / AEP (*14.18*%) / APS (*6.05*%) / ATSI (*7.92*%) / BGE (*4.23*%) / ComEd (*13.20*%) / Dayton (*2.05*%) / DEOK (*3.18*%) / DL (*1.68*%) / DPL (*2.58*%) / Dominion (*12.56*%) / EKPC (*1.94*%) / JCPL (*3.82*%) / ME (1.88%) / NEPTUNE* (0.42%) / *OVEC (0.08%) /* PECO (*5.31*%) / PENELEC (*1.90*%) / PEPCO (*3.90*%) / PPL (*5.00*%) / PSEG (*6.15*%) / RE (*0.25*%)
			DFAX Allocation: PSEG (100%)
b2436.91	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades		PSEG (100%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2437.10	New Bergen 345/230 kV transformer and any associated substation upgrades		PSEG (*100*%)
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 (*100*%)
b2437.21	New Bayway 345/138 kV transformer #2 and any associated substation upgrades		PSEG (*100*%)
b2437.30	New Linden 345/230 kV transformer and any associated substation upgrades		PSEG (*96.06*%) / RE (*3.94*%)
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%)
b2439	Replace the Tosco 138kV breaker 'CB1/2 (CBT)' with 63kA		PSEG (100%)
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 (*1.72*%) / AEP (*14.18*%) / APS (*6.05*%) / ATSI (*7.92*%) / BGE (*4.23*%) / ComEd (*13.20*%) / Dayton (*2.05*%) / DEOK (*3.18*%) / DL (*1.68*%) / DPL (*2.58*%) / Dominion (*12.56*%) / EKPC (*1.94*%) / JCPL (*3.82*%) / ME (1.88%) / NEPTUNE* (0.42%) / *OVEC (0.08%) /* PECO (*5.31*%) / PENELEC (*1.90*%) / PEPCO (*3.90*%) / PPL (*5.00*%) / PSEG (*6.15*%) / RE (*0.25*%)
			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 (*1.72*%) / AEP (*14.18*%) / APS (*6.05*%) / ATSI (*7.92*%) / BGE (*4.23*%) / ComEd (*13.20*%) / Dayton (*2.05*%) / DEOK (*3.18*%) / DL (*1.68*%) / DPL (*2.58*%) / Dominion (*12.56*%) / EKPC (*1.94*%) / JCPL (*3.82*%) / ME (1.88%) / NEPTUNE* (0.42%) / *OVEC (0.08%) /* PECO (*5.31*%) / PENELEC (*1.90*%) / PEPCO (*3.90*%) / PPL (*5.00*%) / PSEG (*6.15*%) / RE (*0.25*%)
			DFAX Allocation: AEC (8.01%) / BGE (1.94%) / DPL (12.99%) / JCPL (13.85%) / ME (5.88%) / NEPTUNE* (3.45%) / PECO (17.62%) / PPL (14.85%) / PSEG (20.79%) / RE (0.62%)

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 (8.01%) / BGE (1.94%) / DPL (12.99%) / JCPL (13.85%) / ME (5.88%) / NEPTUNE* (3.45%) / PECO (17.62%) / PPL (14.85%) / PSEG (20.79%) / RE (0.62%)
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 (*1.72*%) / AEP (*14.18*%) / APS (*6.05*%) / ATSI (*7.92*%) / BGE (*4.23*%) / ComEd (*13.20*%) / Dayton (*2.05*%) / DEOK (*3.18*%) / DL (*1.68*%) / DPL (*2.58*%) / Dominion (*12.56*%) / EKPC (*1.94*%) / JCPL (*3.82*%) / ME (1.88%) / NEPTUNE* (0.42%) / *OVEC (0.08%) /* PECO (*5.31*%) / PENELEC (*1.90*%) / PEPCO (*3.90*%) / PPL (*5.00*%) / PSEG (*6.15*%) / RE (*0.25*%)
			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 (*1.72*%) / AEP (*14.18*%) / APS (*6.05*%) / ATSI (*7.92*%) / BGE (*4.23*%) / ComEd (*13.20*%) / Dayton (*2.05*%) / DEOK (*3.18*%) / DL (*1.68*%) / DPL (*2.58*%) / Dominion (*12.56*%) / EKPC (*1.94*%) / JCPL (*3.82*%) / ME (1.88%) / NEPTUNE* (0.42%) / *OVEC (0.08%) /* PECO (*5.31*%) / PENELEC (*1.90*%) / PEPCO (*3.90*%) / PPL (*5.00*%) / PSEG (*6.15*%) / RE (*0.25*%)
			DFAX Allocation: PSEG (100%)
b2703	Install a 100 MVAR reactor at Bergen 230 kV		PSEG (100%)
b2704	Install a 150 MVAR reactor at Essex 230 kV		PSEG (100%)
b2705	Install a 200 MVAR reactor (variable) at Bergen 345 kV		PSEG (100%)
b2706	Install a 200 MVAR reactor (variable) at Bayway 345 kV		PSEG (100%)
b2707	Install a 100 MVAR reactor at Bayonne 345 kV		PSEG (100%)

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Public Service Electric and Gas Company (cont.)

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2835.1	*Conver the R-1318 and Q-1317 (Edison – Metuchen) 138 kV circuits to one 230 kV circuit (Brunswick – Meadow Road)*		*PECO (100%)*
b2835.2	*Convert the R-1318 and Q-1317 (Edison - Metuchen) 138 kV circuits to one 230 kV circuit (Meadow Road - Pierson Ave)*		*PECO (100%)*
b2835.3	*Convert the R-1318 and Q-1317 (Edison - Metuchen) 138 kV circuits to one 230 kV circuit (Pierson Ave - Metuchen)*		*PECO (40.15%) / PSEG (57.49%) / RE (2.36%)*
b2836	Convert the N-1340 and T-1372/D-1330 (Brunswick – Trenton) 138 kV circuits to 230 kV circuits		*See sub-IDs for cost allocations*
b2836.1	*Convert the N-1340 and T-1372/D-1330 (Brunswick - Trenton) 138 kV circuits to 230 kV circuits (Brunswick - Hunterglen)*		*PSEG (100%)*
b2836.2	*Convert the N-1340 and T-1372/D-1330 (Brunswick - Trenton) 138 kV circuits to 230 kV circuits (Hunterglen - Trenton)*		*NEPTUNE (100%)*
b2836.3	*Convert the N-1340 and T-1372/D-1330 (Brunswick - Trenton) 138 kV circuits to 230 kV circuits (Brunswick - Devils Brook)*		*NEPTUNE (100%)*
b2836.4	*Convert the N-1340 and T-1372/D-1330 (Brunswick - Trenton) 138 kV circuits to 230 kV circuits (Devils Brook - Trenton)*		*NEPTUNE (100%)*

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		*Annual Revenue Requirement*	*Responsible Customer(s)*
b2837	Convert the F-1358/Z1326 and K1363/Y-1325 (Trenton – Burlington) 138 kV circuits to 230 kV circuits		*See sub-IDs for cost allocations*
b2837.1	*Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Trenton - Yardville K)*		*NEPTUNE (100%)*
b2837.2	*Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Yardville - Ward Ave K)*		*NEPTUNE (100%)*
b2837.3	*Convert the N-1340 and T-1372/D-1330 (Brunswick - Trenton) 138 kV circuits to 230 kV circuits (Brunswick - Devils Brook)*		*NEPTUNE (100%)*
b2837.4	*Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Crosswicks - Bustleton Y)*		*NEPTUNE (7.65%) / PSEG (88.71%) / RECO (3.64%)*
b2837.5	*Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Bustleton - Burlington Y)*		*NEPTUNE (6.18%) / PSEG (90.12%) / RECO (3.70%)*
b2837.6	*Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Trenton - Yardville F)*		*NEPTUNE (100%)*

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		*Annual Revenue Requirement*	*Responsible Customer(s)*
b2837.7	*Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Yardville - Ward Ave F)*		*NEPTUNE (100%)*
b2837.8	*Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Ward Ave - Crosswicks Z)*		*NEPTUNE (100%)*
b2837.9	*Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Crosswicks - Williams Z)*		*NEPTUNE (9.14%) / PSEG (87.28%) / RECO (3.58%)*
b2837.10	*Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Williams - Bustleton Z)*		*NEPTUNE (7.50%) / PSEG (88.85%) / RECO (3.65%)*
b2837.11	*Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Bustleton - Burlington Z)*		*NEPTUNE (5.89%) / PSEG (90.40%) / RECO (3.71%)*
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		*See sub-IDs for cost allocations*

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
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%)
b2933.31	*Construct a 69 kV network between Front Street, Springfield and Stanley Terrace (Front Street - Springfield)*		*NEPTUNE (100%)*
b2933.32	*Construct a 69 kV network between Front Street, Springfield and Stanley Terrace (Springfield – 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 (*92.14*%) / NEPTUNE* (*7.86*%)
b2956	Replace existing cable on Cedar Grove - Jackson Rd. with 5000kcmil XLPE cable		PSEG (*100*%)
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		*See sub-IDs for cost allocations*

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2986.11	*Roseland-Branchburg 230 kV corridor rebuild (Roseland - Readington)*		*PSEG (100%)*
b2986.12	*Roseland-Branchburg 230kV corridor rebuild (Readington - Branchburg)*		*JCPL (100%)*
b2986.21	*Branchburg-Pleasant Valley 230kV corridor rebuild (Branchburg - East Flemington)*		*PECO (100%)*
b2986.22	*Branchburg-Pleasant Valley 230kV corridor rebuild (East Flemington - Pleasant Valley)*		*NEPTUNE (0.77%) / PECO (99.23%)*
b2986.23	*Branchburg-Pleasant Valley 230kV corridor rebuild (Pleasant Valley - Rocktown)*		*JCPL (31.39%) / NEPTUNE (5.26%) / PECO (6.68%) / PSEG (54.43%) / RECO (2.23%)*
b2986.24	*Branchburg-Pleasant Valley 230kV corridor rebuild (the PSEG portion of Rocktown - Buckingham)*		*JCPL (37.95%) / NEPTUNE (4.70%) / PECO (5.38%) / PSEG (49.92%) / RECO (2.05%)*
b3003	Construct a 230/69 kV station at Maywood		PSEG (100%)
b3003.1	Purchase properties at Maywood to accommodate new construction		PSEG (100%)
b3003.2	Extend Maywood 230 kV bus and install one (1) 230 kV breaker		PSEG (100%)
b3003.3	Install one (1) 230/69 kV transformer at Maywood		PSEG (100%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		*Annual Revenue Requirement*	*Responsible Customer(s)*
b3003.4	Install Maywood 69 kV ring bus		PSEG (100%)
b3003.5	Construct a 69 kV network between Spring Valley Road, Hasbrouck Heights, and Maywood		PSEG (100%)
b3004	Construct a 230/69/13 kV station by tapping the Mercer – Kuser Rd 230 kV circuit		PSEG (100%)
b3004.1	Install a new Clinton 230 kV ring bus with one (1) 230/69 kV transformer Mercer - Kuser Rd 230 kV circuit		PSEG (100%)
b3004.2	Expand existing 69 kV ring bus at Clinton Ave with two (2) additional 69 kV breakers		PSEG (100%)
b3004.3	Install two (2) 69/13 kV transformers at Clinton Ave		PSEG (100%)
b3004.4	Install 18 MVAR capacitor bank at Clinton Ave 69 kV		PSEG (100%)
b3025	Construct two (2) new 69/13 kV stations in the Doremus area and relocate the Doremus load to the new stations		PSEG (100%)

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b3025.1	Install a new 69/13 kV station (Vauxhall) with a ring bus configuration		PSEG (100%)
b3025.2	Install a new 69/13 kV station (19th Ave) with a ring bus configuration		PSEG (100%)
b3025.3	Construct a 69 kV network between Stanley Terrace, Springfield Road, McCarter, Federal Square, and the two new stations (Vauxhall & 19th Ave)		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%)

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** 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%)

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** 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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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%)
b2809	Install a bypass switch at Mount Pleasant 34.5 kV substation to allow the Mount Pleasant substation load to be removed from the N14 line and transfer to O769 line		JCPL (100%)
b3023	Replace West Wharton 115 kV breakers ‘G943A’ and ‘G943B’ with 40kA breakers		JCPL (100%)
b3042	Replace substation conductor at Raritan River 230 kV substation on the Kilmer line terminal		JCPL (100%)

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b3130	Construct seven new 34.5 kV circuits on existing pole lines (total of 53.5 miles), rebuild/reconductor two 34.5 kV circuits (total of 5.5 miles) and install a second 115/34.5 kV transformer (Werner)		JCPL (100%)
b3130.1	Construct a new 34.5 kV circuit from Oceanview to Allenhurst 34.5 kV (4 miles)		JCPL (100%)
b3130.2	Construct a new 34.5 kV circuit from Atlantic to Red Bank 34.5 kV (12 miles)		JCPL (100%)
b3130.3	Construct a new 34.5 kV circuit from Freneau to Taylor Lane 34.5 kV (6.5 miles)		JCPL (100%)
b3130.4	Construct a new 34.5 kV circuit from Keyport to Belford 34.5 kV (6 miles)		JCPL (100%)
b3130.5	Construct a new 34.5 kV circuit from Red Bank to Belford 34.5 kV (5 miles)		JCPL (100%)
b3130.6	Construct a new 34.5 kV circuit from Werner to Clark Street (7 miles)		JCPL (100%)
b3130.7	Construct a new 34.5 kV circuit from Atlantic to Freneau (13 miles)		JCPL (100%)
b3130.8	Rebuild/reconductor the Atlantic – Camp Woods Switch Point (3.5 miles) 34.5 kV circuit		JCPL (100%)
b3130.9	Rebuild/reconductor the Allenhurst – Elberon (2 miles) 34.5 kV circuit		JCPL (100%)
b3130.10	Install 2nd 115/34.5 kV transformer at Werner substation		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 (91.28%) / PSEG (8.29%) / RE (0.23%) / ECP** (0.20%)
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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: AEC (100%)
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
**East Coast Power, L.L.C.
†Cost allocations associated with Regional Facilities and Necessary Lower Voltage Facilities associated with the project
††Cost allocations associated with below 500 kV elements of the project

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 (12.82%) / NEPTUNE (1.18%) / HTP (0.79%) / PECO (51.08%) / PEPCO (0.57%) / ECP** (0.85%) / PSEG (31.46%) / RE (1.25%)
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 (88.83%) / JCPL (4.74%) / HTP (0.20%) / ECP** (0.22%) / PSEG (5.78%) / RE (0.23%)
b2157	Re-build 5.3 miles of the Corson - Tuckahoe 69 kV circuit		AEC (100%)

* Neptune Regional Transmission System, LLC
**East Coast Power, L.L.C.
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 (100%)
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%)

Atlantic City Electric Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b3135	Install back-up relay on the 138 kV bus at Corson substation		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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: *APS (24.07%) / BGE (9.92%) / Dominion (54.43%) / PEPCO (11.58%)*
b0222	Install 150 MVAR capacitor at Loudoun 500 kV		***Load-Ratio Share Allocation:*** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: *Dominion (91.39%)* / PEPCO (8.61%)

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

Virginia Electric and Power Company (cont.)

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0231	Install 500 kV breakers & 500 kV bus work at Suffolk		***Load-Ratio Share Allocation:*** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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

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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: *Dominion (*91.39%*)* / PEPCO (8.61%)

* Neptune Regional Transmission System, 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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: *APS (42.58%) / Dominion (57.42%)*
b0328.4	Upgrade Loudoun 500 kV substation		***Load-Ratio Share Allocation:*** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: *Dominion (91.39%)* / PEPCO (8.61%)

* Neptune Regional Transmission System, 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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: *Dominion (100%)*
b0329.1	Replace Thole Street 115 kV breaker '48T196'		Dominion (100%)
b0329.2	Replace Chesapeake 115 kV breaker 'T242'		Dominion (100%)
b0329.3	Replace Chesapeake 115 kV breaker '8722'		Dominion (100%)
b0329.4	Replace Chesapeake 115 kV breaker '16422'		Dominion (100%)
b0329.5	Install 2nd Suffolk 500/230 kV transformer & build Suffolk – Thrasher 230 kV circuit		Dominion (100%)††
b0330	Install Crewe 115 kV breaker and shift load from line 158 to 98		Dominion (100%)
b0331	Upgrade/resag Shell Bank – Whealton 115 kV (Line 165)		Dominion (100%)

* 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

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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%) ***DFAX Allocation:*** APS (55.52%) / ATSI (0.01%) / *PEPCO (44.47%)*
b0450	Install 150 MVAR Capacitor at Fredricksburg 230 kV		Dominion (100%)
b0451	Install 25 MVAR Capacitor at Somerset 115 kV		Dominion (100%)
b0452	Install 150 MVAR Capacitor at Northwest 230 kV		Dominion (100%)
b0453.1	Convert Remington – Sowego 115 kV to 230 kV		APS (0.31%) / BGE (3.01%) / DPL (0.04%) / Dominion (92.75%) / ME (0.03%) / PEPCO (3.86%)
b0453.2	Add Sowego – Gainsville 230 kV		APS (0.31%) / BGE (3.01%) / DPL (0.04%) / Dominion (92.75%) / ME (0.03%) / PEPCO (3.86%)
b0453.3	Add Sowego 230/115 kV transformer		APS (0.31%) / BGE (3.01%) / DPL (0.04%) / Dominion (92.75%) / ME (0.03%) / PEPCO (3.86%)
b0454	Reconductor 2.4 miles of Newport News – Chuckatuck 230 kV		Dominion (100%)

* Neptune Regional Transmission System, LLC

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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: DEOK (5.02%) / *Dominion* (92.89%) / EKPC (2.09%)
b0467.2	Reconductor the Dickerson – Pleasant View 230 kV circuit		AEC (1.75%) / APS (19.70%) / BGE (22.13%) / DPL (3.70%) / JCPL (0.71%) / ME (2.48%) / Neptune* (0.06%) / PECO (5.54%) / PEPCO (41.86%) / PPL (2.07%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0492.6	Replace Mount Storm 500 kV breaker 55072		***Load-Ratio Share Allocation:*** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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

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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0512.5	Advance n0716 (Ox - Replace 230kV breaker L242)		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: AEC (3.94%) / APS (0.33%) / BGE (34.54%) / DPL (14.69%) / Dominion (0.30%) / JCPL (9.43%) / ME (2.16%) / NEPTUNE (0.90%) / PECO (10.52%) / PEPCO (2.44%) / PPL (5.50%) / PSEG (14.71%) / RE (0.54%)
b0512.6	Advance n0717 (Possum Point - Replace 230kV breaker SC192)		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: AEC (3.94%) / APS (0.33%) / BGE (34.54%) / DPL (14.69%) / Dominion (0.30%) / JCPL (9.43%) / ME (2.16%) / NEPTUNE (0.90%) / PECO (10.52%) / PEPCO (2.44%) / PPL (5.50%) / PSEG (14.71%) / RE (0.54%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0583	Install dual primary protection schemes on Gosport lines 62 and 51 at the remote terminals (Chesapeake on the 62 line and Reeves Ave on the 51 line)		Dominion (100%)
b0756	Install a second 500/115 kV autotransformer at Chancellor 500 kV		Dominion (100%)
b0756.1	Install two 500 kV breakers at Chancellor 500 kV		***Load-Ratio Share Allocation:*** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: *Dominion (100%)*

* Neptune Regional Transmission System, LLC

Virginia Electric and Power Company (cont.)

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

* Neptune Regional Transmission System, LLC

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%)

* Neptune Regional Transmission System, LLC

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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: *APS (24.07%) / BGE (9.92%) / Dominion (54.43%) / PEPCO (11.58%)*
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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: *Dominion (100%)*
b1648	Upgrade name plate rating at Morrisville 500kV breaker 'H2T545' with 50kA breaker		***Load-Ratio Share Allocation:*** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: *Dominion (100%)*
b1650	Replace Morrisville 500kV breaker 'H2T569' with 50kA breaker		***Load-Ratio Share Allocation:*** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: *Dominion (100%)*
b1651	Replace Loudoun 230kV breaker '295T2030' with 63kA breaker		Dominion (100%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1652	Replace Ox 230kV breaker '209742' with 63kA breaker		Dominion (100%)
b1653	Replace Clifton 230kV breaker '26582' with 63kA breaker		Dominion (100%)
b1654	Replace Clifton 230kV breaker '26682' with 63kA breaker		Dominion (100%)
b1655	Replace Clifton 230kV breaker '205182' with 63kA breaker		Dominion (100%)
b1656	Replace Clifton 230kV breaker '265T266' with 63kA breaker		Dominion (100%)
b1657	Replace Clifton 230kV breaker '2051T2063' with 63kA breaker		Dominion (100%)
b1694	Rebuild Loudoun - Brambleton 500 kV		***Load-Ratio Share Allocation:*** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: BGE (11.54%) / *Dominion (75.32%)* / PEPCO (13.14%)
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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: *ATSI (3.01%) / Dayton (0.77%) / DEOK (1.85%) / Dominion (5.17%) / EKPC (0.79%) / PEPCO (88.41%)*
b1798	Build a 450 MVAR SVC and 300 MVAR switched shunt at Loudoun 500 kV		***Load-Ratio Share Allocation:*** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: *Dominion (91.39%)* / PEPCO (8.61%)

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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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (6.31%) / DL (1.34%) / *Dominion (*85.81*%)* / ME (1.66%) / PEPCO (4.88%)
b1805	Install a 250 MVAR SVC at the existing Mt. Storm 500kV substation		***Load-Ratio Share Allocation:*** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: *APS (*70.95*%) / PEPCO (*29.05*%)*
b1809	Replace Brambleton 230 kV Breaker '22702'		Dominion (100%)
b1810	Replace Brambleton 230 kV Breaker '227T2094'		Dominion (100%)

* Neptune Regional Transmission System, LLC

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1905.1	Surry to Skiffes Creek 500 kV Line (7 miles overhead)		***Load-Ratio Share Allocation:*** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%) ***DFAX Allocation:*** *Dominion (100%)*
b1905.2	Surry 500 kV Station Work		***Load-Ratio Share Allocation:*** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%) ***DFAX Allocation:*** *Dominion (100%)*
b1905.3	Skiffes Creek 500-230 kV Tx and Switching Station		Dominion (99.84%) / PEPCO (0.16%)
b1905.4	New Skiffes Creek - Whealton 230 kV line		Dominion (99.84%) / PEPCO (0.16%)
b1905.5	Whealton 230 kV breakers		Dominion (99.84%) / PEPCO (0.16%)

* Neptune Regional Transmission System, LLC

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1905.6	Yorktown 230 kV work		Dominion (99.84%) / PEPCO (0.16%)
b1905.7	Lanexa 115 kV work		Dominion (99.84%) / PEPCO (0.16%)
b1905.8	Surry 230 kV work		Dominion (99.84%) / PEPCO (0.16%)
b1905.9	Kings Mill, Peninmen, Toano, Waller, Warwick		Dominion (99.84%) / PEPCO (0.16%)
b1906.1	At Yadkin 500 kV, install six 500 kV breakers		***Load-Ratio Share Allocation:*** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: *Dominion (100%)*
b1906.2	Install a 2nd 230/115 kV TX at Yadkin		Dominion (100%)
b1906.3	Install a 2nd 230/115 kV TX at Chesapeake		Dominion (100%)
b1906.4	Uprate Yadkin – Chesapeake 115 kV		Dominion (100%)
b1906.5	Install a third 500/230 kV TX at Yadkin		Dominion (100%)
b1907	Install a 3rd 500/230 kV TX at Clover		APS (5.83%) / BGE (4.74%) / Dominion (81.79%) / PEPCO (7.64%)

* Neptune Regional Transmission System, LLC

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1908	Rebuild Lexington – Dooms 500 kV		***Load-Ratio Share Allocation:*** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: DEOK (5.02%) / *Dominion (92.89%)* / EKPC (2.09%)
b1909	Uprate Bremo – Midlothian 230 kV to its maximum operating temperature		APS (6.31%) / BGE (3.81%) / Dominion (81. 90%) / PEPCO (7.98%)
b1910	Build a Suffolk – Yadkin 230 kV line (14 miles) and install 4 breakers		Dominion (100%)
b1911	Add a second Valley 500/230 kV TX		APS (14.85%) / BGE (3.10%) / Dominion (74.12%) / PEPCO (7.93%)
b1912	Install a 500 MVAR SVC at Landstown 230 kV		DEOK (0.46%) / Dominion (99.54%)
b2053	Rebuild 28 mile line		AEP (100%)
b2125	Install four additional 230 kV 100 MVAR variable shunt reactor banks at Clifton, Gallows Road, Garrisonville, and Virginia Hills substations		Dominion (100%)
b2126	Install two additional 230 kV 100 MVAR variable shunt reactor banks at Churchland and Shawboro substations		Dominion (100%)

* Neptune Regional Transmission System, LLC

Virginia Electric and Power Company (cont.)

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

* Neptune Regional Transmission System, LLC

SCHEDULE 12 – APPENDIX A

(20) Virginia Electric and Power Company

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2368	Replace the Brambleton 230 kV breaker '209502' with 63kA breaker		Dominion (100%)
b2369	Replace the Brambleton 230 kV breaker '213702' with 63kA breaker		Dominion (100%)
b2370	Replace the Brambleton 230 kV breaker 'H302' with 63kA breaker		Dominion (100%)
b2373	Build a 2nd Loudoun - Brambleton 500 kV line within the existing ROW. The Loudoun - Brambleton 230 kV line will be relocated as an underbuild on the new 500 kV line		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (30.46%) / Dominion (69.54%)
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%)

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)
b2403	Replace the Beaumeade 230 kV breaker '274T2130' with 63kA		Dominion (100%)
b2404	Replace the Beaumeade 230 kV breaker '227T2095' with 63kA		Dominion (100%)
b2405	Replace the Pleasant view 230 kV breaker '203T274' with 63kA		Dominion (100%)
b2443	Construct new underground 230 kV line from Glebe to Station C, rebuild Glebe Substation, construct 230 kV high side bus at Station C with option to install 800 MVA PAR		Dominion (97.11%) / ME (0.18%) / PEPCO (2.71%)
b2443.1	Replace the Idylwood 230 kV breaker ‘203512’ with 50kA		Dominion (100%)
b2443.2	Replace the Ox 230 kV breaker ‘206342’ with 63kA breaker		Dominion (100%)
b2443.3	Glebe – Station C PAR		**DFAX Allocation:** Dominion (22.57%) / PEPCO (77.43%)
b2443.6	Install a second 500/230 kV transformer at Possum Point substation and replace bus work and associated equipment as needed		Dominion (100%)
b2443.7	Replace 19 63kA 230 kV breakers with 19 80kA 230 kV breakers		Dominion (100%)
b2457	Replace 24 115 kV wood h-frames with 230 kV Dominion pole H-frame structures on the Clubhouse – Purdy 115 kV line		Dominion (100%)
b2458.1	Replace 12 wood H-frame structures with steel H-frame structures and install shunts on all conductor splices on Carolina – Woodland 115 kV		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2458.2	Upgrade all line switches and substation components at Carolina 115 kV to meet or exceed new conductor rating of 174 MVA		Dominion (100%)
b2458.3	Replace 14 wood H-frame structures on Carolina – Woodland 115 kV		Dominion (100%)
b2458.4	Replace 2.5 miles of static wire on Carolina – Woodland 115 kV		Dominion (100%)
b2458.5	Replace 4.5 miles of conductor between Carolina 115 kV and Jackson DP 115 kV with min. 300 MVA summer STE rating; Replace 8 wood H-frame structures located between Carolina and Jackson DP with steel H-frames		Dominion (100%)
b2460.1	Replace Hanover 230 kV substation line switches with 3000A switches		Dominion (100%)
b2460.2	Replace wave traps at Four River 230 kV and Elmont 230 kV substations with 3000A wave traps		Dominion (100%)
b2461	Wreck and rebuild existing Remington CT – Warrenton 230 kV (approx. 12 miles) as a double-circuit 230 kV line		Dominion (100%)
b2461.1	Construct a new 230 kV line approximately 6 miles from NOVEC's Wheeler Substation a new 230 kV switching station in Vint Hill area		Dominion (100%)
b2461.2	Convert NOVEC's Gainesville – Wheeler line (approximately 6 miles) to 230 kV		Dominion (100%)
b2461.3	Complete a Vint Hill – Wheeler – Loudoun 230 kV networked line		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2471	Replace Midlothian 500 kV breaker 563T576 and motor operated switches with 3 breaker 500 kV ring bus. Terminate Lines # 563 Carson – Midlothian, #576 Midlothian –North Anna, Transformer #2 in new ring		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: Dominion (100%)
b2504	Rebuild 115 kV Line #32 from Halifax-South Boston (6 miles) for min. of 240 MVA and transfer Welco tap to Line #32. Moving Welco to Line #32 requires disabling auto-sectionalizing scheme		Dominion (100%)
b2505	Install structures in river to remove the 115 kV #65 line (Whitestone-Harmony Village 115 kV) from bridge and improve reliability of the line		Dominion (100%)
b2542	Replace the Loudoun 500 kV 'H2T502' breaker with a 50kA breaker		Dominion (100%)
b2543	Replace the Loudoun 500 kV 'H2T584' breaker with a 50kA breaker		Dominion (100%)
b2565	Reconductor wave trap at Carver Substation with a 2000A wave trap		Dominion (100%)
b2566	Reconductor 1.14 miles of existing line between ACCA and Hermitage and upgrade associated terminal equipment		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2582	Rebuild the Elmont – Cunningham 500 kV line		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (9.27%) / Dominion (90.73%)
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		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%)
b2654.3	Install a 2nd 224 MVA 230/115 kV transformer at Hathaway		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2665	Rebuild the Cunningham – Dooms 500 kV line		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: 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%)
b2686.2	Install a 3rd 230/115 kV transformer at Gordonsville Substation		Dominion (100%)
b2686.3	Upgrade Line 2088 between Gordonsville Substation and Louisa CT Station		Dominion (100%)
b2686.4	Replace the Remington CT 230 kV breaker “2114T2155” with a 63 kA breaker		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%)

*Neptune Regional Transmission System, LLC

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2717.1	De-energize Davis – Rosslyn #179 and #180 69 kV lines		Dominion (100%)
b2717.2	Remove splicing and stop joints in manholes		Dominion (100%)
b2717.3	Evacuate and dispose of insulating fluid from various reservoirs and cables		Dominion (100%)
b2717.4	Remove all cable along the approx. 2.5 mile route, swab and cap-off conduits for future use, leave existing communication fiber in place		Dominion (100%)
b2719.1	Expand Perth substation and add a 115 kV four breaker ring		Dominion (100%)
b2719.2	Extend the Hickory Grove DP tap 0.28 miles to Perth and terminate it at Perth		Dominion (100%)
b2719.3	Split Line #31 at Perth and terminate it into the new ring bus with 2 breakers separating each of the line terminals to prevent a breaker failure from taking out both 115 kV lines		Dominion (100%)
b2720	Replace the Loudoun 500 kV ‘H1T569’ breakers with 50kA breaker		Dominion (100%)
b2729	Optimal Capacitors Configuration: New 175 MVAR capacitor at Brambleton, new 175 MVAR capacitor at Ashburn, new 300 MVAR capacitor at Shelhorm, new 150 MVAR capacitor at Liberty		AEC (1.96%) / BGE (14.37%) / Dominion (35.11%) / DPL (3.76%) / ECP (0.29%) / HTP (0.34%) / JCPL (3.31%) / ME (2.51%) / Neptune (0.63%) / PECO (6.26%) / PEPCO (20.23%) / PPL (3.94%) / PSEG (7.29%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2744	Rebuild the Carson – Rogers Rd 500 kV circuit		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: Dominion (100%)
b2745	Rebuild 21.32 miles of existing line between Chesterfield – Lakeside 230 kV		Dominion (100%)
b2746.1	Rebuild Line #137 Ridge Rd – Kerr Dam 115 kV, 8.0 miles, for 346 MVA summer emergency rating		Dominion (100%)
b2746.2	Rebuild Line #1009 Ridge Rd – Chase City 115 kV, 9.5 miles, for 346 MVA summer emergency rating		Dominion (100%)
b2746.3	Install a second 4.8 MVAR capacitor bank on the 13.8 kV bus of each transformer at Ridge Rd		Dominion (100%)
b2747	Install a Motor Operated Switch and SCADA control between Dominion's Gordonsville 115 kV bus and FirstEnergy's 115 kV line		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2757	Install a +/-125 MVAr Statcom at Colington 230 kV		Dominion (100%)
b2758	Rebuild Line #549 Dooms – Valley 500kV		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (0.09%) / DL (0.03%) / Dominion (99.88%)
b2759	Rebuild Line #550 Mt. Storm – Valley 500kV		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (87.50%) / ATSI (0.37%) / DL (0.19%) / Dominion (1.04%) / EKPC (10.90%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
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		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: 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		See sub-IDs for cost allocations

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2960.1	Replace fixed series capacitors on 500 kV Line #547 at Lexington		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: DEOK (6.04%) / Dominion (91.37%) / EKPC (2.59%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2960.2	Replace fixed series capacitors on 500 kV Line #548 at Valley		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: DEOK (29.79%) / Dominion (60.32%) / EKPC (9.89%)
b2961	Rebuild approximately 3 miles of Line #205 & Line #2003 from Chesterfield to Locks & Poe respectively		Dominion (100%)
b2962	Split Line #227 (Brambleton – Beaumeade 230 kV) and terminate into existing Belmont substation		Dominion (100%)
b2962.1	Replace the Beaumeade 230 kV breaker “274T2081” with 63kA breaker		Dominion (100%)
b2962.2	Replace the NIVO 230 kV breaker “2116T2130” with 63kA breaker		Dominion (100%)
b2963	Reconductor the Woodbridge to Occoquan 230 kV line segment of Line #2001 with 1047 MVA conductor and replace line terminal equipment at Possum Point, Woodbridge, and Occoquan		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2978	Install 2-125 MVAR STATCOMs at Rawlings and 1-125 MVAR STATCOM at Clover 500 kV substations		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: Dominion (100%)
b2980	Rebuild 115 kV Line #43 between Staunton and Harrisonburg (22.8 miles) to current standards with a summer emergency rating of 261 MVA at 115 kV		Dominion (100%)
b2981	Rebuild 115 kV Line #29 segment between Fredericksburg and Aquia Harbor to current 230 kV standards (operating at 115 kV) utilizing steel H-frame structures with 2-636 ACSR to provide a normal continuous summer rating of 524 MVA at 115 kV (1047 MVA at 230 kV)		Dominion (100%)

*Neptune Regional Transmission System, LLC

Virginia Electric and Power Company (cont.)

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b3019	Rebuild 500 kV Line #552 Bristers to Chancellor – 21.6 miles long		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: Dominion (89.20%) / PEPCO (10.80%)
b3019.1	Update the nameplate for Morrisville 500 kV breaker “H1T594” to be 50kA		Dominion (100%)
b3019.2	Update the nameplate for Morrisville 500 kV breaker “H1T545” to be 50kA		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b3020	Rebuild 500 kV Line #574 Ladysmith to Elmont – 26.2 miles long		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (16.36%) / DEOK (11.61%) / Dominion (51.27%) / EKPC (5.30%) / PEPCO (15.46%)
b3021	Rebuild 500 kV Line #581 Ladysmith to Chancellor – 15.2 miles long		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: Dominion (100%)
b3026	Reconductor Line #274 (Pleasant View – Ashburn – Beaumeade 230 kV) with a minimum rating of 1200 MVA. Also upgrade terminal equipment		Dominion (100%)

Virginia Electric and Power Company (cont.)

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

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b3060	Rebuild 4.6 mile Elklick – Bull Run 230 kV Line #295 and the portion (3.85 miles) of the Clifton – Walney 230 kV Line #265 which shares structures with Line #295		Dominion (100%)
b3088	Rebuild 4.75 mile section of Line #26 between Lexington and Rockbridge with a minimum summer emergency rating of 261 MVA		Dominion (100%)
b3089	Rebuild 230 kV Line #224 between Lanexa and Northern Neck utilizing double circuit structures to current 230 kV standards. Only one circuit is to be installed on the structures with this project with a minimum summer emergency rating of 1047 MVA		Dominion (100%)
b3090	Convert the overhead portion (approx. 1500 feet) of 230 kV Lines #248 & #2023 to underground and convert Glebe substation to gas insulated substation		Dominion (100%)
b3096	Rebuild 230 kV line No.2063 (Clifton – Ox) and part of 230 kV line No.2164 (Clifton – Keene Mill) with double circuit steel structures using double circuit conductor at current 230 kV northern Virginia standards with a minimum rating of 1200 MVA		Dominion (100%)
b3097	Rebuild 4 miles of 115 kV Line #86 between Chesterfield and Centralia to current standards with a minimum summer emergency rating of 393 MVA		Dominion (100%)
b3098	Rebuild 9.8 miles of 115 kV Line #141 between Balcony Falls and Skimmer and 3.8 miles of 115 kV Line #28 between Balcony Falls and Cushaw to current standards with a minimum rating of 261 MVA		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b3110.1	Rebuild Line #2008 between Loudoun to Dulles Junction using single circuit conductor at current 230 kV northern Virginia standards with minimum summer ratings of 1200 MVA. Cut and loop Line #265 (Clifton – Sully) into Bull Run substation. Add three (3) 230 kV breakers at Bull Run to accommodate the new line and upgrade the substation		Dominion (100%)
b3110.2	Replace the Bull Run 230 kV breakers “200T244” and “200T295” with 50 kA breakers		Dominion (100%)
b3113	Rebuild approximately 1 mile of 115 kV Lines #72 and #53 to current standards with a minimum summer emergency rating of 393 MVA. The resulting summer emergency rating of Line #72 segment from Brown Boveri to Bellwood is 180 MVA. There is no change to Line #53 ratings		Dominion (100%)
b3114	Rebuild the 18.6 mile section of 115 kV Line #81 which includes 1.7 miles of double circuit Line #81 and 230 kV Line #2056. This segment of Line #81 will be rebuilt to current standards with a minimum rating of 261 MVA. Line #2056 rating will not change		Dominion (100%)
b3121	Rebuild Clubhouse – Lakeview 230 kV Line #254 with single-circuit wood pole equivalent structures at the current 230 kV standard with a minimum rating of 1047 MVA		Dominion (100%)

Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b3122	Rebuild Hathaway – Rocky Mount (Duke Energy Progress) 230 kV Line #2181 and Line #2058 with double circuit steel structures using double circuit conductor at current 230 kV standards with a minimum rating of 1047 MVA		Dominion (100%)
b3161.1	*Split Chesterfield-Plaza 115 kV Line No. 72 by rebuilding the Brown Boveri tap line as double circuit loop in-and-out of the Brown Boveri Breaker station*		*Dominion (100%)*
b3161.2	*Install a 115 kV breaker at the Brown Boveri Breaker station. Site expansion is required to accommodate the new layout*		*Dominion (100%)*
b3162	*Acquire land and build a new 230 kV switching station (Stevensburg) with a 224 MVA, 230/115 kV transformer. Gordonsville-Remington 230 kV Line No. 2199 will be cut and connected to the new station. Remington-Mt. Run 115 kV Line No.70 and Mt. Run-Oak Green 115 kV Line No. 2 will also be cut and connected to the new station*		*Dominion (100%)*
b3211	Rebuild the 1.3 mile section of 500 kV Line No. 569 (Loudoun – Morrisville) with single-circuit 500 kV structures at the current 500 kV standard. This will increase the rating of the line to 3424 MVA		Dominion (100%)

- Attachment 7e (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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (53.02%) / Dominion (33.27%) / PEPCO (13.71%)
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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: Dominion (91.39%) / PEPCO (8.61%)
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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (70.95%) / PEPCO (29.05%)
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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (42.58%) / Dominion (57.42%)

* 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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (70.95%) / PEPCO (29.05%)
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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (42.58%) / Dominion (57.42%)

* 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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (70.95%) / PEPCO (29.05%)
b0347.6	Upgrade (per ABB inspection) breaker HL-6		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (70.95%) / PEPCO (29.05%)

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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (70.95%) / PEPCO (29.05%)
b0347.8	Upgrade (per ABB inspection) breaker HL-8		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (70.95%) / PEPCO (29.05%)

*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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (70.95%) / PEPCO (29.05%)
b0347.10	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-1		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (70.95%) / PEPCO (29.05%)

*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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (70.95%) / PEPCO (29.05%)
b0347.12	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-4		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (70.95%) / PEPCO (29.05%)

*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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (70.95%) / PEPCO (29.05%)
b0347.14	Upgrade (per ABB Inspection) Hatfield 500 kV breakers HFL-7		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (70.95%) / PEPCO (29.05%)

*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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (70.95%) / PEPCO (29.05%)
b0347.16	Upgrade (per ABB inspection) Harrison 500 kV breaker 'HL-3'		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (70.95%) / PEPCO (29.05%)

*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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (42.58%) / Dominion (57.42%)
b0347.18	Replace Meadow Brook 138 kV breaker 'MD-11'		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (42.58%) / Dominion (57.42%)

*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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (42.58%) / Dominion (57.42%)
b0347.20	Replace Meadow Brook 138 kV breaker 'MD-13'		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (42.58%) / Dominion (57.42%)

*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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (42.58%) / Dominion (57.42%)
b0347.22	Replace Meadow Brook 138 kV breaker 'MD-15'		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (42.58%) / Dominion (57.42%)

*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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (42.58%) / Dominion (57.42%)
b0347.24	Replace Meadow Brook 138 kV breaker 'MD-17'		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (42.58%) / Dominion (57.42%)

*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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (42.58%) / Dominion (57.42%)
b0347.26	Replace Meadow Brook 138 kV breaker 'MD-22#1 CAP'		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (42.58%) / Dominion (57.42%)

*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)

b0347.27	Replace Meadow Brook 138 kV breaker ‘MD-4’		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (42.58%) / Dominion (57.42%)
b0347.28	Replace Meadow Brook 138 kV breaker ‘MD-5’		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (42.58%) / Dominion (57.42%)

*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)
b0347.29	Replace Meadowbrook 138 kV breaker 'MD-6'		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (42.58%) / Dominion (57.42%)
b0347.30	Replace Meadowbrook 138 kV breaker 'MD-7'		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (42.58%) / Dominion (57.42%)

*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)
b0347.31	Replace Meadowbrook 138 kV breaker 'MD-8'		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (42.58%) / Dominion (57.42%)
b0347.32	Replace Meadowbrook 138 kV breaker 'MD-9'		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (42.58%) / Dominion (57.42%)

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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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (19.10%) / ATSI (25.82%) / Dayton (18.43%) / DEOK (29.32%) / DL (1.19%) / EKPC (5.96%) / OVEC (0.18%)

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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%) **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%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0460	Raise limiting structures on Albright – Bethelboro 138 kV to raise the rating to 175 MVA normal 214 MVA emergency		APS (100%)
b0491	Construct an Amos to Welton Spring to WV state line 765 kV circuit (APS equipment)	As specified under the procedures detailed in Attachment H-19B	**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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)
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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0492.5	Replace Eastalco 230 kV breaker D-31		APS (100%)
b0495	Replace existing Kammer 765/500 kV transformer with a new larger transformer		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (31.25%) / BGE (19.37%) / Dayton (9.85%) / DEOK (13.77%) / EKPC (2.73%) / PEPCO (23.03%)
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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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%)

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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)
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 (97.68%) / DL (0.96%) / PENELEC (1.09%) / ECP** (0.01%) / PSEG (0.25%) / RE (0.01%)
b0674.1	Replace the Osage 138 kV breaker 'CollinsF126'		APS (100%)
b0675.1	Convert Monocacy - Walkersville 138 kV to 230 kV		AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)
b0675.2	Convert Walkersville - Catoctin 138 kV to 230 kV		AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0675.3	Convert Ringgold - Catoctin 138 kV to 230 kV		AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)
b0675.4	Convert Catoctin - Carroll 138 kV to 230 kV		AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)
b0675.5	Convert portion of Ringgold Substation from 138 kV to 230 kV		AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)
b0675.6	Convert Catoctin Substation from 138 kV to 230 kV		AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)
b0675.7	Convert portion of Carroll Substation from 138 kV to 230 kV		AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)
b0675.8	Convert Monocacy Substation from 138 kV to 230 kV		AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0675.9	Convert Walkersville Substation from 138 kV to 230 kV		AEC (1.02%) / APS (81.96%) / DPL (0.85%) / JCPL (1.75%) / ME (6.37%) / NEPTUNE* (0.15%) / PECO (3.09%) / PPL (2.24%) / PSEG (2.42%) / RE (0.09%) / ECP** (0.06%)
b0676.1	Reconductor Doubs - Lime Kiln (#207) 230kV		AEC (0.64%) / APS (86.70%) / DPL (0.53%) / JCPL (1.93%) / ME (4.04%) / NEPTUNE* (0.18%) / PECO (1.93%) / PENELEC (0.93%) / PSEG (2.92%) / RE (0.12%) / ECP** (0.08%)
b0676.2	Reconductor Doubs - Lime Kiln (#231) 230kV		AEC (0.64%) / APS (86.70%) / DPL (0.53%) / JCPL (1.93%) / ME (4.04%) / NEPTUNE* (0.18%) / PECO (1.93%) / PENELEC (0.93%) / PSEG (2.92%) / RE (0.12%) / ECP** (0.08%)
b0677	Reconductor Double Toll Gate – Riverton with 954 ACSR		APS (100%)
b0678	Reconductor Glen Falls - Oak Mound 138kV with 954 ACSR		APS (100%)
b0679	Reconductor Grand Point – Letterkenny with 954 ACSR		APS (100%)
b0680	Reconductor Greene – Letterkenny with 954 ACSR		APS (100%)
b0681	Replace 600/5 CT's at Franklin 138 kV		APS (100%)
b0682	Replace 600/5 CT's at Whiteley 138 kV		APS (100%)

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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)
b0684	Reconductor Guilford – South Chambersburg with 954 ACSR		APS (100%)
b0685	Replace Ringgold 230/138 kV #3 with larger transformer		APS (71.93%) / JCPL (4.17%) / ME (6.79%) / NEPTUNE* (0.38%) / PECO (4.05%) / PENELEC (5.88%) / ECP** (0.18%) / PSEG (6.37%) / RE (0.25%)
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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**East Coast Power, L.L.C.

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
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 (78.59%) / PENELEC (14.08%) / ECP ** (0.23%) / PSEG (6.83%) / RE (0.27%)
b1138	Reconductor the King Farm – Sony 138 kV line with 954 ACSR		APS (100%)
b1139	Reconductor the Yukon – Waltz Mills 138 kV line with high temperature conductor		APS (100%)
b1140	Reconductor the Bracken Junction – Luxor 138 kV line with 954 ACSR		APS (100%)
b1141	Reconductor the Sewickley – Waltz Mills Tap 138 kV line with high temperature conductor		APS (100%)
b1142	Reconductor the Bartonsville – Stephenson 138 kV; Stonewall – Stephenson 138 kV line with 954 ACSR		APS (100%)
b1143	Reconductor the Youngwood – Yukon 138 kV line with high temperature conductor		APS (89.92%) / PENELEC (10.08%)
b1144	Reconductor the Bull Creek Junction – Cabot 138 kV line with high temperature conductor		APS (100%)

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

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

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

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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (24.07%) / BGE (9.92%) / Dominion (54.43%) / PEPCO (11.58%)

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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (24.07%) / BGE (9.92%) / Dominion (54.43%) / PEPCO (11.58%)
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%)

* 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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (42.58%) / Dominion (57.42%)
b0560	Install 250 MVAR capacitor at Kemptown 500 kV substation		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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)
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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (24.07%) / BGE (9.92%) / Dominion (54.43%) / PEPCO (11.58%)
b1804	Install a new 600 MVAR SVC at Meadowbrook 500kV		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: APS (42.58%) / Dominion (57.42%)
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) 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)
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%)
b2747.1	Relocate the FirstEnergy Pratts 138 kV terminal CVTs at Gordonsville substation to allow for the installation of a new motor operated switch being installed by Dominion		APS (100%)
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		APS (100%)
b2966	Reconductor the Yukon – Smithton – Shepler Hill Jct 138 kV line with 795 ACSS conductor. Replace Line Disconnect Switch at Yukon		APS (100%)
b2966.1	Reconductor the Yukon - Smithton - Shepler Hill Jct 138 kV line and replace terminal equipment as necessary to achieve required rating		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%)

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)
b2970.5	Convert Garfield 138/12.5 kV substation to 230/12.5 kV		APS (100%)
b2996	Construct new Flint Run 500/138 kV substation		See sub-IDs for cost allocations
b2996.1	Construct a new 500/138 kV substation as a 4-breaker ring bus with expansion plans for double-breaker-double-bus on the 500 kV bus and breaker-and-a-half on the 138 kV bus to provide EHV source to the Marcellus shale load growth area. Projected load growth of additional 160 MVA to current plan of 280 MVA, for a total load of 440 MVA served from Waldo Run substation. Construct additional 3-breaker string at Waldo Run 138 kV bus. Relocate the Sherwood #2 line terminal to the new string. Construct two single circuit Flint Run - Waldo Run 138 kV lines using 795 ACSR (approximately 3 miles). After terminal relocation on new 3-breaker string at Waldo Run, terminate new Flint Run 138 kV lines onto the two open terminals		APS (100%)
b2996.2	Loop the Belmont – Harrison 500 kV line into and out of the new Flint Run 500 kV substation (less than 1 mile). Replace primary relaying and carrier sets on Belmont and Harrison 500 kV remote end substations		APS (100%)
b2996.3	*Upgrade two (2) existing 138 kV breakers (Rider 50 and #1/4 transformer breaker) at Glen Falls with 63 kA 3000A units*		*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)
b3005	Reconductor 3.1 mile 556 ACSR portion of Cabot to Butler 138 kV with 556 ACSS and upgrade terminal equipment. 3.1 miles of line will be reconductored for this project. The total length of the line is 7.75 miles		APS (100%)
b3006	Replace four Yukon 500/138 kV transformers with three transformers with higher rating and reconfigure 500 kV bus		APS (52.84%) / DL (47.16%)
b3007.1	Reconductor the Blairsville East to Social Hall 138 kV line and upgrade terminal equipment - AP portion. 4.8 miles total. The new conductor will be 636 ACSS replacing the existing 636 ACSR conductor. At Social Hall, meters, relays, bus conductor, a wave trap, circuit breaker and disconnects will be replaced		APS (100%)
b3010	Replace terminal equipment at Keystone and Cabot 500 kV buses. At Keystone, bus tubing and conductor, a wave trap, and meter will be replaced. At Cabot, a wave trap and bus conductor will be replaced		APS (100%)
b3011.1	Construct new Route 51 substation and connect 10 138 kV lines to new substation		DL (100%)
b3011.2	Upgrade terminal equipment at Yukon to increase rating on Yukon to Charleroi #2 138 kV line (New Yukon to Route 51 #4 138 kV line)		DL (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)
b3011.3	Upgrade terminal equipment at Yukon to increase rating on Yukon to Route 51 #1 138 kV line		DL (100%)
b3011.4	Upgrade terminal equipment at Yukon to increase rating on Yukon to Route 51 #2 138 kV line		DL (100%)
b3011.5	Upgrade terminal equipment at Yukon to increase rating on Yukon to Route 51 #3 138 kV line		DL (100%)
b3011.6	Upgrade remote end relays for Yukon – Allenport – Iron Bridge 138 kV line		DL (100%)
b3012.1	Construct two new 138 kV ties with the single structure from APS's new substation to Duquesne's new substation. The estimated line length is approximately 4.7 miles. The line is planned to use multiple ACSS conductors per phase		ATSI (38.21%) / DL (61.79%)
b3012.3	Construct a new Elrama – Route 51 138 kV No.3 line: reconductor 4.7 miles of the existing line, and construct 1.5 miles of a new line to the reconductored portion. Install a new line terminal at APS Route 51 substation		DL (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)

b3013	Reconductor Vasco Tap to Edgewater Tap 138 kV line. 4.4 miles. The new conductor will be 336 ACSS replacing the existing 336 ACSR conductor		APS (100%)
b3015.6	Reconductor Elrama to Mitchell 138 kV line – AP portion. 4.2 miles total. 2x 795 ACSS/TW 20/7		DL (100%)
b3015.8	Upgrade terminal equipment at Mitchell for Mitchell – Elrama 138 kV line		APS (100%)
b3028	Upgrade substation disconnect leads at William 138 kV substation		APS (100%)
b3051.1	Ronceverte cap bank and terminal upgrades		APS (100%)
b3052	Install a 138 kV capacitor (29.7 MVAR effective) at West Winchester 138 kV		APS (100%)
b3064.3	Upgrade line relaying at Piney Fork and Bethel Park for Piney For – Elrama 138 kV line and Bethel Park – Elrama 138 kV		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)
b3068	Reconductor the Yukon – Westraver 138 kV line (2.8 miles), replace the line drops and relays at Yukon 138 kV and replace switches at Westraver 138 kV bus		APS (100%)
b3069	Reconductor the Westraver – Route 51 138 kV line (5.63 miles) and replace line switches at Westraver 138 kV bus		APS (100%)
b3070	Reconductor the Yukon – Route 51 #1 138 kV line (8 miles), replace the line drops, relays and line disconnect switch at Yukon 138 kV bus		APS (100%)
b3071	Reconductor the Yukon – Route 51 #2 138 kV line (8 miles) and replace relays at Yukon 138 kV bus		APS (100%)
b3072	Reconductor the Yukon – Route 51 #3 138 kV line (8 miles) and replace relays at Yukon 138 kV bus		APS (100%)
b3074	Reconductor the 138 kV bus at Armstrong substation		APS (100%)
b3075	Replace the 500/138 kV transformer breaker and reconductor 138 kV bus at Cabot substation		APS (100%)
b3076	Reconductor the Edgewater – Loyalhanna 138 kV line (0.67 mile)		APS (100%)
b3079	Replace the Wylie Ridge 500/345 kV transformer #7		ATSI (72.30%) / DL (27.70%)
b3083	Reconductor the 138 kV bus at Butler and reconductor the 138 kV bus and replace line trap at Karns City		APS (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b3128	Relocate 34.5 kV lines from generating station roof R. Paul Smith 138 kV station		APS (100%)

- Attachment 7f (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%)
b0367.1	Reconductor circuit “23035” for Dickerson – Quince Orchard 230 kV		AEC (1.78%) / BGE (26.52%) / DPL (3.25%) / JCPL (2.67%) / ME (1.16%) / Neptune* (0.25%) / PECO (4.79%) / PEPCO (52.46%) / PPL (3.23%) / PSEG (3.81%) / ECP** (0.08%)

* 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)
b0367.2	Reconductor circuit "23033" for Dickerson – Quince Orchard 230 kV		AEC (1.78%) / BGE (26.52%) / DPL (3.25%) / JCPL (2.67%) / ME (1.16%) / Neptune* (0.25%) / PECO (4.79%) / PEPCO (52.46%) / PPL (3.23%) / PSEG (3.81%) / ECP** (0.08%)
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
**East Coast Power, L.L.C.

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)
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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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)
b0512.8	Advance n0773 (Replace Chalk Point 230 kV breaker (1B) with 80 kA breaker)		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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)
b0512.10	Advance n0775 (Replace Chalk Point 230 kV breaker (2B) with 80 kA breaker)		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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)
b0512.12	Advance n0777 (Replace Chalk Point 230 kV breaker (3A) with 80 kA breaker)		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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)
b0512.14	Advance n0779 (Replace Chalk Point 230 kV breaker (3C) with 80 kA breaker)		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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)
b0512.16	Advance n0781 (Replace Chalk Point 230 kV breaker (4B) with 80 kA breaker)		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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)
b0512.28	Advance n0793 (Replace Chalk Point 230 Kv breaker (6C) with 80 kA breaker)		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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)
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%)
b0561	Install 300 MVAR capacitor at Dickerson Station “D” 230 kV substation		AEC (8.58%) / APS (1.69%) / DPL (12.24%) / JCPL (18.16%) / ME (1.55%) / Neptune* (1.77%) / PECO (21.78%) / PPL (6.40%) / ECP** (0.73%) / PSEG (26.13%) / RE (0.97%)
b0562	Install 500 MVAR capacitor at Brighton 230 kV substation		AEC (8.58%) / APS (1.69%) / DPL (12.24%) / JCPL (18.16%) / ME (1.55%) / Neptune* (1.77%) / PECO (21.78%) / PPL (6.40%) / ECP** (0.73%) / PSEG (26.13%) / RE (0.97%)
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%)

* Neptune Regional Transmission System, LLC

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%)

* Neptune Regional Transmission System, LLC

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 (2.39%) / APS (3.82%) / BGE (65.72%) / DPL (4.43%) / JCPL (3.93%) / ME (2.16%) / Neptune* (0.39%) / HTP (0.10%) / PECO (8.35%) / PPL (2.83%) / ECP** (0.13%) / PSEG (5.53%) / RE (0.22%)
b1593	Reconductor the Bowie - Burtonsville 230 kV circuit and upgrade terminal equipments at Bowie and Burtonsville 230 kV substations		AEC (2.39%) / APS (3.82%) / BGE (65.72%) / DPL (4.43%) / JCPL (3.93%) / ME (2.16%) / Neptune* (0.39%) / HTP (0.10%) / PECO (8.35%) / PPL (2.83%) / ECP** (0.13%) / PSEG (5.53%) / 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 (2.38%) / APS (3.84%) / BGE (65.72%) / DPL (4.44%) / JCPL (3.93%) / ME (2.16%) / Neptune* (0.39%) / HTP (0.10%) / PECO (8.33%) / PPL (2.83%) / ECP** (0.13%) / PSEG (5.53%) / 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 (2.38%) / APS (3.84%) / BGE (65.72%) / DPL (4.44%) / JCPL (3.93%) / ME (2.16%) / Neptune* (0.39%) / HTP (0.10%) / PECO (8.33%) / PPL (2.83%) / ECP** (0.13%) / PSEG (5.53%) / 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%)

* Neptune Regional Transmission System, LLC

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 7g (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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: AEC (4.19%) / DPL (5.88%) / JCPL (19.81%) / PECO (70.12%)

* Neptune Regional Transmission System, LLC

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0172.1	Replace wave trap at Alburtis 500kV substation		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: AEC (4.49%) / JCPL (29.72%) / NEPTUNE (4.97%) / PECO (9.91%) / PSEG (48.90%) / RE (2.01%)
b0284.2	Replace two wave traps at Juniata 500 kV – on the two Juniata – Airydale 500 kV		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: BGE (21.26%) / JCPL (18.75%) / ME (14.00%) / NEPTUNE (2.11%) / PECO (18.78%) / PSEG (24.11%) / RE (0.99%)

* Neptune Regional Transmission System, LLC

PPL Electric Utilities Corporation (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
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 (4.55%) / Neptune* (0.37%) / PECO (1.79%) / PENELEC (0.33%) / PPL (86.63%) / ECP** (0.18%) / PSEG (5.93%) / RE (0.22%)

* 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)
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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: JCPL (32.93%) / NEPTUNE (4.37%) / PSEG (60.23%) / RE (2.47%)
b0487.1	Install Lackawanna 500/230 kV transformer and upgrade 230 kV substation and switchyard		PENELEC (16.90%) / PPL (77.59%) / ECP** (0.19%) / PSEG (5.13%) / 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 (6.27%) / 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%)

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

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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
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%)
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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)†
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 (1.10%) / ECP** (0.37%) / HTP (0.37%) / JCPL (9.61%) / ME (19.42%) / Neptune* (0.75%) / PECO (6.01%) / PPL (50.57%) / PSEG (11.35%) / RE (0.45%)
b2006.1	Install North Lancaster 500/230 kV substation (500 kV portion)		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: PPL (100%)
b2006.2	Construct a new 230/69 kV North Lancaster substation. The sub will be supplied from the SAKR-BERK 230kV Line		PPL (100%)
b2006.3	Construct new 69/138 kV transmission from North Lancaster 230/69 kV sub to Brecknock and Honeybrook areas		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)
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%)

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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%) **DFAX Allocation:** PPL (100%)
b2238	100 MVAR shunt reactor at Elimsport 230 kV		PPL (100%)

* Neptune Regional Transmission System, 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 (95.43%) / PPL (4.57%)
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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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

PPL Electric Utilities Corporation (cont.)

<table>
<tr><th colspan="2">Required Transmission Enhancements</th><th>Annual Revenue Requirement</th><th>Responsible Customer(s)</th></tr>
<tr><td rowspan="2">b2824</td><td rowspan="2">Reconfigure/Expand the Lackawanna 500 kV substation by adding a third bay with three breakers</td><td rowspan="2"></td><td>Load-Ratio Share Allocation:
AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)</td></tr>
<tr><td>DFAX Allocation:
PPL (100%)</td></tr>
<tr><td>b2838</td><td>Build a new 230/69 kV substation by tapping the Montour – Susquehanna 230 kV double circuits and Berwick – Hunlock & Berwick – Colombia 69 kV circuits</td><td></td><td>PPL (100%)</td></tr>
<tr><td>b2979</td><td>Replace Martins Creek 230 kV circuit breakers with 80 kA rating</td><td></td><td>PPL (100%)</td></tr>
</table>

* Neptune Regional Transmission System, LLC

- Attachment 7h (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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)

* Neptune Regional Transmission System, LLC

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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
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%)

* Neptune Regional Transmission System, LLC

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 (16.10%) / PEPCO (6.66%)
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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: AEC (1.12%) / ATSI (6.83%) / BGE (9.41%) / DPL (6.56%) / JCPL (17.79%) / NEPTUNE* (2.00%) / PEPCO (19.80%) / PSEG (35.05%) / RE (1.44%)

*Neptune Regional Transmission System, 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 7i (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 (6.71%) / APS (3.97%) / DPL (9.10%) / JCPL (16.85%) / ME (10.53%) / Neptune* (1.69%) / PECO (19.00%) / PPL (7.55%) / PSEG (22.67%) / RE (0.34%) / UGI (0.95%) / ECP** (0.64%)
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
**East Coast Power, L.L.C.

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

(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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: DL (0.02%) / DPL (36.96%) / JCPL (0.04%) / ME (62.90%) / PSEG (0.08%)
b1801	Build a 250 MVAR SVC at Altoona 230 kV		AEC (6.47%) / AEP (2.58%) / APS (6.88%) / BGE (6.57%) / DPL (12.39%) / Dominion (14.89%) / JCPL (8.14%) / ME (6.21%) / Neptune* (0.82%) / PECO (21.56%) / PPL (4.89%) / PSEG (8.18%) / RE (0.33%) / ECP** (0.09%

*Neptune Regional Transmission System, LLC

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

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

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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

* Neptune Regional Transmission System, LLC
**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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
b0284.3	Replace wave trap and upgrade a bus section at Keystone 500 kV – on the Keystone – Airydale 500 kV		AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)

* Neptune Regional Transmission System, LLC
** East Coast Power, L.L.C.
***Hudson Transmission Partners, 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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
b0285.2	Replace wave trap and relay at Conemaugh 500 kV – on the Conemaugh – Keystone 500 kV		AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)

* Neptune Regional Transmission System, LLC
** East Coast Power, L.L.C.
***Hudson Transmission Partners, 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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
b0370	Install 500 MVAR Dynamic Reactive Device at Airydale 500 kV substation		AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)

* Neptune Regional Transmission System, LLC
** East Coast Power, L.L.C.
***Hudson Transmission Partners, 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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: BGE (21.26%) / JCPL (18.75%) / ME (14.00%) / NEPTUNE (2.11%) / PECO (18.78%) / PSEG (24.11%) / 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
** East Coast Power, L.L.C.
***Hudson Transmission Partners, 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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: AEC (4.26%) / ATSI (0.03%) / BGE (26.21%) / DL (0.01%) / JCPL (15.53%) / ME (14.86%) / NEPTUNE (1.75%) / PECO (17.49%) / PSEG (19.08%) / RE (0.78%)
b0550	Install 25 MVAR capacitor at Lewis Run 115 kV substation		AEC (8.58%) / APS (1.69%) / DPL (12.24%) / JCPL (18.16%) / ME (1.55%) / Neptune* (1.77%) / PECO (21.78%) / PPL (6.40%) / ECP** (0.73%) / PSEG (26.13%) / RE (0.97%)
b0551	Install 25 MVAR capacitor at Saxton 115 kV substation		AEC (8.58%) / APS (1.69%) / DPL (12.24%) / JCPL (18.16%) / ME (1.55%) / Neptune* (1.77%) / PECO (21.78%) / PPL (6.40%) / ECP** (0.73%) / PSEG (26.13%) / RE (0.97%)

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0552	Install 50 MVAR capacitor at Altoona 230 kV substation		AEC (8.58%) / APS (1.69%) / DPL (12.24%) / JCPL (18.16%) / ME (1.55%) / Neptune* (1.77%) / PECO (21.78%) / PPL (6.40%) / ECP** (0.73%) / PSEG (26.13%) / RE (0.97%)
b0553	Install 50 MVAR capacitor at Raystown 230 kV substation		AEC (8.58%) / APS (1.69%) / DPL (12.24%) / JCPL (18.16%) / ME (1.55%) / Neptune* (1.77%) / PECO (21.78%) / PPL (6.40%) / ECP** (0.73%) / PSEG (26.13%) / RE (0.97%)
b0555	Install 100 MVAR capacitor at Johnstown 230 kV substation		AEC (8.58%) / APS (1.69%) / DPL (12.24%) / JCPL (18.16%) / ME (1.55%) / Neptune* (1.77%) / PECO (21.78%) / PPL (6.40%) / ECP** (0.73%) / PSEG (26.13%) / RE (0.97%)
b0556	Install 50 MVAR capacitor at Grover 230 kV substation		AEC (8.58%) / APS (1.69%) / DPL (12.24%) / JCPL (18.16%) / ME (1.55%) / Neptune* (1.77%) / PECO (21.78%) / PPL (6.40%) / ECP** (0.73%) / PSEG (26.13%) / RE (0.97%)
b0557	Install 75 MVAR capacitor at East Towanda 230 kV substation		AEC (8.58%) / APS (1.69%) / DPL (12.24%) / JCPL (18.16%) / ME (1.55%) / Neptune* (1.77%) / PECO (21.78%) / PPL (6.40%) / ECP** (0.73%) / PSEG (26.13%) / RE (0.97%)
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
**East Coast Power, L.L.C.

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%)

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

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 (3.74%) / APS (6.26%) / BGE (16.82%) / DL (0.32%) / JCPL (12.57%) / ME (6.89%) / PECO (11.53%) / PEPCO (0.55%) / PPL (15.42%) / PSEG (20.52%) / RE (0.72%) / NEPTUNE* (1.70%) / ECP** (2.96%)
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%)

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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 (6.47%) / AEP (2.58%) / APS (6.88%) / BGE (6.57%) / / DPL (12.39%) / Dominion (14.89%) / JCPL (8.14%) / ME (6.21%) / NEPTUNE* (0.82%) / PECO (21.56%) / PPL (4.89%) / PSEG (8.18%) / RE (0.33%) / ECP** (0.09%)

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

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%)

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

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 (10.09%) / ECP** (0.45%) / HTP (0.49%) / JCPL (5.14%) / Neptune* (0.54%) / PENELEC (70.71%) / PSEG (12.10%) / 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 (33.20%) / ECP** (0.44%) / HTP (0.44%) / JCPL (8.64%) / ME (5.52%) / Neptune (0.86%) / PENELEC (36.81%) / PSEG (13.55%) / 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%)

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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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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%)
b3136	Replace bus conductor at Smith 115 kV substation		ME (100%)
b3145	Rebuild the Hunterstown – Lincoln 115 kV Line No. 962 (approx. 2.6 miles). Upgrade limiting terminal equipment at Hunterstown and Lincoln		AEP (16.60%) / APS (8.09%) / BGE (2.74%) / Dayton (2.00%) / DEOK (0.35%) / DL (1.31%) / Dominion (52.77%) / EKPC (1.54%) / OVEC (0.06%) / PEPCO (14.54%)

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 (95.41%) / PPL (4.59%)
b2573	Replace the Warren 115 kV ‘B12’ breaker with a 40kA breaker		PENELEC (100%)
b2587	Reconfigure Pierce Brook 345 kV station to a ring bus and install a 125 MVAR shunt reactor at the station		PENELEC (100%)
b2621	Replace relays at East Towanda and East Sayre 115 kV substations (158/191 MVA SN/SE)		PENELEC (100%)
b2677	Replace wave trap, bus conductor and relay at Hilltop 115 kV substation. Replace relays at Prospect and Cooper substations		PENELEC (100%)
b2678	Convert the East Towanda 115 kV substation to breaker and half configuration		PENELEC (100%)
b2679	Install a 115 kV Venango Jct. line breaker at Edinboro South		PENELEC (100%)
b2680	Install a 115 kV breaker on Hooversville #1 115/23 kV transformer		PENELEC (100%)
b2681	Install a 115 kV breaker on the Eclipse #2 115/34.5 kV transformer		PENELEC (100%)

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

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

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

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

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

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

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

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

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

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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b3024	Upgrade terminal equipment at Corry East 115 kV to increase rating of Warren to Corry East 115 kV line. Replace bus conductor		PENELEC (100%)
b3043	Install one 115 kV 36 MVAR capacitor at West Fall 115 kV substation		PENELEC (100%)
b3073	Replace the Blairsville East 138/115 kV transformer and associated equipment such as breaker disconnects and bus conductor		PENELEC (100%)
b3077	Reconductor the Franklin Pike B – Wayne 115 kV line (6.78 miles)		PENELEC (100%)
b3078	Reconductor the 138 kV bus and replace the line trap, relays Morgan Street. Reconductor the 138 kV bus at Venango Junction		PENELEC (100%)
b3082	Construct 4-breaker 115 kV ring bus at Geneva		PENELEC (100%)
b3137	*Rebuild 20 miles of the East Towanda – North Meshoppen 115 kV line*		*PENELEC (100%)*
b3144	Upgrade bus conductor and relay panels of the Jackson Road – Nanty Glo 46 kV SJN line		PENELEC (100%)
b3144.1	Upgrade line relaying and substation conductor on the 46 kV Nanty Glo line exit at Jackson Road substation		PENELEC (100%)
b3144.2	Upgrade line relaying and substation conductor on the 46 kV Jackson Road line exit at Nanty Glo substation		PENELEC (100%)
b3154	Install one (1) 13.2 MVAR 46 kV capacitor at the Logan substation		PENELEC (100%)

- Attachment 7j (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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: AEC (4.19%) / DPL (5.88%) / JCPL (19.81%) / PECO (70.12%)
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 kV Center Point substation in PECO by tapping the Elroy – Whitpain 500 kV circuit		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)†
			DFAX Allocation: PECO (100%)

* Neptune Regional Transmission System, LLC

PECO Energy Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: PECO (100%)
b0269.7	Replace North Wales 230 kV breaker #105		PECO (100%)
b0269.10	Install a new 230 kV Center Point substation in PECO by tapping the North Wales – Perkiomen 230 kV circuit. Install a new 500/230 kV Center Point transformer		AEC (8.25%) / DPL (9.56%) / PECO (82.19%)††
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%

* 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)
b0280.4	Install 18 MVAR capacitor at Waverly 13.8 kV substation		PECO 100%
b0287	Install 600 MVAR Dynamic Reactive Device in Whitpain 500 kV vicinity		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: AEC (4.19%) / DPL (5.88%) / JCPL (19.81%) / PECO (70.12%)
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%)

* 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)
b0354	Eddystone – Island Road Upgrade line terminal equipment		PECO 100%
b0355	Reconductor Master – North Philadelphia 230 kV line		PECO 100%
b0357	Reconductor Buckingham – Pleasant Valley 230 kV		JCPL (37.17%) / Neptune* (4.46%) / PSEG (54.14%) / RE (2.32%) / ECP** (1.91%)
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%)

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

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 (0.72%) / JCPL (17.36%) / NEPTUNE* (1.70%) / PECO (44.47%) / ECP** (0.92%) / PSEG (33.52%) / RE (1.31%)
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 (17.30%) / NEPTUNE* (1.69%) / PECO (45.09%) / ECP** (0.93%) / PSEG (33.68%) / RE (1.31%)
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
**East Coast Power, L.L.C.

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%)

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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 (4.14%) / Neptune (0.44%) / PECO (82.19%) / ECP (0.33%) / HTP (0.32%) / PSEG (12.10%) / 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%)

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

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 (5.08%) / Neptune (0.54%) / PECO (78.85%) / ECP (0.39%) / HTP (0.38%) / PSEG (14.20%) / RE (0.56%)
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 (12.82%) / NEPTUNE (1.18%) / HTP (0.79%) / PECO (51.08%) / PEPCO (0.57%) / ECP** (0.85%) / PSEG (31.46%) / RE (1.25%)

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

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 (12.82%) / NEPTUNE (1.18%) / HTP (0.79%) / PECO (51.08%) / PEPCO (0.57%) / ECP** (0.85%) / PSEG (31.46%) / RE (1.25%)
b1398.12	Replace Graysferry 230 kV breaker ‘115’		PECO (100%)
b1398.13	Upgrade Peach Bottom 500 kV breaker ‘225’		AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)†
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 (3.05%) / ME (0.83%) / HTP (0.21%) / PECO (91.36%) / PEPCO (1.93%) / PPL (2.46%) / ECP** (0.16%)
b1591	Reconductor the underground portion of the Richmond – Waneeta 230 kV and replace terminal equipment		BGE (4.54%) / DL (0.27%) / ME (1.04%) / HTP (0.03%) / PECO (88.08%) / PEPCO (2.79%) / PPL (3.25%)

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

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		HTP (0.04%) / PECO (99.96%)
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 (69.62%) / JCPL (6.02%) / ATSI (1.23%) / PSEG (20.83%) / RE (0.83%) / NEPTUNE* (0.59%) / ECP** (0.45%) / HTP (0.43%)
b2140	Install a 3rd Emilie 230/138 kV transformer		PECO (97.04%) / ECP** (1.62%) / HTP (1.34%)
b2145	Replace two sections of conductor inside Richmond substation		PECO (100%)

* Neptune Regional Transmission System, LLC
**East Coast Power, L.L.C.
***Hudson Transmission Partners, 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 (3.97%)/ AEP (5.77%)/ APS (4.27%)/ ATSI (6.15%)/ BGE (1.63%)/ ComEd (0.72%)/ Dayton (1.06%)/ DEOK (1.97%)/ DL (2.25%)/ Dominion (0.35%)/ DPL (14.29%)/ ECP (0.69%)/ EKPC (0.39%)/ HTP (0.96%)/ JCPL (6.84%) MetEd (3.28%)/ Neptune (2.14%)/ PECO (16.42%)/ PENELEC (3.94%)/ PPL (8.32%)/ PSEG (14.13%)/ RECO (0.44%)
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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: AEC (1.12%) / ATSI (6.83%) / BGE (9.41%) / DPL (6.56%) / JCPL (17.79%) / NEPTUNE* (2.00%) / PEPCO (19.80%) / PSEG (35.05%) / RE (1.44%)

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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%)
b3041	Peach Bottom – Furnace Run 500 kV terminal equipment		PECO (100%)
b3120	Replace the Whitpain 230 kV breaker “125” with a 63 kA breaker		PECO (100%)
b3138	Move 2 MVA load from the Roxborough to Bala substation. Adjust the tap setting on the Master 138/69 kV transformer #2		PECO (100%)
b3146	*Upgrade the Richmond 69 kV breaker “140” with 40 kA breaker*		*PECO (100%)*

- Attachment 7k (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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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)
b0490.2	Replace Amos 138 kV breaker 'B'		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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)
b0490.3	Replace Amos 138 kV breaker 'B1'		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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)
b0490.4	Replace Amos 138 kV breaker ‘C’		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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)
b0490.5	Replace Amos 138 kV breaker ‘C1’		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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)
b0490.6	Replace Amos 138 kV breaker ‘D’		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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)
b0490.7	Replace Amos 138 kV breaker 'D2'		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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)
b0490.9	Replace Amos 138 kV breaker ‘E2’		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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 (75.06%) / APS (1.25%) / BGE (1.81%) / ComEd (5.91%) / Dayton (0.86%) / DL (1.23%) / DPL (0.95%) / Dominion (3.89%) / JCPL (1.58%) / NEPTUNE (0.15%) / HTP (0.07%) / PECO (2.08%) / PEPCO (1.66%) / ECP (0.07%)** / PSEG (2.62%) / RE (0.10%)
b1465.2	Replace the 100 MVAR 765 kV shunt reactor bank on Rockport – Jefferson 765 kV line with a 300 MVAR bank at Rockport Station		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: AEP (100%)

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

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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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: AEP (100%)
b1465.4	Make switching improvements at Sullivan and Jefferson 765 kV stations		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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 (87.22%) / BGE (1.03%) / ComEd (3.38%) / Dayton (1.23%) / DL (1.46%) / DPL (0.54%) / JCPL (0.90%) / NEPTUNE (0.09%) / HTP (0.04%) / PECO (1.18%) / PEPCO (0.94%) / ECP** (0.04%) / PSEG (1.48%) / RE (0.06%)
b1496	Replace 138 kV bus and risers at Johnson Mountain Station		AEP (100%)
b1497	Replace 138 kV bus and risers at Leesville Station		AEP (100%)
b1498	Replace 138 kV risers at Wurno Station		AEP (100%)
b1499	Perform a sag study on Sporn A – Gavin 138 kV to determine if the emergency rating can be improved		AEP (100%)
b1500	The North East Canton – Wagenhals 138 kV circuit would need an electrical clearance study to determine if the emergency rating can be utilized		AEP (100%)
b1501	The Moseley – Reusens 138 kV circuit requires a sag study to determine if the emergency rating can be utilized to address a thermal loading issue for a category C3		AEP (100%)

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

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1659.11	Replace Sorenson 138 kV breaker 'O'		AEP (100%)
b1659.12	Replace McKinley 138 kV breaker 'L1'		AEP (100%)
b1659.13	Establish 765 kV yard at Sorenson and install four 765 kV breakers		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: AEP (76.97%) / Dayton (10.17%) / DEOK (12.86%)
b1659.14	Build approximately 14 miles of 765 kV line from existing Dumont - Marysville line		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: AEP (61.24%) / ATSI (23.28%) / Dayton (5.43%) / DL (8.02%) / EKPC (1.78%) / OVEC (0.25%)

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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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: ATSI (25.80%) / Dayton (7.12%) / DEOK (17.02%) / Dominion (42.82%) / EKPC (7.24%)
b1661	Install a 765 kV circuit breaker at Wyoming station		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: AEP (100%)
b1664	Install switched capacitor banks at Kenwood 138 kV stations		AEP (100%)
b1665	Install a second 138/69 kV transformer at Thelma station		AEP (100%)
b1665.1	Construct a single circuit 69 kV line from West Paintsville to the new Paintsville station		AEP (100%)

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

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

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

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

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

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

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

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

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

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

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

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

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1962	Add four 765 kV breakers at Kammer		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			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 (33.51%) / ATSI (32.21%) / DL (18.64%) / Dominion (6.01%) / ECP** (0.10%) / HTP (0.11%) / JCPL (1.68%) / Neptune* (0.18%) / PENELEC (4.58%) / PSEG (2.87%) / RE (0.11%)
b1971	Perform a sag study to improve the emergency rating on the Bridgville – Chandlersville 138 kV line		AEP (100%)
b1972	Replace disconnect switch on the South Canton 765/345 kV transformer		AEP (100%)

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

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

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

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

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

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

*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)
b1570.4	Add a 345 kV breaker at Marysville station and a 0.1 mile 345 kV line extension from Marysville to the new 345/69 kV Dayton transformer		AEP (100%)
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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: ATSI (25.80%) / Dayton (7.12%) / DEOK (17.02%) / Dominion (42.82%) / EKPC (7.24%)

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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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: ATSI (3.01%) / Dayton (0.77%) / DEOK (1.85%) / Dominion (5.17%) / EKPC (0.79%) / PEPCO (88.41%)
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 (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: AEP (100%)
b2231	Install 765 kV reactor breaker at Dumont 765 kV substation on the Dumont - Wilton Center line		AEP (100%)
b2232	Install 765 kV reactor breaker at Marysville 765 kV substation on the Marysville - Maliszewski line		AEP (100%)
b2233	Change transformer tap settings for the Baker 765/345 kV transformer		AEP (100%)
b2252	Loop the North Muskingum - Crooksville 138 kV line into AEP's Philo 138 kV station which lies approximately 0.4 miles from the line		AEP (100%)

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

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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

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

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2394	Replace the Sporn 345 kV breaker 'CC1'		AEP (100%)
b2409	Install two 56.4 MVAR capacitor banks at the Melmore 138 kV station in Ohio		AEP (100%)
b2410	Convert Hogan Mullin 34.5 kV line to 138 kV, establish 138 kV line between Jones Creek and Strawton, rebuild existing Mullin Elwood 34.5 kV and terminate line into Strawton station, retire Mullin station		AEP (100%)
b2411	Rebuild the 3/0 ACSR portion of the Hadley - Kroemer Tap 69 kV line utilizing 795 ACSR conductor		AEP (100%)
b2423	Install a 300 MVAR shunt reactor at AEP's Wyoming 765 kV station		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: AEP (100%)

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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

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

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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

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

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2687.1	Install a +/- 450 MVAR SVC at Jacksons Ferry 765 kV substation		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: AEP (100%)

*Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2687.2	Install a 300 MVAR shunt line reactor on the Broadford end of the Broadford – Jacksons Ferry 765 kV line		**Load-Ratio Share Allocation:** AEC (1.72%) / AEP (14.18%) / APS (6.05%) / ATSI (7.92%) / BGE (4.23%) / ComEd (13.20%) / Dayton (2.05%) / DEOK (3.18%) / DL (1.68%) / DPL (2.58%) / Dominion (12.56%) / EKPC (1.94%) / JCPL (3.82%) / ME (1.88%) / NEPTUNE* (0.42%) / OVEC (0.08%) / PECO (5.31%) / PENELEC (1.90%) / PEPCO (3.90%) / PPL (5.00%) / PSEG (6.15%) / RE (0.25%)
			DFAX Allocation: AEP (100%)
b2697.1	Mitigate violations identified by sag study to operate Fieldale-Thornton-Franklin 138 kV overhead line conductor at its max. operating temperature. 6 potential line crossings to be addressed.		AEP (100%)
b2697.2	Replace terminal equipment at AEP's Danville and East Danville substations to improve thermal capacity of Danville – East Danville 138 kV circuit		AEP (100%)

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

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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

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

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2760	Perform a Sag Study of the Saltville – Tazewell 138 kV line to increase the thermal rating of the line		AEP (100%)
b2761.1	Replace the Hazard 161/138 kV transformer		AEP (100%)
b2761.2	Perform a Sag Study of the Hazard – Wooten 161 kV line to increase the thermal rating of the line		AEP (100%)
b2761.3	Rebuild the Hazard – Wooton 161 kV line utilizing 795 26/7 ACSR conductor (300 MVA rating)		AEP (100%)
b2762	Perform a Sag Study of Nagel – West Kingsport 138 kV line to increase the thermal rating of the line		AEP (100%)
b2776	Reconductor the entire Dequine – Meadow Lake 345 kV circuit #2		AEP (100%)
b2777	Reconductor the entire Dequine – Eugene 345 kV circuit #1		AEP (100%)
b2779.1	Construct a new 138 kV station, Campbell Road, tapping into the Grabill – South Hicksville138 kV line		AEP (100%)
b2779.2	Reconstruct sections of the Butler-N.Hicksville and Auburn-Butler 69 kV circuits as 138 kV double circuit and extend 138 kV from Campbell Road station		AEP (100%)

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2779.3	Construct a new 345/138 kV SDI Wilmington Station which will be sourced from Collingwood 345 kV and serve the SDI load at 345 kV and 138 kV, respectively		AEP (100%)
b2779.4	Loop 138 kV circuits in-out of the new SDI Wilmington 138 kV station resulting in a direct circuit to Auburn 138 kV and an indirect circuit to Auburn and Rob Park via Dunton Lake, and a circuit to Campbell Road; Reconductor 138 kV line section between Dunton Lake – SDI Wilmington		AEP (100%)
b2779.5	Expand Auburn 138 kV bus		AEP (100%)
b2787	Reconductor 0.53 miles (14 spans) of the Kaiser Jct. - Air Force Jct. Sw section of the Kaiser - Heath 69 kV circuit/line with 336 ACSR to match the rest of the circuit (73 MVA rating, 78% loading)		AEP (100%)
b2788	Install a new 3-way 69 kV line switch to provide service to AEP's Barnesville distribution station. Remove a portion of the #1 copper T-Line from the 69 kV through-path		AEP (100%)

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

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

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

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

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2817	Replace Delaware 138 kV breaker ‘P’ with a 40 kA breaker		AEP (100%)
b2818	Replace West Huntington 138 kV breaker ‘F’ with a 40 kA breaker		AEP (100%)
b2819	Replace Madison 138 kV breaker ‘V’ with a 63 kA breaker		AEP (100%)
b2820	Replace Sterling 138 kV breaker ‘G’ with a 40 kA breaker		AEP (100%)
b2821	Replace Morse 138 kV breakers ‘103’, ‘104’, ‘105’, and ‘106’ with 63 kA breakers		AEP (100%)
b2822	Replace Clinton 138 kV breakers ‘105’ and ‘107’ with 63 kA breakers		AEP (100%)
b2826.1	Install 300 MVAR reactor at Ohio Central 345 kV substation		AEP (100%)

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b2826.2	Install 300 MVAR reactor at West Bellaire 345 kV substation		AEP (100%)
b2831.1	Upgrade the Tanner Creek – Miami Fort 345 kV circuit (AEP portion)		**DFAX Allocation:** Dayton (34.34%) / DEOK (56.45%) / EKPC (9.21%)
b2832	Six wire the Kyger Creek – Sporn 345 kV circuits #1 and #2 and convert them to one circuit		AEP (100%)
b2833	Reconductor the Maddox Creek – East Lima 345 kV circuit with 2-954 ACSS Cardinal conductor		**DFAX Allocation:** Dayton (100%)
b2834	Reconductor and string open position and sixwire 6.2 miles of the Chemical – Capitol Hill 138 kV circuit		AEP (100%)
b2872	Replace the South Canton 138 kV breaker 'K2' with a 80 kA breaker		AEP (100%)
b2873	Replace the South Canton 138 kV breaker "M" with a 80 kA breaker		AEP (100%)
b2874	Replace the South Canton 138 kV breaker "M2" with a 80 kA breaker		AEP (100%)
b2878	Upgrade the Clifty Creek 345 kV risers		AEP (100%)
b2880	Rebuild approximately 4.77 miles of the Cannonsburg – South Neal 69 kV line section utilizing 795 ACSR conductor (90 MVA rating)		AEP (100%)

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

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

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

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2890.1	Rebuild 23.55 miles of the East Cambridge – Smyrna 34.5 kV circuit with 795 ACSR conductor (128 MVA rating) and convert to 69 kV		AEP (100%)
b2890.2	East Cambridge: Install a 2000 A 69 kV 40 kA circuit breaker for the East Cambridge – Smyrna 69 kV circuit		AEP (100%)
b2890.3	Old Washington: Install 69 kV 2000 A two way phase over phase switch		AEP (100%)
b2890.4	Install 69 kV 2000 A two way phase over phase switch		AEP (100%)
b2891	Rebuild the Midland Switch to East Findlay 34.5 kV line (3.31 miles) with 795 ACSR (63 MVA rating) to match other conductor in the area		AEP (100%)
b2892	Install new 138/12 kV transformer with high side circuit switcher at Leon and a new 138 kV line exit towards Ripley. Establish 138 kV at the Ripley station with a new 138/69 kV 130 MVA transformer and move the distribution load to 138 kV service		AEP (100%)
b2936.1	Rebuild approximately 6.7 miles of 69 kV line between Mottville and Pigeon River using 795 ACSR conductor (129 MVA rating). New construction will be designed to 138 kV standards but operated at 69 kV		AEP (100%)

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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%)
b2993	Rebuild the Torrey – South Gambrinus Switch – Gambrinus Road 69 kV line section (1.3 miles) with 1033 ACSR ‘Curlew’ conductor and steel poles		AEP (100%)
b3000	Replace South Canton 138 kV breaker ‘N’ with an 80kA breaker		AEP (100%)
b3001	Replace South Canton 138 kV breaker ‘N1’ with an 80kA breaker		AEP (100%)
b3002	Replace South Canton 138 kV breaker ‘N2’ with an 80kA breaker		AEP (100%)
b3036	Rebuild 15.6 miles of Haviland - North Delphos 138 kV line		AEP (100%)
b3037	Upgrades at the Natrium substation		AEP (100%)
b3038	Reconductor the Capitol Hill – Coco 138 kV line section		AEP (100%)
b3039	Line swaps at Muskingum 138 kV station		AEP (100%)
b3040.1	Rebuild Ravenswood – Racine tap 69 kV line section (~15 miles) to 69 kV standards, utilizing 795 26/7 ACSR conductor		AEP (100%)

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Required Transmission Enhancements Annual Revenue Requirement Responsible Customer(s)

b3040.2	Rebuild existing Ripley – Ravenswood 69 kV circuit (~9 miles) to 69 kV standards, utilizing 795 26/7 ACSR conductor		AEP (100%)
b3040.3	Install new 3-way phase over phase switch at Sarah Lane station to replace the retired switch at Cottageville		AEP (100%)
b3040.4	Install new 138/12 kV 20 MVA transformer at Polymer station to transfer load from Mill Run station to help address overload on the 69 kV network		AEP (100%)
b3040.5	Retire Mill Run station		AEP (100%)
b3040.6	Install 28.8 MVAR cap bank at South Buffalo station		AEP (100%)
b3051.2	Adjust CT tap ratio at Ronceverte 138 kV		AEP (100%)
b3085	Reconductor Kammer – George Washington 138 kV line (approx. 0.08 mile). Replace the wave trap at Kammer 138 kV		AEP (100%)
b3086.1	Rebuild New Liberty – Findlay 34 kV line Str’s 1–37 (1.5 miles), utilizing 795 26/7 ACSR conductor		AEP (100%)
b3086.2	Rebuild New Liberty – North Baltimore 34 kV line Str’s 1-11 (0.5 mile), utilizing 795 26/7 ACSR conductor		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b3086.3	Rebuild West Melrose – Whirlpool 34 kV line Str's 55–80 (1 mile), utilizing 795 26/7 ACSR conductor		AEP (100%)
b3086.4	North Findlay station: Install a 138 kV 3000A 63kA line breaker and low side 34.5 kV 2000A 40kA breaker, high side 138 kV circuit switcher on T1		AEP (100%)
b3086.5	Ebersole station: Install second 90 MVA 138/69/34 kV transformer. Install two low side (69 kV) 2000A 40kA breakers for T1 and T2		AEP (100%)
b3087.1	Construct a new greenfield station to the west (approx. 1.5 miles) of the existing Fords Branch Station in the new Kentucky Enterprise Industrial Park. This station will consist of six 3000A 40kA 138 kV breakers laid out in a ring arrangement, two 30 MVA 138/34.5 kV transformers, and two 30 MVA 138/12 kV transformers. The existing Fords Branch Station will be retired		AEP (100%)
b3087.2	Construct approximately 5 miles of new double circuit 138 kV line in order to loop the new Kewanee station into the existing Beaver Creek – Cedar Creek 138 kV circuit		AEP (100%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b3087.3	Remote end work will be required at Cedar Creek Station		AEP (100%)
b3095	Rebuild Lakin – Racine Tap 69 kV line section (9.2 miles) to 69 kV standards, utilizing 795 26/7 ACSR conductor		AEP (100%)
b3099	Install a 138 kV 3000A 40 kA circuit switcher on the high side of the existing 138/34.5 kV transformer No.5 at Holston station		AEP (100%)
b3100	Replace the 138 kV MOAB switcher “YY” with a new 138 kV circuit switcher on the high side of Chemical transformer No.6		AEP (100%)
b3101	Rebuild the 1/0 Cu. conductor sections (approx. 1.5 miles) of the Fort Robinson – Moccasin Gap 69 kV line section (approx. 5 miles) utilizing 556 ACSR conductor and upgrade existing relay trip limit (WN/WE: 63 MVA, line limited by remaining conductor sections)		AEP (100%)
b3102	Replace existing 50 MVA 138/69 kV transformers #1 and #2 (both 1957 vintage) at Fremont station with new 130 MVA 138/69 kV transformers		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)
b3103.1	Install a 138/69 kV transformer at Royerton station. Install a 69 kV bus with one 69 kV breaker toward Bosman station. Rebuild the 138 kV portion into a ring bus configuration built for future breaker and a half with four 138 kV breakers		AEP (100%)
b3103.2	Rebuild the Bosman/Strawboard station in the clear across the road to move it out of the flood plain and bring it up to 69 kV standards		AEP (100%)
b3103.3	Retire 138 kV breaker L at Delaware station and re-purpose 138 kV breaker M for the Jay line		AEP (100%)
b3103.4	Retire all 34.5 kV equipment at Hartford City station. Re-purpose breaker M for the Bosman line 69 kV exit		AEP (100%)
b3103.5	Rebuild the 138 kV portion of Jay station as a 6 breaker, breaker and a half station re-using the existing breakers “A”, “B”, and “G.” Rebuild the 69 kV portion of this station as a 6 breaker ring bus re-using the 2 existing 69 kV breakers. Install a new 138/69 kV transformer		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)
b3103.6	Rebuild the 69 kV Hartford City – Armstrong Cork line but instead of terminating it into Armstrong Cork, terminate it into Jay station		AEP (100%)
b3103.7	Build a new 69 kV line from Armstrong Cork – Jay station		AEP (100%)
b3103.8	Rebuild the 34.5 kV Delaware – Bosman line as the 69 kV Royerton – Strawboard line. Retire the line section from Royerton to Delaware stations		AEP (100%)
b3104	Perform a sag study on the Polaris – Westerville 138 kV line (approx. 3.6 miles) to increase the summer emergency rating to 310 MVA		AEP (100%)
b3105	Rebuild the Delaware – Hyatt 138 kV line (approx. 4.3 miles) along with replacing conductors at both Hyatt and Delaware substations		AEP (100%)
b3106	Perform a sag study (6.8 miles of line) to increase the SE rating to 310 MVA. Note that results from the sag study could cover a wide range of outcomes, from no work required to a complete rebuild		AEP (100%)
b3109	Rebuild 5.2 miles Bethel – Sawmill 138 kV line including ADSS		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b3112	Construct a single circuit 138 kV line (approx. 3.5 miles) from Amlin to Dublin using 1033 ACSR Curlew (296 MVA SN), convert Dublin station into a ring configuration, and re-terminating the Britton UG cable to Dublin station		AEP (100%)
b3116	Replace existing Mullens 138/46 kV 30 MVA transformer No.4 and associated protective equipment with a new 138/46 kV 90 MVA transformer and associated protective equipment		AEP (100%)
b3118.1	Expand existing Chadwick station and install a second 138/69 kV transformer at a new 138 kV bus tied into the Bellefonte – Grangston 138 kV circuit. The 69 kV bus will be reconfigured into a ring bus arrangement to tie the new transformer into the existing 69 kV via installation of four 3000A 63 kA 69 kV circuit breakers		AEP (100%)
b3118.2	Perform 138 kV remote end work at Grangston station		AEP (100%)
b3118.3	Perform 138 kV remote end work at Bellefonte station		AEP (100%)
b3118.4	Relocate the Chadwick – Leach 69 kV circuit within Chadwick 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)
b3118.5	Terminate the Bellefonte – Grangston 138 kV circuit to the Chadwick 138 kV bus		AEP (100%)
b3118.6	Chadwick – Tri-State #2 138 kV circuit will be reconfigured within the station to terminate into the newly established 138 kV bus #2 at Chadwick due to construability aspects		AEP (100%)
b3118.7	Reconductor Chadwick – Leach and Chadwick -– England Hill 69 kV lines with 795 ACSS conductor. Perform a LiDAR survey and a sag study to confirm that the reconductored circuits would maintain acceptable clearances		AEP (100%)
b3118.8	Replace the 20 kA 69 kV circuit breaker ‘F’ at South Neal station with a new 3000A 40 kA 69 kV circuit breaker. Replace line risers towards Leach station		AEP (100%)
b3118.9	Rebuild 336 ACSR portion of Leach – Miller S.S 69 kV line section (approx. 0.3 mile) with 795 ACSS conductor		AEP (100%)
b3118.10	Replace 69 kV line risers (towards Chadwick) at Leach station		AEP (100%)
b3119.1	Rebuild the Jay – Pennville 138 kV line as double circuit 138/69 kV. Build a new 9.8 mile single circuit 69 kV line from near Pennville station to North Portland station		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b3119.2	Install three (3) 69 kV breakers to create the “U” string and add a low side breaker on the Jay transformer 2		AEP (100%)
b3119.3	Install two (2) 69 kV breakers at North Portland station to complete the ring and allow for the new line		AEP (100%)
b3129	At Conesville 138 kV station: Remove line leads to generating units, transfer plant AC service to existing station service feeds in Conesville 345/138 kV yard, and separate and reconfigure protection schemes		AEP (100%)
b3131	At East Lima and Haviland 138 kV stations, replace line relays and wavetrap on the East Lima – Haviland 138 kV facility		AEP (100%)
b3132	Rebuild 3.11 miles of the LaPorte Junction – New Buffalo 69 kV line with 795 ACSR		AEP (100%)
b3139	*Rebuild the Garden Creek – Whetstone 69 kV line (approx. 4 miles)*		*AEP (100%)*
b3140	*Rebuild the Whetstone – Knox Creek 69 kV line (approx. 3.1 miles)*		*AEP (100%)*
b3141	*Rebuild the Knox Creek – Coal Creek 69 kV line (approx. 2.9 miles)*		*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)*
b3148.1	*Rebuild the 46 kV Bradley – Scarbro line to 96 kV standards using 795 ACSR to achieve a minimum rate of 120 MVA. Rebuild the new line adjacent to the existing one leaving the old line in service until the work is completed*		*AEP (100%)*
b3148.2	*Bradley remote end station work, replace 46 kV bus, install new 12 MVAR capacitor bank*		*AEP (100%)*
b3148.3	*Replace the existing switch at Sun substation with a 2-way SCADA-controlled motor-operated air-breaker switch*		*AEP (100%)*
b3148.4	*Remote end work and associated equipment at Scarbro station*		*AEP (100%)*
b3148.5	*Retire Mt. Hope station and transfer load to existing Sun station*		*AEP (100%)*
b3149	*Rebuild the 2.3 mile Decatur – South Decatur 69 kV line using 556 ACSR*		*AEP (100%)*
b3150	*Rebuild Ferguson 69/12 kV station in the clear as the 138/12 kV Bear station and connect it to an approx. 1 mile double circuit 138 kV extension from the Aviation – Ellison Road 138 kV line to remove the load from the 69 kV line*		*AEP (100%)*

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b3151.1	*Rebuild the 30 mile Gateway – Wallen 34.5 kV circuit as the 27 mile Gateway – Wallen 69 kV line*		*AEP (100%)*
b3151.2	*Retire approx. 3 miles of the Columbia – Whitley 34.5 kV line*		*AEP (100%)*
b3151.3	*At Gateway station, remove all 34.5 kV equipment and install one (1) 69 kV circuit breaker for the new Whitley line entrance*		*AEP (100%)*
b3151.4	*Rebuild Whitley as a 69 kV station with two (2) lines and one (1) bus tie circuit breaker*		*AEP (100%)*
b3151.5	*Replace the Union 34.5 kV switch with a 69 kV switch structure*		*AEP (100%)*
b3151.6	*Replace the Eel River 34.5 kV switch with a 69 kV switch structure*		*AEP (100%)*
b3151.7	*Install a 69 kV Bobay switch at Woodland station*		*AEP (100%)*
b3151.8	*Replace the Carroll and Churubusco 34.5 kV stations with the 69 kV Snapper station. Snapper station will have two (2) line circuit breakers, one (1) bus tie circuit breaker and a 14.4 MVAR cap bank*		*AEP (100%)*
b3151.9	*Remove 34.5 kV circuit breaker "AD" at Wallen station*		*AEP (100%)*
b3151.10	*Rebuild the 2.5 miles of the Columbia – Gateway 69 kV line*		*AEP (100%)*

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Required Transmission Enhancements		*Annual Revenue Requirement*	*Responsible Customer(s)*
b3151.11	*Rebuild Columbia station in the clear as a 138/69 kV station with two (2) 138/69 kV transformers and 4-breaker ring buses on the high and low side. Station will reuse 69 kV breakers "J" & "K" and 138 kV breaker "D"*		*AEP (100%)*
b3151.12	*Rebuild the 13 miles of the Columbia – Richland 69 kV line*		*AEP (100%)*
b3151.13	*Rebuild the 0.5 mile Whitley – Columbia City No.1 line as 69 kV*		*AEP (100%)*
b3151.14	*Rebuild the 0.5 mile Whitley – Columbia City No.2 line as 69 kV*		*AEP (100%)*
b3151.15	*Rebuild the 0.6 mile double circuit section of the Rob Park – South Hicksville / Rob Park – Diebold Road as 69 kV*		*AEP (100%)*
b3160.1	Construct an approx. 2.4 miles double circuit 138 kV extension using 1033 ACSR (Aluminum Conductor Steel Reinforced) to connect Lake Head to the 138 kV network		AEP (100%)
b3160.2	Retire the approx.2.5 miles 34.5 kV Niles – Simplicity Tap line		AEP (100%)
b3160.3	Retire the approx.4.6 miles Lakehead 69 kV Tap		AEP (100%)

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Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b3160.4	Build new 138/69 kV drop down station to feed Lakehead with a 138 kV breaker, 138 kV switcher, 138/69 kV transformer and a 138 kV Motor-Operated Air Break		AEP (100%)
b3160.5	Rebuild the approx.1.2 miles Buchanan South 69 kV Radial Tap using 795 ACSR (Aluminum Conductor Steel Reinforced)		AEP (100%)
b3160.6	Rebuild the approx.8.4 miles 69 kV Pletcher – Buchanan Hydro line as the approx. 9 miles Pletcher – Buchanan South 69 kV line using 795 ACSR (Aluminum Conductor Steel Reinforced)		AEP (100%)
b3160.7	Install a PoP (Point-of-Presence) switch at Buchanan South station with 2 line MOABs (Motor-Operated Air Break)		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)*
b3208	*Retire approximately 38 miles of the 44 mile Clifford – Scottsville 46 kV circuit. Build new 138 kV "in and out" to two new distribution stations to serve the load formerly served by Phoenix, Shipman, Schuyler (AEP), and Rockfish stations. Construct new 138 kV lines from Joshua Falls – Riverville (approx. 10 miles) and Riverville – Gladstone (approx. 5 miles). Install required station upgrades at Joshua Falls, Riverville and Gladstone stations to accommodate the new 138 kV circuits. Rebuild Reusen – Monroe 69 kV (approx. 4 miles)*		*AEP (100%)*
b3209	*Rebuild the 10.5 mile Berne – South Decatur 69 kV line using 556 ACSR*		*AEP (100%)*
b3210	*Replace approx. 0.7 mile Beatty – Galloway 69 kV line with 4000 kcmil XLPE cable*		*AEP (100%)*

- Attachment 8a ER18-680 FERC Order

170 FERC ¶ 61,295
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Neil Chatterjee, Chairman;
Richard Glick and Bernard L. McNamee.

PJM Interconnection, L.L.C. Docket No. ER18-680-000

ORDER ON COMPLIANCE FILING

(Issued March 31, 2020)

1. On January 19, 2018, PJM submitted proposed revisions to Schedule 12-Appendix and Schedule 12-Appendix A of the PJM Tariff to comply with the requirements of the December 15, 2017 Orders (January 19, 2018 Filing) as a result of the conversion of Linden VFT, LLC (Linden) and Hudson Transmission Partners, LLC (Hudson) Firm Transmission Withdrawal Rights to Non-Firm Transmission Withdrawal Rights.[1] These revisions reassign cost responsibility for certain transmission facilities, including Economic Projects and Lower Voltage Facilities, as defined below, which are included in Schedule 12-Appendix and Schedule 12-Appendix A, and for which the cost responsibility assignments were not included as part of the annual update of cost responsibility assignments filed pursuant to Schedule 12 of the PJM Tariff. PJM requests that the proposed revisions to Schedule 12-Appendix and Schedule 12-Appendix A be made effective on January 1, 2018.

2. In this order we accept in part and reject in part the January 19, 2018 Filing.

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[1] *Linden VFT, LLC v. Pub. Serv. Elec. & Gas Co.*, 161 FERC ¶ 61,264 (2017) (Linden Order), *order on reh'g*, 170 FERC ¶ 61,023 (2020); *PJM Interconnection, L.L.C.*, 161 FERC ¶ 61,262 (2017) (Hudson Order), *order on reh'g*, 170 FERC ¶ 61,021 (2020) (Linden Order and Hudson Order together, December 15, 2017 Orders); *PJM Interconnection, L.L.C.*, 162 FERC ¶ 61,201 (2018), (accepting proposed revisions to Linden's Interconnection Service Agreement, effective December 31, 2017, to reflect the conversion of Firm Transmission Withdrawal Rights to Non-Firm Transmission Withdrawal Rights); *PJM Interconnection, L.L.C.*, 162 FERC ¶ 61,200 (2018), (accepting proposed revisions to Hudson's Interconnection Service Agreement, effective December 15, 2017, to reflect the conversion of Firm Transmission Withdrawal Rights to Non-Firm Transmission Withdrawal Rights).

I. Background

3. In 2009, the Commission found that Merchant Transmission Facilities with Firm Transmission Withdrawal Rights are like loads in that they remove energy from PJM, thus requiring PJM to study deliverability of energy from the PJM system to the point of interconnection.[2] The Commission stated that "[a]s the system changes for a variety of reasons (e.g., retirements and load growth), it may be necessary to construct additional facilities in order to be able to provide the level of Firm Transmission Withdrawal Rights to which the customers subscribed."[3] Additionally, the Commission found that "PJM must plan its system to meet peak load on its system, including the full amount of the [Firm Transmission Withdrawal Rights] allocated to Merchant Transmission Facilities. Thus, these facilities legitimately can be charged their proportionate share of the upgrade costs needed to ensure such deliveries."[4]

4. The assignment of cost responsibility for Required Transmission Enhancements that are included in the PJM Regional Transmission Expansion Plan (RTEP) is included in the PJM Tariff at Schedule 12. Schedule 12 of the Tariff establishes Transmission Enhancement Charges and provides that "[o]ne or more of the Transmission Owners may be designated to construct and own and/or finance Required Transmission Enhancements by: (1) the [PJM RTEP] periodically developed pursuant to Operating Agreement, Schedule 6; or (2) any joint planning or coordination agreement between PJM and

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[2] *PJM Interconnection, L.L.C.*, Opinion No. 503, 129 FERC ¶ 61,161, at P 3 (2009) (Merchant Transmission Order). Firm Transmission Withdrawal Rights are defined in the PJM Tariff as the rights to schedule energy and capacity withdrawals from a Point of Interconnection of a Merchant Transmission Facility with the Transmission System. *See* PJM, Intra-PJM Tariffs, E-F, OATT Definitions – E - F, 22.1.0. Merchant Transmission Facilities are defined as "A.C. or D.C. transmission facilities that are interconnected with or added to the Transmission System pursuant to Tariff, Part IV and Part VI and that are so identified in Tariff, Attachment T, provided, however, that Merchant Transmission Facilities shall not include: (i) any Customer Interconnection Facilities; (ii) any physical facilities of the Transmission System that were in existence on or before March 20, 2003; (iii) any expansions or enhancements of the Transmission System that are not identified as Merchant Transmission Facilities in the Regional Transmission Expansion Plan and Attachment T to the Tariff; or (iv) any transmission facilities that are included in the rate base of a public utility and on which a regulated return is earned." PJM, Intra-PJM Tariffs, L-M-N, OATT Definitions – L – M - N, 21.1.0.

[3] Merchant Transmission Order, 129 FERC ¶ 61,161 at P 110.

[4] *Id*. P 73 (citing Initial Decision, 124 FERC ¶ 63,022 at P 66).

another region or transmission planning authority set forth in Tariff, Schedule 12-Appendix B."[5]

5. PJM assigns the costs of reliability projects that are selected in the RTEP for purposes of cost allocation pursuant to the cost allocation method that the Commission accepted in compliance with Order No. 1000.[6] Specifically, in the case of Regional Facilities and Necessary Lower Voltage Facilities that address a reliability need,[7] costs are allocated pursuant to a hybrid cost allocation method in which 50% of the costs of those facilities are allocated on a load-ratio share basis and the other 50% are allocated to the transmission owner zones based on the solution-based distribution factor (DFAX)

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[5] PJM, Intra-PJM Tariffs, Schedule 12, OATT Schedule 12, 14.0.0, § (a)(1). Required Transmission Enhancements are defined as "enhancements and expansions of the Transmission System that: (1) a [RTEP] developed pursuant to Operating Agreement, Schedule 6; or (2) any joint planning or coordination agreement between PJM and another region or transmission planning authority set forth in Tariff, Schedule 12-Appendix B ('Appendix B Agreement') designates one or more of the Transmission Owner(s) to construct and own or finance." PJM, Intra-PJM Tariffs, OATT Definitions – R - S, OATT Definitions – R - S, 18.2.0. Transmission Enhancement Charges are established to recover the revenue requirement with respect to a Required Transmission Enhancement. PJM, Intra-PJM Tariffs, Schedule 12, OATT Schedule 12, 14.0.0, § (a)(i).

[6] *See Transmission Planning & Cost Allocation by Transmission Owning & Operating Pub. Utils.*, Order No. 1000, 136 FERC ¶ 61,051 (2011), *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); *see also PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 (2013), *order on reh'g and compliance*, 147 FERC ¶ 61,128 (2014), *order on reh'g and compliance*, 150 FERC ¶ 61,038, *order on reh'g and compliance*, 151 FERC ¶ 61,250 (2015).

[7] Regional Facilities are defined as Required Transmission Enhancements included in the RTEP 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 § (b)(i)(D). PJM, Intra-PJM Tariffs, Schedule 12, OATT Schedule 12, 14.0.0, § (b)(i) (Regional Facilities and Necessary Lower Voltage Facilities). Necessary Lower Voltage Facilities are defined as Required Transmission Enhancements included in the RTEP that are lower voltage facilities that must be constructed or reinforced to support new Regional Facilities. *Id.*

method.[8] Pursuant to the cost allocation method that the Commission accepted in PJM's compliance with Order No. 1000, all of the costs of Lower Voltage Facilities are allocated using the solution-based DFAX method.[9] Prior to the cost allocation method accepted in compliance with Order No. 1000, assignment of cost responsibility for Lower Voltage Facilities was determined using a violation-based DFAX method.[10]

6. Schedule 12 also includes provisions for the assignment of cost responsibility for Required Transmission Enhancements included in RTEP to relieve one or more economic constraints which are determined to be Economic Projects.[11] As relevant in this filing, PJM allocates the costs of Economic Projects below 500 kV that are new enhancements or expansions based on the net present value of the changes in load energy payments over the first 15 years of the life of the Economic Project (load energy payment method).[12]

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[8] The solution-based DFAX method evaluates the projected relative use on the new Reliability Project by the load in each zone and withdrawals by Merchant Transmission Facilities, and through this power flow analysis, identifies projected benefits for individual entities in relation to power flows. *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 at P 416.

[9] Lower Voltage Facilities are defined as Required Transmission Enhancements that: (a) are not Regional Facilities; and (b) are not "Necessary Lower Voltage Facilities." PJM, Intra-PJM Tariffs, Schedule 12, OATT Schedule 12, 14.0.0, § (b)(ii) (Lower Voltage Facilities).

[10] Under the violation-based DFAX method, to determine cost responsibility for all new Required Transmission Enhancements, PJM conducted studies to determine which loads contribute to the reliability violation that caused the need for the upgrade by examining power flows on the constrained facilities at the time of a reliability violation. The zones that "cause" the violation and "benefit from" the addition of upgrades that eliminate the violation are allocated the costs of the Required Transmission Enhancements. *See PJM Interconnection, L.L.C.*, Opinion No. 494, 119 FERC ¶ 61,063, at PP 2 n.3, 69 (2007).

[11] *See* PJM, Intra-PJM Tariffs, OATT Schedule 12, OATT Schedule 12, 14.0.0, § (b)(v). Economic Projects are defined as Required Transmission Enhancements that relieve one or more economic constraints described in the PJM Operating Agreement Schedule 6, § 1.5.7(b)(iii). PJM, Intra-PJM Tariffs, OATT Schedule 12, OATT Schedule 12, 14.0.0, § (b)(i)(A)(2)(b).

[12] *Id.* § (b)(v)(C).

7. For the portion of cost responsibility for Regional Facilities and Necessary Lower Voltage Facilities assigned pursuant to the load-ratio share, Schedule 12 provides that with respect to Merchant Transmission Facilities, costs are allocated based on: (1) for the calendar year following the year in which it initiates operation, the actually awarded Firm Transmission Withdrawal Rights associated with its existing Merchant Transmission Facility; and (2) for all subsequent calendar years, the annual peak load of the Merchant Transmission Facility (not to exceed its actual Firm Transmission Withdrawal Rights) from the 12-month period ending October 31 of the calendar year preceding the calendar year for which the annual cost responsibility allocation is determined.[13] With respect to the portion of cost responsibility assigned in accordance with the solution-based DFAX method, zonal peak load shall mean (i) the existing Firm Transmission Withdrawal Rights of the Merchant Transmission Facility being evaluated, if the Merchant Transmission Facility is in service.[14]

8. Schedule 12 further provides that the collection of Transmission Enhancement Charges associated with Required Transmission Enhancements from a Merchant Transmission Facility is based on the actual Firm Transmission Withdrawal Rights that have been awarded to the Merchant Transmission Facility.[15]

9. As noted above, on December 15, 2017, the Commission allowed Hudson and Linden to amend their interconnection service agreements to convert their Firm Transmission Withdrawal Rights to Non-Firm Transmission Withdrawal Rights.

II. Filing

10. In the January 19, 2018 Filing, PJM proposes to implement the December 15, 2017 Orders to eliminate Hudson's and Linden's cost responsibility for those RTEP projects that are generally not updated in Schedule 12-Appendix or Schedule 12-Appendix A.[16] PJM cites to the December 15, 2017 Orders in which the Commission stated that "RTEP costs will no longer be allocable" as of the effective date of conversions from Firm Transmission Withdrawal Rights to Non-Firm Transmission Withdrawal Rights as support for the elimination of cost responsibility for Hudson and

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[13] *Id.* § 12(b)(i)(A)(1).

[14] *Id.* § (b)(iii)(A)(3).

[15] *Id.* § (b)(x)(B)(2).

[16] PJM states that in a separate filing, it proposed to eliminate any allocation of costs to Hudson and Linden effective January 1, 2018 for those upgrades that are annually updated under Schedule 12 of the Tariff. *See* Docket No. ER18-579-000.

Linden.[17] PJM states that it interprets the December 15, 2017 Orders as directing that all allocations to Hudson and Linden cease as of January 1, 2018, and thus PJM proposes to eliminate such cost responsibility by pro-rating the allocations to the remaining zones.[18]

11. PJM states that there are no provisions in Schedule 12 that address how PJM should implement the Commission's December 15, 2017 Orders, and that the instant filing represents PJM's good faith attempt to comply with the Commission's directive.[19] Specifically, PJM states that: (1) Schedule 12 does not provide for a mid-month or mid-year termination and recalculation of cost responsibility; (2) cost responsibility assignments for RTEP projects allocated using load-ratio share and solution-based DFAX are updated annually by December 31 to be effective on January 1 of the upcoming year; (3) RTEP cost responsibility assignments that use load-ratio share do not end at year end, but are based on the prior year's peak load and, therefore, such assignments roll off a year later; and (4) there are no provisions that permit PJM to reassign cost responsibility for Economic Projects below 500 kV or Lower Voltage Facilities that used the violation-based DFAX methodology.[20]

III. <u>Notice</u>

12. Notice of the January 19, 2018 Filing was published in the *Federal Register*, 83 Fed. Reg. 4,044 (Jan. 29, 2018), with interventions and protests due on or before February 9, 2018.

13. Notice of intervention was filed by the New Jersey Board of Public Utilities (New Jersey Board). Timely motions to intervene were filed by American Electric Power Service Corporation, The Daytona Power and Light Company, Exelon Corporation, Direct Energy, LLC, Dominion Energy Services, Inc., PPL Electric Utilities Corporation, Independent Market Monitor for PJM, Hudson, Linden, Power Supply Long Island and Long Island Power Authority, NRG Power Marketing, LLC and GenOn Energy Management LLC., American Municipal Power, Inc., New York Power Authority (NYPA), Public Service Electric and Gas Company, North Carolina Electric Membership Cooperative, and FirstEnergy Service Company.

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[17] PJM Transmittal at 7 (citing Linden Order, 161 FERC ¶ 61,264 at P 32; Hudson Order, 161 FERC ¶ 61,262 at P 50).

[18] *Id.* at 8.

[19] PJM Transmittal at 6-7.

[20] *Id.*

IV. Pleadings

14. Hudson and Linden filed comments in support of the January 19, 2018 Filing. The New Jersey Board, and the PJM Transmission Owners filed protests.[21] Hudson, Linden, and NYPA filed answers to the protests and PJM Transmission Owners filed an answer in response.

15. The New Jersey Board argues that eliminating the allocation to Hudson and Linden: (1) is the product of an unjust and unreasonable operation of the PJM Tariff; (2) will result in unduly burdensome costs on PJM customers, particularly in northern New Jersey, at a preference to New York load; and (3) is particularly egregious in light of the benefits retained by New York load regardless of the character of Hudson's and Linden's transmission rights.[22]

16. The PJM Transmission Owners contend that the PJM Tariff does not permit PJM to reallocate cost responsibility for Economic Projects below 500 kV or Lower Voltage Facilities cost assignments allocated using violation-based DFAX.[23] The PJM Transmission Owners contend that cost responsibility assignments for projects allocated using the violation-based DFAX method and Economic Projects below 500 kV projects are fixed when initially made and cannot later be reallocated.[24] The PJM Transmission Owners contend that the December 15, 2017 Orders addressed assignment of costs that are updated annually, and should not be read to disregard the fixed nature of cost responsibility assignments for projects in which cost responsibility is assigned under violation-based DFAX or for Economic Projects. With Economic Projects that accelerate or modify a Lower Voltage Facility reliability project, the PJM Transmission Owners further point out that the Commission acknowledged that the assignment of cost responsibility for such Economic Projects is a one-time affair and such assignments are not re-evaluated.[25]

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[21] PJM Transmission Owners, acting through the Consolidated Transmission Owners Agreement. PJM, Rate Schedules, TOA, TOA-42 Rate Schedule FERC No. 42, 1.0.0.

[22] New Jersey Board Protest at 4-5.

[23] PJM Transmission Owners Protest at 9.

[24] *Id.* at 10 (citing *Midwest Indep. Trans. Sys. Operator, Inc. & Duquesne Light Co*, 124 FERC ¶ 61,219 (2008) (*Duquesne*)).

[25] PJM Transmission Owners Protest at 11 (citing *PJM Interconnection, L.L.C.*, Opinion No. 503, 129 FERC ¶ 61,161 at P 133).

17. The PJM Transmission Owners contend that cost responsibility assignments that do not update annually were not contemplated by the December 15, 2017 Orders, and the only reasonable reading of the December 15, 2017 Orders is that the Commission intended PJM to limit the applicability to provisions of Schedule 12 to Linden's and Hudson's changed circumstances, i.e., their conversion of Firm Transmission Withdrawal Rights to Non-Firm Transmission Withdrawal Rights, but not when Schedule 12 does not explicitly provide for adjustments.

18. With respect to PJM's proposal to eliminate Hudson's and Linden's cost responsibility for all other RTEP projects under Schedule 12-Appendix A that were not previously revised in the Docket No. ER18-579-000 annual update filing (2018 Annual Update), the PJM Transmission Owners contend that the provisions of Schedule 12 do not result in the immediate reduction of RTEP cost responsibility to zero.[26] The PJM Transmission Owners maintain that Schedule 12 makes clear that cost responsibility assignments are based on conditions, including the levels of Firm Transmission Withdrawal Rights held by Merchant Transmission Facilities, in the specified period "*preceding* the calendar year for which the *annual* cost responsibility allocation is determined" and the RTEP base case inputs, again, including Merchant Transmission Facilities' Firm Transmission Withdrawal Rights, approved "*prior* to the date" of the annual update of Solution-based DFAX allocations.[27] Accordingly, the PJM Transmission Owners argue that PJM's proposal to eliminate Hudson's and Linden's cost responsibility assignments for these projects immediately is inconsistent with the applicable provisions of the PJM Tariff.

19. Linden answers that the PJM Transmission Owners' challenge to the January 19, 2018 Filing is a collateral attack on the December 15, 2017 Orders and is not properly raised in the context of a compliance filing.[28] Linden maintains that reallocation of the cost responsibility for transmission facilities included in Schedule 12-Appendix A is consistent with the provisions of Schedule 12, and that Schedule 12, section (b)(x)(B)(2) is a limitation on PJM's ability to recover RTEP costs from Merchant Transmission Facilities without Firm Transmission Withdrawal Rights.[29] Linden further contends that the PJM Transmission Owners' arguments regarding the allocation of costs as part of an annual update filing are inconsistent with *Duquesne*.[30] With respect to the assignment of

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[26] *Id.* at 12.

[27] *Id.* at 14 (emphasis in original).

[28] Linden Answer at 4.

[29] *Id.* at 6.

[30] *Id.* at 9.

cost responsibility for Economic Projects costs and for Lower Voltage Facilities assigned pursuant to the violation-based DFAX method, Linden maintains that the PJM Transmission Owners' arguments ignore the finding that Linden no longer holds Firm Transmission Withdrawal Rights, which is the basis of RTEP costs being allocated to Merchant Transmission Facilities.[31] Finally, Linden argues that it relied on the December 15, 2017 Orders, and it would be unjust and unreasonable to continue to allocate costs to Linden after it had converted its Firm Transmission Withdrawal Rights to Non-Firm Transmission Withdrawal Rights.[32]

20. In its answer, NYPA asserts that the PJM Transmission Owners' reading of Schedule 12 would read out the language of Schedule 12 limiting the collection of RTEP costs on the basis of Firm Transmission Withdrawal Rights.[33] NYPA contends that the PJM Transmission Owners' interpretation that cost responsibility assignments under a violation-based DFAX are fixed and not subject to an annual recalculation ignores the requirement for a Merchant Transmission Facility to hold Firm Transmission Withdrawal Rights in order for RTEP charges to apply.[34] NYPA argues that precluding reassignment of cost responsibility for Economic Projects, or costs for Lower Voltage Facilities assigned pursuant to the violation-based DFAX method, would be inconsistent with the reallocation of costs assigned to Consolidated Edison Company of New York with the termination of its transmission service agreements.[35] NYPA further argues that assignment of cost responsibility in *Duquesne* was not challenged and therefore does not prevent PJM from revising cost responsibility assignments to a Merchant Transmission Facility that has converted its Firm Transmission Withdrawal Rights to Non-Firm Transmission Withdrawal Rights.[36]

21. In response, the PJM Transmission Owners state that nothing in Schedule 12 permits reallocation or adjustment of cost responsibility for Economic Projects or for Lower Voltage Facilities costs assigned pursuant to the violation-based DFAX method. The PJM Transmission Owners also assert that Schedule 12, section (a)(v) prohibits

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[31] *Id.* at 11.

[32] *Id.* at 14.

[33] NYPA Answer at 5.

[34] *Id.*

[35] *Id.* at 7-8.

[36] *Id.*

changes to Schedule 12-Appendix, where the assignments of cost responsibility for Lower Voltage Facilities pursuant to the violation-based DFAX methodology are listed.[37]

V. Discussion

A. Procedural Matters

22. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2019), the notice of intervention and timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.

23. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2019), prohibits an answer to a protest unless otherwise ordered by the decisional authority. We accept the answers as they have provided information that assisted us in our decision-making process.

B. Substantive Matters

24. Based on its interpretation of the December 15, 2017 Orders, PJM proposes to eliminate the entirety of cost responsibility assignments for Merchant Transmission Facilities that converted their Firm Transmission Withdrawal Rights to Non-Firm Transmission Withdrawal Rights. As discussed below, we accept the Tariff revisions to Schedule 12-Appendix A, listed in Appendix 1 of this order, to be effective January 1, 2018, and we reject the Tariff revisions to Schedule 12-Appendix and Schedule 12-Appendix A listed in Appendix 2 of this order. Regarding the Tariff provisions that we are rejecting, based on the PJM Tariff, the Merchant Transmission Facilities remain responsible for the assignment of cost responsibility for Lower Voltage Facilities that use the pre-Order No. 1000 violation-based DFAX method. We also note that, for the Economic Projects at issue in this filing, the Tariff provides that the cost allocations for those projects rely on the load energy payment method, which is also fixed at the time the projects are included in the RTEP. We therefore do not accept PJM's proposal to eliminate the cost responsibility for these projects. We address these issues further below.

1. Collateral Attack on the December 15, 2017 Orders

25. We disagree with Linden's contention that the PJM Transmission Owners' protest of the January 19, 2018 Filing is a collateral attack on the December 15, 2017 Orders. This protest is not a collateral attack on the December 15, 2017 Orders as it does not challenge the Commission's determinations and underlying basis in the orders, but rather directly addresses PJM's proposed method of complying with the Commission's orders.

[37] PJM Response at 3-5.

Moreover, in addressing the PJM Transmission Owners' request for clarification of the December 15, 2017 Orders regarding the annual adjustments to assignment of cost responsibility to Merchant Transmission Facilities, the Commission expressly stated that it would address the cost allocation issues raised by the PJM Transmission Owners in pending cost allocation proceedings.[38] We therefore address the PJM Transmission Owners' contentions below.

2. New Jersey Board's Challenge to the Reasoning of the December 15, 2017 Orders

26. We find the arguments raised in the protest of the New Jersey Board to be beyond the scope of a challenge to a compliance filing. The New Jersey Board argues that the conversion of the Merchant Transmission Facilities' Firm Transmission Withdrawal Rights to Non-Firm Transmission Withdrawal Rights has resulted in unjust and unreasonable rates to New Jersey's ratepayers. The January 19, 2018 Filing is a compliance filing that only implements the December 15, 2017 Orders. The New Jersey Board does not contend that PJM has not correctly implemented the December 15, 2017 Orders. Its arguments instead go to the underlying basis of the December 15, 2017 Orders and therefore must be raised in a rehearing request, not a protest to the compliance filing implementing that order.[39]

3. PJM Transmission Owner's Protest to Reassignment of Cost Responsibility for 2018

27. We are not persuaded by the PJM Transmission Owners' protest of the January 1, 2018 effective date of the adjustment to the assignment of cost responsibility to Merchant Transmission Facilities included in Schedule 12-Appendix A that have been allocated under the load-ratio share and/or solution-based DFAX cost allocation methods, but that

[38] *PJM Interconnection, L.L.C.*, 170 FERC ¶ 61,021 at P 31 (denying rehearing of the Hudson Order); *PJM Interconnection, L.L.C.*, 170 FERC ¶ 61,023 at P 26 (denying rehearing of the Linden Order).

[39] The Commission also rejected similar arguments by the New Jersey Board in two other orders. Linden Order, 161 FERC ¶ 61,264 at P 31; Hudson Order, 161 FERC ¶ 61,262 at P 49. *See N.J. Bd. of Pub. Utils. v. PJM Interconnection, L.L.C.*, 163 FERC ¶ 61,139 (2018) (denying a complaint by the New Jersey Board alleging that the cost allocation resulting from the Merchant Transmission Facilities terminating their Firm Transmission Withdrawal Rights results in unjust and unreasonable rates for New Jersey ratepayers), *order on reh'g*, 170 FERC ¶ 61,180 (2020).

were not included in the 2018 Annual Update of cost responsibility.[40] In reviewing the 2018 Annual Update, the Commission was not persuaded by the PJM Transmission Owners' protest of the January 1, 2018 effective date for adjustment of cost responsibility of Merchant Transmission Facilities that convert their Firm Transmission Withdrawal Rights to Non-Firm Transmission Withdrawal Rights.[41] The Commission interpreted the provisions of Schedule 12 to provide that RTEP cost responsibility assignments and their corresponding updates, whether allocated through load-ratio share or solution-based DFAX, should be based on actual Firm Transmission Withdrawal Rights that exist at the time PJM makes the assignment of cost responsibility for the upcoming year, not on the determination of peak load used as an input to that calculation.[42] The Commission specifically stated that "[t]he yearly period ending on October 31 cited by PJM Transmission Owners is not relevant to the cost responsibility assignments for Merchant [Transmission] Facilities, because they no longer hold Firm Transmission Withdrawal Rights at the time the annual cost responsibility allocation is established at the beginning of the calendar year (i.e., January 1, 2018 for this filing)."[43] In this proceeding, the PJM Transmission Owners repeat arguments raised in their protest of the 2018 Annual Update, and have presented no further persuasive arguments on this issue. We therefore also accept PJM's proposed Tariff revisions to reassign cost responsibility for these transmission facilities,[44] consistent with the Commission's order accepting the 2018 Annual Update.

4. PJM Transmission Owners' Protest Regarding Reassignment of Prior Cost Assignments in Schedule 12-Appendix

28. We agree with the PJM Transmission Owners' protest that PJM should not have reassigned cost responsibility for the Lower Voltage Facilities that rely on the violation-based DFAX cost allocation method, which are identified in Schedule 12-Appendix. The December 15, 2017 Orders determined that, under Schedule 12, section (b)(x), the Merchant Transmission Facilities who relinquished their Firm Transmission Withdrawal

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[40] Specifically, projects b2218, b2766.1, and b2766.2. PJM also deleted footnote references to Hudson and Linden for project b2702, which was included in the 2018 Annual Update.

[41] *PJM Interconnection, L.L.C.*, 162 FERC ¶ 61,197 (2018); *reh'g denied*, 170 FERC ¶ 61,296 (2020).

[42] *PJM Interconnection, L.L.C.*, 162 FERC ¶ 61,197 at P 31 (citing PJM, Intra-PJM Tariffs, Schedule 12, OATT Schedule 12, 0.0.0, § 12(b)(x)(B)(2)).

[43] *Id.*

[44] *Supra* n.40.

Rights would not be responsible for ongoing cost allocations in Schedule 12-Appendix A as PJM redetermines those cost allocations every year based on the level of Firm Transmission Withdrawal Rights. Since the Merchant Transmission Facilities' Firm Transmission Withdrawal Rights would be reduced to zero once they relinquish those rights, the Commission found that they would no longer be responsible for future cost allocations. However, the requirements of Schedule 12, section (b)(x), and the Commission's aforementioned reasoning do not apply to prior cost allocations for Lower Voltage Facilities included in Schedule 12-Appendix. Indeed, Schedule 12, section (a)(v) provides specifically that the currently-effective provisions of Schedule 12 do not change the assignment of cost responsibility for Required Transmission Enhancements included in Schedule 12-Appendix:

> **Effective Date.** The assignment of cost responsibility or classification of Required Transmission Enhancements either (1) made by the Transmission Provider prior to February 1, 2013, or (2) applicable to Required Transmission Enhancements approved by the PJM Board pursuant to Operating Agreement, section 1.6 prior to February 1, 2013 are set forth in Tariff, Schedule 12-Appendix. *Except as specifically set forth herein, nothing in this Schedule 12 shall change the assignment of cost responsibility or classification of Required Transmission Enhancements included in Tariff, Schedule 12-Appendix. The assignment of cost responsibility or classification of all other Required Transmission Enhancements shall be set forth in Tariff, Schedule 12-Appendix A.*[45]

We therefore conclude that the Merchant Transmission Facilities remain responsible for the assignment of costs for the Lower Voltage Facilities included in Schedule 12-Appendix.[46]

[45] *See* PJM, Intra-PJM Tariffs, Schedule 12, OATT Schedule 12, 14.0.0, § 12(a)(v) (Effective Date) (emphasis added).

[46] Schedule 12-Appendix includes all the Required Transmission Enhancements for assigned costs the PJM Board approved prior to February 1, 2013. For Lower Voltage Facilities in Schedule 12-Appendix, the cost allocations do not change pursuant to Schedule 12, § (a)(v). For the costs of facilities planned to operate at or above 500 kV, including any Necessary Lower Voltage facilities, the costs are reallocated pursuant to Schedule 12 Appendix-C. PJM, Intra-PJM Tariffs, SCHEDULE 12-C, OATT SCHEDULE 12-C - Assignment of Cost Responsibility CTE, 0.0.0. *See PJM Interconnection L.LC.*, 163 FERC ¶ 61,168 (2018) (approving settlement of cost

29. Linden and NYPA maintain that, because the Merchant Transmission Facilities no longer hold Firm Transmission Withdrawal Rights, the provisions of Schedule 12 permit reallocation or adjustment of cost responsibility for Lower Voltage Facilities whose costs are assigned pursuant to the violation-based DFAX method. But as we explain above, Schedule 12, section (b)(x) does not affect the assignment of cost responsibility for projects identified in Schedule 12-Appendix (i.e., prior to February 1, 2013).

5. Assignment of the Costs of Economic Projects

30. Regarding the Economic Projects at issue in this filing, all of which are new enhancements or expansions, Schedule 12 applies the load energy payment method for allocating costs.[47] Because these allocations are not based on the level of Firm Transmission Withdrawal Rights held by the Merchant Transmission Facilities, they are still responsible for these costs because they are still transmission owners whose load benefits from these investments. Our finding here accords with the Commission's prior holding that the Merchant Transmission Facilities remain responsible for Targeted Market Efficiency Projects, because these calculations were not based on the level of Firm Transmission Withdrawal, but on the basis of congestion savings. The Merchant Transmission Facilities continue to benefit from these savings regardless of whether they hold Firm Transmission Withdrawal Rights.[48] For these reasons, we reject PJM's proposal to reassign cost responsibility from Hudson and Linden for the Economic Projects identified in PJM's compliance filing.

6. Further Compliance

31. Because we reject the proposed revisions to Schedule 12-Appendix and Schedule 12-Appendix A included in the January 19, 2018 Filing for: (1) Lower Voltage Facilities whose allocations are based on the violation-based DFAX method projects; and (2) Economic Projects, we require PJM to submit, within 60 days of the date of this

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responsibility for Regional Facilities and Necessary Lower Voltage Facilities approved by the PJM Board prior to February 1, 2013); Docket No. EL05-121-009, Settlement, § 2.2(a), Covered Transmission Enhancements, filed June 15, 2016.

[47] *Supra* P 6 & n.12.

[48] *PJM Interconnection, L.L.C,* et al., 164 FERC ¶ 61,002 at P 42 (2018), *order on reh'g and compliance*, 167 FERC ¶ 61,233 (2019), *order on reh'g*, 168 FERC ¶ 61,124 (2019) (allocation of costs to Merchant Transmission Facility for Targeted Market Efficiency Projects based on reductions in congestion costs to all Market Buyers are unrelated to the level of Firm Transmission Withdrawal Rights held by a Merchant Transmission Facility); PJM, Intra-PJM Tariffs, Schedule 12, OATT Schedule 12, 12.0.0, § 12(a)(xvii).

order, a filing in eTariff to make all Tariff corrections necessary to reflect the rejection of the proposed Tariff revisions included in Appendix 2 of this order. We note that we cannot partially reject Tariff sheets for PECO Energy Company under Schedule 12-Appendix A, and thus reject those sheets entirely but require PJM to refile Tariff sheets that only remove cost responsibility assignments for the Regional Facilities.[49]

The Commission orders:

(A) The January 19, 2018 proposed revisions to Schedule 12-Appendix A of the PJM Tariff as listed in Appendix 1 of this order are accepted to be effective January 1, 2018, as discussed in body of this order.

(B) PJM is directed to make a compliance filing eliminating the Tariff revisions included in the January 19, 2018 filing for revisions to Schedule 12-Appendix and Schedule 12-Appendix A of the PJM Tariff, as listed in Appendix 2 of this order, as discussed in the body of this order.

(C) PJM is directed, within 60 days of the date of this order, to make a filing in eTariff to make all Tariff corrections necessary to reflect the rejection of the proposed Tariff revisions included in Appendix 2 of this order, as discussed in the body of this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

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[49] The revised Tariff sheets for Schedule 12-Appendix A for PECO Energy Company reassign cost responsibility for multiple categories of RTEP projects: (1) Regional Facilities, for which costs were assigned using the load-ratio share and solution-based DFAX allocation methods; and (2) Economic Projects below 500 kV, for which costs were assigned using the load energy payment method. Because we cannot partially accept or reject this Tariff record, we include this record in Appendix 2.

Appendix 1

PJM Interconnection, L.L.C., Intra-PJM Tariffs

SCHEDULE 12.APPX A - 2, OATT SCHEDULE 12.APPENDIX A - 2 Baltimore Gas and Electric, 6.0.1

SCHEDULE 12.APPX A - 12, OATT SCHEDULE 12.APPENDIX A - 12 Public Service Electric and, 15.0.3

Appendix 2

PJM Interconnection, L.L.C., Intra-PJM Tariffs

SCHEDULE 12.APPENDIX 1, OATT SCHEDULE 12.APPENDIX 1 Atlantic City Electric Company, 15.0.0

SCHEDULE 12.APPENDIX 2, OATT SCHEDULE 12.APPENDIX 2 Baltimore Gas and Electric Com, 10.0.0

SCHEDULE 12.APPENDIX 3, OATT SCHEDULE 12.APPENDIX 3 Delmarva Power & Light Company, 16.0.0

SCHEDULE 12.APPENDIX 4, OATT SCHEDULE 12.APPENDIX 4 Jersey Central Power & Light C, 10.0.0

SCHEDULE 12.APPENDIX 5, OATT SCHEDULE 12.APPENDIX 5 Metropolitan Edison Company, 19.0.0

SCHEDULE 12.APPENDIX 7, OATT SCHEDULE 12.APPENDIX 7 Pennsylvania Electric Company, 20.0.0

SCHEDULE 12.APPENDIX 8, OATT SCHEDULE 12.APPENDIX 8 PECO Energy Company, 18.0.0

SCHEDULE 12.APPENDIX 9, OATT SCHEDULE 12.APPENDIX 9 PPL Electric Utilities Corpora, 18.0.0

SCHEDULE 12.APPENDIX 10, OATT SCHEDULE 12.APPENDIX 10 Potomac Electric Power Compan, 17.0.0

SCHEDULE 12.APPENDIX 12, OATT SCHEDULE 12.APPENDIX 12 Public Service Electric and G, 19.0.0

SCHEDULE 12.APPENDIX 14, OATT SCHEDULE 12.APPENDIX 14 Monongahela Power Company, Th, 21.0.0

SCHEDULE 12.APPENDIX 15, OATT SCHEDULE 12.APPENDIX 15 Commonwealth Edison Company, 8.0.0

SCHEDULE 12.APPENDIX 17, OATT SCHEDULE 12.APPENDIX 17 AEP Service Corporation, 19.0.0

SCHEDULE 12.APPENDIX 23, OATT SCHEDULE 12.APPENDIX 23 American Transmission Systems, 6.0.0

SCHEDULE 12.APPX A - 8, OATT SCHEDULE 12.APPENDIX A - 8 PECO Energy Company, 10.0.2

SCHEDULE 12.APPX A - 15, OATT SCHEDULE 12.APPENDIX A - 15 Commonwealth Edison Company, 8.0.1

SCHEDULE 12.APPX A - 18, OATT SCHEDULE 12.APPENDIX A - 18 Duquesne Light Company, 3.0.0

SCHEDULE 12.APPX A - 20, OATT SCHEDULE 12.APPENDIX A - 20 Virginia Electric and Power, 14.0.2

- Attachment 8b FERC Order

171 FERC ¶ 61,012
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Neil Chatterjee, Chairman;
Richard Glick and Bernard L. McNamee.

PJM Interconnection, L.L.C. Docket Nos. ER15-1387-005
ER15-1344-006

ORDER DENYING REHEARING AND GRANTING CLARIFICATION

(Issued April 3, 2020)

1. On August 3, 2018, the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) reversed the Commission's acceptance of a March 26, 2015 proposal from the PJM Interconnection, L.L.C. (PJM) Transmission Owners to revise the PJM Open Access Transmission Tariff (PJM Tariff) pursuant to section 205 of the Federal Power Act (FPA).[1] PJM Transmission Owners had proposed to allocate 100 percent of the costs of projects that are included in the PJM Regional Transmission Expansion Plan (RTEP) solely to address individual transmission owner Form No. 715 local planning criteria to the transmission zone of the transmission owner whose Form No. 715 local planning criteria underlie each project (2015 PJM Transmission Owner Tariff Revision). The D.C. Circuit remanded the case to the Commission for further proceedings.[2]

2. On August 30, 2019, the Commission issued an order on remand rejecting the 2015 PJM Transmission Owner Tariff Revision and directing PJM to make a filing in eTariff to make all tariff corrections necessary to reflect the rejection of the 2015 PJM

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[1] *PJM Interconnection, L.L.C.*, 154 FERC ¶ 61,096 (February 2016 Order), *reh'g denied*, 157 FERC ¶ 61,192 (2016), *rev'd sub nom. Old Dominion Elec. Coop. v. FERC* (*Old Dominion*), 898 F.3d 1254, *reh'g denied*, 905 F.3d 671 (D.C. Cir. 2018); 16 U.S.C. § 824d (2018).

[2] The appeal challenged both the orders in Docket No. ER15-1387 accepting the 2015 PJM Transmission Owner Tariff Revision and the orders in Docket No. ER15-1344 applying the revised PJM Tariff to specific projects. The D.C. Circuit set aside the orders under review to the extent they applied the 2015 PJM Transmission Owner Tariff Revision to specific projects at issue. *Old Dominion*, 898 F.3d at 1264.

Transmission Owner Tariff Revision.[3] The Commission also directed PJM to refile the assignment of cost responsibility in Schedule 12-Appendix A, of the PJM Tariff for transmission projects included in the RTEP between May 25, 2015, and the date of Order on Remand that solely address individual transmission owner Form No. 715 local planning criteria, consistent with that order.[4]

3. On September 23, 2019, Old Dominion Electric Cooperative (ODEC) and Dominion Energy Services, Inc. (Dominion) on behalf of Virginia Electric and Power Company filed a request for clarification and rehearing (ODEC and Dominion Request for Clarification).

4. On September 30, 2019, Consolidated Edison Company of New York, Inc. (Con Edison) filed a request for rehearing (Con Edison Request for Rehearing). Also, on September 30, 2019, Linden VFT, LLC (Linden) filed an answer to ODEC and Dominion's request for clarification and a request for rehearing (Linden Answer and Request for Rehearing).

5. As discussed below, ODEC and Dominion's request for clarification is granted. Con Edison and Linden's requests for rehearing are denied.

I. Background

6. The factual background and procedural history are discussed in detail in the Order on Remand and will not be repeated here.[5]

7. Schedule 12 of the Tariff establishes Transmission Enhancement Charges and allows that "[o]ne or more of the Transmission Owners may be designated to construct and own and/or finance Required Transmission Enhancements by (1) the [PJM RTEP] periodically developed pursuant to Operating Agreement, Schedule 6 or (2) any joint planning or coordination agreement between PJM and another region or transmission planning authority set forth in Tariff, Schedule 12-Appendix B."[6] PJM assigns the costs

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[3] *PJM Interconnection, L.L.C.* (Order on Remand), 168 FERC ¶ 61,133, at P 2 (2019).

[4] *Id.*

[5] *See* Order on Remand, 168 FERC ¶ 61,133 at PP 3-18.

[6] PJM, Intra-PJM Tariffs, Schedule 12, OATT Schedule 12, 14.0.0, § (a)(1). Required Transmission Enhancements are defined as "enhancements and expansions of the Transmission System that (1) a [RTEP] developed pursuant to Operating Agreement, Schedule 6 or (2) any joint planning or coordination agreement between PJM and another region or transmission planning authority set forth in Tariff, Schedule 12-Appendix B

of reliability projects that are selected in the RTEP for purposes of cost allocation pursuant to the cost allocation method that the Commission accepted in compliance with Order No. 1000.[7] Specifically, in the case of Regional Facilities and Necessary Lower Voltage Facilities that address a reliability need,[8] costs are allocated pursuant to a hybrid cost allocation method in which 50 percent of the costs of those facilities are allocated on a load-ratio share basis and the other 50 percent are allocated to the transmission owner zones based on the solution-based distribution factor (DFAX) method.[9] Prior to the 2015 PJM Transmission Owner Tariff Revision at issue in this proceeding, PJM assigned the costs of reliability projects that are included in the RTEP solely to address individual transmission owner Form No. 715 local planning criteria according to the PJM cost

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('Appendix B Agreement') designates one or more of the Transmission Owner(s) to construct and own or finance." PJM, Intra-PJM Tariffs, OATT Definitions – R - S, OATT Definitions – R - S, 18.2.0. Transmission Enhancement Charges are established to recover the revenue requirement with respect to a Required Transmission Enhancement. PJM, Intra-PJM Tariffs, Schedule 12, OATT Schedule 12, 14.0.0, § (a)(i).

[7] *See Transmission Planning & Cost Allocation by Transmission Owning & Operating Pub. Utils.*, Order No. 1000 (Order No. 1000), 136 FERC ¶ 61,051 (2011), *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); *see also PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 (2013), *order on reh'g and compliance*, 147 FERC ¶ 61,128 (2014), *order on reh'g and compliance*, 150 FERC ¶ 61,038, *order on reh'g and compliance*, 151 FERC ¶ 61,250 (2015).

[8] Regional Facilities are defined as Required Transmission Enhancements included in the RTEP 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). PJM, Intra-PJM Tariffs, Schedule 12, OATT Schedule 12, 14.0.0, § (b)(i) (Regional Facilities and Necessary Lower Voltage Facilities). Necessary Lower Voltage Facilities are defined as Required Transmission Enhancements included in the RTEP that are lower voltage facilities that must be constructed or reinforced to support new Regional Facilities. PJM, Intra-PJM Tariffs, Schedule 12, OATT Schedule 12, 14.0.0, § (b)(i) (Regional Facilities and Necessary Lower Voltage Facilities).

[9] *See PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 at P 416 (the solution-based DFAX method "evaluates the projected relative use of a new Reliability Project by load in each zone and withdrawals by merchant transmission facilities, and through this power flow analysis, identifies projected benefits for individual entities in relation to power flows").

allocation method accepted in compliance with Order No. 1000.[10] As relevant here, PJM used the solution-based DFAX method for 100 percent of the costs assigned pursuant to Lower Voltage Facilities to identify the beneficiaries of those facilities.[11]

8. As noted above, PJM Transmission Owners proposed the 2015 PJM Transmission Owner Tariff Revision to revise the PJM Tariff to allocate 100 percent of costs for projects that are included in the RTEP solely to address individual transmission owner Form No. 715 local planning criteria to the transmission zone of the transmission owner whose Form No. 715 local planning criteria underlie each project.[12] The Commission ultimately approved this filing.[13]

9. Subsequently, the D.C. Circuit found that the Commission acted arbitrarily and capriciously in approving the 2015 PJM Transmission Owner Tariff Revision and applying it to high-voltage projects, granted the petition for review, set aside the Commission orders, and remanded the case to the Commission for further proceedings consistent with the court's opinion.[14]

10. The D.C. Circuit stated that the 2015 PJM Transmission Owner Tariff Revision violated the cost-causation principle that requires "comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party."[15] The D.C. Circuit found that, given the significant regional benefits of high-voltage transmission facilities, the Commission's decision to approve the 2015 PJM Transmission Owner Tariff Revision was arbitrary. The D.C. Circuit found that "the amendment denies cost sharing for *all* projects included in the Regional Plan only to satisfy the planning criteria of individual

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[10] *See supra* note 7.

[11] Lower Voltage Facilities are defined as Required Transmission Enhancements that: (a) are not Regional Facilities; and (b) are not "Necessary Lower Voltage Facilities." PJM, Intra-PJM Tariffs, Schedule 12, OATT Schedule 12, 14.0.0, § (b)(ii) (Lower Voltage Facilities).

[12] PJM Transmission Owners, Transmittal, Docket No. ER15-1387-000, at 2 (filed Mar. 26, 2015).

[13] *PJM Interconnection, L.L.C.*, 151 FERC ¶ 61,172, *granting reh'g*, 154 FERC ¶ 61,096, *reh'g denied*, 157 FERC ¶ 61,192.

[14] As previously noted, the D.C. Circuit set aside the orders under review to the extent they applied the 2015 PJM Transmission Owner Tariff Revision to the projects at issue. *Old Dominion*, 898 F.3d at 1264.

[15] *Old Dominion*, 898 F.3d at 1261 (internal citations omitted).

utilities—*including* for high-voltage transmission facilities"[16] and found that "the cost-causation principle focuses on project benefits."[17] Accordingly, the D.C. Circuit concluded that the 2015 PJM Transmission Owner Tariff Revision "produced a severe misallocation of the costs of such projects," stating that the Tariff revisions "involve a wholesale departure from the cost-causation principle, which would shift a disproportionate share of [the] costs" of these high-voltage projects to a single zone.[18]

11. In the Order on Remand, the Commission rejected the 2015 PJM Transmission Owner Tariff Revision as unjust and unreasonable as inconsistent with the cost-causation principle.[19]

12. In addressing remedies, the Commission found:

> Because we reject the 2015 PJM Transmission Owner Tariff Revision, we require PJM to make a filing in eTariff to make all tariff corrections necessary to reflect the rejection of the 2015 PJM Transmission Owner Tariff Revision. We also must address the cost assignment of those projects that were included in the RTEP starting on May 25, 2015 solely to address individual transmission owner Form No. 715 local planning criteria. Consistent with our action in the December 2016 Order, we require PJM to correct the cost assignment for projects included in the RTEP solely to address individual transmission owner Form No. 715 local planning criteria that were allocated incorrectly for the period starting on, and continuing after, May 25, 2015. The courts have recognized that section 309 of the FPA provides the Commission with broad remedial authority, including in situations where the Commission has made a legal error. In exercising this remedial authority, the Commission "will

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[16] *Id.* (emphasis in original).

[17] *Id.* at 1262.

[18] *Id.* (citing *Ill. Commerce Comm'n v. FERC*, 756 F.3d 556, 565 (7th Cir. 2014)). The D.C. Circuit further noted that the cost-causation principle requires "comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party." *Id.* (citing *Midwest ISO Transmission Owners*, 373 F.3d 1361, 1368 (D.C. Cir. 2004)).

[19] Order on Remand, 168 FERC ¶ 61,133 at P 24.

> consider whether to require refunds in cost allocation and rate design cases based on the specific facts and equities of each case."
>
> We find, based on the specific facts and equities of this case, that it is appropriate to require PJM to correct the cost assignments.[20]

II. Requests for Rehearing and Clarification

13. ODEC and Dominion request clarification that the Order on Remand "requires PJM's compliance filing to include a calculation of refunds, plus interest, resulting from the reallocation of costs directed by the Commission."[21] ODEC and Dominion note that the Order on Remand "specifically directed that 'PJM's cost assignment corrections must be in accordance [with] 18 C.F.R. § 35.19(a)(2019)' which is the provision of the Commission's Regulations which details the requirement to make refunds, plus interest."[22] In the alternative, if ODEC and Dominion's request for clarification is denied and the Commission finds that the Order on Remand did not require refunds, ODEC and Dominion request rehearing of this determination.[23]

14. Linden argues that ODEC and Dominion's Request for Clarification should be rejected because Linden contends that the Order on Remand does not require refunds to be paid. In the alternative, Linden requests rehearing of the Order on Remand.[24] Linden argues that requiring refunds where an error has occurred is discretionary and should not be done where recovering the costs would be difficult and customers have made decisions in reliance on the previous rates.[25] Linden argues that the Commission's default position is not to require refunds in rate design cases such as this one.[26] Linden argues that it has made fundamental changes to its business model in reliance on the previous rates. Linden states it has shifted transmission withdrawal rights from firm to

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[20] *Id.* PP 29-30 (internal citations omitted).

[21] ODEC and Dominion Request for Clarification at 3-6.

[22] *Id.* at 4 (quoting Order on Remand, 168 FERC ¶ 61,133 at P 29 n. 43).

[23] *Id.* at 6-9.

[24] Linden Answer and Request for Rehearing at 16.

[25] *Id.* at 12-13, 19-22.

[26] *Id.* at 4, 12.

non-firm to avoid RTEP costs related to the Sewaren Project,[27] and entered into a new transmission scheduling rights purchase agreement, premised on the idea that it would not face additional RTEP charges.[28] Further, Linden states that if the Commission grants ODEC and Dominion's Request for Clarification and PJM reverts to its previously-used solution-based DFAX method, then Linden will be burdened with 100 percent of the Sewaren Project costs despite only receiving around 38 percent of the benefits.[29] Linden states that unless the Commission adopts Linden's position, its expenses will exceed its revenues and Linden's economic viability will be impacted.[30]

15. Linden states that the Commission insufficiently explained the basis for its ruling requiring refunds,[31] departed from its own reasoning and principles of cost allocation, and failed to ensure that rates are just and reasonable.[32]

16. Similarly, Con Edison argues that the Commission erred by requiring retroactive correction of costs related to the Sewaren Project, and by failing to differentiate between low- and high-voltage projects when determining equitable remedies.[33] Con Edison argues that the D.C. Circuit focused on high-voltage projects and that the concerns the D.C. Circuit cited "had nothing to do with low-voltage projects" like the Sewaren Project.[34] Con Edison echoes Linden's arguments that PSEG was the true beneficiary of the Sewaren Project.[35] Con Edison argues that, at a minimum, the Commission should "defer its exercise of its refund authority pending its determination, on the merits, of the

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[27] Linden states that the Sewaren Project was a $125 million low-voltage project undertaken to address the needs of Public Service Electric & Gas Company (PSEG). *Id.* at 4, 8.

[28] *Id.*

[29] *Id.* at 15, 21.

[30] *Id.* at 14.

[31] *Id.* at 22-23.

[32] *Id.* at 23-28.

[33] Con Edison Request for Rehearing at 8-10.

[34] *Id.* at 6.

[35] *Id.* at 9.

multiple cost allocation rehearing requests pertaining to [the Sewaren Project] that remain pending before it."[36]

III. Commission Determination

17. Rule 713(d)(1) of the Commission's Rules of Practice and Procedure prohibits an answer to a request for rehearing.[37] However, the Commission has considered responses to motions for clarification in certain circumstances,[38] and we consider Linden's answer to ODEC and Dominion's request for clarification here because it has provided information that aids the Commission in its decision-making process.

A. Requirement for Refunds

18. We grant ODEC and Dominion's request for clarification, and clarify that the Order on Remand requires PJM to rebill parties with interest. The Commission's Order on Remand stated that "it is appropriate to require PJM to correct the cost assignments" and directed PJM to make a filing in eTariff to make all tariff corrections necessary to reflect the rejection of the 2015 PJM Transmission Owner Tariff Revision, and refile the cost responsibility assignments in Schedule 12-Appendix A.[39] In requiring PJM to correct cost responsibility assignments, the Commission cited to 18 C.F.R. § 35.19(a) (2019), which details the requirements for providing refunds.[40] Thus, the Order on Remand requires PJM to issue refunds dating back to May 25, 2015.

19. We deny Linden's request for rehearing as to refunds. The Commission has broad remedial authority to correct Commission legal error,[41] and we continue to find that ordering refunds here is appropriate. In fashioning a remedy in this proceeding, the Commission has followed the equitable principle "to regard as being done that which

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[36] *Id.* at 4, 11 (citing *See Consol. Edison Co. of N.Y., Inc. v. PJM Interconnection, L.L.C.*, Request for Rehearing, Docket Nos. EL15-67; ER15-2562-002 (filed May 23, 2016)).

[37] 18 C.F.R. § 385.713(d)(1) (2019).

[38] *See El Paso Nat. Gas Co., L.L.C.*, 152 FERC ¶ 61,039, at P 12 (2015).

[39] Order on Remand, 168 FERC ¶ 61,133 at PP 30-31.

[40] *Id.* P 29 n.43

[41] *Id.* P 29 (citing *Xcel Energy Servs. Inc. v. FERC*, 815 F.3d 947, 954-55 (D.C. Cir. 2016)).

should have been done."[42] In other words, the Commission found that an equitable remedy is to apply the cost allocation methods that would have been applied had the Commission not committed legal error in accepting the 2015 PJM Transmission Owner Tariff Revision, including the application of the solution-based DFAX method to assign cost responsibility for the Sewaren Project.

20. Linden argues that the Commission's "default" policy is to reject refunds in cases of rate design.[43] However, as the case cited by Linden notes, the Commission does not have a general policy concerning refunds.[44] Rather, "the Commission will consider whether to require refunds in cost allocation and rate design cases based on the specific facts and equities of each case, even where such refunds must be funded through surcharges on certain parties."[45] Here, the Commission has found the facts and equities favor refunds. For example, requiring refunds in this case requires only redetermining past payments; it does not involve the difficult issues often associated with the re-running of auctions.[46]

21. Linden maintains that the Commission should not require refunds and surcharges because it made business decisions in reliance on the Commission's initial cost allocation.[47] Linden argues further that it shifted its transmission withdrawal rights from firm to non-firm and entered into a new transmission scheduling rights purchase agreement following the February 2016 Order accepting the 2015 PJM Transmission

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[42] *Xcel Energy Servs. Inc.*, 815 F.3d at 954-55.

[43] Linden Answer and Request for Rehearing at 12 (citing *La. Pub. Serv. Comm'n v. FERC*, 883 F.3d 929, 931-33 (D.C. Cir. 2018)).

[44] *La. Pub. Serv. Comm'n*, 883 F.3d at 931 (noting the Commission "has no general policy of ordering refunds in cases of rate design").

[45] *Black Oak Energy, LLC v. PJM Interconnection, L.L.C.*, 167 FERC ¶ 61,250, at P 27 (2019).

[46] *Compare id.* PP 28-34 (requiring refunds and surcharges when doing so would not require re-running the market) *with PJM Interconnection, L.L.C.*, 161 FERC ¶ 61,252 (2017) (not requiring refunds and surcharges when doing so would entail complicated issues related to re-running auctions), *reh'g denied*, 169 FERC ¶ 61,237 (2019).

[47] Linden Answer and Request for Rehearing at 15 (arguing "if PJM uses the previous [s]olution-based DFAX result for the Sewaren Project, for a period of time PJM will allocate Linden VFT 100 [percent] of the Sewaren Project costs, despite Linden VFT only receiving 38.35 [percent] of the PJM-determined benefits.").

Owner Tariff Revision.[48] The equities cited by Linden do not favor granting rehearing. Linden made its business decisions with knowledge that the case was on appeal. In similar circumstances, the D.C. Circuit found in *Transcontinental Gas Pipe Line Corp. v. FERC*[49] that the pipeline's "petition for rehearing . . . put customers on notice that" an alternate rate design might ultimately prevail, just as the rehearing and ensuing court appeal did in this case.[50] While the D.C. Circuit recognized that, during the rehearing period, "every party's action or inaction involved some risk," it concluded that in balancing these interests, application of the "right rate, i.e., whatever rate the Commission lawfully determines to be right" seemed most appropriate because "the expectations of those who act in anticipation of the right rate are protected, and they would seem presumptively the most deserving."[51] In applying a similar balancing here, we continue to conclude that the equities lie in favor of putting the parties in the position in which they would have been had the Commission not erred.

B. Application to Lower Voltage Facilities

22. We deny Con Edison and Linden's requests for rehearing contending that the Commission should have limited its response on remand solely to high-voltage facilities, and not, in PJM parlance, to Regional Facilities, Necessary Lower Voltage Facilities, and Lower Voltage Facilities. We also deny Con Edison's rehearing request contending that it is inequitable for it to bear the financial impact of the Sewaren Project costs when Con Edison does not derive any benefit from the project.[52] As an initial matter, we note that the arguments that Con Edison and Linden make here, specifically, arguments that applying the solution-based DFAX method to the Sewaren Project violated principles of cost allocation and otherwise failed to ensure that rates are just and reasonable,[53] are beyond the scope of this proceeding, which relates solely to the section 205 filing regarding cost responsibility assignments for Form No. 715 local planning criteria projects. Con Edison and Linden's concerns regarding the application of the solution-

[48] Linden Answer and Request for Rehearing at 13.

[49] 54 F.3d 893 (D.C. Cir. 1995).

[50] *Id.* at 899.

[51] *Id.*

[52] Con Edison Request for Rehearing at 9-10.

[53] Linden Answer and Request for Rehearing at 25-28; Con Edison Request for Rehearing at 8-10.

based DFAX method to the Sewaren Project have been raised in other proceedings, and the Commission has made determinations in those proceedings.[54]

23. We also are not persuaded by Linden and Con Edison's arguments that the Commission should have distinguished between high-voltage and low-voltage projects in the Order on Remand.[55] Contrary to Linden and Con Edison's arguments,[56] the D.C. Circuit's ruling in *Old Dominion* did not apply only to high-voltage projects. While the court's discussion focused on high-voltage projects, the court also more broadly found that the 2015 PJM Transmission Owner Tariff Revision "denies cost sharing for *all* projects included in the Regional Plan only to satisfy the planning criteria of individual utilities — *including* for high-voltage lines."[57] Moreover, the 2015 PJM Transmission Owner Tariff Revision expressly applied both to Lower Voltage Facilities as well as Regional and Necessary Lower Voltage Facilities.[58] PJM's Tariff uses the solution-based DFAX method to determine whether transmission facilities have benefits outside of the zone of the transmission owner constructing the project and allocates costs to zones based on the application of that methodology.[59] Because the benefits of Lower Voltage Facilities may accrue to other zones, we do not see a basis for limiting cost allocation for Lower Voltage Facilities planned under Form No. 715 local planning criteria to only the local zone of the constructing transmission owner.

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[54] *Linden VFT, LLC v. PJM Interconnection, L.L.C.*, 155 FERC ¶ 61,089, at PP 55 (2016), *reh'g denied*, 170 FERC ¶ 61,122, at PP 34-42, 68 (2020).

[55] Linden Answer and Request for Rehearing at 23; Con Edison Request for Rehearing at 10 (asserting that "the August 30 Order should have differentiated between low- and high-voltage projects, at least with respect to the grant of equitable remedies").

[56] Con Edison Request for Rehearing at 6-7.

[57] *Old Dominion*, 898 F.3d at 1261 (emphasis in original).

[58] In the panel opinion on rehearing, the D.C. Circuit also recognized that because it "set aside FERC's approval of the proposed tariff amendment, the unamended tariff remains in effect." *Old Dominion*, 905 F.3d 671. As stated in the Order on Remand, "[b]ecause the 2015 PJM Transmission Owner Tariff Revision proposes a blanket rule applicable to projects included in the RTEP solely to address individual transmission owner Form No. 715 local planning criteria that is inconsistent with the cost-causation principle, we reject the 2015 PJM Transmission Owner Tariff Revision in its entirety." Order on Remand, 168 FERC ¶ 61,133 at P 27.

[59] PJM, Intra-PJM Tariffs, Schedule 12, OATT Schedule 12, 14.0.0, § (b)(ii).

The Commission orders:

(A) ODEC and Dominion's request for clarification is hereby granted, as discussed in the body of this order.

(B) Con Edison's and Linden's respective requests for rehearing are hereby denied, as discussed in the body of this order.

By the Commission. Commissioner Danly is not participating.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

- Attachment 8c FERC Order

171 FERC ¶ 61,013
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Neil Chatterjee, Chairman;
Richard Glick and Bernard L. McNamee.

PJM Interconnection, L.L.C. Docket Nos. ER15-1387-006
PJM Interconnection, L.L.C. ER15-1344-007

ORDER ACCEPTING COMPLIANCE FILINGS

(Issued April 3, 2020)

1. On August 30, 2019, the Commission issued an order (Order on Remand) rejecting the provisions of the PJM Interconnection, L.L.C. (PJM) Open Access Transmission Tariff (Tariff) implementing a proposal from the PJM Transmission Owners, under section 205 of the Federal Power Act (FPA),[1] to allocate 100% of the costs of projects that are included in the PJM Regional Transmission Expansion Plan (RTEP) solely to address individual transmission owner Form No. 715 local planning criteria to the transmission zone of the transmission owner whose Form No. 715 local planning criteria underlie each project (2015 PJM Transmission Owner Tariff Revision).[2] The Order on Remand responded to the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) granting petitions for review and setting aside the Commission orders accepting the 2015 PJM Transmission Owner Transmission Revision and applying the Tariff provision to specific projects, and remanded to the Commission for further proceedings.[3] In the Order on Remand, the Commission required PJM to file

[1] 16 U.S.C. § 824e (2018).

[2] *PJM Interconnection, L.L.C.* (Order on Remand), 168 FERC ¶ 61,133 (2019). The 2015 PJM Transmission Owner Tariff Revision was included in Schedule 12 of the PJM Tariff at § (b)(xv). PJM, Intra-PJM Tariffs, Schedule 12, OATT Schedule 12, 7.0.0, § (b)(xv) (Required Transmission Enhancements to Address Transmission Owner Planning Criteria).

[3] *Old Dominion Elec. Coop. v. FERC*, 898 F.3d 1254, *reh'g denied*, 905 F.3d 671 (D.C. Cir. 2018). The petitions for review challenged the order accepting the 2015 PJM Transmission Owner Tariff Revision in Docket No. ER15-1387, and orders applying the revised PJM Tariff to specific projects in Docket No. ER15-1344.

Tariff corrections necessary to reflect the rejection of the 2015 PJM Transmission Owner Tariff Revisions within the 30 days.

2. On September 27, 2019, in Docket No. ER15-1387-006, the PJM Transmission Owners submitted revisions to Schedule 12 of the PJM Tariff replacing the 2015 PJM Transmission Owner Tariff Revision with a provision stating "Reserved" (Schedule 12 Compliance Filing).[4] The PJM Transmission Owners request a May 25, 2015 effective date.

3. On October 29, 2019, in Docket No. ER15-1344-007, PJM submitted revised cost responsibility assignments for Schedule 12-Appendix A of the PJM Tariff for 44 transmission projects that were allocated pursuant to the 2015 PJM Transmission Owner Tariff Revision during the period from May 25, 2015 through August 30, 2019 (Cost Allocation Compliance Filing).[5]

4. In this order, we accept the Schedule 12 Compliance Filing and the Cost Allocation Compliance Filing.

I. Background

5. PJM files cost responsibility assignments for transmission projects that the PJM Board of Managers (PJM Board) approves as part of PJM's RTEP in accordance with Schedule 12 of PJM's Tariff and Schedule 6 of the Operating Agreement.[6] Schedule 12 of the PJM Tariff establishes Transmission Enhancement Charges and allows that "[o]ne

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[4] PJM, Intra-PJM Tariffs, Schedule 12, OATT Schedule 12, 7.1.0.

[5] *See* Appendix.

[6] In accordance with the Tariff and the Operating Agreement, PJM "shall file with FERC a report identifying the expansion or enhancement, its estimated cost, the entity or entities that will be responsible for constructing and owning or financing the project, and the market participants designated under Section 1.5.6(l) above to bear responsibility for the costs of the project." PJM, Intra-PJM Tariffs, OA Schedule 6 Sec 1.6, OA Schedule 6 Sec 1.6 Approval of the Final Regional Trans, 4.0.0, § 1.6 (b). "Within thirty 30 days of the approval of each Regional Transmission Expansion Plan or an addition to such plan by the PJM Board pursuant to Section 1.6 of Schedule 6 of the PJM Operating Agreement, the Transmission Provider shall designate in the Schedule 12-Appendix A and in a report filed with the FERC the customers using Point-to-Point Transmission Service and/or Network Integration Transmission Service and Merchant Transmission Facility owners that will be subject to each such Transmission Enhancement Charge "Responsible Customers" based on the cost responsibility assignments determined pursuant to this Schedule 12." *Id.*, Schedule 12, OATT Schedule 12, 14.0.0, § (b)(viii).

or more of the Transmission Owners may be designated to construct and own and/or finance Required Transmission Enhancements by (1) the [PJM RTEP] periodically developed pursuant to Operating Agreement, Schedule 6 or (2) any joint planning or coordination agreement between PJM and another region or transmission planning authority set forth in Tariff, Schedule 12-Appendix B."[7]

6. In developing the RTEP, PJM identifies transmission projects to address different criteria,[8] including PJM planning procedures, North American Electric Reliability Corporation (NERC) Reliability Standards, Regional Entity reliability principles and standards,[9] and individual transmission owner Form No. 715 local planning criteria. Form No. 715 is the Annual Transmission Planning and Evaluation Report that any transmitting utility that operates integrated transmission facilities at or above 100 kV must file with the Commission on or before April 1 of each year.[10] As relevant here,

[7] Required Transmission Enhancements are defined as "enhancements and expansions of the Transmission System that (1) a [RTEP] developed pursuant to Operating Agreement, Schedule 6 or (2) any joint planning or coordination agreement between PJM and another region or transmission planning authority set forth in Tariff, Schedule 12-Appendix B ("Appendix B Agreement") designates one or more of the Transmission Owner(s) to construct and own or finance." PJM, Intra-PJM Tariffs, OATT Definitions – R - S, OATT Definitions – R - S, 18.2.0. Transmission Enhancement Charges are established to recover the revenue requirement with respect to a Required Transmission Enhancement. *See id.*, Schedule 12, OATT Schedule 12, 14.0.0, § (a)(i).

[8] 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 that they provide. *See PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 at P 441; PJM, Intra-PJM Tariffs, Schedule 12, OATT Schedule 12, 12.0.0, § (b)(v) (Economic Projects) (assigning cost responsibility for Economic Projects that are either accelerations or modifications of Reliability Projects, or new enhancements or expansions that relieve one or more economic constraints); *Id.*, OA Schedule 6 Sec 1.5, OA Schedule 6 Sec 1.5 Procedure for Development of the Regi, 23.0.0, § 1.5.7(b)(iii).

[9] As established by Reliability First Corporation, Southeastern Electric Reliability Council, and other applicable Regional Entities. *See* PJM, Intra-PJM Tariffs, OA Schedule 6 Sec 1.2, OA Schedule 6 Sec 1.2 Conformity with NERC and Other Applic, 2.0.0, §§ 1.2(b) and 1.2(d) (Conformity with NERC and Other Applicable Reliability Criteria) (2.0.0).

[10] *See* 18 C.F.R. § 141.300 (2019).

Form No. 715 requires submission of transmission planning reliability criteria that the transmission owner uses to assess and test the strength and limits of its transmission system.

7. Types of Reliability Projects[11] identified in the RTEP include Regional Facilities,[12] Necessary Lower Voltage Facilities,[13] and Lower Voltage Facilities.[14] PJM assigns the costs of Reliability Projects that are selected in the RTEP for purposes of cost allocation pursuant to the cost allocation method that the Commission accepted in compliance with Order No. 1000.[15] Specifically, in the case of Regional Facilities and Necessary Lower Voltage Facilities that address a reliability need, costs are allocated pursuant to a hybrid cost allocation method in which 50% of the costs of those facilities are allocated on a load-ratio share basis and the other 50% are allocated to the transmission owner zones based on the solution-based distribution factor (DFAX)

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[11] Reliability Projects are Required Transmission Enhancements that are included in the RTEP to address one or more reliability violations or to address operational adequacy and performance issues. PJM, Intra-PJM Tariffs, Schedule 12, OATT Schedule 12, 14.0.0, § (b)(i)(A)(2)(a).

[12] Regional Facilities are defined as Required Transmission Enhancements included in the RTEP 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). *Id.*, § (b)(i) (Regional Facilities and Necessary Lower Voltage Facilities).

[13] Necessary Lower Voltage Facilities are defined as Required Transmission Enhancements included in the RTEP that are lower voltage facilities that must be constructed or reinforced to support new Regional Facilities. *Id.*, § (b)(i) (Regional Facilities and Necessary Lower Voltage Facilities).

[14] Lower Voltage Facilities are defined as Required Transmission Enhancements that: (a) are not Regional Facilities; and (b) are not "Necessary Lower Voltage Facilities." *Id.*, § (b)(ii) (Lower Voltage Facilities).

[15] *See Transmission Planning & Cost Allocation by Transmission Owning & Operating Pub. Utils.*, Order No. 1000, 136 FERC ¶ 61,051 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g & 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); *see also PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 (2013), *order on reh'g & compliance*, 147 FERC ¶ 61,128 (2014), *order on reh'g & compliance*, 150 FERC ¶ 61,038, *order on reh'g & compliance*, 151 FERC ¶ 61,250 (2015).

method.[16] Pursuant to the cost allocation method that the Commission accepted in compliance with Order No. 1000, all of the costs of Lower Voltage Facilities were allocated using the solution-based DFAX method.

8. On February 12, 2016, the Commission accepted the 2015 PJM Transmission Owner Tariff Revision to allocate 100% of the costs for Required Transmission Enhancements that are included in the RTEP solely to address individual transmission owner Form No. 715 local planning criteria to the zone of the individual transmission owner whose Form No. 715 local planning criteria underlie each project.[17]

9. As previously noted, on August 3, 2018, the D.C. Circuit granted petitions for review and set aside the Commission orders accepting the 2015 PJM Transmission Owner Transmission Revision and remanded the case to the Commission for further proceedings.[18] On August 30, 2019, the Commission issued the Order on Remand rejecting the 2015 PJM Transmission Owner Tariff Revision.

II. <u>Order on Remand</u>

10. In the Order on Remand, the Commission rejected the 2015 PJM Transmission Owner Tariff Revision. The Commission directed PJM, within 30 days of the date of the Order on Remand, to make a filing in eTariff to make all tariff corrections necessary to reflect the rejection of the 2015 PJM Transmission Owner Tariff Revision.[19] The Commission also directed PJM to refile the cost responsibility assignments in Schedule 12-Appendix A, of the PJM Tariff for transmission projects included in the RTEP

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[16] "The solution-based DFAX method evaluates the projected relative use on the new Reliability Project by the load in each zone and withdrawals by merchant transmission facilities, and through this power flow analysis, identifies projected benefits for individual entities in relation to power flows." *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 at P 416.

[17] *PJM Interconnection, L.L.C.*, (February 2016 Order) 154 FERC ¶ 61,096 (2016) (granting rehearing and accepting the 2015 PJM Transmission Owner Tariff Revision), *order on reh'g*, 157 FERC ¶ 61,192.

[18] The D.C. Circuit set aside the orders under review to the extent they applied the 2015 PJM Transmission Owner Tariff Revision to the projects at issue. *Old Dominion*, 898 F.3d at 1264.

[19] On September 19, 2019, the Commission granted a PJM motion requesting a 30-day extension of time until October 29, 2019 to file the revised cost responsibility assignments.

between May 25, 2015, and the date of this order that are needed solely to address individual transmission owner Form No. 715 local planning criteria.

III. Compliance Filings

A. Schedule 12 Compliance Filing

11. In the Order on Remand, the Commission rejected the 2015 PJM Transmission Owner Tariff Revision and directed PJM to, within 30 days of the date of the order, make a filing in eTariff to make all tariff corrections necessary to reflect the rejection of the 2015 PJM Transmission Owner Tariff Revision. Instead of deleting the provision, the PJM Transmission Owners propose to replace the 2015 PJM Transmission Owner Tariff Revision with a provision stating "Reserved".[20]

B. Cost Allocation Compliance Filing

12. PJM explains that it reviewed the cost responsibility assignments for 443 transmission projects that had been assigned 100% to the zone of the transmission owner who filed the Form No. 715 planning criteria, during the period of May 25, 2015 through August 30, 2019, and determined that revisions to cost responsibility assignments were needed for only 44 transmission projects (Remand Projects). PJM explains the majority of transmission facilities needed solely to address individual transmission owner Form No. 715 local planning criteria continue to be allocated to a single transmission owner zone.[21]

13. Of the 44 Remand Projects, PJM explains the cost allocation will be revised for 11 Regional Facilities and 33 Lower Voltage Facilities. PJM explains the cost allocation for the Regional Facilities will be based on PJM's hybrid cost allocation method, with 50% of the costs of the transmission projects allocated on a load-ratio share basis and the other 50% based on the solution-based DFAX method. PJM explains the cost allocation for the Lower Voltage Facilities will be based on the cost allocation methodology in Schedule 12 of the PJM Tariff which is the solution-based DFAX method.[22] PJM also

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[20] PJM, Intra-PJM Tariffs, Schedule 12, OATT Schedule 12, 7.1.0, § (b)(xv) (Reserved).

[21] PJM, Intra-PJM Tariffs, Schedule 12, OATT Schedule 12, 14.0.0, §§ (b)(iii) – (iv), (b)(xvi).

[22] PJM Transmittal at 5.

states that one Regional Facility and five Lower Voltage Facilities required sub identification numbers be created to accommodate the Order on Remand.[23]

IV. Notice, Intervention and Responsive Pleadings

A. Schedule 12 Compliance Filing

14. Notice of the Schedule 12 Compliance Filing was published in the *Federal Register* 84 Fed. Reg. 54,879 (Oct. 11, 2019). Interventions were due on or before October 18, 2019. Notice of intervention was submitted by New Jersey Board of Public Utilities (New Jersey Board). Out of time motions to intervene were submitted by Southern Maryland Electric Cooperative, Inc. (SMECO) and East Kentucky Power Cooperative, Inc. (EKPC). No protests or comments were submitted.

B. Cost Allocation Compliance Filing

15. Notice of the Cost Allocation Compliance Filing was published in the *Federal Register* 84 Fed. Reg. 59,797 (Nov. 6, 2019). The Commission granted a request by Long Island Power Authority (LIPA) and Neptune Regional Transmission System, LLC (Neptune) to extend the comment period to December 3, 2019. Notices of intervention were filed by the New Jersey Board, and the Illinois Commerce Commission (Illinois Commission). Timely motions to intervene were filed by LIPA, Neptune, SMECO, Delaware Municipal Electric Corporation, Inc., EKPC, LSP Transmission Holdings II, LLC (LSP Transmission), and Duquesne Light Company (Duquesne). Old Dominion Electric Cooperative (ODEC), Dominion Energy Services, Inc. on behalf of Virginia Electric Power Company (Dominion), PPL Electric Utilities Corporation (PPL), Dayton Power and Light Company (Dayton), American Municipal Power (AMP) and Linden VFT, LLC (Linden) submitted timely motions in the underlying docket to this proceeding. AMP, LSP Transmission, and ODEC collectively filed an out of time motion to intervene and an answer as the PJM Industrial Customer Coalition (Industrial Customer Coalition).

16. Protests of the Cost Allocation Compliance Filing were submitted by ODEC and Dominion, Neptune, LIPA, PPL, and Dayton, Illinois Commission, and Duquesne.

17. PJM filed an answer to the protests of LIPA, Neptune, PPL, Dayton, and Duquesne. Linden filed an answer opposing the protest of ODEC and Dominion. EKPC submitted an answer supporting the protest of PPL and Dayton. The Industrial Customer Coalition, ODEC and Dominion, and Neptune submitted an answer opposing the protest of PPL and Dayton. ODEC and Dominion filed an answer to the answer of Linden.

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[23] The Regional Facility b2960 includes b2960.1 and b2960.2. The five Lower Voltage Facilities include: b2835, b2836, b2837, b2933 and b2986. *Id.* at 5.

LIPA and Neptune filed answers to the answer of PJM. Linden, and PPL and Dayton filed answers to the answer of ODEC and Dominion. LIPA filed an answer to the answer of Neptune. ODEC and Dominion, and AMP filed answers to the answer of PPL and Dayton. PPL and Dayton filed an answer to the answer of ODEC and Dominion.

V. Pleadings

A. Cost Allocation Compliance Filing

1. Cost Allocation of Remand Projects

a. Metuchen-Trenton-Burlington Project and Front Street-Springfield Project

18. LIPA and Neptune argue that the revised cost responsibility assignments for PSEG projects b2836 and b2837, the Metuchen-Trenton-Burlington Project (MTB Project), and b2933.31, the Front Street-Springfield Project (Springfield Project), in the Cost Allocation Compliance Filing are not commensurate with the benefits received by those parties allocated costs, and cannot be based on the usage of the facilities.[24] Neptune specifically argues that the costs of these projects are not commensurate with benefits because 100% of the costs are allocated to Neptune, despite the facts that the projects are: 1) located within PSEG's zone; 2) serve multiple PSEG load substations; 3) driven by PSEG's end of life criteria; and 4) located multiple zones away from the Neptune.[25] LIPA argues that the benefits of the MTB Project only pertain to PSEG's load, and the majority of the projects involve substations serving PSEG load or the replacement of a transmission line that only provides distribution service in the PSEG zone.[26]

19. LIPA and Neptune also argue PJM has not met its burden under section 205 to demonstrate that the filing is just and reasonable. LIPA argues that the Cost Allocation Compliance Filing lacks "substantial evidence,"[27] including supporting information such

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[24] LIPA represents the costs of project b2836 and b2837 is $302 million and $312 million, respectively. Neptune Protest at 9-12, LIPA Protest at 2-3, 11-13, 17.

[25] Neptune Protest at 4-6, 12-13, Neptune Answer at 1-3, 9-10, 12-13, 17-19 (Jan. 14, 2020).

[26] LIPA Protest at 12.

[27] *Id*. at 3, 7, (citing 5 U.S.C. § 706(2)(E) (2012); *Motor Vehicles Mfrs. Ass'n of U.S., Inc. v. State Farm Mut. Auto. Ins. Co*., 463 U.S. 29, 43-44 (1983); *S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41, 54 (D.C. Cir. 2014)).

as the purpose for the subdivision of projects, disaggregate costs per subproject, actual flows and usage by subproject.[28] Neptune states PJM has not explained the effect of separating projects into subprojects on the cost responsibility assignments, nor did it provide any calculation or other explanation to explain the proposed cost reallocations.[29] Neptune argues this lack of information does not allow intervenors to review or confirm the proposed cost responsibility assignments.[30]

20. Neptune and LIPA argue that the MTB Project and Springfield Project should not be included in regional cost allocation because they are needed only to address PSEG end of life criteria and have not been identified by PJM as addressing a reliability contingency.[31] Neptune states the solution-based DFAX method has not produced a just and reasonable rate for the MTB Project and the Springfield Project because they are driven by non-flow based criteria, and the Commission should direct PJM to establish a different cost allocation as it has in other proceedings.[32] LIPA and Neptune request that the Commission set the matter for hearing, and Neptune requests that the Commission set the impact of the *de minimis* threshold to the MTB Project cost responsibility assignments for hearing as well.[33]

21. In response, PJM explains that when initially designating the cost responsibility assignments for the MTB Project, it did not create subprojects because the project was allocated 100% to the transmission owner zone and subprojects were not needed.[34] As to Neptune's arguments that the MTB Project cost responsibility assignments are not commensurate with benefits, PJM argues that it follows the solution-based DFAX

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[28] *Id.* at 6, LIPA Answer at 5 (Jan. 2, 2020).

[29] Neptune Protest at 6-9, 16, Neptune Answer at 5, 11-12, 14-18 (Jan. 14, 2020).

[30] Neptune Protest at 9.

[31] *Id.* at 13; Neptune Answer at 12-13 (Jan. 14, 2020).

[32] Neptune argues the cost responsibility assignments are unjust and unreasonable, similar to the cost responsibility assignments of the Artificial Island Project. *Id.* at 19 - 21, Neptune Answer at 17-19 (January 14, 2020) (citing *Del. Pub. Serv. Comm'n v. PJM Interconnection, L.L.C*, 166 FERC ¶ 61,161 (2019)).

[33] Neptune argues that the use of the *de minimis* assumption used in the solution-based DFAX method distorts cost responsibility assignments by shifting costs from large transmission zones to smaller transmission zones. *Id.*at 21 -22, LIPA Protest at 3.

[34] PJM Answer at 5-6 (Dec. 18, 2019).

method established in its Tariff.[35] PJM provides a table outlining the DFAX data used to establish cost responsibility allocations for the MTB Project. PJM explains that the table includes the applicable directional usage, the DFAX and the peak load information used to develop the 2019 cost allocations for the MTB Project which were used in the calculations for its cost responsibility assignments under Schedule 12 of the PJM Tariff.[36] PJM explains that it does not have discretion over the formulaic cost allocation method, which is based on a computer model of its electricity network that evaluates the relative use of a new facility.[37]

22. In its answers, Neptune reiterates that the revised cost responsibility assignments to Neptune for the MTB Project and Springfield do not meet cost causation principles established in the courts.[38] Neptune also argues the DFAX percentages are misleading because they imply that Neptune and PSEG have the same MW usage of the facilities comprising the MTB Project, but they do not and this is not reflected in the data.[39] Neptune provides a table using the data provided by PJM demonstrating that its relative use of these subprojects is the lowest of any PJM zone, and far lower than PSEG, Jersey Central Power & Light and PECO zones.[40] LIPA states that PJM's flow calculations vary significantly, demonstrating that the DFAX results produce a disparate allocation of costs for newly created subprojects for the PSEG zone. LIPA argues that PJM cites to no Tariff language that directs how a subdivision of a transmission project should occur, and does not explain how it approached the subdivision of transmission facilities needed solely to address individual transmission owner Form No. 715 local planning criteria.[41]

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[35] *Id.* at 7-9 (citing PJM, Intra-PJM Tariffs, Schedule 12, OATT Schedule 12, 14.0.0, § (b)(iii)).

[36] *Id.* at 7-8.

[37] *Id.* at 8-9.

[38] Neptune Answer at 3, (Dec. 26, 2019) (citing *Old Dominion, 905 F.3d* 671 and *Ill. Commerce Comm'n v. FERC*, 756 F.3d 470 (7th Cir. 2009)); Neptune Answer at 16-18 (Jan. 14, 2020).

[39] Neptune Answer at 1-3 (Dec. 26, 2019). LIPA argues the relative megawatt flows to PSEG and JCPL zones for the MTB Project are five to ten times greater than the megawatt flows to Neptune, which are 10 MW or less. LIPA Answer at 3-6 (Jan. 2, 2020).

[40] Neptune Answer at 3-7, 9-10 (Dec. 26, 2019).

[41] LIPA Answer at 3-6 (Jan. 2, 2020).

b. Other Remand Projects

23. Several parties argue that as a general matter, transmission facilities needed solely to address individual transmission owner Form No. 715 local planning criteria are asset management projects that only benefit the transmission owner building the facility,[42] not other transmission owner zones, and are distinct from regionally planned transmission facilities.[43] The Illinois Commission argues that the revised cost responsibility assignments for the 11 Regional Facilities included as Remand Projects are unjust and unreasonable because the revisions will cause inequitable cost shifts that fail to account for the "burdens imposed"[44] to other transmission zones. PPL and Dayton argue that PJM failed to apply Schedule 12, section (b)(xiii) to allocate the costs of the Remand Projects,[45] given that the replacement of transmission facilities at the end of their useful life is the responsibility of transmission owners and their loads, and this provision requires the costs of transmission projects addressing the replacement of equipment to be assigned to the transmission owner zones or merchant facilities responsible for the replacement facilities. PPL and Dayton further state that the filing of Form No. 715 local transmission criteria by transmission owners cannot change this allocation.[46] PPL and Dayton also argue that *Old Dominion* does not address whether only high voltage Regional Facilities needed solely to address individual transmission owner Form No. 715 local planning criteria should be included in RTEP, or whether transmission facilities

[42] Duquesne Protest at 2-4, EKPC Answer at 1-3. PPL and Dayton Protest at 15-19, 24 (citing *PJM Interconnection, L.L.C.*, 119 FERC ¶ 61,063 at PP 48–56 (2007) (Opinion No. 494), *reh'g denied*, 122 FERC ¶ 61,082 (2008) (Opinion No. 494-A), *rev'd on other grounds, Ill. Commerce Comm'n v. FERC*, 576 F.3d 470,473-474, 476, and PJM, Rate Schedules, TOA, TOA-42 Rate Schedule FERC No. 42, 1.0.0, § 4.1.4, 6.3.3, 6.3.4).

[43] PPL and Dayton argue PJM's transmission owners both retained responsibility for these projects and are obligated to maintain them under the PJM Consolidated Transmission Owner Agreement. PPL and Dayton Protest at 15-18.

[44] Illinois Commission states that Dominion will pay 13.87%, or $50.47 million of the costs for the 11 Regional Facilities, shifting $332 million to other transmission owner zones. Illinois Commission argues that the Commonwealth Edison Company will receive $50.74 million in costs, in which no commensurate benefit to Illinois has been shown. Illinois Commission Protest at 4, (citing *Ill. Commerce Comm'n v. FERC*, 576 F.3d 470, 476).

[45] PPL and Dayton Protest at 2-3 (citing PJM, Intra-PJM Tariffs, Schedule 12, OATT Schedule 12, 14.0.0, § (b)(xiii)).

[46] *Id.* at 2-3, 9-10; PPL and Dayton Answer, at 8-10 (Jan. 2, 2020).

needed solely to address individual transmission owner Form No. 715 local planning criteria that do not expand or enhance the transmission system actually address regional needs.[47] Neptune states it agrees with PPL and Dayton that the costs of transmission facilities needed to address end of life criteria, such as the MTB Project, should be allocated under Schedule 12, section (b)(xiii) of the PJM Tariff.[48]

24. In its answer, PJM states that it has never designated a transmission facility needed solely to address individual transmission owner Form No. 715 local planning criteria as a replacement project or applied Schedule 12, section (b)(xiii) to this type of project. PJM explains that if the Commission agrees that this provision is applicable to transmission facilities needed solely to address individual transmission owner Form No. 715 local planning criteria, PJM would need to make a preliminary determination on whether replacement projects enhance or expand the PJM transmission system more than incidentally.[49]

25. The Industrial Customer Coalition, ODEC and Dominion argue that PPL's and Dayton's assertions that PJM should not have included Dominion's high voltage projects in the RTEP because they are not enhancements to the transmission system are incorrect. They state that the cost allocation provisions under Schedule 12, section (b)(xiii) are consistent with *Old Dominion* and Commission precedent that determined that these provisions do not apply to Required Transmission Enhancements.[50] ODEC and Dominion state the Cost Allocation Compliance Filing correctly includes the Remand Projects in the RTEP as Required Transmission Enhancements in accordance with the Tariff because they are high voltage transmission facilities that address regional reliability violations that clearly enhance PJM's transmission system.[51] Industrial Customer Coalition argues that applying Schedule 12 (b)(xiii) to allocate the costs of transmission facilities needed solely to address a transmission owner zone Form No. 715 planning criteria would produce an impermissible outcome as determined by the Order on Remand, constitutes an untimely request for rehearing of the Order on Remand, and is a

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[47] PPL and Dayton Protest at 22-26. PPL and Dayton state the Order on Remand also did not clarify these issues. PPL and Dayton Answer at, 5-8 (Jan. 2, 2020).

[48] Neptune Answer at 1-4, 6-9 (Dec. 18, 2019).

[49] PJM Answer at 3-5.

[50] Industrial Customer Coalition Answer at 2-4, ODEC and Dominion Answer, at 3-6 (Dec. 18, 2019) (citing Orders on PJM Transmission Owner Tariff Revisions).

[51] *Id.*at 8-12, 16 (Dec. 18, 2019) (citing PJM, Intra-PJM Tariffs, Schedule 12, OATT Schedule 12, 14.0.0, § (b)(iv)); ODEC and Dominion Answer, at 7-8 (Jan. 16, 2020) (citing *Old Dominion*, 898 F.3d at 1262).

collateral attack on the Commission's acceptance that Form No. 715 planning criteria is included in the RTEP planning criteria under the PJM Operating Agreement.[52] AMP refutes PPL and Dayton's characterization of end of life facilities and replacement facilities, arguing that their characterization is inconsistent with the principles of cost causation.[53] AMP states that the replacement of these facilities today is distinct from when PJM's system was created, and provides that PJM's transmission system is planned according to current and future needs.[54] Industrial Customer Coalition explains there is currently a stakeholder process underway in PJM to provide resolution of the issue surrounding transmission projects driven by end of life planning criteria.[55]

26. In response to protests from ODEC, Dominion, and the Industrial Customer Coalition, PPL and Dayton answer that they do not dispute transmission facilities properly included in PJM's RTEP should be subject to the same cost allocation as Replacement Facilities but rather argue transmission facilities that replace asset management facilities should not be considered Required Transmission Enhancements.[56] PPL and Dayton argue it is inconsistent with *Old Dominion* to allocate costs of transmission facilities without quantifying the benefits to other transmission customers, and no such review has occurred here.[57] PPL and Dayton argue that assuming a transmission facility needed to address Form No. 715 planning criteria provides regional benefits only because it is high voltage, as ODEC and Dominion assert, is an argument that the courts have rejected.[58] PPL and Dayton also argue that any cost shifts not based

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[52] Industrial Customer Coalition Answer at 8-9, (citing PJM Operating Agreement, Schedule 6 § 1.2(e)). ODEC and Dominion also argue that disputes over this provision and terms in the Consolidated Transmission Owner Agreement should have been raised on rehearing to the Order on Remand. ODEC and Dominion Answer at 3-5 (Dec. 18, 2019).

[53] AMP Answer at 2-5.

[54] *Id.* at 4-7.

[55] Industrial Customer Coalition Answer at 10.

[56] PPL and Dayton Answer at 3-4 (Jan. 2, 2020).

[57] *Id.* at 13-14 (Jan. 2, 2020).

[58] *Id.* at 9-10 (Jan. 31, 2020) (citing *Ill. Commerce Comm'n v. FERC*, 576 F. 3d 470).

on cost causation principles, even gradual, would be unjust and unreasonable.[59] ODEC and Dominion argue that the Consolidated Transmission Owners Agreement does not apply to facilities that can no longer be maintained, and that PJM has recognized that deteriorating facilities can be replaced with new assets to which regional cost allocation principles apply.[60] In response, PPL and Dayton refute ODEC and Dominion's characterization of requirements under the Consolidated Transmission Owners Agreement, and state the plain language of that agreement requires transmission owners to maintain the functionality of their transmission facilities in the PJM transmission system.[61]

27. Several parties present arguments regarding the applicability of Order No. 890 and Order No. 1000 transmission planning processes to transmission facilities needed solely to address individual transmission owner Form No. 715 local planning criteria, or specifically the Remand Projects.[62] PPL and Dayton argue recent determinations from the Commission related to asset management transmission facilities affirm that these types of facilities do not benefit customers in other transmission owner zones, and should not be subject to Order No. 890 transmission planning.[63] The Illinois Commission argues that the Cost Allocation Compliance Filing contradicts Commission policy under Order No. 1000[64] regarding competitive transmission planning processes for all regional

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[59] PPL and Dayton state that approximately $60 million will be shifted from the Dominion zone to other transmission owner zones. *Id.,* at 11-12 (Jan. 31, 2020).

[60] *Id.* at 3-5 (Jan. 16, 2020).

[61] *Id.* at 2-4 (Jan. 31, 2020) (citing PJM Interconnection, L.L.C., Consolidated Transmission Owners Agreement, Rate Schedule. No. 42 § 4.5 (June 19, 2008)).

[62] *Preventing Undue Discrimination & Preference in Transmission Serv.*, Order No. 890, 118 FERC ¶ 61,119, *order on reh'g*, Order No. 890-A, 121 FERC ¶ 61,297 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[63] PPL and Dayton Protest at 16-17, 19-21, 25 (citing *Southern Cal. Edison Co., et al.*, 164 FERC ¶ 61,160 (2018); *Cal. Pub. Util. Comm'n v. Pac. Gas & Elec. Co.*, 164 FERC ¶ 61,161 (2018) (California Orders)). PPL and Dayton Answer at, 4-5 (Jan. 31, 2020).

[64] *See* Order No. 1000, 136 FERC ¶ 61,051 at P 328 ("the Commission requires each public utility transmission provider to amend its OATT to describe a transparent and not unduly discriminatory process for evaluating whether to select a proposed transmission facility in the regional transmission plan for purposes of cost allocation").

projects that have regional cost allocation. The Illinois Commission argues that because proposal windows cannot be applied retroactively to the 11 Regional Facilities in the Remand Projects, the costs of those projects should not be permitted to be allocated outside of the transmission owner zone whose Form No. 715 local planning criteria drive each project.[65] PPL and Dayton argue transmission projects included in the RTEP solely to address individual transmission owner Form No. 715 local planning criteria are not planned through regional transmission planning criteria, are not planned as a cost effective solution utilizing regional transmission processes established by the PJM transmission owners, and are a type of projects not subject to Order No. 1000.[66] In response, ODEC and Dominion argue that the California Orders are not applicable precedent because they are limited to the issues of those proceedings, do not reverse Commission findings regarding transmission facilities needed solely to address individual transmission owner Form No. 715 local transmission planning criteria, and are related to transmission facilities more limited in scope than the large replacement transmission facilities at issue in this Cost Allocation Compliance Filing.[67]

B. Refunds for Remand Projects

28. ODEC and Dominion argue that PJM has not complied with the Commission's directive regarding refunds in the Order on Remand because PJM does not clearly explain nor include the Commission's refund obligation in the Cost Allocation Compliance Filing.[68] ODEC and Dominion argue that the Commission directed that "PJM's cost assignment corrections must be in accordance with 18 C.F.R. § 35.19(a),"[69] which points to the Commission's requirement to make refunds with interest. ODEC and Dominion argue PJM is required to not only correct cost responsibility assignments starting May 25, 2015, but also must provide refunds plus interest, that are associated with the corrected cost responsibility assignments. ODEC and Dominion state that the Cost Allocation Compliance Filing does not mention calculating refunds with interest as a result of the revised cost responsibility assignments.[70] Therefore, ODEC and Dominion request that the Commission: 1) reject the Cost Allocation Compliance Filing, and 2) require PJM to submit a further compliance filing that includes a calculation of refunds

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[65] Illinois Commission Protest at 6-7.

[66] PPL and Dayton Protest at 11-14.

[67] ODEC and Dominion Answer at 18-19 (Dec. 18, 2019).

[68] *Id.* at 1-3.

[69] *Id.* at 2 (citing Order on Remand, 168 FERC ¶ 61,133 at n.43).

[70] *Id.* at 3.

plus interest associated with the revised cost responsibility assignments for the transmission projects needed to address Form No. 715 local planning criteria at issue in this proceeding.[71]

29. The Illinois Commission argues that the Commission was silent on refunds in its Order on Remand, and absent an order directing refunds the only impact of the Cost Allocation Compliance Filing is to revise cost responsibility assignments going forward.[72] Linden argues that neither the Order on Remand nor the Commission's regulations have an express directive to require refunds, but rather the Commission has discretion to do so.[73] Linden states that the Commission has declined to order refunds when it determines cost allocation should have been allocated differently but the correct level was collected, which is similar to the cost allocation issues in the Cost Allocation Compliance Filing here.[74]

30. In response, ODEC and Dominion argue that Linden disregards that the Commission has already required refunds, and Linden has not sought rehearing of this directive. ODEC and Dominion argue that Linden's arguments regarding the Sewaren Project provide no new information, and given that *Old Dominion* determined the "unamended tariff remains in effect" all Remand Projects must be reallocated without the 2015 PJM Transmission Owner Tariff Revision.[75] ODEC and Dominion argue that, contrary to Linden's characterization, the Commission has used its broad remedial authority to determine refunds that were appropriate in order to correct cost allocation.[76] ODEC and Dominion argue that in the February 2016 Order, the Commission did not direct payment of refunds, which contrasts to the Commission's directive in Order on

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[71] *Id.* at 4.

[72] Illinois Commission Protest at 7-8.

[73] Linden Answer, at 3 (Dec. 4, 2019) (citing 18 C.F.R. § 35.19a(a)(1) (2019)).

[74] Linden argues requiring refunds would be inconsistent with *Old Dominion* because it would allocate costs of the projects b2276, b2276.1 b2276.2 (Sewaren Project) 100% to Linden despite Linden receiving only 38% of the benefits from that project, which is inconsistent with cost causation principles. *Id.* at 3-5 (citing *La. Pub. Serv. Comm'n v. FERC*, 883 F.3d 929, 932-33 (D.C. Cir. 2018)).

[75] ODEC and Dominion Answer at 4 (Dec. 19, 2019) (citing *Old Dominion*, 905 F.3d at 671).

[76] *Id.* at 4-5 (Dec. 19, 2019) (citing *Black Oak Energy, LLC*, 167 FERC ¶ 61,250, at P 27 (2019)).

Remand.[77] In a limited answer to ODEC and Dominion, Linden argues that ODEC and Dominion do not point to an explicit directive to order refunds.[78]

VI. Determination

A. Procedural Matters

31. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2019), the notice of intervention and timely, unopposed motions to intervene serve to make the entities that filed them parties to the proceeding.

32. Pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214(d) (2019), we grant the Industrial Customer Coalition late-filed motion to intervene given its interest in the proceeding, the early stage of the proceeding, and the absences of undue prejudice or delay.

33. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.217(a)(2) (2019), prohibits an answer to a protest unless otherwise ordered by the decisional authority. We accept the answers because they have provided information that assisted us in our decision-making process.

B. Substantive Matters

1. Schedule 12 Compliance Filing

34. We accept the PJM Transmission Owners' proposal to replace the 2015 PJM Transmission Owner Tariff Revision with a revision to Schedule 12, section (b)(xv) as "Reserved," effective May 25, 2015. However, this Tariff record does not correctly remove the 2015 PJM Transmission Owner Tariff Revision in Schedule 12, section (b)(xv) from superseded versions. Accordingly, we direct PJM Transmission Owners to revise and refile each subsequent version of Tariff records going forward, starting from the records accepted after May 25, 2015.[79]

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[77] *Id.* at 6 (Dec. 19, 2019) (citing February 2016 Order, 154 FERC ¶ 61,096).

[78] Linden Answer at 3-4 (Jan. 3, 2020) (citing Request for Clarification or, in the Alternative, Rehearing of ODEC and Dominion, Docket No. ER15-1387-004, et al. (filed Sept. 23, 2019)).

[79] The PJM Transmission Owners acknowledge that the revisions in the Schedule 12 Compliance Filing have been superseded and commit to work with PJM to submit requisite "clean up" filings once the Commission issues an order on this compliance filing. PJM Transmission Owners Transmittal, at 2, n.2 (Sept. 27, 2019).

2. Cost Allocation Compliance Filing

35. As we explain below, we accept PJM's Cost Allocation Compliance Filing.

a. Metuchen-Trenton-Burlington Project and Front Street-Springfield Project

36. Neptune and LIPA argue that the cost allocation for the MTB Project and the Springfield Project results in cost responsibility assignments that are not commensurate with the benefits Neptune receives from these projects, and that PJM has not determined that either project addresses a reliability contingency. Neptune and LIPA also raise arguments that the *de minimis* threshold is unjust and unreasonable.

37. The only issue in this proceeding is whether the Cost Allocation Compliance Filing makes the corrections to the PJM Tariff necessary to reflect the rejection of the 2015 PJM Transmission Owner Tariff Revision. Therefore, we find that arguments regarding the just and reasonableness of the solution-based DFAX method and the *de minimis* threshold are beyond the scope of this compliance proceeding. We find that PJM has complied with the directive of the Order on Remand, and applied the cost responsibility assignments for the Remand Projects pursuant to its currently-effective just and reasonable Tariff.[80]

b. Other Remand Projects

38. Protestors raise a variety of arguments regarding the regional cost allocation for transmission facilities included in RTEP to address Form No. 715 local planning criteria. We reject these arguments. As noted above, the Cost Allocation Compliance Filing addresses the reallocation of costs for the Remand Projects as directed in the Order on Remand under PJM's existing cost allocation method, not how the projects are planned or whether different cost allocation provisions under Schedule 12 should be applied to the Remand Projects. We reiterate that PJM has followed the directives of the Order on Remand and has adhered to the correct Schedule 12 provisions to reallocate the costs of the Remand Projects.

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[80] The Commission has determined that because the solution-based DFAX methodology is the *ex ante* methodology for determining cost allocation in the PJM transmission planning process, PJM's cost responsibility assignment filings need only demonstrate that the cost responsibility assignments comply with the PJM Tariff and do not "require[] a separate justification under section 205." *See Linden VFT, LLC*, 170 FERC ¶ 61,122, at PP 43-45, 69 (2020); *see also PJM Interconnection, L.L.C.*, 165 FERC ¶ 61,078, at P 20 (2018).

39. The Order on Remand addressed arguments related to whether the transmission facilities needed solely to address individual transmission owner Form No. 715 local planning criteria provide regional benefits to other transmission zones and determined that there was no basis to distinguish beneficiaries of these projects from other projects included in the RTEP.[81] The Order on Remand also concluded that the 2015 PJM Transmission Owner Tariff Revision, as a FPA section 205 filing, needed to be rejected in its entirety, and thus would no longer apply to all transmission facilities that are needed solely to address individual transmission owner Form No. 715 local planning criteria.[82] Arguments that the 2015 PJM Transmission Owner Tariff Revision should not have been rejected in its entirety are beyond the scope of this compliance filing.[83]

40. We are not persuaded by arguments that the Remand Projects should be treated as replacement projects pursuant to Schedule 12, section (b)(xiii). Schedule 12, section (b)(xiii) provides that "[u]nless determined by PJM to be a Required Transmission Enhancement included in a Regional Transmission Expansion Plan, cost responsibility for the replacement of Transmission Facilities, as defined in Consolidated Transmission Owners Agreement, section 1.27, shall be assigned to the Zonal loads and Merchant Transmission Facilities responsible for the costs of the Transmission Facilities being replaced."[84] The Remand Projects are included in the RTEP as Required Transmission Enhancements, and therefore the costs of Remand Projects are not replacement projects pursuant to Schedule 12, section (b)(xiii).

41. We deny the Illinois Commission's protest of the regional cost allocation for projects included in the RTEP that were exempt from the competitive procurement window process. While the Commission, as a result of the Order on Remand, required PJM to revise the PJM Operating Agreement to reestablish the competitive window procurement process, transmission projects included in the RTEP during the period in which the Commission committed legal error were exempted from a competitive window procurement process under the then-applicable Tariff. The Order on Remand directed the reassignment of cost responsibility, and PJM in this proceeding has complied with that directive.

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[81] Order on Remand, 168 FERC ¶ 61,133 at PP 24-27.

[82] *Id.* at P 27.

[83] Concurrent with this order, the Commission is rejecting arguments on rehearing to the Order on Remand. *See PJM Interconnection, L.L.C.*, 171 FERC ¶ 61,012 (2020).

[84] PJM, Intra-PJM Tariffs, Schedule 12, OATT Schedule 12, 14.0.0, § (b)(xiii).

3. Refunds

42. ODEC and Dominion argue PJM did not comply with the refund directive in the Order on Remand because PJM does not explain, and therefore seemingly excludes, that directive in the Cost Allocation Compliance Filing. The Illinois Commission argues that costs should only apply going forward, and Linden argues the Order on Remand did not require refunds. In an order on rehearing being issued concurrently with this order, the Commission finds that the Order on Remand requires PJM to rebill with interest.[85]

The Commission orders:

(A) The PJM Cost Allocation Compliance Filing is accepted to be effective May 25, 2015, as discussed in body of this order.

(B) The PJM Transmission Owners' Schedule 12 Compliance Filing is accepted, as discussed in the body of this order.

(C) The PJM Transmission Owners are directed, within 60 days of the date of this order, to make a filing in eTariff to make all Schedule 12 Tariff corrections necessary to reflect the rejection of the 2015 PJM Transmission Owners Tariff Revision that have been superseded, as discussed in the body of this order.

By the Commission. Commissioner Danly is not participating.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

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[85] *PJM Interconnection, L.L.C.*, 171 FERC ¶ 61,012 (denying rehearing and granting clarification).

Appendix

PJM Interconnection, L.L.C.
Intra-PJM Tariffs

SCHEDULE 12.APPX A - 12, OATT SCHEDULE 12.APPENDIX A - 12 Public Service Electric and, 3.1.4 Effective 5/25/2015

SCHEDULE 12.APPX A - 12, OATT SCHEDULE 12.APPENDIX A - 12 Public Service Electric and, 3.3.0 Effective 1/1/2016

SCHEDULE 12.APPX A - 12, OATT SCHEDULE 12.APPENDIX A - 12 Public Service Electric and, 7.2.2 Effective 2/16/2016

SCHEDULE 12.APPX A - 12, OATT SCHEDULE 12.APPENDIX A - 12 Public Service Electric and, 7.4.0 Effective 4/14/2016

SCHEDULE 12.APPX A - 12, OATT SCHEDULE 12.APPENDIX A - 12 Public Service Electric and, 8.4.0 Effective 4/25/2016

SCHEDULE 12.APPX A - 12, OATT SCHEDULE 12.APPENDIX A - 12 Public Service Electric and, 9.2.0 Effective 11/30/2016

SCHEDULE 12.APPX A - 12, OATT SCHEDULE 12.APPENDIX A - 12 Public Service Electric and, 9.3.0 Effective 1/1/2017

SCHEDULE 12.APPX A - 12, OATT SCHEDULE 12.APPENDIX A - 12 Public Service Electric and, 10.2.0 Effective 2/15/2017

SCHEDULE 12.APPX A - 12, OATT SCHEDULE 12.APPENDIX A - 12 Public Service Electric and, 11.2.0 Effective 4/6/2017

SCHEDULE 12.APPX A - 12, OATT SCHEDULE 12.APPENDIX A - 12 Public Service Electric and, 12.2.0 Effective 5/1/2017

SCHEDULE 12.APPX A - 12, OATT SCHEDULE 12.APPENDIX A - 12 Public Service Electric and, 13.2.0 Effective 6/15/2017

SCHEDULE 12.APPX A - 12, OATT SCHEDULE 12.APPENDIX A - 12 Public Service Electric and, 14.2.0 Effective 10/10/2017

SCHEDULE 12.APPX A - 12, OATT SCHEDULE 12.APPENDIX A - 12 Public Service Electric and, 15.1.0 Effective 11/23/2017

SCHEDULE 12.APPX A - 12, OATT SCHEDULE 12.APPENDIX A - 12 Public Service Electric and, 15.1.4 Effective 1/1/2018

SCHEDULE 12.APPX A - 12, OATT SCHEDULE 12.APPENDIX A - 12 Public Service Electric and, 16.2.0 Effective 2/15/2018

SCHEDULE 12.APPX A - 12, OATT SCHEDULE 12.APPENDIX A - 12 Public Service Electric and, 17.1.0 Effective 4/5/2018

SCHEDULE 12.APPX A - 12, OATT SCHEDULE 12.APPENDIX A - 12 Public Service Electric and, 18.1.0 Effective 6/14/2018

SCHEDULE 12.APPX A - 12, OATT SCHEDULE 12.APPENDIX A - 12 Public Service Electric and, 19.1.0 Effective 8/9/2018

SCHEDULE 12.APPX A - 12, OATT SCHEDULE 12.APPENDIX A - 12 Public Service Electric and, 20.1.0 Effective 11/28/2018

SCHEDULE 12.APPX A - 12, OATT SCHEDULE 12.APPENDIX A - 12 Public Service Electric and, 20.1.2 Effective 1/1/2019

SCHEDULE 12.APPX A - 12, OATT SCHEDULE 12.APPENDIX A - 12 Public Service Electric and, 21.2.0 Effective 1/31/2019

SCHEDULE 12.APPX A - 20, OATT SCHEDULE 12.APPENDIX A - 20 Virginia Electric and Power, 6.5.0 Effective 2/16/2016

SCHEDULE 12.APPX A - 20, OATT SCHEDULE 12.APPENDIX A - 20 Virginia Electric and Power, 7.5.0 Effective 4/14/2016

SCHEDULE 12.APPX A - 20, OATT SCHEDULE 12.APPENDIX A - 20 Virginia Electric and Power, 8.3.0 Effective 6/16/2016

SCHEDULE 12.APPX A - 20, OATT SCHEDULE 12.APPENDIX A - 20 Virginia Electric and Power, 9.3.0 Effective 11/30/2016

SCHEDULE 12.APPX A - 20, OATT SCHEDULE 12.APPENDIX A - 20 Virginia Electric and Power, 10.2.0 Effective 1/1/2017

SCHEDULE 12.APPX A - 20, OATT SCHEDULE 12.APPENDIX A - 20 Virginia Electric and Power, 11.2.0 Effective 4/6/2017

SCHEDULE 12.APPX A - 20, OATT SCHEDULE 12.APPENDIX A - 20 Virginia Electric and Power, 12.3.0 Effective 5/1/2017

SCHEDULE 12.APPX A - 20, OATT SCHEDULE 12.APPENDIX A - 20 Virginia Electric and Power, 13.2.0 Effective 6/15/2017

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

Public Service Electric and Gas Company

ATTACHMENT H-10A

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

Public Service Electric and Gas Company

ATTACHMENT H-10A

	Formula Rate -- Appendix A	**Notes**	**FERC Form 1 Page # or Instruction**	**12 Months Ended 12/31/2020**
	Shaded cells are input cells			
	Adjustment To Rate Base			
	Accumulated Deferred Income Taxes			
44	**ADIT net of FASB 106 and 109**	(Note Q)	Attachment 1	-1,952,250,535
	Regulatory Assets and Liabilities			
44a	Deficient Deferred Taxes Regulatory Asset (Account 182.3)	(Note V)		0
44b	Excess Deferred Taxes Regulatory Liability (Account 254)	(Note V)		-700,653,076
44c	**Deficient/Excess Deferred Taxes Regulatory Assets and Liabilities Allocated to Transmission**		(Line 44a + 44b)	**-700,653,076**
	CWIP for Incentive Transmission Projects			
45	CWIP Balances for Current Rate Year	(Note B & H)	Attachment 6	0
	Abandoned Transmission Projects			
45a	Unamortized Abandoned Transmission Projects	(Note R)	Attachment 5	0
46	**Plant Held for Future Use**	(Note C & Q)	Attachment 5	24,787,616
	Prepayments			
47	Prepayments	(Note A & Q)	Attachment 5	377,686
	Materials and Supplies			
48	Undistributed Stores Expense	(Note Q)	Attachment 5	0
49	Wage & Salary Allocator		(Line 5)	18.5000%
50	Total Undistributed Stores Expense Allocated to Transmission		(Line 48 * Line 49)	0
51	Transmission Materials & Supplies	(Note N & Q))	Attachment 5	5,438,864
52	Total Materials & Supplies Allocated to Transmission		(Line 50 + Line 51)	5,438,864
	Cash Working Capital			
53	Operation & Maintenance Expense		(Line 80)	136,939,600
54	1/8th Rule		1/8	12.5%
55	Total Cash Working Capital Allocated to Transmission		(Line 53 * Line 54)	17,117,450
	Network Credits			
56	Outstanding Network Credits	(Note N & Q))	Attachment 5	0
57	**Total Adjustment to Rate Base**		**(Lines 44 + 44c+ 45 + 45a + 46 + 47 + 52 + 55 - 56)**	**(2,605,181,996)**
58	**Rate Base**		(Line 43 + Line 57)	**9,656,457,143**
	Operations & Maintenance Expense			
	Transmission O&M			
59	Transmission O&M	(Note O)	Attachment 5	119,900,000
60	Plus Transmission Lease Payments	(Note O)	Attachment 5	0
61	**Transmission O&M**		(Lines 59 + 60)	**119,900,000**
	Allocated Administrative & General Expenses			
62	Total A&G	(Note O)	Attachment 5	95,466,338
63	Plus: Actual PBOP expense	(Note J)	Attachment 5	-44,948,588
64	Less: Actual PBOP expense	(Note O)	Attachment 5	-44,948,588
65	Less Property Insurance Account 924	(Note O)	Attachment 5	2,908,029
66	Less Regulatory Commission Exp Account 928	(Note E & O)	Attachment 5	10,698,000
67	Less General Advertising Exp Account 930.1	(Note O)	Attachment 5	2,731,244
68	Less EPRI Dues	(Note D & O)	Attachment 5	0
69	**Administrative & General Expenses**		Sum (Lines 62 to 63) - Sum (Lines 64 to 68)	79,129,065
70	Wage & Salary Allocator		(Line 5)	18.5000%
71	**Administrative & General Expenses Allocated to Transmission**		(Line 69 * Line 70)	**14,638,877**
	Directly Assigned A&G			
72	Regulatory Commission Exp Account 928	(Note G & O)	Attachment 5	600,000
73	General Advertising Exp Account 930.1	(Note K & O)	Attachment 5	0
74	Subtotal - Accounts 928 and 930.1 - Transmission Related		(Line 72 + Line 73)	600,000
75	Property Insurance Account 924		(Line 65)	2,908,029
76	General Advertising Exp Account 930.1	(Note F & O)	Attachment 5	0
77	Total Accounts 928 and 930.1 - General		(Line 75 + Line 76)	2,908,029
78	Net Plant Allocator		(Line 18)	61.9225%
79	**A&G Directly Assigned to Transmission**		(Line 77 * Line 78)	**1,800,723**
80	**Total Transmission O&M**		**(Lines 61 + 71 + 74 + 79)**	**136,939,600**

Public Service Electric and Gas Company

ATTACHMENT H-10A

Formula Rate -- Appendix A		**Notes**	**FERC Form 1 Page # or Instruction**	**12 Months Ended 12/31/2020**
Shaded cells are input cells				
Depreciation & Amortization Expense				
	Depreciation Expense			
81	Transmission Depreciation Expense Including Amortization of Limited Term Plant	(Note J & O)	Attachment 5	314,999,246
81a	Amortization of Abandoned Plant Projects	(Note R)	Attachment 5	0
82	General Depreciation Expense Including Amortization of Limited Term Plant	(Note J & O)	Attachment 5	25,877,721
83	Less: Amount of General Depreciation Expense Associated with Acct. 397	(Note J & O)	Attachment 5	5,322,079
84	Balance of General Depreciation Expense		(Line 82 - Line 83)	20,555,642
85	Intangible Amortization	(Note A & O)	Attachment 5	14,970,855
86	Total		(Line 84 + Line 85)	35,526,497
87	Wage & Salary Allocator		(Line 5)	18.50%
88	General Depreciation & Intangible Amortization Allocated to Transmission		(Line 86 * Line 87)	6,572,402
89	General Depreciation Expense for Acct. 397 Directly Assigned to Transmission	(Note J & O)	Attachment 5	593,444
90	**General Depreciation and Intangible Amortization Functionalized to Transmission**		(Line 88 + Line 89)	**7,165,846**
91	**Total Transmission Depreciation & Amortization**		**(Lines 81 + 81a + 90)**	**322,165,092**
Taxes Other than Income Taxes				
92	Taxes Other than Income Taxes	(Note O)	Attachment 2	13,745,442
93	**Total Taxes Other than Income Taxes**		(Line 92)	**13,745,442**
Return \ Capitalization Calculations				
94	**Long Term Interest**		p117.62.c through 67.c	345,679,200
95	**Preferred Dividends**	enter positive	p118.29.d	0
	Common Stock			
96	Proprietary Capital	(Note P)	Attachment 5	10,426,269,000
97	Less Accumulated Other Comprehensive Income Account 219	(Note P)	Attachment 5	-124,929
98	Less Preferred Stock		(Line 106)	0
99	Less Account 216.1	(Note P)	Attachment 5	347,223
100	**Common Stock**		(Line 96 - 97 - 98 - 99)	10,426,046,707
	Capitalization			
101	Long Term Debt	(Note P)	Attachment 5	8,936,676,372
102	Less Loss on Reacquired Debt	(Note P)	Attachment 5	51,694,145
103	Plus Gain on Reacquired Debt	(Note P)	Attachment 5	0
104	Less ADIT associated with Gain or Loss	(Note P)	Attachment 5	11,359,479
105	Total Long Term Debt		(Line 101 - 102 + 103 - 104)	8,873,622,748
106	Preferred Stock	(Note P)	Attachment 5	0
107	Common Stock		(Line 100)	10,426,046,707
108	**Total Capitalization**		(Sum Lines 105 to 107)	19,299,669,455
109	Debt % — Total Long Term Debt		(Line 105 / Line 108)	45.98%
110	Preferred % — Preferred Stock		(Line 106 / Line 108)	0.00%
111	Common % — Common Stock		(Line 107 / Line 108)	54.02%
112	Debt Cost — Total Long Term Debt		(Line 94 / Line 105)	0.0390
113	Preferred Cost — Preferred Stock		(Line 95 / Line 106)	0.0000
114	Common Cost — Common Stock	(Note J)	Fixed	0.1168
115	Weighted Cost of Debt — Total Long Term Debt (WCLTD)		(Line 109 * Line 112)	0.0179
116	Weighted Cost of Preferred — Preferred Stock		(Line 110 * Line 113)	0.0000
117	Weighted Cost of Common — Common Stock		(Line 111 * Line 114)	0.0631
118	**Rate of Return on Rate Base (ROR)**		(Sum Lines 115 to 117)	**0.0810**
119	**Investment Return = Rate Base * Rate of Return**		**(Line 58 * Line 118)**	**782,257,201**

Public Service Electric and Gas Company

ATTACHMENT H-10A

	Formula Rate -- Appendix A		**Notes**	**FERC Form 1 Page # or Instruction**	**12 Months Ended 12/31/2020**
	Shaded cells are input cells				
	Composite Income Taxes				
	Income Tax Rates				
120	FIT=Federal Income Tax Rate		(Note I)		21.00%
121	SIT=State Income Tax Rate or Composite				9.00%
122	p	(percent of federal income tax deductible for state purposes)		Per State Tax Code	0.00%
123	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			28.11%
124	T / (1-T)				39.10%
	ITC Adjustment				
125	Amortized Investment Tax Credit	enter negative	(Note O)	Attachment 5	-596,182
126	1/(1-T)			1 / (1 - Line 123)	139.10%
127	Net Plant Allocation Factor			(Line 18)	61.92%
128	**ITC Adjustment Allocated to Transmission**			(Line 125 * Line 126 * Line 127)	**-513,521**
	Deficient/Excess Deferred Taxes Amortization				
128a	Amortized Deficient Deferred Taxes (Account 410.1)		(Note S & V)		0
128b	Amortized Excess Deferred Taxes (Account 411.1)	enter negative	(Note T & V)		-3,054,643
128c	Total			(Line 128a + Line 128b)	-3,054,643
128d	1/(1-T)			1 / (1 - Line 123)	139.10%
128e	**Deficient/Excess Deferred Taxes Allocated to Transmission**			(Line 128c * Line 128d)	**-4,249,051**
	AFUDC Equity Permanent Difference				
128f	Tax Effect of AFUDC Equity Permanent Difference		(Note U)		1,671,969
128g	1/(1-T)			1 / (1 - Line 123)	139.10%
128h	**AFUDC Equity Permanent Difference Tax Adjustment**			(Line 128f * Line 128g)	**2,325,732**
129	**Income Tax Component =**	(T/1-T) * Investment Return * (1-(WCLTD/ROR)) =		[Line 124 * Line 119 * (1- (Line 115 / Line 118))]	**238,244,464**
130	**Total Income Taxes**			**(Lines 128 + 128e + 128h + 129)**	**235,807,623**
	Revenue Requirement				
	Summary				
131	Net Property, Plant & Equipment			(Line 43)	12,261,639,139
132	Total Adjustment to Rate Base			(Line 57)	-2,605,181,996
133	**Rate Base**			(Line 58)	**9,656,457,143**
134	Total Transmission O&M			(Line 80)	136,939,600
135	Total Transmission Depreciation & Amortization			(Line 91)	322,165,092
136	Taxes Other than Income			(Line 93)	13,745,442
137	Investment Return			(Line 119)	782,257,201
138	Income Taxes			(Line 130)	235,807,623
139	**Gross Revenue Requirement**			**(Sum Lines 134 to 138)**	**1,490,914,959**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
140	Transmission Plant In Service			(Line 19)	13,452,583,031
141	Excluded Transmission Facilities		(Note B & M)	Attachment 5	0
142	Included Transmission Facilities			(Line 140 - Line 141)	13,452,583,031
143	Inclusion Ratio			(Line 142 / Line 140)	100.00%
144	Gross Revenue Requirement			(Line 139)	1,490,914,959
145	**Adjusted Gross Revenue Requirement**			(Line 143 * Line 144)	**1,490,914,959**
	Revenue Credits & Interest on Network Credits				
146	**Revenue Credits**		(Note O)	Attachment 3	25,142,484
147	**Interest on Network Credits**		(Note N & O)	Attachment 5	0
148	**Net Revenue Requirement**			**(Line 145 - Line 146 + Line 147)**	**1,465,772,474**
	Net Plant Carrying Charge				
149	Gross Revenue Requirement			(Line 144)	**1,490,914,959**
150	Net Transmission Plant, CWIP and Abandoned Plant			(Line 19 - Line 32 + Line 45 + Line 45a)	**12,205,804,738**
151	Net Plant Carrying Charge			(Line 149 / Line 150)	**12.2148%**
152	Net Plant Carrying Charge without Depreciation			(Line 149 - Line 81) / Line 150	**9.6341%**
153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes			(Line 149 - Line 81 - Line 119 - Line 130) / Line 150	**1.2932%**
	Net Plant Carrying Charge Calculation per 100 Basis Point increase in ROE				
154	Gross Revenue Requirement Less Return and Taxes			(Line 144 - Line 137 - Line 138)	**472,850,134**
155	Increased Return and Taxes			Attachment 4	**1,090,628,476**
156	Net Revenue Requirement per 100 Basis Point increase in ROE			(Line 154 + Line 155)	**1,563,478,610**
157	Net Transmission Plant, CWIP and Abandoned Plant			(Line 19 - Line 32 + Line 45 + Line 45a)	**12,205,804,738**
158	Net Plant Carrying Charge per 100 Basis Point increase in ROE			(Line 156 / Line 157)	**12.8093%**
159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation			(Line 156 - Line 81) / Line 157	**10.2286%**
160	**Net Revenue Requirement**			(Line 148)	**1,465,772,474**
161	True-up amount			Attachment 6	**54,284,878**
162	Plus any increased ROE calculated on Attachment 7 other than PJM Sch. 12 projects not paid by other PJM transmission zon			Attachment 7	**6,240,455**
163	Facility Credits under Section 30.9 of the PJM OATT			Attachment 5	**0**
164	**Net Zonal Revenue Requirement**			(Line 160 + 161 + 162 + 163)	**1,526,297,808**

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

Public Service Electric and Gas Company			
ATTACHMENT H-10A			
Formula Rate -- Appendix A	**Notes**	**FERC Form 1 Page # or Instruction**	**12 Months Ended 12/31/2020**

Shaded cells are input cells

Notes

A Electric portion only

B Calculated using 13-month average balances

C Includes Transmission portion only. At each annual informational filing, Company will identify for each parcel of land an intended use within a 15 year period

D Includes all EPRI Annual Membership Dues

E Includes all Regulatory Commission Expenses

F Includes Safety related advertising included in Account 930.1

G Includes Regulatory Commission Expenses directly related to transmission service, RTO filings, or transmission siting itemized in Form 1 at 351.h

H CWIP can only be included if authorized by the Commission

I The currently effective income tax rate where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = the percentage of federal income tax deductible for state income taxes

J ROE will be supported in the original filing and no change in ROE will be made absent a filing at FERC

PBOP expense shall be based upon the Company's Actual Annual PBOP Expense until changed by a filing at FERC

The actual Annual PBOP Expense to be included in the Formula Rate Annual Update that is required to be filed on or before October 15 of each year shall be based upon the Actual Annual PBOP Expense as charged to FERC Account 926 on behalf of electric employees for PBOP and as included by the Company in its most recent True-up Adjustment filing.

PSEG will provide, in connection with each annual True-Up Adjustment filing a confidential copy of relevant pages from annual actuarial valuation report supporting the derivation of the Actual Annual PBOP Expense as charged to FERC Account 926 on behalf of electric employees

Depreciation rates shown in Attachment 8 are fixed until changed as the result of a filing at FERC

If book depreciation rates are different than the Attachment 8 rates, PSE&G will provide workpapers at the annual update to reconcile formula depreciation expense and depreciation accruals to FERC Form 1 amounts

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

L As provided for in Section 34.1 of the PJM OATT; the PJM established billing determinants will not be revised or updated in the annual rate reconciliations

M Amount of transmission plant excluded from rates per Attachment 5

N Outstanding Network Credits is the balance of Network Facilities Upgrades Credits due Transmission Customers who have made lump-sum payments towards the construction of Network Transmission Facilities consistent with Paragraph 657 of Order 2003-A

Interest on the Network Credits as booked each year is added to the revenue requirement to make the Transmission Owner whole on Line "&A248&"."

O Expenses reflect full year plan

P The projected capital structure shall reflect the capital structure from the FERC Form 1 data. For all other formula rate calculations, the projected capital structure and actual capital structure shall reflect the capital structure from the most recent FERC Form 1 data available.

Calculated using the average of the prior year and current year balances

Q Calculated using beginning and year end projected balances

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

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

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

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

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

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

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

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

	Only Transmission Related	Plant Related	Labor Related	Total ADIT	
ADIT- 282 (Not Subject to Proration)	(643,692,362)	0	(4,977,254)		From Acct. 282 (Not Subject to Proration) total, below
ADIT-283	0	(7,434,037)	0		From Acct. 283 total, below
ADIT-190	0	0	2,421,243		From Acct. 190 total, below
Subtotal	(643,692,362)	(7,434,037)	(2,556,011)		
Wages & Salary Allocator			18.5000%		
Net Plant Allocator		61.9225%			
End of Year ADIT	(643,692,362)	(4,603,338)	(472,862)	**(648,768,563)**	
End of Previous Year ADIT (from Sheet 1A-ADIT)	(589,527,551)	(4,878,080)	(327,522)	**(594,733,153)**	
Average Beginning and End of Year ADIT	(616,609,957)	(4,740,709)	(400,192)	**(621,750,858)**	
ADIT- 282 (Subject to Proration)	(1,327,246,612)	0	(3,253,066)	**(1,330,499,678)**	From Acct. 282 (Subject to Proration) total, below
Total Accumulated Deferred Income Taxes				**(1,952,250,535)**	Appendix A, Line 44

Note: ADIT associated with Gain or Loss on Reacquired Debt is included in Column A here and included in Cost of Debt on Appendix A, Line 108
(7,434,037) < From Acct 283, below

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

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

Instructions for Account 190:

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

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

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

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

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

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

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

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

A	B	C	D	E	F	G
ADIT- 282 (Subject to Proration)	*Total*	*Gas, Prod Or Other Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
Depreciation - Liberalized Depreciation (Federal)	(2,713,961,903)	(1,369,131,152)	(1,327,246,612)	0	(17,584,139)	For federal - Column D represents the direct assignment of prorated ADIT associated with Transmission assets,, column F represents ADIT associated with the allocation of common plant and column C represents estimated electrical distribution ADI
Subtotal - ADIT- 282 (Subject to Proration)	**(2,713,961,903)**	**(1,369,131,152)**	**(1,327,246,612)**	**0**	**(17,584,139)**	
Less FASB 109 Above if not separately removed						
Less FASB 106 Above if not separately removed						
Total ADIT- 282 (Subject to Proration)	**(2,713,961,903)**	**(1,369,131,152)**	**(1,327,246,612)**	**0**	**(17,584,139)**	

Instructions for Account 282:

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

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

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

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

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

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

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

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

Instructions for Account 283:

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

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

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

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

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

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

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

Note: ADIT associated with Gain or Loss on Reacquired Debt is included in Column A here and included in Cost of Debt on Appendix A, Line 108
(7,877,723) < From Acct 283, below

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

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

Instructions for Account 190:

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

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

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

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

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

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

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

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

A	B	C	D	E	F	G
ADIT- 282 (Subject to Proration)	*Total*	*Gas, Prod Or Other Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
Depreciation - Liberalized Depreciation (Federal)	(2,629,727,733)	(1,369,131,152)	(1,247,846,528)	0	(12,750,053)	For federal - Column D represents the direct assignment of prorated ADIT associated with Transmission assets,, column F represents ADIT associated with the allocation of common plant and column C represents estimated electrical distribution ADIT
Subtotal - ADIT- 282 (Subject to Proration)	**(2,629,727,733)**	**(1,369,131,152)**	**(1,247,846,528)**	**0**	**(12,750,053)**	
Less FASB 109 Above if not separately removed						
Less FASB 106 Above if not separately removed						
Total ADIT- 282 (Subject to Proration)	**(2,629,727,733)**	**(1,369,131,152)**	**(1,247,846,528)**	**0**	**(12,750,053)**	

Instructions for Account 282:

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

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

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

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

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

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

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

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

Instructions for Account 283:

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

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

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

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

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

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 2 - Taxes Other Than Income Worksheet - December 31, 2020

	Other Taxes	*Page 263 Col (i)*	*Allocator*	*Allocated Amount*	
	Plant Related				
1	Real Estate	24,262,000			Attachment #5
2	***Total Plant Related***	24,262,000	N/A	10,788,000	
	Labor Related		***Wages & Salary Allocator***		
3	FICA	14,967,550			
4	Federal Unemployment Tax	83,153			
5	New Jersey Unemployment Tax	623,648			
6	New Jersey Workforce Development	311,824			
7					
8	***Total Labor Related***	15,986,175	18.5000%	2,957,442	
	Other Included		***Net Plant Allocator***		
9		0			
10		0			
11		0			
12		0			
13	***Total Other Included***	0	61.9225%	0	
14	***Total Included (Lines 8 + 14 + 19)***	40,248,175		13,745,442	
	Currently Excluded				
15	Corporate Business Tax	0			
16	TEFA	0			
17	Use & Sales Tax	0			
18	Local Franchise Tax	0			
19	PA Corporate Income Tax	0			
20	Municipal Utility	0			
21	Public Utility Fund	0			
22	**Subtotal, Excluded**	0			
23	**Total, Included and Excluded (Line 20 + Line 28)**	40,248,175			
24	**Total Other Taxes from p114.14.g - Actual**	40,248,175			
25	Difference (Line 29 - Line 30)	-			

Criteria for Allocation:

A Other taxes that are incurred through ownership of plant including transmission plant will be allocated based on the Net Plant Allocator. If the taxes are 100% recovered at retail they shall not be included. Real Estate taxes are directly assigned to Transmission.

B Other taxes that are incurred through ownership of only general or intangible plant will be allocated based on the Wages and Salary Allocator. If the taxes are 100% recovered at retail they shall not be included.

C Other taxes that are assessed based on labor will be allocated based on the Wages and Salary Allocator.

D Other taxes except as provided for in A, B and C above, that are incurred and (1) are not fully recovered at retail or (2) are directly or indirectly related to transmission service will be allocated based on the Net Plant Allocator; provided, however, that overheads shall be treated as in footnote B above.

E Excludes prior period adjustments in the first year of the formula's operation and reconciliation for the first year.

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 3 - Revenue Credit Workpaper - December 31, 2020

	Accounts 450 & 451		
1	Late Payment Penalties Allocated to Transmission		0
	Account 454 - Rent from Electric Property		
2	Rent from Electric Property - Transmission Related (Note 2)		700,000
	Account 456 - Other Electric Revenues		
3	Transmission for Others		0
4	Schedule 1A		5,225,000
5	Net revenues associated with Network Integration Transmission Service (NITS) for which the load is not included in the divisor (difference between NITS credits from PJM and PJM NITS charges paid by Transmission Owner)		
6	Point to Point Service revenues for which the load is not included in the divisor received by Transmission Owner		10,200,000
7	Professional Services (Note 2)		20,000
8	Revenues from Directly Assigned Transmission Facility Charges (Note 1)		7,811,551
9	Rent or Attachment Fees associated with Transmission Facilities (Note 2)		4,582,359
10	Gross Revenue Credits	(Sum Lines 1-9)	28,538,910
11	Less line 18	- line 18	(3,396,426)
12	Total Revenue Credits	line 10 + line 11	25,142,484

13	Revenues associated with lines 2, 7, and 9 (Note 2)	5,302,359
14	Income Taxes associated with revenues in line 13	1,490,493
15	One half margin (line 13 - line 14)/2	1,905,933
16	All expenses (other than income taxes) associated with revenues in line 13 that are included in FERC accounts recovered through the formula times the allocator used to functionalize the amounts in the FERC account to the transmission service at issue.	-
17	Line 15 plus line 16	1,905,933
18	Line 13 less line 17	3,396,426

Note 1 If the costs associated with the Directly Assigned Transmission Facility Charges are included in the Rates, the associated revenues are included in the Rates. If the costs associated with the Directly Assigned Transmission Facility Charges are not included in the Rates, the associated revenues are not included in the Rates.

Note 2 Ratemaking treatment for the following specified secondary uses of transmission assets: (1) right-of-way leases and leases for space on transmission facilities for telecommunications; (2) transmission tower licenses for wireless antennas; (3) right-of-way property leases for farming, grazing or nurseries; (4) licenses of intellectual property (including a portable oil degasification process and scheduling software); and (5) transmission maintenance and consulting services (including energized circuit maintenance, high-voltage substation maintenance, safety training, transformer oil testing, and circuit breaker testing) to other utilities and large customers (collectively, products). PSE&G will retain 50% of net revenues consistent with *Pacific Gas and Electric Company* , 90 FERC ¶ 61,314. Note: in order to use lines 13-18, the utility must track in separate subaccounts the revenues and costs associated with each secondary use (except for the cost of the associated income taxes).

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 4 - Calculation of 100 Basis Point Increase in ROE

	Return and Taxes with 100 Basis Point increase in ROE			
A	100 Basis Point increase in ROE and Income Taxes		Line 27 + Line 47 from below	1,090,628,476
B	100 Basis Point increase in ROE			1.00%
	Return Calculation			
			Appendix A Line or Source Reference	
1	**Rate Base**		(Line 43 + Line 57)	9,656,457,143
2	**Long Term Interest**		p117.62.c through 67.c	345,679,200
3	**Preferred Dividends**	enter positive	p118.29.d	0
	Common Stock			
4	Proprietary Capital		Attachment 5	10,426,269,000
5	Less Accumulated Other Comprehensive Income Account 219		p112.15.c	-124,929
6	Less Preferred Stock		(Line 106)	0
7	Less Account 216.1		Attachment 5	347,223
8	Common Stock		(Line 96 - 97 - 98 - 99)	10,426,046,707
	Capitalization			
9	Long Term Debt		Attachment 5	8,936,676,372
10	Less Loss on Reacquired Debt		Attachment 5	51,694,145
11	Plus Gain on Reacquired Debt		Attachment 5	0
12	Less ADIT associated with Gain or Loss		Attachment 5	11,359,479
13	Total Long Term Debt		(Line 101 - 102 + 103 - 104)	8,873,622,748
14	Preferred Stock		Attachment 5	0
15	Common Stock		(Line 100)	10,426,046,707
16	Total Capitalization		(Sum Lines 105 to 107)	19,299,669,455
17	Debt %	Total Long Term Debt	(Line 105 / Line 108)	46.0%
18	Preferred %	Preferred Stock	(Line 106 / Line 108)	0.0%
19	Common %	Common Stock	(Line 107 / Line 108)	54.0%
20	Debt Cost	Total Long Term Debt	(Line 94 / Line 105)	0.0390
21	Preferred Cost	Preferred Stock	(Line 95 / Line 106)	0.0000
22	Common Cost	Common Stock	(Line 114 + 100 basis points)	0.1268
23	Weighted Cost of Debt	Total Long Term Debt (WCLTD)	(Line 109 * Line 112)	0.0179
24	Weighted Cost of Preferred	Preferred Stock	(Line 110 * Line 113)	0.0000
25	Weighted Cost of Common	Common Stock	(Line 111 * Line 114)	0.0685
26	**Rate of Return on Rate Base (ROR)**		**(Sum Lines 115 to 117)**	**0.0864**
27	**Investment Return = Rate Base * Rate of Return**		**(Line 58 * Line 118)**	**834,423,210**
	Composite Income Taxes			
	Income Tax Rates			
28	FIT=Federal Income Tax Rate			21.00%
29	SIT=State Income Tax Rate or Composite			9.00%
30	p = percent of federal income tax deductible for state purposes		Per State Tax Code	0.00%
31	T	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		28.11%
32	CIT = T / (1-T)			39.10%
33	1 / (1-T)			139.10%
	ITC Adjustment			
34	Amortized Investment Tax Credit	enter negative	Attachment 5	-596,182
35	1/(1-T)		1 / (1 - Line 123)	139.10%
36	Net Plant Allocation Factor		(Line 18)	61.9225%
37	**ITC Adjustment Allocated to Transmission**		(Line 125 * Line 126 * Line 127)	**-513,521**
	Deficient/Excess Deferred Taxes Amortization			
38	Amortized Deficient Deferred Taxes (Account 410.1)		(Line 128a)	0
39	Amortized Excess Deferred Taxes (Account 411.1)	enter negative	(Line 128b)	-3,054,643
40	Total		(Line 128a + Line 128b)	-3,054,643
41	1/(1-T)		1 / (1 - Line 123)	139.10%
42	**Deficient/Excess Deferred Taxes Allocated to Transmission**		(Line 128c * Line 128d)	**-4,249,051**
	AFUDC Equity Permanent Difference			
43	Tax Effect of AFUDC Equity Permanent Difference		(Line 128f)	1,671,969
44	1/(1-T)		1 / (1 - Line 123)	139.10%
45	**AFUDC Equity Permanent Difference Tax Adjustment**		(Line 128f * Line 128g)	**2,325,732**
46	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		258,642,106
47	**Total Income Taxes**			**256,205,266**

Electric / Non-electric Cost Support

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

Wages & Salary

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

Transmission / Non-transmission Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Beginning Year Balance	End of Year	Average
	Plant Held for Future Use (Including Land)	(Note C & Q)	p214.47.d	25,282,793	25,282,793	25,282,793
46	Transmission Only			24,787,616	24,787,616	24,787,616

Prepayments

Line #s	Descriptions	Notes	Page #'s & Instructions	Previous Year	Electric Beginning Year Balance	Electric End of Year Balance	Average Balance	Wage & Salary Allocator	To Line 47
	Prepayments								
47	Prepayments	(Note A & Q)	p111.57c	10,176,785	2,041,544	2,041,544	2,041,544	18.500%	377,686

Materials and Supplies

Line #s	Descriptions	Notes	Page #'s & Instructions	Beginning Year Balance	End of Year	Average
	Materials and Supplies					
48	Undistributed Stores Exp	(Note Q)	p227.16.b,c	0	0	0
51	Transmission Materials & Supplies	(Note N & Q))	p227.8.b,c	5,233,800	5,643,927	5,438,864

Outstanding Network Credits Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Beginning Year Balance	End of Year	Average
	Network Credits					
56	**Outstanding Network Credits**	(Note N & Q))	From PJM	0	0	0

O&M Expenses

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
59	Transmission O&M	(Note O)	p.321.112.b	119,900,000
60	Transmission Lease Payments		p321.96.b	0

Property Insurance Expenses

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

Adjustments to A & G Expense

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

Regulatory Expense Related to Transmission Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year	Transmission Related
	Allocated General & Common Expenses				
66	Regulatory Commission Exp Account 928	(Note E & O)	p323.189b	10,698,000	-
	Directly Assigned A&G				
72	Regulatory Commission Exp Account 928	(Note G & O)	p351.11-13h	600,000	600,000

General & Common Expenses

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

Safety Related Advertising Cost Support

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

Education and Out Reach Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year	Education & Outreach	Other
	Directly Assigned A&G					
76	General Advertising Exp Account 930.1	(Note K & O)	p323.191b	2,731,244	0	2,731,244

Depreciation Expense

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

Direct Assignment of Transmission Real Estate Taxes

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year	Transmission Related	Non-Transmission
92	Real Estate Taxes - Directly Assigned to Transmission		p263.33i	24,262,000	10,788,000	13,474,000

PSE&G's real estate taxes detail is in an access database which contains a list of the towns PSE&G pays taxes to, which are billed on a quarterly basis for various parcels of property by major classification.
Every parcel is associated with a Lot & Block number. These Lot & Blocks are identified to a particular type of property and are labeled. This is the breakout of transmission real estate taxes from total electric.

~~Attachment 9 PSE&G Formula Rate~~

Return \ Capitalization

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

MultiState Workpaper

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

Amortized Investment Tax Credit

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

Excluded Transmission Facilities

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

Interest on Outstanding Network Credits Cost Support

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

Facility Credits under Section 30.9 of the PJM OATT

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

PJM Load Cost Support

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

Abandoned Transmission Projects

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

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

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

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

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

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

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

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

Summary of Formula Rate Process including True-Up Adjustment

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

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

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

Calendar Year — Complete for Each Calendar Year beginning in 2009

A	ATRR based on actual costs included for the previous calendar year but excludes the true-up	1,300,562,584	
B	ATRR based on projected costs included for the previous calendar year but excludes the true	1,248,819,352	
C	Difference (A-B)	51,743,232	<Note: for the first rate year, divide this reconciliation amount by 12 and multiply by the number of months and fractional months the rate was in effect.
D	Future Value Factor (1+i)^24	1.04912	
E	True-up Adjustment (C*D)	54,284,878	

Where:
i = average interest rate as calculated below

Interest on Amount of Refunds or Surcharges

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

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

Estimated Additions - 2020

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

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

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

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

Total Projects	Branchburg (B0130)	Kittatinny (B0134)	Essex Aldene (B0145)	New Freedom Trans.(B0411)	New Freedom Loop (B0498)	Metuchen Transformer (B0161)	Branchburg-Flagtown-Somerville (B0169)	Flagtown-Somerville-Bridgewater (B0170)	Roseland Transformers (B0274)	Wave Trap Branchburg (B0172.2)	Reconductor Hudson - South Waterfront (B0813)	Reconductor South Mahwah J-3410 Circuit (B1017)	Reconductor South Mahwah K-3411 Circuit (B1018)
557,792,331	1,816,716	739,676	7,924,480	2,008,572	2,554,747	2,463,871	1,506,600	658,328	2,016,205	2,582	909,564	2,070,898	2,151,506

Actual Transmission Enhancement Charges - 2018

Total Projects	Branchburg (B0130)	Kittatinny (B0134)	Essex Aldene (B0145)	New Freedom Trans.(B0411)	New Freedom Loop (B0498)	Metuchen Transformer (B0161)	Branchburg-Flagtown-Somerville (B0169)	Flagtown-Somerville-Bridgewater (B0170)	Roseland Transformers (B0274)	Wave Trap Branchburg (B0172.2)	Reconductor Hudson - South Waterfront (B0813)	Reconductor South Mahwah J-3410 Circuit (B1017)	Reconductor South Mahwah K-3411 Circuit (B1018)
526,176,658	1,953,369	793,960	8,506,133	2,157,095	2,738,764	2,639,774	1,614,339	705,757	2,160,233	2,771	973,247	2,214,984	2,300,157

Public Service Electric and Gas Company
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Reconciliation by Project (without interest)

	Total Projects	Branchburg (B0130)	Kittatinny (B0134)	Essex Aldene (B0145)	New Freedom Trans.(B0411)	New Freedom Loop (B0498)	Metuchen Transformer (B0161)	Branchburg-Flagtown-Somerville (B0169)	Flagtown-Somerville-Bridgewater (B0170)	Roseland Transformers (B0274)	Wave Trap Branchburg (B0172.2)	Reconductor Hudson - South Waterfront (B0813)	Reconductor South Mahwah J-3410 Circuit (B1017)	Reconductor South Mahwah K-3411 Circuit (B1018)
	18,922,618	**51,370**	**21,117**	**226,442**	**57,149**	**73,535**	**71,520**	**43,500**	**18,947**	**58,375**	**73**	**26,497**	**60,485**	**63,020**
Interest		1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912	1.04912

True Up by Project (with interest) -2018

Total Projects	Branchburg (B0130)	Kittatinny (B0134)	Essex Aldene (B0145)	New Freedom Trans.(B0411)	New Freedom Loop (B0498)	Metuchen Transformer (B0161)	Branchburg-Flagtown-Somerville (B0169)	Flagtown-Somerville-Bridgewater (B0170)	Roseland Transformers (B0274)	Wave Trap Branchburg (B0172.2)	Reconductor Hudson - South Waterfront (B0813)	Reconductor South Mahwah J-3410 Circuit (B1017)	Reconductor South Mahwah K-3411 Circuit (B1018)
19,852,104	**53,893**	**22,154**	**237,565**	**59,956**	**77,147**	**75,033**	**45,637**	**19,878**	**61,242**	**77**	**27,799**	**63,456**	**66,116**

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

Total Projects	Branchburg (B0130)	Kittatinny (B0134)	Essex Aldene (B0145)	New Freedom Trans.(B0411)	New Freedom Loop (B0498)	Metuchen Transformer (B0161)	Branchburg-Flagtown-Somerville (B0169)	Flagtown-Somerville-Bridgewater (B0170)	Roseland Transformers (B0274)	Wave Trap Branchburg (B0172.2)	Reconductor Hudson - South Waterfront (B0813)	Reconductor South Mahwah J-3410 Circuit (B1017)	Reconductor South Mahwah K-3411 Circuit (B1018)
577,644,435	**1,870,610**	**761,830**	**8,162,045**	**2,068,528**	**2,631,894**	**2,538,904**	**1,552,237**	**678,205**	**2,077,448**	**2,658**	**937,362**	**2,134,354**	**2,217,622**

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

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

Branchburg 400 MVAR Capacitor (B0290)	Saddle Brook - Athenia Upgrade Cable (B0472)	Branchburg-Sommerville-Flagtown Reconductor (B0664 & B0665)	Somerville-Bridgewater Reconductor (B0668)	New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie (B0814)	Salem 500 kV breakers (B1410-B1415)	230kV Lawrence Switching Station Upgrade (B1228)	Branchburg-Middlesex Switch Rack (B1155)	Aldene-Springfield Rd. Conversion (B1399)	Upgrade Camden-Richmond 230kV Circuit (B1590)	Susquehanna Roseland Breakers (b0489.5-B0489.15)	Susquehanna Roseland < 500KV (B0489.4)	Susquehanna Roseland > 500KV (B0489)	Burlington - Camden 230kV Conversion (B1156)
7,897,105	**1,479,178**	**1,912,347**	**659,719**	**4,781,410**	**1,666,407**	**2,286,639**	**6,667,112**	**7,813,732**	**1,222,104**	**618,695**	**4,549,433**	**82,109,464**	**37,827,676**

Actual Transmission Enhancement Charges - 2018

Branchburg 400 MVAR Capacitor (B0290)	Saddle Brook - Athenia Upgrade Cable (B0472)	Branchburg-Sommerville-Flagtown Reconductor (B0664 & B0665)	Somerville-Bridgewater Reconductor (B0668)	New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie (B0814)	Salem 500 kV breakers (B1410-B1415)	230kV Lawrence Switching Station Upgrade (B1228)	Branchburg-Middlesex Switch Rack (B1155)	Aldene-Springfield Rd. Conversion (B1399)	Upgrade Camden-Richmond 230kV Circuit (B1590)	Susquehanna Roseland Breakers (b0489.5-B0489.15)	Susquehanna Roseland < 500KV (B0489.4)	Susquehanna Roseland > 500KV (B0489)	Burlington - Camden 230kV Conversion (B1156)
8,441,111	**1,580,774**	**2,043,862**	**704,894**	**5,107,695**	**1,779,404**	**2,441,551**	**7,790,721**	**8,335,470**	**1,303,530**	**660,864**	**4,848,227**	**87,438,438**	**40,377,399**

Public Service Electric and Gas Company
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Reconciliation by Project (without interest)													
Branchburg 400 MVAR Capacitor (B0290)	Saddle Brook - Athenia Upgrade Cable (B0472)	Branchburg-Sommerville-Flagtown Reconductor (B0664 & B0665)	Somerville-Bridgewater Reconductor (B0668)	New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie (B0814)	Salem 500 kV breakers (B1410-B1415)	230kV Lawrence Switching Station Upgrade (B1228)	Branchburg-Middlesex Switch Rack (B1155)	Aldene-Springfield Rd. Conversion (B1399)	Upgrade Camden-Richmond 230kV Circuit (B1590)	Susquehanna Roseland Breakers (b0489.5-B0489.15)	Susquehanna Roseland < 500KV (B0489.4)	Susquehanna Roseland > 500KV (B0489)	Burlington - Camden 230kV Conversion (B1156)
224,477	**43,431**	**56,120**	**19,394**	**140,841**	**49,207**	**67,642**	**870,925**	**231,726**	**36,300**	**18,044**	**134,377**	**2,573,984**	**1,119,475**

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

True Up by Project (with interest) -2018													
Branchburg 400 MVAR Capacitor (B0290)	Saddle Brook - Athenia Upgrade Cable (B0472)	Branchburg-Sommerville-Flagtown Reconductor (B0664 & B0665)	Somerville-Bridgewater Reconductor (B0668)	New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie (B0814)	Salem 500 kV breakers (B1410-B1415)	230kV Lawrence Switching Station Upgrade (B1228)	Branchburg-Middlesex Switch Rack (B1155)	Aldene-Springfield Rd. Conversion (B1399)	Upgrade Camden-Richmond 230kV Circuit (B1590)	Susquehanna Roseland Breakers (b0489.5-B0489.15)	Susquehanna Roseland < 500KV (B0489.4)	Susquehanna Roseland > 500KV (B0489)	Burlington - Camden 230kV Conversion (B1156)
235,503	**45,564**	**58,877**	**20,347**	**147,759**	**51,624**	**70,965**	**913,705**	**243,108**	**38,083**	**18,930**	**140,978**	**2,700,419**	**1,174,464**

Estimated Transmission Enhancement Charges (After True-Up) - 2020													
Branchburg 400 MVAR Capacitor (B0290)	Saddle Brook - Athenia Upgrade Cable (B0472)	Branchburg-Sommerville-Flagtown Reconductor (B0664 & B0665)	Somerville-Bridgewater Reconductor (B0668)	New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie (B0814)	Salem 500 kV breakers (B1410-B1415)	230kV Lawrence Switching Station Upgrade (B1228)	Branchburg-Middlesex Switch Rack (B1155)	Aldene-Springfield Rd. Conversion (B1399)	Upgrade Camden-Richmond 230kV Circuit (B1590)	Susquehanna Roseland Breakers (b0489.5-B0489.15)	Susquehanna Roseland < 500KV (B0489.4)	Susquehanna Roseland > 500KV (B0489)	Burlington - Camden 230kV Conversion (B1156)
8,132,608	**1,524,743**	**1,971,224**	**680,066**	**4,929,169**	**1,718,031**	**2,357,604**	**7,580,817**	**8,056,840**	**1,260,187**	**637,626**	**4,690,410**	**84,809,883**	**39,002,140**

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

Mickleton-Gloucester-Camden(B1398-B1398.7)	North Central Reliability (West Orange Conversion) (B1154)	Northeast Grid Reliability Project (B1304.1-B1304.4)	Northeast Grid Reliability Project (B1304.5-B1304.21)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83)
47,986,044	**38,876,415**	**69,412,039**	**39,417,609**	**20,086,787**	**7,561,879**	**5,585,111**	**18,329,401**	**14,698,486**	**7,644,939**	**4,884,265**	**9,433,963**	**6,320,199**	**6,320,199**

Actual Transmission Enhancement Charges - 2018

Mickleton-Gloucester-Camden(B1398-B1398.7)	North Central Reliability (West Orange Conversion) (B1154)	Northeast Grid Reliability Project (B1304.1-B1304.4)	Northeast Grid Reliability Project (B1304.5-B1304.21)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83)
51,158,369	**41,512,081**	**73,990,538**	**-**	**21,470,382**	**6,824,760**	**4,648,728**	**15,752,824**	**10,529,391**	**5,038,025**	**4,592,318**	**7,365,226**	**5,721,000**	**5,721,000**

Public Service Electric and Gas Company
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Reconciliation by Project (without interest)

Mickleton-Gloucester-Camden(B1398-B1398.7)	North Central Reliability (West Orange Conversion) (B1154)	Northeast Grid Reliability Project (B1304.1-B1304.4)	Northeast Grid Reliability Project (B1304.5-B1304.21)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83)
1,416,666	**1,147,874**	**2,054,546**	0	**1,207,516**	**(486,694)**	**(299,765)**	**(727,672)**	**322,676**	**(407,765)**	**(26,620)**	**(1,105,904)**	**454,182**	**454,182**

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

True Up by Project (with interest) -2018

Mickleton-Gloucester-Camden(B1398-B1398.7)	North Central Reliability (West Orange Conversion) (B1154)	Northeast Grid Reliability Project (B1304.1-B1304.4)	Northeast Grid Reliability Project (B1304.5-B1304.21)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83)
1,486,253	**1,204,258**	**2,155,466**	**-**	**1,266,830**	**(510,601)**	**(314,490)**	**(763,416)**	**338,526**	**(427,795)**	**(27,928)**	**(1,160,226)**	**476,492**	**476,492**

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

Mickleton-Gloucester-Camden(B1398-B1398.7)	North Central Reliability (West Orange Conversion) (B1154)	Northeast Grid Reliability Project (B1304.1-B1304.4)	Northeast Grid Reliability Project (B1304.5-B1304.21)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83)
49,472,297	**40,080,673**	**71,567,505**	**39,417,609**	**21,353,617**	**7,051,279**	**5,270,621**	**17,565,986**	**15,037,012**	**7,217,145**	**4,856,337**	**8,273,737**	**6,796,691**	**6,796,691**

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

Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33)	Upgrade Eagle Point-Gloucester 230kV Circuit (B1588)	Mickleton-Gloucester 230kV Circuit (B2139)	Ridge Road 69kV Breaker Station (B1255)	Cox's Corner-Lumberton 230kV Circuit (B1787)
6,142,767	**6,142,767**	**3,507,445**	**2,801,044**	**3,121,750**	**3,121,750**	**994,130**	**994,104**	**3,939,723**	**1,697,623**	**1,320,595**	**2,145,003**	**4,943,629**	**3,535,865**

Actual Transmission Enhancement Charges - 2018

Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33)	Upgrade Eagle Point-Gloucester 230kV Circuit (B1588)	Mickleton-Gloucester 230kV Circuit (B2139)	Ridge Road 69kV Breaker Station (B1255)	Cox's Corner-Lumberton 230kV Circuit (B1787)
5,578,331	**5,578,331**	**3,734,130**	**-**	**3,303,681**	**3,303,681**	**1,890,122**	**1,890,095**	**2,404,813**	**-**	**1,407,364**	**2,284,765**	**5,123,159**	**3,769,058**

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

Reconciliation by Project (without interest)

Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33)	Upgrade Eagle Point-Gloucester 230kV Circuit (B1588)	Mickleton-Gloucester 230kV Circuit (B2139)	Ridge Road 69kV Breaker Station (B1255)	Cox's Corner-Lumberton 230kV Circuit (B1787)
237,762	**237,762**	**(215,530)**	0	**195,730**	**195,730**	**54,884**	**54,883**	**178,200**	0	**38,515**	**90,863**	**1,007,151**	**105,022**

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

True Up by Project (with interest) -2018

Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33)	Upgrade Eagle Point-Gloucester 230kV Circuit (B1588)	Mickleton-Gloucester 230kV Circuit (B2139)	Ridge Road 69kV Breaker Station (B1255)	Cox's Corner-Lumberton 230kV Circuit (B1787)
249,441	**249,441**	**(226,117)**	**-**	**205,344**	**205,344**	**57,580**	**57,579**	**186,953**	0	**40,407**	**95,326**	**1,056,623**	**110,181**

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

Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90)	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30)	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33)	Upgrade Eagle Point-Gloucester 230kV Circuit (B1588)	Mickleton-Gloucester 230kV Circuit (B2139)	Ridge Road 69kV Breaker Station (B1255)	Cox's Corner-Lumberton 230kV Circuit (B1787)
6,392,208	**6,392,208**	**3,281,328**	**2,801,044**	**3,327,094**	**3,327,094**	**1,051,710**	**1,051,682**	**4,126,676**	**1,697,623**	**1,361,002**	**2,240,329**	**6,000,252**	**3,646,046**

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

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

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

Install Conemaugh 250MVAR Cap Bank (B0376)	Reconfigure Kearny-Loop in P2216 Ckt (B1589)	Reconfigure Brunswick Sw-New 69kVCkt-T (B2146)	350 MVAR Reactor Hopatcong 500kV (B2702)	New 500 kV bay at Hope Creek (Expansion of Hope Creek substation) (B2633.4)	New 500/230 kV autotransformer at Hope Creek and a new Hope Creek 230 kV substation (B2633.5)	Rebuild Aldene-Warinanco-Linden VFT 230kV Circuit (B2955)	Reconductor L-2238 Cedar Grove - Jackson Rd 230kV (B2956)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (CWIP)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (CWIP)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (CWIP)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33) (CWIP)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34) (CWIP)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50) (CWIP)
122,967	**2,567,335**	**18,305,678**	**2,583,419**	**119,964**	**491,171**	**3,820,197**	**501,301**	0	0	0	0	0	0

Actual Transmission Enhancement Charges - 2018

Install Conemaugh 250MVAR Cap Bank (B0376)	Reconfigure Kearny-Loop in P2216 Ckt (B1589)	Reconfigure Brunswick Sw-New 69kVCkt-T (B2146)	350 MVAR Reactor Hopatcong 500kV (B2702)	New 500 kV bay at Hope Creek (Expansion of Hope Creek substation) (B2633.4)	New 500/230 kV autotransformer at Hope Creek and a new Hope Creek 230 kV substation (B2633.5)	Rebuild Aldene-Warinanco-Linden VFT 230kV Circuit (B2955)	Reconductor L-2238 Cedar Grove - Jackson Rd 230kV (B2956)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (CWIP)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (CWIP)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (CWIP)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33) (CWIP)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34) (CWIP)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50) (CWIP)
131,053	**2,009,945**	**11,848,761**	**1,869,286**	0	0	0	0	**15,052**	**855,590**	**459,606**	**3,262,961**	**3,681,896**	**2,296,570**

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

Reconciliation by Project (without interest)

Install Conemaugh 250MVAR Cap Bank (B0376)	Reconfigure Kearny-Loop in P2216 Ckt (B1589)	Reconfigure Brunswick Sw-New 69kVCkt-T (B2146)	350 MVAR Reactor Hopatcong 500kV (B2702)	New 500 kV bay at Hope Creek (Expansion of Hope Creek substation) (B2633.4)	New 500/230 kV autotransformer at Hope Creek and a new Hope Creek 230 kV substation (B2633.5)	Rebuild Aldene-Warinanco-Linden VFT 230kV Circuit (B2955)	Reconductor L-2238 Cedar Grove - Jackson Rd 230kV (B2956)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (CWIP)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (CWIP)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (CWIP)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33) (CWIP)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34) (CWIP)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50) (CWIP)
1,148	**370,504**	**1,033,475**	**500,560**	0	0	0	0	**(16,292)**	**532,733**	**39,765**	**1,286,256**	**772,987**	**871,156**

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

True Up by Project (with interest) -2018

Install Conemaugh 250MVAR Cap Bank (B0376)	Reconfigure Kearny-Loop in P2216 Ckt (B1589)	Reconfigure Brunswick Sw-New 69kVCkt-T (B2146)	350 MVAR Reactor Hopatcong 500kV (B2702)	New 500 kV bay at Hope Creek (Expansion of Hope Creek substation) (B2633.4)	New 500/230 kV autotransformer at Hope Creek and a new Hope Creek 230 kV substation (B2633.5)	Rebuild Aldene-Warinanco-Linden VFT 230kV Circuit (B2955)	Reconductor L-2238 Cedar Grove - Jackson Rd 230kV (B2956)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (CWIP)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (CWIP)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (CWIP)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33) (CWIP)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34) (CWIP)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50) (CWIP)
1,204	**388,703**	**1,084,240**	525,148	0	0	0	0	**(17,092)**	**558,901**	**41,718**	**1,349,437**	**810,956**	**913,947**

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

Install Conemaugh 250MVAR Cap Bank (B0376)	Reconfigure Kearny-Loop in P2216 Ckt (B1589)	Reconfigure Brunswick Sw-New 69kVCkt-T (B2146)	350 MVAR Reactor Hopatcong 500kV (B2702)	New 500 kV bay at Hope Creek (Expansion of Hope Creek substation) (B2633.4)	New 500/230 kV autotransformer at Hope Creek and a new Hope Creek 230 kV substation (B2633.5)	Rebuild Aldene-Warinanco-Linden VFT 230kV Circuit (B2955)	Reconductor L-2238 Cedar Grove - Jackson Rd 230kV (B2956)	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10) (CWIP)	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21) (CWIP)	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22) (CWIP)	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33) (CWIP)	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34) (CWIP)	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50) (CWIP)
124,171	**2,956,039**	**19,389,918**	**3,108,567**	**119,964**	**491,171**	**3,820,197**	**501,301**	**(17,092)**	**558,901**	**41,718**	**1,349,437**	**810,956**	**913,947**

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

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

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

Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (CWIP)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70) (CWIP)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81) (CWIP)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83) (CWIP)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) (CWIP)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (CWIP)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (CWIP)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (CWIP)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (CWIP)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20) (CWIP)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (CWIP)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (CWIP)
0	0	0	0	0	0	0	0	0	0	0	0

Actual Transmission Enhancement Charges - 2018

Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (CWIP)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70) (CWIP)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81) (CWIP)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83) (CWIP)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) (CWIP)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (CWIP)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (CWIP)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (CWIP)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (CWIP)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20) (CWIP)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (CWIP)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (CWIP)
917,013	**2,282,447**	**17,100**	**17,100**	**4,988**	**4,988**	**72,710**	**11,268**	**5,145**	**81**	**61**	**206,342**

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

Reconciliation by Project (without interest)

Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (CWIP)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70) (CWIP)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81) (CWIP)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83) (CWIP)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) (CWIP)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (CWIP)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (CWIP)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (CWIP)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (CWIP)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20) (CWIP)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (CWIP)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (CWIP)
75,300	**954,055**	**9,054**	**9,362**	**4,988**	**4,988**	**(63,365)**	**(22,476)**	**(28,599)**	**(654)**	**(674)**	**46,180**

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

True Up by Project (with interest) -2018

Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (CWIP)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70) (CWIP)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81) (CWIP)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83) (CWIP)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) (CWIP)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (CWIP)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (CWIP)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (CWIP)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (CWIP)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20) (CWIP)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (CWIP)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (CWIP)
78,999	**1,000,919**	**9,499**	**9,822**	**5,233**	**5,233**	**(66,478)**	**(23,580)**	**(30,004)**	**(686)**	**(707)**	**48,448**

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

Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60) (CWIP)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70) (CWIP)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81) (CWIP)	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83) (CWIP)	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84) (CWIP)	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85) (CWIP)	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90) (CWIP)	New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10) (CWIP)	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11) (CWIP)	New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20) (CWIP)	New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21) (CWIP)	New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30) (CWIP)
78,999	**1,000,919**	**9,499**	**9,822**	**5,233**	**5,233**	**(66,478)**	**(23,580)**	**(30,004)**	**(686)**	**(707)**	**48,448**

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

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

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 **For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the**
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		Branchburg (B0130)	Kittatinny (B0134)	Essex Aldene (B0145)	New Freedom Trans.(B0411)
10		Details		**Branchburg (B0130)**	**Kittatinny (B0134)**	**Essex Aldene (B0145)**	**New Freedom Trans.(B0411)**
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.63%	9.63%	9.63%	9.63%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.63%	9.63%	9.63%	9.63%
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified - End of year	Investment		20,645,602 -	8,069,022	86,467,721	22,188,863
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		491,562	192,120	2,058,755	528,306
19	Months in service for depreciation expense from			13.00	13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)			2006	2007	2007	2007

Line		Invest Yr	Branchburg Ending	Branchburg Depreciation or Amortization	Branchburg Revenue	Kittatinny Ending	Kittatinny Depreciation or Amortization	Kittatinny Revenue	Essex Aldene Ending	Essex Aldene Depreciation or Amortization	Essex Aldene Revenue	New Freedom Ending	New Freedom Depreciation or Amortization	New Freedom Revenue
21		**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**
22	W 11.68 % ROE	2006	20,680,597	492,395	4,652,471									
23	W Increased ROE	2006	20,680,597	492,395	4,652,471									
24	W 11.68 % ROE	2007	20,188,202	492,395	4,553,422	8,069,022	80,050	1,703,202	86,565,629	858,786	18,272,191	22,188,863	484,281	4,947,757
25	W Increased ROE	2007	20,188,202	492,395	4,553,422	8,069,022	80,050	1,703,202	86,565,629	858,786	18,272,191	22,188,863	484,281	4,947,757
26	W 11.68 % ROE	2008	19,695,807	492,395	4,454,372	7,988,972	192,120	1,799,169	85,706,843	2,061,086	19,301,739	21,704,582	528,306	4,894,366
27	W Increased ROE	2008	19,695,807	492,395	4,454,372	7,988,972	192,120	1,799,169	85,706,843	2,061,086	19,301,739	21,704,582	528,306	4,894,366
28	W 11.68 % ROE	2009	19,203,412	492,395	4,523,234	7,796,853	192,120	1,828,696	83,645,756	2,061,086	19,618,517	21,176,276	528,306	4,973,254
29	W Increased ROE	2009	19,203,412	492,395	4,523,234	7,796,853	192,120	1,828,696	83,645,756	2,061,086	19,618,517	21,176,276	528,306	4,973,254
30	W 11.68 % ROE	2010	18,711,016	492,395	4,095,968	7,604,733	192,120	1,656,722	81,584,670	2,061,086	17,773,557	20,647,970	528,306	4,504,919
31	W Increased ROE	2010	18,711,016	492,395	4,095,968	7,604,733	192,120	1,656,722	81,584,670	2,061,086	17,773,557	20,647,970	528,306	4,504,919
32	W 11.68 % ROE	2011	18,218,621	492,395	3,746,858	7,412,613	192,120	1,516,263	79,523,584	2,061,086	16,266,692	20,119,663	528,306	4,122,360
33	W Increased ROE	2011	18,218,621	492,395	3,746,858	7,412,613	192,120	1,516,263	79,523,584	2,061,086	16,266,692	20,119,663	528,306	4,122,360
34	W 11.68 % ROE	2012	17,726,226	492,395	3,154,416	7,220,494	192,120	1,276,451	77,462,497	2,061,086	13,693,952	19,591,357	528,306	3,470,422
35	W Increased ROE	2012	17,726,226	492,395	3,154,416	7,220,494	192,120	1,276,451	77,462,497	2,061,086	13,693,952	19,591,357	528,306	3,470,422
36	W 11.68 % ROE	2013	17,233,831	492,395	2,886,756	7,028,374	192,120	1,168,598	75,401,411	2,061,086	12,536,886	19,063,051	528,306	3,176,807
37	W Increased ROE	2013	17,233,831	492,395	2,886,756	7,028,374	192,120	1,168,598	75,401,411	2,061,086	12,536,886	19,063,051	528,306	3,176,807
38	W 11.68 % ROE	2014	16,741,436	492,395	2,555,172	6,836,255	192,120	1,034,441	73,340,324	2,061,086	11,097,629	18,534,745	528,306	2,812,043
39	W Increased ROE	2014	16,741,436	492,395	2,555,172	6,836,255	192,120	1,034,441	73,340,324	2,061,086	11,097,629	18,534,745	528,306	2,812,043
40	W 11.68 % ROE	2015	16,249,041	492,395	2,397,208	6,644,135	192,120	970,986	71,279,238	2,061,086	10,416,881	18,006,439	528,306	2,639,133
41	W Increased ROE	2015	16,249,041	492,395	2,397,208	6,644,135	192,120	970,986	71,279,238	2,061,086	10,416,881	18,006,439	528,306	2,639,133
42	W 11.68 % ROE	2016	15,743,650	492,086	2,293,690	6,452,016	192,120	930,448	69,120,244	2,058,755	9,968,442	17,478,132	528,306	2,528,394
43	W Increased ROE	2016	15,743,650	492,086	2,293,690	6,452,016	192,120	930,448	69,120,244	2,058,755	9,968,442	17,478,132	528,306	2,528,394
44	W 11.68 % ROE	2017	15,229,564	491,562	2,199,535	6,259,896	192,120	894,158	67,061,488	2,058,755	9,579,601	16,949,826	528,306	2,429,204
45	W Increased ROE	2017	15,229,564	491,562	2,199,535	6,259,896	192,120	894,158	67,061,488	2,058,755	9,579,601	16,949,826	528,306	2,429,204
46	W 11.68 % ROE	2018	14,738,003	491,562	1,953,369	6,067,776	192,120	793,960	65,002,733	2,058,755	8,506,133	16,421,520	528,306	2,157,095
47	W Increased ROE	2018	14,738,003	491,562	1,953,369	6,067,776	192,120	793,960	65,002,733	2,058,755	8,506,133	16,421,520	528,306	2,157,095
44	W 11.68 % ROE	2019	14,246,440	491,562	1,637,120	5,875,657	192,120	664,582	62,943,978	2,058,755	7,120,088	15,893,213	528,306	1,806,282
45	W Increased ROE	2019	14,246,440	491,562	1,637,120	5,875,657	192,120	664,582	62,943,978	2,058,755	7,120,088	15,893,213	528,306	1,806,282
44	W 11.68 % ROE	2020	13,754,878	491,562	1,816,716	5,683,537	192,120	739,676	60,885,223	2,058,755	7,924,480	15,364,907	528,306	2,008,572
45	W Increased ROE	2020	13,754,878	491,562	1,816,716	5,683,537	192,120	739,676	60,885,223	2,058,755	7,924,480	15,364,907	528,306	2,008,572

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

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

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

10		Details		**New Freedom Loop (B0498)**	**Metuchen Transformer (B0161)**	**Branchburg-Flagtown-Somerville (B0169)**	**Flagtown-Somerville-Bridgewater (B0170)**
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.63%	9.63%	9.63%	9.63%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.63%	9.63%	9.63%	9.63%
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified - End of year	Investment		27,005,248	25,654,455	15,731,554	6,961,495
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		642,982	610,820	374,561	165,750
19	Months in service for depreciation expense from			13.00	13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)			2008	2009	2009	2008

			New Freedom Loop (B0498)			Metuchen Transformer (B0161)			Branchburg-Flagtown-Somerville (B0169)			Flagtown-Somerville-Bridgewater (B0170)		
21		**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008	24,921,237	88,646	837,584							6,961,495	25,372	239,734
27	W Increased ROE	2008	24,921,237	88,646	837,584							6,961,495	25,372	239,734
28	W 11.68 % ROE	2009	26,916,602	642,982	6,292,837	19,700,217	288,478	2,831,673	15,773,880	234,561	2,302,423	6,936,122	165,750	1,621,657
29	W Increased ROE	2009	26,916,602	642,982	6,292,837	19,700,217	288,478	2,831,673	15,773,880	234,561	2,302,423	6,936,122	165,750	1,621,657
30	W 11.68 % ROE	2010	26,273,620	642,982	5,703,044	25,488,527	613,738	5,522,598	15,539,319	375,568	3,368,301	6,770,372	165,750	1,469,662
31	W Increased ROE	2010	26,273,620	642,982	5,703,044	25,488,527	613,738	5,522,598	15,539,319	375,568	3,368,301	6,770,372	165,750	1,469,662
32	W 11.68 % ROE	2011	25,630,832	642,987	5,221,521	24,896,838	614,263	5,061,682	15,121,425	374,561	3,075,759	6,604,623	165,750	1,345,559
33	W Increased ROE	2011	25,630,832	642,987	5,221,521	24,896,838	614,263	5,061,682	15,121,425	374,561	3,075,759	6,604,623	165,750	1,345,559
34	W 11.68 % ROE	2012	24,987,652	642,982	4,395,482	24,282,576	614,263	4,260,879	14,746,864	374,561	2,589,159	6,438,873	165,750	1,132,702
35	W Increased ROE	2012	24,987,652	642,982	4,395,482	24,282,576	614,263	4,260,879	14,746,864	374,561	2,589,159	6,438,873	165,750	1,132,702
36	W 11.68 % ROE	2013	24,344,669	642,982	4,025,278	23,668,312	614,263	3,902,590	14,372,303	374,561	2,371,359	6,273,123	165,750	1,037,298
37	W Increased ROE	2013	24,344,669	642,982	4,025,278	23,668,312	614,263	3,902,590	14,372,303	374,561	2,371,359	6,273,123	165,750	1,037,298
38	W 11.68 % ROE	2014	23,701,687	642,982	3,563,358	23,054,049	614,263	3,454,841	13,997,743	374,561	2,099,276	6,107,373	165,750	918,263
39	W Increased ROE	2014	23,701,687	642,982	3,563,358	23,054,049	614,263	3,454,841	13,997,743	374,561	2,099,276	6,107,373	165,750	918,263
40	W 11.68 % ROE	2015	23,058,705	642,982	3,346,067	22,439,786	614,263	3,244,794	13,623,182	374,561	1,971,555	5,941,623	165,750	862,264
41	W Increased ROE	2015	23,058,705	642,982	3,346,067	22,439,786	614,263	3,244,794	13,623,182	374,561	1,971,555	5,941,623	165,750	862,264
42	W 11.68 % ROE	2016	22,415,723	642,982	3,208,097	21,819,123	614,111	3,110,954	13,248,621	374,561	1,890,650	5,775,874	165,750	826,705
43	W Increased ROE	2016	22,415,723	642,982	3,208,097	21,819,123	614,111	3,110,954	13,248,621	374,561	1,890,650	5,775,874	165,750	826,705
44	W 11.68 % ROE	2017	21,772,741	642,982	3,084,762	21,066,812	610,820	2,973,432	12,874,060	374,561	1,818,367	5,610,124	165,750	794,917
45	W Increased ROE	2017	21,772,741	642,982	3,084,762	21,066,812	610,820	2,973,432	12,874,060	374,561	1,818,367	5,610,124	165,750	794,917
46	W 11.68 % ROE	2018	21,129,759	642,982	2,738,764	20,455,991	610,820	2,639,774	12,499,499	374,561	1,614,339	5,444,374	165,750	705,757
47	W Increased ROE	2018	21,129,759	642,982	2,738,764	20,455,991	610,820	2,639,774	12,499,499	374,561	1,614,339	5,444,374	165,750	705,757
44	W 11.68 % ROE	2019	20,486,777	642,982	2,290,326	19,845,171	610,820	2,206,573	12,124,939	374,561	1,349,529	5,278,624	165,750	590,205
45	W Increased ROE	2019	20,486,777	642,982	2,290,326	19,845,171	610,820	2,206,573	12,124,939	374,561	1,349,529	5,278,624	165,750	590,205
44	W 11.68 % ROE	2020	19,843,795	642,982	2,554,747	19,234,351	610,820	2,463,871	11,750,378	374,561	1,506,600	5,112,874	165,750	658,328
45	W Increased ROE	2020	19,843,795	642,982	2,554,747	19,234,351	610,820	2,463,871	11,750,378	374,561	1,506,600	5,112,874	165,750	658,328

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

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

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		**Roseland Transformers (B0274)**			**Wave Trap Branchburg (B0172.2)**			**Reconductor Hudson - South Waterfront (B0813)**			**Reconductor South Mahwah J-3410 Circuit (B1017)**		
10		Details													
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes			Yes			Yes			Yes		
12	Useful life of the project	Life		42			42			42			42		
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No			No			No			No		
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0			0			0			0		
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.63%			9.63%			9.63%			9.63%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.63%			9.63%			9.63%			9.63%		
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified - End of year	Investment		21,014,433			27,988			9,158,918			20,626,991		
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	17,235,419	500,344	2,433,270	21,880	666	3,120	7,831,801	218,069	1,096,394	17,871,199	491,119	2,495,347
45		W Increased ROE	2017	17,235,419	500,344	2,433,270	21,880	666	3,120	7,831,801	218,069	1,096,394	17,871,199	491,119	2,495,347
46		W 11.68 % ROE	2018	16,735,075	500,344	2,160,233	21,214	666	2,770	7,613,732	218,069	973,247	17,380,080	491,119	2,214,984
47		W Increased ROE	2018	16,735,075	500,344	2,160,233	21,214	666	2,770	7,613,732	218,069	973,247	17,380,080	491,119	2,214,984
44		W 11.68 % ROE	2019	16,234,731	500,344	1,805,780	20,548	666	2,319	7,395,662	218,069	812,756	16,888,961	491,119	1,849,162
45		W Increased ROE	2019	16,234,731	500,344	1,805,780	20,548	666	2,319	7,395,662	218,069	812,756	16,888,961	491,119	1,849,162
44		W 11.68 % ROE	2020	15,734,388	500,344	2,016,205	19,881	666	2,582	7,177,593	218,069	909,564	16,397,842	491,119	2,070,898
45		W Increased ROE	2020	15,734,388	500,344	2,016,205	19,881	666	2,582	7,177,593	218,069	909,564	16,397,842	491,119	2,070,898

Public Service Electric and Gas Company
ATTACHMENT H-10A
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			Formula Line		
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5		C		Line B less Line A	0.59%
6	**FCR if a CIAC**				
7		D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.29%

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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		9.63%	9.63%	9.63%	9.63%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.63%	9.63%	9.63%	9.63%
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified - End of year	Investment		21,170,273	77,234,030	14,404,842	18,664,931
		Annual Depreciation or Amort Exp					
18	Line 17 divided by line 12			504,054	1,838,905	342,972	444,403
19	Months in service for depreciation expense from			13.00	13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)			2011	2012	2012	2012

21		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011	20,511,158	37,566	284,735									
33	W Increased ROE	2011	20,511,158	37,566	284,735									
34	W 11.68 % ROE	2012	21,132,707	504,054	3,677,641	79,937,194	1,240,233	9,062,770	14,401,477	210,412	1,537,549	19,820,557	318,342	2,326,229
35	W Increased ROE	2012	21,132,707	504,054	3,677,641	79,937,194	1,240,233	9,062,770	14,401,477	210,412	1,537,549	19,820,557	318,342	2,326,229
36	W 11.68 % ROE	2013	20,628,652	504,054	3,370,070	79,195,082	1,915,127	12,917,996	14,194,429	342,972	2,315,058	18,294,505	443,163	2,984,887
37	W Increased ROE	2013	20,628,652	504,054	3,370,070	79,195,082	1,915,127	12,917,996	14,194,429	342,972	2,315,058	18,294,505	443,163	2,984,887
38	W 11.68 % ROE	2014	20,124,598	504,054	2,983,683	77,279,955	1,915,127	11,437,086	13,851,457	342,972	2,049,664	17,903,425	444,403	2,650,353
39	W Increased ROE	2014	20,124,598	504,054	2,983,683	77,279,955	1,915,127	11,437,086	13,851,457	342,972	2,049,664	17,903,425	444,403	2,650,353
40	W 11.68 % ROE	2015	19,620,544	504,054	2,804,096	75,364,829	1,915,127	10,749,859	13,508,484	342,972	1,926,521	17,459,022	444,403	2,491,058
41	W Increased ROE	2015	19,620,544	504,054	2,804,096	75,364,829	1,915,127	10,749,859	13,508,484	342,972	1,926,521	17,459,022	444,403	2,491,058
42	W 11.68 % ROE	2016	19,116,490	504,054	2,691,625	70,419,117	1,842,970	9,901,291	13,165,512	342,972	1,849,551	17,014,619	444,403	2,391,449
43	W Increased ROE	2016	19,116,490	504,054	2,691,625	70,419,117	1,842,970	9,901,291	13,165,512	342,972	1,849,551	17,014,619	444,403	2,391,449
44	W 11.68 % ROE	2017	18,612,436	504,054	2,591,411	68,524,248	1,841,734	9,526,626	12,822,540	342,972	1,781,001	16,570,216	444,403	2,302,728
45	W Increased ROE	2017	18,612,436	504,054	2,591,411	68,524,248	1,841,734	9,526,626	12,822,540	342,972	1,781,001	16,570,216	444,403	2,302,728
46	W 11.68 % ROE	2018	18,108,382	504,054	2,300,157	66,563,714	1,838,905	8,441,111	12,479,568	342,972	1,580,774	16,125,813	444,403	2,043,862
47	W Increased ROE	2018	18,108,382	504,054	2,300,157	66,563,714	1,838,905	8,441,111	12,479,568	342,972	1,580,774	16,125,813	444,403	2,043,862
44	W 11.68 % ROE	2019	17,604,328	504,054	1,919,620	64,840,780	1,841,734	7,055,589	12,136,595	342,972	1,318,877	15,681,410	444,403	1,705,347
45	W Increased ROE	2019	17,604,328	504,054	1,919,620	64,840,780	1,841,734	7,055,589	12,136,595	342,972	1,318,877	15,681,410	444,403	1,705,347
44	W 11.68 % ROE	2020	17,100,273	504,054	2,151,506	62,883,074	1,838,905	7,897,105	11,793,622	342,972	1,479,178	15,237,006	444,403	1,912,347
45	W Increased ROE	2020	17,100,273	504,054	2,151,506	62,883,074	1,838,905	7,897,105	11,793,622	342,972	1,479,178	15,237,006	444,403	1,912,347

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

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

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

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

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

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)
10		Details					
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.63%	9.63%	9.63%	9.63%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.63%	9.63%	9.63%	9.63%
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified - End of year	Investment		6,390,403	46,035,637	15,865,267	21,732,218
		Annual Depreciation or Amort Exp					
18	Line 17 divided by line 12			152,152	1,096,087	377,744	517,434
19	Months in service for depreciation expense from			13.00	13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)			2012	2012	2011	2013

Line		Invest Yr	Somerville Ending	Somerville Depreciation or Amortization	Somerville Revenue	New Essex Ending	New Essex Depreciation or Amortization	New Essex Revenue	Salem Ending	Salem Depreciation or Amortization	Salem Revenue	Lawrence Ending	Lawrence Depreciation or Amortization	Lawrence Revenue
21		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011							2,640,253	9,537	73,000			
33	W Increased ROE	2011							2,640,253	9,537	73,000			
34	W 11.68 % ROE	2012	4,404,012	57,853	422,751	22,800,866	123,008	898,857	7,275,941	108,279	790,336			
35	W Increased ROE	2012	4,404,012	57,853	422,751	22,800,866	123,008	898,857	7,275,941	108,279	790,336			
36	W 11.68 % ROE	2013	6,291,725	151,180	1,025,313	45,385,800	1,083,543	7,389,162	9,926,683	192,972	1,305,797	22,127,065	248,542	1,698,840
37	W Increased ROE	2013	6,291,725	151,180	1,025,313	45,385,800	1,083,543	7,389,162	9,926,683	192,972	1,305,797	22,127,065	248,542	1,698,840
38	W 11.68 % ROE	2014	6,181,332	152,152	913,777	44,747,660	1,094,148	6,607,679	15,445,872	289,093	1,755,636	21,792,104	524,777	3,209,866
39	W Increased ROE	2014	6,181,332	152,152	913,777	44,747,660	1,094,148	6,607,679	15,445,872	289,093	1,755,636	21,792,104	524,777	3,209,866
40	W 11.68 % ROE	2015	6,029,218	152,152	858,935	43,772,546	1,096,982	6,228,271	15,276,916	378,019	2,168,874	21,267,327	524,777	3,017,865
41	W Increased ROE	2015	6,029,218	152,152	858,935	43,772,546	1,096,982	6,228,271	15,276,916	378,019	2,168,874	21,267,327	524,777	3,017,865
42	W 11.68 % ROE	2016	5,877,066	152,152	824,687	42,662,264	1,096,665	5,978,667	14,899,633	378,036	2,083,057	20,438,822	517,546	2,856,436
43	W Increased ROE	2016	5,877,066	152,152	824,687	42,662,264	1,096,665	5,978,667	14,899,633	378,036	2,083,057	20,438,822	517,546	2,856,436
44	W 11.68 % ROE	2017	5,724,913	152,152	794,193	41,541,291	1,096,087	5,754,880	14,509,330	377,744	2,004,944	19,921,276	517,546	2,751,687
45	W Increased ROE	2017	5,724,913	152,152	794,193	41,541,291	1,096,087	5,754,880	14,509,330	377,744	2,004,944	19,921,276	517,546	2,751,687
46	W 11.68 % ROE	2018	5,572,760	152,152	704,894	40,445,204	1,096,087	5,107,695	14,131,586	377,744	1,779,404	19,399,030	517,434	2,441,551
47	W Increased ROE	2018	5,572,760	152,152	704,894	40,445,204	1,096,087	5,107,695	14,131,586	377,744	1,779,404	19,399,030	517,434	2,441,551
44	W 11.68 % ROE	2019	5,420,608	152,152	588,024	39,349,118	1,096,087	4,260,154	13,753,841	377,744	1,483,693	18,886,184	517,546	2,036,186
45	W Increased ROE	2019	5,420,608	152,152	588,024	39,349,118	1,096,087	4,260,154	13,753,841	377,744	1,483,693	18,886,184	517,546	2,036,186
44	W 11.68 % ROE	2020	5,268,456	152,152	659,719	38,253,031	1,096,087	4,781,410	13,376,097	377,744	1,666,407	18,364,051	517,434	2,286,639
45	W Increased ROE	2020	5,268,456	152,152	659,719	38,253,031	1,096,087	4,781,410	13,376,097	377,744	1,666,407	18,364,051	517,434	2,286,639

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

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

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

		Details		Branchburg-Middlesex Switch Rack (B1155)	Aldene-Springfield Rd. Conversion (B1399)	Upgrade Camden-Richmond 230kV Circuit (B1590)	Susquehanna Roseland Breakers (b0489.5-B0489.15)
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	125
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.63%	9.63%	9.63%	9.63%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.63%	9.63%	9.63%	10.38%
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified - End of year	Investment		62,938,142	72,376,948	11,276,183	5,857,687
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		1,498,527	1,723,261	268,481	139,469
19	Months in service for depreciation expense from			13.00	13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)			2013	2014	2014	2010

21		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010										2,662,585	7,802	70,915
31	W Increased ROE	2010										2,662,585	7,802	70,915
32	W 11.68 % ROE	2011										5,849,885	116,061	966,188
33	W Increased ROE	2011										5,849,885	116,061	1,014,845
34	W 11.68 % ROE	2012										5,733,823	139,469	1,000,541
35	W Increased ROE	2012										5,733,823	139,469	1,051,531
36	W 11.68 % ROE	2013	20,876,286	101,812	695,908							5,594,354	139,469	916,713
37	W Increased ROE	2013	20,876,286	101,812	695,908							5,594,354	139,469	967,047
38	W 11.68 % ROE	2014	60,374,269	1,439,907	8,878,852	68,405,611	556,909	3,438,903	7,389,782	37,992	234,599	5,454,886	139,469	811,586
39	W Increased ROE	2014	60,374,269	1,439,907	8,878,852	68,405,611	556,909	3,438,903	7,389,782	37,992	234,599	5,454,886	139,469	859,361
40	W 11.68 % ROE	2015	61,346,085	1,497,329	8,688,697	71,213,315	1,708,815	10,056,881	11,126,578	265,823	1,570,150	5,315,417	139,469	762,575
41	W Increased ROE	2015	61,346,085	1,497,329	8,688,697	71,213,315	1,708,815	10,056,881	11,126,578	265,823	1,570,150	5,315,417	139,469	808,174
42	W 11.68 % ROE	2016	65,275,261	1,626,531	9,096,222	70,112,484	1,723,291	9,746,523	10,972,368	268,481	1,524,089	5,175,948	139,469	731,772
43	W Increased ROE	2016	65,275,261	1,626,531	9,096,222	70,112,484	1,723,291	9,746,523	10,972,368	268,481	1,524,089	5,175,948	139,469	776,124
44	W 11.68 % ROE	2017	58,272,563	1,498,527	8,033,708	68,392,049	1,723,359	9,393,425	10,703,887	268,481	1,468,905	5,036,479	139,469	704,302
45	W Increased ROE	2017	58,272,563	1,498,527	8,033,708	68,392,049	1,723,359	9,393,425	10,703,887	268,481	1,468,905	5,036,479	139,469	747,840
46	W 11.68 % ROE	2018	62,148,121	1,626,482	7,790,721	66,664,575	1,723,261	8,335,470	10,435,407	268,481	1,303,530	4,897,011	139,469	625,185
47	W Increased ROE	2018	62,148,121	1,626,482	7,790,721	66,664,575	1,723,261	8,335,470	10,435,407	268,481	1,303,530	4,897,011	139,469	660,864
44	W 11.68 % ROE	2019	55,275,530	1,498,527	5,943,239	64,941,230	1,723,261	6,945,193	10,166,926	268,481	1,086,004	4,757,542	139,469	522,023
45	W Increased ROE	2019	55,275,530	1,498,527	5,943,239	64,941,230	1,723,261	6,945,193	10,166,926	268,481	1,086,004	4,757,542	139,469	556,175
44	W 11.68 % ROE	2020	53,649,027	1,498,527	6,667,112	63,218,053	1,723,261	7,813,732	9,898,446	268,481	1,222,104	4,618,073	139,469	584,377
45	W Increased ROE	2020	53,649,027	1,498,527	6,667,112	63,218,053	1,723,261	7,813,732	9,898,446	268,481	1,222,104	4,618,073	139,469	618,695

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

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

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		Susquehanna Roseland < 500KV (B0489.4)	Susquehanna Roseland > 500KV (B0489)	Burlington - Camden 230kV Conversion (B1156)	Mickleton-Gloucester-Camden(B1398-B1398.7)
10		Details					
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		125	125	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.63%	9.63%	9.63%	9.63%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		10.38%	10.38%	9.63%	9.63%
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified - End of year	Investment		40,538,248	721,881,197	356,333,540	439,023,933
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		965,196	17,187,648	8,484,132	10,452,951
19	Months in service for depreciation expense from			13.00	13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)			2011	2012	2011	2013

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				768,277,132								
24	W 11.68 % ROE	2007				770,174,683								
25	W Increased ROE	2007				(1,897,551)								
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011	7,844,331	111,778	905,525				19,902,939	147,204	1,150,144			
33	W Increased ROE	2011	7,844,331	111,778	952,449				19,902,939	147,204	1,150,144			
34	W 11.68 % ROE	2012	7,628,074	184,491	1,331,330	4,694,511	8,598	62,828	19,848,511	475,501	3,452,558			
35	W Increased ROE	2012	7,628,074	184,491	1,399,243	4,694,511	8,598	66,040	19,848,511	475,501	3,452,558			
36	W 11.68 % ROE	2013	6,391,895	159,242	1,047,292	25,426,870	605,606	4,138,257	118,115,741	2,827,106	19,237,368	777,714	1,424	9,736
37	W Increased ROE	2013	6,391,895	159,242	1,104,801	25,426,870	605,606	4,367,027	118,115,741	2,827,106	19,237,368	777,714	1,424	9,736
38	W 11.68 % ROE	2014	40,082,737	717,210	4,387,056	666,963,000	10,160,548	62,692,814	333,325,376	6,107,990	37,392,933	83,696,796	854,944	5,279,191
39	W Increased ROE	2014	40,082,737	717,210	4,647,913	666,963,000	10,160,548	66,426,879	333,325,376	6,107,990	37,392,933	83,696,796	854,944	5,279,191
40	W 11.68 % ROE	2015	39,365,526	965,196	5,579,868	711,440,230	16,714,518	97,780,708	346,271,067	8,256,393	47,814,854	436,685,203	6,739,741	39,857,912
41	W Increased ROE	2015	39,365,526	965,196	5,917,569	711,440,230	16,714,518	103,713,135	346,271,067	8,256,393	47,814,854	436,685,203	6,739,741	39,857,912
42	W 11.68 % ROE	2016	38,400,330	965,196	5,359,489	694,520,844	17,213,677	96,796,429	338,712,254	8,485,957	47,233,422	430,951,154	10,495,692	60,066,502
43	W Increased ROE	2016	38,400,330	965,196	5,688,534	694,520,844	17,213,677	102,755,603	338,712,254	8,485,957	47,233,422	430,951,154	10,495,692	60,066,502
44	W 11.68 % ROE	2017	37,435,134	965,196	5,163,491	677,132,437	17,186,557	93,125,945	330,033,388	8,484,132	45,496,882	420,701,437	10,447,458	57,628,494
45	W Increased ROE	2017	37,435,134	965,196	5,487,093	677,132,437	17,186,557	98,979,324	330,033,388	8,484,132	45,496,882	420,701,437	10,447,458	57,628,494
46	W 11.68 % ROE	2018	36,469,937	965,196	4,582,513	659,838,953	17,184,011	82,630,967	321,549,256	8,484,132	40,377,399	410,411,336	10,451,205	51,158,369
47	W Increased ROE	2018	36,469,937	965,196	4,848,227	659,838,953	17,184,011	87,438,438	321,549,256	8,484,132	40,377,399	410,411,336	10,451,205	51,158,369
44	W 11.68 % ROE	2019	35,504,741	965,196	3,820,137	642,834,128	17,187,649	68,878,020	313,065,125	8,484,132	33,657,737	399,754,320	10,446,356	42,590,650
45	W Increased ROE	2019	35,504,741	965,196	4,075,005	642,834,128	17,187,649	73,492,563	313,065,125	8,484,132	33,657,737	399,754,320	10,446,356	42,590,650
44	W 11.68 % ROE	2020	34,539,544	965,196	4,292,760	625,620,033	17,187,648	77,460,316	304,580,993	8,484,132	37,827,676	389,587,112	10,452,951	47,986,044
45	W Increased ROE	2020	34,539,544	965,196	4,549,433	625,620,033	17,187,648	82,109,464	304,580,993	8,484,132	37,827,676	389,587,112	10,452,951	47,986,044

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

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

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

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

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		**North Central Reliability (West Orange Conversion (B1154)**	**Northeast Grid Reliability Project (B1304.1-B1304.4)**	**Northeast Grid Reliability Project (B1304.5-B1304.21)**	**Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)**
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	25	25	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.63%	9.63%	9.63%	9.63%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.63%	9.78%	9.78%	9.63%
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified - End of year	Investment		370,007,352	625,166,511	350,966,539	179,379,994
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		8,809,699	14,884,917	8,356,346	4,270,952
19	Months in service for depreciation expense from			13.00	13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)			2012	2013	2016	2016

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	16,441,748	30,113	220,046									
35	W Increased ROE	2012	16,441,748	30,113	220,046									
36	W 11.68 % ROE	2013	257,640,264	6,135,009	41,929,935	23,466,022	86,647	592,253						
37	W Increased ROE	2013	257,640,264	6,135,009	41,929,935	23,466,022	86,647	598,801						
38	W 11.68 % ROE	2014	360,673,484	7,742,354	47,135,528	274,113,325	2,382,627	14,708,781						
39	W Increased ROE	2014	360,673,484	7,742,354	47,135,528	274,113,325	2,382,627	14,884,013						
40	W 11.68 % ROE	2015	355,885,266	8,777,921	50,370,637	433,597,024	7,852,675	46,296,391						
41	W Increased ROE	2015	355,885,266	8,777,921	50,370,637	433,597,024	7,852,675	46,859,053						
42	W 11.68 % ROE	2016	347,072,992	8,805,472	48,529,997	615,905,487	12,804,341	73,330,415	352,027,464	8,381,606	48,665,417	178,685,539	2,436,719	14,148,115
43	W Increased ROE	2016	347,072,992	8,805,472	48,529,997	615,905,487	12,804,341	74,236,857	352,027,464	8,381,606	49,268,709	178,685,539	2,436,719	14,148,115
44	W 11.68 % ROE	2017	338,516,483	8,809,699	46,773,815	602,065,287	14,885,514	82,406,233	342,609,998	8,356,943	46,780,141	176,296,656	4,203,493	23,733,009
45	W Increased ROE	2017	338,516,483	8,809,699	46,773,815	602,065,287	14,885,514	83,447,128	342,609,998	8,356,943	47,372,470	176,296,656	4,203,493	23,733,009
46	W 11.68 % ROE	2018	329,706,784	8,809,699	41,512,081	587,254,037	14,887,282	73,134,812	334,327,320	8,358,711	41,519,387	174,138,554	4,283,105	21,470,381
47	W Increased ROE	2018	329,706,784	8,809,699	41,512,081	587,254,037	14,887,282	73,990,538	334,327,320	8,358,711	42,006,557	174,138,554	4,283,105	21,470,381
44	W 11.68 % ROE	2019	320,897,093	8,809,699	34,613,073	572,224,877	14,883,974	60,896,647	334,253,055	8,356,943	35,234,272	169,419,235	4,291,004	17,914,025
45	W Increased ROE	2019	320,897,093	8,809,699	34,613,073	572,224,877	14,883,974	61,718,183	334,253,055	8,356,943	35,714,155	169,419,235	4,291,004	17,914,025
44	W 11.68 % ROE	2020	312,087,386	8,809,699	38,876,415	557,383,451	14,884,917	68,583,626	317,512,336	8,356,346	38,945,705	164,165,674	4,270,952	20,086,787
45	W Increased ROE	2020	312,087,386	8,809,699	38,876,415	557,383,451	14,884,917	69,412,039	317,512,336	8,356,346	39,417,609	164,165,674	4,270,952	20,086,787

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

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

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		**Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.21)**	**Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.22)**	**Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades (B2436.33)**	**Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34)**
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.63%	9.63%	9.63%	9.63%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.63%	9.63%	9.63%	9.63%
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified - End of year	Investment		66,233,353	48,848,837	158,323,120	126,346,267
		Annual Depreciation or Amort Exp					
18	Line 17 divided by line 12			1,576,985	1,163,068	3,769,598	3,008,244
19	Months in service for depreciation expense from			13.00	13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)			2016	2016	2015	2018

21		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011												
33	W Increased ROE	2011												
34	W 11.68 % ROE	2012												
35	W Increased ROE	2012												
36	W 11.68 % ROE	2013												
37	W Increased ROE	2013												
38	W 11.68 % ROE	2014												
39	W Increased ROE	2014												
40	W 11.68 % ROE	2015							225,037	412	2,441			
41	W Increased ROE	2015							225,037	412	2,441			
42	W 11.68 % ROE	2016	23,849,835	322,903	1,874,846	23,849,835	322,903	1,874,846	349,923	8,202	47,577			
43	W Increased ROE	2016	23,849,835	322,903	1,874,846	23,849,835	322,903	1,874,846	349,923	8,202	47,577			
44	W 11.68 % ROE	2017	42,938,400	916,068	5,198,758	24,558,823	583,272	3,294,965	14,747,154	214,966	1,226,916			
45	W Increased ROE	2017	42,938,400	916,068	5,198,758	24,558,823	583,272	3,294,965	14,747,154	214,966	1,226,916			
46	W 11.68 % ROE	2018	63,528,886	1,341,837	6,824,760	47,639,887	913,654	4,648,728	164,431,353	3,052,775	15,752,824	125,948,110	2,038,280	10,529,391
47	W Increased ROE	2018	63,528,886	1,341,837	6,824,760	47,639,887	913,654	4,648,728	164,431,353	3,052,775	15,752,824	125,948,110	2,038,280	10,529,391
44	W 11.68 % ROE	2019	61,564,011	1,530,357	6,480,727	45,509,601	1,128,954	4,788,386	161,066,436	3,918,488	16,869,860	122,507,954	2,965,269	12,816,149
45	W Increased ROE	2019	61,564,011	1,530,357	6,480,727	45,509,601	1,128,954	4,788,386	161,066,436	3,918,488	16,869,860	122,507,954	2,965,269	12,816,149
44	W 11.68 % ROE	2020	62,122,188	1,576,985	7,561,879	45,900,054	1,163,068	5,585,111	151,128,277	3,769,598	18,329,401	121,342,718	3,008,244	14,698,486
45	W Increased ROE	2020	62,122,188	1,576,985	7,561,879	45,900,054	1,163,068	5,585,111	151,128,277	3,769,598	18,329,401	121,342,718	3,008,244	14,698,486

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

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

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50)	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60)	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70)	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.81)
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.63%	9.63%	9.63%	9.63%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.63%	9.63%	9.63%	9.63%
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified - End of year	Investment		65,664,032	42,471,432	81,535,606	54,818,781
		Annual Depreciation or Amort Exp					
18	Line 17 divided by line 12			1,563,429	1,011,225	1,941,324	1,305,209
19	Months in service for depreciation expense from			13.00	13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)			2018	2015	2015	2015

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

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

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

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		**Convert the 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		9.63%			9.63%			9.63%			9.63%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.63%			9.63%			9.63%			9.63%		
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified - End of year	Investment		54,818,781			53,423,989			53,423,988			31,266,389		
		Annual Depreciation or Amort Exp													
18	Line 17 divided by line 12			1,305,209			1,272,000			1,272,000			744,438		
19	Months in service for depreciation expense from			13.00			13.00			13.00			13.00		
20	Year placed in Service (0 if CWIP)			2015			2015			2015			2016		
21			Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
22		W 11.68 % ROE	2006												
23		W Increased ROE	2006												
24		W 11.68 % ROE	2007												
25		W Increased ROE	2007												
26		W 11.68 % ROE	2008												
27		W Increased ROE	2008												
28		W 11.68 % ROE	2009												
29		W Increased ROE	2009												
30		W 11.68 % ROE	2010												
31		W Increased ROE	2010												
32		W 11.68 % ROE	2011												
33		W Increased ROE	2011												
34		W 11.68 % ROE	2012												
35		W Increased ROE	2012												
36		W 11.68 % ROE	2013												
37		W Increased ROE	2013												
38		W 11.68 % ROE	2014												
39		W Increased ROE	2014												
40		W 11.68 % ROE	2015	225,037	412	2,441	225,037	412	2,441	225,037	412	2,441			
41		W Increased ROE	2015	225,037	412	2,441	225,037	412	2,441	225,037	412	2,441			
42		W 11.68 % ROE	2016	723,468	12,273	71,227	723,468	12,273	71,227	723,468	12,273	71,227	28,441,681	387,893	2,252,189
43		W Increased ROE	2016	723,468	12,273	71,227	723,468	12,273	71,227	723,468	12,273	71,227	28,441,681	387,893	2,252,189
44		W 11.68 % ROE	2017	31,239,305	465,743	2,658,611	43,917,206	652,295	3,723,870	43,917,206	652,295	3,723,870	30,818,452	697,633	3,942,807
45		W Increased ROE	2017	31,239,305	465,743	2,658,611	43,917,206	652,295	3,723,870	43,917,206	652,295	3,723,870	30,818,452	697,633	3,942,807
46		W 11.68 % ROE	2018	48,346,394	1,116,292	5,721,000	46,812,614	1,092,190	5,578,331	46,812,613	1,092,190	5,578,331	30,173,644	743,679	3,734,130
47		W Increased ROE	2018	48,346,394	1,116,292	5,721,000	46,812,614	1,092,190	5,578,331	46,812,613	1,092,190	5,578,331	30,173,644	743,679	3,734,130
44		W 11.68 % ROE	2019	47,577,259	1,169,320	4,995,013	44,843,021	1,109,081	4,714,914	46,568,719	1,109,081	4,853,677	29,930,334	757,637	3,164,339
45		W Increased ROE	2019	47,577,259	1,169,320	4,995,013	44,843,021	1,109,081	4,714,914	46,568,719	1,109,081	4,853,677	29,930,334	757,637	3,164,339
44		W 11.68 % ROE	2020	52,054,741	1,305,209	6,320,199	50,557,738	1,272,000	6,142,767	50,557,737	1,272,000	6,142,767	28,679,547	744,438	3,507,445
45		W Increased ROE	2020	52,054,741	1,305,209	6,320,199	50,557,738	1,272,000	6,142,767	50,557,737	1,272,000	6,142,767	28,679,547	744,438	3,507,445

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

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

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		**Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91)**	**New Bergen 345/230 kV transformer and any associated substation upgrades (B2437.10)**	**New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11)**	**New Bayway 345/138 kV transformer #1 and any associated substation upgrades (B2437.20)**
10		Details					
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.63%	9.63%	9.63%	9.63%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.63%	9.63%	9.63%	9.63%
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified - End of year	Investment		24,992,501	27,892,523	27,892,523	9,049,265
		Annual Depreciation or Amort Exp					
18	Line 17 divided by line 12			595,060	664,108	664,108	215,459
19	Months in service for depreciation expense from			13.00	13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)			2016	2016	2016	2015

Line		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
21														
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011												
33	W Increased ROE	2011												
34	W 11.68 % ROE	2012												
35	W Increased ROE	2012												
36	W 11.68 % ROE	2013												
37	W Increased ROE	2013												
38	W 11.68 % ROE	2014												
39	W Increased ROE	2014												
40	W 11.68 % ROE	2015										225,037	412	2,441
41	W Increased ROE	2015										225,037	412	2,441
42	W 11.68 % ROE	2016	23,849,835	322,903	1,874,846	27,523,727	407,034	2,363,328	27,523,727	407,034	2,363,328	349,923	4,465	25,899
43	W Increased ROE	2016	23,849,835	322,903	1,874,846	27,523,727	407,034	2,363,328	27,523,727	407,034	2,363,328	349,923	4,465	25,899
44	W 11.68 % ROE	2017	24,558,823	583,272	3,294,965	27,091,682	653,428	3,685,670	27,091,682	653,428	3,685,670	14,750,891	214,966	1,227,172
45	W Increased ROE	2017	24,558,823	583,272	3,294,965	27,091,682	653,428	3,685,670	27,091,682	653,428	3,685,670	14,750,891	214,966	1,227,172
46	W 11.68 % ROE	2018	24,088,516	593,745	2,977,510	27,083,985	659,568	3,303,681	27,083,985	659,568	3,303,681	15,430,944	370,082	1,890,122
47	W Increased ROE	2018	24,088,516	593,745	2,977,510	27,083,985	659,568	3,303,681	27,083,985	659,568	3,303,681	15,430,944	370,082	1,890,122
44	W 11.68 % ROE	2019	23,486,597	594,836	2,483,396	26,129,595	662,586	2,763,670	26,129,595	662,586	2,763,670	15,238,900	376,860	1,602,222
45	W Increased ROE	2019	23,486,597	594,836	2,483,396	26,129,595	662,586	2,763,670	26,129,595	662,586	2,763,670	15,238,900	376,860	1,602,222
44	W 11.68 % ROE	2020	22,897,745	595,060	2,801,044	25,509,907	664,108	3,121,750	25,509,907	664,108	3,121,750	8,082,480	215,459	994,130
45	W Increased ROE	2020	22,897,745	595,060	2,801,044	25,509,907	664,108	3,121,750	25,509,907	664,108	3,121,750	8,082,480	215,459	994,130

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

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

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

10		Details		**New Bayway 345/138 kV transformer #2 and any associated substation upgrades (B2437.21)**	**New Linden 345/230 kV transformer and any associated substation upgrades (B2437.30)**	**New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33)**	**Upgrade Eagle Point-Gloucester 230kV Circuit (B1588)**
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.63%	9.63%	9.63%	9.63%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.63%	9.63%	9.63%	9.63%
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified - End of year	Investment		9,049,265	33,825,459	14,573,915	12,087,610
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		215,459	805,368	346,998	287,800
19	Months in service for depreciation expense from			13.00	13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)			2015	2016	2018	2015

21		**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011												
33	W Increased ROE	2011												
34	W 11.68 % ROE	2012												
35	W Increased ROE	2012												
36	W 11.68 % ROE	2013												
37	W Increased ROE	2013												
38	W 11.68 % ROE	2014												
39	W Increased ROE	2014												
40	W 11.68 % ROE	2015	225,037	412	2,441							11,980,348	216,491	1,282,387
41	W Increased ROE	2015	225,037	412	2,441							11,980,348	216,491	1,282,387
42	W 11.68 % ROE	2016	349,923	4,743	27,513	2,241,267	24,426	141,823				11,871,005	287,798	1,646,241
43	W Increased ROE	2016	349,923	4,743	27,513	2,241,267	24,426	141,823				11,871,005	287,798	1,646,241
44	W 11.68 % ROE	2017	14,750,613	214,966	1,227,153	18,339,519	295,246	1,684,077				11,583,248	287,798	1,586,839
45	W Increased ROE	2017	14,750,613	214,966	1,227,153	18,339,519	295,246	1,684,077				11,583,248	287,798	1,586,839
46	W 11.68 % ROE	2018	15,430,666	370,082	1,890,095	21,049,155	471,208	2,404,813	14,368,655	223,345	1,153,763	11,289,046	287,646	1,407,364
47	W Increased ROE	2018	15,430,666	370,082	1,890,095	21,049,155	471,208	2,404,813	14,368,655	223,345	1,153,763	11,289,046	287,646	1,407,364
44	W 11.68 % ROE	2019	15,238,622	376,860	1,602,199	20,242,376	500,513	2,128,205	13,620,433	331,313	1,426,533	11,001,247	287,646	1,172,258
45	W Increased ROE	2019	15,238,622	376,860	1,602,199	20,242,376	500,513	2,128,205	13,620,433	331,313	1,426,533	11,001,247	287,646	1,172,258
44	W 11.68 % ROE	2020	8,082,201	215,459	994,104	32,534,065	805,368	3,939,723	14,019,257	346,998	1,697,623	10,720,232	287,800	1,320,595
45	W Increased ROE	2020	8,082,201	215,459	994,104	32,534,065	805,368	3,939,723	14,019,257	346,998	1,697,623	10,720,232	287,800	1,320,595

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

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

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%, which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the 13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		Mickleton-Gloucester 230kV Circuit (B2139)	Ridge Road 69kV Breaker Station (B1255)	Cox's Corner-Lumberton 230kV Circuit (B1787)	Sewaren Switch 230kV Conversion (B2276)
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
12	Useful life of the project	Life		42	42	42	42
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No	No	No	No
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.63%	9.63%	9.63%	9.63%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.63%	9.63%	9.63%	9.63%
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified - End of year	Investment		19,515,077	43,062,455	32,029,640	0
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		464,645	1,025,297	762,610	0
19	Months in service for depreciation expense from			13.00	13.00	13.00	
20	Year placed in Service (0 if CWIP)			2015	2016	2015	2015

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

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

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

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.

8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.

9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

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		9.63%	9.63%	9.63%	9.63%
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.63%	9.63%	9.63%	9.63%
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified - End of year	Investment		1,108,058	22,106,940	157,394,496	22,217,516
		Annual Depreciation or Amort Exp					
18	Line 17 divided by line 12			26,382	526,356	3,747,488	528,988
19	Months in service for depreciation expense from			13.00	13.00	13.00	13.00
20	Year placed in Service (0 if CWIP)			2016	2018	2017	2018

			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)		
21		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
22	W 11.68 % ROE	2006												
23	W Increased ROE	2006												
24	W 11.68 % ROE	2007												
25	W Increased ROE	2007												
26	W 11.68 % ROE	2008												
27	W Increased ROE	2008												
28	W 11.68 % ROE	2009												
29	W Increased ROE	2009												
30	W 11.68 % ROE	2010												
31	W Increased ROE	2010												
32	W 11.68 % ROE	2011												
33	W Increased ROE	2011												
34	W 11.68 % ROE	2012												
35	W Increased ROE	2012												
36	W 11.68 % ROE	2013												
37	W Increased ROE	2013												
38	W 11.68 % ROE	2014												
39	W Increased ROE	2014												
40	W 11.68 % ROE	2015												
41	W Increased ROE	2015												
42	W 11.68 % ROE	2016	1,108,058	26,382	153,181									
43	W Increased ROE	2016	1,108,058	26,382	153,181									
44	W 11.68 % ROE	2017	1,081,675	26,382	147,691	2,060,962	3,775	21,554	75,384,047	433,473	2,475,231			
45	W Increased ROE	2017	1,081,675	26,382	147,691	2,060,962	3,775	21,554	75,384,047	433,473	2,475,231			
46	W 11.68 % ROE	2018	1,055,293	26,382	131,053	22,086,187	389,139	2,009,945	154,527,405	2,298,869	11,848,761	22,306,913	361,856	1,869,285
47	W Increased ROE	2018	1,055,293	26,382	131,053	22,086,187	389,139	2,009,945	154,527,405	2,298,869	11,848,761	22,306,913	361,856	1,869,285
44	W 11.68 % ROE	2019	1,028,911	26,382	109,117	21,887,850	529,005	2,289,010	146,538,027	3,550,621	15,333,762	22,030,024	531,017	2,302,454
45	W Increased ROE	2019	1,028,911	26,382	109,117	21,887,850	529,005	2,289,010	146,538,027	3,550,621	15,333,762	22,030,024	531,017	2,302,454
44	W 11.68 % ROE	2020	1,002,528	26,382	122,967	21,185,021	526,356	2,567,335	151,111,534	3,747,488	18,305,678	21,324,643	528,988	2,583,419
45	W Increased ROE	2020	1,002,528	26,382	122,967	21,185,021	526,356	2,567,335	151,111,534	3,747,488	18,305,678	21,324,643	528,988	2,583,419

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

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

The FCR resulting from Formula in a given year is used for that year only.
Therefore actual revenues collected in a year do not change based on cost data for subsequent years.
8 Per FERC Order dated December 30, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.93%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
9 For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

Line		Details		**New 500 kV bay at Hope Creek (Expansion of Hope Creek substation) (B2633.4)**			**New 500/230 kV autotransformer at Hope Creek and a new Hope Creek 230 kV substation (B2633.5)**			**Rebuild Aldene-Warinanco-Linden VFT 230kV Circuit (B2955)**			**Reconductor L-2238 Cedar Grove - Jackson Rd 230kV (B2956)**		
10															
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes			Yes			Yes			Yes		
12	Useful life of the project	Life		42			42			42			42		
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)	No			No			No			No		
14	Input the allowed increase in ROE	Increased ROE (Basis Points)		0			0			0			0		
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.63%			9.63%			9.63%			9.63%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.63%			9.63%			9.63%			9.63%		
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified - End of year	Investment		12,979,846			53,143,656			92,900,015			54,239,691		
		Annual Depreciation or Amort Exp													
18	Line 17 divided by line 12			309,044			1,265,325			2,211,905			1,291,421		
19	Months in service for depreciation expense from			1.00			1.00			4.45			1.00		
20	Year placed in Service (0 if CWIP)			2020			2020			2020			2020		
21			**Invest Yr**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**	**Ending**	**Depreciation or Amortization**	**Revenue**
22		W 11.68 % ROE	2006												
23		W Increased ROE	2006												
24		W 11.68 % ROE	2007												
25		W Increased ROE	2007												
26		W 11.68 % ROE	2008												
27		W Increased ROE	2008												
28		W 11.68 % ROE	2009												
29		W Increased ROE	2009												
30		W 11.68 % ROE	2010												
31		W Increased ROE	2010												
32		W 11.68 % ROE	2011												
33		W Increased ROE	2011												
34		W 11.68 % ROE	2012												
35		W Increased ROE	2012												
36		W 11.68 % ROE	2013												
37		W Increased ROE	2013												
38		W 11.68 % ROE	2014												
39		W Increased ROE	2014												
40		W 11.68 % ROE	2015												
41		W Increased ROE	2015												
42		W 11.68 % ROE	2016												
43		W Increased ROE	2016												
44		W 11.68 % ROE	2017												
45		W Increased ROE	2017												
46		W 11.68 % ROE	2018												
47		W Increased ROE	2018												
44		W 11.68 % ROE	2019												
45		W Increased ROE	2019												
44		W 11.68 % ROE	2020	12,979,846	23,773	119,964	53,143,656	97,333	491,171	92,900,015	757,028	3,820,197	54,239,691	99,340	501,301
45		W Increased ROE	2020	12,979,846	23,773	119,964	53,143,656	97,333	491,171	92,900,015	757,028	3,820,197	54,239,691	99,340	501,301

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

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

10		Details	
11	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)
12	Useful life of the project	Life	
13	"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 29, Otherwise "No"	CIAC	(Yes or No)
14	Input the allowed increase in ROE	Increased ROE (Basis Points)	
15	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE	
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project	
17	Project subaccount of Plant in Service Account 101 or 106 if not yet classified - End of year	Investment	
		Annual Depreciation or Amort Exp	
18	Line 17 divided by line 12		
19	Months in service for depreciation expense from		
20	Year placed in Service (0 if CWIP)		

21			**Invest Yr**	**Total**	**Incentive Charged**	**Revenue Credit**	
22		W 11.68 % ROE	2006				
23		W Increased ROE	2006				
24		W 11.68 % ROE	2007				
25		W Increased ROE	2007				
26		W 11.68 % ROE	2008				
27		W Increased ROE	2008				
28		W 11.68 % ROE	2009				
29		W Increased ROE	2009				
30		W 11.68 % ROE	2010				
31		W Increased ROE	2010				
32		W 11.68 % ROE	2011				
33		W Increased ROE	2011				
34		W 11.68 % ROE	2012				
35		W Increased ROE	2012				
36		W 11.68 % ROE	2013				
37		W Increased ROE	2013				
38		W 11.68 % ROE	2014				
39		W Increased ROE	2014				
40		W 11.68 % ROE	2015				
41		W Increased ROE	2015				
42		W 11.68 % ROE	2016				
43		W Increased ROE	2016				
44		W 11.68 % ROE	2017				
45		W Increased ROE	2017				
46		W 11.68 % ROE	2018				
47		W Increased ROE	2018				
44		W 11.68 % ROE	2019				
45		W Increased ROE	2019				
44		W 11.68 % ROE	2020	$ 551,551,876		$ 551,551,876	
45		W Increased ROE	2020	$ 557,792,331	$ 557,792,331		$ 6,240,455

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

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

Public Service Electric and Gas Company
Projected Costs of Plant in Forecasted Rate Base and In-Service Dates
12 Months Ended December 31, 2020

Required Transmission Enhancements

Upgrade ID	RTEP Baseline Project Description	Estimated/Actual Project Cost (thru 2020) *	Anticipated/Actual In-Service Date *
b0130	Replace all derated Branchburg 500/230 kv transformers	$ 20,645,602	Jan-06
b0134	Reconductor Kittatinny - Newtown 230 kV with 1590 ACSS	$ 8,069,022	Aug-07
b0145	Build new Essex - Aldene 230 kV cable connected through phase angle regulator at Essex	$ 86,467,721	Aug-07
b0411	Install 4th 500/230 kV transformer at New Freedom	$ 22,188,863	May-07
b0498	Loop the 5021 circuit into New Freedom 500 kV substation	$ 27,005,248	May-08
b0161	Install 230-138kV transformer at Metuchen substation	$ 25,654,455	Nov-09
b0169	Build a new 230 kV section from Branchburg - Flagtown and move the Flagtown - Somerville 230 kV circuit to the new section	$ 15,731,554	May-09
b0170	Reconductor the Flagtown-Somerville-Bridgewater 230 kV circuit with 1590 ACSS	$ 6,961,495	May-08
b0172.2	Replace wave trap at Branchburg 500kV substation	$ 27,988	Feb-08
b0274	Replace both 230/138 kV transformers at Roseland	$ 21,014,433	May-09
b0813	Reconductor Hudson - South Waterfront 230kV circuit	$ 9,158,918	May-10
b1017	Reconductor South Mahwah 345 kV J-3410 Circuit	$ 20,626,991	Dec-11
b1018	Reconductor South Mahwah 345 kV K-3411 Circuit	$ 21,170,273	May-11
b0290	Branchburg 400 MVAR Capacitor	$ 77,234,030	Nov-12
b0472	Saddle Brook - Athenia Upgrade Cable	$ 14,404,842	Nov-12
b0664-b0665	Branchburg-Somerville-Flagtown Reconductor	$ 18,664,931	Apr-12
b0668	Somerville -Bridgewater Reconductor	$ 6,390,403	Apr-12
b0814	New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie	$ 46,035,637	Dec-12
b1410-b1415	Replace Salem 500 kV breakers	$ 15,865,267	Oct-12
b1228	230kV Lawrence Switching Station Upgrade	$ 21,732,218	May-13
b1155	Branchburg-Middlesex Swich Rack	$ 62,938,142	Dec-13
b1399	Aldene-Springfield Rd. Conversion	$ 72,376,948	Dec-14
b1590	Upgrade Camden-Richmond 230kV Circuit	$ 11,276,183	Apr-14
b1588	Uprate EaglePoint-Gloucester 230kV Circuit	$ 12,087,610	May-15
b2139	Build Mickleton-Gloucester Corridor Ultimate Design	$ 19,515,077	Dec-15
b1255	Ridge Road 69kV Breaker Station	$ 43,062,455	Jun-16
b1787	New Cox's Corner-Lumberton 230kV Circuit	$ 32,029,640	Nov-15
b0376	Install Conemaugh 250MVAR Cap Bank	$ 1,108,058	Mar-16
b1589	Reconfigure Kearny- Loop in P2216 Ckt	$ 22,106,940	May-18
b2146	Reconfigure Brunswick Sw-New 69kVCkt-T	$ 157,394,496	Oct-17
b2702	350 MVAR Reactor Hopatcong 500kV	$ 22,217,516	Jun-18
b0489.5-b0489.15	Susquehanna Roseland Breakers	$ 5,857,687	Jun-10
b0489.4	Build new 500 kV transmission facilities from Pennsylvania - New Jersey border at Bushkill to Roseland (Below 500 kV elements of the project)	$ 40,538,248	Nov-11
b0489	Build new 500 kV transmission facilities from Pennsylvania - New Jersey border at Bushkill to Roseland (500kV and above elements of the project)	$ 721,881,197	Mar-12
b1156	Burlington - Camden 230kV Conversion	$ 356,333,540	Oct-11
b1398 - b1398.7	Mickleton-Gloucester-Camden	$ 439,023,933	Jun-13
b1154	North Central Reliability (West Orange Conversion)	$ 370,007,352	Jun-12
b1304.1-b1304.4	Northeast Grid Reliability Project	$ 625,166,511	Jun-13
b1304.5-b1304.21	Northeast Grid Reliability Project (In-Service)	$ 350,966,539	Dec-16
b2436.10	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades	$ 179,379,994	Jan-16
b2436.21	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades	$ 66,233,353	May-16
b2436.22	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades	$ 48,848,837	May-16

Upgrade ID	RTEP Baseline Project Description	Estimated/Actual Project Cost (thru 2020) *	Anticipated/Actual In-Service Date *
b2436.33	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades	$ 158,323,120	Dec-15
b2436.34	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34)	$ 126,346,267	Apr-18
b2436.50	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50)	$ 65,664,032	Apr-18
b2436.60	Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60)	$ 42,471,432	Dec-15
b2436.70	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70)	$ 81,535,606	Dec-15
b2436.81	Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades	$ 54,818,781	Dec-15
b2436.83	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades	$ 54,818,781	Dec-15
b2436.84	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades	$ 53,423,989	Dec-15
b2436.85	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades	$ 53,423,988	Dec-15
b2436.90	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades	$ 31,266,389	May-16
b2436.91	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades (B2436.91)	$ 24,992,501	Jun-16
b2437.10	New Bergen 345/230 kV transformer and any associated substation upgrades	$ 27,892,523	May-16
b2437.11	New Bergen 345/138 kV transformer #1 and any associated substation upgrades (B2437.11)	$ 27,892,523	Jun-16
b2437.20	New Bayway 345/138 kV transformer #1 and any associated substation upgrades	$ 9,049,265	Dec-15
b2437.21	New Bayway 345/138 kV transformer #2 and any associated substation upgrades	$ 9,049,265	Dec-15
b2437.30	New Linden 345/230 kV transformer and any associated substation upgrades	$ 33,825,459	Jul-16
b2437.33	New Bayonne 345/69 kV transformer and any associated substation upgrades (B2437.33)	$ 14,573,915	Apr-18
b2633.4	New 500 kV bay at Hope Creek (Expansion of Hope Creek substation) (B2633.4)	$ 12,979,846	Dec-20
b2633.5	New 500/230 kV autotransformer at Hope Creek and a new Hope Creek 230 kV substation	$ 53,143,656	Dec-20
b2955	Rebuild Aldene-Warinanco-Linden VFT 230kV Circuit (B2955)	$ 92,900,015	Jun-20
b2956	Reconductor L-2238 Cedar Grove - Jackson Rd 230kV (B2956)	$ 54,239,691	Dec-20
	Total	**$ 5,228,031,190**	

- Attachment 10 (JCP&L FERC Formula Rate filing)

Attachment 10 JCP&L Formula Rate

Period II

Statement BK
Attachment H-4A
page 1 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2020

Jersey Central Power & Light

Line No.	(1)	(2)	(3)	(4)		(5) Allocated Amount
1	GROSS REVENUE REQUIREMENT [page 3, line 42, col 5]					$ 170,350,964
	REVENUE CREDITS	(Note T)	Total	Allocator		
2	Account No. 451	(page 4, line 29)	-	TP	0.99785	-
3	Account No. 454	(page 4, line 30)	81,960	TP	0.99785	81,784
4	Account No. 456	(page 4, line 31)	712,824	TP	0.99785	711,292
5	Revenues from Grandfathered Interzonal Transactions		-	TP	0.99785	-
6	Revenues from service provided by the ISO at a discount		-	TP	0.99785	-
7	TEC Revenue	Attachment 11, Page 2, Line 3, Col. 12	22,087,043	TP	0.99785	22,039,589
8	TOTAL REVENUE CREDITS (sum lines 2-7)		22,881,826			22,832,665
9	True-up Adjustment with Interest	(Attachment 13, Line 28) enter negative				-
10	NET REVENUE REQUIREMENT	(Line 1 - Line 8 + Line 9)				$ 147,518,299
	DIVISOR					Total
11	1 Coincident Peak (CP) (MW)			(Note A)		6,057.1
12	Average 12 CPs (MW)			(Note CC)		4,053.2
			Total			
13	Annual Rate ($/MW/Yr)	(line 10 / line 11)	24,354.61			
			Peak Rate Total			Off-Peak Rate Total
14	Point-to-Point Rate ($/MW/Year)	(line 10 / line 12)	36,395.51			36,395.51
15	Point-to-Point Rate ($/MW/Month)	(line 14/12)	3,032.96			3,032.96
16	Point-to-Point Rate ($/MW/Week)	(line 14/52)	699.91			699.91
17	Point-to-Point Rate ($/MW/Day)	(line 16/5; line 16/7)	139.98			99.99
18	Point-to-Point Rate ($/MWh)	(line 14/4,160; line 14/8,760)	8.75			4.15

Attachment 10 JCP&L Formula Rate

Period II

Statement BK
Attachment H-4A
page 2 of 5

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2020

Jersey Central Power & Light

Line No.	(1)	(2) Source	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	RATE BASE:					
	GROSS PLANT IN SERVICE					
1	Production	Attachment 3, Line 14, Col. 1 (Notes U & X)	66,119,792	NA		
2	Transmission	Attachment 3, Line 14, Col. 2 (Notes U & X)	1,737,008,985	TP	0.99785	1,733,277,022
3	Distribution	Attachment 3, Line 14, Col. 3 (Notes U & X)	5,116,015,184	NA		
4	General & Intangible	Attachment 3, Line 14, Col. 4 & 5 (Notes U & X)	377,371,631	W/S	0.08600	32,453,170
5	Common	Attachment 3, Line 14, Col. 6 (Notes U & X)	-	CE	0.08600	-
6	TOTAL GROSS PLANT (sum lines 1-5)		7,296,515,593	GP=	24.200%	1,765,730,192
	ACCUMULATED DEPRECIATION					
7	Production	Attachment 4, Line 14, Col. 1 (Notes U & X)	25,087,116	NA		
8	Transmission	Attachment 4, Line 14, Col. 2 (Notes U & X)	427,905,189	TP	0.99785	426,985,834
9	Distribution	Attachment 4, Line 14, Col. 3 (Notes U & X)	1,560,925,134	NA		
10	General & Intangible	Attachment 4, Line 14, Col. 4 & 5 (Notes U & X)	192,165,542	W/S	0.08600	16,525,834
11	Common	Attachment 4, Line 14, Col. 6 (Notes U & X)	-	CE	0.08600	-
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		2,206,082,980			443,511,669
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)	41,032,677			
14	Transmission	(line 2- line 8)	1,309,103,796			1,306,291,187
15	Distribution	(line 3 - line 9)	3,555,090,051			
16	General & Intangible	(line 4 - line 10)	185,206,090			15,927,336
17	Common	(line 5 - line 11)	-			-
18	TOTAL NET PLANT (sum lines 13-17)		5,090,432,613	NP=	25.975%	1,322,218,523
	ADJUSTMENTS TO RATE BASE					
19	Account No. 281 (enter negative)	Attachment 5, Line 1, Col. 1 (Notes C, F)	-	NA		
20	Account No. 282 (enter negative)	Attachment 5, Line 1, Col. 2 (Note C, F)	(410,523,282)	DA	1.00000	(410,523,282)
21	Account No. 283 (enter negative)	Attachment 5, Line 1, Col. 3 (Notes C, F)	(11,050,625)	DA	1.00000	(11,050,625)
22	Account No. 190	Attachment 5, Line 1, Col. 4 (Notes C, F)	40,366,553	DA	1.00000	40,366,553
23	Account No. 255 (enter negative)	Attachment 5, Line 1, Col. 5 (Notes C, F)	-	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 Abandoned Plant	Attachment 16, Line 15, Col. 7 (Notes X & BB)	-	DA	1.00000	-
28	TOTAL ADJUSTMENTS (sum lines 19-27)		(381,207,354)			(381,207,354)
29	LAND HELD FOR FUTURE USE	214.x.d (Attachment 14, Line 3, Col. 1) (Notes G & Y)	-	TP	0.99785	-
30	WORKING CAPITAL (Note H)					
31	CWC	1/8*(Page 3, Line 14 minus Page 3, Line 11)	7,680,797.26			4,054,251.40
32	Materials & Supplies (Note G)	227.8.c & .16.c (Attachment 14, Line 3, Col. 2) (Note Y)	-	TE	0.95325	-
33	Prepayments (Account 165)	111.57.c (Attachment 14, Line 3, Col. 3) (Notes B & Y)	2,131,064	GP	0.24200	515,710
34	TOTAL WORKING CAPITAL (sum lines 31 - 33)		9,811,862			4,569,961
35	RATE BASE (sum lines 18, 28, 29, & 34)		4,719,037,121			945,581,130

Attachment 10 JCP&L Formula Rate

Period II

Statement BK
Attachment H-4A
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Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2020

Jersey Central Power & Light

Line No.	(1)	(2) Source	(3) Company Total	(4) Allocator		(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	321.112.b	32,288,618	TE	0.95325	30,779,178
2	Less LSE Expenses Included in Transmission O&M Accounts (Note W)		255,960	DA	1.00000	255,960
3	Less Account 565	321.96.b	306,000	DA	1.00000	306,000
4	Less Account 566	321.97.b	(7,388,875)	DA	1.00000	(7,388,875)
5	A&G	323.197.b	35,565,079	W/S	0.08600	3,058,522
6	Less FERC Annual Fees		-	W/S	0.08600	-
7	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)		5,474,418	W/S	0.08600	470,789
8	Plus Transmission Related Reg. Comm. Exp. (Note I)			TE	0.95325	-
9	PBOP Expense Adjustment in Year	Attachment 6, Line 11 (Note C)	(370,941)	DA	1.00000	(370,941)
10	Common	356.1	-	CE	0.08600	-
11	Account 566 Amortization of Regulatory Assets	321.97.b (notes)	-	DA	1.00000	-
12	Acct. 566 Miscellaneous Transmission Expense (less amortization of regulatory asset)	321.97.b - line 11	(7,388,875)	DA	1.00000	(7,388,875)
13	Total Account 566 (sum lines 11 & 12, ties to 321.97.b)		(7,388,875)			(7,388,875)
14	TOTAL O&M (sum lines 1, 5,8, 9, 10, 13 less 2, 3, 4, 6, 7)		61,446,378			32,434,011
	DEPRECIATION AND AMORTIZATION EXPENSE					
15	Transmission	336.7.b (Note U)	38,470,624	TP	0.99785	38,387,970
16	General & Intangible	336.1.f & 336.10.f (Note U)	20,282,906	W/S	0.08600	1,744,287
17	Common	336.11.b (Note U)	-	CE	0.08600	-
18	Amortization of Abandoned Plant	Attachment 16, Line 15, Col. 5 (Note BB)	-	DA	1.00000	-
19	TOTAL DEPRECIATION (sum lines 15 -18)		58,753,530			40,132,257
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
20	Payroll	263.i (Attachment 7, line 1z)	11,650,873	W/S	0.08600	1,001,951
21	Highway and vehicle	263.i (Attachment 7, line 2z)	6,975	W/S	0.08600	600
22	PLANT RELATED					
23	Property	263.i (Attachment 7, line 3z)	6,340,843	GP	0.24200	1,534,461
24	Gross Receipts	263.i (Attachment 7, line 4z)	-	NA		-
25	Other	263.i (Attachment 7, line 5z)	3,085	GP	0.24200	747
26	Payments in lieu of taxes	Attachment 7, line 6z	-	GP	0.24200	-
27	TOTAL OTHER TAXES (sum lines 20 - 26)		18,001,776			2,537,758
	INCOME TAXES	(Note K)				
28	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		28.11%			
29	CIT=(T/1-T) * (1-(WCLTD/R)) =		27.61%			
	where WCLTD=(page 4, line 22) and R= (page 4, line 25)					
	and FIT, SIT & p are as given in footnote K.					
30	1 / (1 - T) = (from line 29)		1.3910			
31	Amortized Investment Tax Credit (266.8.f) (enter negative)		(131,199)			
32	Tax Effect of Permanent Differences and AFUDC Equity (Attachment 15, Line 1, Col. 3) (Note D)		242,045			
33	(Excess)/Deficient Deferred Income Taxes (Attachment 15, Lines 2 & 3, Col. 3) (Note E)		(2,196,889)			
34	Income Tax Calculation = line 29 * line 39		105,839,824	NA		21,207,746
35	ITC adjustment (line 30 * line 31)		(182,500)	NP	0.25975	(47,404)
36	Permanent Differences and AFUDC Equity Tax Adjustment (line 30 * line 32)		336,688	DA	1.00000	336,688
37	(Excess)/Deficient Deferred Income Tax Adjustment (line 30 * line 33)		(3,055,904)	DA	1.00000	(3,055,904)
38	Total Income Taxes	sum lines 34 through 37	102,938,108			18,441,126
39	RETURN	[Rate Base (page 2, line 35) * Rate of Return (page 4, line 25, col. 6)]	383,308,698.69	NA		76,805,811
40	GROSS REV. REQUIREMENT (WITHOUT INCENTIVE)	(sum lines 14, 19, 27, 38, 39)	624,448,491			170,350,964
41	ADDITIONAL INCENTIVE REVENUE	Attachment 11, Line 4 (Note AA)	0			0
42	GROSS REV. REQUIREMENT	(line 40 + line 41)	624,448,491			170,350,964

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/2020

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)						1,737,008,985			
2	Less transmission plant excluded from ISO rates (Note M)						-			
3	Less transmission plant included in OATT Ancillary Services (Note N)						3,731,963			
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)						1,733,277,022			
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)					TP=	0.99785			
	TRANSMISSION EXPENSES									
6	Total transmission expenses (page 3, line 1, column 3)						32,288,618			
7	Less transmission expenses included in OATT Ancillary Services (Note L)						1,443,168			
8	Included transmission expenses (line 6 less line 7)						30,845,450			
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)						0.95530			
10	Percentage of transmission plant included in ISO Rates (line 5)					TP	0.99785			
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)					TE=	0.95325			
	WAGES & SALARY ALLOCATOR (W&S)									
		Form 1 Reference	$	TP	Allocation					
12	Production	354.20.b	-	0.00	-					
13	Transmission	354.21.b	7,056,263	1.00	7,041,103					
14	Distribution	354.23.b	58,655,533	0.00	-		W&S Allocator			
15	Other	354.24, 354.25, 354.26.b	16,163,483	0.00	-		($ / Allocation)			
16	Total (sum lines 12-15)		81,875,279		7,041,103	=	0.08600	= WS		
	COMMON PLANT ALLOCATOR (CE) (Note O)									
			$		% Electric (line 17 / line 20)		W&S Allocator (line 16, col. 6)			CE
17	Electric	200.3.c	-							
18	Gas	201.3.d	-		1.00000	*	0.08600		=	0.08600
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)		1,650,629,970	47%	0.0509		0.0239	=WCLTD		
23	Preferred Stock (112.3d) (Attachment 8, Line 14, Col. 2) (Note X)		-	0%	0.0000		0.0000			
24	Common Stock Attachment 8, Line 14, Col. 6) (Note X)		1,869,617,757	53%	0.1080		0.0574			
25	Total (sum lines 22-24)		3,520,247,727				0.0812	=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)				81,960			
31	ACCOUNT 456 (OTHER ELECTRIC REVENUE) (Note V)		(330.x.n)				712,824			

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data

For the 12 months ended 12/31/2020

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.
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 14, column 5 minus amortization of regulatory assets (page 3, line 11, 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 30).

Inputs Required:	FIT =	21.00%	
	SIT=	9.00%	(State Income Tax Rate or Composite SIT)
	p =		(percent of federal income tax deductible for state purposes)

L	Removes dollar amount of transmission expenses included in the OATT ancillary services rates, including Account Nos. 561.1 - 561.3, and 561.BA., and related to generation step-up facilities, which are deemed included in OATT ancillary 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.
M	Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).
N	Removes dollar amount of transmission plant included in the development of OATT ancillary services rates and generation step-up facilities, which are deemed included in OATT ancillary services. For these purposes, generation step-up facilities are those facilities at a generator substation on which there is no through-flow when the generator is shut down.
O	Enter dollar amounts
P	Debt cost rate = 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 no 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 its own reference.
U	Plant in Service, Accumulated Depreciation, and Depreciation Expense amounts exclude Asset Retirement Obligation amounts unless authorized by FERC.
V	On Page 4, Line 31, enter revenues from RTO settlements that are associated with NITS and firm Point-to-Point Service for which the load is not included in the divisor to derive 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.

Attachment 10 JCP&L Formula Rate

Period II

Statement BK
Attachment H-4A, Attachment 1
page 1 of 1
For the 12 months ended 12/31/2020

Schedule 1A Rate Calculation

1	$ 1,443,168	Attachment H-4A, Page 4, Line 7
2	$ 126,913	Revenue Credits for Sched 1A - Note A
3	$ 1,316,255	Net Schedule 1A Expenses (Line 1 - Line 2)
4	22,380,876	Annual MWh in JCP&L Zone - Note B
5	$ 0.0588	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.

Attachment 10 JCP&L Formula Rate

Period II

Incentive ROE Calculation

Line	Description		Source Reference	Amount
	Return Calculation			
1	Rate Base		Attachment H-4A, page 2, Line 35, Col. 5	945,581,130
2	Preferred Dividends	enter positive	Attachment H-4A, page 4, Line 21, Col. 6	0
	Common Stock			
3	Proprietary Capital		Attachment 8, Line 14, Col. 1	3,674,649,455
4	Less Preferred Stock		Attachment 8, Line 14, Col. 2	0
5	Less Accumulated Other Comprehensive Income Account 219		Attachment 8, Line 14, Col. 4	-5,863,989
6	Less Account 216.1 & Goodwill		Attachment 8, Line 14, Col. 3 & 5	1,810,895,687
7	Common Stock		Attachment 8, Line 14, Col. 6	1,869,617,757
	Capitalization			
8	Long Term Debt		Attachment H-4A, page 4, Line 22, Col. 3	1,650,629,970
9	Preferred Stock		Attachment H-4A, page 4, Line 23, Col. 3	0
10	Common Stock		Attachment H-4A, page 4, Line 24, Col. 3	1,869,617,757
11	Total Capitalization		Attachment H-4A, page 4, Line 25, Col. 3	3,520,247,727
12	Debt %	Total Long Term Debt	Attachment H-4A, page 4, Line 22, Col. 4	46.8896%
13	Preferred %	Preferred Stock	Attachment H-4A, page 4, Line 23, Col. 4	0.0000%
14	Common %	Common Stock	Attachment H-4A, page 4, Line 24, Col. 4	53.1104%
15	Debt Cost	Total Long Term Debt	Attachment H-4A, page 4, Line 22, Col. 5	0.0509
16	Preferred Cost	Preferred Stock	Attachment H-4A, page 4, Line 23, Col. 5	0.0000
17	Common Cost	Common Stock		0.1080
18	Weighted Cost of Debt	Total Long Term Debt (WCLTD)	(Line 12 * Line 15)	0.0239
19	Weighted Cost of Preferred	Preferred Stock	(Line 13 * Line 16)	0.0000
20	Weighted Cost of Common	Common Stock	(Line 14 * Line 17)	0.0574
21	Rate of Return on Rate Base (ROR)		(Sum Lines 18 to 20)	**0.0812**
22	Investment Return = Rate Base * Rate of Return		**(Line 1 * Line 21)**	**76,805,811**
	Income Taxes			
	Income Tax Rates			
23	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		Attachment H-4A, page 3, Line 28, Col. 3	28.11%
24	CIT=(T/1-T) * (1-(WCLTD/R)) =		Calculated	27.61%
25	1 / (1 - T) = (from line 23)		Attachment H-4A, page 3, Line 30, Col. 3	1.3910
26	Amortized Investment Tax Credit (266.8.f) (enter negative)		Attachment H-4A, page 3, Line 31, Col. 3	(131,199.25)
27	Tax Effect of Permanent Differences and AFUDC Equity		Attachment H-4A, page 3, Line 32, Col. 3	242,044.73
28	(Excess)/Deficient Deferred Income Taxes		Attachment H-4A, page 3, Line 33, Col. 3	(2,196,889.16)
29	Income Tax Calculation		(line 22 * line 24)	21,207,745.93
30	ITC adjustment		Attachment H-4A, page 3, Line 35, Col. 5	(47,403.61)
31	Permanent Differences and AFUDC Equity Tax Adjustment		Attachment H-4A, page 3, Line 36, Col. 5	336,687.62
32	(Excess)/Deficient Deferred Income Tax Adjustment		Attachment H-4A, page 3, Line 37, Col. 5	(3,055,903.69)
33	Total Income Taxes		Sum lines 29 to 32	18,441,126.26
	Increased Return and Taxes			
34	Return and Income taxes with increase in ROE		(Line 22 + Line 33)	95,246,937.12
35	Return without incentive adder		Attachment H-4A, Page 3, Line 39, Col. 5	76,805,810.86
36	Income Tax without incentive adder		Attachment H-4A, Page 3, Line 38, Col. 5	18,441,126.26
37	Return and Income taxes without increase in ROE		Line 35 + Line 36	95,246,937.12
38	Return and Income taxes with increase in ROE		Line 34	95,246,937.12
39	Incremental Return and incomes taxes for increase in ROE		Line 38 - Line 37	-
40	Rate Base		Line 1	945,581,130.31
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.

Attachment 10 JCP&L Formula Rate

Period II

Statement BK
Attachment H-4A, Attachment 3
page 1 of 1

Gross Plant Calculation

For the 12 months ended 12/31/2020

				[1]	[2]	[3]	[4]	[5]	[6]	[7]
				Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**	**Total**
1	December	2019		65,664,771	1,680,641,203	5,022,857,976	130,840,338	237,606,634	-	7,137,610,921
2	January	2020		65,702,563	1,687,974,268	5,038,038,578	130,926,303	238,368,774	-	7,161,010,485
3	February	2020		65,729,169	1,690,688,677	5,052,552,093	130,954,929	239,365,530	-	7,179,290,398
4	March	2020		65,744,576	1,693,172,844	5,066,586,416	135,805,534	240,145,749	-	7,201,455,118
5	April	2020		65,761,093	1,701,712,842	5,081,516,295	135,830,277	240,674,458	-	7,225,494,965
6	May	2020		65,777,851	1,704,349,531	5,096,843,420	135,862,423	241,118,615	-	7,243,951,838
7	June	2020		65,798,634	1,753,537,862	5,114,910,847	135,903,246	241,520,119	-	7,311,670,708
8	July	2020		65,820,872	1,755,825,300	5,131,538,873	135,917,967	241,996,462	-	7,331,099,475
9	August	2020		66,008,232	1,758,151,398	5,148,137,598	135,933,059	242,446,892	-	7,350,677,180
10	September	2020		66,224,968	1,761,075,778	5,163,960,416	135,949,131	242,828,130	-	7,370,038,423
11	October	2020		66,690,964	1,763,986,714	5,180,530,843	137,334,564	243,411,645	-	7,391,954,730
12	November	2020		67,141,503	1,803,914,332	5,196,603,995	137,361,936	243,995,320	-	7,449,017,087
13	December	2020		67,492,107	1,826,086,058	5,214,120,048	146,672,259	247,060,913	-	7,501,431,386
14	**13-month Average**		**[A] [C]**	**66,119,792**	**1,737,008,985**	**5,116,015,184**	**135,791,690**	**241,579,942**	**-**	**7,296,515,593**

				Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**	**Total**
			[B]	205.46.g	207.58.g	207.75.g	205.5.g	207.99.g	356.1	
15	December	2019		65,664,771	1,680,644,614	5,022,903,633	130,840,338	239,202,245		7,139,255,600
16	January	2020		65,702,563	1,687,977,678	5,038,084,235	130,926,303	239,964,385		7,162,655,163
17	February	2020		65,729,169	1,690,692,087	5,052,597,750	130,954,929	240,961,142		7,180,935,076
18	March	2020		65,744,576	1,693,176,254	5,066,632,072	135,805,534	241,741,360		7,203,099,797
19	April	2020		65,761,093	1,701,716,253	5,081,561,952	135,830,277	242,270,069		7,227,139,643
20	May	2020		65,777,851	1,704,352,941	5,096,889,076	135,862,423	242,714,226		7,245,596,517
21	June	2020		65,798,634	1,753,541,272	5,114,956,503	135,903,246	243,115,731		7,313,315,386
22	July	2020		65,820,872	1,755,828,710	5,131,584,530	135,917,967	243,592,074		7,332,744,153
23	August	2020		66,008,232	1,758,154,809	5,148,183,255	135,933,059	244,042,504		7,352,321,858
24	September	2020		66,224,968	1,761,079,188	5,164,006,073	135,949,131	244,423,742		7,371,683,101
25	October	2020		66,690,964	1,763,990,124	5,180,576,499	137,334,564	245,007,257		7,393,599,408
26	November	2020		67,141,503	1,803,917,743	5,196,649,652	137,361,936	245,590,932		7,450,661,766
27	December	2020		67,492,107	1,826,089,468	5,214,165,705	146,672,259	248,656,525		7,503,076,064
28	13-month Average			66,119,792	1,737,012,396	5,116,060,841	135,791,690	243,175,553	-	7,298,160,272

Asset Retirement Costs

				Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**
			[B]	205.44.g	207.57.g	207.74.g	company records	207.98.g	company records
29	December	2019			3,410	45,657		1,595,611	
30	January	2020			3,410	45,657		1,595,611	
31	February	2020			3,410	45,657		1,595,611	
32	March	2020			3,410	45,657		1,595,611	
33	April	2020			3,410	45,657		1,595,611	
34	May	2020			3,410	45,657		1,595,611	
35	June	2020			3,410	45,657		1,595,611	
36	July	2020			3,410	45,657		1,595,611	
37	August	2020			3,410	45,657		1,595,611	
38	September	2020			3,410	45,657		1,595,611	
39	October	2020			3,410	45,657		1,595,611	
40	November	2020			3,410	45,657		1,595,611	
41	December	2020			3,410	45,657		1,595,611	
42	13-month Average			-	3,410	45,657	-	1,595,611	-

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

Attachment 10 JCP&L Formula Rate

Period II

Statement BK
Attachment H-4A, Attachment 4
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For the 12 months ended 12/31/2020

Accumulated Depreciation Calculation

			[1]	[2]	[3]	[4]	[5]	[6]	[7]
			Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**	**Total**
1	December	2019	24,309,320	417,984,760	1,522,091,139	89,394,107	93,099,161	-	2,146,878,487
2	January	2020	24,442,853	419,810,687	1,528,524,213	90,241,153	93,840,303	-	2,156,859,209
3	February	2020	24,577,692	422,179,355	1,535,040,430	91,088,677	94,556,115	-	2,167,442,270
4	March	2020	24,713,817	424,583,933	1,541,615,906	91,956,531	95,296,732	-	2,178,166,919
5	April	2020	24,849,850	426,295,524	1,548,117,647	92,844,699	96,065,852	-	2,188,173,573
6	May	2020	24,985,888	428,663,114	1,554,603,055	93,733,105	96,844,792	-	2,198,829,954
7	June	2020	25,121,517	425,904,594	1,560,814,191	94,621,814	97,628,843	-	2,204,090,958
8	July	2020	25,257,025	428,407,122	1,567,215,008	95,446,470	98,404,971	-	2,214,730,596
9	August	2020	25,374,393	430,912,627	1,573,667,266	96,271,250	99,184,388	-	2,225,409,924
10	September	2020	25,488,892	433,380,630	1,580,254,478	97,096,161	99,971,861	-	2,236,192,021
11	October	2020	25,576,366	435,849,127	1,586,787,678	97,926,911	100,737,279	-	2,246,877,361
12	November	2020	25,666,456	434,208,352	1,593,404,891	98,763,547	101,503,181	-	2,253,546,427
13	December	2020	25,768,436	434,587,628	1,599,890,840	99,639,091	101,995,047	-	2,261,881,041
14	**13-month Average**	**[A] [C]**	**25,087,116**	**427,905,189**	**1,560,925,134**	**94,540,271**	**97,625,271**	**-**	**2,206,082,980**

			Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**	**Total**
		[B]	219.20-24.c	219.25.c	219.26.c	200.21.c	219.28.c	356.1	
15	December	2019	24,309,320	417,986,307	1,522,091,139	89,394,107	93,730,844		2,147,511,717
16	January	2020	24,442,853	419,812,237	1,528,524,213	90,241,153	94,478,755		2,157,499,212
17	February	2020	24,577,692	422,180,910	1,535,040,430	91,088,677	95,201,336		2,168,089,045
18	March	2020	24,713,817	424,585,491	1,541,615,906	91,956,531	95,948,721		2,178,820,468
19	April	2020	24,849,850	426,297,087	1,548,117,647	92,844,699	96,724,611		2,188,833,894
20	May	2020	24,985,888	428,664,681	1,554,603,055	93,733,105	97,510,319		2,199,497,048
21	June	2020	25,121,517	425,906,164	1,560,814,191	94,621,814	98,301,140		2,204,764,825
22	July	2020	25,257,025	428,408,696	1,567,215,008	95,446,470	99,084,036		2,215,411,235
23	August	2020	25,374,393	430,914,205	1,573,667,266	96,271,250	99,870,222		2,226,097,336
24	September	2020	25,488,892	433,382,212	1,580,254,478	97,096,161	100,664,464		2,236,886,206
25	October	2020	25,576,366	435,850,714	1,586,787,678	97,926,911	101,436,651		2,247,578,319
26	November	2020	25,666,456	434,209,942	1,593,404,891	98,763,547	102,209,322		2,254,254,158
27	December	2020	25,768,436	434,589,222	1,599,890,840	99,639,091	102,707,956		2,262,595,544
28	13-month Average		25,087,116	427,906,759	1,560,925,134	94,540,271	98,297,567	-	2,206,756,847

Reserve for Depreciation of Asset Retirement Costs

			Production	**Transmission**	**Distribution**	**Intangible**	**General**	**Common**
		[B]	Company Records	Company Records	Company Records	Company Records	Company Records	Company Records
29	December	2019		1,547			631,683	
30	January	2020		1,551			638,452	
31	February	2020		1,555			645,221	
32	March	2020		1,559			651,990	
33	April	2020		1,563			658,759	
34	May	2020		1,567			665,528	
35	June	2020		1,571			672,296	
36	July	2020		1,575			679,065	
37	August	2020		1,579			685,834	
38	September	2020		1,583			692,603	
39	October	2020		1,586			699,372	
40	November	2020		1,590			706,140	
41	December	2020		1,594			712,909	
42	13-month Average		-	1,571	-	-	672,296	-

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

Attachment 10 JCP&L Formula Rate

Period II

Statement BK
Attachment H-4A, Attachment 5
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For the 12 months ended 12/31/2020

			[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) [B]	**Acct. No. 283** (enter negative) [C]	**Acct. No. 190** [D]	**Acct. No. 255** (enter negative) [E]	**Total**
1	December 31	2020	-	(410,523,282)	(11,050,625)	40,366,553	-	(381,207,354)
			ADIT Total Transmission-related only, including Plant & Labor Related Transmission ADITs (prior to adjusments from notes below)					
			Acct. No. 281	**Acct. No. 282**	**Acct. No. 283**	**Acct. No. 190**	**Acct. No. 255**	**Total**
2	December 31	2020 [G]	-	299,146,653	(24,031,443)	44,328,672	1,523,750	320,967,632

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 [F]
3	2020	-	620,640	(116,234,402)		4,237,132

[C] FERC Account No. 283 is adjusted for the following items.

		FAS 143 - ARO	FAS 106	FAS 109	CIAC	Normalization [F]
4	2020	19,002	-	(35,928,497)		827,427

[D] FERC Account No. 190 is adjusted for the following items:

		FAS 143 - ARO	FAS 106	FAS 109	CIAC	Normalization [F]
5	2020	-	-	(6,302,072)	10,692,658	(428,467)

[E] See Attachment H-4A, page 5, note K; A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f).

[F] Sourced from Attachment 5b, page 1, col. O for PTRR & Attachment 5C, page 2, col. O for ATRR

[G] Sourced from Attachment 5a, page 1, lines 1-5, col. 4

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Statement BK
Attachment H-4A, Attachment 5a
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For the 12 months ended 12/31/2020

Jersey Central Power & Light
Summary of Transmission ADIT (Prior to adjusted items)

Line	1	2	3	4
		Transmission Ending	End Plant & Labor Related Allocated to Transmission	Total Transmission Ending (col. 2 + col. 3)
		(Note F)	(page 1, Col. K)	(Note E)
1	**ADIT- 282 From Account Subtotal Below**	299,146,653	-	299,146,653
2	**ADIT-283 From Account Subtotal Below**	(24,031,443)	-	(24,031,443)
3	**ADIT-190 From Account Subtotal Below**	44,328,672	-	44,328,672
4	**ADIT-281 From Account Subtotal Below**	-	-	-
5	**ADIT-255 From Account Subtotal Below**	1,523,750	-	1,523,750
	Total (sum rows 1-5)	320,967,632	-	320,967,632

Jersey Central Power & Light
Summary of Transmission ADIT (Prior to adjusted items)

Line		A	B	C	D	E	F
		End Plant Related	End Labor Related	Plant & Labor Subtotal	Gross Plant Allocator	Wages & Salary Allocator	End Plant & Labor Related ADIT
		(Note A)	(Note B)	Col. A + Col. B	(Note C)	(Note D)	(Col. A * Col. D) + (Col. B * Col. E)
1	ADIT- 282 From Account Total Below	-	-	-	24.20%	8.60%	-
2	ADIT-283 From Account Total Below	-	-	-	24.20%	8.60%	-
3	ADIT-190 From Account Total Below	-	-	-	24.20%	8.60%	-
4	ADIT-281 From Account Total Below	-	-	-	24.20%	8.60%	-
5	ADIT-255 From Account Total Below	-	-	-	24.20%	8.60%	-
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 Ending taken to Attachment 5, line 2
- F From column E (beginning on page 2) by account

Period II

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Attachment H-4A, Attachment 5a
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For the 12 months ended 12/31/2020

Jersey Central Power & Light

A	B	C	D	E	F	G	
ADIT-190	End of Year Balance p234.18.c	Retail Related	Gas, Prod Or Other Related	Only Transmission Related	Plant Related	Labor Related	JUSTIFICATION
Asset Impairment	5,270,265			5,270,265			
Capitalized Interest	8,557,430			8,557,430			
Contribution in Aid of Construction	10,692,658			10,692,658			
Investment Tax Credit	595,808			595,808			
FAS109 Related to Property	(6,302,072)			(6,302,072)			
Federal NOL	18,278,881			18,278,881			
NJ State NOL	7,069,693			7,069,693			
AMT Credit Carryforward	119,554			119,554			
General Business Credit Carryforward	46,455			46,455			
	-						
	-						
Subtotal	44,328,672	-	-	44,328,672	-	-	

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

Period II

Statement BK
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For the 12 months ended 12/31/2020

A	B	C	D	E	F	G	
	Jersey Central Power & Light						
ADIT- 282	End of Year Balance p275.9.k	Retail Related	Gas, Prod Or Other Related	Only Transmission Related	Plant Related	Labor Related	JUSTIFICATION
263A Capitalized Overheads	78,686,827			78,686,827			
Accelarated Depreciation	266,529,087			266,529,087			
AFUDC	7,089,368			7,089,368			
AFUDC Equity (FAS109)	3,232,622			3,232,622			
Asset Impairment	-			-			
Capitalized Interest	-			-			
Capitalized Tree Trimming	8,452,807			8,452,807			
Casualty Loss	12,191,244			12,191,244			
Contribution in Aid of Construction	-			-			
OPEBs	620,640			620,640			
Other	972,719			972,719			
Pension and Capitalized Benefits	12,208,190			12,208,190			
Tax Repairs	28,634,975			28,634,975			
Sale of Property - Book/Tax Gain/Loss	(4,804)			(4,804)			
FAS109 Related to Property	(119,467,024)			(119,467,024)			
	-						
Subtotal	299,146,653	-	-	299,146,653	-	-	

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

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Statement BK
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For the 12 months ended 12/31/2020

A	B	C	D	E	F	G	
	Jersey Central Power & Light						
ADIT-283	End of Year Balance p277.19.k	Retail Related	Gas, Prod Or Other Related	Only Transmission Related	Plant Related	Labor Related	JUSTIFICATION
AFUDC Equity Flow Thru (Gross up)	1,264,000			1,264,000			
Property FAS109	(44,249,086)			(44,249,086)			
Accrued Taxes	(58,843)			(58,843)			
Accum. Prov. For Injuries and Damages	(81,216)			(81,216)			
Asset Retirement Obligation	19,002			19,002			
Company Debt - Issuance Discount	(23,004)			(23,004)			
Deferred Charge - EIB	45,460			45,460			
FAS 112 - Medical Benefit Accrual	(358,474)			(358,474)			
FAS 158 Pension & OPEB	(82,715)			(82,715)			
FE Service Timing Allocation	10,445,026			10,445,026			
Fed Rate Change - Non Property Gross-up	2,759,226			2,759,226			
GR&F Tax Audit	(81,081)			(81,081)			
Pension Expense	(5,563,028)			(5,563,028)			
PJM Payable / Receivable	-			-			
PJM Unbilled Deferral	(1,719,738)			(1,719,738)			
Post Retirement Benefits FAS 106	(3,229,826)			(3,229,826)			
State Income Tax Deductible	1,020,111			1,020,111			
Storm Damage	17,595,320			17,595,320			
Unamortized Gain/Loss on Reacquired Debt	222,781			222,781			
Vacation Accrual	(302,361)			(302,361)			
Vegetation Management	(1,652,997)			(1,652,997)			
	-			-			
Subtotal	(24,031,443)	-	-	(24,031,443)	-	-	

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

Period II

Statement BK
Attachment H-4A, Attachment 5a
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For the 12 months ended 12/31/2020

A	B	C	D	E	F	G	
	Jersey Central Power & Light						
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.

Period II

Statement BK
Attachment H-4A, Attachment 5a
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For the 12 months ended 12/31/2020

A	B	C	D	E	F	G	
	Jersey Central Power & Light						
ADIT-255	End of Year Balance p267.h	Retail Related	Gas, Prod Or Other Related	Only Transmission Related	Plant Related	Labor Related	JUSTIFICATION
Investment Tax Credit	1,523,750			1,523,750			
				-			
				-			
				-			
				-			
				-			
				-			
				-			
				-			
Subtotal	1,523,750	-	-	1,523,750	-	-	

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.

Period II

Statement BK
Attachment H-4A, Attachment 5b
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For the 12 months ended 12/31/2020

Line		A	B	C	D	E	F	G	H	I
			2020 Quarterly Activity and Balances							
		Beginning 190 (including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
1	PTRR	40,194,744	184,064	40,378,808	43,215	40,422,023	41,642	40,463,665	40,990	40,504,655
		Beginning 190 (including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
2	PTRR	**40,194,744**	**139,183**		**21,904**		**10,610**		**112**	
		Beginning 282 (including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
3	PTRR	405,271,792	5,626,083	410,897,875	1,320,910	412,218,785	1,272,835	413,491,620	1,252,888	414,744,508
		Beginning 282 (including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
4	PTRR	**405,271,792**	**4,254,244**		**669,502**		**324,311**		**3,433**	
		Beginning 283 Including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
5	PTRR	10,017,938	1,106,349	11,124,287	259,752	11,384,039	250,299	11,634,338	246,376	11,880,714
		Beginning 283 Including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
6	PTRR	**10,017,938**	**836,582**		**131,655**		**63,775**		**675**	

2020 PTRR

Line		Account	J Estimated Ending Balance (Before Adjustments)	K Page 1, B+D+F+H Projected Activity	L Page 1, row 2,4,6 Column A+B+D+F+H Prorated Ending Balance	M J-L Prorated - Estimated End (Before Adjustments)	N Sum of end ADIT Adjustments	O M-N Normalization	P Line 7= J-N-O Lines 8-9= -J+N+O Ending ADIT Balance Included in Formula Rate
7	PTRR	Total Account 190	44,328,672	309,911	40,366,553	3,962,120	4,390,586	**(428,467)**	**40,366,553**
8	PTRR	Total Account 282	299,146,653	9,472,716	410,523,282	(111,376,629)	(115,613,762)	**4,237,132**	**(410,523,282)**
9	PTRR	Total Account 283	(24,031,443)	1,862,776	11,050,625	(35,082,067)	(35,909,495)	**827,427**	**(11,050,625)**
10	PTRR	Total ADIT Subject to Normalization	(230,786,538)	(11,025,581)	(381,207,354)	150,420,816	(147,132,670)	4,636,093	(381,207,354)

Notes:
1. Attachment 5b will only be populated within the PTRR

Attachment 10 JCP&L Formula Rate

Period II

Statement BK
Attachment H-4A, Attachment 5c
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For the 12 months ended 12/31/2020

Line		A	B	C	D	E	F	G	H	I
			2020 Quarterly Activity and Balances							
		Beginning 190 (including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
1	PTRR	0	0	0	0	0	0	0	0	0
2	ATRR	0	0	0	0	0	0	0	0	0
		Beginning 190 (including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
3	PTRR	**0**	**0**		**0**		**0**		**0**	
4	ATRR	**0**	**0**		**0**		**0**		**0**	
		Beginning 282 (including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
5	PTRR	0	0	0	0	0	0	0	0	0
6	ATRR	0	0	0	0	0	0	0	0	0
		Beginning 282 (including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
7	PTRR	**0**	**0**		**0**		**0**		**0**	
8	ATRR	**0**	**0**		**0**		**0**		**0**	
		Beginning 283 Including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
9	PTRR	0	0	0	0	0	0	0	0	0
10	ATRR	0	0	0	0	0	0	0	0	0
		Beginning 283 Including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
11	PTRR	**0**	**0**		**0**		**0**		**0**	
12	ATRR	**0**	**0**		**0**		**0**		**0**	

Attachment 10 JCP&L Formula Rate

Period II

Statement BK
Attachment H-4A, Attachment 5c
page 2 of 2
For the 12 months ended 12/31/2020

2020 PTRR

Line		Account	A Estimated Ending Balance (Before Adjustments)	B Page 1, B+D+F+H Projected Activity	C Page 1, row 3,7,11 Column A+B+D+F+H Prorated Ending Balance	D A-C Prorated - Estimated End (Before Adjustments)	E Sum of end ADIT Adjustments	F D-E Normalization	G Line 1= A-E-F Lines 2-3= -A+E+F Ending ADIT Balance Included in Formula Rate
1	PTRR	Total Account 190	-	0	0	-	-	-	-
2	PTRR	Total Account 282	-	0	0	-	-	-	-
3	PTRR	Total Account 283	-	0	0	-	-	-	-
4	PTRR	Total ADIT Subject to Normalization	-	-	-	-	-	-	-

2020 ATRR

Line		Account	H Actual Ending Balance (Before Adjustments)	I Page 1, B+D+F+H Actual Activity	J Page 1, row 4,8,12 column A+B+D+F+H Prorated Ending Balance	K H-J Prorated - Actual End (Before Adjustments)	L D-K Prorated Activity Not Projected	M Sum of end ADIT Adjustments	N E-M ADIT Adjustments not projected	O K+L-M-N Normalization	P Line 5= H-M-O Lines 6-7= -H+M+O Ending ADIT Balance Included in Formula Rate
5	ATRR	Total Account 190	-	0	0	-	-	-	-	-	-
6	ATRR	Total Account 282	-	0	0	-	-	-	-	-	-
7	ATRR	Total Account 283	-	0	0	-	-	-	-	-	-
8	ATRR	Total ADIT Subject to Normalization	-	-	-	-	-	-	-	-	-

Notes:
1. Attachment 5c will only be populated within the ATRR

Period II

Statement BK
Attachment H-4A, Attachment 6
page 1 of 1
For the 12 months ended 12/31/2020

1	**Calculation of PBOP Expenses**		
2	**JCP&L**	**Amount**	**Source**
3	Total FirstEnergy PBOP expenses	-$155,537,000	FirstEnergy 2018 Actuarial Study
4	Labor dollars (FirstEnergy)	$2,363,633,077	FirstEnergy 2018 Actual: Company Records
5	cost per labor dollar (line 3 / line 4)	-$0.0658	
6	labor (labor not capitalized) current year, transmission only	6,276,276	JCP&L Labor: Company Records
7	PBOP Expense for current year (line 5 * line 6)	-$413,005	
8	PBOP expense in Account 926 for current year, total company	(489,135)	JCP&L Account 926: Company Records
9	W&S Labor Allocator	8.600%	
10	Allocated Transmission PBOP (line 8 * line 9)	(42,065)	
11	PBOP Adjustment for Attachment H-4A, page 3, line 9 (line 7 - line 10)	(370,941)	
12	Lines 3-4 cannot change absent a Section 205 or 206 filing approved or accepted by FERC in a separate proceeding		

Period II

Statement BK
Attachment H-4A, Attachment 7
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For the 12 months ended 12/31/2020

Taxes Other than Income Calculation

			[A]	Dec 31, 2020
1	**Payroll Taxes**			
1a	FICA & unemployement taxes	263.i		11,650,873
1b		263.i		
1c		263.i		
1d		263.i		
1z	**Payroll Taxes Total**			11,650,873
2	**Highway and Vehicle Taxes**			
2a	Federal Excise Tax	263.i		6,975
2z	**Highway and Vehicle Taxes**			6,975
3	**Property Taxes**			
3a	New Jersey Property Tax	263.i		6,340,768
3b	PA PURTA Tax	263.i		75
3c		263.i		-
3d		263.i		-
3z	**Property Taxes**			6,340,843
4	**Gross Receipts Tax**			
4a	Gross Receipts Tax	263.i		-
4z	**Gross Receipts Tax**			-
5	**Other Taxes**			
5a	Sales & Use Tax	263.i		3,085
5b		263.i		
5c		263.i		
5d				-
5z	**Other Taxes**			3,085
6z	**Payments in lieu of taxes**			
7	Total other than income taxes (sum lines 1z, 2z, 3z, 4z, 5z, 6z) [tie to 114.14c]			$18,001,776.00

Notes:

[A] Reference for December balances as would be reported in FERC Form 1.

Attachment 10 JCP&L Formula Rate

Period II

Statement BK
Attachment H-4A, Attachment 8
page 1 of 1
For the 12 months ended 12/31/2020

Capital Structure Calculation

				[1]	[2]	[3]	[4]	[5]	[6]	[7]
				Proprietary Capital	**Preferred Stock**	**Account 216.1**	**Account 219**	**Goodwill**	**Common Stock**	**Long Term Debt**
			[A]	112.16.c	112.3.c	112.12.c	112.15.c	233.5.f	(1) - (2) - (3) - (4) - (5)	112.24.c
1	December	2019		3,616,361,135	-	(40,438)	(5,689,656)	1,810,936,125	1,811,155,104	1,650,811,724
2	January	2020		3,629,988,160		(40,438)	(5,718,712)	1,810,936,125	1,824,811,185	1,650,781,432
3	February	2020		3,642,398,273		(40,438)	(5,747,767)	1,810,936,125	1,837,250,353	1,650,751,139
4	March	2020		3,628,891,236		(40,438)	(5,776,823)	1,810,936,125	1,823,772,372	1,650,720,847
5	April	2020		3,638,837,224		(40,438)	(5,805,878)	1,810,936,125	1,833,747,415	1,650,690,555
6	May	2020		3,654,010,566		(40,438)	(5,834,934)	1,810,936,125	1,848,949,813	1,650,660,262
7	June	2020		3,653,946,728		(40,438)	(5,863,989)	1,810,936,125	1,848,915,030	1,650,629,970
8	July	2020		3,687,446,863		(40,438)	(5,893,045)	1,810,936,125	1,882,444,221	1,650,599,678
9	August	2020		3,719,564,976		(40,438)	(5,922,101)	1,810,936,125	1,914,591,390	1,650,569,385
10	September	2020		3,712,492,592		(40,438)	(5,951,156)	1,810,936,125	1,907,548,061	1,650,539,093
11	October	2020		3,725,041,950		(40,438)	(5,980,212)	1,810,936,125	1,920,126,475	1,650,508,801
12	November	2020		3,737,320,890		(40,438)	(6,009,267)	1,810,936,125	1,932,434,470	1,650,478,508
13	December	2020		3,724,142,321		(40,438)	(6,038,323)	1,810,936,125	1,919,284,957	1,650,448,216
14	13-month Average			3,674,649,455	-	(40,438)	(5,863,989)	1,810,936,125	1,869,617,757	1,650,629,970

Notes:
[A] Reference for December balances as would be reported in FERC Form 1.

Attachment 10 JCP&L Formula Rate

Period II

Statement BK
Attachment H-4A, Attachment 9
page 1 of 1

Stated Value Inputs

For the 12 months ended 12/31/2020

Formula Rate Protocols
Section VIII.A

1. Rate of Return on Common Equity ("ROE")

JCP&L's stated ROE is set to: 10.8%

2. Postretirement Benefits Other Than Pension ("PBOP")

**sometimes referred to as Other Post Employment Benefits, or "OPEB"*

Total FirstEnergy PBOP expenses	-$155,537,000
Labor dollars (FirstEnergy)	$2,363,633,077
cost per labor dollar	$-0.0658

3. Depreciation Rates (1)(2)

FERC Account	Depr %
350.2	1.53%
352	1.14%
353	2.43%
354	0.83%
355	1.95%
356	2.45%
356.1	1.09%
357	1.39%
358	1.88%
359	1.10%
389.2	3.92%
390.1	1.51%
390.2	0.46%
391.1	4.00%
391.15	5.00%
391.2	20.00%
391.25	20.00%
392	3.84%
393	3.33%
394	4.00%
395	5.00%
396	3.03%
397	5.00%
398	5.00%

Note: (1) Account 303 amortization period is 7 years.

(2) Accounts 391.10, 391.15, 391.20, 391.25, 393, 394, 395, 397, and 398 have an unrecovered reserve to be amortized over 5 years separately from the assets in these accounts beginning January 1, 2020 through December 31, 2025.

Period II

Debt Cost Calculation

TABLE 1: Summary Cost of Long Term Debt

CALCULATION OF COST OF DEBT

YEAR ENDED 12/31/2020

Long Term Debt 12/31/2020 (t=N)	(a) Issue Date	(b) Maturity Date	(c) ORIGINAL ISSUANCE (table 2, col. cc)	(d) Net Proceeds At Issuance (table 2, col. hh)	(e) Net Amount Outstanding at t=N	(f) Months Outstanding at t=N	(g) Average Net Outstanding in Year* z* ((col e. * col. F)/12)	(h) Weighted Outstanding Ratios (col. g/col. g total)	(i) Effective Cost Rate (Table 2, Col. ll)	(j) Weighted Debt Cost at t = N (h) * (i)
First Mortgage Bonds:										
(1) 6.40% Series	5/12/2006	5/15/2036	$ 200,000,000	$ 196,437,127	$ 198,174,028	12	$ 198,174,027.59	12.05%	6.54%	0.79%
(2) 6.15% Series	5/16/2007	6/1/2037	$ 300,000,000	$ 295,979,779	$ 297,803,097	12	$ 297,803,096.98	18.11%	6.25%	1.13%
(3) 4.30% Series	2/8/2019	1/15/2026	$ 400,000,000	$ 402,287,000	$ 401,667,604	12	$ 401,667,604.17	24.43%	4.20%	1.03%
(4) 4.70% Series	8/21/2013	4/1/2024	$ 500,000,000	$ 493,197,650	$ 497,937,870	12	$ 497,937,870.28	30.29%	4.87%	1.47%
(5) 4.30% Series	8/18/2015	1/15/2026	$ 250,000,000	$ 247,086,512	$ 248,589,872	12	$ 248,589,871.61	15.12%	4.44%	0.67%
			$ 1,650,000,000		$ 1,644,172,471		$ 1,644,172,471	100.000%		5.09% **

t = time
The current portion of long term debt is included in the Net Amount Outstanding at t = N in these calculations.
The outstanding amount (column (e)) for debt retired during the year is the outstanding amount at the last month it was outstanding.
* z = Average of monthly balances for months outstanding during the year (averge of the balances for the 12 months of the year, with zero in months that the issuance is not outstanding in a month.).
Interim (individual debenture) debt cost calculations shall be taken to four decimals in percentages (7.2300%, 5.2582%); Final Total Weighted Average Debt Cost for the Formula Rate shall be rounded to two decimals of a percent (7.03%).
** This Total Weighted Average Debt Cost will be shown on page 4, line 22, column 5 of formula rate Attachment H-4A.

TABLE 2: Effective Cost Rates For Traditional Front-Loaded Debt Issuances:

YEAR ENDED 12/31/2020

Long Term Debt 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. hh / col. cc)*100)	(jj) Coupon Rate	(kk) Annual Interest (col. cc * col. jj)	(ll) Effective Cost Rate* (Yield to Maturity at Issuance, t = 0)
(1) 6.40% Series	5/12/2006	5/15/2036	$ 200,000,000	$ (1,216,000)	$ 2,346,873	-	xxx	$ 196,437,127	98.2186	0.0640	$ 12,800,000	6.54%
(2) 6.15% Series	5/16/2007	6/1/2037	$ 300,000,000	$ (3,693,000)	$ 327,221			$ 295,979,779	98.6599	0.0615	$ 18,450,000	6.25%
(3) 4.30% Series	2/8/2019	1/15/2026	$ 400,000,000	$ 5,884,000	$ 3,597,000			$ 402,287,000	100.5718	0.0430	$ 17,200,000	4.20%
(4) 4.70% Series	8/21/2013	4/1/2024	$ 500,000,000	$ (2,595,000)	$ 4,207,350			$ 493,197,650	98.6395	0.0470	$ 23,500,000	4.87%
(5) 4.30% Series	8/18/2015	1/15/2026	$ 250,000,000	$ (800,000)	$ 2,113,488			$ 247,086,512	98.8346	0.0430	$ 10,750,000	4.44%
TOTALS			$ 1,650,000,000	(2,420,000)	$ 12,591,932	-	xxx	$ 1,634,988,068			$ 82,700,000	

* YTM at issuance calculated from an acceptable bond table or from YTM = Internal Rate of Return (IRR) calculation
Effective Cost Rate of Individual Debenture (YTM at issuance): the t=0 Cashflow C_o equals Net Proceeds column (gg); Semi-annual (or other) interest cashflows ($C_{t=1}$, $C_{t=2}$, etc.).

Period II

Statement BK
Attachment H-4A, Attachment 11
page 1 of 2
For the 12 months ended 12/31/2020

Transmission Enhancement Charge (TEC) Worksheet
To be completed in conjunction with Attachment H-4A

	(1)	(2)	(3)	(4)
Line No.		**Reference**	**Transmission**	**Allocator**
1	Gross Transmission Plant - Total	Attach. H-4A, p. 2, line 2, col. 5 (Note A)	$ 1,733,277,022	
2	Net Transmission Plant - Total	Attach. H-4A, p. 2, line 14, col. 5 (Note B)	$ 1,306,291,187	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Attach. H-4A, p. 3, line 14, col. 5	$ 32,434,011	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1, col. 3)	1.871254%	1.871254%
	GENERAL, INTANGIBLE, AND COMMON (G,I, & C) DEPRECIATION EXPENSE			
5	Total G, I, & C depreciation expense	Attach. H-4A, p. 3, lines 16 & 17, col. 5	$ 1,744,287	
6	Annual allocation factor for G, I, & C depreciation expense	(line 5 divided by line 1, col. 3)	0.100635%	0.100635%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Attach. H-4A, p. 3, line 27, col. 5	$ 2,537,758	
8	Annual Allocation Factor for Other Taxes	(line 7 divided by line 1, col. 3)	0.146414%	0.146414%
9	**Annual Allocation Factor for Expense**	**Sum of line 4, 6, & 8**		**2.118303%**
	INCOME TAXES			
10	Total Income Taxes	Attach. H-4A, p. 3, line 38, col. 5	$ 18,441,126	
11	Annual Allocation Factor for Income Taxes	(line 10 divided by line 2, col. 3)	1.411716%	1.411716%
	RETURN			
12	Return on Rate Base	Attach. H-4A, p. 3, line 39, col. 5	$ 76,805,811	
13	Annual Allocation Factor for Return on Rate Base	(line 12 divided by line 2, col. 3)	5.879685%	5.879685%
14	**Annual Allocation Factor for Return**	**Sum of line 11 and 13**		**7.291402%**

Columns 5-9 (page 1) only applies with incentive ROE project(s) (Note F)

(5)	(6)	(7)	(8)	(9)
Line No.		**Reference**	**Transmission**	**Allocator**
	INCOME TAXES			
10b	Total Income Taxes	Attachment 2, line 33	$ 18,441,126	
11b	Annual Allocation Factor for Income Taxes	(line 10b divided by line 2, col. 3)	1.411716%	1.411716%
	RETURN			
12b	Return on Rate Base	Attachment 2, line 22	$ 76,805,811	
13b	Annual Allocation Factor for Return on Rate Base	(line 12b divided by line 2, col. 3)	5.879685%	5.879685%
14b	**Annual Allocation Factor for Return**	**Sum of line 11b and 13b**		**7.291402%**
15	**Additional Annual Allocation Factor for Return**	**Line 14 b, col. 9 less line 14, col. 4**		**0.00000%**

Period II

Statement BK
Attachment H-4A, Attachment 11
page 2 of 2
For the 12 months ended 12/31/2020

Transmission Enhancement Charge (TEC) Worksheet
To be completed in conjunction with Attachment H-4A

	(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
1			(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	Upgrade the Portland – Greystone 230kV circuit	b0174	$ 12,588,179	2.118303%	$266,656	$ 9,605,485	7.291402%	$700,374	$ 333,478	$1,300,508	0	$1,300,508		$1,300,508
2b	Reconductor the 8 mile Gilbert – Glen Gardner 230 kV circuit	b0268	$ 5,983,501	2.118303%	$126,749	$ 4,891,189	7.291402%	$356,636	$ 158,812	$642,197	0	$642,197		$642,197
2c	Add a 2nd Raritan River 230/115 kV transformer	b0726	$ 7,324,741	2.118303%	$155,160	$ 6,471,309	7.291402%	$471,849	$ 192,824	$819,833	0	$819,833		$819,833
2d	Build a new 230 kV circuit from Larrabee to Oceanview	b2015	$ 171,769,848	2.118303%	$3,638,606	$ 160,880,601	7.291402%	$11,730,451	$3,955,448	$19,324,505	0	$19,324,505		$19,324,505
3	Transmission Enhancement Credit taken to Attachment H-4A Page 1, Line 7											$22,087,043		
4	Additional Incentive Revenue taken to Attachment H-4A, Page 3, Line 41										$0.00			

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 15.
- 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

Period II

TEC Worksheet Support
Net Plant Detail

Statement BK
Attachment H-4A, Attachment 11a
page 1 of 2
For the 12 months ended 12/31/2020

Line No.	Project Name	RTEP Project Number	Project Gross Plant	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20
			(Note A)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)
2a	Upgrade the Portland – Greystone 230kV circuit	b0174	$ 12,588,179	$ 12,588,179	$ 12,588,179	$ 12,588,179	$ 12,588,179	$ 12,588,179	$ 12,588,179	$ 12,588,179	$ 12,588,179	$ 12,588,179	$ 12,588,179	$ 12,588,179	$ 12,588,179	$ 12,588,179
2b	Reconductor the 8 mile Gilbert – Glen Gardner 230 kV circuit	b0268	$ 5,983,501	$ 5,983,501	$ 5,983,501	$ 5,983,501	$ 5,983,501	$ 5,983,501	$ 5,983,501	$ 5,983,501	$ 5,983,501	$ 5,983,501	$ 5,983,501	$ 5,983,501	$ 5,983,501	$ 5,983,501
2c	Add a 2nd Raritan River 230/115 kV transformer	b0726	$ 7,324,741	$ 7,324,741	$ 7,324,741	$ 7,324,741	$ 7,324,741	$ 7,324,741	$ 7,324,741	$ 7,324,741	$ 7,324,741	$ 7,324,741	$ 7,324,741	$ 7,324,741	$ 7,324,741	$ 7,324,741
2d	Build a new 230 kV circuit from Larrabee to Oceanview	b2015	$ 171,769,848	$171,769,848	$171,769,848	$171,769,848	$171,769,848	$171,769,848	$171,769,848	$171,769,848	$171,769,848	$171,769,848	$171,769,848	$171,769,848	$171,769,848	$171,769,848

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.
[D] Company records

Period II

TEC Worksheet Support
Net Plant Detail

Statement BK
Attachment H-4A, Attachment 11a
page 2 of 2
For the 12 months ended 12/31/2020

Accumulated Depreciation	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Project Net Plant
(Note B)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note D)	(Note B & C)
$ 2,982,694	$ 2,828,781	$ 2,854,434	$ 2,880,086	$ 2,905,738	$ 2,931,390	$ 2,957,042	$ 2,982,694	$ 3,008,346	$ 3,033,998	$ 3,059,650	$ 3,085,303	$ 3,110,955	$ 3,136,607	$9,605,485
$ 1,092,312	$ 1,019,014	$ 1,031,230	$ 1,043,446	$ 1,055,663	$ 1,067,879	$ 1,080,095	$ 1,092,312	$ 1,104,528	$ 1,116,744	$ 1,128,961	$ 1,141,177	$ 1,153,393	$ 1,165,609	$4,891,189
$ 853,432	$ 764,436	$ 779,269	$ 794,102	$ 808,934	$ 823,767	$ 838,599	$ 853,432	$ 868,265	$ 883,097	$ 897,930	$ 912,762	$ 927,595	$ 942,428	$6,471,309
$ 10,889,247	$9,063,655	$9,367,921	$9,672,186	$9,976,451	$10,280,716	$10,584,982	$10,889,247	$11,193,512	$11,497,777	$11,802,043	$12,106,308	$12,410,573	$12,714,838	$160,880,601

NOTE
[B] Utilizing a 13-month average.
[C] Taken to Attachment 11, Page 2, Col. 6
[D] Company records

Period II

Statement BK
Attachment H-4A, Attachment 12
page 1 of 1
For the 12 months ended 12/31/2020

TEC - True-up
To be completed after Attachment 11 for the True-up Year is updated using actual data

		(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.

Attachment 10 JCP&L Formula Rate

Period II

Statement BK
Attachment H-4A, Attachment 13
page 1 of 1
For the 12 months ended 12/31/2020

Net Revenue Requirement True-up with Interest

	Reconciliation Revenue Requirement For Year 2018 Available June 10, 2019		2018 Revenue Requirement Collected by PJM Based on Forecast filed on Oct 31, 2017		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 [A]			0.0000%				
	An over or under collection will be recovered prorata over 2018, held for 2019 and returned prorate over 2020							
	Calculation of Interest					Monthly		
3	January	Year 2018	-	0.0000%	12	-		-
4	February	Year 2018	-	0.0000%	11	-		-
5	March	Year 2018	-	0.0000%	10	-		-
6	April	Year 2018	-	0.0000%	9	-		-
7	May	Year 2018	-	0.0000%	8	-		-
8	June	Year 2018	-	0.0000%	7	-		-
9	July	Year 2018	-	0.0000%	6	-		-
10	August	Year 2018	-	0.0000%	5	-		-
11	September	Year 2018	-	0.0000%	4	-		-
12	October	Year 2018	-	0.0000%	3	-		-
13	November	Year 2018	-	0.0000%	2	-		-
14	December	Year 2018	-	0.0000%	1	-		-
						-		-
						Annual		
15	January through December	Year 2019	-	0.0000%	12	-		-
	Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					Monthly		
16	January	Year 2020	-	0.0000%		-	-	-
17	February	Year 2020	-	0.0000%		-	-	-
18	March	Year 2020	-	0.0000%		-	-	-
19	April	Year 2020	-	0.0000%		-	-	-
20	May	Year 2020	-	0.0000%		-	-	-
21	June	Year 2020	-	0.0000%		-	-	-
22	July	Year 2020	-	0.0000%		-	-	-
23	August	Year 2020	-	0.0000%		-	-	-
24	September	Year 2020	-	0.0000%		-	-	-
25	October	Year 2020	-	0.0000%		-	-	-
26	November	Year 2020	-	0.0000%		-	-	-
27	December	Year 2020	-	0.0000%		-	-	-
						-		

28	True-Up with Interest	$	-
29	Less Over (Under) Recovery	$	-
30	Total Interest	$	-

[A] Interest rate equal to: (i) JCP&L's actual short-term debt costs capped at the interest rate determined by 18 C.F.R. 35.19a; or (ii) the interest rate determined by 18 C.F.R. 35.19, if JCP&L does not have short term debt

Period II

Statement BK
Attachment H-4A, Attachment 13a
page 1 of 1
For the 12 months ended 12/31/2020

TEC Revenue Requirement True-up with Interest

	TEC Reconciliation Revenue Requirement For Year 2018 Available June 10, 2019		TEC 2018 Revenue Requirement Collected by PJM Based on Forecast filed on Oct 31, 2017		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 [A]			0.0000%				
	An over or under collection will be recovered prorata over 2018, held for 2019 and returned prorate over 2020							
	Calculation of Interest					Monthly		
3	January	Year 2018	-	0.0000%	12	-		-
4	February	Year 2018	-	0.0000%	11	-		-
5	March	Year 2018	-	0.0000%	10	-		-
6	April	Year 2018	-	0.0000%	9	-		-
7	May	Year 2018	-	0.0000%	8	-		-
8	June	Year 2018	-	0.0000%	7	-		-
9	July	Year 2018	-	0.0000%	6	-		-
10	August	Year 2018	-	0.0000%	5	-		-
11	September	Year 2018	-	0.0000%	4	-		-
12	October	Year 2018	-	0.0000%	3	-		-
13	November	Year 2018	-	0.0000%	2	-		-
14	December	Year 2018	-	0.0000%	1	-		-
						-		-
						Annual		
15	January through December	Year 2019	-	0.0000%	12	-		-
	Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					Monthly		
16	January	Year 2020	-	0.0000%		-	-	-
17	February	Year 2020	-	0.0000%		-	-	-
18	March	Year 2020	-	0.0000%		-	-	-
19	April	Year 2020	-	0.0000%		-	-	-
20	May	Year 2020	-	0.0000%		-	-	-
21	June	Year 2020	-	0.0000%		-	-	-
22	July	Year 2020	-	0.0000%		-	-	-
23	August	Year 2020	-	0.0000%		-	-	-
24	September	Year 2020	-	0.0000%		-	-	-
25	October	Year 2020	-	0.0000%		-	-	-
26	November	Year 2020	-	0.0000%		-	-	-
27	December	Year 2020	-	0.0000%		-	-	-
						-		
28	True-Up with Interest						$ -	
29	Less Over (Under) Recovery						$ -	
30	Total Interest						$ -	

[A] Interest rate equal to: (i) JCP&L's actual short-term debt costs capped at the interest rate determined by 18 C.F.R. 35.19a; or (ii) the interest rate determined by 18 C.F.R. 35.19, if JCP&L does not have short term debt

Attachment 10 JCP&L Formula Rate

Period II

Statement BK
Attachment H-4A, Attachment 14
page 1 of 1

Other Rate Base Items

For the 12 months ended 12/31/2020

			[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 [B]			
1	December 31	2019	-	-	2,131,064		2,131,064	
2	December 31	2020	-	-	2,131,064		2,131,064	
3	Begin/End Average		-	-	2,131,064		2,131,064	

Unfunded Reserve - Plant Related

								Total
	FERC Acct No.		**228.1**	**228.2**	**228.3**	**228.4**	**242**	
		[A] [C]	112.27.c	112.28.c	112.29.c	112.30.c	113.48.c	
4	December 31	2019	-	-	-	-	-	-
5	December 31	2020	-	-	-	-	-	-
6	Begin/End Average		-	-	-	-	-	-

Unfunded Reserve - Labor Related

								Total
	FERC Acct No.		**228.1**	**228.2**	**228.3**	**228.4**	**242**	
		[A] [C]	112.27.c	112.28.c	112.29.c	112.30.c	113.48.c	
7	December 31	2019	-	-	-	-	-	-
8	December 31	2020	-	-	-	-	-	-
9	Begin/End Average		-	-	-	-	-	-

Notes:

[A] Reference for December balances as would be reported in FERC Form 1.

[B] Prepayments shall exclude prepayments of income taxes.

[C] Includes transmission-related balance only

Period II

Statement BK
Attachment H-4A, Attachment 15
page 1 of 1
For the 12 months ended 12/31/2020

Income Tax Adjustments

	[1]	[2]	[3] Dec 31, 2020	Reference
1	Tax adjustment for Permanent Differences & AFUDC Equity	[A] [C]	242,045	JCP&L Company Records
2	Amortized Excess Deferred Taxes (enter negative)	[B] [C]	(2,196,889)	JCP&L Company Records
3	Amortized Deficient Deferred Taxes	[B] [C]	-	JCP&L Company Records

Notes:

[A] AFUDC equity component is the gross cumulative annual amount based upon tax records of capitalized AFUDC equity embedded in the gross plant attributable to the transmission function.

[B] Upon enactment of changes in tax law, income tax rates (including changes in apportionment) and other actions taken by a taxing authority, deferred taxes are re-measured and adjusted in the Company's books of account, resulting in excess or deficient accumulated deferred taxes. Such excess or deficient deferred taxes attributed to the transmission function will be based upon tax records and calculated in the calendar year in which the excess or deficient amount was measured and recorded for financial reporting purposes. The balance located within Column 3, row 2 and row 3, is the net impact of excess deferred and deficient amortization.

[C] Year end balance for line 1 taken to Attachment H-4A, page 3, line 32; Year end balance for lines 2-3 taken to Attachment H-4A, page 3, line 33

Attachment 10 JCP&L Formula Rate

Period II

Statement BK
Attachment H-4A, Attachment 15a
page 1 of 1
For the 12 months ended 12/31/2020

	COLUMN A	COLUMN B	COLUMN C	COLUMN D	COLUMN E	COLUMN F
Line No.	Description	EDIT Transmission Allocation	Amortization Period	Years Remaining at Year End	Amortization of EDIT	Protected (P) Non-Protected (N)
1	Accrued Taxes: FICA on Vacation Accrual	8,680	10	7	868	N
2	Accrued Taxes: Tax Audit Reserves	6,238	10	7	624	N
3	Accum Prov For Inj and Damage-Gen Liability	15,386	10	7	1,539	N
4	Accum Prov For Inj and Damage-Workers Comp	50,817	10	7	5,082	N
5	Asset Retirement Obligation Liability	(1,647)	10	7	(165)	N
6	Company Debt - Issuance Discount	16,436	10	7	1,644	N
7	Deferred Charge-EIB	(15,677)	10	7	(1,568)	N
8	FAS 112 - Medical Benefit Accrual	165,849	10	7	16,585	N
9	FAS 158 OPEB OCI Offset	(22,157)	10	7	(2,216)	N
10	FAS 158 Pension OCI Offset	1,790	10	7	179	N
11	FE Service Tax Interest Allocation	(712)	10	7	(71)	N
12	FE Service Timing Allocation	(503,373)	10	7	(50,337)	N
13	Federal Long Term NOL	5,037,433	35	32	143,927	P
14	Federal Long Term NOL	6,981,827	10	7	698,183	N
15	GR&F Tax Audit	36,747	10	7	3,675	N
16	NOL Deferred Tax Asset - LT NJ	(106,781)	10	7	(10,678)	N
17	Pension/OPEB : Other Def Cr. or Dr.	2,289,854	10	7	228,985	N
18	Pensions Expense	2,716,133	10	7	271,613	N
19	PJM Receivable	(1,381,762)	10	7	(138,176)	N
20	Post Retirement Benefits SFAS 106 Accrual	3,107,222	10	7	310,722	N
21	Post Retirement Benefits SFAS 106 Payments	(1,090,624)	10	7	(109,062)	N
22	Sale of Property - Book Gain or (Loss)	89,727	10	7	8,973	N
23	Sale of Property - Tax Gain or (Loss)	(94,435)	10	7	(9,444)	N
24	State Income Tax Deductible	(680,043)	10	7	(68,004)	N
25	Storm Damage	(6,198,498)	10	7	(619,850)	N
26	Unamortized Gain on Reacquired Debt	1,606	10	7	161	N
27	Unamortized Loss on Reacquired Debt	(204,887)	10	7	(20,489)	N
28	Vacation Pay Accrual	95,018	10	7	9,502	N
29	Vegetation Management	(29,221)	10	7	(2,922)	N
30	**Total Non-Property Amortization (Total of lines 1 thru 29)**				**669,278**	
31	**Property Book-Tax Timing Difference [B] [C]**				(2,866,167)	N & P
32	**Total Non-Property & Property Amortization [A] [B] [C]**				**(2,196,889)**	N & P

Notes:

Above amortization is populated from company records

[A] Ties to Attachment 15, page 1, line 2, column 3 for net excess & Attachment 15, page 1, line 3, Column 3 for net deficient

[B] The amortization schedule of the EDIT balance related to Tax Cuts and Job Act of 2017 shall be consistent with the following periods:

Protected Property & Non-Protected Property	ARAM
Non-Protected, Non-Property:	10 years
Protected, Non-Property:	35 years

[C] The regulatory assets and liabilities, included in FERC accounts 182.3 and 254, respectively, will amortize through FERC income statement accounts 410.1 and 411.1

Period II

Statement BK
Attachment H-4A, Attachment 16
page 1 of 1
For the 12 months ended 12/31/2020

Abandoned Plant

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
1	**Monthly Balance**	Source	Months Remaining In Amortization Period	BegInning Balance	Amortization Expense (p114.10.c)	Additions (Deductions)	Ending Balance
2	December 2019	p111.71.d (and Notes)	13				-
3	January	FERC Account 182.2	12	-	-	-	-
4	February	FERC Account 182.2	11	-	-	-	-
5	March	FERC Account 182.2	10	-	-	-	-
6	April	FERC Account 182.2	9	-	-	-	-
7	May	FERC Account 182.2	8	-	-	-	-
8	June	FERC Account 182.2	7	-	-	-	-
9	July	FERC Account 182.2	6	-	-	-	-
10	August	FERC Account 182.2	5	-	-	-	-
11	September	FERC Account 182.2	4	-	-	-	-
12	October	FERC Account 182.2	3	-	-	-	-
13	November	FERC Account 182.2	2	-	-	-	-
14	December 2020	p111.71.c (and Notes) Detail on p230b	1	-	-	-	-
15	**Ending Balance 13-Month Average**	(sum lines 2-14) /13			$0.00		$0.00
					Attachment H-4A, page 3, Line 18		Attachment H-4A, page 2, Line 27

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

Attachment 10 JCP&L Formula Rate

Period II

Statement BK
Attachment H-4A, Attachment 17
page 1 of 1
For the 12 months ended 12/31/2020

			CWIP [A] 216.b
1	December	2019	
2	January	2020	
3	February	2020	
4	March	2020	
5	April	2020	
6	May	2020	
7	June	2020	
8	July	2020	
9	August	2020	
10	September	2020	
11	October	2020	
12	November	2020	
13	December	2020	
14	13-month Average		-

Notes:

[A] Includes only CWIP authorized by the Commission for inclusion in rate base.

Attachment 10 JCP&L Formula Rate

Period II

Statement BK
Attachment H-4A, Attachment 18
page 1 of 1
For the 12 months ended 12/31/2020

Federal Income Tax Rate

Nominal Federal Income Tax Rate (entered on Attachment H-4A, page 5 of 5, Note K)	21.00%

State Income Tax Rate

	New Jersey	Combined Rate (entered on Attachment H-4A, page 5 of 5, Note K)
Nominal State Income Tax Rate	9.00%	
Times Apportionment Percentage	100.00%	
Combined State Income Tax Rate	9.000%	9.000%

Attachment 10 JCP&L Formula Rate

Period II

Statement BK
Attachment H-4A, Attachment 19
page 1 of 1
For the 12 months ended 12/31/2020

Regulatory Asset

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
			Months Remaining In Amortization Period		Amortization Expense (Company Records)	Additions (Deductions)	
1	**Monthly Balance**	Source		BegInning Balance			Ending Balance
2	December 2019	p232 (and Notes)	13				-
3	January	FERC Account 182.3	12	-	-	-	-
4	February	FERC Account 182.3	11	-	-	-	-
5	March	FERC Account 182.3	10	-	-	-	-
6	April	FERC Account 182.3	9	-	-	-	-
7	May	FERC Account 182.3	8	-	-	-	-
8	June	FERC Account 182.3	7	-	-	-	-
9	July	FERC Account 182.3	6	-	-	-	-
10	August	FERC Account 182.3	5	-	-	-	-
11	September	FERC Account 182.3	4	-	-	-	-
12	October	FERC Account 182.3	3	-	-	-	-
13	November	FERC Account 182.3	2	-	-	-	-
14	December 2020	p232 (and Notes)	1	-	-	-	-
15	**Ending Balance 13-Month Average**	(sum lines 2-14) /13			$0.00	-	$0.00

Period II

Statement BK
Attachment H-4A, Attachment 20
page 1 of 2
For the 12 months ended 12/31/2020

Operation and Maintenance Expenses

FF1 Page 321 Line No.	**Account Reference**	**Description**	**Account Balance [A]**
82		***Operation***	
83	560	Operation Supervision and Engineering	$306,210
84			
85	561.1	Load Dispatch-Reliability	$1,220,421
86	561.2	Load Dispatch-Monitor and Operate Transmission System	$222,747
87	561.3	Load-Dispatch-Transmission Service and Scheduling	
88	561.4	Scheduling, System Control and Dispatch Services	$246,660
89	561.5	Reliability, Planning and Standards Development	$570,765
90	561.6	Transmission Service Studies	$55,682
91	561.7	Generation Interconnection Studies	-$626,846
92	561.8	Reliability, Planning and Standards Development Services	$9,300
93	562	Station Expenses	
94	563	Overhead Lines Expense	$903,726
95	564	Underground Lines Expense	
96	565	Transmission of Electricity by Others	$306,000
97	566	Miscellaneous Transmission Expense	-$7,388,875
98	567	Rents	$10,387,615
99		TOTAL Operation (Enter Total of Lines 83 thru 98)	$6,213,405
100		***Maintenance***	
101	568	Maintenance Supervision and Engineering	$3,094,294
102	569	Maintenance of Structures	
103	569.1	Maintenance of Computer Hardware	$22,115
104	569.2	Maintenance of Computer Software	$27,442
105	569.3	Maintenance of Communication Equipment	
106	569.4	Maintenance of Miscellaneous Regional Transmission Plant	
107	570	Maintenance of Station Equipment	$4,040,963
108	571	Maintenance of Overhead Lines	$18,879,685
109	572	Maintenance of Underground Lines	
110	573	Maintenance of Miscellaneous Transmission Plant	$10,714
111		TOTAL Maintenance (Total of lines 101 thru 110)	$26,075,213
112		**TOTAL Transmission Expenses (Total of lines 99 and 111)**	**$32,288,618**

Notes:
[A] December balances as would be reported in FERC Form 1

Attachment H-4A, Attachment 20
page 2 of 2
For the 12 months ended 12/31/2020

Administrative and General (A&G) Expenses

FF1 Page 323 Line No.	Account Reference	Description	Account Balance [B]
180		***Operation***	
181	920	Administrative and General Salaries	-$45,147
182	921	Office Supplies and Expenses	$78,157
183	Less 922	Administrative Expenses Transferred - Credit	
184	923	Outside Services Employed	$3,975,503
185	924	Property Insurance	$24,239
186	925	Injuries and Damages	$259,311
187	926	Employee Pensions and Benefits	-$2,183,646
188	927	Franchise Requirements	
189	928	Regulatory Commission Expense	$408,174
190	Less 929	(Less) Duplicate Charges-Cr.	
191	930.1	General Advertising Expenses	$62,614
192	930.2	Miscellaneous General Expenses	$222,802
193	931	Rents	$55,193
194		**Total Operation (Enter Total of lines 181 thru 193)**	$2,857,200
195		***Maintenance***	
196	935	Maintenance of General Plant	$201,322
197		**TOTAL A&G Expenses (Total of lines 194 and 196)**	**$3,058,522**

Notes:
[B] December balances as would be reported in FERC Form 1, transmission only

- Attachment 11 (ACE FERC Formula Rate filing)

atlantic city electric
An Exelon Company

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May 15, 2020

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E. Room 1A
Washington, DC 20426

Re: Atlantic City Electric Company ("Atlantic City"), Docket No. ER09-1156
Informational Filing of 2020 Formula Rate Annual Update;
Notice of Annual Update

Dear Ms. Bose,

Atlantic City hereby submits electronically, for informational purposes, its 2020 Annual Formula Rate Update. On November 3, 2015, the Commission approved an uncontested settlement agreement ("Settlement") filed in Docket Nos. EL13-48, *et al*.[1] Formula Rate implementation protocols contained in the Settlement provide that:

> [o]n or before May 15 of each year, Atlantic [Atlantic City Electric Company] shall recalculate its Annual Transmission Revenue Requirements, producing an "Annual Update" for the upcoming Rate Year, and:
>
> (i) cause such Annual Update to be posted at a publicly accessible location on PJM's internet website;
>
> (ii) cause notice of such posting to be provided to PJM's membership; and
>
> (iii) file such Annual Update with the FERC as an informational filing.[2]

The same information contained in this informational filing has been transmitted to PJM for posting on its website as required by the Formula Rate implementation

[1] Baltimore Gas and Electric Company, *et al.*, 153 FERC ¶ 61,140 (2015).
[2] *See* Settlement, Exhibit A containing PJM Tariff Attachment H1-B, Section 2.b.

protocols. Thus, all interested parties should have ample notice of and access to the Annual Update. The protocols provide specific procedures for notice, review, exchanges of information and potential challenges to aspects of the Annual Update. Consequently, and as the Commission has concluded, there is no need for the Commission to notice this informational filing for comment. [3]

Atlantic City's 2020 Annual Update contains no expenses or costs that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices, as defined in 18 C.F.R. § 35.13(b)(7).

In addition, Atlantic City provides notification regarding accounting changes made in 2019. Atlantic City made certain reclassifications between FERC accounts that had no impact to transmission customers. Atlantic City also updated certain estimates with 2019 data, including the salaries and wages allocator, ratios used to allocate costs from the service companies, and ratios used to distribute overhead and other indirect costs. ACE also advises that a correction was made in the second quarter of 2019 to address an overstatement of plant in service at the end of 2018.[4]

Other accounting changes as defined in the Settlement are discussed in applicable disclosure statements filed within the Securities and Exchange Commission Form 10-K and/or within the FERC Form No. 1. Atlantic City has made no change to Other Post-Employment Benefits ("OPEB") charges that exceed the filing threshold set forth in the Protocols.[5]

Thank you for your attention to this informational filing. Please direct any questions to the undersigned.

Very truly yours,

/s/ Amy L. Blauman

Amy L. Blauman

Enclosures

cc: All parties on Service Lists in Docket Nos. ER05-515, EL13-48 and EL15-27.

[3] *See* Letter Order Re: Annual Update to Formula Rate in Docket No. ER09-1156 (February 17, 2010).
[4] Additional detail regarding these items will be provided to interested parties during the Annual Customer Meeting to be held pursuant to the Annual Update.
[5] *See* Settlement, Exhibit A containing PJM Tariff Attachment H1-B, Section 2.h.

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		2019
	Allocators				
	Wages & Salary Allocation Factor				
1	Transmission Wages Expense		p354.21.b	$	3,743,276
2	Total Wages Expense		p354.28b	$	37,797,468
3	Less A&G Wages Expense		p354.27b	$	2,879,522
4	Total		(Line 2 - 3)		34,917,946
5	Wages & Salary Allocator		(Line 1 / 4)		10.7202%
	Plant Allocation Factors				
6	Electric Plant in Service	(Note B)	p207.104g (see Attachment 5)	$	4,196,220,307
7	Common Plant In Service - Electric		(Line 24)		0
8	Total Plant In Service		(Sum Lines 6 & 7)		4,196,220,307
9	Accumulated Depreciation (Total Electric Plant)		p219.29c (see Attachment 5)	$	852,328,717
10	Accumulated Intangible Amortization	(Note A)	p200.21c (see Attachment 5)	$	21,922,426
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)		874,251,144
14	Net Plant		(Line 8 - 13)		3,321,969,163
15	Transmission Gross Plant		(Line 29 - Line 28)		1,546,829,720
16	Gross Plant Allocator		(Line 15 / 8)		36.8625%
17	Transmission Net Plant		(Line 39 - Line 28)		1,270,660,955
18	Net Plant Allocator		(Line 17 / 14)		38.2502%
	Plant Calculations				
	Plant In Service				
19	Transmission Plant In Service	(Note B)	p207.58.g (see Attachment 5)	$	1,524,090,059
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)		1,524,090,059
23	General & Intangible		p205.5.g & p207.99.g (see Attachment 5)	$	212,119,611
24	Common Plant (Electric Only)	(Notes A & B)	p356	$	-
25	Total General & Common		(Line 23 + 24)		212,119,611
26	Wage & Salary Allocation Factor		(Line 5)		10.72021%
27	General & Common Plant Allocated to Transmission		(Line 25 * 26)		22,739,661
28	Plant Held for Future Use (Including Land)	(Note C)	p214		1,194,950
29	TOTAL Plant In Service		(Line 22 + 27 + 28)		1,548,024,670
	Accumulated Depreciation				
30	Transmission Accumulated Depreciation	(Note B)	p219.25.c	$	269,061,580
31	Accumulated General Depreciation		p219.28.c (see Attachment 5)	$	44,374,658
32	Accumulated Intangible Amortization		(Line 10)		21,922,426
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)		66,297,085
36	Wage & Salary Allocation Factor		(Line 5)		10.72021%
37	General & Common Allocated to Transmission		(Line 35 * 36)		7,107,185
38	TOTAL Accumulated Depreciation		(Line 30 + 37)		276,168,765
39	TOTAL Net Property, Plant & Equipment		(Line 29 - 38)		1,271,855,905
	Adjustment To Rate Base				
	Accumulated Deferred Income Taxes (ADIT)				
40a	Account No. 190 (ADIT)	(Note W)	Attachment 1A - ADIT, Line 1		9,378,606
40b	Account No. 281 (ADIT - Accel. Amort)	(Note W)	Attachment 1A - ADIT, Line 2		0
40c	Account No. 282 (ADIT - Other Property)	(Note W)	Attachment 1A - ADIT, Line 3		-260,815,851
40d	Account No. 283 (ADIT - Other)	(Note W)	Attachment 1A - ADIT, Line 4		-3,545,388
40e	Account No. 255 (Accum. Deferred Investment Tax Credits)	(Note V)	Attachment 1A - ADIT		0
40f	Accumulated Deferred Income Taxes Allocated To Transmission		(Line 40a + 40b + 40c + 40d + 40e)		-254,982,633
	Unamortized Deficient / (Excess) ADIT				
41a	Unamortized Deficient / (Excess) ADIT (Federal)	(Note X)	Attachment 1B - ADIT Amortization		-82,582,144
41b	Unamortized Deficient / (Excess) ADIT (State)	(Note X)	Attachment 1B - ADIT Amortization		0
42	Unamortized Deficient / (Excess) ADIT Allocated to Transmission		(Line 41a + 41b)		-82,582,144
43	Adjusted Accumulated Deferred Income Taxes Allocated To Transmission		(Line 40f + 42)		-337,564,778
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		-5,114,226
	Prepayments				
45	Prepayments	(Note A)	Attachment 5		5,707,132
46	Total Prepayments Allocated to Transmission		(Line 45)		5,707,132
	Materials and Supplies				
47	Undistributed Stores Exp	(Note A)	p227.6c & 16.c		0
48	Wage & Salary Allocation Factor		(Line 5)		10.72%
49	Total Transmission Allocated		(Line 47 * 48)		0
50	Transmission Materials & Supplies	(Note U)	p227.8c + p227.5c	$	292,214
51	Total Materials & Supplies Allocated to Transmission		(Line 49 + 50)		292,214
	Cash Working Capital				
52	Operation & Maintenance Expense		(Line 85)		36,956,750
53	1/8th Rule		x 1/8		12.5%
54	Total Cash Working Capital Allocated to Transmission		(Line 52 * 53)		4,619,594
	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)	-332,060,064
59	Rate Base		(Line 39 + 58)	939,795,842

Line	Description		Note	Source	Amount
	O&M				
	Transmission O&M				
60	Transmission O&M			p321.112.b (see Attachment 5)	$ 26,866,774
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)	26,866,774
	Allocated General & Common Expenses				
67	Common Plant O&M		(Note A)	p356	$ -
68	Total A&G			p323.197.b (see Attachment 5)	$ 96,617,849
68a	For informational purposes: PBOB expense in FERC Account 926		(Note S)	Attachment 5	$ 381,359
69	Less Property Insurance Account 924			p323.185b	$ 359,314
70	Less Regulatory Commission Exp Account 928		(Note E)	p323.189b	$ 4,137,986
71	Less General Advertising Exp Account 930.1			p323.191b	$ 833,948
72	Less DE Enviro & Low Income and MD Universal Funds			p335.b	$ -
73	Less EPRI Dues		(Note D)	p352-353 (see Attachment 5)	$ 319,978
74	General & Common Expenses			(Lines 67 + 68) - Sum (69 to 73)	90,966,623
75	Wage & Salary Allocation Factor			(Line 5)	10.7202%
76	General & Common Expenses Allocated to Transmission			(Line 74 * 75)	9,751,810
	Directly Assigned A&G				
77	Regulatory Commission Exp Account 928		(Note G)	p323.189b (see Attachment 5)	200,728
78	General Advertising Exp Account 930.1		(Note K)	p323.191b	0
79	Subtotal - Transmission Related			(Line 77 + 78)	200,728
80	Property Insurance Account 924			p323.185b	$ 359,314
81	General Advertising Exp Account 930.1		(Note F)	p323.191b	0
82	Total			(Line 80 + 81)	359,314
83	Net Plant Allocation Factor			(Line 18)	38.25%
84	A&G Directly Assigned to Transmission			(Line 82 * 83)	137,438
85	Total Transmission O&M			(Line 66 + 76 + 79 + 84)	36,956,750
	Depreciation & Amortization Expense				
	Depreciation Expense				
86	Transmission Depreciation Expense			p336.7b&c	36,542,405
87	General Depreciation			p336.10b&c (see Attachment 5)	7,555,695
88	Intangible Amortization		(Note A)	p336.1d&e (see Attachment 5)	5,642,771
89	Total			(Line 87 + 88)	13,198,465
90	Wage & Salary Allocation Factor			(Line 5)	10.7202%
91	General Depreciation Allocated to Transmission			(Line 89 * 90)	1,414,903
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)	10.7202%
96	Common Depreciation - Electric Only Allocated to Transmission			(Line 94 * 95)	0
97	Total Transmission Depreciation & Amortization			(Line 86 + 91 + 96)	37,957,308
	Taxes Other than Income				
98	Taxes Other than Income			Attachment 2	1,100,877
99	Total Taxes Other than Income			(Line 98)	1,100,877
	Return / Capitalization Calculations				
	Long Term Interest				
100	Long Term Interest			p117.62c through 67c	57,709,830
101	Less LTD Interest on Securitization Bonds		(Note P)	Attachment 8	2,579,701
102	Long Term Interest			"(Line 100 - line 101)"	55,130,129
103	Preferred Dividends		enter positive	p118.29c	$ -
	Common Stock				
104	Proprietary Capital			p112.16c	$ 1,276,295,808
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)	1,276,295,808
	Capitalization				
108	Long Term Debt			p112.17c through 21c	$ 1,313,398,829
109	Less Loss on Reacquired Debt		enter negative	p111.81.c	$ (3,855,349)
110	Plus Gain on Reacquired Debt		enter positive	p113.61.c	$ -
111	Less ADIT associated with Gain or Loss		enter negative	Attachment 1A - ADIT, Line 6	1,083,739
112	Less LTD on Securitization Bonds	(Note P)	enter negative	Attachment 8	-26,383,829
113	Total Long Term Debt			(Sum Lines Lines 108 to 112)	1,284,243,390
114	Preferred Stock			p112.3c	$ -
115	Common Stock			(Line 107)	1,276,295,808
116	Total Capitalization			(Sum Lines 113 to 115)	2,560,539,198
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)	0.0429
121	Preferred Cost	Preferred Stock		(Line 103 / 114)	0.0000
122	Common Cost	Common Stock	(Note)	Fixed	0.1050
123	Weighted Cost of Debt	Total Long Term Debt (WCLTD)		(Line 117 * 120)	0.0215
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)	0.0740
127	Investment Return = Rate Base * Rate of Return			(Line 59 * 126)	69,511,107

Composite Income Taxes

Line	Description	Formula / Notes	Note	Reference	Amount
	Income Tax Rates				
128	FIT=Federal Income Tax Rate		(Note I)		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%
132a	T/ (1-T)				39.10%
132b	Tax Gross-Up Factor	1*1/(1-T)			1.3910
	ITC Adjustment		(Note V)		
133	Investment Tax Credit Amortization		enter negative	Attachment 1A - ADIT	-325,830
134	Tax Gross-Up Factor			(Line 132a)	1.3910
135	Net Plant Allocation Factor			(Line 18)	38.2502%
136a	ITC Adjustment Allocated to Transmission			(Line 133 * 134 * 135)	-173,363
	Other Income Tax Adjustment				
136b	Tax Adjustment for AFUDC Equity Component of Transmission Depreciation Expense		(Note T)	Attachment 5, Line 136b	55,326
136c	Amortization Deficient / (Excess) Deferred Taxes (Federal) - Transmission Component		(Note T)	Attachment 5, Line 136c	-12,992,454
136d	Amortization Deficient / (Excess) Deferred Taxes (State) - Transmission Component		(Note T)	Attachment 5, Line 136d	0
136e	Amortization of Other Flow-Through Items - Transmission Component		(Note T)	Attachment 5, Line 136e	134,274
136f	Other Income Tax Adjustments - Expense / (Benefit)			(Line 136b + 136c + 136d + 136e)	-12,802,854
136g	Tax Gross-Up Factor			(Line 132b)	1.3910
136h	Other Income Tax Adjustment			(Line 136f * 136g)	-17,808,950
137	Income Tax Component =	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		[Line 132a * 127 * (1-(123 / 126))]	19,292,352
138	Total Income Taxes			(Line 136a + 136h + 137)	1,310,039

REVENUE REQUIREMENT

Line	Description	Note	Reference	Amount
	Summary			
139	Net Property, Plant & Equipment		(Line 39)	1,271,855,905
140	Adjustment to Rate Base		(Line 58)	-332,060,064
141	Rate Base		(Line 59)	939,795,842
142	O&M		(Line 85)	36,956,750
143	Depreciation & Amortization		(Line 97)	37,957,308
144	Taxes Other than Income		(Line 99)	1,100,877
145	Investment Return		(Line 127)	69,511,107
146	Income Taxes		(Line 138)	1,310,039
147	Gross Revenue Requirement		(Sum Lines 142 to 146)	146,836,082
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities			
148	Transmission Plant In Service		(Line 19)	1,524,090,059
149	Excluded Transmission Facilities	(Note M)	Attachment 5	0
150	Included Transmission Facilities		(Line 148 - 149)	1,524,090,059
151	Inclusion Ratio		(Line 150 / 148)	100.00%
152	Gross Revenue Requirement		(Line 147)	146,836,082
153	Adjusted Gross Revenue Requirement		(Line 151 * 152)	146,836,082
	Revenue Credits & Interest on Network Credits			
154	Revenue Credits		Attachment 3	2,901,517
155	Interest on Network Credits	(Note N)	PJM Data	-
156	Net Revenue Requirement		(Line 153 - 154 + 155)	143,934,564
	Net Plant Carrying Charge			
157	Net Revenue Requirement		(Line 156)	143,934,564
158	Net Transmission Plant		(Line 19 - 30)	1,255,028,479
159	Net Plant Carrying Charge		(Line 157 / 158)	11.4686%
160	Net Plant Carrying Charge without Depreciation		(Line 157 - 86) / 158	8.5569%
161	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes		(Line 157 - 86 - 127 - 138) / 158	2.9140%
	Net Plant Carrying Charge Calculation per 100 Basis Point increase in ROE			
162	Net Revenue Requirement Less Return and Taxes		(Line 156 - 145 - 146)	73,113,418
163	Increased Return and Taxes		Attachment 4	77,357,492
164	Net Revenue Requirement per 100 Basis Point increase in ROE		(Line 162 + 163)	150,470,910
165	Net Transmission Plant		(Line 19 - 30)	1,255,028,479
166	Net Plant Carrying Charge per 100 Basis Point increase in ROE		(Line 164 / 165)	11.9894%
167	Net Plant Carrying Charge per 100 Basis Point increase in ROE without Depreciation		(Line 163 - 86) / 165	9.0778%
168	Net Revenue Requirement		(Line 156)	143,934,564
169	True-up amount		Attachment 6	(19,145,765)
170	Plus any increased ROE calculated on Attachment 7 other than PJM Sch. 12 projects		Attachment 7	286,839
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)	125,075,638
	Network Zonal Service Rate			
173	1 CP Peak	(Note L)	PJM Data	2,737
174	Rate ($/MW-Year)		(Line 172 / 173)	45,693
175	Network Service Rate ($/MW/Year)		(Line 174)	45,693

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.
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.
T See Attachment 5 - Cost Support, section entitled "Other Income Tax Adjustment" for additional information.
U Only the transmission portion of amounts reported at Form 1, page 227, line 5 is used. The transmission portion of line 5 is specified in a footnote to the Form 1, page 227.
V Atlantic City Electric Company elected to amortize investment tax credits against recoverable income tax expense, rather than to reduce rate base by unamortized investment tax credit. Amortization reduces income tax expense and reduces the revenue requirement by the amount of the Investment Tax Credit Amortization multiplied by (1/(1-T)).
W The Accumulated Deferred Income Tax (ADIT) balances in Accounts 190, 281, 282, and 283 are measured using the enacted tax rate that is expected to apply when the underlying temporary differences are expected to be settled or realized. See Attachment 1A - ADIT for additional information.
X These balances represent the unamortized federal and state deficient / (excess) deferred income taxes. See Attachment 1B - ADIT Amortization for additional information.

Atlantic City Electric Company
Accumulated Deferred Income Taxes (ADIT)
Attachment 1A - Accumulated Deferred Income Taxes (ADIT) Worksheet

Line	ADIT	Total	Gas, Production, Distribution, or Other Related	Only Transmission Related	Plant Related	Labor Related	
1	ADIT-190	9,378,606	-	-	8,740,681	637,924	Total entered in ATT H-1A, Line 40a
2	ADIT-281	-	-	-	-	-	Total entered in ATT H-1A, Line 40b
3	ADIT-282	(260,815,851)	-	-	(260,815,851)	-	Total entered in ATT H-1A, Line 40c
4	ADIT-283	(3,545,388)	-	(1,973,303)	78,513	(1,650,598)	Total entered in ATT H-1A, Line 40d
5	**Subtotal - Transmission ADIT**	(254,982,633)	-	(1,973,303)	(251,996,656)	(1,012,674)	

Line	Description	Total
6	ADIT (Reacquired Debt)	(1,083,739)

Note: ADIT associated with Gain or Loss on Reacquired Debt included in ADIT-283, Column A is excluded from rate base and instead included in Cost of Debt on Attachment H-1A, Line 111. A deferred tax (liability) should be reported as a positive balance and a deferred tax asset should be reported as a negative balance on Attachment H-1A, Line 111.

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, Production, Distribution, or Other Related	(D) Only Transmission Related	(E) Plant Related	(F) Labor Related	(G) Justification
Accrued Benefits	683,891	-	-	-	683,891	ADIT relates to all functions and attributable to underlying operating and maintenance expenses that are recoverable in the transmission formula.
Accrued Bonuses & Incentives	1,996,214	-	-	-	1,996,214	ADIT relates to all functions and attributable to underlying operating and maintenance expenses that are recoverable in the transmission formula.
Accrued Environmental Liability	385,895	385,895	-	-	-	ADIT excluded because the underlying account(s) are not recoverable in the transmission formula.
Accrued OPEB	4,937,139	-	-	-	4,937,139	FAS No. 106 requires accrual basis instead of cash basis accounting for post retirement health care and life insurance benefits for book purposes. These amounts are removed from rate base below.
Accrued Other Expenses	2,059,852	2,059,852	-	-	-	ADIT excluded because the underlying account(s) are not recoverable in the transmission formula.
Accrued Payroll Taxes - AIP	124,712	-	-	-	124,712	ADIT relates to all functions and attributable to underlying operating and maintenance expenses that are recoverable in the transmission formula.
Accrued Retention	23,019	-	-	-	23,019	ADIT relates to all functions and attributable to underlying operating and maintenance expenses that are recoverable in the transmission formula.
Accrued Severance	133,245	-	-	-	133,245	ADIT relates to all functions and attributable to underlying operating and maintenance expenses that are recoverable in the transmission formula.
Accrued Vacation	711,217	711,217	-	-	-	ADIT excluded because the underlying account(s) are not recoverable in the transmission formula.
Accrued Worker's Compensation	2,983,638	-	-	-	2,983,638	ADIT relates to all functions and attributable to underlying operating and maintenance expenses that are recoverable in the transmission formula.
Allowance for Doubtful Accounts	5,077,467	5,077,467	-	-	-	ADIT excluded because the underlying account(s) are not recoverable in the transmission formula.
Asset Retirement Obligation	1,153,381	1,153,381	-	-	-	ADIT excluded because the underlying account(s) are not recoverable in the transmission formula.
Deferred Compensation	10,872	10,872	-	-	-	ADIT excluded because the underlying account(s) are not recoverable in the transmission formula.
Long-term Incentive Plan	5,955	-	-	-	5,955	ADIT relates to all functions and attributable to underlying operating and maintenance expenses that are recoverable in the transmission formula.
Merger Commitments	48,959	48,959	-	-	-	ADIT excluded because the underlying account(s) are not recoverable in the transmission formula.
NJ AMA Credit	443,467	-	-	443,467	-	ADIT relates to all functions and attributable to plant in service that is included in rate base.
Regulatory Liability	1,536,312	1,536,312	-	-	-	ADIT excluded because the underlying account(s) are not recoverable in the transmission formula.
Sales & Use Tax Reserve	534,557	534,557	-	-	-	ADIT excluded because the underlying account(s) are not recoverable in the transmission formula.
Charitable Contribution Carryforward	173,732	173,732	-	-	-	ADIT excluded because the underlying account(s) are not recoverable in the transmission formula.
State Net Operating Loss Carryforward	31,107,204	7,839,061	-	23,268,144	-	The state net operating loss carry-forward, net of federal taxes, is included to the extent attributable to plant in service that is included in rate base.
Unamortized Investment Tax Credit	852,848	-	-	852,848	-	Pursuant to the requirements of ASC 740, 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 of unamortized ITC. These amounts are removed from rate base below.
Other 190	(8,365)	(8,365)	-	-	-	ADIT excluded because the underlying account(s) are not recoverable in the transmission formula.
FAS 109 Regulatory Liability Gross Up	99,972,544	-	-	99,972,544	-	Accumulated Deferred Income Taxes attributable to income tax related regulatory assets and liabilities. This balance is excluded from rate base and removed below.
Subtotal: ADIT-190 (FERC Form)	154,947,755	19,522,940	-	124,537,003	10,887,812	
Less: ASC 740 ADIT Adjustments excluded from rate base	-	-	-	-	-	
Less: ASC 740 ADIT Adjustments related to unamortized ITC	(852,848)	-	-	(852,848)	-	
Less: ASC 740 ADIT balances related to income tax regulatory assets / (liabilities)	(99,972,544)	-	-	(99,972,544)	-	
Less: OPEB related ADIT, Above if not separately removed	(4,937,139)	-	-	-	(4,937,139)	
Total: ADIT-190	49,185,224	19,522,940	-	23,711,611	5,950,673	
Wages & Salary Allocator					10.7202%	
Gross Plant Allocator				36.8625%		
Transmission Allocator			100.0000%			
Other Allocator		0.0000%				
ADIT - Transmission	9,378,606	-	-	8,740,681	637,924	

Instructions for Account 190:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer), Production or Distribution Only 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.

Attachment 1A - Accumulated Deferred Income Taxes (ADIT) Worksheet

(A) ADIT- 282	(B) Total	(C) Gas, Production, Distribution, or Other Related	(D) Only Transmission Related	(E) Plant Related	(F) Labor Related	(G) Justification
Plant Deferred Taxes - FAS 109	(705,122,212)	2,415,764	-	(707,537,976)	-	ADIT attributable to plant in service that is included in rate base.
CIAC	37,411,528	37,411,528	-	-	-	ADIT attributable to contributions-in-aid of construction excluded from rate base.
AFUDC Equity	(7,227,919)	(5,077,168)	(2,150,751)	-	-	Under ASC 740, deferred income taxes must be provided on all tax temporary differences, including AFUDC-Equity. Deferred income taxes on AFUDC-Equity are not recognized for Regulatory purposes and are excluded from Rate Base.
Plant Deferred Taxes - Flow-through	(12,877,804)	(12,743,533)	(134,271)	-	-	Pursuant to the requirements of ASC 740, ADIT must encompass all timing differences regardless of whether the difference is normalized or flowed-through. These items are removed below.
Subtotal: ADIT-282 (FERC Form)	(687,816,407)	22,006,591	(2,285,022)	(707,537,976)	-	
Less: ASC 740 ADIT Adjustments excluded from rate base	12,877,804	12,743,533	134,271	-	-	
Less: ASC 740 ADIT Adjustments related to AFUDC Equity	7,227,919	5,077,168	2,150,751	-	-	
Less: ASC 740 ADIT balances related to income tax regulatory assets / (liabilities)	-	-	-	-	-	
Less: OPEB related ADIT, Above if not separately removed	-	-	-	-	-	
Total: ADIT-282	(667,710,684)	39,827,292	-	(707,537,976)	-	
Wages & Salary Allocator					10.7202%	
Gross Plant Allocator				36.8625%		
Transmission Allocator			100.0000%			
Other Allocator		0.0000%				
ADIT - Transmission	(260,815,851)	-	-	(260,815,851)	-	

Instructions for Account 282:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer), Production or Distribution Only 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.

Attachment 1A - Accumulated Deferred Income Taxes (ADIT) Worksheet

(A) ADIT-283	(B) Total	(C) Gas, Production, Distribution, or Other Related	(D) Only Transmission Related	(E) Plant Related	(F) Labor Related	(G) Justification
Asset Retirement Obligation	(162,572)	(162,572)	-	-	-	ADIT excluded because the underlying account(s) are not recoverable in the transmission formula.
Materials Reserve	212,989	-	-	212,989	-	ADIT relates to all functions and attributable materials and supplies included in rate base.
Other Deferred Debits	(219,485)	(219,485)	-	-	-	ADIT excluded because the underlying account(s) are not recoverable in the transmission formula.
Pension Asset	(15,397,073)	-	-	-	(15,397,073)	Included because the pension asset is included in rate base. Related to accrual recognition of expense for book purposes & deductibility of cash funding's for tax purposes.
Regulatory Asset	(21,662,413)	(21,662,413)	-	-	-	ADIT excluded because the underlying account(s) are not recoverable in the transmission formula.
Regulatory Asset - Accrued Vacation	(1,193,868)	(1,193,868)	-	-	-	ADIT excluded because the underlying account(s) are not recoverable in the transmission formula.
Regulatory Asset - FERC Transmission True-up	(1,973,303)	-	(1,973,303)	-	-	ADIT relates to transmission function and included in rate base.
Renewable Energy Credits	(127,726)	(127,726)	-	-	-	ADIT excluded because the underlying account(s) are not recoverable in the transmission formula.
Unamortized Loss on Reacquired Debt	(1,083,739)	(1,083,739)	-	-	-	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
Subtotal: ADIT-283 (FERC Form)	(41,607,190)	(24,449,802)	(1,973,303)	212,989	(15,397,073)	
Less: ASC 740 ADIT Adjustments excluded from rate base	-	-	-	-	-	
Less: ASC 740 ADIT Adjustments related to unamortized ITC	-	-	-	-	-	
Less: ASC 740 ADIT balances related to income tax regulatory assets / (liabilities)	-	-	-	-	-	
Less: OPEB related ADIT, Above if not separately removed	-	-	-	-	-	
Total: ADIT-283	(41,607,190)	(24,449,802)	(1,973,303)	212,989	(15,397,073)	
Wages & Salary Allocator					10.7202%	
Gross Plant Allocator				36.8625%		
Transmission Allocator			100.0000%			
Other Allocator		0.0000%				
ADIT - Transmission	(3,545,388)	-	(1,973,303)	78,513	(1,650,598)	

Instructions for Account 283:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer), Production or Distribution Only 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.

Attachment 1A - Accumulated Deferred Income Taxes (ADIT) Worksheet

	ADITC-255		Unamortized ITC Balance	Current Year Amortization
1	Rate Base Treatment			
2	Account No. 255 (Accum. Deferred Investment Tax Credits)	To ATT H-1A, Line 40e	-	-
3	Amortization			
4	Investment Tax Credit Amortization	To ATT H-1A, Line 133	3,033,967	325,830
5	Total		3,033,967	325,830
6	Form No. 1 balance (p.266) for amortization		3,033,967	325,830
7	Difference /1		-	-

/1 Difference must be zero

END

Atlantic City Electric Company
Deficient / Excess Deferred Income Taxes
Attachment 1B - Deficient / Excess Deferred Income Tax Amortization Worksheet

Federal Deficient / (Excess) Deferred Income Taxes

Tax Cuts and Jobs Act of 2017

Line	(A) Deficient / (Excess) Deferred Income Taxes	(B) Notes	(C) Amortization Fixed Period	(D) December 31, 2017 ADIT Deficient / (Excess)	(E) December 31, 2018 BOY Balance	(F) Current Year Amortization	(G) December 31, 2019 EOY Balance
1	**Unprotected Non-Property**						
2	ADIT - 190	(Note A)	4 Years	$ (831,666)	$ (623,750)	$ 207,916	$ (415,833)
3	ADIT - 281	(Note A)	4 Years	-	-	-	-
4	ADIT - 282	(Note A)	4 Years	-	-	-	-
5	ADIT - 283	(Note A)	4 Years	(5,013,302)	(3,759,977)	1,253,325	(2,506,651)
6	**Subtotal - Deficient / (Excess) ADIT**			$ (5,844,968)	$ (4,383,726)	$ 1,461,242	$ (2,922,484)
7	**Unprotected Property**						
8	ADIT - 190	(Note A)	5 Years	$ -	$ -	$ -	$ -
9	ADIT - 281	(Note A)	5 Years	-	-	-	-
10	ADIT - 282	(Note A)	5 Years	(54,437,932)	(43,550,346)	10,887,586	(32,662,759)
11	ADIT - 283	(Note A)	5 Years	-	-	-	-
12	**Subtotal - Deficient / (Excess) ADIT**			$ (54,437,932)	$ (43,550,346)	$ 10,887,586	$ (32,662,759)
13	**Protected Property**						
14	ADIT - 190	(Note A)	ARAM	$ 3,570,954	3,570,954	-	3,570,954
15	ADIT - 281	(Note A)	ARAM	$ -	-	-	-
16	ADIT - 282	(Note A)	ARAM	$ (51,415,785)	(50,995,671)	594,442	(50,401,229)
17	ADIT - 283	(Note A)	ARAM	$ -	-	-	-
18	**Subtotal - Deficient / (Excess) ADIT**			$ (47,844,831)	$ (47,424,717)	$ 594,442	$ (46,830,275)
19	**Total - Deficient / (Excess) ADIT**			$ (108,127,731)	$ (95,358,789)	$ 12,943,270	$ (82,415,518)

Tax Reform Act of 1986

Line	(A) Deficient / (Excess) Deferred Income Taxes	(B) Notes	(C) Amortization Fixed Period	(D) September 30, 2018 ADIT Deficient / (Excess)	(E) December 31, 2018 BOY Balance	(F) Current Year Amortization	(G) December 31, 2019 EOY Balance
20	**Protected Property**						
21	ADIT - 190	(Note B)	ARAM	$ -	$ -	$ -	$ -
22	ADIT - 281	(Note B)	ARAM	-	-	-	-
23	ADIT - 282	(Note B)	ARAM	(228,106)	(215,810)	49,184	(166,626)
24	ADIT - 283	(Note B)	ARAM	-	-	-	-
25	**Subtotal - Deficient / (Excess) ADIT**			$ (228,106)	$ (215,810)	$ 49,184	$ (166,626)
26	**Total - Deficient / (Excess) ADIT**			$ (228,106)	$ (215,810)	$ 49,184	$ (166,626)

Total Federal Deficient / (Excess) Deferred Income Taxes

Line	(A) Deficient / (Excess) Deferred Income Taxes	(B) Notes	(C) Amortization Fixed Period	(D) ADIT Deficient / (Excess)	(E) December 31, 2018 BOY Balance	(F) Current Year Amortization	(G) December 31, 2019 EOY Balance
27	ADIT - 190			$ 2,739,288	$ 2,947,204	$ 207,916	$ 3,155,121
28	ADIT - 281			-	-	-	-
29	ADIT - 282			(106,081,823)	(94,761,827)	11,531,212	(83,230,614)
30	ADIT - 283			(5,013,302)	(3,759,977)	1,253,325	(2,506,651)
31	**Total - Deficient / (Excess) ADIT**	Col G entered in ATT H-1A, Line 41a		$ (108,355,837)	$ (95,574,599)	$ 12,992,454	$ (82,582,144)
32	Tax Gross-Up Factor	Att. H-1A, Line 132b		1.3910	1.3910	1.3910	1.3910
33	**Regulatory Asset / (Liability)**			$ (150,724,491)	$ (132,945,610)	$ 18,072,686	$ (114,872,923)

Federal Income Tax Regulatory Asset / (Liability)

Line	(A) Regulatory Assets / (Liabilities)	(B) Notes	(C)	(D) ADIT Deficient / (Excess)	(E) December 31, 2018 BOY Balance	(F) Current Year Amortization	(G) December 31, 2019 EOY Balance
34	Account 182.3 (Other Regulatory Assets)			$ -	$ -	$ -	$ -
35	Account 254 (Other Regulatory Liabilities)			(150,724,491)	(132,945,610)	18,072,686	(114,872,923)
36	**Total - Transmission Regulatory Asset / (Liability)**			$ (150,724,491)	$ (132,945,610)	$ 18,072,686	$ (114,872,923)

Atlantic City Electric Company
Deficient / Excess Deferred Income Taxes
Attachment 1B - Deficient / Excess Deferred Income Tax Amortization Worksheet

State Deficient / (Excess) Deferred Income Taxes

State Tax Rate Change

Line	(A) Deficient / (Excess) Deferred Income Taxes	(B) Notes	(C) Amortization Fixed Period	(D) ADIT Deficient / (Excess)	(E) December 31, 2018 BOY Balance	(F) Current Year Amortization	(G) December 31, 2019 EOY Balance
37	**Unprotected Non-Property**						
38	ADIT - 190		4 Years	$ -	$ -	$ -	$ -
39	ADIT - 281		4 Years	-	-	-	-
40	ADIT - 282		4 Years	-	-	-	-
41	ADIT - 283		4 Years	-	-	-	-
42	**Subtotal - Deficient / (Excess) ADIT**			$ -	$ -	$ -	$ -
43	**Unprotected Property**						
44	ADIT - 190		5 Years	$ -	$ -	$ -	$ -
45	ADIT - 281		5 Years	-	-	-	-
46	ADIT - 282		5 Years	-	-	-	-
47	ADIT - 283		5 Years	-	-	-	-
48	**Subtotal - Deficient / (Excess) ADIT**			$ -	$ -	$ -	$ -
49	**Protected Property**						
50	ADIT - 190		NA	$ -	$ -	$ -	$ -
51	ADIT - 281		NA	-	-	-	-
52	ADIT - 282		NA	-	-	-	-
53	ADIT - 283		NA	-	-	-	-
54	**Subtotal - Deficient / (Excess) ADIT**			$ -	$ -	$ -	$ -
55	**Total - Deficient / (Excess) ADIT**			$ -	$ -	$ -	$ -

Total State Deficient / (Excess) Deferred Income Taxes

Line	(A) Deficient / (Excess) Deferred Income Taxes	(B) Notes	(C) Amortization Fixed Period	(D) ADIT Deficient / (Excess)	(E) December 31, 2018 BOY Balance	(F) Current Year Amortization	(G) December 31, 2019 EOY Balance
56	ADIT - 190			$ -	$ -	$ -	$ -
57	ADIT - 281			-	-	-	-
58	ADIT - 282			-	-	-	-
59	ADIT - 283			-	-	-	-
60	**Total - Deficient / (Excess) ADIT**	Col G entered in ATT H-1A, Line 41b		$ -	$ -	$ -	$ -
61	Tax Gross-Up Factor	Att. H-1A, Line 132b		1.3910	1.3910	1.3910	1.3910
62	**Regulatory Asset / (Liability)**			$ -	$ -	$ -	$ -

State Income Tax Regulatory Asset / (Liability)

Line	(A) Regulatory Assets / (Liabilities)	(B) Notes	(C)	(D) ADIT Deficient / (Excess)	(E) December 31, 2018 BOY Balance	(F) Current Year Amortization	(G) December 31, 2019 EOY Balance
63	Account 182.3 (Other Regulatory Assets)			$ -	$ -	$ -	$ -
64	Account 254 (Other Regulatory Liabilities)			-	-	-	-
65	**Total - Transmission Regulatory Asset / (Liability)**			$ -	$ -	$ -	$ -

Federal and State Income Tax Regulatory Asset / (Liability)

Federal and State Income Tax Regulatory Asset / (Liability) related to Deficient / (Excess) Deferred Income Taxes

Line	(A) Regulatory Assets / (Liabilities)	(B) Notes	(C)	(D) ADIT Deficient / (Excess)	(E) December 31, 2018 BOY Balance	(F) Current Year Amortization	(G) December 31, 2019 EOY Balance
66	Account 182.3 (Other Regulatory Assets)			$ -	$ -	$ -	$ -
67	Account 254 (Other Regulatory Liabilities)			(150,724,491)	(132,945,610)	18,072,686	(114,872,923)
68	**Total - Transmission Regulatory Asset / (Liability)**			$ (150,724,491)	$ (132,945,610)	$ 18,072,686	$ (114,872,923)

Instructions

1. For transmission allocated deficient / (excess) accumulated deferred income taxes (ADIT) related to rate change(s) to income tax rates occurring after September 30, 2018, insert new amortization table(s) that delineates the deficient and (excess) ADIT by category (i.e., protected property, unprotected property, and unprotected non-property).

2. Set the amortization period for unprotected property to 5 years and unprotected non-property to 4 years. The amortization of deficient and (excess) ADIT designated as protected will be calculated using the Average Rate Assumption Method (ARAM) or a manner that complies with the normalization requirements.

3. Update applicable formulas in the "Total Federal Deficient / (Excess) Deferred Income Taxes" and "Total State Deficient / (Excess) Deferred Income Taxes" sections to ensure appropriate inclusion of deficient / (excess) ADIT balances related to rate changes occurring after September 30, 2018.

4. Insert note explaining the event giving rise to the deficient / (excess) ADIT including the start and end date for the amortization. The amortization ceases after the related regulatory asset / liability is drawn down to zero.

Notes

A Deficient and (excess) ADIT related to the Tax Cuts and Jobs Act of 2017 (TCJA) will be amortized beginning January 1, 2018 based on the prescribed amortization periods as provided in the Settlement in Docket No. ER19-5 et al. The amortization periods for unprotected property and unprotected non-property related deficient and (excess) ADIT are fixed and cannot be changed without the Commission's express approval except, balances and categorizations may be changed if required by audit adjustments, amendments to income tax returns, or new IRS guidance. The amortization of protected property related deficient and (excess) ADIT will be calculated using the Average Rate Assumption Method (ARAM) or a manner that complies with the normalization requirements and may vary by year depending on where each underlying asset resides in its individual life cycle. The unprotected property related deficient and (excess) ADIT will be fully amortized by December 31, 2022. The unprotected non-property related deficient and (excess) ADIT will be fully amortized by December 31, 2021. Note - The amortization formula in Column F will change based on where ACE resides in the amortization cycle. The current year amortization of deficient and (excess) ADIT is recorded in FERC Accounts 410.1 and 411.1.

B The remaining unamortized deficient and (excess) ADIT related to the Tax Reform Act of 1986 will be amortized using the Average Rate Assumption Method (ARAM) as provided in the Settlement in Docket No. ER19-5 et al. The current year amortization of deficient and (excess) ADIT is recorded in FERC Accounts 410.1 and 411.1.

END

Atlantic City Electric Company
Accumulated Deferred Income Taxes Remeasurement
Attachment 1C - Deficient / Excess Deferred Income Taxes Worksheet

Tax Cuts and Jobs Act of 2017

Line	Detailed Description	Description	Category	ADIT - Pre Rate Change (December 31, 2017): Federal Gross Timing Difference	Federal ADIT @ 35%	State ADIT	FIT on SIT	Total ADIT	ADIT - Post Rate Change (December 31, 2017): Federal Gross Timing Difference	Federal ADIT @ 21%	State ADIT	FIT on SIT	Total ADIT	Deficient / (Excess) Deferred Income Taxes (December 31, 2017): Rate Change Deferred Tax Impact	Non-Recoverable	Income Tax Regulatory Asset / Liability Deferred Taxes	Deficient / (Excess) ADIT Balance	Jurisdiction Allocator	Electric Transmission	Allocator (Note B)	Transmission Allocated	FERC Account
	(A)	(B)	(C)	(D)	(E) = (D) * 35%	(F)	(G) = (F) * 35%	(H) = (E) + (F) + (G)	(I)	(J) = (I) * 21%	(K)	(L) = (K) * 21%	(M) = (J) + (K) + (L)	(N) = (H) - (M)	(O)	(P)	(Q) = (N) - (O) - (P)	(R)	(S)	(T)	(U) = (Q) * (T)	(V)
	FERC Account 190 - Non-Current (Note A)																					
1	NJ AMA	1999 AMT	Non-Property	$ -	$ -	$ 561,351	$ (196,473)	$ 364,878	$ -	$ -	$ 561,351	$ (117,884)	$ 443,467	$ (78,589)	$ -	$ -	$ (78,589)	Plant	Yes	33.300%	$ (26,170)	190
2	Accrued Payroll Taxes - Manual	Accrual Labor Related	Non-Property	222,052	77,718	19,985	(6,995)	90,708	222,052	46,631	19,985	(4,197)	62,419	28,289	-	-	28,289	Labor	Yes	6.530%	1,847	190
3	Accrued Liab-Required Health Claims	Accrual Labor Related	Non-Property	561,536	196,538	50,538	(17,688)	229,387	561,536	117,923	50,538	(10,613)	157,848	71,540	-	-	71,540	Labor	Yes	6.530%	4,672	190
4	Accrued Liabilities - Workers Comp	Accrual Labor Related	Non-Property	1,350,412	472,644	121,537	(42,538)	551,643	1,350,412	283,587	121,537	(25,523)	379,601	172,042	-	-	172,042	Labor	Yes	6.530%	11,234	190
5	Accrued Liabilities - Disability	Accrual Labor Related	Non-Property	156,169	54,659	14,055	(4,919)	63,795	156,169	32,796	14,055	(2,952)	43,899	19,896	-	-	19,896	Labor	Yes	6.530%	1,299	190
6	Accrued Liability - PHI Incentive Plan	Accrual Labor Related	Non-Property	3,405,704	1,191,996	306,513	(107,280)	1,391,230	3,405,704	715,198	306,513	(64,368)	957,343	433,887	-	-	433,887	Labor	Yes	6.530%	28,333	190
7	Accrued Liab-Sick Pay Carryover	Accrual Labor Related	Non-Property	1,776,911	621,919	159,922	(55,973)	725,868	1,776,911	373,151	159,922	(33,584)	499,490	226,378	-	-	226,378	Labor	Yes	6.530%	14,783	190
8	Accrued Liab-Vacation	Accrual Labor Related	Non-Property	2,978,952	1,042,633	268,106	(93,837)	1,216,902	2,978,952	625,580	268,106	(56,302)	837,384	379,519	-	-	379,519	Labor	Yes	6.530%	24,783	190
9	Acc Liab - Deferred Comp ST	Accrual Labor Related	Non-Property	135,000	47,250	12,150	(4,253)	55,148	135,000	28,350	12,150	(2,552)	37,949	17,199	-	-	17,199	Labor	Yes	6.530%	1,123	190
10	Liabilities-Disability (92420L)-Contra	Accrual Labor Related	Non-Property	(156,169)	(54,659)	(14,055)	4,919	(63,795)	(156,169)	(32,796)	(14,055)	2,952	(43,899)	(19,896)	-	-	(19,896)	Labor	Yes	6.530%	(1,299)	190
11	Liab-Workers Comp (92420L)-Contra	Accrual Labor Related	Non-Property	(1,350,412)	(472,644)	(121,537)	42,538	(551,643)	(1,350,412)	(283,587)	(121,537)	25,523	(379,601)	(172,042)	-	-	(172,042)	Labor	Yes	6.530%	(11,234)	190
12	Accrued Liabilities - Workers Comp - Long Term	Accrual Labor Related	Non-Property	8,741,596	3,059,559	786,744	(275,360)	3,570,942	8,741,596	1,835,735	786,744	(165,216)	2,457,263	1,113,679	-	-	1,113,679	Labor	Yes	6.530%	72,723	190
13	Accrued Liabilities - Disability - Long Term	Accrual Labor Related	Non-Property	518,589	181,506	46,673	(16,336)	211,844	518,589	108,904	46,673	(9,801)	145,775	66,068	-	-	66,068	Labor	Yes	6.530%	4,314	190
14	Liability-Deferred Comp (92530P)-Contra	Accrual Labor Related	Non-Property	(135,000)	(47,250)	(12,150)	4,253	(55,148)	(135,000)	(28,350)	(12,150)	2,552	(37,949)	(17,199)	-	-	(17,199)	Labor	Yes	6.530%	(1,123)	190
15	Acc Liab - Deferred Comp LT -Old Plans	Accrual Labor Related	Non-Property	140,236	49,083	12,621	(4,417)	57,286	140,236	29,450	12,621	(2,650)	39,420	17,866	-	-	17,866	Labor	Yes	6.530%	1,167	190
16	Section 481(a) Adjustments - Payroll Taxes	Accrual Labor Related	Non-Property	(122,306)	(42,807)	(11,008)	3,853	(49,962)	(122,306)	(25,684)	(11,008)	2,312	(34,380)	(15,582)	-	-	(15,582)	Labor	Yes	6.530%	(1,017)	190
17	Accrued Liab-Auto Liability	Accrued Liab - Auto	Non-Property	249,150	87,203	22,424	(7,848)	101,778	249,150	52,322	22,424	(4,709)	70,036	31,742	-	-	31,742	Labor	Yes	6.530%	2,073	190
18	Accrued Liab-General Liability	Accrued Liab - Misc.	Non-Property	2,941,546	1,029,541	264,739	(92,659)	1,201,622	2,941,546	617,725	264,739	(55,595)	826,869	374,753	-	-	374,753	Plant	Yes	33.300%	124,793	190
19	Regulatory Liability-Current-Rev Acct	Accrued Liab - Misc.	Non-Property	1,093,270	382,645	98,394	(34,438)	446,601	1,093,270	229,587	98,394	(20,663)	307,318	139,283	-	-	139,283	Plant	Yes	0.000%	-	190
20	Reg Liab-NJ Dfd Energy Supply-Netting	Accrued Liab - Misc.	Non-Property	(10,676,348)	(3,736,722)	(960,871)	336,305	(4,361,288)	(10,676,348)	(2,242,033)	(960,871)	201,783	(3,001,121)	(1,360,167)	-	-	(1,360,167)	Plant	Yes	0.000%	-	190
21	NJ Oth Reg Liability-Deferred DSM	Accrued Liab - Misc.	Non-Property	648,725	227,054	58,385	(20,435)	265,004	648,725	136,232	58,385	(12,261)	182,357	82,648	-	-	82,648	Plant	Yes	0.000%	-	190
22	Regulatory Liability - NJ Distribution Deferral SBC	Accrued Liab - Misc.	Non-Property	399,147	139,701	35,923	(12,573)	163,052	399,147	83,821	35,923	(7,544)	112,200	50,851	-	-	50,851	Plant	Yes	0.000%	-	190
23	NJ Reg Liability-Universal Service Fund	Accrued Liab - Misc.	Non-Property	890,926	311,824	80,183	(28,064)	363,943	890,926	187,094	80,183	(16,838)	250,439	113,504	-	-	113,504	Plant	Yes	0.000%	-	190
24	NJ Reg Liability-Lifeline	Accrued Liab - Misc.	Non-Property	465,468	162,914	41,892	(14,662)	190,144	465,468	97,748	41,892	(8,797)	130,843	59,301	-	-	59,301	Plant	Yes	0.000%	-	190
25	ACE - Unbilled Generation Deferral	Accrued Liab - Misc.	Non-Property	11,121,011	3,892,354	1,000,891	(350,312)	4,542,933	11,121,011	2,335,412	1,000,891	(210,187)	3,126,116	1,416,817	-	-	1,416,817	Plant	Yes	0.000%	-	190
26	ACE - Unbilled Societal Benefits Charge	Accrued Liab - Misc.	Non-Property	2,534,006	886,902	228,061	(79,821)	1,035,141	2,534,006	532,141	228,061	(47,893)	712,309	322,832	-	-	322,832	Plant	Yes	0.000%	-	190
27	ACE - Unbilled Transmission Deferral	Accrued Liab - Misc.	Non-Property	1,371,625	480,069	123,446	(43,206)	560,309	1,371,625	288,041	123,446	(25,924)	385,564	174,745	-	-	174,745	100% Transmission	Yes	0.000%	-	190
28	Regulatory Liability-Contra-Rev Acctg	Accrued Liab - Misc.	Non-Property	(1,093,270)	(382,645)	(98,394)	34,438	(446,601)	(1,093,270)	(229,587)	(98,394)	20,663	(307,318)	(139,283)	-	-	(139,283)	Plant	Yes	0.000%	-	190
29	Other Regulatory Liability - General	Accrued Liab - Misc.	Non-Property	(25,730)	(9,006)	(2,316)	810	(10,511)	(25,730)	(5,403)	(2,316)	486	(7,233)	(3,278)	-	-	(3,278)	Plant	Yes	0.000%	-	190
30	Reg Liab-Asset Retirement Oblig-Electric	Accrued Liab - Misc.	Non-Property	(1,450,366)	(507,628)	(130,533)	45,687	(592,474)	(1,450,366)	(304,577)	(130,533)	27,412	(407,698)	(184,777)	-	-	(184,777)	Plant	Yes	0.000%	-	190
31	Asset Retirement Obligation - Non-Utility	Accrued Liab - Misc.	Non-Property	2,210,220	773,577	198,920	(69,622)	902,875	2,210,220	464,146	198,920	(41,773)	621,293	281,582	281,582	-	(0)	Plant	No	0.000%	-	190
32	Asset Retirement Obligation-Electric Utility	Accrued Liab - Misc.	Non-Property	1,450,366	507,628	130,533	(45,687)	592,474	1,450,366	304,577	130,533	(27,412)	407,698	184,777	-	-	184,777	Plant	Yes	0.000%	-	190
33	Accrued Liab-General	Accrued Liability - General	Non-Property	1,898,241	664,384	170,842	(59,795)	775,431	1,898,241	398,631	170,842	(35,877)	533,596	241,836	-	-	241,836	Plant	Yes	33.300%	80,531	190
34	Oth Reg Liab-Asset Retirement Obligation	Accrued Liability - General	Non-Property	1,450,366	507,628	130,533	(45,687)	592,474	1,450,366	304,577	130,533	(27,412)	407,698	184,777	-	-	184,777	Plant	Yes	0.000%	-	190
35	Merger Commitments	Accrued Liability - General	Non-Property	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Plant	No	0.000%	-	190
36	Accrued Charitable Contributions-NJ	Accrued Liability - General	Non-Property	968,920	339,122	87,203	(30,521)	395,804	968,920	203,473	87,203	(18,313)	272,363	123,440	123,440	-	(0)	Plant	No	0.000%	-	190
37	Accrued Charitable Contributions-NJ-Long Term	Accrued Liability - General	Non-Property	6,720,799	2,352,280	604,872	(211,705)	2,745,447	6,720,799	1,411,368	604,872	(127,023)	1,889,217	856,230	856,230	-	(0)	Plant	No	0.000%	-	190
38	Accumulated Deferred Investment Tax Credit	Accumulated Deferred Investment Tax Credit	Protected Property	3,697,280	1,294,048	332,755	(116,464)	1,510,339	3,697,280	776,429	332,755	(69,879)	1,039,305	471,033	-	-	471,033	Plant	Yes	33.300%	156,854	190
39	Provision for Uncollectible Accounts-Special Billing	BAD DEBT RESERVE	Non-Property	1,831,322	640,963	164,819	(57,687)	748,095	1,831,322	384,578	164,819	(34,612)	514,785	233,310	-	-	233,310	Plant	Yes	0.000%	-	190
40	Provision for Uncollectible Accounts-NJ	BAD DEBT RESERVE	Non-Property	15,938,799	5,578,580	1,434,492	(502,072)	6,511,000	15,938,799	3,347,148	1,434,492	(301,243)	4,480,397	2,030,603	-	-	2,030,603	Plant	Yes	0.000%	-	190
41	Charitable Contributions - Fed	Charitable Contribution Limit	Non-Property	2,031,658	711,080	-	-	711,080	2,031,658	426,648	-	-	426,648	284,432	284,432	-	(0)	Plant	No	0.000%	-	190
42	Charitable Contributions - NJ	Charitable Contribution Limit	Non-Property	-	-	196,724	(68,854)	127,871	-	-	196,724	(41,312)	155,412	(27,541)	(27,541)	-	(0)	Plant	No	0.000%	-	190
43	Accrued Liab-Environmental Site Exp	ENVIRONMENTAL EXPENSE	Non-Property	285,000	99,750	25,650	(8,978)	116,423	285,000	59,850	25,650	(5,387)	80,114	36,309	-	-	36,309	Plant	Yes	0.000%	-	190
44	Liability-Environmental (92530O)-Contra	ENVIRONMENTAL EXPENSE	Non-Property	(285,000)	(99,750)	(25,650)	8,978	(116,423)	(285,000)	(59,850)	(25,650)	5,387	(80,114)	(36,309)	-	-	(36,309)	Plant	Yes	0.000%	-	190
45	Accrued Liab-Environmental Site Exp - Long Term	ENVIRONMENTAL EXPENSE	Non-Property	628,942	220,130	56,605	(19,812)	256,923	628,942	132,078	56,605	(11,887)	176,796	80,127	-	-	80,127	Plant	Yes	0.000%	-	190
46	Accrued Liab-LTIP	OPEB	Non-Property	427,575	149,651	38,482	(13,469)	174,664	427,575	89,791	38,482	(8,081)	120,191	54,473	-	-	54,473	Labor	Yes	6.530%	3,557	190
47	Accrued Liab-OPEB	OPEB	Non-Property	16,383,106	5,734,087	1,474,480	(516,068)	6,692,499	16,383,106	3,440,452	1,474,480	(309,641)	4,605,291	2,087,208	-	-	2,087,208	Labor	Yes	6.530%	136,295	190
48	Accrued Liability - LTIP - Long-Term	OPEB	Non-Property	130,121	45,542	11,711	(4,099)	53,155	130,121	27,325	11,711	(2,459)	36,577	16,577	-	-	16,577	Plant	Yes	6.530%	1,083	190
49	SERP Asset	SERP	Non-Property	881,501	308,525	79,335	(27,767)	360,093	881,501	185,115	79,335	(16,660)	247,790	112,303	104,970	-	7,333	Labor	Yes	0.000%	-	190
50	Liabilities-SERP (92420L) - Contra	SERP	Non-Property	(881,501)	(308,525)	(79,335)	27,767	(360,093)	(881,501)	(185,115)	(79,335)	16,660	(247,790)	(112,303)	(104,970)	-	(7,333)	Labor	Yes	0.000%	-	190
51	Accrued Liab-SERP	SERP	Non-Property	881,501	308,525	79,335	(27,767)	360,093	881,501	185,115	79,335	(16,660)	247,790	112,303	-	-	112,303	Labor	Yes	6.530%	7,333	190
52	Deferred Credits - Deferred MTC Tax Rev	Stranded Costs	Non-Property	3,889,954	1,361,484	350,096	(122,534)	1,589,046	3,889,954	816,890	350,096	(73,520)	1,093,466	495,580	-	-	495,580	Plant	Yes	0.000%	-	190
53	NJ Oth Reg Liability-Tax Benefits	Stranded Costs	Non-Property	444,546	155,591	40,009	(14,003)	181,597	444,546	93,355	40,009	(8,402)	124,962	56,635	-	-	56,635	Plant	Yes	0.000%	-	190
54	Use Tax Payable	Use Tax Reserve	Non-Property	2,791,067	976,873	251,196	(87,919)	1,140,151	2,791,067	586,124	251,196	(52,751)	784,569	355,582	-	-	355,582	Plant	Yes	0.000%	-	190
55	Federal NOL	Federal NOL	Protected Property	73,232,517	25,631,381	-	-	25,631,381	73,232,517	15,378,829	-	-	15,378,829	10,252,552	-	-	10,252,552	Plant	Yes	33.300%	3,414,100	190
56	NJ NOL	State NOL	Non-Property	-	-	28,158,807	(9,855,582)	18,303,224	-	-	28,158,807	(5,913,349)	22,245,457	(3,942,233)	-	-	(3,942,233)	Plant	Yes	33.300%	(1,312,764)	190
57	SFAS109-Regulatory Liability Electric	FAS109 Non-TCJA	N/A	2,553,399	893,690	229,806	(80,432)	1,043,063	2,553,399	536,214	229,806	(48,259)	717,760	325,303	-	325,303	-	N/A	No	0.000%	-	190
58	FAS 109 - Regulatory Asset Electric	FAS109 Non-TCJA	N/A	(48,928,894)	(17,125,113)	(4,403,600)	1,541,260	(19,987,453)	(48,928,894)	(10,275,068)	(4,403,600)	924,756	(13,753,912)	(6,233,541)	-	(6,233,541)	-	N/A	No	0.000%	-	190
59	SFAS109-Regulatory Liability Electric	FAS 109 Regulatory Liability	N/A	-	-	-	-	-	458,773,646	96,342,508	41,289,646	(8,670,826)	128,961,328	(128,961,328)	-	(128,961,328)	-	N/A	No	0.000%	-	190
60	**Total FERC Account 190**			**$ 117,324,236**	**$ 41,063,482**	**$ 32,702,288**	**$ (11,445,801)**	**$ 62,319,969**	**$ 576,098,081**	**$ 120,980,597**	**$ 73,991,934**	**$ (15,538,306)**	**$ 179,434,225**	**$ (117,114,255)**	**$ 1,518,143**	**$ (134,869,566)**	**$ 16,237,168**				**$ 2,739,288**	
	FERC Account 282 - Property (Note A)																					
61	Fixed Asset Basis Differences (PowerTax) - Protected	Protected Property (PowerTax)	Protected Property	$ (1,102,869,694)	$ (386,004,393)	$ -	$ -	$ (386,004,393)	$ (1,102,869,694)	$ (231,602,636)	$ -	$ -	$ (231,602,636)	$ (154,401,757)	$ -	$ -	$ (154,401,757)	Plant	Yes	33.300%	$ (51,415,785)	282
62	Fixed Asset Basis Differences (PowerTax) - Non-Protected	Non-Protected Property (PowerTax)	Unprotected Property	(1,313,024,379)	(459,558,533)	-	-	(459,558,533)	(1,313,024,379)	(275,735,120)	-	-	(275,735,120)	(183,823,413)	-	(10,247,068)	(173,576,345)	Plant	Yes	33.300%	(57,800,923)	282
63	Fixed Asset Basis Differences (PowerTax) - Non-Protected CIAC	Non-Protected Property (PowerTax)	Unprotected Property	119,800,703	41,930,246	-	-	41,930,246	119,800,703	25,158,148	-	-	25,158,148	16,772,098	-	-	16,772,098	100% Distribution	No	0.000%	-	282
64	Fixed Asset Basis Differences (PowerTax FT) - Non-Protected	Non-Protected Property (PowerTax)	Unprotected Property	(74,991,897)	(26,247,164)	-	-	(26,247,164)	(74,991,897)	(15,748,298)	-	-	(15,748,298)	(10,498,866)	-	-	(10,498,866)	Plant	Yes	33.300%	(3,496,122)	282
65	State Fixed Asset Basis (PowerTax)	Non-Protected Property (PowerTax)	Unprotected Property	-	-	(149,120,470)	52,192,164	(96,928,305)	-	-	(149,120,470)	31,315,299	(117,805,171)	20,876,866	-	-	20,876,866	Plant	Yes	33.300%	6,951,996	282
66	State Fixed Asset Basis (PowerTax) - CIAC	Non-Protected Property (PowerTax)	Unprotected Property	-	-	10,782,063	(3,773,722)	7,008,341	-	-	10,782,063	(2,264,233)	8,517,830	(1,509,489)	-	-	(1,509,489)	100% Distribution	No	0.000%	-	282
67	State Fixed Asset Basis (PowerTax FT)	Non-Protected Property (PowerTax)	Unprotected Property	-	-	(1,798,551)	629,493	(1,169,058)	-	-	(1,798,551)	377,696	(1,420,855)	251,797	-	-	251,797	Plant	Yes	33.300%	83,848	282
68	Fixed Asset Basis Differences (Non-PowerTax) - Non-Protected	Non-Protected Property (Non-PowerTax)	Unprotected Property	(4,165,822)	(1,458,038)	-	-	(1,458,038)	(4,165,822)	(874,823)	-	-	(874,823)	(583,215)	-	-	(583,215)	Plant	Yes	33.300%	(194,211)	282
69	Fixed Asset Basis Differences (Non-PowerTax) - Non-Protected CIAC	Non-Protected Property (Non-PowerTax)	Unprotected Property	13,291,551	4,652,043	-	-	4,652,043	13,291,551	2,791,226	-	-	2,791,226	1,860,817	-	-	1,860,817	100% Distribution	No	0.000%	-	282
70	State Fixed Asset Basis (Non-PowerTax)	Non-Protected Property (Non-PowerTax)	Unprotected Property	-	-	(374,924)	131,223	(243,701)	-	-	(374,924)	78,734	(296,190)	52,489	-	-	52,489	Plant	Yes	33.300%	17,479	282
71	State Fixed Asset Basis (Non-PowerTax) - CIAC	Non-Protected Property (Non-PowerTax)	Unprotected Property	-	-	1,196,240	(418,684)	777,556	-	-	1,196,240	(251,210)	945,029	(167,474)	-	-	(167,474)	100% Distribution	No	0.000%	-	282
72	**Total FERC Account 282**			**$ (2,361,959,539)**	**$ (826,685,839)**	**$ (139,315,642)**	**$ 48,760,475**	**$ (917,241,006)**	**$ (2,361,959,539)**	**$ (496,011,503)**	**$ (139,315,642)**	**$ 29,256,285**	**$ (606,070,860)**	**$ (311,170,146)**	**$ -**	**$ (10,247,068)**	**$ (300,923,077)**				**$ (105,853,717)**	
	FERC Account 283 - Non-Current (Note A)																					
73	Other Regulatory Assets - Vacation Accrual	Accrual Labor Related	Non-Property	$ (5,186,943)	$ (1,815,430)	$ (466,825)	$ 163,389	$ (2,118,866)	$ (5,186,943)	$ (1,089,258)	$ (466,825)	$ 98,033	$ (1,458,050)	$ (660,817)	$ -	$ -	$ (660,817)	Labor	Yes	6.530%	$ (43,151)	283
74	Regulatory Assets - NJ BGS Deferral	BGS Deferred Related - Retail	Non-Property	(4,574,838)	(1,601,193)	(411,735)	144,107	(1,868,821)	(4,574,838)	(960,716)	(411,735)	86,464	(1,285,987)	(582,834)	-	-	(582,834)	Plant	Yes	33.300%	$ (194,084)	283
75	Regulatory Assets - NJ NGC Deferral	BGS Deferred Related - Retail	Non-Property	(4,729,886)	(1,655,460)	(425,690)	148,991	(1,932,158)	(4,729,886)	(993,276)	(425,690)	89,395	(1,329,571)	(602,587)	-	-	(602,587)	Plant	Yes	33.300%	$ (200,662)	283
76	Deferred Credits-General	Interest on Contingent Taxes	Non-Property	171,753	60,114	15,458	(5,410)	70,161	171,753	36,068	15,458	(3,246)	48,280	21,881	21,881	-	(0)	Plant	No	0.000%	$ -	283
77	Unamortized Loss on Reacquired Debt	Loss on Reacquired Debt	Non-Property	(5,278,948)	(1,847,632)	(475,105)	166,287	(2,156,450)	(5,278,948)	(1,108,579)	(475,105)	99,772	(1,483,912)	(672,538)	-	-	(672,538)	Plant	Yes	33.300%	$ (223,955)	283
78	Miscellaneous Deferred Debits - General	Misc. Deferred Debits - Retail	Non-Property	(1,723,744)	(603,311)	(155,137)	54,298	(704,150)	(1,723,744)	(361,986)	(155,137)	32,579	(484,545)	(219,605)	-	-	(219,605)	Plant	Yes	33.300%	$ (73,128)	283
79	NUG Buyout	NUG BUYOUT	Non-Property	(23,578,421)	(8,252,447)	(2,122,058)	742,720	(9,631,785)	(23,578,421)	(4,951,468)	(2,122,058)	445,632	(6,627,894)	(3,003,891)	-	-	(3,003,891)	Plant	Yes	33.300%	$ (1,000,296)	283
80	Renewable Energy Credits - NJ	Other- 283	Non-Property	(1,249,135)	(437,197)	(112,422)	39,348	(510,272)	(1,249,135)	(262,318)	(112,422)	23,609	(351,132)	(159,140)	-	-	(159,140)	Plant	Yes	33.300%	$ (52,994)	283
81	Solar Renewable Energy Credits II - NJ	Other- 283	Non-Property	548,391	191,937	49,355	(17,274)	224,018	548,391	115,162	49,355	(10,365)	154,153	69,865	-	-	69,865	Plant	Yes	33.300%	$ 23,265	283
82	Accrued Severance	Other- 283	Non-Property	69,901	24,465	6,291	(2,202)	28,555	69,901	14,679	6,291	(1,321)	19,649	8,905	-	-	8,905	Plant	Yes	33.300%	$ 2,965	283
83	Def'd Credits - Def'd Transitional Bond	Other- 283	Non-Property	(1,479,389)	(517,786)	(133,145)	46,601	(604,331)	(1,479,389)	(310,672)	(133,145)	27,960	(415,856)	(188,474)	-	-	(188,474)	Plant	Yes	33.300%	$ (62,762)	283
84	Prepaid Pension Costs	PENSION PAYMENT RESERVE	Non-Property	(79,930,586)	(27,975,705)	(7,193,753)	2,517,813	(32,651,645)	(79,930,586)	(16,785,423)	(7,193,753)	1,510,688	(22,468,488)	(10,183,157)	-	-	(10,183,157)	Labor	Yes	6.530%	$ (664,960)	283
85	Reg Assets-FERC Formula Rate Adj-Transmission	Reg Asset - FERC Formula Rate Adj. Trans. Svc	Non-Property	(10,602,815)	(3,710,985)	(954,253)	333,989	(4,331,250)	(10,602,815)	(2,226,591)	(954,253)	200,393	(2,980,451)	(1,350,799)	-	-	(1,350,799)	100% Transmission	Yes	100.000%	$ (1,350,799)	283
86	Regulatory Assets - NJ Recovery - Base	Reg Asset-NJ Rec-Base	Non-Property	(18,516,983)	(6,480,944)	(1,666,528)	583,285	(7,564,187)	(18,516,983)	(3,888,566)	(1,666,528)	349,971	(5,205,124)	(2,359,064)	-	-	(2,359,064)	Plant	Yes	33.300%	$ (785,568)	283
87	Regulatory Assets - NJ	Reg Asset-NJ Rec-Base	Non-Property	(9,126,247)	(3,194,187)	(821,362)	287,477	(3,728,072)	(9,126,247)	(1,916,512)	(821,362)	172,486	(2,565,388)	(1,162,684)	-	-	(1,162,684)	Plant	Yes	33.300%	$ (387,174)	283
88	Regulatory Assets-Current-Corp Acctg	Regulatory Asset - General	Non-Property	(24,618,339)	(8,616,419)	(2,215,651)	775,478	(10,056,592)	(24,618,339)	(5,169,851)	(2,215,651)	465,287	(6,920,215)	(3,136,376)	-	-	(3,136,376)	Plant	Yes	0.000%	$ -	283
89	Reg Assets-Current-Rev Acctg	Regulatory Asset - General	Non-Property	(28,268,277)	(9,893,897)	(2,544,145)	890,451	(11,547,591)	(28,268,277)	(5,936,338)	(2,544,145)	534,270	(7,946,213)	(3,601,379)	-	-	(3,601,379)	Plant	Yes	0.000%	$ -	283
90	Reg Asset-NJ Dfd Energy Supply	Regulatory Asset - General	Non-Property	10,676,348	3,736,722	960,871	(336,305)	4,361,288	10,676,348	2,242,033	960,871	(201,783)	3,001,121	1,360,167	-	-	1,360,167	Plant	Yes	0.000%	$ -	283
91	Regulatory Assets-Elec Gen'l	Regulatory Asset - General	Non-Property	(156,579)	(54,803)	(14,092)	4,932	(63,963)	(156,579)	(32,882)	(14,092)	2,959	(44,014)	(19,948)	-	-	(19,948)	Plant	Yes	0.000%	$ -	283
92	Regulatory Assets-Contra-Corp Acctg	Regulatory Asset - General	Non-Property	24,618,339	8,616,419	2,215,651	(775,478)	10,056,592	24,618,339	5,169,851	2,215,651	(465,287)	6,920,215	3,136,376	-	-	3,136,376	Plant	Yes	0.000%	$ -	283
93	Regulatory Assets-Contra-Rev Acctg	Regulatory Asset - General	Non-Property	28,268,277	9,893,897	2,544,145	(890,451)	11,547,591	28,268,277	5,936,338	2,544,145	(534,270)	7,946,213	3,601,379	-	-	3,601,379	Plant	Yes	0.000%	$ -	283
94	Regulatory Assets - Asset Retirement Obligation	Regulatory Asset - General	Non-Property	(181,590)	(63,557)	(16,343)	5,720	(74,180)	(181,590)	(38,134)	(16,343)	3,432	(51,045)	(23,135)	-	-	(23,135)	Plant	Yes	0.000%	$ -	283
95	Regulatory Assets-Elec Gen'l-Contra	Regulatory Asset - General	Non-Property	156,579	54,803	14,092	(4,932)	63,963	156,579	32,882	14,092	(2,959)	44,014	19,948	-	-	19,948	Plant	Yes	0.000%	$ -	283
96	Reg Assets-Solar Renew Energy Credit	Regulatory Asset - General	Non-Property	(483,908)	(169,368)	(43,552)	15,243	(197,676)	(483,908)	(101,621)	(43,552)	9,146	(136,026)	(61,650)	-	-	(61,650)	Plant	Yes	0.000%	$ -	283
97	Reg Assets - Solar Renew Energy Certification	Regulatory Asset - SREC Program	Non-Property	(634,878)	(222,207)	(57,139)	19,999	(259,348)	(634,878)	(133,324)	(57,139)	11,999	(178,464)	(80,883)	-	-	(80,883)	Plant	Yes	0.000%	$ -	283
98	Recoverable NJ Stranded Costs	Stranded Costs	Non-Property	(5,905,595)	(2,066,958)	(531,504)	186,026	(2,412,436)	(5,905,595)	(1,240,175)	(531,504)	111,616	(1,660,063)	(752,373)	-	-	(752,373)	Plant	Yes	0.000%	$ -	283
99	Deferred Securitization Cost Transaction	Stranded Costs	Non-Property	(649,767)	(227,418)	(58,479)	20,468	(265,430)	(649,767)	(136,451)	(58,479)	12,281	(182,650)	(82,780)	-	-	(82,780)	Plant	Yes	0.000%	$ -	283
100	Other Regulatory Assets - NJ BGS	Stranded Costs	Non-Property	(16,325,389)	(5,713,886)	(1,469,285)	514,250	(6,668,921)	(16,325,389)	(3,428,332)	(1,469,285)	308,550	(4,589,067)	(2,079,855)	-	-	(2,079,855)	Plant	Yes	0.000%	$ -	283
101	Stranded Cost-BL England	Stranded Costs	Non-Property	(9,967,333)	(3,488,566)	(897,060)	313,971	(4,071,655)	(9,967,333)	(2,093,140)	(897,060)	188,383	(2,801,817)	(1,269,838)	-	-	(1,269,838)	Plant	Yes	0.000%	$ -	283
102	Stranded Cost-PCLP	Stranded Costs	Non-Property	(34,756,750)	(12,164,863)	(3,128,108)	1,094,838	(14,198,132)	(34,756,750)	(7,298,918)	(3,128,108)	656,903	(9,770,122)	(4,428,010)	-	-	(4,428,010)	Plant	Yes	0.000%	$ -	283
103	Stranded Cost-Ref-Fuel	Stranded Costs	Non-Property	(965,000)	(337,750)	(86,850)	30,398	(394,203)	(965,000)	(202,650)	(86,850)	18,239	(271,262)	(122,941)	-	-	(122,941)	Plant	Yes	0.000%	$ -	283
104	Stranded Cost-Capital Reduction Costs	Stranded Costs	Non-Property	(2,026,810)	(709,383)	(182,413)	63,844	(827,952)	(2,026,810)	(425,630)	(182,413)	38,307	(569,736)	(258,216)	-	-	(258,216)	Plant	Yes	0.000%	$ -	283
105	**Total FERC Account 283**			**$ (226,408,561)**	**$ (79,242,996)**	**$ (20,376,771)**	**$ 7,131,870**	**$ (92,487,897)**	**$ (226,408,561)**	**$ (47,545,798)**	**$ (20,376,771)**	**$ 4,279,122**	**$ (63,643,447)**	**$ (28,844,451)**	**$ 21,881**	**$ -**	**$ (28,866,332)**				**$ (5,013,302)**	
106	**Grand Total**			**$ (2,471,043,865)**	**$ (864,865,353)**	**$ (126,990,125)**	**$ 44,446,544**	**$ (947,408,934)**	**$ (2,012,270,019)**	**$ (422,576,704)**	**$ (85,700,479)**	**$ 17,997,101**	**$ (490,280,082)**	**$ (457,128,852)**	**$ 1,540,024**	**$ (145,116,635)**	**$ (313,552,241)**				**$ (108,127,731)**	

	Deficient / (Excess) ADIT Balance (Q)	Transmission Allocated (U)
Protected Property	$ (143,678,171)	$ (47,844,831)
Unprotected Property	(146,521,320)	(54,437,932)
Non-Property	(23,352,750)	(5,844,968)
Total Unprotected	$ (169,874,070)	$ (60,282,899)
Total Deficient / (Excess)ADIT	$ (313,552,241)	$ (108,127,731)

Instructions

1. In accordance with ASC 740, deferred tax assets and liabilities are adjusted (re-measured) for the effect of the changes in tax law (including tax rates) in the period that the change is enacted. Adjustments are recorded in the appropriate deferred tax balance sheet accounts (Accounts 190, 281, 282 and 283) based on the nature of the temporary difference and the related classification requirements of the accounts. If as a result of action or expected action by a regulator, it is probable that the effect of a future increase or decrease in taxes payable resulting from a change in tax law or rates will be recovered from or passed through to customers through future rates, a regulatory asset or liability is recognized in Account 182.3 (Other Regulatory Assets), or Account 254 (Other Regulatory Liabilities), as appropriate, for that probable future revenue or reduction in future revenue. The amortization of deficient and excess deferred income taxes that will be recovered from or passed through to customers through future rates will be recorded in FERC Accounts 410.1 (Provision for Deferred Income Taxes, Utility Operating Income) and 411.1 (Provision for Deferred Income Taxes—Credit, Utility Operating Income), as appropriate. Re-measurements of deferred tax balance sheet accounts may also result in re-measurements of tax-related regulatory assets or liabilities that had been recorded prior to the change in tax law. If it is not probable that the effect of a future increase or decrease in taxes payable resulting from a change in tax law or rates will be recovered from or passed through to customers through future rates, tax expense will be recognized in Account 410.2 (Provision for Deferred Income Taxes, Other Income or Deductions) or tax benefit is recognized in Account 411.2 (Provision for Deferred Income Taxes-Credit, Other Income or Deductions), as appropriate.

2. For deficient and (excess) accumulated deferred income taxes (ADIT) related to change(s) to income tax rates occurring after September 30, 2018, insert calculations that support the re-measurement amount delineated by category (i.e., protected property, unprotected property, and unprotected non-property).

3. Set the allocation percentages equal to the applicable percentages at the date of the rate change.

Notes

A Categorization of items as protected or non-protected will remain as originally agreed, absent a change in guidance from the Internal Revenue Service (IRS) with respect to that items. Balances associated with the tax rate change will not be adjusted (except for amortization each year) absent audit adjustments, tax return amendments, or a change in IRS guidance. Any resulting changes will be prominently disclosed including the basis for the change.

B The allocation percentage in Column T are based on the applicable percentages at the date of the rate change and must remain fixed absent the Commission's express approval.

END

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)	2,169,180		
2	Personal property	-		
3	City License	-		
4	Federal Excise	10,552		
		.		
	Total Plant Related	2,179,732	36.8625%	803,503
	Labor Related		***Wages & Salary Allocator***	
5	Federal FICA & Unemployment and Unemployment(State)	2,773,965		
6				
	Total Labor Related	2,773,965	10.7202%	297,375
	Other Included		***Gross Plant Allocator***	
7	Miscellaneous			
	Total Other Included	0	36.8625%	0
	Total Included			1,100,877
	Excluded			
8	State Franchise tax	-		
9	TEFA	-		
10	Use & Sales Tax	(615,971)		
10.1	Excluded State Dist RA Amort in line 5	44,891		
11	Total "Other" Taxes (included on p. 263)	4,382,616		
12	Total "Taxes Other Than Income Taxes" - acct 408.10 (p. 114.14)	4,382,616		
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

Line	Description	Reference	Amount
	Account 454 - Rent from Electric Property		
1	Rent from Electric Property - Transmission Related (Note 3)		$ 830,783
2	Total Rent Revenues	(Sum Line 1)	830,783
	Account 456 - Other Electric Revenues (Note 1)		
3	Schedule 1A		$ 830,470
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)		957,837
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)	3,238,470
12	Less line 17g		(532,158)
13	Total Revenue Credits		2,901,517

<u>Revenue Adjustment to determine Revenue Credit</u>

Line	Description	Reference	Amount
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.		830,783
17b	Costs associated with revenues in line 17a	Attachment 5 - Cost Support	233,533
17c	Net Revenues (17a - 17b)		597,250
17d	50% Share of Net Revenues (17c / 2)		298,625
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)		298,625
17g	Line 17f less line 17a		(532,158)
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.		18,337,529
19	Amount offset in line 4 above		142,987,355
20	Total Account 454, 456 and 456.1		166,384,265
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)	77,357,492
B	100 Basis Point increase in ROE				1.00%
	Return Calculation				
59	Rate Base			(Line 39 + 58)	939,795,842
	Long Term Interest				
100	Long Term Interest			p117.62c through 67c	57,709,830
101	Less LTD Interest on Securitization Bonds	(Note P)		Attachment 8	2,579,701
102	**Long Term Interest**			"(Line 100 - line 101)"	55,130,129
103	**Preferred Dividends**		enter positive	p118.29c	0
	Common Stock				
104	Proprietary Capital			p112.16c	1,276,295,808
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)	1,276,295,808
	Capitalization				
108	Long Term Debt			p112.17c through 21c	1,313,398,829
109	Less Loss on Reacquired Debt		enter negative	p111.81.c	-3,855,349
110	Plus Gain on Reacquired Debt		enter positive	p113.61.c	0
111	Less ADIT associated with Gain or Loss		enter negative	Attachment 1A - ADIT, Line 6	1,083,739
112	Less LTD on Securitization Bonds		enter negative	Attachment 8	-26,383,829
113	Total Long Term Debt			(Sum Lines Lines 108 to 112)	1,284,243,390
114	Preferred Stock			p112.3c	0
115	Common Stock			(Line 107)	1,276,295,808
116	**Total Capitalization**			(Sum Lines 113 to 115)	2,560,539,198
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)	0.0429
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)	0.0215
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)**	**0.0790**
127	Investment Return = Rate Base * Rate of Return			**(Line 59 * 126)**	**74,210,086**
	Composite Income Taxes		(Note L)		
	Income Tax Rates				
128	FIT=Federal Income Tax Rate		(Note I from ATT H1-A)		21.00%
129	SIT=State Income Tax Rate or Composite		(Note I from ATT H1-A)		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%
132a	T/ (1-T)				39.10%
132b	Tax Gross-Up Factor	1*1/(1-T)			1.3910
	ITC Adjustment		(Note V from ATT H1-A)		
133	Investment Tax Credit Amortization		enter negative	Attachment 1A - ADIT	-325,830
134	Tax Gross-Up Factor			(Line 132b)	1.39
135	Net Plant Allocation Factor			(Line 18)	38.25%
136a	ITC Adjustment Allocated to Transmission			(Line 133 * 134 * 135)	-173,363
	Other Income Tax Adjustment				
136b	Tax Adjustment for AFUDC Equity Component of Transmission Depreciation Expense		(Note T from ATT H1-A)	Attachment 5, Line 136b	55,326
136c	Amortization Deficient / (Excess) Deferred Taxes (Federal) - Transmission Component		(Note T from ATT H1-A)	Attachment 5, Line 136c	-12,992,454
136d	Amortization Deficient / (Excess) Deferred Taxes (State) - Transmission Component		(Note T from ATT H1-A)	Attachment 5, Line 136d	0
136e	Amortization of Other Flow-Through Items - Transmission Component		(Note T from ATT H1-A)	Attachment 5, Line 136e	134,274
136f	Other Income Tax Adjustments - Expense / (Benefit)			(Line 136b + 136c + 136d + 136e)	-12,802,854
136g	Tax Gross-Up Factor			(Line 132b)	1.3910
136h	Other Income Tax Adjustment			(Line 136f * 136g)	-17,808,950
137	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		[Line 132a * 127 * (1-(123 / 126))]	21,129,719
138	**Total Income Taxes**			**(Line 136a + 136h + 137)**	**3,147,406**

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 Attachment 5)	22,872,299	22,872,299	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						
40e	(Note V)	(Note V)	p267.h	3,033,967	3,033,967	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	5,813,108	5,813,108	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	13,262,694	1,194,950	12,067,744	Transmission Right of Way - Carll's Corner to Landis, Terrace Substation - Land Expansion for Storm Water

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	4,207,834,817	0	0	See ARO Exclusion - Cost Support section below for Electric Plant in Service without AROs
	Plant In Service						
19	Transmission Plant In Service	(Note B)	p207.58.g (see Attachment 5)	1,542,090,059	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	269,061,580	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 (see Attachment 5)	319,978	319,978	See Form 1

Regulatory Expense Related to Transmission Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	Transmission Related	Non-transmission Related	Details
	Allocated General & Common Expenses						
70	Less Regulatory Commission Exp Account 928	(Note E)	p323.189b	4,137,986	200,728	3,937,258	FERC Form 1 page 351 line 9 (h) and 10 (h)
	Directly Assigned A&G						
77	Regulatory Commission Exp Account 928	(Note G)	p323.189b	4,137,986	200,728	3,937,258	FERC Form 1 page 351 line 9 (h) and 10 (h)

Safety Related Advertising Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	Safety Related	Non-safety Related	Details
	Directly Assigned A&G						
81	General Advertising Exp Account 930.1	(Note F)	p323.191b	833,948	-	833,948	None

Multistate Workpaper

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			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%					Apportioned: NJ 100.0000%, PA 0.0000%

Education and Out Reach Cost Support

	Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	Education & Outreach	Other	Details
	Directly Assigned A&G						
78	General Advertising Exp Account 930.1	(Note K)	p323.191b	833,948	-	833,948	None

Excluded Plant Cost Support

Atlantic City Electric Company

Attachment 5 - Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Excluded Transmission Facilities	Description of the Facilities
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
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

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	-	100%	-	
	Labor Related, General plant related or Common Plant related	35,108,694	10.72%	3,763,725	
	Plant Related	3,663,624	36.86%	1,350,502	
	Other		0.00%	-	
	Total Transmission Related Reserves	38,772,318		5,114,226	

Prepayments

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions						Description of the Prepayments
45	Prepayments					
5	Wages & Salary Allocator			10.720%	To Line 45	
	Pension Liabilities, if any, in Account 242		-	10.720%	-	
	Prepayments	$	880,784	10.720%	94,422	Prepayment is recorded in FERC account 165 (see FERC Form 1 page 111)
	Prepaid Pensions if not included in Prepayments	$	52,356,364	10.720%	5,612,710	Prepaid Pension is recorded in FERC account 186 (see FERC Form 1 page 233).
			53,237,148		5,707,132	
						Add more lines if necessary

Atlantic City Electric Company

Attachment 5 - Cost Support

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	$ -	$ -

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)	-	Settlement 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	2,737.3	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 & Dist RA Related	
6	Electric Plant in Service	p207.104g	4,207,834,817	969,311	4,206,865,506	
9	Accumulated Depreciation (Total Electric Plant)	p219.29c	852,666,367	31,058	852,635,309	
10	Accumulated Intangible Amortization	p200.21c	22,872,299	348,268	22,524,031	
23	General & Intangible	p205.5.g & p207.99.g	221,679,056	969,311	220,709,745	
60	Transmission O&M	p321.112.b	26,866,774	-	26,866,774	
68	Total A&G	p323.197.b	96,793,991	38,296	96,755,695	Removal of $38,296 of 2019 merger related costs in 923
87	General Depreciation	p336.10b&c	7,579,413	23,718	7,555,695	
88	Intangible Amortization	p336.1d&e	5,813,108	170,337	5,642,771	

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	4,207,834,817	2,165,288	4,205,669,529	Distribution ARO-$2,055,065 General ARO-$110,223
9	Accumulated Depreciation (Total Electric Plant)	p219.29c	852,666,367	306,591	852,359,776	Distribution ARO-$192,072 and General ARO-$101,674
23	General & Intangible	p205.5.g & p207.99.g	221,679,056	110,223	221,568,833	General ARO-$110,223
31	Accumulated General Depreciation	p219.28.c	44,534,504	128,787	44,405,717	General ARO-$128,787

Atlantic City Electric Company

Attachment 5 - Cost Support

Plant Related Exclusions - Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Form 1 Amount	ARO's	Merger Costs	Capital Leases	Non-ARO's & Non Merger Related & Non-Leases	
6	Electric Plant in Service	p207.104g	4,207,834,817	2,165,288	969,311	8,479,911	4,196,220,307	Distribution ARO-$2,055,065 General ARO-$110,223, Merger Cost $969,311, and General Capital Lease $8,479,911
9	Accumulated Depreciation (Total Electric Plant)	p219.29c	852,666,367	306,591	31,058	-	852,328,717	Distribution ARO-$177,804 and General ARO-$128,787, Merger Cost $31,058
10	Accumulated Intangible Amortization	p200.21c	22,872,299	-	348,268	601,604	21,922,426	Intangible Merger Cost $348,268 and General Capital Lease $601,604
19	Transmission Plant In Service	p207.58.g	1,524,090,059	-	-	-	1,524,090,059	
23	General & Intangible	p205.5.g & p207.99.g	221,679,056	110,223	969,311	8,479,911	212,119,611	General ARO-$110,223, General and Intangible Merger Cost $969,311 and General Capital Lease $8,479,911
31	Accumulated General Depreciation	p219.28.c	44,534,504	128,787	31,058	-	44,374,658	General ARO-$128,787, General Merger Cost $31,058

Expense Related Exclusions - Cost Support

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Total A&G Form 1 Amount	Merger Costs	State Approved Distribution Reg Asset Amortization	Below the line Membership Dues in 923 current rate year	Below the line Pro Bono Climate Change Expenses in 923 current rate year	Non Merger & Non Dist RA Amot & Membership Dues Below the Line	
68	Total A&G	Total: p.323.197.b	96,793,991	38,296	135,404	2,063	379	96,617,849	Merger costs in 923 $38,296, Distribution Reg Asset amortization $135,404, Below the Line Membership Dues $2,063 and Below the Line Pro Bono Climate Change expenses $379.

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	96,793,991	11,448,146	381,359	15,100	The actuarially determined amount of OPEB expense in FERC 926 increased $0.4 million from the prior year; the increase primarily represents a change in the discount rate from 3.57% in 2018 to 4.27% in 2019, a ~70 basis points change. In addition, expected return on plan assets decreased due to year over year market changes.

Atlantic City Electric Company

Attachment 5 - Cost Support

Attachment 3 - Revenue Credit Workpaper

17b	Costs associated with revenues in line 17a	$	233,533

Revenue Subject to 50/50 sharing (Attachment 3 - line 17a)	$	830,783
Federal Income Tax Rate		21.00%
Federal Tax on Revenue subject to 50/50 sharing		174,464
Net Revenue subject to 50/50 sharing		656,318
Composite State Income Tax Rate		9.000%
State Tax on Revenue subject to 50/50 sharing		59,069
Total Tax on Revenue subject to 50/50 sharing	$	233,533

Miscellaneous Revenue Credits

		Allocator	Allocation Factor	Description
Acct 456	799,633	10.72%	Wages & Salary	Intercompany Facilities
Acct 456	632,663	10.72%	Wages & Salary	Intercompany Vehicles
Acct 456	388,615	10.72%	Wages & Salary	Intracompany Sales
	-	100%	100% Transmission	
	-	36.86%	Gross Plant	
	1,820,911			
	195,205	Attachment 3 - Revenue Credit line 13		

Transmission Materials & Supplies

50	Transmission Materials & Supplies	The amount shown for 2019 does not include any amounts from FERC Form 1, page 227, line 5, Assigned to - Construction consistent with the May 5, 2020 FERC Order in Docket ER20-1187

Other Income Tax Adjustments

Line	Component Descriptions	Instruction References	Transmission Depreciation Expense Amount		Tax Rate from Attachment H-1A, Line 131		Amount to Attachment H-1A, Line 136f
136b	Tax Adjustment for AFUDC Equity Component of Transmission Depreciation Expense	Instr. 1, 2, 3 below	$ 196,820	X	28.11%	=	$ 55,326
	Amortization of Deficient / (Excess) Deferred Taxes - Transmission Component						
136c	Amortization Deficient / (Excess) Deferred Taxes (Federal) - Transmission Component	Instr. 4 below					(12,992,454)
136d	Amortization Deficient / (Excess) Deferred Taxes (State) - Transmission Component	Instr. 4 below					-
136e	Amortization of Other Flow-Through Items - Transmission Component	Instr. 5 below					134,274
136f	**Total Other Income Tax Adjustments - Expense / (Benefit)**						$ (12,802,854)

Instr. #s	Instructions
Inst. 1	Transmission Depreciation Expense is the gross cumulative amount based upon tax records of capitalized AFUDC equity embedded in the gross plant attributable to the transmission function multiplied by the Capital Recovery Rate (described in Instruction 2). Within five years of the effective date of the Settlement in Docket No ER19-5 et al, and at least every five years thereafter, ACE will file an FPA Section 205 rate proceeding to revise its depreciation rates (unless the company has otherwise submitted an FPA Section 205 rate filing that addresses its depreciation rates in the prior five years).
Inst. 2	Capital Recovery Rate is the book depreciation rate applicable to the underlying plant assets.
Inst. 3	"AFUDC-Equity" category reflects the nondeductible component of depreciation expense related to the capitalized equity portion of Allowance for Funds Used During Construction (AFUDC).
Inst. 4	Upon enactment of changes in tax law, accumulated deferred income taxes are re-measured and adjusted in the Company's books of account, resulting in deficient or (excess) accumulated deferred income taxes (ADIT). Such deficient or (excess) ADIT attributed to the transmission function will be based upon tax records and calculated in the calendar year in which the deficient or (excess) amount was measured and recorded for financial reporting purposes. See Attachment 1B - ADIT Amortization, Column F, Line 31 and Line 60 for additional information and support for the current year amortization. The current year amortization of deficient and (excess) ADIT is recorded in FERC Accounts 410.1 and 411.1.
Inst. 5	Other Flow-Through Items - In the past regulatory agencies required certain federal and state income tax savings resulting from temporary differences between the amount of Other Flow-Through Items - In the past regulatory agencies required certain federal and state income tax savings resulting from temporary differences between the amount of taxes computed for ratemaking purposes and taxes on the amount of actual current federal income tax liability to be immediately "flowed through" rates for certain assets. The "flow-through" savings were accounted for in deferred tax balances, based on the expectation and understanding that while tax savings would be immediately flowed through to ratepayers, the flow-through expense incurred when the temporary differences reverse would be recovered from ratepayers. The "Amortization of Other Flow-Through Items" represents the transmission portion of tax expense relating to the reversal of these temporary differences. The Other Flow-Through balance as of September 30, 2018 will reverse beginning October 1, 2018 based on the prescribed period.

Atlantic City Electric Company

Attachment 5a - Allocations of Costs to Affiliate

	Delmarva Power	Atlantic City	Pepco	Other	Total
Executive Management	1,929,537	1,773,167	3,294,875	4,189	7,001,768
Support Services	8,626,317	7,084,800	15,276,145	8,929,256	39,916,518
Financial Services	7,342,634	6,815,575	12,627,064	114,319	26,899,592
Human Resources	2,890,976	1,940,455	4,338,456		9,169,887
Legal Services	1,424,466	1,318,747	2,335,250	68,899	5,147,362
Customer Services	34,440,116	32,631,689	23,978,310		91,050,115
Information Technology	14,935,213	13,563,626	23,629,092	4,616	52,132,547
Government Affairs	4,282,118	4,938,355	5,869,562	15,960	15,105,995
Communication Services	1,932,707	1,682,506	3,099,755	3,005	6,717,973
Regulatory Services	7,414,502	6,777,269	10,700,981	603	24,893,355
Regulated Electric and Gas Operation Services	34,581,530	29,260,143	50,013,513	436,674	114,291,860
Supply Services	704,911	678,207	1,697,376	162	3,080,656
Total	**$ 120,505,027**	**$ 108,464,539**	**$ 156,860,379**	**$ 9,577,683**	**$ 395,407,628**

Name of Respondent PHI Service Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, 2019

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	44,157,691	112,640,215	62,473	156,860,379
2	Delmarva Power & Light Company	34,280,920	86,187,876	36,231	120,505,027
3	Atlantic City Electric Company	26,895,792	81,534,709	34,038	108,464,539
4	Exelon Business Services Company, LLC	297,200	8,279,289		8,576,489
5	Constellation NewEnergy, Inc.		637,174		637,174
6	Pepco Holdings LLC	79,088	26,789	80	105,957
7	Commonwealth Edison Company	579	140,532		141,111
8	PECO Energy Company		56,696		56,696
9	Baltimore Gas and Electric Company		43,658		43,658
10	Exelon Generation Company, LLC	16,598			16,598
11					
12					
13					
14					
15					
16					
17					
18					
19					
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27					
28					
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30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	**Total**	**105,727,868**	**289,546,938**	**132,822**	**395,407,628**

Service Company Billing Analysis by Utility FERC Account
YTD Dec 2019
Total PHI

FERC Accounts	FERC Account Name	Delmarva Power	Atlantic City	PEPCO	Other	Total	Inclusion in ATRR
107	Constr Work In Progress	17,963,994	16,017,260	29,690,053	237,600	63,908,907	Not included
108	Accumulated Provision for Depreciation	1,426,547	1,851,771	1,561,729		4,840,047	Wage & Salary Factor
163	Stores Expense Undistributed	630,518	606,970	1,571,433		2,808,921	Wage & Salary Factor
182.3	Other Regulatory Assets	1,045,306	111,919	2,743,135		3,900,360	Not included
184	Clearing Accounts - Other *	1,900,784	1,208,585	6,098,031		9,207,400	Not included
186	Misc Deferred debits	-	-	198		198	Not included
253	Other Deferred Credits	-	-	54,698		54,698	Not included
254	Other Regulatory Liabilities	23,375	-	-		23,375	Not included
416-421.2	Other Income -Below the Line	(103,891)	(59,579)	16,774	9,336,218	9,189,522	Not included
426.1-426.5	Other Income Deductions - Below the Line	975,046	747,659	1,854,913		3,577,618	Not included
430	Interest-Debt to Associated Companies	2,109	1,935	3,598		7,642	Not included
431	Other Interest Expense	53,884	49,822	92,261		195,967	Not included
556	System cont & load dispatch	1,804,218	1,424,155	1,306,262		4,534,635	Not included
557	Other expenses	887,919	709,648	1,274,558		2,872,125	Not included
560	Operation Supervision & Engineering	1,697,750	591,552	371,504		2,660,806	100% included
561.1	Load Dispatching - Reliability	(1,530)	433	-		(1,097)	100% included
561.2	Load Dispatch - Monitor & Operate Transmission Sy:	(3,864)	1,036	72,947		70,119	100% included
561.3	Load Dispatch - Transmission Service & Scheduling	(712)	1,164	-		452	100% included
561.5	Reliability, Planning and Standards	44,359	5,206	-		49,565	100% included
566	Miscellaneous transmission expenses	1,402,646	1,455,412	2,433,579		5,291,637	100% included
568	Maintenance Supervision & Engineering	7,191	6,115	33,177		46,483	100% included
569	Maint of structures	-	302	-		302	100% included
569.2	Maintenance of Computer Softw are	-	(1)	8,225		8,224	100% included
570	Maintenance of station equipment	(29,861)	150,721	9,890		130,750	100% included
571	Maintenance of overhead lines	501,340	373,146	384,102		1,258,588	100% included
572	Maintenance of underground lines	111	-	-		111	100% included
573	Maintenance of miscellaneous transmission plant	(1,098)	(673)	-		(1,771)	100% included
580	Operation Supervision & Engineering	413,542	488,161	415,291		1,316,994	Not included
581	Load dispatching	167,051	101,668	89,535		358,254	Not included
582	Station expenses	4	1,885	73,231		75,120	Not included
583	Overhead line expenses	3	1,135	218		1,356	Not included
584	Underground line expenses	430	24,259	6		24,695	Not included
586	Meter expenses	841,048	197,670	5		1,038,723	Not included
587	Customer installations expenses	376,994	168,410	341,539		886,943	Not included
588	Miscellaneous distribution expenses	2,028,683	1,653,974	2,816,435		6,499,092	Not included
589	Rents	50	(2)	4		52	Not included
590	Maintenance Supervision & Engineering	357,611	6,104	140,943		504,658	Not included
591	Maintain structures	-	84	-		84	Not included
592	Maintain equipment	154,570	177,026	279,619		611,215	Not included
593	Maintain overhead lines	575,451	592,352	1,323,273	579	2,491,655	Not included
594	Maintain underground line	304	562	12		878	Not included
595	Maintain line transformers	31	74	(2,685)		(2,580)	Not included
596	Maintain street lighting & signal systems	246	128	2		376	Not included
597	Maintain meters	380,571	2	-		380,573	Not included
598	Maintain distribution plant	19,754	21,032	37,107		77,893	Not included
813	Other gas supply expenses	269,144	-	-		269,144	Not included
859	Other transmission expenses	108	-	-		108	Not included
878	Meter & house regulator expense	610,854	-	-		610,854	Not included
880	Other distribution expenses	53,757	-	-		53,757	Not included
888	Maintenance of compressor station equipment	3	-	-		3	Not included
893	Maintenance of meters & house regulators	452,515	-	-		452,515	Not included
902	Uncollectable Accounts	103,292	291,165	-		394,457	Not included
903	Customer records and collection expenses	38,177,659	38,283,600	29,193,537		105,654,796	Not included
904	Uncollectable Accounts	150	140	258		548	Not included
907	Supervision - Customer Svc & Information	-	85,509	-		85,509	Not included
908	Customer assistance expenses	1,374,758	267,258	215,364		1,857,380	Not included
909	Informational & instructional advertising	117,558	108,708	201,264		427,530	Not included
923	Outside services employed	41,918,164	39,433,285	68,207,833	3,286	149,562,568	Wage & Salary Factor
924	Property insurance	(6,581)	(5,927)	(11,140)		(23,648)	Net Plant Factor
925	Injuries & damages	326	299	557		1,182	Wage & Salary Factor
928	Regulatory commission expenses	973,766	400,118	2,274,057		3,647,941	Direct transmission Only
930.1	General ad expenses	355,219	329,987	609,435		1,294,641	Direct transmission Only
930.2	Miscellaneous general expenses	561,847	581,315	1,073,612		2,216,774	Wage & Salary Factor
935	Maintenance of general plant	4	-	-		4	Wage & Salary Factor
		120,505,027	**108,464,539**	**156,860,379**	**9,577,683**	**395,407,628**	

* Primarily represents vehicle and facility cost that are charged to the utilities and included within the clearing account. The cost in the utility clearing accounts get distributed to various FERC accounts during the utility overhead allocation process.

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)

140,950,282 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	-				9.5	-	-	-	-	-	-	-	-	
Apr	2,941,169				8.5	24,999,937	-	-	-	2,083,328	-	-	-	
May	21,088,727				7.5	158,165,453	-	-	-	13,180,454	-	-	-	
Jun	-				6.5	-	-	-	-	-	-	-	-	
Jul	94,340,615				5.5	518,873,383	-	-	-	43,239,449	-	-	-	
Aug	6,173,290				4.5	27,779,805	-	-	-	2,314,984	-	-	-	
Sep					3.5	-	-	-	-	-	-	-	-	
Oct					2.5	-	-	-	-	-	-	-	-	
Nov					1.5	-	-	-	-	-	-	-	-	
Dec					0.5	-	-	-	-	-	-	-	-	
Total	124,543,801	-	-	-		729,818,577	-	-	-	60,818,215	-	-	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										60,818,215	-	-	-	
								Input to Line 21 of Appendix A		60,818,215	-		-	60,818,215
								Input to Line 43a of Appendix A				-		-
								Month In Service or Month for CWIP		6.14	#DIV/0!	#DIV/0!	#DIV/0!	

3 April Year 2 TO adds weighted Cap Adds to plant in service in Formula

$ 60,818,215 Input to Formula Line 21

4 May Year 2 Post results of Step 3 on PJM web site

145,555,921 — 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)

$ 145,555,921

6 April Year 3 TO populates the formula with Year 2 data from FERC Form 1 for Year 2 (e.g., 2005)

144,298,756 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 $ 190,815,797 Input to Formula Line 20

Add weighted Cap Adds actually placed in service in Year 2

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
	Monthly Additions	Monthly Additions	Monthly Additions	Monthly Additions		Other Plant In Service	Other Plant In Service	MAPP CWIP	MAPP In Service	Other Plant In Service	Other Plant In Service	MAPP CWIP	MAPP In Service	
	Other Plant In Service	Other Plant In Service	MAPP CWIP	MAPP In Service	Weighting	Amount (A x E)	Amount (B x E)	Amount (C x E)	Amount (D x E)	(F / 12)	(G / 12)	(H / 12)	(I / 12)	
Jan	2,011,085				11.5	23,127,477	-	-	-	1,927,290	-	-	-	
Feb	1,743,374				10.5	18,305,423	-	-	-	1,525,452	-	-	-	
Mar	2,153,368				9.5	20,456,999	-	-	-	1,704,750	-	-	-	
Apr	18,629,367				8.5	158,349,618	-	-	-	13,195,801	-	-	-	
May	121,976,221				7.5	914,821,657	-	-	-	76,235,138	-	-	-	
Jun	21,212,990				6.5	137,884,433	-	-	-	11,490,369	-	-	-	
Jul	1,326,934				5.5	7,298,135	-	-	-	608,178	-	-	-	
Aug	818,623				4.5	3,683,804	-	-	-	306,984	-	-	-	
Sep	1,140,060				3.5	3,990,210	-	-	-	332,518	-	-	-	
Oct	6,093,547				2.5	15,233,867	-	-	-	1,269,489	-	-	-	
Nov	9,993,786				1.5	14,990,679	-	-	-	1,249,223	-	-	-	
Dec	3,716,444				0.5	1,858,222	-	-	-	154,852	-	-	-	
Total	190,815,797	-	-	-		1,320,000,523	-	-	-	110,000,044	-	-	-	
New Transmission Plant Additions and CWIP (weighted by months in service)										110,000,044	-	-	-	
								Input to Line 21 of Appendix A		110,000,044	-		-	110,000,044
								Input to Line 43a of Appendix A				-		-
								Month In Service or Month for CWIP		5.08	#DIV/0!	#DIV/0!	#DIV/0!	

137,873,229 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)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	
	Monthly Additions	Monthly Additions	Monthly Additions	Monthly Additions		Other Plant In Service	Other Plant In Service	MAPP CWIP	MAPP In Service	Other Plant In Service	Other Plant In Service	MAPP CWIP	MAPP In Service	
	Other Plant In Service	Other Plant In Service	MAPP CWIP	MAPP In Service	Weighting	Amount (A x E)	Amount (B x E)	Amount (C x E)	Amount (D x E)	(F / 12)	(G / 12)	(H / 12)	(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)										-	-	-	-	
144,221,403								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		
137,873,229	-	139,682,567	=	(1,809,338)

Interest on Amount of Refunds or Surcharges

Interest rate pursuant to 35.19a for March of 0.4200% updated

Month	Yr	1/12 of Step 9	Interest rate for March of the Current Yr	Months	Interest	Surcharge (Refund) Owed
Jun	Year 1	(150,778)	0.4200%	11.5	(7,283)	(158,061)
Jul	Year 1	(150,778)	0.4200%	10.5	(6,649)	(157,427)
Aug	Year 1	(150,778)	0.4200%	9.5	(6,016)	(156,794)
Sep	Year 1	(150,778)	0.4200%	8.5	(5,383)	(156,161)
Oct	Year 1	(150,778)	0.4200%	7.5	(4,750)	(155,528)
Nov	Year 1	(150,778)	0.4200%	6.5	(4,116)	(154,894)
Dec	Year 1	(150,778)	0.4200%	5.5	(3,483)	(154,261)
Jan	Year 2	(150,778)	0.4200%	4.5	(2,850)	(153,628)
Feb	Year 2	(150,778)	0.4200%	3.5	(2,216)	(152,995)
Mar	Year 2	(150,778)	0.4200%	2.5	(1,583)	(152,361)
Apr	Year 2	(150,778)	0.4200%	1.5	(950)	(151,728)
May	Year 2	(150,778)	0.4200%	0.5	(317)	(151,095)
Total		(1,809,338)				(1,854,933)

		Balance	Interest rate from above	Amortization over Rate Year	Balance
Jun	Year 2	(1,854,933)	0.4200%	(158,830)	(1,703,894)
Jul	Year 2	(1,703,894)	0.4200%	(158,830)	(1,552,220)
Aug	Year 2	(1,552,220)	0.4200%	(158,830)	(1,399,909)
Sep	Year 2	(1,399,909)	0.4200%	(158,830)	(1,246,959)
Oct	Year 2	(1,246,959)	0.4200%	(158,830)	(1,093,366)
Nov	Year 2	(1,093,366)	0.4200%	(158,830)	(939,128)
Dec	Year 2	(939,128)	0.4200%	(158,830)	(784,242)
Jan	Year 3	(784,242)	0.4200%	(158,830)	(628,705)
Feb	Year 3	(628,705)	0.4200%	(158,830)	(472,516)
Mar	Year 3	(472,516)	0.4200%	(158,830)	(315,670)
Apr	Year 3	(315,670)	0.4200%	(158,830)	(158,166)
May	Year 3	(158,166)	0.4200%	(158,830)	(0)
Total with interest				(1,905,962)	

The difference between the Reconciliation in Step 7 and the forecast in Prior Year with interest	(1,905,962)
One Time True-Up for FAS 109 Incurred Prior to Settlement Docket No. ER19-5 et al.	(17,239,803)
Total true-up amount	(19,145,765)

Rev Req based on Year 2 data with estimated Cap Adds and CWIP for Year 3 (Step 8)	$ 144,221,403
Revenue Requirement for Year 3	125,075,638

10 May Year 3 ılts of Step 9 on PJM web site

$ 125,075,638

11 June Year 3 ır the Rate Year 2 (e.g., June 1, 2006 - May 31, 2007)

$ 125,075,638

Atlantic City Electric Company

Attachment 7 - Transmission Enhancement Charge Worksheet

Line					
1	New Plant Carrying Charge				
2	**Fixed Charge Rate (FCR) if not a CIAC**				
3			Formula Line		
4		A	160	Net Plant Carrying Charge without Depreciation	8.5569%
5		B	167	Net Plant Carrying Charge per 100 Basis Point increase in ROE without Depreciation	9.0778%
6		C		Line B less Line A	0.5208%
7	**FCR if a CIAC**				
8		D	161	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	2.9140%

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**

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		8.5569%	0.781%	8.5569%	8.5569%
17	Line 6 times line 15 divided by 100 basis points	FCR for This Project		9.3382%		8.5569%	8.5569%
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	Mickelton Depreciation	Mickelton Ending	Mickelton Revenue	Monroe Beginning	Monroe Depreciation	Monroe Ending	Monroe Revenue	Union-Corson Beginning	Union-Corson Depreciation	Union-Corson Ending	Union-Corson Revenue
43	Base FCR	2019	3,536,967	138,705	3,398,262	470,807	5,739,737	225,088	5,514,650	764,018	9,703,499	392,061	9,311,439	1,302,040
44	W Increased ROE	2019	3,536,967	138,705	3,398,262	497,580	5,739,737	225,088	5,514,650	764,018	9,703,499	392,061	9,311,439	1,302,040
45	Base FCR	2020	3,398,262	138,705	3,259,557	417,623	5,514,650	225,088	5,289,562	677,713	9,311,439	392,061	8,919,378	1,155,287
46	W Increased ROE	2020	3,398,262	138,705	3,259,557	443,088	5,514,650	225,088	5,289,562	677,713	9,311,439	392,061	8,919,378	1,155,287
47	Base FCR	2021	3,259,557	138,705	3,120,853	405,754	5,289,562	225,088	5,064,474	658,452	8,919,378	392,061	8,527,317	1,121,739
48	W Increased ROE	2021	3,259,557	138,705	3,120,853	430,135	5,289,562	225,088	5,064,474	658,452	8,919,378	392,061	8,527,317	1,121,739
49	Base FCR	2022	3,120,853	138,705	2,982,148	393,886	5,064,474	225,088	4,839,386	639,192	8,527,317	392,061	8,135,257	1,088,190
50	W Increased ROE	2022	3,120,853	138,705	2,982,148	417,183	5,064,474	225,088	4,839,386	639,192	8,527,317	392,061	8,135,257	1,088,190
51	Base FCR	2023	2,982,148	138,705	2,843,444	382,017	4,839,386	225,088	4,614,299	619,931	8,135,257	392,061	7,743,196	1,054,642
52	W Increased ROE	2023	2,982,148	138,705	2,843,444	404,230	4,839,386	225,088	4,614,299	619,931	8,135,257	392,061	7,743,196	1,054,642
53	Base FCR	2024	2,843,444	138,705	2,704,739	370,148	4,614,299	225,088	4,389,211	600,670	7,743,196	392,061	7,351,136	1,021,094
54	W Increased ROE	2024	2,843,444	138,705	2,704,739	391,278	4,614,299	225,088	4,389,211	600,670	7,743,196	392,061	7,351,136	1,021,094
55	Base FCR	2025	2,704,739	138,705	2,566,035	358,279	4,389,211	225,088	4,164,123	581,410	7,351,136	392,061	6,959,075	987,545
56	W Increased ROE	2025	2,704,739	138,705	2,566,035	378,325	4,389,211	225,088	4,164,123	581,410	7,351,136	392,061	6,959,075	987,545
57	Base FCR	2026	2,566,035	138,705	2,427,330	346,410	4,164,123	225,088	3,939,035	562,149	6,959,075	392,061	6,567,015	953,997
58	W Increased ROE	2026	2,566,035	138,705	2,427,330	365,373	4,164,123	225,088	3,939,035	562,149	6,959,075	392,061	6,567,015	953,997
59	Base FCR	2027	2,427,330	138,705	2,288,625	334,541	3,939,035	225,088	3,713,948	542,888	6,567,015	392,061	6,174,954	920,448
60	W Increased ROE	2027		138,705	(138,705)	125,752	3,939,035	225,088	3,713,948	542,888	6,567,015	392,061	6,174,954	920,448
61		....		....	.....	....	....	....	.....	....	....	....	.....	....
62		....	....	.....	.....	....	....	.....	.....	....	....	.....	.....	....
63														

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%.

B0210 Orchard-500kV			
Yes			
35			
No			
150			
8.5569%			
9.3382%			
26,046,638			
744,190			
7.00			
Beginning	Depreciation	Ending	Revenue
18,294,662	744,190	17,550,473	2,459,345
18,294,662	744,190	17,550,473	2,597,617
17,550,473	744,190	16,806,283	2,182,295
17,550,473	744,190	16,806,283	2,313,589
16,806,283	744,190	16,062,093	2,118,615
16,806,283	744,190	16,062,093	2,244,095
16,062,093	744,190	15,317,904	2,054,935
16,062,093	744,190	15,317,904	2,174,601
15,317,904	744,190	14,573,714	1,991,255
15,317,904	744,190	14,573,714	2,105,108
14,573,714	744,190	13,829,524	1,927,575
14,573,714	744,190	13,829,524	2,035,614
13,829,524	744,190	13,085,335	1,863,895
13,829,524	744,190	13,085,335	1,966,120
13,085,335	744,190	12,341,145	1,800,215
13,085,335	744,190	12,341,145	1,896,627
12,341,145	744,190	11,596,955	1,736,535
12,341,145	744,190	11,596,955	1,827,133
....	....	.....	....
....	.....	.....	....

B0210 Orchard-Below 500kV			
Yes			
35			
No			
150			
8.5569%			
9.3382%			
18,572,212			
530,635			
7			
Beginning	Depreciation	Ending	Revenue
13,044,768	530,635	12,514,133	1,753,603
13,044,768	530,635	12,514,133	1,852,197
12,514,133	530,635	11,983,499	1,556,057
12,514,133	530,635	11,983,499	1,649,674
11,983,499	530,635	11,452,864	1,510,650
11,983,499	530,635	11,452,864	1,600,122
11,452,864	530,635	10,922,229	1,465,244
11,452,864	530,635	10,922,229	1,550,571
10,922,229	530,635	10,391,595	1,419,838
10,922,229	530,635	10,391,595	1,501,019
10,391,595	530,635	9,860,960	1,374,432
10,391,595	530,635	9,860,960	1,451,468
9,860,960	530,635	9,330,326	1,329,026
9,860,960	530,635	9,330,326	1,401,916
9,330,326	530,635	8,799,691	1,283,620
9,330,326	530,635	8,799,691	1,352,365
8,799,691	530,635	8,269,056	1,238,214
8,799,691	530,635	8,269,056	1,302,813
....	....	.....	....
....	.....	.....	....

B0277 Cumberland Sub:2nd Xfmr			
No			
35			
No			
150			
8.5569%			
9.3382%			
6,759,777			
193,136			
2			
Beginning	Depreciation	Ending	Revenue
5,053,738	193,136	4,860,602	668,148
5,053,738	193,136	4,860,602	706,443
4,860,602	193,136	4,667,465	592,529
4,860,602	193,136	4,667,465	628,992
4,667,465	193,136	4,474,329	576,003
4,667,465	193,136	4,474,329	610,957
4,474,329	193,136	4,281,192	559,476
4,474,329	193,136	4,281,192	592,921
4,281,192	193,136	4,088,056	542,949
4,281,192	193,136	4,088,056	574,886
4,088,056	193,136	3,894,919	526,423
4,088,056	193,136	3,894,919	556,851
3,894,919	193,136	3,701,783	509,896
3,894,919	193,136	3,701,783	538,815
3,701,783	193,136	3,508,646	493,370
3,701,783	193,136	3,508,646	520,780
3,508,646	193,136	3,315,510	476,843
3,508,646	193,136	3,315,510	502,744
....	....	.....	....
....	.....	.....	....

B1398.5 Reconductor Mickleton - Depford - 230 Kv line			
Yes			
35			
No			
0			
8.5569%			
8.5569%			
4,045,398			
115,583			
5			
Beginning	Depreciation	Ending	Revenue
3,711,571	115,583	3,595,988	467,008
3,711,571	115,583	3,595,988	467,008
3,595,988	115,583	3,480,405	413,399
3,595,988	115,583	3,480,405	413,399
3,480,405	115,583	3,364,823	403,509
3,480,405	115,583	3,364,823	403,509
3,364,823	115,583	3,249,240	393,619
3,364,823	115,583	3,249,240	393,619
3,249,240	115,583	3,133,657	383,728
3,249,240	115,583	3,133,657	383,728
3,133,657	115,583	3,018,074	373,838
3,133,657	115,583	3,018,074	373,838
3,018,074	115,583	2,902,491	363,948
3,018,074	115,583	2,902,491	363,948
2,902,491	115,583	2,786,909	354,057
2,902,491	115,583	2,786,909	354,057
2,786,909	115,583	2,671,326	344,167
2,786,909	115,583	2,671,326	344,167
....	....	.....	....
....	.....	.....	....

B1398.3.1 Mickleton Dep	
Yes	
35	
No	
0	
8.5569%	
8.5569%	
13,176,210	
376,463	
5	
Beginning	Depreciation
11,451,929	376,463
11,451,929	376,463
11,075,466	376,463
11,075,466	376,463
10,699,003	376,463
10,699,003	376,463
10,322,539	376,463
10,322,539	376,463
9,946,076	376,463
9,946,076	376,463
9,569,613	376,463
9,569,613	376,463
9,193,150	376,463
9,193,150	376,463
8,816,687	376,463
8,816,687	376,463
8,440,224	376,463
8,440,224	376,463
....	....
....	.....

tford 230kv terminal		B1600 Upgrade Mill T2 138/69 kV Transformer				b0210.1 Orchard-Cumberland - Install second 230kV line				b0212 Corson upgrade 138kV line trap					
		Yes				Yes				Yes					
		35				35				35					
		No				No				No					
		0				0				0					
		8.5569%				8.5569%				8.5569%					
		8.5569%				8.5569%				8.5569%					
		14,841,978				13,000,000				70,000					
		424,057				371,429				2,000					
		6				1				3					
Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue	Beginning	Depreciation	Ending	Revenue		Total
11,075,466	1,458,835	13,799,277	424,057	13,375,221	1,731,177	11,885,714	371,429	11,514,286	1,356,700	48,500	2,000	46,500	5,979		$ 11,074,980
11,075,466	1,458,835	13,799,277	424,057	13,375,221	1,731,177	11,885,714	371,429	11,514,286	1,356,700	48,500	2,000	46,500	5,979		$ 11,376,914
10,699,003	1,291,971	13,375,221	424,057	12,951,164	1,532,281	11,514,286	371,429	11,142,857	1,324,917	46,500	2,000	44,500	5,808		$ 11,149,881
10,699,003	1,291,971	13,375,221	424,057	12,951,164	1,532,281	11,514,286	371,429	11,142,857	1,324,917	46,500	2,000	44,500	5,808		$ 11,436,720
10,322,539	1,259,758	12,951,164	424,057	12,527,107	1,495,995	11,142,857	371,429	10,771,429	1,293,134	44,500	2,000	42,500	5,637		$ 10,849,246
10,322,539	1,259,758	12,951,164	424,057	12,527,107	1,495,995	11,142,857	371,429	10,771,429	1,293,134	44,500	2,000	42,500	5,637		$ 11,123,533
9,946,076	1,227,544	12,527,107	424,057	12,103,051	1,459,709	10,771,429	371,429	10,400,000	1,261,351	42,500	2,000	40,500	5,466		$ 10,548,611
9,946,076	1,227,544	12,527,107	424,057	12,103,051	1,459,709	10,771,429	371,429	10,400,000	1,261,351	42,500	2,000	40,500	5,466		$ 10,810,346
9,569,613	1,195,330	12,103,051	424,057	11,678,994	1,423,422	10,400,000	371,429	10,028,571	1,229,568	40,500	2,000	38,500	5,294		$ 10,247,976
9,569,613	1,195,330	12,103,051	424,057	11,678,994	1,423,422	10,400,000	371,429	10,028,571	1,229,568	40,500	2,000	38,500	5,294		$ 10,497,160
9,193,150	1,163,116	11,678,994	424,057	11,254,938	1,387,136	10,028,571	371,429	9,657,143	1,197,785	38,500	2,000	36,500	5,123		$ 9,947,341
9,193,150	1,163,116	11,678,994	424,057	11,254,938	1,387,136	10,028,571	371,429	9,657,143	1,197,785	38,500	2,000	36,500	5,123		$ 10,183,973
8,816,687	1,130,903	11,254,938	424,057	10,830,881	1,350,850	9,657,143	371,429	9,285,714	1,166,002	36,500	2,000	34,500	4,952		$ 9,646,705
8,816,687	1,130,903	11,254,938	424,057	10,830,881	1,350,850	9,657,143	371,429	9,285,714	1,166,002	36,500	2,000	34,500	4,952		$ 9,870,786
8,440,224	1,098,689	10,830,881	424,057	10,406,825	1,314,563	9,285,714	371,429	8,914,286	1,134,220	34,500	2,000	32,500	4,781		$ 9,346,070
8,440,224	1,098,689	10,830,881	424,057	10,406,825	1,314,563	9,285,714	371,429	8,914,286	1,134,220	34,500	2,000	32,500	4,781		$ 9,557,599
8,063,761	1,066,475	10,406,825	424,057	9,982,768	1,278,277	8,914,286	371,429	8,542,857	1,102,437	32,500	2,000	30,500	4,610		$ 9,045,435
8,063,761	1,066,475	10,406,825	424,057	9,982,768	1,278,277	8,914,286	371,429	8,542,857	1,102,437	32,500	2,000	30,500	4,610		$ 9,017,745
.....	....	....	....	.....	....	....	....	.....	....	....	....	.....	....		
.....	....	....	.....	.....	....	....	.....	.....	....	....	.....	.....	....		
											$ 212,323,652	$ 205,723,471			

Incentive Charged	Revenue Credit	
	$ 11,074,980	
$ 11,376,914		$ 301,934
	$ 11,149,881	
$ 11,436,720		$ 286,839
	$ 10,849,246	
$ 11,123,533		$ 274,287
	$ 10,548,611	
$ 10,810,346		$ 261,735
	$ 10,247,976	
$ 10,497,160		$ 249,184
	$ 9,947,341	
$ 10,183,973		$ 236,632
	$ 9,646,705	
$ 9,870,786		$ 224,081
	$ 9,346,070	
$ 9,557,599		$ 211,529
	$ 9,045,435	
$ 9,017,745		
	$ -	
$ -		

Atlantic City Electric Company

Attachment 8 - Company Exhibit - Securitization Workpaper

Line #		
	Long Term Interest	
101	**Less LTD Interest on Securitization Bonds**	2,579,701
	Capitalization	
112	**Less LTD on Securitization Bonds**	26,383,829

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)

- Attachment 12 (PECO FERC Formula Rate filing)

PECO
An Exelon Company

July 17, 2020

Ms. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E. Room 1A
Washington, DC 20426
Via e-filing

Re: PECO Energy Company
Docket No. ER17-1519
Updated Informational Filing of 2020 Formula Rate Annual Update

Dear Ms. Bose,

PECO Energy Company ("PECO") hereby submits electronically, for informational purposes, this updated Annual Update Information ("Updated Information") pursuant to the Formula Rate Implementation Protocols ("Protocols") of PECO contained in Attachment H-7C of the PJM Interconnection, L.L.C. ("PJM") Open Access Transmission Tariff ("Tariff"). This Updated Information is being submitted consistent with the Federal Energy Regulatory Commission's ("Commission" or "FERC") July 6, 2020 Order ("July 6th Depreciation Order")[1] accepting PECO's Section 205 Formula Rate - Depreciation Rate Revision.[2]

Pursuant to the December 5, 2019 Order in the above-referenced docket,[3] the Rules of Practice and Procedure of FERC, and the Commission-approved Protocols, on May 29, 2020, PECO submitted an informational filing containing its Annual Update and True-Up Adjustments to FERC ("May 29th Informational Filing"). As required by the Protocols, PECO caused the same information to be posted on the PJM website. Per the terms of Section 4.K. of its Protocols, PECO is required to adjust its depreciation and amortization rates in an annual Section 205 filing, which must be submitted no later than March 31st so that the updated depreciation rates can be included in PECO's Annual Update filed no later than May 31st of each year. As the July 6th Depreciation Order was not issued prior to the May 29th Informational Filing, the rates

[1] *PECO Energy Company*, Docket No. ER20-1383-001 (Jul. 6, 2020) (unreported) (accepting PECO amendments to formula rate depreciation and amortization rates, effective May 29, 2020).

[2] In accordance with its Protocols, on March 25, 2020, a revised tariff record to the Tariff was filed by PJM (on behalf of PECO) in Docket No. ER20-1383-000 to adjust the depreciation rates for Accounts 352 through 359 and 390 through 398 and amortization rates for Account 303 in PECO's Formula Rate Template. Prior to Commission action on the March 25th Filing, PECO discovered errors in the calculation of the revised depreciation rates. Therefore, on May 8, 2020, PECO submitted and updated filing that corrected the March 25th filing in Docket No. ER20-1383-001.

[3] *PJM Interconnection, L.L.C.*, 169 FERC ¶ 61,186 (2019).

set forth in the May 29th Informational Filing were based on the 2018 depreciation rates – the rates last approved by the Commission at the time of filing.

In its July 6th Depreciation Order, the Commission accepted PECO's revised depreciation and amortization rates with an effective date of May 29, 2020. Therefore, PECO is submitting this Updated Information incorporating the Commission-approved depreciation and amortization rates. For ease of review, PECO is resubmitting its entire filing package (less the Annual Meeting Notice, as the Annual Meeting was held on July 1, 2020). The following appendices have not changed since their initial submission on May 29th:

- Appendix 1B – Populated Projected Net Revenue Requirement – MDTAC
- Appendix 2B – 2019 True Up Adjustment Calculation – MDTAC
- Appendix 2C – 2018 Actuals – NITS
- Appendix 2D – 2018 Actuals – MDTAC
- Appendix 3 – Additional Workpapers Required by the Protocols

PECO has prepared the Updated Information in a manner consistent with its Protocols, as set forth in Attachment H-7C of the PJM Tariff. Updated Appendices 1A and 1B are the projected net revenue requirements for the Network Integration Transmission Service ("NITS") and Monthly Deferred Tax Adjustment Charge ("MDTAC"), respectively, used by PJM to determine charges for service to the PECO zone during the June 1, 2020 through May 31, 2021 rate period. Updated Appendices 2A and 2B are the True-Up Calculations that provide the formula worksheets that reflect 2019 actuals and support the True-Up Adjustments for NITS and MDTAC, respectively. Updated Appendices 2C and 2D are the calculations that provide the formula worksheets that reflect 2018 actuals for NITS and MDTAC. Updated Appendix 3 is the additional workpapers that, in accordance with Protocols, must be submitted with Annual Update.

Sections II.F and II.G of the Protocols identify certain information that is to be provided in the Annual Update and projected net revenue requirement. This information has not been updated since the May 29th submission, but is being restated below for ease of review:

A. Changes to Formula References to the FERC Form No. 1

In accordance with Section II.F.6 of the Protocols, PECO has identified one change in the Formula References to the FERC Form No. 1.

This change relates to the adjustment of lines associated with the calculation for Land Held for Future Use as a result of line adjustments to the FERC Form No. 1 page 214. Accordingly, the instruction for the calculation on Attachment 4- Rate Base, page 1 of 2, Column f of the Formula Rate has been updated from "214.16,d, 214.17,d, 214.18,d, 214.20,d, 214.23,d, and 214.25,d for end of year, records for other months" to "to include the appropriate FERC Form No. 1 references."

B. Material Adjustments to the FERC Form No. 1

In accordance with Section II.F.7 of the Protocols, PECO confirms that the Annual Update Information contains no material adjustments to FERC Form No 1.[4, 5]

C. Affiliate Cost Allocation

In accordance with Section II.F.8 of the Protocols, PECO is hereby providing information about affiliate cost allocation. Exelon Business Services Company ("EBSC") offers a range of services to PECO and other affiliated members of the Exelon family of companies. Under the terms of the General Services Agreement ("GSA") between PECO and the EBSC, which was approved in the PECO/Unicom merger proceeding with the Pennsylvania Public Utility Commission ("PA PUC") at Docket No. A-110550F0147, the services furnished by the EBSC to PECO are to be billed at the EBSC's cost. Direct charges are made for services where possible. Otherwise, costs are allocated to affiliates of EBSC on the basis of the allocation factors/methodologies identified in the attachment to the GSA, which were previously reviewed and approved by the U.S. Securities and Exchange Commission ("SEC"). Costs distributed to PECO are recorded to the appropriate common Administrative & General expense accounts on PECO's books. No changes to cost allocation methodologies were made from the prior year. Refer to pages 429 and 429.1 of the FERC Form No. 1 for the magnitude of such costs that have been allocated or directly assigned to PECO and each affiliate by service category or function.

D. Accounting Changes

In accordance with Sections II.F.9 and II.G.5 of the Protocols, PECO confirms that any accounting changes are discussed in applicable disclosure statements filed with the SEC or contained within PECO's FERC Form No. 1.

E. Items Included on a Non-Historical Cost Basis

In accordance with Sections II.F.10 and II.G.6 of the Protocols, PECO has identified the following item included in the projected net revenue requirement that is on a non-historical cost basis:

(1) Other Post-Employment Benefits ("OPEB"). PECO has made no change to OPEB costs reflected in the formula.

[4] "Tower Rentals and Land Leasing – Transmission" revenue referenced within the footnote for schedule page 300, line no. 19, column b of the 2019 FERC Form 1 was adjusted to include a $1,328,684 million increase in rental revenue. See Appendix 1 and Appendix 2A, Attachment 5A – Revenue Credits, line 24c.

[5] "Land Held for Future Use" balance has been reduced by $334,450 to exclude the asset retirement costs for the land.

F. Reorganization or Merger Transaction

In accordance with Sections II.F.11 and II.G.7 of the Protocols, PECO confirms there are no reorganization or merger transactions.

G. FERC Audit Refund

In accordance with Commission's November 21, 2019 Letter Order in Docket No. PA 18-3-000, PECO has included in its 2018 actuals a one-time refund of $271.41. In Appendix 2C, Attachment 4E COA, page 1 of 2, Line 3, PECO included an exclusion of PECO total merger cost of $2,746.89, of which 9.88% (W&S allocator to transmission for 2018 actuals) or $271.41 was allocated to PECO transmission to be excluded from the formula rates.

Thank you for your attention to this informational filing. Please direct any questions to the undersigned.

Very truly yours,

/s/ Jack R. Garfinkle
Associate General Counsel

Enclosures

cc: All parties on Service Lists in Docket No. ER17-1519

Appendix 1A
Populated Projected Net Revenue Requirement – NITS

ATTACHMENT H-7A
FORMULA RATE TEMPLATE

Attachment 12 PECO Formula Rate Updated

Attachment H-7
Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data
PECO Energy Company

For the 12 months ended 12/31/2020

Line No.	(1)	(2)	(3)	(4)		(5) Allocated Amount
1	GROSS REVENUE REQUIREMENT	(page 3, line 48)				198,830,583
2a	Additional Annual Refund (from 2018 to 2021)	Attachment 1, line 17, col 15a				850,000
			Total	Allocator		
2	REVENUE CREDITS	Attachment 5A, line 15	10,105,185	TP	100.00%	10,105,185
3	NET REVENUE REQUIREMENT	(line 1 minus lines 2 and 2a)				187,875,399
4	REGIONAL NET REVENUE REQUIREMENT	Attachment 1, line 18, col. 14 - Attachment 1, line 17a, col. 14				30,435,447
5	Regional True-up Adjustment with Interest	Attachment 1, line 18, col. 15 - Attachment 1, line 17a, col. 15				(4,696,184)
6	REGIONAL NET REVENUE REQUIREMENT with TRUE-UP	Attachment 1, line 18, col. 16 - Attachment 1, line 17a, col. 16				25,739,263
7	ZONAL NET REVENUE REQUIREMENT	Attachment 1, line 17a, col. 14 less line 2				157,439,952
8	Zonal True-up Adjustment with Interest	Attachment 1, line 17a, col. 15				(22,402,307)
9	ZONAL NET REVENUE REQUIREMENT with TRUE-UP	Line 7 + Line 8				135,037,645
10	Competitive Bid Concessions	Attachment 1, line 18, col. 13				-
11	Zonal Load	1 CP from PJM in MW				8,428
12	Network Integration Transmission Service rate for PECO Zone	(line 9/11)				$16,022

Attachment 12 PECO Formula Rate Updated

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data
PECO Energy Company

For the 12 months ended 12/31/2020

Line No.	(1) RATE BASE:	(2) Source	(3) Company Total	Allocator	(4)	(5) Transmission (Col 3 times Col 4)
	GROSS PLANT IN SERVICE (Notes U and R)					
1	Production	205.46.g for end of year, records for other months	-	NA		-
2	Transmission	Attachment 4, Line 14, Col. (b)	1,723,143,701	TP	100.00%	1,723,143,701
3	Distribution	207.75.g for end of year, records for other months	7,008,706,132	NA	0.00%	-
4	General	Attachment 4, Line 14, Col. (c)	286,311,836	W/S	9.45%	27,053,850
5	Intangible	Attachment 4D, Line 19, Col. (s) and Line 21, Col. (s)	194,590,045	DA		20,263,800
6	Common	Attachment 4, Line 14, Col. (d)	723,522,758	W/S	9.45%	68,366,285
7	Costs To Achieve	(enter negative) Attach. 4E, Line 25, Col. (x)	(3,185,568)	W/S	9.45%	(301,007)
8	TOTAL GROSS PLANT	(Sum of Lines 1 through 7)	9,933,088,904	GP=	18.51%	1,838,526,629
9	ACCUMULATED DEPRECIATION (Notes U and R)					
10	Production	219.20-24.c for end of year, records for other months	-	NA		-
11	Transmission	Attachment 8, Page 3, Line 10, Col. (E)	535,112,730	TP	100.00%	535,112,730
12	Distribution	219.26.c for end of year, records for other months	1,859,694,491	NA	0.00%	-
13	General	Attachment 8, Page 3, Line 11, Col. (E)	92,316,071	W/S	9.45%	8,723,025
14	Intangible	Attachment 8, Page 3, Line 16, Col. (E) and Col. (G)	139,223,656	DA		16,141,388
15	Common	Attachment 8, Page 3, Line 12, Col. (E)	321,189,525	W/S	9.45%	30,349,473
16	Costs To Achieve	(enter negative) Attach. 4E, Line 39, Col. (x)	(1,681,931)	W/S	9.45%	(158,927)
17	TOTAL ACCUM. DEPRECIATION	(Sum of Lines 10 through 16)	2,945,854,543			590,167,689
18	NET PLANT IN SERVICE					
19	Production	(line 1 minus line 10)	-			-
20	Transmission	(line 2 minus line 11)	1,188,030,970			1,188,030,970
21	Distribution	(line 3 minus line 12)	5,149,011,640			-
22	General	(line 4 minus line 13)	193,995,765			18,330,826
23	Intangible	(line 5 minus line 14)	55,366,389			4,122,413
24	Common	(line 6 minus line 15)	402,333,233			38,016,812
25	Costs To Achieve	(line 7 minus line 16)	(1,503,637)			(142,080)
26	TOTAL NET PLANT	(Sum of Lines 19 through 25)	6,987,234,361	NP=	17.87%	1,248,358,941
27	ADJUSTMENTS TO RATE BASE (Note R)					
28	Account No. 281 (enter negative)	Attachment 4, Line 28, Col. (d) (Notes B and X)	Zero	NA	zero	-
29	Account No. 282 (enter negative)	Attachment 4A, Line 28, Col. (e) (Notes B and X)	(211,876,798)	TP	100.00%	(211,876,798)
30	Account No. 283 (enter negative)	Attachment 4A, Line 28, Col. (f) (Notes B and X)	(10,877,541)	TP	100.00%	(10,877,541)
31	Account No. 190	Attachment 4A, Line 28, Col. (g) (Notes B and X)	14,605,421	TP	100.00%	14,605,421
31a	Unamortized EDIT Balance - Protected Property (enter negative)	Attachment 9 - EDIT, Line 22, Col. (n)	(79,502,510)	TP	100.00%	(79,502,510)
31b	Unamortized EDIT Balance - Non-Protected Property (enter negative)	Attachment 9 - EDIT, Line 23, Col. (n)	(13,327,933)	TP	100.00%	(13,327,933)
31c	Unamortized EDIT Balance - Non-Protected, Non-Property (enter negative)	Attachment 9 - EDIT, Line 26, Col. (n)	182,013	TP	100.00%	182,013
32	Account No. 255 (enter negative)	Attachment 4, Line 28, Col. (h) (Notes B and X)	-	TP	100.00%	-
33	Unfunded Reserves (enter negative)	Attachment 4, Line 31, Col. (h) (Note Y)	(5,754,589)	DA	100.00%	(5,754,589)
34	CWIP	Attachment 4, Line 14, Col. (e)	-	DA	100.00%	-
35	Pension Asset	Attachment 4, Line 28, Col. (i)	27,745,514	DA	100.00%	27,745,514
36	Unamortized Regulatory Asset	Attachment 4, Line 28, Col. (b) (Note T)	-	DA	100.00%	-
37	Unamortized Abandoned Plant	Attachment 4, Line 28, Col. (c) (Note S)	-	DA	100.00%	-
38	Outstanding Network Credits	From PJM	-	DA	100.00%	-
39	Less Accum. Deprec. associated with Facilities with Outstanding Network Credits	From PJM	-	DA	100.00%	-
40	TOTAL ADJUSTMENTS	(Sum of Lines 28 through 39)	(278,806,423)			(278,806,423)
41	LAND HELD FOR FUTURE USE	Attachment 4, Line 14, Col. (f) (Note C)	4,782,367	TP	100.00%	4,782,367
42	WORKING CAPITAL	(Note D)				
43	CWC	1/8*(Page 3, Line 12 minus Page 3, Line 7)	27,639,173			8,270,384
44	Materials & Supplies	Attachment 4, Line 14, Col. (g)	10,128,797	TP	100.00%	10,128,797
45	Prepayments (Account 165)	Attachment 4, Line 14, Col. (h)	1,670,294	DA	100.00%	1,670,294
46	TOTAL WORKING CAPITAL	(Sum of Lines 43 through 45)	39,438,264			20,069,476
47	RATE BASE	(Sum of Lines 26, 40, 41 & 46)	6,752,648,569			994,404,360

Attachment 12 PECO Formula Rate Updated

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data
PECO Energy Company

For the 12 months ended 12/31/2020

Line No.	(1)	(2) Source	(3) Company Total	Allocator	(4)	(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	Attachment 5, Line 1, Col. (a)	116,080,855	TP	100.00%	116,080,855
2	Less Account 566 (Misc Trans Expense) (enter negative)	Attachment 5, Line 1, Col. (b)	(10,863,927)	TP	100.00%	(10,863,927)
3	Less Account 565 (enter negative)	Attachment 5, Line 1, Col. (c)	-	TP	100.00%	-
4	Less Accounts 561.4 and 561.8 (enter negative)	Attachment 5, Line 1, Col. (d)	(65,204,955)	TP	100.00%	(65,204,955)
5	A&G	Attachment 5B, Line 15, Col. (a) and Line 18, Col. (e)	170,353,503	DA		15,298,139
6	Account 566					
7	Amortization of Regulatory Asset	(Note T) Attachment 5, Line 1, Col. (e)	-	DA	100.00%	-
8	Miscellaneous Transmission Expense (less amortization of regulatory asset)	Attachment 5, Line 1, Col .(f)	10,863,927	TP	100.00%	10,863,927
9	Total Account 566	(Line 7 plus Line 8) Ties to 321.97.b	10,863,927			10,863,927
10	PBOP Adjustment	Attachment 7, line 3, Col. (d)	(108,275)	W/S	9.45%	(10,231)
11	Less O&M Cost to Achieve Included in O&M Above (enter negative)	Attachment 4E, Line 11, Col. (x)	(7,746)	W/S	9.45%	(732)
12	TOTAL O&M	(Sum of Lines 1 to 5, 9, 10 and 11)	221,113,382			66,163,076
13	DEPRECIATION EXPENSE (Note U)					
14	Transmission	Attachment 5, Line 1, Col. (g)	26,801,531	TP	100.00%	26,801,531
15	General	Attachment 5, Line 2, Col. (a)	18,971,738	W/S	9.45%	1,792,656
16	Intangible - Transmission	Attachment 5, Line 1, Col. (i)	5,120,743	TP	100.00%	5,120,743
16a	Intangible - General	Attachment 5, Line 1, Col. (j)	4,026,335	W/S	9.45%	380,452
16b	Intangible - Distribution	Attachment 5, Line 1, Col. (k)	11,053,897	NA	zero	-
17	Common - Electric	Attachment 5, Line 1, Col. (h)	32,943,973	W/S	9.45%	3,112,904
18	Common Depreciation Expense Related to Costs To Achieve	(enter negative) Attachment 4E, Line 66, Col (x)	(699,484)	W/S	9.45%	(66,095)
19	Amortization of Abandoned Plant	(Note S) Attachment 5, Line 2, Col. (b)	-	DA	100.00%	-
20	TOTAL DEPRECIATION	(Sum of Lines 14 through 19)	98,218,732			37,142,191
21	TAXES OTHER THAN INCOME TAXES	(Note F)				
22	LABOR RELATED					
23	Payroll	Attachment 5, Line 2, Col. (c)	12,308,308	W/S	9.45%	1,163,023
24	Labor Related Taxes to be Excluded	Attachment 5, Line 2, Col. (d)	-	W/S	9.45%	-
25	PLANT RELATED					
26	Property	Attachment 5, Line 2, Col. (e)	12,835,970	GP	18.51%	2,375,824
27	Excluded Taxes Per Attchment 5C Line 5	Attachment 5, Line 2, Col. (f)	132,585,408	NA	zero	-
28	Other	Attachment 5, Line 2, Col. (g)	450,022	GP	18.51%	83,295
29	Plant Related Taxes to be Excluded	Attachment 5, Line 2, Col. (h)	-	GP	18.51%	-
30	TOTAL OTHER TAXES	(Sum of Lines 23 through 29)	158,179,708			3,622,142
31	INTEREST ON NETWORK CREDITS	From PJM	-	DA	100.00%	-
32	INCOME TAXES	(Note G)				
33	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)}	WCLTD = Page 4, Line 19	0.2889			
34	CIT=(T/1-T) * (1-(WCLTD/R)) =	R = Page 4, Line 15	0.3064			
35	FIT & SIT & P	(Note G)				
36						
37	1 / (1 - T) = (T from line 33)		1.4063			
38	Amortized Investment Tax Credit (enter negative)	Attachment 5, Line 2, Col. (i)	(2,976)			
39	Excess Deferred Income Taxes (enter negative)	Attachment 5, Line 2, Col. (j)	(3,250,820)			
40	Tax Effect of Permanent Differences	Attachment 5, Line 2, Col. (k) (Note W)	282,655			
41	Income Tax Calculation	(Line 34 times Line 47)	154,509,159	NA		22,753,232
42	ITC adjustment	(Line 37 times Line 38)	(4,186)	TP	100.00%	(4,186)
43	Excess Deferred Income Tax Adjustment	(Line 37 times Line 39)	(4,571,672)	TP	100.00%	(4,571,672)
44	Permanent Differences Tax Adjustment	(Line 37 times Line 40)	397,502	TP	100.00%	397,502
45	Total Income Taxes	(Sum of Lines 41 through 44)	150,330,803			18,574,876
46	RETURN					
47	Rate Base times Return	(Page 2, Line 47 times Page 4, Line 18)	504,222,872	NA		74,252,557
48a	Net Pension Asset ATRR Discount (enter negative)	Attachment 10, Line 9	(924,259)	DA	100.00%	(924,259)
48	REVENUE REQUIREMENT	(Sum of Lines 12, 20, 30, 31, 45, 47)	1,131,141,239			198,830,583

Attachment 12 PECO Formula Rate Updated

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data
PECO Energy Company

For the 12 months ended 12/31/2020

SUPPORTING CALCULATIONS AND NOTES

Line No.	(1)	(2)	(3) $	(3)	(4)		(5)	
	TRANSMISSION PLANT INCLUDED IN ISO RATES							
1	Total Transmission plant	(Page 2, Line 2, Column 3)					1,723,143,701	
2	Less Transmission plant excluded from PJM rates	(Note H)					-	
3	Less Transmission plant included in OATT Ancillary Services	(Note I)					-	
4	Transmission plant included in PJM rates	(Line 1 minus Lines 2 & 3)					1,723,143,701	
5	Percentage of Transmission plant included in PJM Rates	(Line 4 divided by Line 1)				TP=	100.00%	
6	WAGES & SALARY ALLOCATOR (W&S)							
		Form 1 Reference	$	TP	Allocation			
7	Electric Production	354.20.b	-	0.0%	-			
8	Electric Transmission	354.21.b	12,935,717	100.0%	12,935,717			
9	Electric Distribution	354.23.b	91,501,226	0.0%	-		W&S Allocator	
10	Electric Other	354.24,25,26.b	32,462,198	0.0%	-		($ / Allocation)	
11	Total (W& S Allocator is 1 if lines 7-10 are zero)	(Sum of Lines 7 through 10)	136,899,141		12,935,717	=	9.45%	= WS
12	RETURN (R)	(Note V)					$	
13					Cost			
14			$	%	(Notes K, Q, & R)		Weighted	
15	Long Term Debt	(Attachment 5, line 10 Notes Q & R)	3,409,418,609	45.59%	4.03%		1.84%	=WCLTD
16	Preferred Stock (112.3.c)	(Attachment 5, line 11 Notes Q & R)	-	0.00%	0.00%		0.00%	
17	Common Stock	(Attachment 5, line 12 Notes K, Q & R)	4,069,011,413	54.41%	10.35%		5.63%	
18	Total	(Attachment 5, line 13)	7,478,430,022				7.47%	=R

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data
PECO Energy Company

For the 12 months ended 12/31/2020

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)

Notes:

A Reserved

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

C Reserved

D Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 12, column 5 minus amortization of Regulatory Asset at page 3, line 7, column 5. For Prepayments, refer to Note K in Attachment 4.

E Page 3, Line 5: Attachment 5B, Line 4 - Exclude: (1) amortization of CAP Shopping and Seamless Moves; (2) amortization of DSP IV Admin Costs; (3) Miscellaneous Advertising; (4) SEPA Solar Power Study; (5) PSU Sponsorship; (6) EU IT Prepaid Meter Assess O&M; and (7) Customer Operations AMI/CI O&M. Include Communications, Public Advocacy and Corporate Relations and Government and Regulatory Affairs and Public Policy expenses listed in Account 923 found at Form 1 323.184.b.
Attachment 5B, Lines, 11, and 12 - Exclude EPRI Annual Membership Dues listed in Form 1 at 353.f, non-safety-related advertising included in Account 930.1 found at 323.191.b and Chamber of Commerce Dues and Civic Organization Expenses in Account 930.2 found at 323.192.b; include the costs related to Project Cancellation Fees and Remediation Expenditures (provided, that with regard to the Metal Bank Superfund, PECO must include as a credit any receipts received from the EPA and/or obtained through litigation with the remediation contractors related to Metal Bank Superfund).
Attachment 5B, Line 9- include Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h., and exclude all other Regulatory Commission Expenses itemized at 351.h.

F 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.

G 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 36). Excess Deferred Income Taxes reduce income tax expense by the amount of the expense multiplied by (T/1-T).

Inputs Required:	FIT =	21.00%	
	SIT=	9.99%	(State Income Tax Rate or Composite SIT)
	p =	0.00%	(percent of federal income tax deductible for state purposes)

H Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).

I Removes dollar amount of transmission plant to be 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.

J Reserved

K ROE will be supported in the original filing and no change in ROE may be made absent a Section 205 or Section 206 filing with FERC. The equity component of the capital structure will be capped at 55.75% and shall not be subject to change during the ROE Moratorium Period established under the Settlement Agreement in Docket No. ER17-1519. Thereafter, the cap shall be subject to change pursuant to sections 205 and 206 of the Federal Power Act.

L Reserved

M Reserved

N All items related to Contributions in Aid of Construction (CIAC), including investment in CIAC and CIAC related ADIT, excess/(deficient) ADIT and amortization of excess/(deficient) ADIT shall be excluded from the formula rate.

O Transmission-related ADIT, Excess/(Deficient) ADIT, and the amortization of Excess/(Deficient) ADIT shall be included in the formula rate except as noted in Notes N and P. For clarity of administration of the formula rate, this specifically includes (but is not limited to) transmission-related amounts related to Amortization of Book Premiums on Reacquired Debt, Pension Expense Provision, Loss on Reacquired Debt, FAS 112 and Electric Rate Case Expense – Regulatory Asset – Current.

P ADIT, Excess/(Deficient) ADIT and the amortizaiton of Excess/(Deficient) ADIT related to Accrued Benefits, Deferred Compensation, Vacation pay Change in Provision and Accrued Vacation shall be excluded from the formula rate.

Q All ADIT-190, ADIT-282, and ADIT-283 amounts reflected on Attachment 4C must be based on a timing difference between book expense recognition and expense recognition for tax purposes.

R Calculated using 13 month average balance, except ADIT.

S Unamortized Abandoned Plant and Amortization of Abandoned Plant will be zero until FERC explicitly approves recovery of the cost of abandoned plant pursuant to Section 205 of the FPA.

T Recovery of Regulatory Asset is permitted only as specifically authorized pursuant to Section 205 or 206 of the FPA by FERC. Recovery of any regulatory assets not specifically identified in the initial version of this formula rate template approved by FERC in Docket No. ER17-1519-000 will require specific authorization from FERC.

U Excludes Asset Retirement Obligation balances

V Company shall include only gains and losses on interest rate locks associated with debt issuances. Absent a Section 205 filing, Company shall not include in the Formula Rate, the gains, losses, or costs related to other hedges.

W The Tax Effect of Permanent Differences captures the differences in the income taxes due under the Federal and State calculations and the income taxes calculated in Attachment H that are not the result of a timing difference. Items that can be included in formula for recovery are AFUDC Equity, Meals & Entertainment (50%), Memberships & Dues Not Deductible, Additional Compensation to Employee Stock, and Life Insurance Premiums. Items that can not be included in formula for recovery are Dividend Received Deductions, Equity in Earnings of Unconsol. Subs, and Other Perms (Rabbi Trust). Commission authorization is required in order to include any other permanent difference as an adjustment to the income tax allowance computation in the Formula Rate Template.

X Calculated on Attachment 4A.

Y Unfunded Reserves are customer contributed capital such as when Injuries and Damages expense is accrued but not yet incurred. Also, pursuant to Special Instructions to Accounts 228.1 through 228.4, no amounts shall be credited to accounts 228.1 through 228.4 unless authorized by a regulatory authority or authorities to be collected in a utility’s rates.

Z Amortization of Regulatory Asset for Environmental Remediation of Manufactured Gas Plants shall be excluded from the formula rate.

Attachment 1
Project Revenue Requirement Worksheet
PECO Energy Company

To be completed in conjunction with Attachment H-7.

Line No.	(1)	(2) Attachment H-7 Page, Line, Col.	(3) Transmission	(4) Allocator
1	Gross Transmission Plant - Total	Attach H-7, p 2, line 2 col 5 (Note A)	1,723,143,701	
2	Net Transmission Plant - Total	Attach H-7, p 2, line 20 col 5 plus line 34 & 37 col 5 (Note B)	1,188,030,970	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Attach H-7, p 3, line 12 col 5	66,163,076	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1 col 3)	0.04	0.04
	GENERAL, INTANGIBLE AND COMMON (G&C) DEPRECIATION EXPENSE			
5	Total G, I & C Depreciation Expense	Attach H-7, p 3, lines 15 to 18, col 5 (Note H)	10,340,660	
6	Annual Allocation Factor for G, I & C Depreciation Expense	(line 5 divided by line 1 col 3)	0.01	0.01
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Attach H-7, p 3, line 30 col 5	3,622,142	
8	Annual Allocation Factor for Other Taxes	(line 7 divided by line 1 col 3)	0.00	0.00
9	Less Revenue Credits	Attach H-7, p 1, line 2 col 5	10,105,185	
10	Annual Allocation Factor Revenue Credits	(line 9 divided by line 1 col 3)	-	-
11	**Annual Allocation Factor for Expense**	**Sum of lines 4, 6, 8, and 10**		**0.05**
	INCOME TAXES			
12	Total Income Taxes	Attach H-7, p 3, line 45 col 5	18,574,876	
13	Annual Allocation Factor for Income Taxes	(line 12 divided by line 2 col 3)	0.02	0.02
	RETURN			
14	Return on Rate Base	Attach H-7, p 3, lines 47 and 48a col 5	73,328,298	
15	Annual Allocation Factor for Return on Rate Base	(line 14 divided by line 2 col 3)	0.06	0.06
16	**Annual Allocation Factor for Return**	**Sum of lines 13 and 15**	0.08	**0.08**

Attachment 12 PECO Formula Rate Updated

Attachment 1
Project Revenue Requirement Worksheet
PECO Energy Company

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(12a)	(13)	(14)	(15)	(15a)
Line No.	**Project Name**	**RTO Project Number or Zonal**	**Project Gross Plant**	**Annual Allocation Factor for Expense**	**Annual Expense Charge**	**Project Net Plant or CWIP Balance**	**Annual Allocation Factor for Return**	**Annual Return Charge**	**Project Depreciation/Amortization Expense**	**Annual Revenue Requirement**	**Incentive Return in basis Points**	**Incentive Return**	**Ceiling Rate**	**Competitive Bid Concession**	**Total Annual Revenue Requirement**	**True-Up Adjustment**	**Additional Refund (Note Q)**
			(Note C)	(Page 1 line 11)	(Col. 3 * Col. 4)	(Notes D & I)	(Page 1 line 16)	(Col. 6 * Col. 7)	(Notes E & I)	(Sum Col. 5, 8 & 9)	(Note K)	(Attachment 2, Line 28 /100 * Col. 11 * Col. 6)	(Sum Col. 10 & 12)	(Note J)	(Sum Col. 10 & 12 Less Col. 13)	(Note F)	$ (850,000)
17a	Zonal	Zonal	$ 1,500,556,508	0.05	69,775,613	$ 988,042,155	0.08	76,432,528	22,056,326	168,264,467	-	-	168,264,467	-	168,264,467	(22,402,307)	(719,330)
17b	Center Point 500-230 kV Substation Addition	b0269	$ 34,380,112	0.05	1,598,669	$ 27,689,252	0.08	2,141,973	$ 622,980	4,363,622	-	-	4,363,622	-	4,363,622	(420,338)	(18,654)
17c	Center Point 500-230 kV Substation Addition	b0269	$ 17,190,056	0.05	799,335	$ 13,844,626	0.08	1,070,986	$ 311,490	2,181,811	-	-	2,181,811	-	2,181,811	(1,655,355)	(9,327)
17d	Richmond-Waneeta 230 kV Line Re-conductor	b1591	$ 4,605,741	0.05	214,166	$ 4,170,549	0.08	322,624	$ 106,204	642,994	-	-	642,994	-	642,994	(934,564)	(2,749)
17e	Richmond-Waneeta 230 kV Line Re-conductor	b1398.8	$ 1,535,247	0.05	71,389	$ 1,390,183	0.08	107,541	$ 35,401	214,331	-	-	214,331	-	214,331	45,820	(916)
17f	Whitpain 500 kV Circuit Breaker Addition	b0269.6	$ 3,258,302	0.05	151,510	$ 2,618,565	0.08	202,566	$ 59,395	413,471	-	-	413,471	-	413,471	(113,854)	(1,768)
17g	Elroy-Hosensack 500 kV Line Rating Increase	b0171.1	$ 4,456,731	0.05	207,237	$ 3,498,245	0.08	270,616	$ 79,348	557,201	-	-	557,201	-	557,201	(157,359)	(2,382)
17h	Camden-Richmond 230 kV Line Rating Increase	b1590.1 and b1590.2 (c	$ 13,634,041	0.05	633,980	$ 12,011,480	0.08	929,179	$ 287,401	1,850,561	-	-	1,850,561	-	1,850,561	6,131	(7,911)
17i	Chichester-Linwood 230 kV Line Upgrades	b1900	$ 23,835,043	0.05	1,108,325	$ 30,915,746	0.08	2,391,567	$ 747,532	4,247,424	-	-	4,247,424	-	4,247,424	1,008,441	(18,158)
17j	Bryn Mawr-Plymouth 138 kV Line Rebuild	b0727	$ 18,036,480	0.05	838,693	$ 15,498,974	0.08	1,198,963	$ 411,727	2,449,383	-	-	2,449,383	-	2,449,383	(944,906)	(10,471)
17k	Emilie 230-138 kV Transformer Addition	b2140	$ 16,739,503	0.05	778,384	$ 15,183,535	0.08	1,174,561	$ 349,291	2,302,236	-	-	2,302,236	-	2,302,236	(747,813)	(9,842)
17l	Chichester-Saville 138 kV Line Re-conductor	b1182	$ 17,916,132	0.05	833,097	$ 14,858,395	0.08	1,149,409	$ 390,521	2,373,027	-	-	2,373,027	-	2,373,027	(691,356)	(10,145)
17m	Waneeta 230-138 kV Transformer Addition	b1717	$ 11,068,177	0.05	514,668	$ 10,125,107	0.08	783,254	$ 230,431	1,528,353	-	-	1,528,353	-	1,528,353	(500,925)	(6,534)
17n	Chichester 230-138 kV Transformer Addition	b1178	$ 8,327,759	0.05	387,239	$ 6,981,624	0.08	540,081	$ 158,370	1,085,691	-	-	1,085,691	-	1,085,691	(316,858)	(4,641)
17o	Bradford-Planebrook 230 kV Line Upgrades	b0790	$ 1,712,754	0.05	79,643	$ 1,513,820	0.08	117,105	$ 34,337	231,085	-	-	231,085	-	231,085	(66,666)	(988)
17p	North Wales-Hartman 230 kV Line Re-conductor	b0506	$ 2,229,232	0.05	103,659	$ 1,765,695	0.08	136,590	$ 47,715	287,964	-	-	287,964	-	287,964	(83,914)	(1,231)
17q	North Wales-Whitpain 230 kV Line Re-conductor	b0505	$ 2,546,903	0.05	118,431	$ 1,952,437	0.08	151,036	$ 52,761	322,228	-	-	322,228	-	322,228	(90,313)	(1,378)
17r	Bradford-Planebrook 230 kV Line Upgrades	b0789	$ 2,359,200	0.05	109,702	$ 2,065,241	0.08	159,762	$ 46,844	316,309	-	-	316,309	-	316,309	(91,120)	(1,352)
17s	Planebrook 230 kV Capacitor Bank Addition	b0206	$ 3,631,396	0.05	168,859	$ 2,624,264	0.08	203,007	$ 59,524	431,390	-	-	431,390	-	431,390	(116,053)	(1,844)
17t	Newlinville 230 kV Capacitor Bank Addition	b0207	$ 4,811,873	0.05	223,751	$ 3,573,027	0.08	276,401	$ 81,045	581,196	-	-	581,196	-	581,196	(157,304)	(2,485)
17u	Chichester-Mickleton 230 kV Series Reactor Addition	b0209	$ 2,699,444	0.05	125,524	$ 2,036,609	0.08	157,547	$ 46,195	329,266	-	-	329,266	-	329,266	(89,432)	(1,408)
17v	Chichester-Mickleton 230 kV Line Re-conductor	b0264	$ 2,221,241	0.05	103,287	$ 1,637,670	0.08	126,686	$ 44,255	274,229	-	-	274,229	-	274,229	(76,357)	(1,172)
17w	Buckingham-Pleasant Valley 230 kV Line Re-conductor	b0357	$ 1,723,078	0.05	80,123	$ 1,830,683	0.08	141,617	$ 51,674	273,414	-	-	273,414	-	273,414	(94,961)	(1,169)
17x	Elroy 500 kV Dynamic Reactive Device	b0287	$ 5,325,225	0.05	247,622	$ 4,498,633	0.08	348,003	$ 102,040	697,665	-	-	697,665	-	697,665	150,240	(2,983)
17y	Heaton 230 kV Capacitor Bank Addition	b0208	$ 4,315,230	0.05	200,657	$ 3,204,248	0.08	247,873	$ 72,680	521,210	-	-	521,210	-	521,210	114,765	(2,228)
17z	Peach Bottom 500-230 kV Transformer Rating Increase	b2694	$ 13,038,203	0.05	606,274	$ 13,472,623	0.08	1,042,209	$ 292,734	1,941,218	-	-	1,941,218	-	1,941,218	1,268,861	(8,299)
17aa	Peach Bottom 500 kV Substation Upgrades	b2766.2	$ 990,089	0.05	46,039	$ 1,027,584	0.08	79,491	$ 23,308	148,838	-	-	148,838	-	148,838	59,007	(636)
18	Annual Totals		1,723,143,701			1,188,030,970		91,903,175	26,801,531	198,830,583		-	198,830,583	-	198,830,583	(27,098,491)	(850,000)

Notes:

- A Gross Transmission Plant is that identified on page 2 line 2 of Attachment H
- B Inclusive of any CWIP or unamortized abandoned plant included in rate base when authorized by FERC order less any prefunded AFUDC, if applicable.
- 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. This value includes subsequent capital investments required to maintain the facilities to their original capabilities. Gross plant does not include Unamortized Abandoned Plant.
- D Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation. Net Plant includes CWIP and Unamortized Abandoned Plant and excludes any regulatory asset, which are to be entered as separate line items.
- E Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H, page 3, line 14. Project Depreciation Expense includes the amortization of Abandoned Plant
- F True-Up Adjustment is calculated on the Attachment 3 Project True-up Schedule for the Rate Year
- G The Net Rev Req is the value to be used in the rate calculation under the applicable Schedule 12 under the PJM OATT for each project.
- H The Total General, Intangible and Common Depreciation Expense excludes any depreciation expense directly associated with a project and thereby included in page 2 column 9.
- I The Unamortized Abandoned Plant balance is included in Net Plant, and Amortization of Abandoned Plant is included in Depreciation/Amortization Expense.
- J The Competitive Bid Concession is the reduction in revenue, if any, that the company agreed to, for instance, to be selected to build facilities as the result of a competitive process and equals the amount by which the annual revenue requirement is reduced from the ceiling rate
- K Requires approval by FERC of incentive return applicable to the specified project(s)
- M All transmission facilities reflected in the revenue requirement on Attachment H-7, page 1 line 3 are to be included in this Attachment 1.
- N Facilities that provide Wholesale Distribution Service are not to be listed as projects on lines 15, the revenue requirements associated with these facilities are calculated on Attachment 11
- O When an updated projected net revenue requirement is posted due to an asset acquisition as provided for in the Protocols, the difference between the updated net revenue requirement in Col (16) and the revenues collected to date will be recovered over the remaining months of the Rate Year.
- P Zonal on line 17a refers to all projects not qualifying for regional recovery
- Q Additional refund $850,00 per year for 2018-2021 and $0 for 2022 and beyond.

(16)
Net Rev Req
Sum Col. 14, 15 & 15(a) (Note G)
3,924,630
517,129
(294,319)
259,235
297,849
397,461
1,848,780
5,237,707
1,494,006
1,544,581
1,671,526
1,020,894
764,192
163,431
202,818
230,537
223,837
313,493
421,407
238,426
196,699
177,284
844,922
633,747
3,201,780
207,209
25,739,263

Attachment 2
Incentive ROE
PECO Energy Company

1	Rate Base	Attachment H-7, Page 2 line 47, Col.5							994,404,360
2	100 Basis Point Incentive Return							$	
							Cost		
				$	%			Weighted	
3	Long Term Debt	(Attachment H-7, Notes Q and R)		3,409,418,609	45.6%		4.03%	1.8%	
4	Preferred Stock	(Attachment H-7, Notes Q and R)		-	0.0%		0.00%	0.0%	
5	Common Stock	(Attachment H-7, Notes K, Q and R)	Cost = Attachment H-7, Page 4 Line 17, Cost plus .01	4,069,011,413	54.4%		11.35%	6.2%	
6	Total (sum lines 3-5)			7,478,430,022				8.0%	
7	100 Basis Point Incentive Return multiplied by Rate Base (line 1 * line 6)								79,663,107.98
8	INCOME TAXES								
9	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			28.8921%					
10	CIT=(T/1-T) * (1-(WCLTD/R)) =			31.3214%					
11	WCLTD = Line 3								
12	and FIT, SIT & p are as given in footnote K.								
13	1 / (1 - T) = (from line 9)			1.4063					
14	Amortized Investment Tax Credit (266.8f) (enter negative)		Attachment H-7, Page 3, Line 38	(2,976)					
15	Excess Deferred Income Taxes (enter negative)		Attachment H-7, Page 3, Line 39	(3,250,820)					
16	Tax Effect of Permanent Differences (Note B)		Attachment H-7, Page 3, Line 40	282,655					
17	Income Tax Calculation = line 10 * line 7			24,951,612		NA		24,951,612	
18	ITC adjustment (line 13 * line 14)			(4,186)		TP	100.0%	(4,186)	
19	Excess Deferred Income Tax Adjustment (line 13 * line 15)			(4,571,672)		TP	100.0%	(4,571,672)	
20	Permanent Differences Tax Adjustment (line 13 * 16)			397,502		TP	100.0%	397,502	
21	Total Income Taxes (sum lines 17 - 20)			20,773,256				20,773,256	20,773,256
22	Return and Income Taxes with 100 basis point increase in ROE		(Sum lines 7 & 21)						100,436,364
23	Return (Attach. H-7, page 3 line 47 col 5)								74,252,557
24	Income Tax (Attach. H-7, page 3 line 45 col 5)								18,574,876
25	Return and Income Taxes without 100 basis point increase in ROE		(Sum lines 23 & 24)						92,827,433
26	Incremental Return and Income Taxes for 100 basis point increase in ROE		(Line 22 - line 25)						7,608,931
27	Rate Base (line 1)								994,404,360
28	Incremental Return and Income Taxes for 100 basis point increase in ROE divided by Rate Base			(Line 26 / line 27)					0.0077

Notes:

A Line 5 includes a 100 basis point increase in ROE that is used only to determine the increase in return and income taxes associated with a 100 basis point increase in ROE. Any actual ROE incentive must be approved by the Commission.
For example, if the Commission were to grant a 137 basis point ROE incentive, the increase in return and taxes for a 100 basis point increase in ROE would be multiplied by 1.37 on Attachment 1 column 12.

B The Tax Effect of Permanent Differences captures the differences in the income taxes due under the Federal and State calculations and the income taxes calculated in Attachment H-7 that are not the result of a timing difference

Attachment 12 PECO Formula Rate Updated

Attachment 3
Project True-Up
PECO Energy Company

1	Rate Year being Trued-Up		Revenue Requirement Projected For Rate Year		Revenue Received[3]	Actual Revenue Requirement (Note C)	Annual True-Up Calculation			
2										
	A	B	C	D	E	F	G	H	I	J
	Project Name	PJM Project Number or Zonal	Projected Net Revenue Requirement[1]	% of Total Revenue Requirement	Revenue Received	Actual Net Revenue Requirement[2]	Net Under/(Over) Collection (F)-(E)	Prior Period Adjustment [5]	Interest Income (Expense)[4]	Total True-Up (G) + (H) + (I)
3	Zonal	Zonal	162,880,139	0.83	163,487,627	142,632,752	(20,854,875)	-	(1,547,432)	(22,402,307)
3a	Center Point 500-230 kV Substation Addition	b0269	6,756,243	0.03	5,297,647	4,906,344	(391,303)	-	(29,035)	(420,338)
3b	Center Point 500-230 kV Substation Addition	b0269	882,294	0.00	2,315,583	774,571	(1,541,012)	-	(114,343)	(1,655,355)
3c	Richmond-Waneeta 230 kV Line Re-conductor	b1591	735,440	0.00	663,818	(206,191)	(870,009)	-	(64,555)	(934,564)
3d	Richmond-Waneeta 230 kV Line Re-conductor	b1398.8	245,147	0.00	254,120	296,775	42,655	-	3,165	45,820
3e	Whitpain 500 kV Circuit Breaker Addition	b0269.6	474,739	0.00	473,079	367,089	(105,990)	-	(7,864)	(113,854)
3f	Elroy-Hosensack 500 kV Line Rating Increase	b0171.1	639,848	0.00	637,066	490,577	(146,489)	-	(10,870)	(157,359)
3g	Camden-Richmond 230 kV Line Rating Increase	b1590.1 and b159	2,188,057	0.01	2,244,498	2,250,205	5,707	-	423	6,131
3h	Chichester-Linwood 230 kV Line Upgrades	b1900	4,796,813	0.02	4,927,934	5,866,717	938,783	-	69,658	1,008,441
3i	Bryn Mawr-Plymouth 138 kV Line Rebuild	b0727	2,945,772	0.01	2,945,212	2,065,575	(879,637)	-	(65,269)	(944,906)
3j	Emilie 230-138 kV Transformer Addition	b2140	2,690,818	0.01	2,684,828	1,988,671	(696,158)	-	(51,655)	(747,813)
3k	Chichester-Saville 138 kV Line Re-conductor	b1182	2,746,065	0.01	2,739,629	2,096,028	(643,601)	-	(47,755)	(691,356)
3l	Waneeta 230-138 kV Transformer Addition	b1717	1,782,467	0.01	1,778,033	1,311,709	(466,324)	-	(34,601)	(500,925)
3m	Chichester 230-138 kV Transformer Addition	b1178	1,251,557	0.01	1,247,275	952,304	(294,971)	-	(21,887)	(316,858)
3n	Bradford-Planebrook 230 kV Line Upgrades	b0790	265,192	0.00	264,288	202,227	(62,061)	-	(4,605)	(66,666)
3o	North Wales-Hartman 230 kV Line Re-conductor	b0506	331,812	0.00	330,404	252,286	(78,118)	-	(5,796)	(83,914)
3p	North Wales-Whitpain 230 kV Line Re-conductor	b0505	371,343	0.00	369,949	285,874	(84,074)	-	(6,238)	(90,313)
3q	Bradford-Planebrook 230 kV Line Upgrades	b0789	363,012	0.00	361,747	276,921	(84,826)	-	(6,294)	(91,120)
3r	Planebrook 230 kV Capacitor Bank Addition	b0206	495,602	0.00	493,472	385,436	(108,037)	-	(8,016)	(116,053)
3s	Newlinville 230 kV Capacitor Bank Addition	b0207	667,606	0.00	664,875	518,436	(146,439)	-	(10,866)	(157,304)
3t	Chichester-Mickleton 230 kV Series Reactor Addition	b0209	378,186	0.00	376,685	293,430	(83,255)	-	(6,177)	(89,432)
3u	Chichester-Mickleton 230 kV Line Re-conductor	b0264	316,078	0.00	314,787	243,704	(71,083)	-	(5,274)	(76,357)
3v	Buckingham-Pleasant Valley 230 kV Line Re-conductor	b0357	314,953	0.00	314,437	226,036	(88,402)	-	(6,559)	(94,961)
3w	Elroy 500 kV Dynamic Reactive Device	b0287	800,828	0.00	829,980	969,841	139,862	-	10,378	150,240
3x	Heaton 230 kV Capacitor Bank Addition	b0208	598,701	0.00	619,769	726,607	106,838	-	7,927	114,765
3y	Peach Bottom 500-230 kV Transformer Rating Increase	b2694	635,490	0.00	370,703	1,551,918	1,181,215	-	87,646	1,268,861
3z	Peach Bottom 500 kV Substation Upgrades	b2766.2	-	-	-	54,931	54,931	-	4,076	59,007
4	Total Annual Revenue Requirements (Note A)		196,554,200	1.00	197,007,443	171,780,772	(25,226,672)		(1,871,819)	(27,098,491)

Monthly Interest Rate		0.00
Interest Income (Expense)		(1,871,819)

Notes:
1) From Attachment 1, line 17, col. 14 for the projection for the Rate Year.
2) From Attachment 1, line 17, col. 14, less col. 15(a) for each project and Attachment H-7, line 7 for zonal.
3) "Revenue Received" on line 3 Zonal, Col. (E), is the total amount of revenue received for the True-Up Year under PJM OATT Attachments 7, 8 and H-7 and "Revenue Received" on letter-denominated line 3 entries, Col. (E), is the amount of revenue received for the True-Up Year for the project designated in Cols. A and B under PJM OATT Schedule 12 PECO Appendix and PECO Appendix A as reported on pages 328-330 of the Form No 1. The Revenue Received in Col. E excludes any True-Up revenues

4) Interest from Attachment 6.
5) Prior Period Adjustment from line 5 is pro rata to each project, unless the error was project specific.

Prior Period Adjustments

	(a)	(b)	(c)	(d)
	Prior Period Adjustments (Note B)	Amount In Dollars	Interest (Note B)	Total Col. (b) + Col. (c)
5	-	-	-	-

Notes:

A For each project or Attachment H, the utility will populate the formula rate with the inputs for the True-Up Year. The revenue requirements, based on actual operating results for the True-Up Year, associated with the projects and Attachment H will then be entered in Col. (F) above. Column (E) above contains the actual revenues received associated with Attachment H and any Projects paid by the RTO to the utility during the True-Up Year. Then in Col. (G), Col. (E) is subtracted from Col. (F) to calculate the True-up Adjustment. The Prior Period Adjustment from Line 5 below is input in Col. (H). Column (I) is the applicable interest rate from Attachment 6. Column (I) adds the interest on the sum of Col.(G) and (H). Col. (J) is the sum of Col. (G), (H), and (I).

B Prior Period Adjustment is the amount of an adjustment to correct an error in a prior period. Interest will be calculated for the prior period adjustment based on the FERC Refund interest rate specified in 18 CFR 35.19(a) for the period up to the date the projected rates went into effect. PECO will provide the supporting worksheet for the interest calculation when prior period adjustment is needed.

C The Actual Revenue Requirement in the True-up Adjustment calculation for years 2020 and later shall use the depreciation and amortization rates approved for use by the Commission when PECO performs the True-Up Adjustment.

Attachment 12 PECO Formula Rate Updated

Attachment 4
Rate Base Worksheet
PECO Energy Company

Line No	Month (a)	Gross Plant In Service: Transmission (b)	Gross Plant In Service: General (c)	Gross Plant In Service: Common (d) (Note J)	CWIP: CWIP in Rate Base (e)	LHFFU: Held for Future Use (f)	Working Capital: Materials & Supplies (g)	Prepayments (h) (Note K)	Accumulated Depreciation: Transmission (i) (Note J)	Accumulated Depreciation: General (j) (Note J)	Accumulated Depreciation: Common (k) (Note J)
	Attachment H, Page 2, Line No:	2	4	5	27	31	34	35	9	11	12
		207.58.g minus 207.57.g. Projected monthly balances that are the amounts expected to be included in 207.58.g for end of year and records for other months (Note I)	207.99.g minus 207.98.g for end of year, records for other months	Electric Only, Form No 1, page 356 for end of year, records for other months	(Note C)	214.16,d, 214.17,d, 214.18,d, 214.20,d, 214.23,d, and 214.25,d for end of year, records for other months	227. 8. c + (227.16.c * Labor Ratio) + TLF for end of year, records for other months (Note L)	111.57.c for end of year, records for other months	Projected monthly balances that are expected to be included in 219.25.c for end of year and records for other months (Note I)	219.28.c for end of year, records for other months	Electric Only, Form No 1, page 356 for end of year, records for other months
1	December Prior Year	1,694,670,228	283,844,048	681,307,081	-	244,519	9,885,240	1,484,479	521,171,515	84,322,356	301,612,461
2	January	1,700,330,180	284,174,590	693,139,411	-	244,519	9,714,961	1,317,061	523,476,303	85,713,317	304,796,797
3	February	1,703,001,390	284,552,365	697,339,740	-	244,519	9,727,194	1,002,601	525,789,983	87,086,780	308,059,663
4	March	1,706,917,857	284,999,401	707,304,208	-	253,019	9,618,713	2,599,275	528,105,666	88,443,588	311,343,671
5	April	1,711,729,114	285,454,289	712,439,103	-	875,690	9,691,538	1,983,986	530,425,603	89,784,447	314,643,435
6	May	1,715,119,980	285,894,159	717,311,223	-	4,376,463	9,890,741	1,518,989	532,749,240	91,109,774	317,909,594
7	June	1,720,095,983	286,352,271	722,444,132	-	7,519,830	10,174,825	1,785,546	535,076,731	92,420,004	321,146,882
8	July	1,724,868,799	286,799,508	727,403,894	-	7,533,309	10,287,886	1,276,265	537,409,502	93,715,561	324,399,337
9	August	1,728,766,411	287,199,067	731,862,644	-	7,555,759	10,196,294	1,511,607	539,746,382	94,996,629	327,668,990
10	September	1,733,850,282	287,612,120	736,624,542	-	7,556,903	10,763,580	1,626,104	542,087,687	96,263,456	330,955,185
11	October	1,739,233,116	288,019,091	744,735,110	-	7,912,555	10,665,701	2,594,870	544,434,964	97,516,419	334,274,737
12	November	1,748,731,034	288,382,327	749,153,792	-	8,909,222	10,032,544	1,841,107	546,792,823	98,755,690	337,585,039
13	December	1,773,553,735	288,770,627	784,730,980	-	8,944,464	11,025,145	1,171,935	549,181,632	99,981,531	341,065,613
14	Average of the 13 Monthly Balances	1,723,143,701	286,311,836	723,522,758	-	4,782,367	10,128,797	1,670,294	535,111,387	92,316,119	321,189,339

Adjustments to Rate Base

Line No	Month (a)	Unamortized Regulatory Asset (b)	Unamortized Abandoned Plant (c)	Account No. 281 Accumulated Deferred Income Taxes (Note D) (d)	Account No. 282 Accumulated Deferred Income Taxes (Note D) (e)	Account No. 283 Accumulated Deferred Income Taxes (Note D) (f)	Account No. 190 Accumulated Deferred Income Taxes (Note D) (g)	Account No. 255 Accumulated Deferred Investment Credit (h)	Pension Asset (i)
	Attachment H, Page 2, Line No:	28	29	22	23	24	25	26	27a
		Notes A & E	Notes B & F	Attachment 4A, line 20 for the projection and line 44 for the true-up	Attachment 4A, line 14 for the projection and line 38 for the true-up	Attachment 4A, line 17 for the projection and line 41 for the true-up	Attachment 4A, line 34 for the projection and line 47 for the true-up	Consistent with 266.8.b, 266.17.b, 267.8.h & 267.17.h	Transmission-Related Pension Asset booked to Account 186
15	December Prior Year	-	-	[redacted]				-	26,305,595
16	January	-	-					-	28,171,954
17	February	-	-					-	28,143,643
18	March	-	-					-	28,080,733
19	April	-	-					-	28,031,893
20	May	-	-					-	27,983,969
21	June	-	-					-	27,935,129
22	July	-	-					-	27,886,288
23	August	-	-					-	27,837,449
24	September	-	-					-	27,651,853
25	October	-	-					-	27,605,311
26	November	-	-					-	27,556,341
27	December	-	-					-	27,501,525
28	Average of the 13 Monthly Balances (except ADIT which is the amount shown on Attachment 4A)	-	-	Zero	(211,876,798)	(10,877,541)	14,605,421	-	27,745,514

Attachment 4
Rate Base Worksheet
PECO Energy Company

Unfunded Reserves (Notes G & H)

	(a)	(b)	(c) Amount	(d) Enter 1 if NOT in a trust or reserved account, enter zero (0) if included in a trust or reserved account	(e) Enter 1 if the accrual account is included in the formula rate, enter (0) if O if the accrual account is NOT included in the formula rate	(f) Enter the percentage paid for by the transmission formula customers	(g) Allocation (Plant or Labor Allocator)	(h) Amount Allocated, col. c x col. d x col. e x col. f x col. g
29	List of all reserves:							
30a		Environmental Liab - Superfund	(1,267,913)	1.00	1.00	100%	9.45%	(119,806)
30b		Accrued Severance Plans	(605,747)	1.00	1.00	100%	9.45%	(57,238)
30c		Workers Compensation - short term	(1,144,403)	1.00	1.00	100%	9.45%	(108,136)
30d		Workers Compensation - long term	(9,790,517)	1.00	1.00	100%	9.45%	(925,114)
30e		Public claims - Short Term	(20,866)	1.00	1.00	100%	9.45%	(1,972)
30f		Public Claims - Long term	(20,868,831)	1.00	1.00	100%	9.45%	(1,971,914)
30g		Accrued Septa Railroad Rent - transmission	-	1.00	1.00	100%	100.00%	-
30h		AIP	(20,099,009)	1.00	1.00	100%	9.45%	(1,899,173)
30i		401K Match	(1,255,217)	1.00	1.00	100%	9.45%	(118,607)
30j		Long-term incentive Plans	(1,223,348)	1.00	1.00	100%	9.45%	(115,595)
30k		Mgmt. Retention Incentive Plan	(277,223)	1.00	1.00	100%	9.45%	(26,195)
30l		Stock Comp	(4,196,388)	1.00	1.00	100%	9.45%	(396,520)
30m		Severance - Long Term	(151,548)	1.00	1.00	100%	9.45%	(14,320)
30x		...	-	-				-
31		Total	(60,901,010)					(5,754,589)

Notes:

A Recovery of regulatory asset is limited to any regulatory assets authorized by FERC.

B Recovery of abandoned plant is limited to any abandoned plant recovery authorized by FERC.

C Includes only CWIP authorized by the Commission for inclusion in rate base. The annual report filed pursuant to Section 7 of the Protocols will include for each project under construction (i) the CWIP balance eligible for inclusion in rate base; (ii) the CWIP balance ineligible for inclusion in rate base; and (iii) a demonstration that AFUDC is only applied to the CWIP balance that is not included in rate base. The annual report will reconcile the project-specific CWIP balances to the total Account 107 CWIP balance reported on p. 216.b of the FERC Form 1. The demonstration in (iii) above will show that monthly debts and credits do not contain entries for AFUDC for each CWIP project in rate base.

D ADIT and Accumulated Deferred Income Tax Credits are computed using the average of the beginning of the year and the end of the year balances. The projection will use lines 16, 19 and 36 of Attachment 4A to populate the average ADIT balance on line 28 above.

E Recovery of a Regulatory Asset is permitted only for pre-commercial and formation expenses, and is subject to FERC approval before the amortization of the Regulatory Asset can be included in rates. Recovery of any other regulatory assets requires authorization from the Commission. A carrying charge equal to the weighted cost of capital will be applied to the Regulatory Asset prior to the rate year when costs are first recovered.

F Unamortized Abandoned Plant and Amortization of Abandoned Plant will be zero until the Commission accepts or approves recovery of the cost of abandoned plant.

G The Formula Rate shall include a credit to rate base for all unfunded reserves (funds collected from customers that (1) have not been set aside in a trust, escrow or restricted account; (2) whose balance are collected from customers through cost accruals to accounts that are recovered under the Formula Rate; and (3) exclude the portion of any balance offset by a balance sheet account). Each unfunded reserve will be included on lines 30 above. The allocator in Col. (g) will be the same allocator used in the formula for the cost accruals to the account that is recovered under the Formula Rate. Since reserves can be created by an offsetting balance sheet account, rather than through cost accruals, the amount to be deducted from rate base should exclude the portion offset by another balance sheet account.

H Calculate using 13 month average balance, except ADIT. SERP will not be included as an unfunded reserve in the formula rate.

I Projected balances are for the calendar year the revenue under this formula begins to be charged.

J Excludes ARO amounts.

K Total prepayments, including Fleet Activity, allocated to transmission as follows: (1) amounts solely related to transmission allocated 100% to transmission; (2) amounts solely related to distribution, gas or non-utility allocated 0% to transmission; (3) amounts related to electric general allocated using the wages and salaries allocator (Attachment H-7), p. 4, line 11, column (5)); (4) amounts related to common labor or plant allocated using the wages and salaries allocator (Attachment H-7, p. 4, line 11, column (5)), multiplied by either common labor percent to electric (Attachment 7-PBOP, Note B, Electric Labor) or by common utility plant percent to electric (per FF1 page 356) as applicable depending upon the nature of the prepayment item.

L TLF shall be equal to 50 percent of the lesser of (a) the transmission portion of FERC Form 1, page 227, line 5, column c per FERC Form No. 1) and (b) $9 million. The TLF recovery percentage and cap will be subject to modification only through Commission authorization under section 205 or section 206 of the Federal Power Act.

		Allocation	Prior Year End Total	Current Year End Total	Allocation Factor	Prior Year Allocated to T	Current Year Allocated to T	Allocation from Total To Electric (Note K)	Allocation from Electric to Transmission (Note K)
k1	Market Research	Other	$ 20,335	$ -	0.00%	$ -	$ -	0.00%	0.00%
k2	Facilities	Allocation To Transmission	$ 58,423	$ 131	7.32%	$ 4,277	$ 10	77.48%	9.45%
k3	Land Leasing	Other	$ 23,723	$ 5,456	0.00%	$ -	$ -	0.00%	0.00%
k4	Land Leasing	100% Transmission	$ -	$ 16,369	100.00%	$ -	$ 16,369	100.00%	100.00%
k5	Fleet Activity	Allocation To Transmission	$ 321,536	$ 336,859	7.54%	$ 24,239	$ 25,394	79.78%	9.45%
k6	Membership dues	Other	$ 400	$ -	0.00%	$ -	$ -	0.00%	0.00%
k7	IT License & Maintenance Agreements	Allocation To Transmission	$ 598,296	$ 338,557	7.32%	$ 43,802	$ 24,786	77.48%	9.45%
k8	IT License & Maintenance Agreements	Allocation To Transmission	$ -	$ -	7.54%	$ -	$ -	79.78%	9.45%
k9	IT License & Maintenance Agreements	Other	$ 1,317,780	$ 1,241,294	0.00%	$ -	$ -	0.00%	0.00%
k10	Postage	Other	$ 650,426	$ 594,515	0.00%	$ -	$ -	0.00%	0.00%
k11	Prepaid Rent	100% Transmission	$ 1,334,854	$ 964,039	100.00%	$ 1,334,854	$ 964,039	100.00%	100.00%
k12	Prepaid Rent	Other	$ 276,562	$ 415,497	0.00%	$ -	$ -	0.00%	0.00%
k13	Prepaid gross receipts tax	Other	$ -	$ -	0.00%	$ -	$ -	0.00%	0.00%
k14	Prepaid property tax	Allocation To Transmission	$ -	$ -	7.32%	$ -	$ -	77.48%	9.45%
k15	PUC Assessment	Other	$ 4,635,979	$ 4,427,073	0.00%	$ -	$ -	0.00%	0.00%
k16	Retention Incentive	Allocation To Transmission	$ 13,000	$ 2,000	7.54%	$ 980	$ 151	79.78%	9.45%
k17	Marketing	Other	$ 236,261	$ 268,711	0.00%	$ -	$ -	0.00%	0.00%
k18	VEBA	Allocation To Transmission	$ 834,281	$ 135,265	7.54%	$ 62,892	$ 10,197	79.78%	9.45%
k19	Equipment Maintenance	100% Transmission	$ 13,435	$ 10,076	100.00%	$ 13,435	$ 10,076	100.00%	100.00%
k20	Equipment Maintenance	Other	$ 126,509	$ 94,882	0.00%	$ -	$ -	0.00%	0.00%
k21	New Business	Other	$ 173,775	$ 3,050	0.00%	$ -	$ -	0.00%	0.00%
k22	Land Acquisitions	100% Transmission	$ -	$ 18,294	100.00%	$ -	$ 18,294	100.00%	100.00%
k23	Leases	Other	$ -	$ 272,074	0.00%	$ -	$ -	0.00%	0.00%
k24	Building Acquisition	Other	$ -	$ 153,930	0.00%	$ -	$ -	0.00%	0.00%
k25	Building Acquisition	100% Transmission	$ -	$ 102,620	100.00%	$ -	$ 102,620	100.00%	100.00%
...									
Kxxx									
	Total Sum(lines K1 to Kxxx)		10,635,574	9,400,693		1,484,479	1,171,935		

Attachment 4A
PECO Energy Company
ADIT Worksheet for Projection

Projection for the 12 months ended 12/31/2020

ADIT for the Projection

	(a) Beginning Balance & Monthly Changes	(b) Month	(c) Year	(d) Weighting for Projection	(e) Beginning Balance/ Monthly Increment	(f) 100% Transmission	(g) 100% Allocator (f) x Allocator **100%**	(h) (Note A) Plant Related	(i) GP Allocator (h) x Allocator 0.1851 From Attach H Page 2, Line 18	(j) Labor Related	(k) S/W Allocator (j) x Allocator 0.0945 From Attach H Page 4, Line 16	(l) Total ADIT (d) x [(g)+(i)+(k)]
		ADIT- 282										
1	Balance	December	2019	100.00%	-	(200,390,143)	(200,390,143)	-	-	(31,198,496)	(2,947,973)	(203,338,115)
2	Increment	January	2020	91.78%	-	(209,280)	(209,280)	-	-	(77,939)	(7,365)	(198,838)
3	Increment	February	2020	84.11%	-	(209,280)	(209,280)	-	-	(77,939)	(7,365)	(182,219)
4	Increment	March	2020	75.62%	-	(209,280)	(209,280)	-	-	(77,939)	(7,365)	(163,819)
5	Increment	April	2020	67.40%	-	(209,280)	(209,280)	-	-	(77,939)	(7,365)	(146,012)
6	Increment	May	2020	58.90%	-	(209,280)	(209,280)	-	-	(77,939)	(7,365)	(127,613)
7	Increment	June	2020	50.68%	-	(209,280)	(209,280)	-	-	(77,939)	(7,365)	(109,806)
8	Increment	July	2020	42.19%	-	(209,280)	(209,280)	-	-	(77,939)	(7,365)	(91,406)
9	Increment	August	2020	33.70%	-	(209,280)	(209,280)	-	-	(77,939)	(7,365)	(73,006)
10	Increment	September	2020	25.48%	-	(209,280)	(209,280)	-	-	(77,939)	(7,365)	(55,200)
11	Increment	October	2020	16.99%	-	(209,280)	(209,280)	-	-	(77,939)	(7,365)	(36,800)
12	Increment	November	2020	8.77%	-	(209,280)	(209,280)	-	-	(77,939)	(7,365)	(18,993)
13	Increment	December	2020	0.27%	-	(209,280)	(209,280)	-	-	(77,939)	(7,365)	(594)
14	Sum Ties to December		2020	Balance	-	(202,901,503)	(202,901,503)	-	-	(32,133,768)	(3,036,347)	(204,542,422)
15	Increment	Not Subject to Proration	2020			(7,334,377)	(7,334,377)	-	-	-	-	(7,334,377)
16	Total					(210,235,879)	(210,235,879)	-	-	(32,133,768)	(3,036,347)	(211,876,798)
		ADIT-283										
17	Balance	December	2019		-	-	-	(5,165,133)	(956,020)	(104,384,871)	(9,863,416)	(10,819,436)
18	Balance	December	2020		-	-	-	(4,790,923)	(886,757)	(106,347,739)	(10,048,889)	(10,935,646)
19		Average			-	-	-	(4,978,028)	(921,389)	(105,366,305)	(9,956,152)	(10,877,541)
		ADIT-281										
20	Balance	December	2019		Zero	Zero	Zero	Zero	Zero	Zero	Zero	Zero
21	Balance	December	2020		Zero	Zero	Zero	Zero	Zero	Zero	Zero	Zero
22		Average			Zero	Zero	Zero	Zero	Zero	Zero	Zero	Zero
		ADIT-190										
23	Balance	December	2019	100.00%	-	-	-	19,259,193	3,564,706	116,408,740	10,999,562	14,564,267
24	Increment	January	2020	91.78%	-	-	-	-	-	-	-	-
25	Increment	February	2020	84.11%	-	-	-	-	-	-	-	-
26	Increment	March	2020	75.62%	-	-	-	-	-	-	-	-
27	Increment	April	2020	67.40%	-	-	-	-	-	-	-	-
28	Increment	May	2020	58.90%	-	-	-	-	-	-	-	-
29	Increment	June	2020	50.68%	-	-	-	-	-	-	-	-
30	Increment	July	2020	42.19%	-	-	-	-	-	-	-	-
31	Increment	August	2020	33.70%	-	-	-	-	-	-	-	-
32	Increment	September	2020	25.48%	-	-	-	-	-	-	-	-
33	Increment	October	2020	16.99%	-	-	-	-	-	-	-	-
34	Increment	November	2020	8.77%	-	-	-	-	-	-	-	-
35	Increment	December	2020	0.27%	-	-	-	23,998,409	4,441,893	107,996,505	10,204,682	14,646,575
36	Sum Ties to December		2020	Balance	-							14,605,421
	Line 36, If there are no items subject to proration, use average of lines 23 and 35											
37	Total ADIT											(208,148,919)

PECO Energy Company
ADIT Worksheet for True-Up

ADIT for True-Up

True-Up for the 12 months ended 12/31/2019

	(a) Balance	(b) Month	(c) Year	(d) Weighting for Projection	(e) Balance from ADIT BOY and ADIT EOY workpapers	(f) 100% Transmission	(g) 100% Allocator (f) x Allocator **100%**	(h) (Note A) Plant Related	(i) GP Allocator (h) x Allocator 0.1851 From Attach H Page 2, Line 18	(j) Labor Related	(k) S/W Allocator (j) x Allocator 0.0945 From Attach H Page 4, Line 16	(l) Total ADIT (d) x [(g)+(i)+(k)]
		ADIT- 282										
38	Balance	December	2018		(1,139,022,726)	(189,143,729)		-	-	(30,828,318)		
39	Balance	December	2019		(1,261,244,192)	(200,390,143)		-	-	(31,198,496)		
40		Average			(1,200,133,459)	(194,766,936)	(194,766,936)	-	-	(31,013,407)	(2,930,483)	(197,697,419)
		ADIT-283										
41	Balance	December	2018		(139,156,936)	-	-	(5,581,934)	(1,033,166)	(108,797,636)	(10,280,382)	
42	Balance	December	2019		(129,949,790)	-	-	(5,165,133)	(956,020)	(104,384,871)	(9,863,416)	
43		Average			(134,553,363)	-	-	(5,373,534)	(994,593)	(106,591,253)	(10,071,899)	(11,066,492)
		ADIT-281										
44	Balance	December	2018		Zero	Zero	Zero	Zero	Zero	Zero	Zero	Zero
45	Balance	December	2019		Zero	Zero	Zero	Zero	Zero	Zero	Zero	Zero
46		Average			Zero	Zero	Zero	Zero	Zero	Zero	Zero	Zero
		ADIT-190										
47	Balance	December	2018		178,589,500	-	-	13,690,676	2,534,023	131,938,478	12,466,980	15,001,002
48	Balance	December	2019		169,734,784	-	-	19,259,193	3,564,706	116,408,740	10,999,562	14,564,267
49		Average			174,162,142	-	-	16,474,934	3,049,364	124,173,609	11,733,271	14,782,635

Note:

A Plant Related ADIT reflects the total Electric plant related ADIT from Attachment 4B and 4C, which is allocated to transmission in Column (i) with GP allocation factor.

Attachment 4B
PECO Energy Company

ADIT BOY Worksheet

	A	B	C	D	E	F	
		Total	Gas, Prod, Retail Or Other Related	Only Transmission Related	Plant Related	Labor Related	
a	ADIT- 282	(1,139,022,726)		(189,143,729)	-	(30,828,318)	(From line 17 for the column)
b	ADIT-283	(139,156,936)		-	(5,581,934)	(108,797,636)	(From line 29 for the column)
c	ADIT-190	178,589,500		-	13,690,676	131,938,478	(From line 5 for the column)
d	Subtotal	(1,099,590,162)		(189,143,729)	8,108,741	(7,687,475)	(Sum a - c)

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.

Line	A ADIT-190 (Attachment H-7 Notes P and Q)	B Total	C Gas, Prod Retail Or Other Related	D Only Transmission Related	E Plant Related	F Labor Related	G Justification
1	ACCRUED BENEFITS	237,053	237,053	-	-	-	Related to employer costs of benefits, such as health insurance, 401 (k), etc. The amounts are recorded to the liability and cleared through payments during each bi-weekly payroll. Any balance in the account at the end of the month would relate to the month-end accrual that is recorded at the end of the month and reversed on the first calendar day of the next month. As such, there is a book to tax timing difference.
1a	ADDBACK OF NQSO EXPENSE	1,773,851	-	-	-	1,773,851	No current book activity, tax deducts as distributions are made from the trust - employees in all functions.
1b	ADDBACK OF OTHER EQUITY COMP EXPENSE	1,863,208	-	-	-	1,863,208	Book expense recorded when stock is granted, tax expense when stock is issued at market price - employees in all functions.
1c	AMORT-ORGANIZATIONAL COSTS	-	-	-	-	-	Excluded because the underlying account(s) are not included in model
1d	BAD DEBT - CHANGE IN PROVISION	15,064,698	15,064,698	-	-	-	Retail bad debt. For book, expense taken as it's identified; tax deduction not taken until fully written-off and all collection efforts abandoned. Relates to retail operations.
1e	CHARITABLE CARRYFORWARD	1,013,502	1,013,502	-	-	-	Excluded because the underlying account(s) are not included in model
1f	CUSTOMER ADVANCES - CONSTRUCTION	335,650	335,650	-	-	-	Excluded because the underlying account(s) are not included in model
1g	DEFERRED COMPENSATION	1,698,133	1,698,133	-	-	-	Book records estimated accrued compensation; tax deducts only upon the retirement or other separation from service by the employees. Relates to all functions.
1h	DEFERRED REVENUE	225,134	225,134	-	-	-	Excluded because the underlying account(s) are not included in model
1i	FAS 112	18,627	-	-	-	18,627	Employer provided benefits to former employees but before retirement.
1j	FEDERAL NOL	-	-	-	-	-	PECO is in a net operating loss situation, therefore, losses are carried forward until such losses can be applied to taxable income.
1k	FIN 47 ARO	5,371,606	5,371,606	-	-	-	Accrual of future removal/retirements. Book recognized the expense estimate accrual, tax recognizes when paid. Related to all functions. ARO must be approved by FERC in order to include amounts.
1l	Gross Up-Bill E Credit	-	-	-	-	-	Excluded because the underlying account(s) are not included in model
1m	INCENTIVE PAY	9,990,749	-	-	-	9,990,749	Book records an accrual in filing year on estimated payouts; tax reverses the accrual and deducts the actual paid out. Relates to all functions.
1n	INJURIES AND DAMAGE PAYMENTS	-	-	-	-	-	Books records an estimated liability for injuries and damages; tax purposes a deduction is only taken when actual payments are made.
1o	MERGER COSTS NC	-	-	-	-	-	Excluded because the underlying account(s) are not included in model
1p	DEFFERRED CHARGES - TAX REPAIRS BILL CREDIT-DI	67,489	67,489	-	-	-	Excluded because the underlying account(s) are not included in model
1q	OBSOLETE MATERIALS PROVISION	428,906	428,906	-	-	-	Excluded because the underlying account(s) are not included in model
1r	OTHER CURRENT	(15,328)	(15,328)	-	-	-	
1s	FACILITY COMMITMENT FEES	10,794	-	-	10,794	-	Debt related
1t	FINES & OTHER	192,052	192,052	-	-	-	Excluded because the underlying account(s) are not included in model
1u	OTHER NONCURRENT- RAILROAD LIABILITY	83,758	-	-	83,758	-	Related to reserve for required maintenance on right of ways.
1v	OTHER UNEARNED REVENUE-DEFERRED RENTS	262,092	-	-	262,092	-	Rent expense deferred and amortized ratably for books, tax deduction when paid - used for all functions.
1w	PAYROLL TAXES	-	-	-	-	-	Book records a payroll tax accrual; tax reverses the accrual and deducts the actual amount paid out. Relates to all functions.
1x	PENNSYLVANIA NOL	13,825,356	-	-	13,825,356	-	PECO is in a net operating loss situation, therefore, losses are carried forward until such losses can be applied to taxable income.
1y	PENSION EXPENSE PROVISION	-	-	-	-	-	Book accrues and capitalizes anticipated Pension costs based on actuarial analysis. Tax deducts or capitalizes retirement benefits only when the amounts are paid. Related to all functions.
1z	POLE ATTACHMENT RESERVE	-	-	-	-	-	Excluded because the underlying account(s) are not included in model
1aa	POST RETIREMENT BENEFITS	71,389,972	-	-	-	71,389,972	Book accrues anticipated post retirement costs based on actuarial analysis. Tax deducts retirement benefits only when the amounts are paid or contributed to a fund.
1ab	RESERVE FOR EMPLOYEE LITIGATIONS Current	48,886	48,886	-	-	-	Related to reserves associated with ongoing and/or pending litigation. These are not legal service fees, but accrual for possible liability payments upon resolution of ongoing litigation matters. Since we have accrued, but not yet paid, we have to book the tax reserve.
1ac	SA UNBILLED RESERVE	3,158,623	3,158,623	-	-	-	Retail related
1ad	SECA REFUND	-	-	-	-	-	Retail related
1ae	SEPTA RAILROAD RENT	132,515	132,515	-	-	-	Reserve for potential transmission rent expense
1af	SEVERANCE PMTS CHANGE IN PROVISION	51,322	-	-	-	51,322	Book records an accrual; tax takes the deduction when actually paid. Relates to all functions.
1ag	VACATION PAY CHANGE IN PROVISION	1,145,678	1,145,678	-	-	-	Capitalized portion of vacation pay earned and expensed for books, tax takes the deduction when paid out. Related to all functions.
1ah	VEGETATION MGMT ACCRUAL	1,701,178	1,701,178	-	-	-	Excluded because the underlying account(s) are not included in model
1ai	WORKERS COMPENSATION RESERVE	9,646,333	-	-	-	9,646,333	These accounts are reserves for public claims, workers compensation and other third party incidents. For tax purposes these are not deductible until paid. Related to all functions.
1aj							
1ak							
1al							
1am							
1an							
…							
2	**Subtotal - p234.8.b**	139,721,837	30,805,775	-	14,182,000	94,734,062	
3	**Less FASB 109 Above if not separately removed**	(38,867,663)	(2,154,571)	-	491,324	(37,204,416)	
4	**Less FASB 106 Above if not separately removed**						
5	**Total**	178,589,500	32,960,347	-	13,690,676	131,938,478	

6 **Instructions for Account 190:**
7 **1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C**
8 **2. ADIT items related only to Transmission are directly assigned to Column D**
9 **3. ADIT items related to Plant other than general plant, intangible plant or common plant and not in Columns C & D are included in Column E**
10 **4. ADIT items related to labor, general plant, intangible plant, or common plant 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

Attachment 12 PECO Formula Rate Updated

PECO Energy Company

ADIT BOY Worksheet

	A	B	C	D	E	F	G
	ADIT- 282 (Attachment H-7 Notes N and Q)	*Total*	*Gas, Prod Retail Or Other Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
13a	Property Related ADIT, Excl. ARO	-	-	-	-	-	
13b	Common	(29,503,593)	-	-	-	(29,503,593)	Included because plant in service is included in rate base.
13c	Distribution	(1,188,168,321)	(1,188,168,321)	-	-	-	Related to Distribution property.
13d	Electric General	(3,041,661)	-	-	-	(3,041,661)	Included because plant in service is included in rate base.
13e	Transmission	(226,271,862)	-	(226,271,862)	-	-	Included because plant in service is included in rate base.
13f							
13g							
13h							
…							
14	**Subtotal - p275.2.b**	(1,446,985,437)	(1,188,168,321)	(226,271,862)	-	(32,545,254)	
15	**Less FASB 109 Above if not separately removed**	(307,962,711)	(269,117,641)	(37,128,133)	-	(1,716,937)	
16	**Less FASB 106 Above if not separately removed**						
17	**Total (Line 14 - Line 15 - Line 16)**	(1,139,022,726)	(919,050,680)	(189,143,729)	-	(30,828,318)	

18 **Instructions for Account 282:**
19 **1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C**
20 **2. ADIT items related only to Transmission are directly assigned to Column D**
21 **3. ADIT items related to Plant other than general plant, intangible plant or common plant and not in Columns C & D are included in Column E**
22 **4. ADIT items related to labor, general plant, intangible plant, or common plant and not in Columns C & D are included in Column F**
23 **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,**
24 **the associated ADIT amount shall be excluded**

PECO Energy Company

ADIT BOY Worksheet

	A	B	C	D	E	F	G
	ADIT-283 (Attachment H-7 Notes O, P and Q)	*Total*	*Gas, Prod Retail Or Other Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
25	ACT 129 SMART METER	(3,337,244)	(3,337,244)	-	-	-	Retail related
25a	AEC RECEIVABLE	(848,268)	(848,268)	-	-	-	Retail related
25b	AMORT-BK-PREMIUMS ON REACQD DEBT-9.5%	(321,464)	-	-	(321,464)	-	Book recapitalizes costs incurred to retire or reacquire debt issuances. Tax deducts these costs when incurred.
25c	CAP FORGIVENESS REG ASSET	(417,587)	(417,587)	-	-	-	Retail related
25d	CAP SHOPPING REG ASSET	(1,350,453)	(1,350,453)	-	-	-	Retail related
25e	DSP 2 - REGULATORY ASSET	(68,443)	(68,443)	-	-	-	Retail related
25f	ELEC RATE CASE EXP - REG ASSET	(415,762)	(415,762)	-	-	-	Retail related
25g	ENERGY EFFICIENCY REG ASSET	(203,599)	(203,599)	-	-	-	Retail related
25h	Gross Up on State Def Tax Adj- AMR Reg Asset	(385,014)	(385,014)	-	-	-	Retail related
25i	HOLIDAY PAY CHANGE IN PROVISION	(242,518)	-	-	-	(242,518)	The book expense on Jan 1 of calendar year; accelerated tax expense taken in previous calendar year. Related to all functions.
25j	OCI-Def FIT & SIT	(575,647)	(575,647)	-	-	-	Excluded because the underlying account(s) are not included in model
25k	OTHER CURRENT REG ASSET:	-	-	-	-	-	0
25l	LOSS OF REAQUIRED DEBT	(111,361)	-	-	(111,361)	-	Book recapitalizes costs incurred to retire or reacquire debt issuances. Tax deducts these costs when incurred. Included in debt capitalization ratio on Appendix A, line 111.
25m	VACATION ACCRUAL	(1,595,005)	(1,595,005)	-	-	-	Current portion of vacation pay earned and expensed for books, tax takes the deduction when paid out. Related to all functions.
25n	SMART METER	(3,337,244)	(3,337,244)	-	-	-	Retail related
25o	CAP SHOPPING REG ASSET - CURRENT	(0)	(0)	-	-	-	Retail related
25p	CAP FORGIVENESS REG ASSET - CURRENT	(1,567,342)	(1,567,342)	-	-	-	Retail related
25q	FAS 112	(205,034)	-	-	-	(205,034)	Employer provided benefits to former employees but before retirement.
25r	ELEC RATE CASE EXP - REG ASSET - CURRENT	(0)	-	-	-	-	Property taxes. Book records on an accrual method based on the prior year; tax reverses the book accrual and deducts the actual payments made. . Relates to all functions.
25s	PURTA	-	-	-	-	-	Retail related
25t	SEAMLESS MOVES	(0)	-	-	-	(0)	Book accrues and capitalizes anticipated Pension costs based on actuarial analysis. Tax deducts or capitalizes retirement benefits only when the amounts are paid. Retail related.
25u	OTHER CURRENT REG ASSET	237,902	237,902	-	-	-	Gas Related
25v	PENSION EXPENSE PROVISION	(92,669,768)	-	-	-	(92,669,768)	Book accrues and capitalizes anticipated Pension costs based on actuarial analysis. Tax deducts or capitalizes retirement benefits only when the amounts are paid. Related to all functions.
25w	RATE CHANGE REG ASSET	(7,896,920)	(7,896,920)	-	-	-	Gross up related to non-property tax rate change/TCJA
25x	STATE TAX RESERVE	(3,278,057)	-	-	(3,278,057)	-	The state income tax is cash basis
25y	ARO- Reg Asset	(5,001,186)	(5,001,186)	-	-	-	
25z	ARO- Reg Asset	-	-	-	-	-	
25aa							
25ab							
25ac							
25ad							
25ae							
25af							
….							
….							
26	**Subtotal - p276.9.b**	(123,590,014)	(26,761,812)	-	(3,710,882)	(93,117,320)	
27	**Less FASB 109 Above if not separately removed**	15,566,922	(1,984,446)	-	1,871,052	15,680,316	
28	**Less FASB 106 Above if not separately removed**						
29	**Total**	(139,156,936)	(24,777,366)	-	(5,581,934)	(108,797,636)	

30 **Instructions for Account 283:**

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

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

33 **3. ADIT items related to Plant other than general plant, intangible plant or common plant and not in Columns C & D are included in Column E**

34 **4. ADIT items related to labor, general plant, intangible plant, or common plant and not in Columns C & D are included in Column F**

35 **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,**

36 **the associated ADIT amount shall be excluded**

Attachment 12 PECO Formula Rate Updated

Attachment 4C
PECO Energy Company

ADIT EOY Worksheet

	A	B	C	D	E	F	
			Gas, Prod	Only			
			Retail Or Other	Transmission	Plant	Labor	
		Total	Related	Related	Related	Related	
a	*ADIT- 282*	(1,261,244,192)		(200,390,143)	-	(31,198,496)	(From line 17 for the column)
b	*ADIT-283*	(129,949,790)		-	(5,165,133)	(104,384,871)	(From line 29 for the column)
c	*ADIT-190*	169,734,784		-	19,259,193	116,408,740	(From line 5 for the column)
d	*Subtotal*	(1,221,459,197)		(200,390,143)	14,094,060	(19,174,626)	(Sum a - c)

Line 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.

Line	A	B	C	D	E	F	G
	ADIT-190 (Attachment H-7 Notes P and Q)	*Total*	*Gas, Prod*	*Only*			
1			*Retail Or Other*	*Transmission*	*Plant*	*Labor*	
1a			*Related*	*Related*	*Related*	*Related*	*Justification*
1b							
1c	ACCRUED BENEFITS	429,824	429,824	-	-	-	Related to employer costs of benefits, such as health insurance, 401 (k), etc. The amounts are recorded to the liability and cleared through payments during each bi-weekly payroll. Any balance in the account at the end of the month would relate to the month-end accrual that is recorded at the end of the month and reversed on the first calendar day of the next month. As such, there is a book to tax timing difference.
1d	ADDBACK OF NQSO EXPENSE	1,541,792	-	-	-	1,541,792	No current book activity, tax deducts as distributions are made from the trust - employees in all functions.
1e	ADDBACK OF OTHER EQUITY COMP EXPENSE	1,122,149	-	-	-	1,122,149	Book expense recorded when stock is granted, tax expense when stock is issued at market price - employees in all functions.
1f	AMORT-ORGANIZATIONAL COSTS	-	-	-	-	-	Excluded because the underlying account(s) are not included in model
1g	BAD DEBT - CHANGE IN PROVISION	15,150,483	15,150,483	-	-	-	Retail bad debt. For book, expense taken as it's identified; tax deduction not taken until fully written-off and all collection efforts abandoned. Relates to retail operations.
1h	CHARITABLE CARRYFORWARD	2,115,506	2,115,506	-	-	-	Excluded because the underlying account(s) are not included in model
1i	CUSTOMER ADVANCES - CONSTRUCTION	767,529	767,529	-	-	-	Excluded because the underlying account(s) are not included in model
1j	DEFERRED COMPENSATION	2,126,325	2,126,325	-	-	-	Book records estimated accrued compensation; tax deducts only upon the retirement or other separation from service by the employees. Relates to all functions.
1k	DEFERRED REVENUE	243,866	243,866	-	-	-	Excluded because the underlying account(s) are not included in model
1l	FAS 112	18,627	-	-	-	18,627	Employer provided benefits to former employees but before retirement.
1m	FEDERAL NOL	-	-	-	-	-	PECO is in a net operating loss situation, therefore, losses are carried forward until such losses can be applied to taxable income.
1n	FIN 47 ARO	5,603,925	5,603,925	-	-	-	Accrual of future removal/retirements. Book recognized the expense estimate accrual, tax recognizes when paid. Related to all functions. ARO must be approved by FERC in order to include amounts.
1o		-	-	-	-	-	Excluded because the underlying account(s) are not included in model
1p	INCENTIVE PAY	11,559,004	-	-	-	11,559,004	Book records an accrual in filing year on estimated payouts; tax reverses the accrual and deducts the actual paid out. Relates to all functions.
1q	INJURIES AND DAMAGE PAYMENTS	-	-	-	-	-	Books records an estimated liability for injuries and damages; tax purposes a deduction is only taken when actual payments are made.
1r	MERGER COSTS NC	-	-	-	-	-	Excluded because the underlying account(s) are not included in model
1s	DEFFERRED CHARGES - TAX REPAIRS BILL CREDIT-DIST	-	-	-	-	-	Excluded because the underlying account(s) are not included in model
1t	OBSOLETE MATERIALS PROVISION	530,272	530,272	-	-	-	Excluded because the underlying account(s) are not included in model
1u	OTHER CURRENT	-	-	-	-	-	
1v	FACILITY COMMITMENT FEES	-	-	-	-	-	Debt related
1w	FINES & OTHER	86,745	86,745	-	-	-	Excluded because the underlying account(s) are not included in model
1x	OTHER NONCURRENT- RAILROAD LIABILITY	70,225	-	-	70,225	-	Related to reserve for required maintenance on right of ways.
1y	OTHER UNEARNED REVENUE-DEFERRED RENTS	258,166	-	-	258,166	-	Rent expense deferred and amortized ratably for books, tax deduction when paid - used for all functions.
1z	PAYROLL TAXES	-	-	-	-	-	Book records a payroll tax accrual; tax reverses the accrual and deducts the actual amount paid out. Relates to all functions.
1aa	PENNSYLVANIA NOL	19,225,596	-	-	19,225,596	-	PECO is in a net operating loss situation, therefore, losses are carried forward until such losses can be applied to taxable income.
1ab	PENSION EXPENSE PROVISION	-	-	-	-	-	Book accrues and capitalizes anticipated Pension costs based on actuarial analysis. Tax deducts or capitalizes retirement benefits only when the amounts are paid. Related to all functions.
1ac	POLE ATTACHMENT RESERVE	-	-	-	-	-	Excluded because the underlying account(s) are not included in model
1ad	POST RETIREMENT BENEFITS	71,516,180	-	-	-	71,516,180	Book accrues anticipated post retirement costs based on actuarial analysis. Tax deducts retirement benefits only when the amounts are paid or contributed to a fund.
1ae	RESERVE FOR EMPLOYEE LITIGATIONS Current	-	-	-	-	-	Related to reserves associated with ongoing and/or pending litigation. These are not legal service fees, but accrual for possible liability payments upon resolution of ongoing litigation matters. Since we have accrued, but not yet paid, we have to book the tax reserve.
1af	SA UNBILLED RESERVE	2,180,599	2,180,599	-	-	-	Retail related
1ag	SECA REFUND	-	-	-	-	-	Retail related
1ah	SEPTA RAILROAD RENT	-	-	-	-	-	Reserve for potential transmission rent expense
1ai	SEVERANCE PMTS CHANGE IN PROVISION	177,323	-	-	-	177,323	Book records an accrual; tax takes the deduction when actually paid. Relates to all functions.
1aj	VACATION PAY CHANGE IN PROVISION	902,265	902,265	-	-	-	Capitalized portion of vacation pay earned and expensed for books, tax takes the deduction when paid out. Related to all functions.
1ak	VEGETATION MGMT ACCRUAL	2,636,769	2,636,769	-	-	-	Excluded because the underlying account(s) are not included in model
1al	WORKERS COMPENSATION RESERVE	8,151,016	-	-	-	8,151,016	Related to all functions.
1am							
1an							
…		-					
2	**Subtotal - p234.8.c**	146,414,186	32,774,108	-	19,553,987	94,086,091	
3	**Less FASB 109 Above if not separately removed**	(23,320,598)	(1,292,743)	-	294,795	(22,322,649)	
4	**Less FASB 106 Above if not separately removed**						
5	**Total (Line 2 - Line 3 - Line 4)**	169,734,784	34,066,851	-	19,259,193	116,408,740	

6 **Instructions for Account 190:**
7 **1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C**
8 **2. ADIT items related only to Transmission are directly assigned to Column D**
9 **3. ADIT items related to Plant other than general plant, intangible plant or common plant and not in Columns C & D are included in Column E**
10 **4. ADIT items related to labor, general plant, intangible plant, or common plant and not in Columns C & D are included in Column F**
11 **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,**
12 **the associated ADIT amount shall be excluded**

Attachment 12 PECO Formula Rate Updated

PECO Energy Company

ADIT EOY Worksheet

	A	B	C	D	E	F	G
	ADIT- 282 (Attachment H-7 Notes N and Q)	*Total*	*Gas, Prod Retail Or Other Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
13a	Property Related ADIT, Excl. ARO	-	-	-	-	-	
13b	Common	(29,107,226)	-	-	-	(29,107,226)	Included because plant in service is included in rate base.
13c	Distribution	(1,277,494,888)	(1,277,494,888)	-	-	-	Related to Distribution property.
13d	Electric General	(3,136,156)	-	-	-	(3,136,156)	Included because plant in service is included in rate base.
13e	Transmission	(235,859,579)	-	(235,859,579)	-	-	Included because plant in service is included in rate base.
13f							
13g							
13h							
…							
14	**Subtotal - p275.2.k**	(1,545,597,849)	(1,277,494,888)	(235,859,579)	-	(32,243,382)	
15	**Less FASB 109 Above if not separately removed**	(284,353,657)	(247,839,335)	(35,469,436)	-	(1,044,886)	
16	**Less FASB 106 Above if not separately removed**						
17	**Total (Line 14 - Line 15 - Line 16)**	(1,261,244,192)	(1,029,655,553)	(200,390,143)	-	(31,198,496)	

18 **Instructions for Account 282:**
19 **1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C**
20 **2. ADIT items related only to Transmission are directly assigned to Column D**
21 **3. ADIT items related to Plant other than general plant, intangible plant or common plant and not in Columns C & D are included in Column E**
22 **4. ADIT items related to labor, general plant, intangible plant, or common plant and not in Columns C & D are included in Column F**
23 **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,**
24 **the associated ADIT amount shall be excluded**

PECO Energy Company

ADIT EOY Worksheet

	A	B	C	D	E	F	G
	ADIT-283 (Attachment H-7 Notes O, P and Q)	*Total*	*Gas, Prod Retail Or Other Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
25a	ACT 129 SMART METER	-	-	-	-	-	Retail related
25b	AEC RECEIVABLE	(930,652)	(930,652)	-	-	-	Retail related
25c	AMORT-BK-PREMIUMS ON REACQD DEBT-9.5%	(269,975)	-	-	(269,975)	-	Book recapitalizes costs incurred to retire or reacquire debt issuances. Tax deducts these costs when incurred.
25d	CAP FORGIVENESS REG ASSET	-	-	-	-	-	Retail related
25e	CAP SHOPPING REG ASSET	-	-	-	-	-	Retail related
25f	DSP 2 - REGULATORY ASSET	(43,613)	(43,613)	-	-	-	Retail related
25g	ELEC RATE CASE EXP - REG ASSET	(142,257)	(142,257)	-	-	-	Retail related
25h	ENERGY EFFICIENCY REG ASSET	(60,561)	(60,561)	-	-	-	Retail related
25i	Gross Up on State Def Tax Adj- AMR Reg Asset	(192,532)	(192,532)	-	-	-	Retail related
25j	HOLIDAY PAY CHANGE IN PROVISION	(262,244)	-	-	-	(262,244)	The book expense on Jan 1 of calendar year; accelerated tax expense taken in previous calendar year. Related to all functions.
25k	OCI-Def FIT & SIT	-	-	-	-	-	Excluded because the underlying account(s) are not included in model
25l	OTHER CURRENT REG ASSET:	-	-	-	-	-	0
25m	LOSS OF REAQUIRED DEBT	(51,488)	-	-	(51,488)	-	Book recapitalizes costs incurred to retire or reacquire debt issuances. Tax deducts these costs when incurred. Included in debt capitalization ratio on Appendix A, line 111.
25n	VACATION ACCRUAL	(1,600,829)	(1,600,829)	-	-	-	Current portion of vacation pay earned and expensed for books, tax takes the deduction when paid out. Related to all functions.
25o	SMART METER	(3,337,244)	(3,337,244)	-	-	-	Retail related
25p	CAP SHOPPING REG ASSET - CURRENT	-	-	-	-	-	Retail related
25q	CAP FORGIVENESS REG ASSET - CURRENT	(1,015,422)	(1,015,422)	-	-	-	Retail related
25r	FAS 112	(206,973)	-	-	-	(206,973)	Employer provided benefits to former employees but before retirement.
25s	PURTA	(67,403)	-	-	(67,403)	-	Property taxes. Book records on an accrual method based on the prior year; tax reverses the book accrual and deducts the actual payments made. . Relates to all functions.
25t	ELEC RATE CASE EXP - REG ASSET - CURRENT	(142,257)	(142,257)	-	-	-	Retail related
25u	SEAMLESS MOVES	(0)	-	-	-	(0)	Book accrues and capitalizes anticipated Pension costs based on actuarial analysis. Tax deducts or capitalizes retirement benefits only when the amounts are paid. Retail related.
25v	OTHER CURRENT REG ASSET	-	-	-	-	-	Gas Related
25w	PENSION EXPENSE PROVISION	(94,537,653)	-	-	-	(94,537,653)	Book accrues and capitalizes anticipated Pension costs based on actuarial analysis. Tax deducts or capitalizes retirement benefits only when the amounts are paid. Related to all functions.
25x	RATE CHANGE REG ASSET	(6,167,317)	(6,167,317)	-	-	-	Gross up related to non-property tax rate change/TCJA
25y	STATE TAX RESERVE	(3,653,636)	-	-	(3,653,636)	-	The state income tax is cash basis
25z	ARO- Reg Asset	(5,140,850)	(5,140,850)	-	-	-	
25aa	FERC 494 SETTLEMENT DECEMBER 2019	(557,890)	(557,890)	-	-	-	
25ab	TSC UNDER RECOVERY	(68,722)	(68,722)	-	-	-	Retail related
25ac	CLOUD COMPUTING	(941,505)	(941,537)	-	-	-	
25ad		-					
25ae		-					
25af		-					
….		-					
….							
26	**Subtotal - p277.9.k**	(119,391,023)	(20,341,683)	-	(4,042,502)	(95,006,870)	
27	**Less FASB 109 Above if not separately removed**	10,558,767	58,135	-	1,122,631	9,378,001	
28	**Less FASB 106 Above if not separately removed**						
29	**Total**	(129,949,790)	(20,399,818)	-	(5,165,133)	(104,384,871)	

30 **Instructions for Account 283:**
31 **1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C**
32 **2. ADIT items related only to Transmission are directly assigned to Column D**
33 **3. ADIT items related to Plant other than general plant, intangible plant or common plant and not in Columns C & D are included in Column E**
34 **4. ADIT items related to labor, general plant, intangible plant, or common plant and not in Columns C & D are included in Column F**
35 **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,**
36 **the associated ADIT amount shall be excluded**

PECO Energy Company

Attachment 4D - Intangible Plant Workpaper

Total Intangible Plant

	(a) **Gross Plant**	(b) December Prior Year	(c) January	(d) February	(e) March	(f) April	(g) May	(h) June	(i) July	(j) August	(k) September	(l) October	(m) November	(n) December	(o) Average =average(b:n)	(p) Transmission	(q) Distribution	(r) S&W Allocation	(s) Total =sum(p:r)
1	Intangible - General	17,881,251	23,945,709	24,556,582	25,360,374	26,132,221	26,836,900	27,604,877	28,331,566	28,995,770	29,747,926	30,492,446	31,167,366	33,565,085	27,278,313			27,278,313	27,278,313
2	IT NERC CIP - Transmission	10,967,791	10,967,791	10,967,791	10,967,791	10,967,791	10,967,791	10,967,791	10,967,791	10,967,791	10,967,791	10,967,791	10,967,791	10,967,791	10,967,791	10,967,791			10,967,791
3	IT NERC CIP - Distribution	1,486,430	1,486,430	1,486,430	1,486,430	1,486,430	1,486,430	1,486,430	1,486,430	1,486,430	1,486,430	1,486,430	1,486,430	1,486,430	1,486,430		1,486,430		1,486,430
4	IT DSP - Distribution	2,231,384	2,231,384	2,231,384	2,231,384	2,231,384	2,231,384	2,231,384	2,231,384	2,231,384	2,231,384	2,231,384	2,231,384	2,231,384	2,231,384		2,231,384		2,231,384
5	IT Business Intelligence Data Analysis - Distribution	26,991,446	27,186,159	27,411,603	27,688,917	27,964,599	28,225,000	28,499,977	28,765,558	29,004,223	29,259,666	29,512,134	29,738,755	30,011,456	28,481,500		28,481,500		28,481,500
6	IT Post 2010 and Other - Distribution	30,137,375	30,137,375	30,137,375	30,137,375	30,137,375	30,137,375	30,137,375	30,137,375	30,137,375	30,137,375	30,137,375	30,137,375	30,137,375	30,137,375		30,137,375		30,137,375
7	IT Smart Meter - Distribution	86,110,083	86,110,083	86,110,083	86,110,083	86,110,083	86,110,083	86,110,083	86,110,083	86,110,083	86,110,083	86,110,083	86,110,083	86,110,083	86,110,083		86,110,083		86,110,083
8	IT Other - Transmission	5,771,259	5,771,259	5,771,259	5,771,259	5,771,259	5,771,259	5,771,259	5,771,259	5,771,259	5,771,259	5,771,259	5,771,259	5,771,259	5,771,259	5,771,259			5,771,259
9	IT Business Intelligence Data Analysis - Transmission	947,199	947,199	947,199	947,199	947,199	947,199	947,199	947,199	947,199	947,199	947,199	947,199	947,199	947,199	947,199			947,199
10	IT CIMS - Distribution Only Portion	-	154,583	332,832	552,094	770,066	975,955	1,193,369	1,403,353	1,592,057	1,794,026	1,993,643	2,172,823	2,388,437	1,178,711		1,178,711		1,178,711
11																			-
12																			-
13																			-
14																			-
15																			-
16																			-
17																			-
18																			-
19	Total	182,524,219	188,937,972	189,952,539	191,252,907	192,518,407	193,689,376	194,949,744	196,151,999	197,243,572	198,453,139	199,649,744	200,730,466	203,616,500	194,590,045	17,686,249	149,625,482	27,278,313	194,590,045
20															Allocation Factor	100.00%	0.00%	9.45%	
21															Total Intangible - Transmission	17,686,249	-	2,577,551	20,263,800

	(a) **Accumulated Depreciation**	(b) December Prior Year	(c) January	(d) February	(e) March	(f) April	(g) May	(h) June	(i) July	(j) August	(k) September	(l) October	(m) November	(n) December	(o) Average =average(b:n)	(p) Transmission	(q) Distribution	(r) S&W Allocation	(s) Total =sum(p:r)
22	Intangible - General	9,817,212	10,327,495	10,846,040	11,362,340	11,886,441	12,420,643	12,967,117	13,526,047	14,096,567	14,678,891	15,273,687	15,880,311	16,508,919	13,045,516			13,045,516	13,045,516
23	IT NERC CIP - Transmission	8,342,199	8,524,468	8,706,738	8,889,007	9,071,277	9,253,546	9,435,816	9,618,086	9,800,355	9,982,625	10,164,894	10,328,785	10,474,297	9,430,161	9,430,161			9,430,161
24	IT NERC CIP - Distribution	1,131,680	1,156,395	1,181,110	1,205,825	1,230,541	1,255,256	1,279,971	1,304,686	1,329,402	1,354,117	1,378,832	1,401,505	1,422,137	1,279,343		1,279,343		1,279,343
25	IT DSP - Distribution	2,231,384	2,231,384	2,231,384	2,231,384	2,231,384	2,231,384	2,231,384	2,231,384	2,231,384	2,231,384	2,231,384	2,231,384	2,231,384	2,231,384		2,231,384		2,231,384
26	IT Business Intelligence Data Analysis - Distribution	7,148,207	7,290,075	7,434,444	7,581,807	7,732,462	7,886,309	8,043,344	8,203,598	8,366,854	8,533,052	8,702,274	8,874,349	9,049,396	8,065,090		8,065,090		8,065,090
27	IT Post 2010 and Other - Distribution	20,319,087	20,837,984	21,354,222	21,867,802	22,375,473	22,877,235	23,378,997	23,880,759	24,377,431	24,869,014	25,360,596	25,852,178	26,343,760	23,361,118		23,361,118		23,361,118
28	IT Smart Meter - Distribution	75,341,753	75,537,580	75,717,825	75,881,967	76,038,978	76,185,229	76,327,333	76,469,436	76,611,539	76,753,642	76,895,745	77,037,848	77,167,442	76,305,101		76,305,101		76,305,101
29	IT Other - Transmission	4,190,529	4,453,984	4,717,439	4,980,894	5,244,349	5,507,804	5,771,259	5,771,259	5,771,259	5,771,259	5,771,259	5,771,259	5,771,259	5,345,678	5,345,678			5,345,678
30	IT Business Intelligence Data Analysis - Transmission	67,725	78,584	89,443	100,302	111,161	122,021	132,880	143,739	154,598	165,457	176,316	187,175	198,034	132,880	132,880			132,880
31	IT CIMS - Distribution Only Portion	-	644	1,387	2,300	5,036	9,537	15,803	23,849	33,556	44,891	57,899	72,486	88,718	27,393		27,393		27,393
32																			-
33																			-
34																			-
35																			-
36																			-
37																			-
38																			-
39																			-
40	Total	128,589,775	130,438,593	132,280,032	134,103,628	135,927,101	137,748,965	139,583,903	141,172,842	142,772,945	144,384,331	146,012,887	147,637,281	149,255,346	139,223,664	14,908,718	111,269,429	13,045,516	139,223,664
41															Allocation Factor	100.00%	0.00%	9.45%	
42															Total Intangible - Transmission	14,908,718	-	1,232,682	16,141,400

PECO Energy Company

Attachment 4D - Intangible Plant Workpaper

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)
	Net Plant in Service	December Prior Year	January	February	March	April	May	June	July	August	September	October	November	December	Average	Transmission	Distribution	S&W Allocation	Total
	Gross Plant Minus Accumulated Depreciation														=average(b:n)				=sum(p:r)
43	Intangible - General	8,064,039	13,618,214	13,710,543	13,998,035	14,245,780	14,416,257	14,637,760	14,805,519	14,899,203	15,069,035	15,218,759	15,287,055	17,056,166	14,232,797			14,232,797	14,232,797
44	IT NERC CIP - Transmission	2,625,593	2,443,323	2,261,054	2,078,784	1,896,514	1,714,245	1,531,975	1,349,706	1,167,436	985,167	802,897	639,006	493,495	1,537,630	1,537,630			1,537,630
45	IT NERC CIP - Distribution	354,751	330,036	305,320	280,605	255,890	231,175	206,459	181,744	157,029	132,313	107,598	84,925	64,294	207,088		207,088		207,088
46	IT DSP - Distribution	-	-	-	-	-	-	-	-	-	-	-	-	-	-		-		-
47	IT Business Intelligence Data Analysis - Distribution	19,843,239	19,896,084	19,977,159	20,107,110	20,232,137	20,338,691	20,456,633	20,561,960	20,637,370	20,726,614	20,809,860	20,864,407	20,962,060	20,416,409		20,416,409		20,416,409
48	IT Post 2010 and Other - Distribution	9,818,288	9,299,391	8,783,153	8,269,573	7,761,903	7,260,140	6,758,378	6,256,616	5,759,944	5,268,361	4,776,779	4,285,197	3,793,615	6,776,257		6,776,257		6,776,257
49	IT Smart Meter - Distribution	10,768,330	10,572,503	10,392,257	10,228,116	10,071,105	9,924,853	9,782,750	9,640,647	9,498,544	9,356,441	9,214,338	9,072,234	8,942,641	9,804,981		9,804,981		9,804,981
50	IT Other - Transmission	1,580,730	1,317,275	1,053,820	790,365	526,910	263,455	-	-	-	-	-	-	-	425,581	425,581			425,581
51	IT Business Intelligence Data Analysis - Transmission	879,474	868,615	857,756	846,897	836,038	825,178	814,319	803,460	792,601	781,742	770,883	760,024	749,165	814,319	814,319	814,319		1,628,639
52	IT CIMS - Distribution Only Portion	-	153,939	331,446	549,794	765,030	966,417	1,177,566	1,379,505	1,558,501	1,749,135	1,935,743	2,100,337	2,299,719	1,151,318		1,151,318		1,151,318
53		-	-	-	-	-	-	-	-	-	-	-	-	-					-
54		-	-	-	-	-	-	-	-	-	-	-	-	-					-
55		-	-	-	-	-	-	-	-	-	-	-	-	-					-
56		-	-	-	-	-	-	-	-	-	-	-	-	-					-
57		-	-	-	-	-	-	-	-	-	-	-	-	-					-
58		-	-	-	-	-	-	-	-	-	-	-	-	-					-
59		-	-	-	-	-	-	-	-	-	-	-	-	-					-
60		-	-	-	-	-	-	-	-	-	-	-	-	-					-
61	Total	53,934,444	58,499,379	57,672,507	57,149,279	56,591,307	55,940,412	55,365,840	54,979,157	54,470,627	54,068,808	53,636,857	53,093,185	54,361,154	55,366,381	2,777,531	39,170,372	14,232,797	56,180,700
62															Allocation Factor	100.00%	0.00%	9.45%	
63															Total Intangible - Transmission	2,777,531	-	1,344,869	4,122,400

	(a)	(b)	(c)	(d)	(e)	(f)
		Total	Transmission	Distribution	S&W Allocation	Total
	Depreciation Expense					=sum(c:e)
64	Intangible - General	4,026,332			4,026,332	4,026,332
65	IT NERC CIP - Transmission	2,012,206	2,012,206			2,012,206
66	IT NERC CIP - Distribution	99,119		99,119		99,119
67	IT DSP - Distribution	-		-		-
68	IT Business Intelligence Data Analysis - Distribution	645,830		645,830		645,830
69	IT Post 2010 and Other - Distribution	6,746,713		6,746,713		6,746,713
70	IT Smart Meter - Distribution	3,562,235		3,562,235		3,562,235
71	IT Other - Transmission	3,088,073	3,088,073			3,088,073
72	IT Business Intelligence Data Analysis - Transmission	20,459	20,459			20,459
73		-				-
74		-				-
75		-				-
76		-				-
77		-				-
78		-				-
79		-				-
80		-				-
81		-				-
82	Total	20,200,967	5,120,737	11,053,897	4,026,332	20,200,967
83		Allocation Factor	100.00%	0.00%	9.45%	
84		Total Intangible - Transmission	5,120,737	-	380,452	5,501,189

PECO Energy Company

Attachment 4E - Cost to Achieve Mergers (Note A)

	(a)	(b)	(c)	(d)	(e)	(…)	(x)
	O&M Cost To Achieve						
	FERC Account	Constellation Merger	PHI Merger				Total
1	923	0	$ 7,746				$ 7,746
2	926	0	$ -				$ -
3	920		$ -				$ -
4							$ -
5							$ -
6							$ -
7							$ -
8							$ -
9							$ -
10							$ -
11	Total	$ -	$ 7,746				$ 7,746
	Capital Cost To Achieve included in the Electric Portion of Common Plant						
	Gross Plant	Constellation Merger	PHI Merger				Total
12	December Prior Year	-	3,205,042				$ 3,205,042
13	January	-	3,183,945				$ 3,183,945
14	February	-	3,183,945				$ 3,183,945
15	March	-	3,183,945				$ 3,183,945
16	April	-	3,183,945				$ 3,183,945
17	May	-	3,183,945				$ 3,183,945
18	June	-	3,183,945				$ 3,183,945
19	July	-	3,183,945				$ 3,183,945
20	August	-	3,183,945				$ 3,183,945
21	September	-	3,183,945				$ 3,183,945
22	October	-	3,183,945				$ 3,183,945
23	November	-	3,183,945				$ 3,183,945
24	December	-	3,183,945				$ 3,183,945
25	Average	-	3,185,568				3,185,568
	Accumulated Depreciation	Constellation Merger	PHI Merger				Total
26	December Prior Year	-	1,329,143				$ 1,329,143
27	January	-	1,389,039				$ 1,389,039
28	February	-	1,448,611				$ 1,448,611
29	March	-	1,507,870				$ 1,507,870
30	April	-	1,566,826				$ 1,566,826
31	May	-	1,625,489				$ 1,625,489
32	June	-	1,683,866				$ 1,683,866
33	July	-	1,741,968				$ 1,741,968
34	August	-	1,799,802				$ 1,799,802
35	September	-	1,857,377				$ 1,857,377
36	October	-	1,914,701				$ 1,914,701
37	November	-	1,971,782				$ 1,971,782
38	December	-	2,028,627				$ 2,028,627
39	Average	-	1,681,931				1,681,931

PECO Energy Company

Attachment 4E - Cost to Achieve Mergers (Note A)

	(a)	(b)	(c)	(d)	(e)	(…)		(x)
	Net Plant = Gross Plant Minus Accumulated Depreciation from above	Constellation Merger	PHI Merger					Total
40	December Prior Year	-	1,875,899	-	-	-	$	1,875,899
41	January	-	1,794,906	-	-	-	$	1,794,906
42	February	-	1,735,334	-	-	-	$	1,735,334
43	March	-	1,676,075	-	-	-	$	1,676,075
44	April	-	1,617,119	-	-	-	$	1,617,119
45	May	-	1,558,456	-	-	-	$	1,558,456
46	June	-	1,500,079	-	-	-	$	1,500,079
47	July	-	1,441,977	-	-	-	$	1,441,977
48	August	-	1,384,143	-	-	-	$	1,384,143
49	September	-	1,326,568	-	-	-	$	1,326,568
50	October	-	1,269,244	-	-	-	$	1,269,244
51	November	-	1,212,163	-	-	-	$	1,212,163
52	December	-	1,155,318	-	-	-	$	1,155,318
53	Average	-	1,503,637	-	-	-		1,503,637
	Depreciation (Monthly Change of Accumulated Depreciation from above)	Constellation Merger	PHI Merger					Total
54	January	-	59,895				$	59,895
55	February	-	59,572				$	59,572
56	March	-	59,259				$	59,259
57	April	-	58,956				$	58,956
58	May	-	58,662				$	58,662
59	June	-	58,377				$	58,377
60	July	-	58,102				$	58,102
61	August	-	57,834				$	57,834
62	September	-	57,575				$	57,575
63	October	-	57,324				$	57,324
64	November	-	57,081				$	57,081
65	December	-	56,845				$	56,845
66	Total	-	699,484				$	699,484

Note:

A: Merger-related costs incurred during hold harmless period are to be excluded from rate unless approved by FERC order.

Attachment 5
Attachment H-7, Pages 3 and 4, Worksheet
PECO Energy Company

Line No.	Month	Transmission O&M Expenses	Account No. 566 (Misc. Trans. Expense)	Account No. 565	Accounts 561.4 and 561.8	Amortization of Regulatory Asset	Miscellaneous Transmission Expense (less amortization of regulatory asset)	Depreciation Expense - Transmission	Depreciation Expense - Common	Depreciation Expense - Transmission Intangible	Depreciation Expense - General Intangible	Depreciation Expense - Distribution
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Attachment H-7, Page 3, Line No.:	1	2	3		11	12	16				
	Form No. 1	321.112.b	321.97.b	321.96.b	321.88.b & 92.b	Portion of Account 566 (Attachment H-7 Notes T and Z)	Balance of Account 566	Attachment 8, Page 1, Line 11, Col J	Attachment 8, Page 2, Line 51, Col J	Attachment 8, Page 2, Line 10, Col J	Attachment 8, Page 2, Line 19, Col J	Attachment 8, Page 2, Line 22, Col J
1	Total	116,080,855	10,863,927	-	65,204,955	-	$ 10,863,927	$ 26,801,531	$ 32,943,973	$ 5,120,743	$ 4,026,335	$ 11,053,897

Line No.	Month	Depreciation Expense - General	Amortization of Abandoned Plant	Labor Related Taxes	Labor Related Taxes to be Excluded	Plant Related Taxes	Excluded Taxes Per Attachment 5C Line 5	Other Included Taxes	Plant Related Taxes to be Excluded	Amortized Investment Tax Credit Consistent with (266.8.f & 266.17.f) - Transmission	Excess Deferred Income Tax Amortization - Transmission	Tax Effect of Permanent Differences - Transmission
		(a)	(b)	(c)	(d) (Note F)	(e)	(f)	(g)	(h) (Note F)	(i)	(j)	(k)
	Attachment H-7, Page 3, Line Number	17	19	23	24	26	27	28	29	38	39	40
	Form No. 1	Attachment 8, Page 1, Line 25, Col J	(Note S)	Attachment 5C Line 2	Attachment 5C Line 9	Attachment 5C Line 1	Attachment 5C Line 5	Attachment 5C Line 3	Attachment 5C Line 10	(Note E)	(Attachment H-7 Note G)	(Attachment H-7 Note W)
2	Total	$ 18,971,738	$ -	$ 12,308,308	$ -	$ 12,835,970	$ 132,585,408	$ 450,022	$ -	$ 2,976	$ 3,250,820	$ 282,655

Attachment 5
Attachment H-7, Pages 3 and 4, Worksheet
PECO Energy Company

			$
3	Long Term Interest (117, sum of 62.c through 67.c), Excluding LVT Interest (Note G)		137,274,572
4	Preferred Dividends (118.29c) (positive number)		-
5	Proprietary Capital		4,070,854,964
6	Less Preferred Stock		-
7	Less Account 216.1 (enter negative) (Note D)		-
8	Less Account 219.1 (enter negative)		(1,843,551)
9	Common Stock	(Sum of Line 5 - Line 6 + Line 7 + Line 8)	4,069,011,413

			$	%	Cost	Weighted	
10	Long Term Debt (Note A)	(100% - Line 11, Col (%) - Line 12, Col (%))	3,409,418,609	45.59%	4.03%	1.84%	=WCLTD
11	Preferred Stock (Note B)	(Line 11, Col ($) / Line 13, Col ($))	-	-	-	0.00%	
12	Common Stock (Note C)	(Line 12, Col ($) / Line 13, Col ($))	4,069,011,413	54.41%	10.35%	5.63%	
13	Total	(Sum of Lines 10-12)	7,478,430,022			7.47%	=R

Notes:

A Long Term Debt balance will reflect the 13 month average of the balances, of which the 1st and 13th are found on page 112 lines 18.c & d to 21.c & d in the Form No. 1.

B Preferred Stock balance will reflect the 13 month average of the balances, of which the 1st and 13th are found on page 112 line 3.c & d in the Form No. 1

C Common Stock balance will reflect the 13 month average of the balances, of which the 1st and 13th are found on page 112 lines 3.c & d, 12.c & d, and 16.c & d in the Form No. 1 as shown on lines 10-12 above
A cap on the equity percentage of PECO's capital structure shall be 55.75%.
ROE will be supported in the original filing and no change in ROE may be made absent FERC authorization pursuant to a section 205 or section 206.

D The Account 216.1 balance is input only if positive number in the FERC Form No. 1 (112.12.c).

E Sum of transmission related electric and common amortized investment tax credit amounts. Total electric amount allocated to transmission as follows: (1) amounts solely related to transmission allocated 100% to transmission; (2) amounts solely related to distribution, gas or non-utility allocated 0% to transmission; (3) amounts related to electric general allocated using the wages and salaries allocator (Attachment H-7, p. 4, line 11, column (5)); (4) amount related to common plant allocated to transmission using the wages and salaries allocator (Attachment H-7, p. 4, line 11, column (5)), multiplied by common utility plant percent to electric (per FF1 page 356).

F Labor and Plant related taxes due to merger are to be excluded consistent with hold harmless commitment.

G All short-term interest related expense will be removed from the formula rate template.

Attachment 12 PECO Formula Rate Updated

PECO Energy Company
Attachment 5A - Revenue Credit Workpaper

	Account 454 - Rent from Electric Property		
1	Rent from Electric Property - Transmission Related, Subject to Sharing (Note 3)		8,608,297
2	Rent from Electric Property - Transmission Related, Pass to Customers (Note 3)		761,781
3	Total Rent Revenues	(Sum Lines 1 to 2)	9,370,078
	Account 456 & 456.1 - Other Electric Revenues (Note 1)		
4	Schedule 1A		$ 5,000,280
5	Firm Point to Point Service revenues for which the load is not included in the divisor received by transmission owner		$ 1,078,490
6	Revenues associated with transmission service not provided under the PJM OATT (Note 4)		-
7	Intercompany Professional Services		356,114
8	PJM Transitional Revenue Neutrality (Note 1)		-
9	PJM Transitional Market Expansion (Note 1)		-
10	Professional Services (Note 3)		-
11	Revenues from Directly Assigned Transmission Facility Charges (Note 2)		-
12	Rent or Attachment Fees associated with Transmission Facilities (Note 3)		-
13	Gross Revenue Credits	(Sum Lines 3, 4-12)	15,804,962
14	Less line 17g		(5,699,777)
15	Total Revenue Credits		10,105,185

<u>Revenue Adjustment to determine Revenue Credit</u>

16a	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 in line 2; provided, that the revenue credit on line 2 will not include revenues associated with transmission service the loads for which are included in the rate divisor in Attachment H-7, page 1, line 11.	-
16b	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.	
16c	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 and by department the revenues and costs associated with each secondary use (except for the cost of the associated income taxes). The cost associated with the secondary transmission use is 3/4 of the total department costs.	
17a	Revenues included in lines 1-11 which are subject to 50/50 sharing.	8,608,297
17b	Costs associated with revenues in line 17a	2,958,183
17c	Net Revenues (17a - 17b)	5,650,114
17d	50% Share of Net Revenues (17c / 2)	2,825,057
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.	83,463
17f	Net Revenue Credit (17d + 17e)	2,908,519
17g	Line 17f less line 17a	(5,699,777)
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.	-
19	Reserved	-
20	Total Account 454, 456 and 456.1	15,804,962
21	Reserved	

Attachment 12 PECO Formula Rate Updated

Attachment 5A - Revenue Credit Workpaper

Costs associated with revenues in line 17a

	Cost Item	Accounts booked to	Total Costs	Costs Allocation to Transmission (Note A)	Transmission Costs	S&W Allocation Factor	Costs Recovered Through A&G Costs
22a	Administrative and General Salaries	920000	635,681	75%	476,760	9.45%	60,066
22b	Employee Pensions and Benefits	926000	247,607	75%	185,705	9.45%	23,397
…							
23	Total Lines 22		$ 883,288		$ 662,466		$ 83,463

	FERC Account 454	Total Amount	Other	100% Transmission	Plant Related	Labor Related	Total
24a	Rent from Electric Distribution	$ 13,620,424	$ 13,620,424				
24b	Rent from Electric Transmission	264,492		264,492			
24c	Tower Rentals and Land Leasing - Transmission	8,608,297		8,608,297			
24d	Tower Rentals and Land Leasing - Distribution	3,175,581	3,175,581				
24e	Intercompany Rent	2,458,806			2,458,806		
24f	Intercompany Rent - Transmission	42,186		42,186			
…							
	Total Lines 24	$ 28,169,786	$ 16,796,006	$ 8,914,975	$ 2,458,806	$ -	
	Allocation Factors		0%	100%	18.51%	9.45%	
	Allocated Amount		$ -	$ 8,914,975	$ 455,103	$ -	$ 9,370,078

	FERC Account 456	Total Amount	Other	100% Transmission	Plant Related	Labor Related	Total
25a	Decommissioning remittances to Generation	$ (3,859,745)	$ (3,859,745)				
25b	Mutual Assistance	1,550,258	$ 1,550,258				
25c	Make Ready	8,613,547	$ 8,613,547				
25d	Intercompany Billings - Transmission	256,013		256,013			
25e	Intercompany Billings - Labor Related	557				557	
25f	Intercompany Billings - Other	1,080,486	1,080,486				
25g	Other	994,848	424,350	(59)	509,877	60,680	
…							
	Total Lines 25	$ 8,635,964	$ 7,808,896	$ 255,954	$ 509,877	$ 61,237	
	Allocation Factors		0%	100%	18.51%	9.45%	
	Allocated Amount		$ -	$ 255,954	$ 94,374	$ 5,786	$ 356,114

	FERC Account 456.1	Total Amount	Other	100% Transmission	Plant Related	Labor Related	Total
26a	Network Integration Credit	$ 142,255,073	$ 142,255,073				
26b	Transmission Owner Scheduling Credits	5,000,280		$ 5,000,280			
26c	Transmission Enhancement	33,519,816	$ 33,519,816				
26d	Revenue - Firm Point to Point	1,078,490		1,078,490			
26e	Other	2,597,170	2,597,170				
…							
	Total Lines 26	$ 184,450,830	$ 178,372,060	$ 6,078,770	$ -	$ -	
	Allocation Factors		0%	100%	18.51%	9.45%	
	Allocated Amount		$ -	$ 6,078,770	$ -	$ -	$ 6,078,770

Note A: Number of employees managing secondary transmission service contracts divided by number of employees managing transmission and distribution secondary service contracts.

PECO Energy Company

Attachment 5B - A&G Workpaper

			(a)	(b)	(c)	(d)	(e)
			323.181.b to 323.196.b				
			Total	S&W Allocation	Gross Plant Allocation	Non-Recoverable	Directly Assigned
1	Administrative and General Salaries	920.0	$ 27,667,179	$ 27,667,179		$ -	$ -
2	Office Supplies and Expenses	921.0	9,038,489	9,000,155		38,335	-
3	Administrative Expenses Transferred-Credit	922.0	-	-		-	-
4	Outside Service Employed (Note E)	923.0	74,403,755	73,736,716		667,039	-
5	Property Insurance	924.0	24,174		24,174	-	-
6	Injuries and Damages	925.0	13,844,910	13,844,910		-	-
7	Employee Pensions and Benefits	926.0	28,504,054	28,504,054		-	-
8	Franchise Requirements	927.0	-	-		-	-
9	Regulatory Commission Expenses (Note E)	928.0	8,049,891	-		7,714,062	335,829
10	Duplicate Charges-Credit	929.0	(2,859,505)	(2,859,505)		-	-
11	General Advertising Expenses (Note E)	930.1	2,643,003	-		2,643,003	-
12	Miscellaneous General Expenses (Note E)	930.2	3,076,972	2,445,200		631,772	-
13	Rents	931.0	-	-		-	-
14	Maintenance of General Plant	935	5,960,581	5,960,581		-	-
15	**Administrative & General - Total (Sum of lines 1-14)**		$ 170,353,503	$ 158,299,290	$ 24,174	$ 11,694,210	$ 335,829
16			Allocation Factor	9.45%	18.51%	0.00%	100.00%
17			Transmission A&G [1]	14,957,835	4,474	-	335,829
18						Total [2]	$15,298,139

Notes:

[1] Multiply total amounts on line 15, columns (b)-(e) by allocation factors on line 16.

[2] Sum of line 17, columns (b), (c), (d), (e).

PECO Energy Company
Attachment 5C - Taxes Other Than Income

	Taxes Other Than Income	**Page 263 Col (i)**
	Plant Related, Subject to Gross Plant Allocator	
1a	PA Real Estate Tax - 2019	7,579,064
1b	Property Tax Payable	5,256,906
1c		
…		
1	**Total Plant Related (Total Lines 1)**	12,835,970
	Labor Related, Subject to Wages & Salary Allocator	
2a	Federal Unemployment	49,816
2b	Social Security	11,940,482
2c	PA Unemployment	318,010
…		
2	**Total Labor Related (Total Lines 2)**	12,308,308
	Other Included, Subject to Gross Plant Allocator	
3a	State Use Taxes	446,333
3b	Miscellaneous Taxes	3,689
3c		
…		
3	**Total Other Included (Total Lines 3)**	450,022
4	**Total Included (Lines 1 to 3)**	25,594,300
	Taxes Other Than Income Excluded Per Notes A to E	
5a	PA Gross Receipts Tax - 2018	1,089,911
5b	PA Gross Receipts Tax - 2019	131,374,951
5c	Sales Tax Payable	120,546
…		
5	**Total Excluded Taxes Other Than Income (Total Lines 5)**	132,585,408
6	**Total Taxes Other Than Income, Included and Excluded (Lines 4 and 5)**	158,179,708
7	**Total Taxes Other Income from p115.14.g**	158,179,708
8	Difference (Line 6 - Line 7)	-
	Items Included in Line 4, that Are To Be Excluded from Formula Per Attachment 5-P3 Support Note F (Enter Negative)	
9a		
9b		
…		
9	Total Labor Related Taxes to be Excluded (Total Lines 9)	-
10a		
10b		
…		
10	Total Plant Related Taxes to be Excluded (Total Lines 10)	-

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 shall 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 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 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.

Attachment 12 PECO Formula Rate Updated

Attachment 6
True-Up Interest Rate
PECO Energy Company

	Month (Note A)	FERC Monthly Interest Rate
1	January	0.0044
2	February	0.0040
3	March	0.0044
4	April	0.0045
5	May	0.0046
6	June	0.0045
7	July	0.0047
8	August	0.0047
9	September	0.0045
10	October	0.0046
11	November	0.0045
12	December	0.0046
13	January	0.0042
14	February	0.0039
15	March	0.0042
16	April	0.0039
17	May	0.0040
18	Average of lines 1-17 above	0.0044

Note:

A The FERC Quarterly Interest Rate in column [A] is the interest applicable to the Month indicated.

19 Year 2020

20

	A	B	C	D	E	F
	Project Name	RTO Project Number or Zonal	Amount	17 Months	Monthly Interest Rate	Interest
			Attachment 3, Col. G + Col H		Line 18 above	Col. C x Col D x Col E
21	Zonal	Zonal	(20,854,875)	17	0.0044	(1,547,432)
21a	Center Point 500-230 kV Substation A	b0269	(391,303)	17	0.0044	(29,035)
21b	Center Point 500-230 kV Substation A	b0269	(1,541,012)	17	0.0044	(114,343)
21c	Richmond-Waneeta 230 kV Line Re-cc	b1591	(870,009)	17	0.0044	(64,555)
21d	Richmond-Waneeta 230 kV Line Re-cc	b1398.8	42,655	17	0.0044	3,165
21e	Whitpain 500 kV Circuit Breaker Addi	b0269.6	(105,990)	17	0.0044	(7,864)
21f	Elroy-Hosensack 500 kV Line Rating I	b0171.1	(146,489)	17	0.0044	(10,870)
21g	Camden-Richmond 230 kV Line Rating	b1590.1 and b1590.2	5,707	17	0.0044	423
21h	Chichester-Linwood 230 kV Line Upgr	b1900	938,783	17	0.0044	69,658
21i	Bryn Mawr-Plymouth 138 kV Line Rel	b0727	(879,637)	17	0.0044	(65,269)
21j	Emilie 230-138 kV Transformer Additi	b2140	(696,158)	17	0.0044	(51,655)
21k	Chichester-Saville 138 kV Line Re-con	b1182	(643,601)	17	0.0044	(47,755)
21l	Waneeta 230-138 kV Transformer Add	b1717	(466,324)	17	0.0044	(34,601)
21m	Chichester 230-138 kV Transformer A	b1178	(294,971)	17	0.0044	(21,887)
21n	Bradford-Planebrook 230 kV Line Upg	b0790	(62,061)	17	0.0044	(4,605)
21o	North Wales-Hartman 230 kV Line Re-	b0506	(78,118)	17	0.0044	(5,796)
21p	North Wales-Whitpain 230 kV Line Re	b0505	(84,074)	17	0.0044	(6,238)
21q	Bradford-Planebrook 230 kV Line Upg	b0789	(84,826)	17	0.0044	(6,294)
21r	Planebrook 230 kV Capacitor Bank Ad	b0206	(108,037)	17	0.0044	(8,016)
21s	Newlinville 230 kV Capacitor Bank Ac	b0207	(146,439)	17	0.0044	(10,866)
21t	Chichester-Mickleton 230 kV Series R	b0209	(83,255)	17	0.0044	(6,177)
21u	Chichester-Mickleton 230 kV Line Re-	b0264	(71,083)	17	0.0044	(5,274)
21v	Buckingham-Pleasant Valley 230 kV L	b0357	(88,402)	17	0.0044	(6,559)
21w	Elroy 500 kV Dynamic Reactive Devic	b0287	139,862	17	0.0044	10,378
21x	Heaton 230 kV Capacitor Bank Additic	b0208	106,838	17	0.0044	7,927
21y	Peach Bottom 500-230 kV Transformer	b2694	1,181,215	17	0.0044	87,646
21z	Peach Bottom 500 kV Substation Upgr	b2766.2	54,931	17	0.0044	4,076
…						

Attachment 7
PBOPs
PECO Energy Company

Calculation of PBOP Expenses

	(a)		(b) PECO Total	(c) Portion not Capitalized	(d) Electric Col. (c) x Electric Labor in Note B
1	Total PBOP expenses allowed (Note A)		1,066,173	679,716	542,277
2	Total PBOP Expenses in A&G in the current year			815,434	650,553
3	PBOP Adjustment	Line 1 minus line 2			(108,275)

Notes:

A The source of the amounts from the Actuary Study supporting the amount in line 1, column (b) is the 3rd page of the attachment to the January 24, 2017 Willis Towers Watson report on PBOPs for PECO.

		$	%
B	Electric Labor (354.28.b)	166,589,129	79.78%
	Gas Labor sum (355.62.b)	42,221,639	20.22%
	Total	208,810,768	

C The Willis Towers Watson report on PBOPs does not breakout the amount related to construction labor that is capitalized. As a result, the portion not capitalized is calculated as labor expensed divided by total labor.

PECO Energy Company
Attachment 8 - Depreciation and Amortization

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
	Number	Plant Type	Estimated Life	Mortality Curve	Weighted Average Remaining Life	Depreciation / Amortization Rate	Gross Depreciable Plant (Year End Balance) $	Accumulated Depreciation $	Net Depreciable Plant $	Depreciation Expense $
			Note 1	Note 1	Note 2		Note 4	Note 4	(I)=(G)-(H)	(J)=(F)*(G)
1							**As of 12/31/2019**			**FY 2019**
2		**Electric Transmission**								
3	352	Structures and Improvements	N/A	N/A	N/A	1.7951%	84,648,186	22,075,677	62,572,509	1,519,520
4	353	Station Equipment	N/A	N/A	N/A	1.7406%	916,183,089	206,465,896	709,717,193	15,947,083
5	354	Towers and Fixtures	N/A	N/A	N/A	1.3697%	289,020,870	160,785,185	128,235,685	3,958,719
6	355	Poles and Fixtures	N/A	N/A	N/A	1.5768%	17,404,687	2,569,179	14,835,508	274,437
7	356	Overhead Conductors and Devices	N/A	N/A	N/A	1.5942%	200,291,092	84,403,607	115,887,485	3,193,041
8	357	Underground Conduit	N/A	N/A	N/A	1.6381%	16,205,140	4,253,018	11,952,122	265,456
9	358	Underground Conductors and Devices	N/A	N/A	N/A	1.5536%	103,883,450	45,482,089	58,401,361	1,613,933
10	359	Roads and Trails	N/A	N/A	N/A	1.1526%	2,545,719	2,087,014	458,705	29,342
11							**1,630,182,233**	**528,121,665**	**1,102,060,568**	**26,801,531**
12		**Electric General**								
13	390	Structures and Improvements	40	R1	26.62	2.9566%	49,534,157	11,870,358	37,663,799	1,464,527
14	391.1	Office Furniture and Equipment - Office Machines	10	SQ	2.50	10.6324%	83,462	65,786	17,676	8,874
15	391.2	Office Furniture and Equipment - Furnitures and Fixtures	15	SQ	10.93	6.8284%	509,566	147,907	361,659	34,795
16	391.3	Office Furniture and Equipment - Computers	5	SQ	3.25	19.7397%	28,616,027	13,187,765	15,428,262	5,648,718
17	391.4	Office Furniture and Equipment - Smart Meter Comp. Equip.	5	SQ	3.25	40.8577%	656,594	(76,065)	732,659	268,269
18	393	Stores Equipment	15	SQ	9.32	8.6809%	46,470	11,016	35,454	4,034
19	394	Tools, Shop, Garage Equipment	15	SQ	9.54	6.7951%	37,811,861	12,704,571	25,107,290	2,569,354
20	395.1	Laboratory Equipment - Testing	20	SQ	6.74	4.3016%	311,026	227,910	83,116	13,379
21	395.2	Laboratory Equipment - Meters	15	SQ	3.50	6.4687%	101,381	81,824	19,557	6,558
22	397	Communication Equipment	20	L3	14.46	5.0575%	128,734,058	32,489,484	96,244,574	6,510,725
23	397.1	Communication Equipment - Smart Meters	15	S2	9.47	6.6081%	36,350,171	13,922,355	22,427,816	2,402,056
24	398	Miscellaneous Equipment	15	SQ	0.54	156.6758%	25,817	3,845	21,972	40,449
25							**282,780,590**	**84,636,756**	**198,143,834**	**18,971,738**

PECO Energy Company
Attachment 8 - Depreciation and Amortization

1		**Electric Intangible**								
2	303	Software - Transmission 2-year Life (Note 10)	2	N/A	N/A	53.5078%	5,771,259	4,190,529	1,580,730	3,088,074
3	303	Software - Transmission 3-year Life (Note 10)	3	N/A	N/A	N/A	-	-	-	-
4	303	Software - Transmission 4-year Life (Note 10)	4	N/A	N/A	N/A	-	-	-	-
5	303	Software - Transmission 5-year Life (Note 10)	5	N/A	N/A	17.0410%	11,928,113	8,410,862	3,517,251	2,032,670
6	303	Software - Transmission 7-year Life (Note 10)	7	N/A	N/A	N/A	-	-	-	-
7	303	Software - Transmission 10-year Life (Note 10)	10	N/A	N/A	N/A	-	-	-	-
8	303	Software - Transmission 13-year Life (Note 10)	13	N/A	N/A	N/A	-	-	-	-
9	303	Software - Transmission 15-year Life (Note 10)	15	N/A	N/A	N/A	-	-	-	-
10							**17,699,372**	**12,601,391**	**5,097,981**	**5,120,743**
11	303	Software - Electric General 2-year Life (Note 10)	2	N/A	N/A	N/A	-	-	-	-
12	303	Software - Electric General 3-year Life (Note 10)	3	N/A	N/A	0.013887	245,411	3,408	242,003	3,408
13	303	Software - Electric General 4-year Life (Note 10)	4	N/A	N/A	N/A	-	-	-	-
14	303	Software - Electric General 5-year Life (Note 10)	5	N/A	N/A	23.0238%	17,472,905	9,813,804	7,659,101	4,022,927
15	303	Software - Electric General 7-year Life (Note 10)	7	N/A	N/A	N/A	-	-	-	-
16	303	Software - Electric General 10-year Life (Note 10)	10	N/A	N/A	N/A	-	-	-	-
17	303	Software - Electric General 13-year Life (Note 10)	13	N/A	N/A	N/A	-	-	-	-
18	303	Software - Electric General 15-year Life (Note 10)	15	N/A	N/A	N/A	-	-	-	-
19							**17,718,316**	**9,817,212**	**7,901,104**	**4,026,335**
20	303	Software - Electric Distribution	N/A	N/A	N/A	N/A	128,162,185	96,978,841	31,183,344	11,053,897
21	303	Regulatory Initiatives/Depr Charged to Reg Asset	N/A	N/A	N/A	N/A	18,781,412	9,192,331	9,589,081	Zero
22							**146,943,597**	**106,171,172**	**40,772,425**	**11,053,897**
23		**Common General - Electric**								
24	303	Software - 2-year Life (Note 10)	2	N/A	N/A	N/A	-	-	-	-
25	303	Software - 3-year Life (Note 10)	3	N/A	N/A	0.052207	332,272	17,347	314,925	17,347
26	303	Software - 4-year Life (Note 10)	4	N/A	N/A	N/A	-	-	-	-
27	303	Software - 5-year Life (Note 10)	5	N/A	N/A	8.4797%	229,959,380	161,634,363	68,325,017	19,499,866
28	303	Software - 7-year Life (Note 10)	7	N/A	N/A	N/A	-	-	-	-
29	303	Software - 10-year Life (Note 10)	10	N/A	N/A	N/A	-	-	-	-
30	303	Software - 13-year Life (Note 10)	13	N/A	N/A	N/A	-	-	-	-
31	303	Software - 15-year Life (Note 10)	15	N/A	N/A	N/A	-	-	-	-
32	303	Regulatory Initiatives/Depr Charged to Reg Asset	N/A	N/A	N/A	N/A	147,738	147,738	-	Zero
33	390	Structures and Improvements	50	R1	36.30	1.9364%	226,634,074	61,764,371	164,869,703	4,388,542
34	391.1	Office Furniture and Equipment - Office Machines	10	SQ	1.50	18.8194%	100,099	15,811	84,288	18,838
35	391.2	Office Furniture and Equipment - Furnitures and Fixtures	15	SQ	10.80	6.7577%	16,548,288	3,061,813	13,486,475	1,118,284
36	391.3	Office Furniture and Equipment - Computers	5	SQ	2.68	19.3400%	29,150,184	13,404,514	15,745,670	5,637,646
37	392.1	Transportation Equipment - Automobiles	6	L3	4.09	N/A	72,553	72,079	474	Zero
38	392.2	Transportation Equipment - Light Trucks	12	L4	7.37	N/A	26,839,337	12,378,794	14,460,543	Zero
39	392.3	Transportation Equipment - Heavy Trucks	14	R4	8.27	N/A	68,038,889	28,792,657	39,246,232	Zero
40	392.4	Transportation Equipment - Tractors	11	L2	2.36	N/A	216,441	217,544	(1,103)	Zero
41	392.5	Transportation Equipment - Trailers	15	R2	9.36	N/A	3,616,256	1,864,725	1,751,531	Zero
42	392.6	Transportation Equipment - Other Vehicles	15	R2	6.24	N/A	3,942,297	3,114,232	828,065	Zero
43	392.7	Transportation Equipment -Medium Trucks	N/A	N/A	7.28	N/A	13,310,723	1,876,790	11,433,933	Zero
44	393	Stores Equipment	15	SQ	8.91	7.4565%	1,111,086	314,348	796,738	82,848
45	394.1	Tools, Shop, Garage Equipment - Construction Tools	15	SQ	3.50	94.0451%	9,001	(16,243)	25,244	8,465
46	394.2	Tools, Shop, Garage Equipment - Common Tools	15	SQ	14.02	6.5410%	799,169	94,114	705,055	52,274
47	394.3	Tools, Shop, Garage Equipment - Garage Equipment	20	SQ	8.33	N/A	1,377,337	647,008	730,329	Zero
48	396	Power Operated Equipment	11	L2	2.70	N/A	143,389	141,445	1,944	Zero
49	397	Communication Equipment	20	L3	12.74	3.9345%	52,249,327	15,816,564	36,432,763	2,055,750
50	398	Miscellaneous Equipment	15	SQ	8.18	6.9008%	929,083	426,874	502,209	64,114
51							**675,526,923**	**305,786,888**	**369,740,035**	**32,943,973**

Attachment 12 PECO Formula Rate Updated

PECO Energy Company
Attachment 8 - Depreciation and Amortization

		Current Year Depr./Amor. Exp Per Formula Total Company (B)	Current Year Depr./Amor. Exp Per FF1 / Atta 4D for Intangible Total Company (C)	Current Year Difference Total Company (D)=(B)-(C)	Allocation % To Transmission (E)	Current Year Difference Allocated To Transmission (F)=(D)*(E)	Prior Year Total Cumulative Difference Total Company (G)	Prior Year Total Cumulative Difference Transmission (H)	Current Year Total Cumulative Difference Total Company (I)=(D)+(G)	Current Year Total Cumulative Difference Transmission (J)=(F)+(H)
1	Transmission	$ 26,801,531	26,802,058	(527)	100.00%	(527)	(1,080)	(1,080)	(1,607)	(1,607)
2	Electric General	$ 18,971,738	18,971,748	(10)	9.45%	(1)	54	5	44	4
3	Common - Electric	$ 32,943,973	32,943,908	65	9.45%	6	(219)	(21)	(154)	(15)
4	Intangible - Transmission	$ 5,120,743	$ 5,120,737	6	100.00%	6	10	10	16	16
5	Intangible - General	$ 4,026,335	$ 4,026,332	2	9.45%	0	(7)	(1)	(4)	(0)
6	Intangible - Distribution	$ 11,053,897	$ 11,053,897	-	0.00%	-	-	-	-	-
7										

8 **Accumulative Depreciation**

9		Average Accumulative Depr./Amor. Per Book Total Company	Total Cumulative Adjustment Total Company	Adjusted Average Accumulative Depr./Amor. Total Company	Allocation % To Transmission	Adjusted Average Accumulative Depr./Amor. Transmission
10	Transmission	$ 535,111,387	(1,344)	535,112,730	100.00%	535,112,730
11	Electric General	$ 92,316,119	49	92,316,071	9.45%	8,723,025
12	Common - Electric	$ 321,189,339	(186)	321,189,525	9.45%	30,349,473
13	Intangible - Transmission	$ 14,908,718	13	14,908,705	100.00%	14,908,705
14	Intangible - General	$ 13,045,516	(6)	13,045,522	9.45%	1,232,683
15	Intangible - Distribution	$ 111,269,429	$ -	111,269,429	0.00%	-
16	Total Intangible	$ 139,223,664	$ 8	$ 139,223,656		$ 16,141,388
17						
18						
19						
20						
21						
22						
23						
24						

Notes:

1 Columns (A), (B), (C), and (D) are fixed and cannot be changed absent Commission approval or acceptance. The depreciation / amortization expense is calculated separately for each row.

2 For Electric General and Common General plant, except FERC account 303, Column (E) is the remaining life of the assets in the account for each vintage (amount of plant added in each year is a vintage) weighted by the gross plant balance of each account or subaccount. The remaining life for each vintage is equal to the area under the Mortality Curve specified in Columns (C) and (D) using a half year convention for the first year placed in service. The weighted remaining life is calculated once a year at the beginning of the year.

3 For FERC accounts 303, 352 through 359 and 390 through 398, Column F is fixed and cannot be changed absent Commission approval or acceptance.

4 Column (G) is the depreciable amount of gross plant investment reported in the annual FERC Form No. 1 filing on pages 207 (Electric) and 356 (Common) by account or subaccount. Column (H) is the accumulated depreciation by account or subaccount.

5 Column (I) is the end of year depreciable net plant in the account or subaccount.

6 Reserved

7 Reserved

8 At least every 5 years, PECO Energy Company will file with the Commission a depreciation study supporting its existing Estimated Life and Mortality Curve for each account or subaccount.

9 The depreciation expense associated with Asset Retirement Obligations (booked to accounts 359.1 and 399.1) are not included in the tables above.

10 The life of each software or other intangible plant will be estimated at the time the plant is placed into service, and will not change over the life of the plant absent Commission approval or acceptance. The combined amortization expense for all intangible plant shall be the sum of each individual plant balance amortized over the life of each individual plant established in this manner.

11 The depreciation expenses related to Common General - Electric reflect electric common plant. The depreciation expenses associated with Transportation Equipment, Garage Equipment and Power Operated Tools are excluded from Account 403 and directly assigned to the functional O&M and capital accounts based on use.

Attachment 9
Excess / (Deficient) Deferred Income Taxes (Note B and Attachment H-7 Notes N, O and P)
PECO Energy Company

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
EDIT Amortization Amount (Note C)		January	February	March	April	May	June	July	August	September	October	November	December	Total
1 **Protected Property**														
2 Transmission		$ 72,177	$ 72,177	$ 72,177	$ 72,177	$ 72,177	$ 72,177	$ 72,177	$ 72,177	$ 72,177	$ 72,177	$ 72,177	$ 72,177	$ 866,126
3 General		$ (2,833)	$ (2,833)	$ (2,833)	$ (2,833)	$ (2,833)	$ (2,833)	$ (2,833)	$ (2,833)	$ (2,833)	$ (2,833)	$ (2,833)	$ (2,833)	$ (33,994)
4 Transmission Allocation % (Att H-7 P4, L11, Col 5)		9.45%												
5 Allocated to Transmission		$ (268)	$ (268)	$ (268)	$ (268)	$ (268)	$ (268)	$ (268)	$ (268)	$ (268)	$ (268)	$ (268)	$ (268)	$ (3,212)
6 Common (To Be Split TDG)		$ 18,962	$ 18,962	$ 18,962	$ 18,962	$ 18,962	$ 18,962	$ 18,962	$ 18,962	$ 18,962	$ 18,962	$ 18,962	$ 18,962	$ 227,539
7 Transmission Allocation % (L 4 * Electric Factor in FERC Form 1 P356)		7.32%												
8 Allocated to Transmission		$ 1,388	$ 1,388	$ 1,388	$ 1,388	$ 1,388	$ 1,388	$ 1,388	$ 1,388	$ 1,388	$ 1,388	$ 1,388	$ 1,388	$ 16,659
9 **Total Protected Property**		$ 73,298	$ 73,298	$ 73,298	$ 73,298	$ 73,298	$ 73,298	$ 73,298	$ 73,298	$ 73,298	$ 73,298	$ 73,298	$ 73,298	$ 879,572
10 **Non-Protected Property (Note A)**		$ 201,938	$ 201,938	$ 201,938	$ 201,938	$ 201,938	$ 201,938	$ 201,938	$ 201,938	$ 201,938	$ 201,938	$ 201,938	$ 201,938	$ 2,423,256
11 **Non-Protected, Non-Property - Pension Asset (Note A)**		$ 74,045	$ 74,045	$ 74,045	$ 74,045	$ 74,045	$ 74,045	$ 74,045	$ 74,045	$ 74,045	$ 74,045	$ 74,045	$ 74,045	$ 888,540
12 **Non-Protected, Non-Property - Non-Pension Asset (Note A)**		$ (78,379)	$ (78,379)	$ (78,379)	$ (78,379)	$ (78,379)	$ (78,379)	$ (78,379)	$ (78,379)	$ (78,379)	$ (78,379)	$ (78,379)	$ (78,379)	$ (940,548)
13 **Total Non-Protected, Non-Property (Note A)**		$ (4,334)	$ (4,334)	$ (4,334)	$ (4,334)	$ (4,334)	$ (4,334)	$ (4,334)	$ (4,334)	$ (4,334)	$ (4,334)	$ (4,334)	$ (4,334)	$ (52,008)

EDIT Balance (Notes C and D)

	December Prior Year	January	February	March	April	May	June	July	August	September	October	November	December	Prior and Current December Average
14 **Protected Property**														
15 Transmission	$ 78,972,292	78,900,115	78,827,938	78,755,761	78,683,583	78,611,406	78,539,229	78,467,052	78,394,875	78,322,698	78,250,521	78,178,344	78,106,166	78,539,229
16 General	$ 1,463,764	1,466,597	1,469,430	1,472,263	1,475,095	1,477,928	1,480,761	1,483,594	1,486,427	1,489,260	1,492,092	1,494,925	1,497,758	1,480,761
17 Transmission Allocation %	9.45%													
18 Allocated to Transmission	$ 138,312	138,580	138,848	139,115	139,383	139,651	139,918	140,186	140,454	140,721	140,989	141,257	141,524	139,918
19 Common (To Be Split TDG)	$ 11,360,123	11,341,161	11,322,200	11,303,238	11,284,277	11,265,315	11,246,353	11,227,392	11,208,430	11,189,468	11,170,507	11,151,545	11,132,584	11,246,353
20 Transmission Allocation %	7.32%													
21 Allocated to Transmission	$ 831,692	830,304	828,915	827,527	826,139	824,751	823,363	821,974	820,586	819,198	817,810	816,422	815,033	823,363
22 **Total Protected Property**	$ 79,942,296	79,868,998	79,795,701	79,722,403	79,649,105	79,575,808	79,502,510	79,429,212	79,355,915	79,282,617	79,209,319	79,136,022	79,062,724	79,502,510
23 **Non-Protected Property (Note A)**	$ 14,539,561	14,337,623	14,135,685	13,933,747	13,731,809	13,529,871	13,327,933	13,125,995	12,924,057	12,722,119	12,520,181	12,318,243	12,116,305	13,327,933
24 **Non-Protected, Non-Property - Pension Asset (Note A)**	$ 3,554,162	3,480,117	3,406,072	3,332,027	3,257,982	3,183,937	3,109,892	3,035,847	2,961,802	2,887,757	2,813,712	2,739,667	2,665,622	3,109,892
25 **Non-Protected, Non-Property - Non-Pension Asset (Note A)**	$ (3,762,179)	(3,683,800)	(3,605,421)	(3,527,042)	(3,448,663)	(3,370,284)	(3,291,905)	(3,213,526)	(3,135,147)	(3,056,768)	(2,978,389)	(2,900,010)	(2,821,631)	(3,291,905)
26 **Total Non-Protected, Non-Property (Note A)**	$ (208,017)	(203,683)	(199,349)	(195,015)	(190,681)	(186,347)	(182,013)	(177,679)	(173,345)	(169,011)	(164,677)	(160,343)	(156,009)	(182,013)

Notes:

A EDIT data, including EDIT amortization amount and balance, for Protected, Non-Protected Property and Non-Protected, Non-Property shall reflect the Transmission portion of EDIT amounts. The amounts and categorization of these balances as of December 31, 2017 is: Protected Property - Transmission (Line 15): $79,726,712; Protected Property - Electric General to be allocated between Distribution and Transmission (Line 16): $1,683,749; Protected Property – Common to be allocated between Distribution, Transmission and Gas (Line 19): $11,901,494; Non-Protected Property (Line 23): $16,962,821; Non-Protected Non-Property (Line 26): ($260,021).

B The amortization schedule of the EDIT balance related to Tax Cuts and Job Act of 2017 shall be consistent with the following periods:

Protected:	ARAM
Non-Protected Property:	7 years
Non-Protected, Non-Property:	5 years

The Non-Protected Property EDIT balance shall be fully amortized by the end of 2024 and the Non-Protected, non-Property EDIT balance shall be fully amortized by the end of 2022.

C The data of the annual amortization amount and balance are from PECO's Tax Accounting records.

D EDIT balance was reclassified from ADIT to EDIT in December 2017.

Attachment 10
Pension Asset Discount Worksheet
PECO Energy Company

				Source
1	13 Month Average Pension Asset (Note A)		27,745,514	(Attachment 4, line 28(i))
	Net ADIT Balance			
2	Prior Year ADIT Related to Transmission Pension Asset		(8,756,446)	(Attachment 4B "PENSION EXPENSE PROVISION" times S&W Allocator)
3	Current Year ADIT Related to Transmission Pension Asset		(8,932,944)	(Attachment 4C "PENSION EXPENSE PROVISION" times S&W Allocator)
4	Average ADIT Balance Related to Transmission Pension Asset		(8,844,695)	(Average of Lines 2 and 3)
5	Net Unamortized EDIT Balance	$	(3,109,892)	(Attachment 9 line 24 "Average")
6	Net Pension Asset	$	15,790,927	(Line 1 plus Line 4 plus Line 5)
7	100% of ATRR on Net Pension Asset		1,540,431	(Line 6 times Attachment H-7 page 3, line 34, col (3) times (1+Attachment H-7 page 4, line 18, col (5))
8	Times Pension Discount %		60%	
9	ATRR Discount on Net Pension Asset	$	924,259	(Line 7 times Line 8)

Note:
A: PECO’s transmission-related Pension Asset balance is capped at $33 million. Such limit may only be changed pursuant to a section 205 or 206 filing.

Attachment 12 PECO Formula Rate Updated

Attachment 11
Cost of Capital
PECO Energy Company

Line		
	Long Term Interest (117, lines 62 through 67), Excluding LVT Interest	
1	Interest on Long-Term Debt (427)	122,359,442
2	Amort. of Debt Disc. and Expense (428)	2,310,300
3	Amortization of Loss on Reacquired Debt (428.1)	455,601
4	(Less) Amort. of Premium on Debt-Credit (429)	
5	(Less) Amortization of Gain on Reacquired Debt-Credit (429.1)	
6	Interest on Debt to Assoc. Companies (430)	12,149,229
7	(Less) Short-term Interest (5-P3 Support Note G)	
8	**Total Long Term Interest (Line 1 + Line 2 + Line 3 - Line 4 - Line 5 + Line 6 - Line 7)**	**$137,274,572**

13-Month Average Balance of Long-term Debt,

Line		December Prior Year	January	February	March	April	May	June	July	August	September	October	November	December	13-Month Average
	Long -term Debt (112, Lines 18 through 21)														
9	Bonds (221)	3,125,000,000	3,125,000,000	3,125,000,000	3,125,000,000	3,125,000,000	3,125,000,000	3,125,000,000	3,125,000,000	3,125,000,000	3,450,000,000	3,450,000,000	3,450,000,000	3,450,000,000	3,225,000,000
10	(Less) Reacquired Bonds (222)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Advances from Associated Companies (223)	184,418,609	184,418,609	184,418,609	184,418,609	184,418,609	184,418,609	184,418,609	184,418,609	184,418,609	184,418,609	184,418,609	184,418,609	184,418,609	184,418,609
12	Other Long-Term Debt (224)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	**Total (Line 9 - Line 10 + Line 11 + Line 12)**	**$ 3,309,418,609**	**$ 3,309,418,609**	**$ 3,309,418,609**	**$ 3,309,418,609**	**$ 3,309,418,609**	**$ 3,309,418,609**	**$ 3,309,418,609**	**$ 3,309,418,609**	**$ 3,309,418,609**	**$ 3,634,418,609**	**$ 3,634,418,609**	**$ 3,634,418,609**	**$ 3,634,418,609**	**$ 3,409,418,609**
	Proprietary Capital (112, line 2 through 15)														
14	Common stock issued (201)	1,423,004,251	1,423,004,251	1,423,004,251	1,423,004,251	1,423,004,251	1,423,004,251	1,423,004,251	1,423,004,251	1,423,004,251	1,423,004,251	1,423,004,251	1,423,004,251	1,423,004,251	1,423,004,251
15	Preferred Stock (204) (112.3.c) (5-P3 Support Note B)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Capital Stock Subscribed (202, 205)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Stock Liability for Conversion (203, 206)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Premium on Capital Stock (207)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Other Paid-in Capital (208-211)	1,155,155,244	1,155,155,244	1,155,155,244	1,300,155,244	1,300,155,244	1,300,155,244	1,300,155,244	1,300,155,244	1,300,155,244	1,329,155,244	1,343,450,423	1,343,450,423	1,343,450,423	1,278,915,670
20	Installments Received on Capital Stock (212)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	(Less) Discount on Capital Stock (213)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	(Less) Capital Stock Expense (214)	86,742	86,742	86,742	86,742	86,742	86,742	86,742	86,742	86,742	86,742	86,742	86,742	86,742	86,742
23	Retained Earning s(215, 215.1, 216)	4,427,930,434	4,510,538,983	4,564,907,417	4,521,682,757	4,552,730,556	4,589,672,684	4,543,291,354	4,609,634,817	4,661,288,172	4,605,783,948	4,627,158,813	4,680,394,559	4,643,271,373	4,579,868,144
24	Unappropriated Undistributed Subsidiary Earnings (216.1)	(3,187,402,048)	(3,194,319,802)	(3,198,854,724)	(3,202,735,205)	(3,205,342,858)	(3,208,420,258)	(3,212,672,862)	(3,218,225,358)	(3,222,449,990)	(3,224,708,274)	(3,226,494,956)	(3,229,417,286)	(3,233,925,200)	(3,212,689,909)
25	(Less) Reacquired Capital Stock (217)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Noncorporate Proprietorship (Non-major only) (218)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Accumulated other Comprehensive Income (219)	1,674,806	1,630,458	1,630,180	1,742,674	1,742,953	1,742,953	1,769,513	1,725,165	1,725,165	2,094,739	2,094,739	2,094,739	2,298,082	1,843,551
28	Total Proprietary Capital (Line 14+ Line 15 + Line 16 + Line 17 + Line 18 + Line 19 + Line 20 - Line 21 - Line 22 + Line 23 + Line 24 - Line 25 + Line 26 + Line 27)	3,820,275,945	$3,895,922,391	$3,945,755,625	$4,043,762,979	$4,072,203,404	$4,106,068,132	$4,055,460,758	$4,116,207,377	$4,163,636,099	$4,135,243,165	$4,169,126,528	$4,219,439,943	$4,178,012,187	4,070,854,964
29	**Preferred Stock (line 15)**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30	**Common Stock (line 28 - line 29)**	**$ 3,820,275,945**	**$ 3,895,922,391**	**$ 3,945,755,625**	**$ 4,043,762,979**	**$ 4,072,203,404**	**$ 4,106,068,132**	**$ 4,055,460,758**	**$ 4,116,207,377**	**$ 4,163,636,099**	**$ 4,135,243,165**	**$ 4,169,126,528**	**$ 4,219,439,943**	**$ 4,178,012,187**	**$ 4,070,854,964**

Appendix 1B
Populated Projected Net Revenue Requirement – MDTAC

ATTACHMENT H-7B
MDTAC FORMULA RATE TEMPLATE

CALCULATION OF MONTHLY AMORTIZED REGULATORY ASSET TO BE RECOVERED			
1	Annual Revenue Requirement on Regulatory Asset Amortization	Attachment 1 - Revenue Requirement Line 3	$3,789,876
2	True-up Adjustment with Interest	Attachment 2 - True-Up Line 24	($384,923)
3	Net Annual Revenue Requirement on Regulatory Asset Amortization with True-up	Line 1 + line 2	$3,404,952
4	Net Monthly Revenue Requirement on Regulatory Asset Amortization with True-up	Line 3 / 12	$283,746

PECO Energy Company

Summary of Transmission SFAS 109 Regulatory Asset (Account 182.3) Amortization

For the 12 months ended 12/31/2019

1	SFAS 109 Reg Asset Amortization (Notes A and B)	$	3,923,411
2	Other Tax Adjustments (Note C)	$	(133,535)
3	**Adjusted Total**	$	3,789,876

Notes:

(A) All items are asssociated with ratemaking flow through requirements

(B) Additional detail is provided on page 2 of this exhibit

(C) Amortization of FAS 109 Regulatory Asset.

True-Up with Interest
PECO Energy Company

		Month (Note A)	FERC Monthly Interest Rate
1		January	0.0044
2		February	0.0040
3		March	0.0044
4		April	0.0045
5		May	0.0046
6		June	0.0045
7		July	0.0047
8		August	0.0047
9		September	0.0045
10		October	0.0046
11		November	0.0045
12		December	0.0046
13		January	0.0042
14		February	0.0039
15		March	0.0042
16		April	0.0039
17		May	0.0040
18	Average of lines 1-17 above		0.0044

Notes:

A The FERC Quarterly Interest Rate in column [A] is the interest applicable to the Month indicated.

19	Actual Revenue Requirement	2,167,305
20	Revenue Received	2,525,640
21	Net Under/(Over) Collection (Line 19 - Line 20)	(358,335)
22	17 Months	17
23	Interest (Line 18*Line 21*Line 22)	(26,588)
24	Total True-up	(384,923)

PECO Energy Company
Summary of Transmission SFAS 109 Regulatory Asset (Account 182.3)
December 31, 2018 through December 31, 2019

		12/31/2018	Activity	12/31/2019
	TRANSMISSION ONLY			
	Repair Allowance	7,627,294	(210,530)	7,416,764
	Federal and State Flow Through	21,776,261	(819,226)	20,957,035
	Excess Deferreds/pre-1981 Deferreds	17,057,254	(1,723,251)	15,334,003
	Other	393,218	(13,122)	380,096
	Total	46,854,027	(2,766,129)	44,087,898
	COMMON (TO BE SPLIT TDG)			
	Repair Allowance	-	-	-
	Federal and State Flow Through	7,502,269	(59,629)	7,442,640
	Excess Deferreds/pre-1981 Deferreds	2,789,109	(215,267)	2,573,842
	Other	1,350,282	(78,933)	1,271,349
	Total	11,641,660	(353,829)	11,287,831
	Transmission Allocation %	7.32%	***(Attachment H-7A, page 4, line 11, column 5 * Common Allocation Factor in FERC Form 1 page 356)***	
	Repair Allowance	-	-	-
	Federal and State Flow Through	549,252	(4,366)	544,887
	Excess Deferreds/pre-1981 Deferreds	204,195	(15,760)	188,435
	Other	98,856	(5,779)	93,077
	Total	852,304	(25,904)	826,399
	ELECTRIC GENERAL (TO BE SPLIT TD)			
	Repair Allowance	9,355	(240)	9,115
	Federal and State Flow Through	848,578	27,532	876,110
	Excess Deferreds/pre-1981 Deferreds	145,948	(4,019)	141,929
	Other	2,581	(214)	2,367
	Total	1,006,462	23,060	1,029,522
	Transmission Allocation %	9.45%	***Source: Attachment H-7A, page 4, line 11, column 5***	
	Repair Allowance	884	(23)	861
	Federal and State Flow Through	80,183	2,602	82,784
	Excess Deferreds/pre-1981 Deferreds	13,791	(380)	13,411
	Other	244	(20)	224
	Total	95,101	2,179	97,280
	Transmission Summary			
	Repair Allowance	7,628,178	(210,553)	7,417,625
	Federal and State Flow Through	22,405,696	(820,990)	21,584,707
	Excess Deferreds/pre-1981 Deferreds	17,275,240	(1,739,391)	15,535,849
	Other	492,318	(18,921)	473,397
	Total	**47,801,432**	**(2,789,855)**	**45,011,577**
Incl	SFAS 109 + Gross-up	67,223,799	(3,923,411)	63,300,389
	2010 Transmission Tax Adjustments b/f gross-up	(166,170)	94,954	(71,216)
	2010 Transmission Tax Adjustments + gross-up	(233,687)	133,535	(100,152)
	Total Transmission SFAS 109	66,990,112	(3,789,876)	63,200,237

Gross-up Factor

Federal Income Tax Rate	21.000%
State Income Tax Rate	9.990%
Composite Rate = F+S(1-F)	28.892%
Gross-up Factor = 1/(1-CR)	140.631%

Appendix 2A
2019 True Up Adjustment Calculation – NITS

ATTACHMENT H-7A
FORMULA RATE TEMPLATE

Attachment 12 PECO Formula Rate Updated

Attachment H-7
Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data
PECO Energy Company

For the 12 months ended 12/31/2019

Line No.	(1)	(2)	(3)	(4)		(5) Allocated Amount
1	GROSS REVENUE REQUIREMENT	(page 3, line 48)				195,164,746
2a	Additional Annual Refund (from 2018 to 2021)	Attachment 1, line 17, col 15a				850,000
			Total	Allocator		
2	REVENUE CREDITS	Attachment 5A, line 15	10,120,044	TP	100.00%	10,120,044
3	NET REVENUE REQUIREMENT	(line 1 minus lines 2 and 2a)				184,194,702
4	REGIONAL NET REVENUE REQUIREMENT	Attachment 1, line 18, col. 14 - Attachment 1, line 17a, col. 14				31,090,270
5	Regional True-up Adjustment with Interest	Attachment 1, line 18, col. 15 - Attachment 1, line 17a, col. 15				(1,942,250)
6	REGIONAL NET REVENUE REQUIREMENT with TRUE-UP	Attachment 1, line 18, col. 16 - Attachment 1, line 17a, col. 16				29,148,020
7	ZONAL NET REVENUE REQUIREMENT	Attachment 1, line 17a, col. 14 less line 2				153,104,432
8	Zonal True-up Adjustment with Interest	Attachment 1, line 17a, col. 15				(10,471,680)
9	ZONAL NET REVENUE REQUIREMENT with TRUE-UP	Line 7 + Line 8				142,632,752
10	Competitive Bid Concessions	Attachment 1, line 18, col. 13				-
11	Zonal Load	1 CP from PJM in MW				8,428
12	Network Integration Transmission Service rate for PECO Zone	(line 9/11)				$16,923

Attachment 12 PECO Formula Rate Updated

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data
PECO Energy Company

For the 12 months ended 12/31/2019

Line No.	(1)	(2) Source	(3) Company Total	Allocator	(4)	(5) Transmission (Col 3 times Col 4)
	RATE BASE:					
	GROSS PLANT IN SERVICE (Notes U and R)					
1	Production	205.46.g for end of year, records for other months	-	NA		-
2	Transmission	Attachment 4, Line 14, Col. (b)	1,647,831,648	TP	100.00%	1,647,831,648
3	Distribution	207.75.g for end of year, records for other months	6,495,218,932	NA	0.00%	-
4	General	Attachment 4, Line 14, Col. (c)	278,322,919	W/S	9.45%	26,298,971
5	Intangible	Attachment 4D, Line 19, Col. (s) and Line 21, Col. (s)	172,047,629	DA		19,146,951
6	Common	Attachment 4, Line 14, Col. (d)	627,620,447	W/S	9.45%	59,304,393
7	Costs To Achieve	(enter negative) Attach. 4E, Line 25, Col. (x)	(3,205,042)	W/S	9.45%	(302,847)
8	TOTAL GROSS PLANT	(Sum of Lines 1 through 7)	9,217,836,533	GP=	19.01%	1,752,279,116
9	ACCUMULATED DEPRECIATION (Notes U and R)					
10	Production	219.20-24.c for end of year, records for other months	-	NA		-
11	Transmission	Attachment 8, Page 3, Line 10, Col. (E)	511,106,639	TP	100.00%	511,106,639
12	Distribution	219.26.c for end of year, records for other months	1,756,956,260	NA	0.00%	-
13	General	Attachment 8, Page 3, Line 11, Col. (E)	78,729,972	W/S	9.45%	7,439,262
14	Intangible	Attachment 8, Page 3, Line 16, Col. (E) and Col. (G)	119,276,697	DA		10,776,263
15	Common	Attachment 8, Page 3, Line 12, Col. (E)	288,424,062	W/S	9.45%	27,253,436
16	Costs To Achieve	(enter negative) Attach. 4E, Line 39, Col. (x)	(1,022,266)	W/S	9.45%	(96,595)
17	TOTAL ACCUM. DEPRECIATION	(Sum of Lines 10 through 16)	2,753,471,363			556,479,006
18	NET PLANT IN SERVICE					
19	Production	(line 1 minus line 10)	-			-
20	Transmission	(line 2 minus line 11)	1,136,725,009			1,136,725,009
21	Distribution	(line 3 minus line 12)	4,738,262,672			-
22	General	(line 4 minus line 13)	199,592,947			18,859,708
23	Intangible	(line 5 minus line 14)	52,770,932			8,370,688
24	Common	(line 6 minus line 15)	339,196,385			32,050,957
25	Costs To Achieve	(line 7 minus line 16)	(2,182,775)			(206,252)
26	TOTAL NET PLANT	(Sum of Lines 19 through 25)	6,464,365,170	NP=	18.50%	1,195,800,110
27	ADJUSTMENTS TO RATE BASE (Note R)					
28	Account No. 281 (enter negative)	Attachment 4, Line 28, Col. (d) (Notes B and X)	Zero	NA	zero	-
29	Account No. 282 (enter negative)	Attachment 4A, Line 28, Col. (e) (Notes B and X)	(197,697,419)	TP	100.00%	(197,697,419)
30	Account No. 283 (enter negative)	Attachment 4A, Line 28, Col. (f) (Notes B and X)	(11,093,389)	TP	100.00%	(11,093,389)
31	Account No. 190	Attachment 4A, Line 28, Col. (g) (Notes B and X)	14,865,099	TP	100.00%	14,865,099
31a	Unamortized EDIT Balance - Protected Property (enter negative)	Attachment 9 - EDIT, Line 22, Col. (n)	(79,502,510)	TP	100.00%	(79,502,510)
31b	Unamortized EDIT Balance - Non-Protected Property (enter negative)	Attachment 9 - EDIT, Line 23, Col. (n)	(13,327,933)	TP	100.00%	(13,327,933)
31c	Unamortized EDIT Balance - Non-Protected, Non-Property (enter negative)	Attachment 9 - EDIT, Line 26, Col. (n)	182,013	TP	100.00%	182,013
32	Account No. 255 (enter negative)	Attachment 4, Line 28, Col. (h) (Notes B and X)	-	TP	100.00%	-
33	Unfunded Reserves (enter negative)	Attachment 4, Line 31, Col. (h) (Note Y)	(5,754,589)	DA	100.00%	(5,754,589)
34	CWIP	Attachment 4, Line 14, Col. (e)	-	DA	100.00%	-
35	Pension Asset	Attachment 4, Line 28, Col. (i)	27,745,514	DA	100.00%	27,745,514
36	Unamortized Regulatory Asset	Attachment 4, Line 28, Col. (b) (Note T)	-	DA	100.00%	-
37	Unamortized Abandoned Plant	Attachment 4, Line 28, Col. (c) (Note S)	-	DA	100.00%	-
38	Outstanding Network Credits	From PJM	-	DA	100.00%	-
39	Less Accum. Deprec. associated with Facilities with Outstanding Network Credits	From PJM	-	DA	100.00%	-
40	TOTAL ADJUSTMENTS	(Sum of Lines 28 through 39)	(264,583,214)			(264,583,214)
41	LAND HELD FOR FUTURE USE	Attachment 4, Line 14, Col. (f) (Note C)	4,782,367	TP	100.00%	4,782,367
42	WORKING CAPITAL	(Note D)				
43	CWC	1/8*(Page 3, Line 12 minus Page 3, Line 7)	27,639,173			8,270,400
44	Materials & Supplies	Attachment 4, Line 14, Col. (g)	10,128,797	TP	100.00%	10,128,797
45	Prepayments (Account 165)	Attachment 4, Line 14, Col. (h)	1,670,294	DA	100.00%	1,670,294
46	TOTAL WORKING CAPITAL	(Sum of Lines 43 through 45)	39,438,264			20,069,491
47	RATE BASE	(Sum of Lines 26, 40, 41 & 46)	6,244,002,587			956,068,754

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data
PECO Energy Company

For the 12 months ended 12/31/2019

Line No.	(1)	(2) Source	(3) Company Total	Allocator	(4)	(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	Attachment 5, Line 1, Col. (a)	116,080,855	TP	100.00%	116,080,855
2	Less Account 566 (Misc Trans Expense) (enter negative)	Attachment 5, Line 1, Col. (b)	(10,863,927)	TP	100.00%	(10,863,927)
3	Less Account 565 (enter negative)	Attachment 5, Line 1, Col. (c)	-	TP	100.00%	-
4	Less Accounts 561.4 and 561.8 (enter negative)	Attachment 5, Line 1, Col. (d)	(65,204,955)	TP	100.00%	(65,204,955)
5	A&G	Attachment 5B, Line 15, Col. (a) and Line 18, Col. (e)	170,353,503	DA		15,298,260
6	Account 566					
7	Amortization of Regulatory Asset	(Note T) Attachment 5, Line 1, Col. (e)	-	DA	100.00%	-
8	Miscellaneous Transmission Expense (less amortization of regulatory asset)	Attachment 5, Line 1, Col .(f)	10,863,927	TP	100.00%	10,863,927
9	Total Account 566	(Line 7 plus Line 8) Ties to 321.97.b	10,863,927			10,863,927
10	PBOP Adjustment	Attachment 7, line 3, Col. (d)	(108,275)	W/S	9.45%	(10,231)
11	Less O&M Cost to Achieve Included in O&M Above (enter negative)	Attachment 4E, Line 11, Col. (x)	(7,746)	W/S	9.45%	(732)
12	TOTAL O&M	(Sum of Lines 1 to 5, 9, 10 and 11)	221,113,382			66,163,197
13	DEPRECIATION EXPENSE (Note U)					
14	Transmission	Attachment 5, Line 1, Col. (g)	26,801,531	TP	100.00%	26,801,531
15	General	Attachment 5, Line 2, Col. (a)	18,971,738	W/S	9.45%	1,792,656
16	Intangible - Transmission	Attachment 5, Line 1, Col. (i)	5,120,743	TP	100.00%	5,120,743
16a	Intangible - General	Attachment 5, Line 1, Col. (j)	4,026,335	W/S	9.45%	380,452
16b	Intangible - Distribution	Attachment 5, Line 1, Col. (k)	11,053,897	NA	zero	-
17	Common - Electric	Attachment 5, Line 1, Col. (h)	32,943,973	W/S	9.45%	3,112,904
18	Common Depreciation Expense Related to Costs To Achieve	(enter negative) Attachment 4E, Line 66, Col (x)	(622,846)	W/S	9.45%	(58,853)
19	Amortization of Abandoned Plant	(Note S) Attachment 5, Line 2, Col. (b)	-	DA	100.00%	-
20	TOTAL DEPRECIATION	(Sum of Lines 14 through 19)	98,295,370			37,149,433
21	TAXES OTHER THAN INCOME TAXES	(Note F)				
22	LABOR RELATED					
23	Payroll	Attachment 5, Line 2, Col. (c)	12,308,308	W/S	9.45%	1,163,023
24	Labor Related Taxes to be Excluded	Attachment 5, Line 2, Col. (d)	-	W/S	9.45%	-
25	PLANT RELATED					
26	Property	Attachment 5, Line 2, Col. (e)	12,835,970	GP	19.01%	2,440,074
27	Excluded Taxes Per Attchment 5C Line 5	Attachment 5, Line 2, Col. (f)	132,585,408	NA	zero	-
28	Other	Attachment 5, Line 2, Col. (g)	450,022	GP	19.01%	85,548
29	Plant Related Taxes to be Excluded	Attachment 5, Line 2, Col. (h)	-	GP	19.01%	-
30	TOTAL OTHER TAXES	(Sum of Lines 23 through 29)	158,179,708			3,688,644
31	INTEREST ON NETWORK CREDITS	From PJM	-	DA	100.00%	-
32	INCOME TAXES	(Note G)				
33	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)}	WCLTD = Page 4, Line 19	0.2889			
34	CIT=(T/1-T) * (1-(WCLTD/R)) =	R = Page 4, Line 15	0.3064			
35	FIT & SIT & P	(Note G)				
36						
37	1 / (1 - T) = (T from line 33)		1.4063			
38	Amortized Investment Tax Credit (enter negative)	Attachment 5, Line 2, Col. (i)	(2,976)			
39	Excess Deferred Income Taxes (enter negative)	Attachment 5, Line 2, Col. (j)	(3,250,820)			
40	Tax Effect of Permanent Differences	Attachment 5, Line 2, Col. (k) (Note W)	282,655			
41	Income Tax Calculation	(Line 34 times Line 47)	142,870,694	NA		21,876,065
42	ITC adjustment	(Line 37 times Line 38)	(4,186)	TP	100.00%	(4,186)
43	Excess Deferred Income Tax Adjustment	(Line 37 times Line 39)	(4,571,672)	TP	100.00%	(4,571,672)
44	Permanent Differences Tax Adjustment	(Line 37 times Line 40)	397,502	TP	100.00%	397,502
45	Total Income Taxes	(Sum of Lines 41 through 44)	138,692,338			17,697,709
46	RETURN					
47	Rate Base times Return	(Page 2, Line 47 times Page 4, Line 18)	466,242,081	NA		71,390,023
48a	Net Pension Asset ATRR Discount (enter negative)	Attachment 10, Line 9	(924,259)	DA	100.00%	(924,259)
48	REVENUE REQUIREMENT	(Sum of Lines 12, 20, 30, 31, 45, 47)	1,081,598,620			195,164,746

Attachment 12 PECO Formula Rate Updated

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data PECO Energy Company | For the 12 months ended 12/31/2019

SUPPORTING CALCULATIONS AND NOTES

Line No.	(1)	(2)	(3)		(4)		(5)	
	TRANSMISSION PLANT INCLUDED IN ISO RATES							
1	Total Transmission plant	(Page 2, Line 2, Column 3)					1,647,831,648	
2	Less Transmission plant excluded from PJM rates	(Note H)					-	
3	Less Transmission plant included in OATT Ancillary Services	(Note I)					-	
4	Transmission plant included in PJM rates	(Line 1 minus Lines 2 & 3)					1,647,831,648	
5	Percentage of Transmission plant included in PJM Rates	(Line 4 divided by Line 1)				TP=	100.00%	
6	WAGES & SALARY ALLOCATOR (W&S)							
		Form 1 Reference	$	TP	Allocation			
7	Electric Production	354.20.b	-	0.0%	-			
8	Electric Transmission	354.21.b	12,935,717	100.0%	12,935,717			
9	Electric Distribution	354.23.b	91,501,226	0.0%	-		W&S Allocator	
10	Electric Other	354.24,25,26.b	32,462,198	0.0%	-		($ / Allocation)	
11	Total (W& S Allocator is 1 if lines 7-10 are zero)	(Sum of Lines 7 through 10)	136,899,141		12,935,717	=	9.45%	= WS
12	RETURN (R)	(Note V)					$	
13					Cost			
14			$	%	(Notes K, Q, & R)		Weighted	
15	Long Term Debt	(Attachment 5, line 10 Notes Q & R)	3,409,418,609	45.59%	4.03%		1.84%	=WCLTD
16	Preferred Stock (112.3.c)	(Attachment 5, line 11 Notes Q & R)	-	0.00%	0.00%		0.00%	
17	Common Stock	(Attachment 5, line 12 Notes K, Q & R)	4,069,011,413	54.41%	10.35%		5.63%	
18	Total	(Attachment 5, line 13)	7,478,430,022				7.47%	=R

Attachment 12 PECO Formula Rate Updated

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data
PECO Energy Company

For the 12 months ended 12/31/2019

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)

Notes:

A Reserved

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

C Reserved

D Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 12, column 5 minus amortization of Regulatory Asset at page 3, line 7, column 5. For Prepayments, refer to Note K in Attachment 4.

E Page 3, Line 5: Attachment 5B, Line 4 - Exclude: (1) amortization of CAP Shopping and Seamless Moves; (2) amortization of DSP IV Admin Costs; (3) Miscellaneous Advertising; (4) SEPA Solar Power Study; (5) PSU Sponsorship; (6) EU IT Prepaid Meter Assess O&M; and (7) Customer Operations AMI/CI O&M. Include Communications, Public Advocacy and Corporate Relations and Government and Regulatory Affairs and Public Policy expenses listed in Account 923 found at Form 1 323.184.b.
Attachment 5B, Lines, 11, and 12 - Exclude EPRI Annual Membership Dues listed in Form 1 at 353.f, non-safety-related advertising included in Account 930.1 found at 323.191.b and Chamber of Commerce Dues and Civic Organization Expenses in Account 930.2 found at 323.192.b; include the costs related to Project Cancellation Fees and Remediation Expenditures (provided, that with regard to the Metal Bank Superfund, PECO must include as a credit any receipts received from the EPA and/or obtained through litigation with the remediation contractors related to Metal Bank Superfund).
Attachment 5B, Line 9- include Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h., and exclude all other Regulatory Commission Expenses itemized at 351.h.

F 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.

G 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 36). Excess Deferred Income Taxes reduce income tax expense by the amount of the expense multiplied by (T/1-T).

Inputs Required:	FIT =	21.00%	
	SIT=	9.99%	(State Income Tax Rate or Composite SIT)
	p =	0.00%	(percent of federal income tax deductible for state purposes)

H Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).

I Removes dollar amount of transmission plant to be 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.

J Reserved

K ROE will be supported in the original filing and no change in ROE may be made absent a Section 205 or Section 206 filing with FERC. The equity component of the capital structure will be capped at 55.75% and shall not be subject to change during the ROE Moratorium Period established under the Settlement Agreement in Docket No. ER17-1519. Thereafter, the cap shall be subject to change pursuant to sections 205 and 206 of the Federal Power Act.

L Reserved

M Reserved

N All items related to Contributions in Aid of Construction (CIAC), including investment in CIAC and CIAC related ADIT, excess/(deficient) ADIT and amortization of excess/(deficient) ADIT shall be excluded from the formula rate.

O Transmission-related ADIT, Excess/(Deficient) ADIT, and the amortization of Excess/(Deficient) ADIT shall be included in the formula rate except as noted in Notes N and P. For clarity of administration of the formula rate, this specifically includes (but is not limited to) transmission-related amounts related to Amortization of Book Premiums on Reacquired Debt, Pension Expense Provision, Loss on Reacquired Debt, FAS 112 and Electric Rate Case Expense – Regulatory Asset – Current.

P ADIT, Excess/(Deficient) ADIT and the amortizaiton of Excess/(Deficient) ADIT related to Accrued Benefits, Deferred Compensation, Vacation pay Change in Provision and Accrued Vacation shall be excluded from the formula rate.

Q All ADIT-190, ADIT-282, and ADIT-283 amounts reflected on Attachment 4C must be based on a timing difference between book expense recognition and expense recognition for tax purposes.

R Calculated using 13 month average balance, except ADIT.

S Unamortized Abandoned Plant and Amortization of Abandoned Plant will be zero until FERC explicitly approves recovery of the cost of abandoned plant pursuant to Section 205 of the FPA.

T Recovery of Regulatory Asset is permitted only as specifically authorized pursuant to Section 205 or 206 of the FPA by FERC. Recovery of any regulatory assets not specifically identified in the initial version of this formula rate template approved by FERC in Docket No. ER17-1519-000 will require specific authorization from FERC.

U Excludes Asset Retirement Obligation balances

V Company shall include only gains and losses on interest rate locks associated with debt issuances. Absent a Section 205 filing, Company shall not include in the Formula Rate, the gains, losses, or costs related to other hedges.

W The Tax Effect of Permanent Differences captures the differences in the income taxes due under the Federal and State calculations and the income taxes calculated in Attachment H that are not the result of a timing difference. Items that can be included in formula for recovery are AFUDC Equity, Meals & Entertainment (50%), Memberships & Dues Not Deductible, Additional Compensation to Employee Stock, and Life Insurance Premiums. Items that can not be included in formula for recovery are Dividend Received Deductions, Equity in Earnings of Unconsol. Subs, and Other Perms (Rabbi Trust). Commission authorization is required in order to include any other permanent difference as an adjustment to the income tax allowance computation in the Formula Rate Template.

X Calculated on Attachment 4A.

Y Unfunded Reserves are customer contributed capital such as when Injuries and Damages expense is accrued but not yet incurred. Also, pursuant to Special Instructions to Accounts 228.1 through 228.4, no amounts shall be credited to accounts 228.1 through 228.4 unless authorized by a regulatory authority or authorities to be collected in a utility's rates.

Z Amortization of Regulatory Asset for Environmental Remediation of Manufactured Gas Plants shall be excluded from the formula rate.

Attachment 12 PECO Formula Rate Updated

Attachment 1
Project Revenue Requirement Worksheet
PECO Energy Company

To be completed in conjunction with Attachment H-7.

Line No.	(1)	(2) Attachment H-7 Page, Line, Col.	(3) Transmission	(4) Allocator
1	Gross Transmission Plant - Total	Attach H-7, p 2, line 2 col 5 (Note A)	1,647,831,648	
2	Net Transmission Plant - Total	Attach H-7, p 2, line 20 col 5 plus line 34 & 37 col 5 (Note B)	1,136,725,009	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Attach H-7, p 3, line 12 col 5	66,163,197	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1 col 3)	0.04	0.04
	GENERAL, INTANGIBLE AND COMMON (G&C) DEPRECIATION EXPENSE			
5	Total G, I & C Depreciation Expense	Attach H-7, p 3, lines 15 to 18, col 5 (Note H)	10,347,902	
6	Annual Allocation Factor for G, I & C Depreciation Expense	(line 5 divided by line 1 col 3)	0.01	0.01
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Attach H-7, p 3, line 30 col 5	3,688,644	
8	Annual Allocation Factor for Other Taxes	(line 7 divided by line 1 col 3)	0.00	0.00
9	Less Revenue Credits	Attach H-7, p 1, line 2 col 5	10,120,044	
10	Annual Allocation Factor Revenue Credits	(line 9 divided by line 1 col 3)	-	-
11	**Annual Allocation Factor for Expense**	**Sum of lines 4, 6, 8, and 10**		**0.05**
	INCOME TAXES			
12	Total Income Taxes	Attach H-7, p 3, line 45 col 5	17,697,709	
13	Annual Allocation Factor for Income Taxes	(line 12 divided by line 2 col 3)	0.02	0.02
	RETURN			
14	Return on Rate Base	Attach H-7, p 3, lines 47 and 48a col 5	70,465,764	
15	Annual Allocation Factor for Return on Rate Base	(line 14 divided by line 2 col 3)	0.06	0.06
16	**Annual Allocation Factor for Return**	**Sum of lines 13 and 15**	0.08	**0.08**

Attachment 12 PECO Formula Rate Updated

Attachment 1
Project Revenue Requirement Worksheet
PECO Energy Company

Line No. (1)	Project Name (1)	RTO Project Number or Zonal (2)	Project Gross Plant (3)	Annual Allocation Factor for Expense (4)	Annual Expense Charge (5)	Project Net Plant or CWIP Balance (6)	Annual Allocation Factor for Return (7)	Annual Return Charge (8)	Project Depreciation/Amortization Expense (9)	Annual Revenue Requirement (10)	Incentive Return in basis Points (11)	Incentive Return (12)	Ceiling Rate (12a)	Competitive Bid Concession (13)	Total Annual Revenue Requirement (14)	True-Up Adjustment (15)	Additional Refund (Note Q) (15a)	Net Rev Req (16)
			(Note C)	(Page 1 line 11)	(Col. 3 * Col. 4)	(Notes D & I)	(Page 1 line 16)	(Col. 6 * Col. 7)	(Notes E & I)	(Sum Col. 5, 8 & 9)	(Note K)	(Attachment 2, Line 28 /100 * Col. 11 * Col. 6)	(Sum Col. 10 & 12)	(Note J)	(Sum Col. 10 & 12 Less Col. 13)	(Note F)	$ (850,000)	Sum Col. 14, 15 & 15(a) (Note G)
17a	Zonal	Zonal	$ 1,425,249,082	0.05	$69,366,679	$ 937,462,956	0.08	72,708,869	21,862,928	163,938,477	-	-	163,938,477	-	163,938,477	(10,471,680)	(714,000)	[redacted]
17b	Center Point 500-230 kV Substation Addition	b0269	$ 34,380,112	0.05	$1,673,275	$ 28,327,997	0.08	2,197,097	$ 654,630	4,525,002	-	-	4,525,002	-	4,525,002	401,049	(19,708)	4,906,344
17c	Center Point 500-230 kV Substation Addition	b0269	$ 17,190,056	0.05	$836,638	$ 14,163,999	0.08	1,098,548	$ 327,315	2,262,501	-	-	2,262,501	-	2,262,501	(1,478,076)	(9,854)	774,571
17d	Richmond-Waneeta 230 kV Line Re-conductor	b1591	$ 4,605,741	0.05	$224,161	$ 4,278,158	0.08	331,810	$ 109,023	664,994	-	-	664,994	-	664,994	(868,289)	(2,896)	(206,191)
17e	Richmond-Waneeta 230 kV Line Re-conductor	b1398.8	$ 1,535,247	0.05	$74,720	$ 1,426,053	0.08	110,603	$ 36,341	221,665	-	-	221,665	-	221,665	76,076	(965)	296,775
17f	Whitpain 500 kV Circuit Breaker Addition	b0269.6	$ 3,258,302	0.05	$158,581	$ 2,679,456	0.08	207,816	$ 62,403	428,801	-	-	428,801	-	428,801	(59,844)	(1,868)	367,089
17g	Elroy-Hosensack 500 kV Line Rating Increase	b0171.1	$ 4,456,731	0.05	$216,909	$ 3,579,592	0.08	277,630	$ 83,367	577,906	-	-	577,906	-	577,906	(84,812)	(2,517)	490,577
17h	Camden-Richmond 230 kV Line Rating Increase	b1590.1 and b1590.2 (c	$ 13,634,041	0.05	$663,567	$ 12,307,689	0.08	954,574	$ 304,926	1,923,067	-	-	1,923,067	-	1,923,067	335,513	(8,376)	2,250,205
17i	Chichester-Linwood 230 kV Line Upgrades	b1900	$ 23,835,043	0.05	$1,160,048	$ 31,694,028	0.08	2,458,163	$ 809,462	4,427,673	-	-	4,427,673	-	4,427,673	1,458,328	(19,284)	5,866,717
17j	Bryn Mawr-Plymouth 138 kV Line Rebuild	b0727	$ 18,036,480	0.05	$877,833	$ 15,934,950	0.08	1,235,902	$ 460,267	2,574,002	-	-	2,574,002	-	2,574,002	(497,217)	(11,211)	2,065,575
17k	Emilie 230-138 kV Transformer Addition	b2140	$ 16,739,503	0.05	$814,709	$ 15,541,516	0.08	1,205,387	$ 366,765	2,386,862	-	-	2,386,862	-	2,386,862	(387,796)	(10,395)	1,988,671
17l	Chichester-Saville 138 kV Line Re-conductor	b1182	$ 17,916,132	0.05	$871,976	$ 15,265,133	0.08	1,183,951	$ 423,168	2,479,095	-	-	2,479,095	-	2,479,095	(372,270)	(10,797)	2,096,028
17m	Waneeta 230-138 kV Transformer Addition	b1717	$ 11,068,177	0.05	$538,687	$ 10,361,377	0.08	803,620	$ 242,077	1,584,383	-	-	1,584,383	-	1,584,383	(265,774)	(6,900)	1,311,709
17n	Chichester 230-138 kV Transformer Addition	b1178	$ 8,327,759	0.05	$405,311	$ 7,143,992	0.08	554,082	$ 166,390	1,125,783	-	-	1,125,783	-	1,125,783	(168,575)	(4,903)	952,304
17o	Bradford-Planebrook 230 kV Line Upgrades	b0790	$ 1,712,754	0.05	$83,360	$ 1,549,021	0.08	120,141	$ 36,076	239,576	-	-	239,576	-	239,576	(36,305)	(1,043)	202,227
17p	North Wales-Hartman 230 kV Line Re-conductor	b0506	$ 2,229,232	0.05	$108,496	$ 1,814,989	0.08	140,769	$ 50,893	300,158	-	-	300,158	-	300,158	(46,566)	(1,307)	252,286
17q	North Wales-Whitpain 230 kV Line Re-conductor	b0505	$ 2,546,903	0.05	$123,957	$ 2,006,944	0.08	155,657	$ 56,275	335,890	-	-	335,890	-	335,890	(48,553)	(1,463)	285,874
17r	Bradford-Planebrook 230 kV Line Upgrades	b0789	$ 2,359,200	0.05	$114,822	$ 2,113,265	0.08	163,903	$ 49,217	327,942	-	-	327,942	-	327,942	(49,593)	(1,428)	276,921
17s	Planebrook 230 kV Capacitor Bank Addition	b0206	$ 3,631,396	0.05	$176,740	$ 2,685,288	0.08	208,269	$ 62,539	447,547	-	-	447,547	-	447,547	(60,162)	(1,949)	385,436
17t	Newlinville 230 kV Capacitor Bank Addition	b0207	$ 4,811,873	0.05	$234,193	$ 3,656,113	0.08	283,565	$ 85,149	602,907	-	-	602,907	-	602,907	(81,845)	(2,626)	518,436
17u	Chichester-Mickleton 230 kV Series Reactor Addition	b0209	$ 2,699,444	0.05	$131,382	$ 2,083,968	0.08	161,631	$ 48,535	341,547	-	-	341,547	-	341,547	(46,629)	(1,488)	293,430
17v	Chichester-Mickleton 230 kV Line Re-conductor	b0264	$ 2,221,241	0.05	$108,108	$ 1,683,389	0.08	130,562	$ 47,203	285,873	-	-	285,873	-	285,873	(40,924)	(1,245)	243,704
17w	Buckingham-Pleasant Valley 230 kV Line Re-conductor	b0357	$ 1,723,078	0.05	$83,862	$ 1,884,077	0.08	146,128	$ 55,139	285,128	-	-	285,128	-	285,128	(57,851)	(1,242)	226,036
17x	Elroy 500 kV Dynamic Reactive Device	b0287	$ 5,325,225	0.05	$259,178	$ 4,603,243	0.08	357,024	$ 107,207	723,409	-	-	723,409	-	723,409	249,583	(3,151)	969,841
17y	Heaton 230 kV Capacitor Bank Addition	b0208	$ 4,315,230	0.05	$210,022	$ 3,278,758	0.08	254,298	$ 76,361	540,680	-	-	540,680	-	540,680	188,281	(2,355)	726,607
17z	Peach Bottom 500-230 kV Transformer Rating Increase	b2694	$ 13,038,203	0.05	$634,568	$ 9,119,114	0.08	707,271	$ 216,868	1,558,706	-	-	1,558,706	-	1,558,706	-	(6,789)	1,551,918
17aa	Peach Bottom 500 kV Substation Upgrades	b2766.2	$ 985,461	0.05	$47,962	$ 79,944	0.08	6,200	$ 1,009	55,171	-	-	55,171	-	55,171	-	(240)	54,931
18	Annual Totals		1,647,831,648			1,136,725,009		88,163,473	26,801,531	195,164,746		-	195,164,746	-	195,164,746	(12,413,931)	(850,000)	29,148,020

Notes:

- A Gross Transmission Plant is that identified on page 2 line 2 of Attachment H
- B Inclusive of any CWIP or unamortized abandoned plant included in rate base when authorized by FERC order less any prefunded AFUDC, if applicable.
- 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. This value includes subsequent capital investments required to maintain the facilities to their original capabilities.
  Gross plant does not include Unamortized Abandoned Plant.
- D Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation. Net Plant includes CWIP and Unamortized Abandoned Plant and excludes any regulatory asset, which are to be entered as separate line items.
- E Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H, page 3, line 14. Project Depreciation Expense includes the amortization of Abandoned Plant
- F True-Up Adjustment is calculated on the Attachment 3 Project True-up Schedule for the Rate Year
- G The Net Rev Req is the value to be used in the rate calculation under the applicable Schedule 12 under the PJM OATT for each project.
- H The Total General, Intangible and Common Depreciation Expense excludes any depreciation expense directly associated with a project and thereby included in page 2 column 9.
- I The Unamortized Abandoned Plant balance is included in Net Plant, and Amortization of Abandoned Plant is included in Depreciation/Amortization Expense.
- J The Competitive Bid Concession is the reduction in revenue, if any, that the company agreed to, for instance, to be selected to build facilities as the result of a competitive process and equals the amount by which the annual revenue requirement is reduced from the ceiling rate
- K Requires approval by FERC of incentive return applicable to the specified project(s)
- M All transmission facilities reflected in the revenue requirement on Attachment H-7, page 1 line 3 are to be included in this Attachment 1.
- N Facilities that provide Wholesale Distribution Service are not to be listed as projects on lines 15, the revenue requirements associated with these facilities are calculated on Attachment 11
- O When an updated projected net revenue requirement is posted due to an asset acquisition as provided for in the Protocols, the difference between the updated net revenue requirement in Col (16) and the revenues collected to date will be recovered
  over the remaining months of the Rate Year.
- P Zonal on line 17a refers to all projects not qualifying for regional recovery
- Q Additional refund $850,00 per year for 2018-2021 and $0 for 2022 and beyond.

Attachment 2
Incentive ROE
PECO Energy Company

1	Rate Base	Attachment H-7, Page 2 line 47, Col.5					956,068,754
2	100 Basis Point Incentive Return					$	
			$	%	Cost	Weighted	
3	Long Term Debt	(Attachment H-7, Notes Q and R)	3,409,418,609	45.6%	4.03%	1.8%	
4	Preferred Stock	(Attachment H-7, Notes Q and R)	-	0.0%	0.00%	0.0%	
5	Common Stock	(Attachment H-7, Notes K, Q and R) Cost = Attachment H-7, Page 4 Line 17, Cost plus .01	4,069,011,413	54.4%	11.35%	6.2%	
6	Total (sum lines 3-5)		7,478,430,022			8.0%	
7	100 Basis Point Incentive Return multiplied by Rate Base (line 1 * line 6)						76,591,989.60
8	INCOME TAXES						
9	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		28.8921%				
10	CIT=(T/1-T) * (1-(WCLTD/R)) =		31.3214%				
11	WCLTD = Line 3						
12	and FIT, SIT & p are as given in footnote K.						
13	1 / (1 - T) = (from line 9)		1.4063				
14	Amortized Investment Tax Credit (266.8f) (enter negative)	Attachment H-7, Page 3, Line 38	(2,976)				
15	Excess Deferred Income Taxes (enter negative)	Attachment H-7, Page 3, Line 39	(3,250,820)				
16	Tax Effect of Permanent Differences (Note B)	Attachment H-7, Page 3, Line 40	282,655				
17	Income Tax Calculation = line 10 * line 7		23,989,694	NA		23,989,694	
18	ITC adjustment (line 13 * line 14)		(4,186)	TP	100.0%	(4,186)	
19	Excess Deferred Income Tax Adjustment (line 13 * line 15)		(4,571,672)	TP	100.0%	(4,571,672)	
20	Permanent Differences Tax Adjustment (line 13 * 16)		397,502	TP	100.0%	397,502	
21	Total Income Taxes (sum lines 17 - 20)		19,811,339			19,811,339	19,811,339
22	Return and Income Taxes with 100 basis point increase in ROE	(Sum lines 7 & 21)					96,403,328
23	Return (Attach. H-7, page 3 line 47 col 5)						71,390,023
24	Income Tax (Attach. H-7, page 3 line 45 col 5)						17,697,709
25	Return and Income Taxes without 100 basis point increase in ROE	(Sum lines 23 & 24)					89,087,732
26	Incremental Return and Income Taxes for 100 basis point increase in ROE	(Line 22 - line 25)					7,315,597
27	Rate Base (line 1)						956,068,754
28	Incremental Return and Income Taxes for 100 basis point increase in ROE divided by Rate Base		(Line 26 / line 27)				0.0077

Notes:

A Line 5 includes a 100 basis point increase in ROE that is used only to determine the increase in return and income taxes associated with a 100 basis point increase in ROE. Any actual ROE incentive must be approved by the Commission.
For example, if the Commission were to grant a 137 basis point ROE incentive, the increase in return and taxes for a 100 basis point increase in ROE would be multiplied by 1.37 on Attachment 1 column 12.

B The Tax Effect of Permanent Differences captures the differences in the income taxes due under the Federal and State calculations and the income taxes calculated in Attachment H-7 that are not the result of a timing difference

Attachment 3
Project True-Up
PECO Energy Company

Line	Project Name	PJM Project Number or Zonal	Revenue Requirement Projected For Rate Year		Revenue Received[3]	Actual Revenue Requirement (Note C)	Annual True-Up Calculation			
1	Rate Year being Trued-Up									
2										
	A	B	C	D	E	F	G	H	I	J
			Projected Net Revenue Requirement[1]	% of Total Revenue Requirement	Revenue Received	Actual Net Revenue Requirement[2]	Net Under/(Over) Collection (F)-(E)	Prior Period Adjustment [5]	Interest Income (Expense)[4]	Total True-Up (G) + (H) + (I)
3	Zonal	Zonal	155,439,100	0.82	157,101,795	148,069,920	(9,031,876)	-	(614,168)	(10,471,680)
3a	Center Point 500-230 kV Substation Addition	b0269	3,255,611	0.02	4,265,983	4,664,358	398,375	-	27,090	401,049
3b	Center Point 500-230 kV Substation Addition	b0269	4,322,188	0.02	3,704,715	2,332,179	(1,372,536)	-	(93,332)	(1,478,076)
3c	Richmond-Waneeta 230 kV Line Re-conductor	b1591	563,547	0.00	1,493,396	683,742	(809,654)	-	(55,056)	(868,289)
3d	Richmond-Waneeta 230 kV Line Re-conductor	b1398.8	266,683	0.00	155,565	227,914	72,349	-	4,920	76,076
3e	Whitpain 500 kV Circuit Breaker Addition	b0269.6	470,755	0.00	495,867	441,999	(53,868)	-	(3,663)	(59,844)
3f	Elroy-Hosensack 500 kV Line Rating Increase	b0171.1	633,172	0.00	672,325	595,833	(76,492)	-	(5,201)	(84,812)
3g	Camden-Richmond 230 kV Line Rating Increase	b1590.1 and b159	2,323,514	0.01	1,659,233	1,983,103	323,871	-	22,023	335,513
3h	Chichester-Linwood 230 kV Line Upgrades	b1900	5,111,504	0.03	3,086,782	4,474,186	1,387,404	-	94,343	1,458,328
3i	Bryn Mawr-Plymouth 138 kV Line Rebuild	b0727	2,944,428	0.02	3,126,716	2,674,264	(452,452)	-	(30,767)	(497,217)
3j	Emilie 230-138 kV Transformer Addition	b2140	2,676,443	0.01	2,808,828	2,457,769	(351,059)	-	(23,872)	(387,796)
3k	Chichester-Saville 138 kV Line Re-conductor	b1182	2,730,618	0.01	2,900,251	2,564,251	(336,000)	-	(22,848)	(372,270)
3l	Waneeta 230-138 kV Transformer Addition	b1717	1,771,825	0.01	1,872,139	1,631,282	(240,857)	-	(16,378)	(265,774)
3m	Chichester 230-138 kV Transformer Addition	b1178	1,241,281	0.01	1,312,126	1,159,969	(152,157)	-	(10,347)	(168,575)
3n	Bradford-Planebrook 230 kV Line Upgrades	b0790	263,024	0.00	279,504	246,720	(32,785)	-	(2,229)	(36,305)
3o	North Wales-Hartman 230 kV Line Re-conductor	b0506	328,432	0.00	351,988	309,906	(42,082)	-	(2,862)	(46,566)
3p	North Wales-Whitpain 230 kV Line Re-conductor	b0505	367,997	0.00	390,663	346,902	(43,761)	-	(2,976)	(48,553)
3q	Bradford-Planebrook 230 kV Line Upgrades	b0789	359,974	0.00	382,532	337,752	(44,780)	-	(3,045)	(49,593)
3r	Planebrook 230 kV Capacitor Bank Addition	b0206	490,492	0.00	515,884	461,816	(54,068)	-	(3,677)	(60,162)
3s	Newlinville 230 kV Capacitor Bank Addition	b0207	661,052	0.00	695,543	621,958	(73,586)	-	(5,004)	(81,845)
3t	Chichester-Mickleton 230 kV Series Reactor Addition	b0209	374,583	0.00	394,216	352,282	(41,934)	-	(2,851)	(46,629)
3u	Chichester-Mickleton 230 kV Line Re-conductor	b0264	312,979	0.00	332,222	295,351	(36,871)	-	(2,507)	(40,924)
3v	Buckingham-Pleasant Valley 230 kV Line Re-conductor	b0357	313,716	0.00	348,929	296,213	(52,716)	-	(3,585)	(57,851)
3w	Elroy 500 kV Dynamic Reactive Device	b0287	870,793	0.00	507,962	745,307	237,345	-	16,139	249,583
3x	Heaton 230 kV Capacitor Bank Addition	b0208	649,264	0.00	378,737	557,764	179,027	-	12,174	188,281
3y	Peach Bottom 500-230 kV Transformer Rating Increase	b2694	-	-	-	-	-	-	-	-
3z	Peach Bottom 500 kV Substation Upgrades	b2766.2	-	-	-	-	-	-	-	-
4	Total Annual Revenue Requirements (Note A)		188,742,973	1.00	189,233,899	178,532,740	(10,701,159)		(727,679)	(12,413,931)

Monthly Interest Rate	0.00
Interest Income (Expense)	(727,679)

Notes:
1) From Attachment 1, line 17, col. 14 for the projection for the Rate Year.
2) From Attachment 1, line 17, col. 14, less col. 15(a) for each project and Attachment H-7, line 7 for zonal.
3) "Revenue Received" on line 3 Zonal, Col. (E), is the total amount of revenue received for the True-Up Year under PJM OATT Attachments 7, 8 and H-7 and "Revenue Received" on letter-denominated line 3 entries, Col. (E), is the amount of revenue received for the True-Up Year for the project designated in Cols. A and B under PJM OATT Schedule 12 PECO Appendix and PECO Appendix A as reported on pages 328-330 of the Form No 1. The Revenue Received in Col. E excludes any True-Up revenues

4) Interest from Attachment 6.
5) Prior Period Adjustment from line 5 is pro rata to each project, unless the error was project specific.

Prior Period Adjustments

	(a)	(b)	(c)	(d)
	Prior Period Adjustments (Note B)	Amount In Dollars	Interest (Note B)	Total Col. (b) + Col. (c)
5	-	-	-	-

Notes:

A For each project or Attachment H, the utility will populate the formula rate with the inputs for the True-Up Year. The revenue requirements, based on actual operating results for the True-Up Year, associated with the projects and Attachment H will then be entered in Col. (F) above. Column (E) above contains the actual revenues received associated with Attachment H and any Projects paid by the RTO to the utility during the True-Up Year. Then in Col. (G), Col. (E) is subtracted from Col. (F) to calculate the True-up Adjustment. The Prior Period Adjustment from Line 5 below is input in Col. (H). Column (I) is the applicable interest rate from Attachment 6. Column (I) adds the interest on the sum of Col.(G) and (H). Col. (J) is the sum of Col. (G), (H), and (I).

B Prior Period Adjustment is the amount of an adjustment to correct an error in a prior period. Interest will be calculated for the prior period adjustment based on the FERC Refund interest rate specified in 18 CFR 35.19(a) for the period up to the date the projected rates went into effect. PECO will provide the supporting worksheet for the interest calculation when prior period adjustment is needed.

C The Actual Revenue Requirement in the True-up Adjustment calculation for years 2020 and later shall use the depreciation and amortization rates approved for use by the Commission when PECO performs the True-Up Adjustment.

Attachment 12 PECO Formula Rate Updated

Attachment 4
Rate Base Worksheet
PECO Energy Company

Line No	Month	Gross Plant In Service			CWIP	LHFFU	Working Capital		Accumulated Depreciation		
	Month	**Transmission**	**General**	**Common**	**CWIP in Rate Base**	**Held for Future Use**	**Materials & Supplies**	**Prepayments**	**Transmission**	**General**	**Common**
	(a)	**(b)**	**(c)**	**(d) (Note J)**	**(e)**	**(f)**	**(g)**	**(h) (Note K)**	**(i) (Note J)**	**(j) (Note J)**	**(k) (Note J)**
	Attachment H, Page 2, Line No:	2	4	5	27	31	34	35	9	11	12
		207.58.g minus 207.57.g. Projected monthly balances that are the amounts expected to be included in 207.58.g for end of year and records for other months (Note I)	207.99.g minus 207.98.g for end of year, records for other months	Electric Only, Form No 1, page 356 for end of year, records for other months	(Note C)	214.16,d, 214.17,d, 214.18,d, 214.20,d, 214.23,d, and 214.25,d for end of year, records for other months	227. 8. c + (227.16.c * Labor Ratio) + TLF for end of year, records for other months (Note L)	111.57.c for end of year, records for other months	Projected monthly balances that are expected to be included in 219.25.c for end of year and records for other months (Note I)	219.28.c for end of year, records for other months	Electric Only, Form No 1, page 356 for end of year, records for other months
1	December Prior Year	1,611,375,786	273,765,315	584,697,265	-	244,519	9,885,240	1,484,479	502,822,050	74,681,276	281,162,662
2	January	1,613,261,126	274,735,574	585,500,517	-	244,519	9,714,961	1,317,061	504,548,549	75,228,248	280,752,427
3	February	1,618,792,904	275,222,885	594,255,209	-	244,519	9,727,194	1,002,601	505,404,809	75,628,800	282,354,814
4	March	1,627,082,797	276,487,113	622,913,574	-	253,019	9,618,713	2,599,275	505,235,767	76,362,517	286,108,018
5	April	1,639,174,063	277,053,842	621,404,981	-	875,690	9,691,538	1,983,986	507,056,646	76,902,187	281,783,055
6	May	1,649,474,262	279,393,591	623,165,660	-	4,376,463	9,890,741	1,518,989	508,385,749	78,620,210	284,740,774
7	June	1,655,203,303	280,754,636	631,173,682	-	7,519,830	10,174,825	1,785,546	510,192,196	79,837,744	287,686,201
8	July	1,661,554,890	277,686,685	633,969,050	-	7,533,309	10,287,886	1,276,265	512,334,326	77,802,585	286,854,048
9	August	1,652,253,765	278,967,092	636,220,079	-	7,555,759	10,196,294	1,511,607	513,814,384	79,287,200	290,138,922
10	September	1,651,947,137	279,924,657	638,583,580	-	7,556,903	10,763,580	1,626,104	515,341,078	80,509,336	292,275,908
11	October	1,663,097,570	279,806,973	650,353,207	-	7,912,555	10,665,701	2,594,870	518,049,592	81,435,126	295,312,322
12	November	1,683,923,592	280,555,538	655,521,930	-	8,909,222	10,032,544	1,841,107	520,012,174	82,872,685	298,728,777
13	December	1,694,670,228	283,844,048	681,307,081	-	8,944,464	11,025,145	1,171,935	521,171,515	84,322,356	301,612,461
14	Average of the 13 Monthly Balances	1,647,831,648	278,322,919	627,620,447	-	4,782,367	10,128,797	1,670,294	511,105,295	78,730,021	288,423,876

Adjustments to Rate Base

Line No	Month	Unamortized Regulatory Asset	Unamortized Abandoned Plant	Account No. 281 Accumulated Deferred Income Taxes (Note D)	Account No. 282 Accumulated Deferred Income Taxes (Note D)	Account No. 283 Accumulated Deferred Income Taxes (Note D)	Account No. 190 Accumulated Deferred Income Taxes (Note D)	Account No. 255 Accumulated Deferred Investment Credit	Pension Asset
	(a)	**(b)**	**(c)**	**(d)**	**(e)**	**(f)**	**(g)**	**(h)**	**(i)**
	Attachment H, Page 2, Line No:	28	29	22	23	24	25	26	27a
		Notes A & E	**Notes B & F**	**Attachment 4A, line 20 for the projection and line 44 for the true-up**	**Attachment 4A, line 14 for the projection and line 38 for the true-up**	**Attachment 4A, line 17 for the projection and line 41 for the true-up**	**Attachment 4A, line 34 for the projection and line 47 for the true-up**	**Consistent with 266.8.b, 266.17.b, 267.8.h & 267.17.h**	**Transmission-Related Pension Asset booked to Account 186**
15	December Prior Year	-	-	[redacted]				-	26,305,595
16	January	-	-					-	28,171,954
17	February	-	-					-	28,143,643
18	March	-	-					-	28,080,733
19	April	-	-					-	28,031,893
20	May	-	-					-	27,983,969
21	June	-	-					-	27,935,129
22	July	-	-					-	27,886,288
23	August	-	-					-	27,837,449
24	September	-	-					-	27,651,853
25	October	-	-					-	27,605,311
26	November	-	-					-	27,556,341
27	December	-	-					-	27,501,525
28	Average of the 13 Monthly Balances	-	-	Zero	(197,697,419)	(11,093,389)	14,865,099	-	27,745,514

(except ADIT which is the amount shown on Attachment 4A)

Attachment 12 PECO Formula Rate Updated

Attachment 4
Rate Base Worksheet

PECO Energy Company

Unfunded Reserves (Notes G & H)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
29	List of all reserves:		Amount	Enter 1 if NOT in a trust or reserved account, enter zero (0) if included in a trust or reserved account	Enter 1 if the accrual account is included in the formula rate, enter (0) if O if the accrual account is NOT included in the formula rate	Enter the percentage paid for by the transmission formula customers	Allocation (Plant or Labor Allocator)	Amount Allocated, col. c x col. d x col. e x col. f x col. g
30a		Environmental Liab - Superfund	(1,267,913)	1.00	1.00	100%	9.45%	(119,806)
30b		Accrued Severance Plans	(605,747)	1.00	1.00	100%	9.45%	(57,238)
30c		Workers Compensation - short term	(1,144,403)	1.00	1.00	100%	9.45%	(108,136)
30d		Workers Compensation - long term	(9,790,517)	1.00	1.00	100%	9.45%	(925,114)
30e		Public claims - Short Term	(20,866)	1.00	1.00	100%	9.45%	(1,972)
30f		Public Claims - Long term	(20,868,831)	1.00	1.00	100%	9.45%	(1,971,914)
30g		Accrued Septa Railroad Rent - transmission	-	1.00	1.00	100%	100.00%	-
30h		AIP	(20,099,009)	1.00	1.00	100%	9.45%	(1,899,173)
30i		401K Match	(1,255,217)	1.00	1.00	100%	9.45%	(118,607)
30j		Long-term incentive Plans	(1,223,348)	1.00	1.00	100%	9.45%	(115,595)
30k		Mgmt. Retention Incentive Plan	(277,223)	1.00	1.00	100%	9.45%	(26,195)
30l		Stock Comp	(4,196,388)	1.00	1.00	100%	9.45%	(396,520)
30m		Severance - Long Term	(151,548)	1.00	1.00	100%	9.45%	(14,320)
30x		...	-	-				-
31		Total	(60,901,010)					(5,754,589)

Notes:

A Recovery of regulatory asset is limited to any regulatory assets authorized by FERC.
B Recovery of abandoned plant is limited to any abandoned plant recovery authorized by FERC.
C Includes only CWIP authorized by the Commission for inclusion in rate base. The annual report filed pursuant to Section 7 of the Protocols will include for each project under construction (i) the CWIP balance eligible for inclusion in rate base; (ii) the CWIP balance ineligible for inclusion in rate base; and (iii) a demonstration that AFUDC is only applied to the CWIP balance that is not included in rate base. The annual report will reconcile the project-specific CWIP balances to the total Account 107 CWIP balance reported on p. 216.b of the FERC Form 1. The demonstration in (iii) above will show that monthly debts and credits do not contain entries for AFUDC for each CWIP project in rate base.
D ADIT and Accumulated Deferred Income Tax Credits are computed using the average of the beginning of the year and the end of the year balances. The projection will use lines 16, 19 and 36 of Attachment 4A to populate the average ADIT balance on line 28 above.
E Recovery of a Regulatory Asset is permitted only for pre-commercial and formation expenses, and is subject to FERC approval before the amortization of the Regulatory Asset can be included in rates. Recovery of any other regulatory assets requires authorization from the Commission. A carrying charge equal to the weighted cost of capital will be applied to the Regulatory Asset prior to the rate year when costs are first recovered.
F Unamortized Abandoned Plant and Amortization of Abandoned Plant will be zero until the Commission accepts or approves recovery of the cost of abandoned plant.
G The Formula Rate shall include a credit to rate base for all unfunded reserves (funds collected from customers that (1) have not been set aside in a trust, escrow or restricted account; (2) whose balance are collected from customers through cost accruals to accounts that are recovered under the Formula Rate; and (3) exclude the portion of any balance offset by a balance sheet account). Each unfunded reserve will be included on lines 30 above. The allocator in Col. (g) will be the same allocator used in the formula for the cost accruals to the account that is recovered under the Formula Rate. Since reserves can be created by an offsetting balance sheet account, rather than through cost accruals, the amount to be deducted from rate base should exclude the portion offset by another balance sheet account.
H Calculate using 13 month average balance, except ADIT. SERP will not be included as an unfunded reserve in the formula rate.
I Projected balances are for the calendar year the revenue under this formula begins to be charged.
J Excludes ARO amounts.
K Total prepayments, including Fleet Activity, allocated to transmission as follows: (1) amounts solely related to transmission allocated 100% to transmission; (2) amounts solely related to distribution, gas or non-utility allocated 0% to transmission; (3) amounts related to electric general allocated using the wages and salaries allocator (Attachment H-7), p. 4, line 11, column (5)); (4) amounts related to common labor or plant allocated using the wages and salaries allocator (Attachment H-7, p. 4, line 11, column (5)), multiplied by either common labor percent to electric (Attachment 7-PBOP, Note B, Electric Labor) or by common utility plant percent to electric (per FF1 page 356) as applicable depending upon the nature of the prepayment item.
L TLF shall be equal to 50 percent of the lesser of (a) the transmission portion of FERC Form 1, page 227, line 5, column c per FERC Form No. 1) and (b) $9 million. The TLF recovery percentage and cap will be subject to modification only through Commission authorization under section 205 or section 206 of the Federal Power Act.

		Allocation	**Prior Year End Total**	**Current Year End Total**	**Allocation Factor**	**Prior Year Allocated to T**	**Current Year Allocated to T**	Allocation from Total To Electric (Note K)	Allocation from Electric to Transmission (Note K)
k1	Market Research	Other	$ 20,335	$ -	0.00%	$ -	$ -	0.00%	0.00%
k2	Facilities	Allocation To Transmission	$ 58,423	$ 131	7.32%	$ 4,277	$ 10	77.48%	9.45%
k3	Land Leasing	Other	$ 23,723	$ 5,456	0.00%	$ -	$ -	0.00%	0.00%
k4	Land Leasing	100% Transmission	$ -	$ 16,369	100.00%	$ -	$ 16,369	100.00%	100.00%
k5	Fleet Activity	Allocation To Transmission	$ 321,536	$ 336,859	7.54%	$ 24,239	$ 25,394	79.78%	9.45%
k6	Membership dues	Other	$ 400	$ -	0.00%	$ -	$ -	0.00%	0.00%
k7	IT License & Maintenance Agreements	Allocation To Transmission	$ 598,296	$ 338,557	7.32%	$ 43,802	$ 24,786	77.48%	9.45%
k8	IT License & Maintenance Agreements	Allocation To Transmission	$ -	$ -	7.54%	$ -	$ -	79.78%	9.45%
k9	IT License & Maintenance Agreements	Other	$ 1,317,780	$ 1,241,294	0.00%	$ -	$ -	0.00%	0.00%
k10	Postage	Other	$ 650,426	$ 594,515	0.00%	$ -	$ -	0.00%	0.00%
k11	Prepaid Rent	100% Transmission	$ 1,334,854	$ 964,039	100.00%	$ 1,334,854	$ 964,039	100.00%	100.00%
k12	Prepaid Rent	Other	$ 276,562	$ 415,497	0.00%	$ -	$ -	0.00%	0.00%
k13	Prepaid gross receipts tax	Other	$ -	$ -	0.00%	$ -	$ -	0.00%	0.00%
k14	Prepaid property tax	Allocation To Transmission	$ -	$ -	7.32%	$ -	$ -	77.48%	9.45%
k15	PUC Assessment	Other	$ 4,635,979	$ 4,427,073	0.00%	$ -	$ -	0.00%	0.00%
k16	Retention Incentive	Allocation To Transmission	$ 13,000	$ 2,000	7.54%	$ 980	$ 151	79.78%	9.45%
k17	Marketing	Other	$ 236,261	$ 268,711	0.00%	$ -	$ -	0.00%	0.00%
k18	VEBA	Allocation To Transmission	$ 834,281	$ 135,265	7.54%	$ 62,892	$ 10,197	79.78%	9.45%
k19	Equipment Maintenance	100% Transmission	$ 13,435	$ 10,076	100.00%	$ 13,435	$ 10,076	100.00%	100.00%
k20	Equipment Maintenance	Other	$ 126,509	$ 94,882	0.00%	$ -	$ -	0.00%	0.00%
k21	New Business	Other	$ 173,775	$ 3,050	0.00%	$ -	$ -	0.00%	0.00%
k22	Land Acquisitions	100% Transmission	$ -	$ 18,294	100.00%	$ -	$ 18,294	100.00%	100.00%
k23	Leases	Other	$ -	$ 272,074	0.00%	$ -	$ -	0.00%	0.00%
k24	Building Acquisition	Other	$ -	$ 153,930	0.00%	$ -	$ -	0.00%	0.00%
k25	Building Acquisition	100% Transmission	$ -	$ 102,620	100.00%	$ -	$ 102,620	100.00%	100.00%
...									
Kxxx									
	Total Sum(lines K1 to Kxxx)		10,635,574	9,400,693		1,484,479	1,171,935		

Attachment 4A
PECO Energy Company
ADIT Worksheet for Projection

Projection for the 12 months ended 12/31/2019

ADIT for the Projection

	(a) Beginning Balance & Monthly Changes	(b) Month	(c) Year	(d) Weighting for Projection	(e) Beginning Balance/ Monthly Increment	(f) 100% Transmission	(g) 100% Allocator (f) x Allocator **100%**	(h) (Note A) Plant Related	(i) GP Allocator (h) x Allocator 0.1901 From Attach H Page 2, Line 18	(j) Labor Related	(k) S/W Allocator (j) x Allocator 0.0945 From Attach H Page 4, Line 16	(l) Total ADIT (d) x [(g)+(i)+(k)]
		ADIT- 282										
1	Balance	December	2019	100.00%	-	(200,390,143)	(200,390,143)	-	-	(31,198,496)	(2,947,973)	(203,338,115)
2	Increment	January	2020	91.78%	-	(209,280)	(209,280)	-	-	(77,939)	(7,365)	(198,838)
3	Increment	February	2020	84.11%	-	(209,280)	(209,280)	-	-	(77,939)	(7,365)	(182,219)
4	Increment	March	2020	75.62%	-	(209,280)	(209,280)	-	-	(77,939)	(7,365)	(163,819)
5	Increment	April	2020	67.40%	-	(209,280)	(209,280)	-	-	(77,939)	(7,365)	(146,012)
6	Increment	May	2020	58.90%	-	(209,280)	(209,280)	-	-	(77,939)	(7,365)	(127,613)
7	Increment	June	2020	50.68%	-	(209,280)	(209,280)	-	-	(77,939)	(7,365)	(109,806)
8	Increment	July	2020	42.19%	-	(209,280)	(209,280)	-	-	(77,939)	(7,365)	(91,406)
9	Increment	August	2020	33.70%	-	(209,280)	(209,280)	-	-	(77,939)	(7,365)	(73,006)
10	Increment	September	2020	25.48%	-	(209,280)	(209,280)	-	-	(77,939)	(7,365)	(55,200)
11	Increment	October	2020	16.99%	-	(209,280)	(209,280)	-	-	(77,939)	(7,365)	(36,800)
12	Increment	November	2020	8.77%	-	(209,280)	(209,280)	-	-	(77,939)	(7,365)	(18,993)
13	Increment	December	2020	0.27%	-	(209,280)	(209,280)	-	-	(77,939)	(7,365)	(594)
14	Sum Ties to December		2020	Balance	-	(202,901,503)	(202,901,503)	-	-	(32,133,768)	(3,036,347)	(204,542,422)
15	Increment	Not Subject to Proration	2020			(7,334,377)	(7,334,377)	-	-	-	-	(7,334,377)
16	Total					(210,235,879)	(210,235,879)	-	-	(32,133,768)	(3,036,347)	(211,876,798)
		ADIT-283										
17	Balance	December	2019		-	-	-	(5,165,133)	(981,874)	(104,384,871)	(9,863,416)	(10,845,290)
18	Balance	December	2020		-	-	-	(4,790,923)	(910,738)	(106,347,739)	(10,048,889)	(10,959,627)
19		Average			-	-	-	(4,978,028)	(946,306)	(105,366,305)	(9,956,152)	(10,902,458)
		ADIT-281										
20	Balance	December	2019		Zero	Zero	Zero	Zero	Zero	Zero	Zero	Zero
21	Balance	December	2020		Zero	Zero	Zero	Zero	Zero	Zero	Zero	Zero
22		Average			Zero	Zero	Zero	Zero	Zero	Zero	Zero	Zero
		ADIT-190										
23	Balance	December	2019	100.00%	-	-	-	19,259,193	3,661,107	116,408,740	10,999,562	14,660,668
24	Increment	January	2020	91.78%	-	-	-	-	-	-	-	-
25	Increment	February	2020	84.11%	-	-	-	-	-	-	-	-
26	Increment	March	2020	75.62%	-	-	-	-	-	-	-	-
27	Increment	April	2020	67.40%	-	-	-	-	-	-	-	-
28	Increment	May	2020	58.90%	-	-	-	-	-	-	-	-
29	Increment	June	2020	50.68%	-	-	-	-	-	-	-	-
30	Increment	July	2020	42.19%	-	-	-	-	-	-	-	-
31	Increment	August	2020	33.70%	-	-	-	-	-	-	-	-
32	Increment	September	2020	25.48%	-	-	-	-	-	-	-	-
33	Increment	October	2020	16.99%	-	-	-	-	-	-	-	-
34	Increment	November	2020	8.77%	-	-	-	-	-	-	-	-
35	Increment	December	2020	0.27%	-	-	-	23,998,409	4,562,015	107,996,505	10,204,682	14,766,697
36	Sum Ties to December		2020	Balance	-							14,713,683
	Line 36, If there are no items subject to proration, use average of lines 23 and 35											
37	Total ADIT											(208,065,574)

PECO Energy Company
ADIT Worksheet for True-Up

ADIT for True-Up

True-Up for the 12 months ended 12/31/2019

	(a) Balance	(b) Month	(c) Year	(d) Weighting for Projection	(e) Balance from ADIT BOY and ADIT EOY workpapers	(f) 100% Transmission	(g) 100% Allocator (f) x Allocator **100%**	(h) (Note A) Plant Related	(i) GP Allocator (h) x Allocator 0.1901 From Attach H Page 2, Line 18	(j) Labor Related	(k) S/W Allocator (j) x Allocator 0.0945 From Attach H Page 4, Line 16	(l) Total ADIT (d) x [(g)+(i)+(k)]
		ADIT- 282										
38	Balance	December	2018		(1,139,022,726)	(189,143,729)		-	-	(30,828,318)		
39	Balance	December	2019		(1,261,244,192)	(200,390,143)		-	-	(31,198,496)		
40		Average			(1,200,133,459)	(194,766,936)	(194,766,936)	-	-	(31,013,407)	(2,930,483)	(197,697,419)
		ADIT-283										
41	Balance	December	2018		(139,156,936)	-	-	(5,581,934)	(1,061,107)	(108,797,636)	(10,280,382)	
42	Balance	December	2019		(129,949,790)	-	-	(5,165,133)	(981,874)	(104,384,871)	(9,863,416)	
43		Average			(134,553,363)	-	-	(5,373,534)	(1,021,490)	(106,591,253)	(10,071,899)	(11,093,389)
		ADIT-281										
44	Balance	December	2018		Zero	Zero	Zero	Zero	Zero	Zero	Zero	Zero
45	Balance	December	2019		Zero	Zero	Zero	Zero	Zero	Zero	Zero	Zero
46		Average			Zero	Zero	Zero	Zero	Zero	Zero	Zero	Zero
		ADIT-190										
47	Balance	December	2018		178,589,500	-	-	13,690,676	2,602,550	131,938,478	12,466,980	15,069,530
48	Balance	December	2019		169,734,784	-	-	19,259,193	3,661,107	116,408,740	10,999,562	14,660,668
49		Average			174,162,142	-	-	16,474,934	3,131,828	124,173,609	11,733,271	14,865,099

Note:
A Plant Related ADIT reflects the total Electric plant related ADIT from Attachment 4B and 4C, which is allocated to transmission in Column (i) with GP allocation factor.

Attachment 4B
PECO Energy Company

ADIT BOY Worksheet

	A	B	C	D	E	F	
			Gas, Prod, Retail	*Only Transmission*	*Plant*	*Labor*	
		Total	*Or Other Related*	*Related*	*Related*	*Related*	
a	***ADIT- 282***	(1,139,022,726)		(189,143,729)	-	(30,828,318)	(From line 17 for the column)
b	***ADIT-283***	(139,156,936)		-	(5,581,934)	(108,797,636)	(From line 29 for the column)
c	***ADIT-190***	178,589,500		-	13,690,676	131,938,478	(From line 5 for the column)
d	***Subtotal***	(1,099,590,162)		(189,143,729)	8,108,741	(7,687,475)	(Sum a - c)

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	C	D	E	F	G
Line	***ADIT-190 (Attachment H-7 Notes P and Q)***	***Total***	***Gas, Prod Retail Or Other Related***	***Only Transmission Related***	***Plant Related***	***Labor Related***	***Justification***
1	ACCRUED BENEFITS	237,053	237,053	-	-	-	Related to employer costs of benefits, such as health insurance, 401 (k), etc. The amounts are recorded to the liability and cleared through payments during each bi-weekly payroll. Any balance in the account at the end of the month would relate to the month-end accrual that is recorded at the end of the month and reversed on the first calendar day of the next month. As such, there is a book to tax timing difference.
1a	ADDBACK OF NQSO EXPENSE	1,773,851	-	-	-	1,773,851	No current book activity, tax deducts as distributions are made from the trust - employees in all functions.
1b	ADDBACK OF OTHER EQUITY COMP EXPENSE	1,863,208	-	-	-	1,863,208	Book expense recorded when stock is granted, tax expense when stock is issued at market price - employees in all functions.
1c	AMORT-ORGANIZATIONAL COSTS	-	-	-	-	-	Excluded because the underlying account(s) are not included in model
1d	BAD DEBT - CHANGE IN PROVISION	15,064,698	15,064,698	-	-	-	Retail bad debt. For book, expense taken as it's identified; tax deduction not taken until fully written-off and all collection efforts abandoned. Relates to retail operations.
1e	CHARITABLE CARRYFORWARD	1,013,502	1,013,502	-	-	-	Excluded because the underlying account(s) are not included in model
1f	CUSTOMER ADVANCES - CONSTRUCTION	335,650	335,650	-	-	-	Excluded because the underlying account(s) are not included in model
1g	DEFERRED COMPENSATION	1,698,133	1,698,133	-	-	-	Book records estimated accrued compensation; tax deducts only upon the retirement or other separation from service by the employees. Relates to all functions.
1h	DEFERRED REVENUE	225,134	225,134	-	-	-	Excluded because the underlying account(s) are not included in model
1i	FAS 112	18,627	-	-	-	18,627	Employer provided benefits to former employees but before retirement.
1j	FEDERAL NOL	-	-	-	-	-	PECO is in a net operating loss situation, therefore, losses are carried forward until such losses can be applied to taxable income.
1k	FIN 47 ARO	5,371,606	5,371,606	-	-	-	Accrual of future removal/retirements. Book recognized the expense estimate accrual, tax recognizes when paid. Related to all functions. ARO must be approved by FERC in order to include amounts.
1l	Gross Up-Bill E Credit	-	-	-	-	-	Excluded because the underlying account(s) are not included in model
1m	INCENTIVE PAY	9,990,749	-	-	-	9,990,749	Book records an accrual in filing year on estimated payouts; tax reverses the accrual and deducts the actual paid out. Relates to all functions.
1n	INJURIES AND DAMAGE PAYMENTS	-	-	-	-	-	Books records an estimated liability for injuries and damages; tax purposes a deduction is only taken when actual payments are made.
1o	MERGER COSTS NC	-	-	-	-	-	Excluded because the underlying account(s) are not included in model
1p	DEFFERRED CHARGES - TAX REPAIRS BILL CREDIT-DI	67,489	67,489	-	-	-	Excluded because the underlying account(s) are not included in model
1q	OBSOLETE MATERIALS PROVISION	428,906	428,906	-	-	-	Excluded because the underlying account(s) are not included in model
1r	OTHER CURRENT	(15,328)	(15,328)	-	-	-	
1s	FACILITY COMMITMENT FEES	10,794	-	-	10,794	-	Debt related
1t	FINES & OTHER	192,052	192,052	-	-	-	Excluded because the underlying account(s) are not included in model
1u	OTHER NONCURRENT- RAILROAD LIABILITY	83,758	-	-	83,758	-	Related to reserve for required maintenance on right of ways.
1v	OTHER UNEARNED REVENUE-DEFERRED RENTS	262,092	-	-	262,092	-	Rent expense deferred and amortized ratably for books, tax deduction when paid - used for all functions.
1w	PAYROLL TAXES	-	-	-	-	-	Book records a payroll tax accrual; tax reverses the accrual and deducts the actual amount paid out. Relates to all functions.
1x	PENNSYLVANIA NOL	13,825,356	-	-	13,825,356	-	PECO is in a net operating loss situation, therefore, losses are carried forward until such losses can be applied to taxable income.
1y	PENSION EXPENSE PROVISION	-	-	-	-	-	Book accrues and capitalizes anticipated Pension costs based on actuarial analysis. Tax deducts or capitalizes retirement benefits only when the amounts are paid. Related to all functions.
1z	POLE ATTACHMENT RESERVE	-	-	-	-	-	Excluded because the underlying account(s) are not included in model
1aa	POST RETIREMENT BENEFITS	71,389,972	-	-	-	71,389,972	Book accrues anticipated post retirement costs based on actuarial analysis. Tax deducts retirement benefits only when the amounts are paid or contributed to a fund.
1ab	RESERVE FOR EMPLOYEE LITIGATIONS Current	48,886	48,886	-	-	-	Related to reserves associated with ongoing and/or pending litigation. These are not legal service fees, but accrual for possible liability payments upon resolution of ongoing litigation matters. Since we have accrued, but not yet paid, we have to book the tax reserve.
1ac	SA UNBILLED RESERVE	3,158,623	3,158,623	-	-	-	Retail related
1ad	SECA REFUND	-	-	-	-	-	Retail related
1ae	SEPTA RAILROAD RENT	132,515	132,515	-	-	-	Reserve for potential transmission rent expense
1af	SEVERANCE PMTS CHANGE IN PROVISION	51,322	-	-	-	51,322	Book records an accrual; tax takes the deduction when actually paid. Relates to all functions.
1ag	VACATION PAY CHANGE IN PROVISION	1,145,678	1,145,678	-	-	-	Capitalized portion of vacation pay earned and expensed for books, tax takes the deduction when paid out. Related to all functions.
1ah	VEGETATION MGMT ACCRUAL	1,701,178	1,701,178	-	-	-	Excluded because the underlying account(s) are not included in model
1ai	WORKERS COMPENSATION RESERVE	9,646,333	-	-	-	9,646,333	These accounts are reserves for public claims, workers compensation and other third party incidents. For tax purposes these are not deductible until paid. Related to all functions.
1aj							
1ak							
1al							
1am							
1an							
…							
2	**Subtotal - p234.8.b**	139,721,837	30,805,775	-	14,182,000	94,734,062	
3	**Less FASB 109 Above if not separately removed**	(38,867,663)	(2,154,571)	-	491,324	(37,204,416)	
4	**Less FASB 106 Above if not separately removed**						
5	**Total**	178,589,500	32,960,347	-	13,690,676	131,938,478	

6 **Instructions for Account 190:**
7 **1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C**
8 **2. ADIT items related only to Transmission are directly assigned to Column D**
9 **3. ADIT items related to Plant other than general plant, intangible plant or common plant and not in Columns C & D are included in Column E**
10 **4. ADIT items related to labor, general plant, intangible plant, or common plant and not in Columns C & D are included in Column F**

11 **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,**
12 **the associated ADIT amount shall be excluded**

PECO Energy Company

ADIT BOY Worksheet

	A	B	C	D	E	F	G
	ADIT- 282 (Attachment H-7 Notes N and Q)	*Total*	*Gas, Prod Retail Or Other Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
13a	Property Related ADIT, Excl. ARO	-	-	-	-	-	
13b	Common	(29,503,593)	-	-	-	(29,503,593)	Included because plant in service is included in rate base.
13c	Distribution	(1,188,168,321)	(1,188,168,321)	-	-	-	Related to Distribution property.
13d	Electric General	(3,041,661)	-	-	-	(3,041,661)	Included because plant in service is included in rate base.
13e	Transmission	(226,271,862)	-	(226,271,862)	-	-	Included because plant in service is included in rate base.
13f							
13g							
13h							
…							
14	**Subtotal - p275.2.b**	(1,446,985,437)	(1,188,168,321)	(226,271,862)	-	(32,545,254)	
15	**Less FASB 109 Above if not separately removed**	(307,962,711)	(269,117,641)	(37,128,133)	-	(1,716,937)	
16	**Less FASB 106 Above if not separately removed**						
17	**Total (Line 14 - Line 15 - Line 16)**	(1,139,022,726)	(919,050,680)	(189,143,729)	-	(30,828,318)	

18 **Instructions for Account 282:**
19 **1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C**
20 **2. ADIT items related only to Transmission are directly assigned to Column D**
21 **3. ADIT items related to Plant other than general plant, intangible plant or common plant and not in Columns C & D are included in Column E**
22 **4. ADIT items related to labor, general plant, intangible plant, or common plant and not in Columns C & D are included in Column F**
23 **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,**
24 **the associated ADIT amount shall be excluded**

Attachment 12 PECO Formula Rate Updated

PECO Energy Company

ADIT BOY Worksheet

	A	B	C	D	E	F	G
	ADIT-283 (Attachment H-7 Notes O, P and Q)	*Total*	*Gas, Prod Retail Or Other Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
25	ACT 129 SMART METER	(3,337,244)	(3,337,244)	-	-	-	Retail related
25a	AEC RECEIVABLE	(848,268)	(848,268)	-	-	-	Retail related
25b	AMORT-BK-PREMIUMS ON REACQD DEBT-9.5%	(321,464)	-	-	(321,464)	-	Book recapitalizes costs incurred to retire or reacquire debt issuances. Tax deducts these costs when incurred.
25c	CAP FORGIVENESS REG ASSET	(417,587)	(417,587)	-	-	-	Retail related
25d	CAP SHOPPING REG ASSET	(1,350,453)	(1,350,453)	-	-	-	Retail related
25e	DSP 2 - REGULATORY ASSET	(68,443)	(68,443)	-	-	-	Retail related
25f	ELEC RATE CASE EXP - REG ASSET	(415,762)	(415,762)	-	-	-	Retail related
25g	ENERGY EFFICIENCY REG ASSET	(203,599)	(203,599)	-	-	-	Retail related
25h	Gross Up on State Def Tax Adj- AMR Reg Asset	(385,014)	(385,014)	-	-	-	Retail related
25i	HOLIDAY PAY CHANGE IN PROVISION	(242,518)	-	-	-	(242,518)	The book expense on Jan 1 of calendar year; accelerated tax expense taken in previous calendar year. Related to all functions.
25j	OCI-Def FIT & SIT	(575,647)	(575,647)	-	-	-	Excluded because the underlying account(s) are not included in model
25k	OTHER CURRENT REG ASSET:	-	-	-	-	-	0
25l	LOSS OF REAQUIRED DEBT	(111,361)	-	-	(111,361)	-	Book recapitalizes costs incurred to retire or reacquire debt issuances. Tax deducts these costs when incurred. Included in debt capitalization ratio on Appendix A, line 111.
25m	VACATION ACCRUAL	(1,595,005)	(1,595,005)	-	-	-	Current portion of vacation pay earned and expensed for books, tax takes the deduction when paid out. Related to all functions.
25n	SMART METER	(3,337,244)	(3,337,244)	-	-	-	Retail related
25o	CAP SHOPPING REG ASSET - CURRENT	(0)	(0)	-	-	-	Retail related
25p	CAP FORGIVENESS REG ASSET - CURRENT	(1,567,342)	(1,567,342)	-	-	-	Retail related
25q	FAS 112	(205,034)	-	-	-	(205,034)	Employer provided benefits to former employees but before retirement.
25r	ELEC RATE CASE EXP - REG ASSET - CURRENT	(0)	-	-	-	-	Property taxes. Book records on an accrual method based on the prior year; tax reverses the book accrual and deducts the actual payments made. . Relates to all functions.
25s	PURTA	-	-	-	-	-	Retail related
25t	SEAMLESS MOVES	(0)	-	-	-	(0)	Book accrues and capitalizes anticipated Pension costs based on actuarial analysis. Tax deducts or capitalizes retirement benefits only when the amounts are paid. Retail related.
25u	OTHER CURRENT REG ASSET	237,902	237,902	-	-	-	Gas Related
25v	PENSION EXPENSE PROVISION	(92,669,768)	-	-	-	(92,669,768)	Book accrues and capitalizes anticipated Pension costs based on actuarial analysis. Tax deducts or capitalizes retirement benefits only when the amounts are paid. Related to all functions.
25w	RATE CHANGE REG ASSET	(7,896,920)	(7,896,920)	-	-	-	Gross up related to non-property tax rate change/TCJA
25x	STATE TAX RESERVE	(3,278,057)	-	-	(3,278,057)	-	The state income tax is cash basis
25y	ARO- Reg Asset	(5,001,186)	(5,001,186)	-	-	-	
25z	ARO- Reg Asset	-	-	-	-	-	
25aa							
25ab							
25ac							
25ad							
25ae							
25af							
….							
….							
26	**Subtotal - p276.9.b**	(123,590,014)	(26,761,812)	-	(3,710,882)	(93,117,320)	
27	**Less FASB 109 Above if not separately removed**	15,566,922	(1,984,446)	-	1,871,052	15,680,316	
28	**Less FASB 106 Above if not separately removed**						
29	**Total**	(139,156,936)	(24,777,366)	-	(5,581,934)	(108,797,636)	

30 **Instructions for Account 283:**

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

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

33 **3. ADIT items related to Plant other than general plant, intangible plant or common plant and not in Columns C & D are included in Column E**

34 **4. ADIT items related to labor, general plant, intangible plant, or common plant and not in Columns C & D are included in Column F**

35 **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,**

36 **the associated ADIT amount shall be excluded**

Attachment 4C
PECO Energy Company

ADIT EOY Worksheet

	A	B	C	D	E	F	
			Gas, Prod	*Only*			
			Retail Or Other	*Transmission*	*Plant*	*Labor*	
		Total	*Related*	*Related*	*Related*	*Related*	
a	***ADIT- 282***	(1,261,244,192)		(200,390,143)	-	(31,198,496)	(From line 17 for the column)
b	***ADIT-283***	(129,949,790)		-	(5,165,133)	(104,384,871)	(From line 29 for the column)
c	***ADIT-190***	169,734,784		-	19,259,193	116,408,740	(From line 5 for the column)
d	***Subtotal***	(1,221,459,197)		(200,390,143)	14,094,060	(19,174,626)	(Sum a - c)

Line 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.

Line	A	B	C	D	E	F	G
	ADIT-190 (Attachment H-7 Notes P and Q)	***Total***	***Gas, Prod***	***Only***			
1			***Retail Or Other***	***Transmission***	***Plant***	***Labor***	
1a			***Related***	***Related***	***Related***	***Related***	***Justification***
1b							
1c	ACCRUED BENEFITS	429,824	429,824	-	-	-	Related to employer costs of benefits, such as health insurance, 401 (k), etc. The amounts are recorded to the liability and cleared through payments during each bi-weekly payroll. Any balance in the account at the end of the month would relate to the month-end accrual that is recorded at the end of the month and reversed on the first calendar day of the next month. As such, there is a book to tax timing difference.
1d	ADDBACK OF NQSO EXPENSE	1,541,792	-	-	-	1,541,792	No current book activity, tax deducts as distributions are made from the trust - employees in all functions.
1e	ADDBACK OF OTHER EQUITY COMP EXPENSE	1,122,149	-	-	-	1,122,149	Book expense recorded when stock is granted, tax expense when stock is issued at market price - employees in all functions.
1f	AMORT-ORGANIZATIONAL COSTS	-	-	-	-	-	Excluded because the underlying account(s) are not included in model
1g	BAD DEBT - CHANGE IN PROVISION	15,150,483	15,150,483	-	-	-	Retail bad debt. For book, expense taken as it's identified; tax deduction not taken until fully written-off and all collection efforts abandoned. Relates to retail operations.
1h	CHARITABLE CARRYFORWARD	2,115,506	2,115,506	-	-	-	Excluded because the underlying account(s) are not included in model
1i	CUSTOMER ADVANCES - CONSTRUCTION	767,529	767,529	-	-	-	Excluded because the underlying account(s) are not included in model
1j	DEFERRED COMPENSATION	2,126,325	2,126,325	-	-	-	Book records estimated accrued compensation; tax deducts only upon the retirement or other separation from service by the employees. Relates to all functions.
1k	DEFERRED REVENUE	243,866	243,866	-	-	-	Excluded because the underlying account(s) are not included in model
1l	FAS 112	18,627	-	-	-	18,627	Employer provided benefits to former employees but before retirement.
1m	FEDERAL NOL	-	-	-	-	-	PECO is in a net operating loss situation, therefore, losses are carried forward until such losses can be applied to taxable income.
1n	FIN 47 ARO	5,603,925	5,603,925	-	-	-	Accrual of future removal/retirements. Book recognized the expense estimate accrual, tax recognizes when paid. Related to all functions. ARO must be approved by FERC in order to include amounts.
1o		-	-	-	-	-	Excluded because the underlying account(s) are not included in model
1p	INCENTIVE PAY	11,559,004	-	-	-	11,559,004	Book records an accrual in filing year on estimated payouts; tax reverses the accrual and deducts the actual paid out. Relates to all functions.
1q	INJURIES AND DAMAGE PAYMENTS	-	-	-	-	-	Books records an estimated liability for injuries and damages; tax purposes a deduction is only taken when actual payments are made.
1r	MERGER COSTS NC	-	-	-	-	-	Excluded because the underlying account(s) are not included in model
1s	DEFFERRED CHARGES - TAX REPAIRS BILL CREDIT-DIST	-	-	-	-	-	Excluded because the underlying account(s) are not included in model
1t	OBSOLETE MATERIALS PROVISION	530,272	530,272	-	-	-	Excluded because the underlying account(s) are not included in model
1u	OTHER CURRENT	-	-	-	-	-	
1v	FACILITY COMMITMENT FEES	-	-	-	-	-	Debt related
1w	FINES & OTHER	86,745	86,745	-	-	-	Excluded because the underlying account(s) are not included in model
1x	OTHER NONCURRENT- RAILROAD LIABILITY	70,225	-	-	70,225	-	Related to reserve for required maintenance on right of ways.
1y	OTHER UNEARNED REVENUE-DEFERRED RENTS	258,166	-	-	258,166	-	Rent expense deferred and amortized ratably for books, tax deduction when paid - used for all functions.
1z	PAYROLL TAXES	-	-	-	-	-	Book records a payroll tax accrual; tax reverses the accrual and deducts the actual amount paid out. Relates to all functions.
1aa	PENNSYLVANIA NOL	19,225,596	-	-	19,225,596	-	PECO is in a net operating loss situation, therefore, losses are carried forward until such losses can be applied to taxable income.
1ab	PENSION EXPENSE PROVISION	-	-	-	-	-	Book accrues and capitalizes anticipated Pension costs based on actuarial analysis. Tax deducts or capitalizes retirement benefits only when the amounts are paid. Related to all functions.
1ac	POLE ATTACHMENT RESERVE	-	-	-	-	-	Excluded because the underlying account(s) are not included in model
1ad	POST RETIREMENT BENEFITS	71,516,180	-	-	-	71,516,180	Book accrues anticipated post retirement costs based on actuarial analysis. Tax deducts retirement benefits only when the amounts are paid or contributed to a fund.
1ae	RESERVE FOR EMPLOYEE LITIGATIONS Current	-	-	-	-	-	Related to reserves associated with ongoing and/or pending litigation. These are not legal service fees, but accrual for possible liability payments upon resolution of ongoing litigation matters. Since we have accrued, but not yet paid, we have to book the tax reserve.
1af	SA UNBILLED RESERVE	2,180,599	2,180,599	-	-	-	Retail related
1ag	SECA REFUND	-	-	-	-	-	Retail related
1ah	SEPTA RAILROAD RENT	-	-	-	-	-	Reserve for potential transmission rent expense
1ai	SEVERANCE PMTS CHANGE IN PROVISION	177,323	-	-	-	177,323	Book records an accrual; tax takes the deduction when actually paid. Relates to all functions.
1aj	VACATION PAY CHANGE IN PROVISION	902,265	902,265	-	-	-	Capitalized portion of vacation pay earned and expensed for books, tax takes the deduction when paid out. Related to all functions.
1ak	VEGETATION MGMT ACCRUAL	2,636,769	2,636,769	-	-	-	Excluded because the underlying account(s) are not included in model
1al	WORKERS COMPENSATION RESERVE	8,151,016	-	-	-	8,151,016	Related to all functions.
1am							
1an							
…		-					
2	**Subtotal - p234.8.c**	146,414,186	32,774,108	-	19,553,987	94,086,091	
3	**Less FASB 109 Above if not separately removed**	(23,320,598)	(1,292,743)	-	294,795	(22,322,649)	
4	**Less FASB 106 Above if not separately removed**						
5	**Total (Line 2 - Line 3 - Line 4)**	169,734,784	34,066,851	-	19,259,193	116,408,740	

6 **Instructions for Account 190:**
7 **1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C**
8 **2. ADIT items related only to Transmission are directly assigned to Column D**
9 **3. ADIT items related to Plant other than general plant, intangible plant or common plant and not in Columns C & D are included in Column E**
10 **4. ADIT items related to labor, general plant, intangible plant, or common plant and not in Columns C & D are included in Column F**
11 **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,**
12 **the associated ADIT amount shall be excluded**

Attachment 12 PECO Formula Rate Updated

PECO Energy Company

ADIT EOY Worksheet

	A	B	C	D	E	F	G
	ADIT- 282 (Attachment H-7 Notes N and Q)	*Total*	*Gas, Prod Retail Or Other Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
13a	Property Related ADIT, Excl. ARO	-	-	-	-	-	
13b	Common	(29,107,226)	-	-	-	(29,107,226)	Included because plant in service is included in rate base.
13c	Distribution	(1,277,494,888)	(1,277,494,888)	-	-	-	Related to Distribution property.
13d	Electric General	(3,136,156)	-	-	-	(3,136,156)	Included because plant in service is included in rate base.
13e	Transmission	(235,859,579)	-	(235,859,579)	-	-	Included because plant in service is included in rate base.
13f							
13g							
13h							
…							
14	**Subtotal - p275.2.k**	(1,545,597,849)	(1,277,494,888)	(235,859,579)	-	(32,243,382)	
15	**Less FASB 109 Above if not separately removed**	(284,353,657)	(247,839,335)	(35,469,436)	-	(1,044,886)	
16	**Less FASB 106 Above if not separately removed**						
17	**Total (Line 14 - Line 15 - Line 16)**	(1,261,244,192)	(1,029,655,553)	(200,390,143)	-	(31,198,496)	

18 **Instructions for Account 282:**
19 **1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C**
20 **2. ADIT items related only to Transmission are directly assigned to Column D**
21 **3. ADIT items related to Plant other than general plant, intangible plant or common plant and not in Columns C & D are included in Column E**
22 **4. ADIT items related to labor, general plant, intangible plant, or common plant and not in Columns C & D are included in Column F**
23 **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,**
24 **the associated ADIT amount shall be excluded**

PECO Energy Company

ADIT EOY Worksheet

	A	B	C	D	E	F	G
	ADIT-283 (Attachment H-7 Notes O, P and Q)	*Total*	*Gas, Prod Retail Or Other Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
25a	ACT 129 SMART METER	-	-	-	-	-	Retail related
25b	AEC RECEIVABLE	(930,652)	(930,652)	-	-	-	Retail related
25c	AMORT-BK-PREMIUMS ON REACQD DEBT-9.5%	(269,975)	-	-	(269,975)	-	Book recapitalizes costs incurred to retire or reacquire debt issuances. Tax deducts these costs when incurred.
25d	CAP FORGIVENESS REG ASSET	-	-	-	-	-	Retail related
25e	CAP SHOPPING REG ASSET	-	-	-	-	-	Retail related
25f	DSP 2 - REGULATORY ASSET	(43,613)	(43,613)	-	-	-	Retail related
25g	ELEC RATE CASE EXP - REG ASSET	(142,257)	(142,257)	-	-	-	Retail related
25h	ENERGY EFFICIENCY REG ASSET	(60,561)	(60,561)	-	-	-	Retail related
25i	Gross Up on State Def Tax Adj- AMR Reg Asset	(192,532)	(192,532)	-	-	-	Retail related
25j	HOLIDAY PAY CHANGE IN PROVISION	(262,244)	-	-	-	(262,244)	The book expense on Jan 1 of calendar year; accelerated tax expense taken in previous calendar year. Related to all functions.
25k	OCI-Def FIT & SIT	-	-	-	-	-	Excluded because the underlying account(s) are not included in model
25l	OTHER CURRENT REG ASSET:	-	-	-	-	-	0
25m	LOSS OF REAQUIRED DEBT	(51,488)	-	-	(51,488)	-	Book recapitalizes costs incurred to retire or reacquire debt issuances. Tax deducts these costs when incurred. Included in debt capitalization ratio on Appendix A, line 111.
25n	VACATION ACCRUAL	(1,600,829)	(1,600,829)	-	-	-	Current portion of vacation pay earned and expensed for books, tax takes the deduction when paid out. Related to all functions.
25o	SMART METER	(3,337,244)	(3,337,244)	-	-	-	Retail related
25p	CAP SHOPPING REG ASSET - CURRENT	-	-	-	-	-	Retail related
25q	CAP FORGIVENESS REG ASSET - CURRENT	(1,015,422)	(1,015,422)	-	-	-	Retail related
25r	FAS 112	(206,973)	-	-	-	(206,973)	Employer provided benefits to former employees but before retirement.
25s	PURTA	(67,403)	-	-	(67,403)	-	Property taxes. Book records on an accrual method based on the prior year; tax reverses the book accrual and deducts the actual payments made. . Relates to all functions.
25t	ELEC RATE CASE EXP - REG ASSET - CURRENT	(142,257)	(142,257)	-	-	-	Retail related
25u	SEAMLESS MOVES	(0)	-	-	-	(0)	Book accrues and capitalizes anticipated Pension costs based on actuarial analysis. Tax deducts or capitalizes retirement benefits only when the amounts are paid. Retail related.
25v	OTHER CURRENT REG ASSET	-	-	-	-	-	Gas Related
25w	PENSION EXPENSE PROVISION	(94,537,653)	-	-	-	(94,537,653)	Book accrues and capitalizes anticipated Pension costs based on actuarial analysis. Tax deducts or capitalizes retirement benefits only when the amounts are paid. Related to all functions.
25x	RATE CHANGE REG ASSET	(6,167,317)	(6,167,317)	-	-	-	Gross up related to non-property tax rate change/TCJA
25y	STATE TAX RESERVE	(3,653,636)	-	-	(3,653,636)	-	The state income tax is cash basis
25z	ARO- Reg Asset	(5,140,850)	(5,140,850)	-	-	-	
25aa	FERC 494 SETTLEMENT DECEMBER 2019	(557,890)	(557,890)	-	-	-	
25ab	TSC UNDER RECOVERY	(68,722)	(68,722)	-	-	-	Retail related
25ac	CLOUD COMPUTING	(941,505)	(941,537)	-	-	-	
25ad		-					
25ae		-					
25af		-					
….		-					
….							
26	**Subtotal - p277.9.k**	(119,391,023)	(20,341,683)	-	(4,042,502)	(95,006,870)	
27	**Less FASB 109 Above if not separately removed**	10,558,767	58,135	-	1,122,631	9,378,001	
28	**Less FASB 106 Above if not separately removed**						
29	**Total**	(129,949,790)	(20,399,818)	-	(5,165,133)	(104,384,871)	

30 **Instructions for Account 283:**
31 **1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C**
32 **2. ADIT items related only to Transmission are directly assigned to Column D**
33 **3. ADIT items related to Plant other than general plant, intangible plant or common plant and not in Columns C & D are included in Column E**
34 **4. ADIT items related to labor, general plant, intangible plant, or common plant and not in Columns C & D are included in Column F**
35 **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,**
36 **the associated ADIT amount shall be excluded**

Attachment 12 PECO Formula Rate Updated

PECO Energy Company

Attachment 4D - Intangible Plant Workpaper

Total Intangible Plant

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)
	Gross Plant	December Prior Year	January	February	March	April	May	June	July	August	September	October	November	December	Average	Transmission	Distribution	S&W Allocation	Total
															=average(b:n)				=sum(p:r)
1	Intangible - General	18,519,044	19,332,194	19,672,683	19,633,397	19,132,360	22,655,813	25,006,568	24,675,786	28,561,979	29,471,711	29,644,666	17,392,658	17,881,251	22,429,239			22,429,239	22,429,239
2	IT NERC CIP - Transmission	11,596,262	11,596,262	11,596,262	11,570,548	11,570,548	10,967,791	10,967,791	10,967,791	10,967,791	10,967,791	10,967,791	10,967,791	10,967,791	11,205,555	11,205,555			11,205,555
3	IT NERC CIP - Distribution	2,369,415	2,369,415	2,369,415	2,089,187	2,089,187	1,486,430	1,486,430	1,486,430	1,486,430	1,486,430	1,486,430	1,486,430	1,486,430	1,782,928		1,782,928		1,782,928
4	IT DSP - Distribution	2,872,703	2,231,384	2,231,384	2,231,384	2,231,384	2,231,384	2,231,384	2,231,384	2,231,384	2,231,384	2,231,384	2,231,384	2,231,384	2,280,716		2,280,716		2,280,716
5	IT Business Intelligence Data Analysis - Distribution	16,318,757	16,318,757	16,318,757	16,318,757	16,318,757	16,318,757	17,914,640	17,914,406	17,914,406	17,914,406	17,914,406	17,106,666	26,991,446	17,814,071		17,814,071		17,814,071
6	IT Post 2010 and Other - Distribution	19,607,929	19,638,254	19,638,254	19,638,254	19,638,254	23,529,716	24,220,864	26,178,856	26,283,125	26,321,729	26,321,430	38,684,939	30,137,375	24,602,998		24,602,998		24,602,998
7	IT Smart Meter - Distribution	86,110,084	86,110,084	86,110,084	86,110,084	86,110,084	86,110,084	86,110,084	86,110,084	86,110,084	86,110,084	86,110,084	86,110,084	86,110,083	86,110,084		86,110,084		86,110,084
8	IT Other - Transmission	5,552,297	5,552,297	5,552,297	5,552,297	5,552,297	5,771,259	5,771,259	5,771,259	5,771,259	5,771,259	5,771,259	5,771,259	5,771,259	5,687,043	5,687,043			5,687,043
9	IT Business Intelligence Data Analysis - Transmission	-	-	-	-	-	-	-	-	-	-	-	807,740	947,199	134,995	134,995			134,995
10																			-
11																			-
12																			-
13																			-
14																			-
15																			-
16																			-
17																			-
18																			-
19	Total	162,946,491	163,148,647	163,489,136	163,143,908	162,642,870	169,071,235	173,709,020	175,335,996	179,326,457	180,274,794	180,447,450	180,558,952	182,524,219	172,047,629	17,027,593	132,590,796	22,429,239	172,047,629
20															Allocation Factor	100.00%	0.00%	9.45%	
21															Total Intangible - Transmission	17,027,593	-	2,119,358	19,146,951

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)
	Accumulated Depreciation	December Prior Year	January	February	March	April	May	June	July	August	September	October	November	December	Average	Transmission	Distribution	S&W Allocation	Total
															=average(b:n)				=sum(p:r)
22	Intangible - General	7,733,452	8,006,018	8,245,577	8,474,678	7,721,863	8,018,165	8,297,442	8,529,911	8,956,657	9,375,597	9,796,601	9,985,319	9,817,212	8,689,115			8,689,115	8,689,115
23	IT NERC CIP - Transmission	6,329,993	6,523,318	6,716,643	6,906,579	7,099,461	7,066,311	7,248,581	7,430,851	7,613,120	7,795,390	7,977,659	8,159,929	8,342,199	7,323,849	7,323,849			7,323,849
24	IT NERC CIP - Distribution	1,032,561	1,072,668	1,112,776	1,114,049	1,149,376	958,673	983,388	1,008,103	1,032,818	1,057,534	1,082,249	1,106,964	1,131,680	1,064,834		1,064,834		1,064,834
25	IT DSP - Distribution	2,222,925	2,220,648	2,223,715	2,226,783	2,229,850	2,231,384	2,231,384	2,231,384	2,231,384	2,231,384	2,231,384	2,231,384	2,231,384	2,228,846		2,228,846		2,228,846
26	IT Business Intelligence Data Analysis - Distribution	3,928,994	4,132,105	4,335,216	4,538,327	4,741,438	4,944,548	5,213,156	5,508,137	5,674,432	5,905,375	6,136,318	6,273,640	7,148,207	5,267,684		5,267,684		5,267,684
27	IT Post 2010 and Other - Distribution	16,855,601	16,992,335	17,130,592	17,267,822	17,405,052	18,093,572	18,301,419	18,814,143	19,061,295	19,309,689	19,558,422	20,118,471	20,319,087	18,402,115		18,402,115		18,402,115
28	IT Smart Meter - Distribution	71,779,518	72,112,873	72,446,229	72,779,585	73,112,940	73,446,296	73,756,705	74,044,168	74,330,951	74,599,937	74,849,048	75,095,400	75,341,753	73,668,877		73,668,877		73,668,877
29	IT Other - Transmission	1,102,456	1,349,669	1,596,883	1,844,096	2,091,310	2,346,343	2,609,798	2,873,253	3,136,708	3,400,163	3,663,619	3,927,074	4,190,529	2,625,531	2,625,531			2,625,531
30	IT Business Intelligence Data Analysis - Transmission	-	-	-	-	-	-	-	-	-	-	-	8,381	67,725	5,854	5,854			5,854
31																			-
32																			-
33																			-
34																			-
35																			-
36																			-
37																			-
38																			-
39																			-
40	Total	110,985,499	112,409,634	113,807,630	115,151,919	115,551,290	117,105,292	118,641,874	120,439,951	122,037,365	123,675,069	125,295,300	126,906,562	128,589,775	119,276,705	9,955,234	100,632,356	8,689,115	119,276,705
41															Allocation Factor	100.00%	0.00%	9.45%	
42															Total Intangible - Transmission	9,955,234	-	821,042	10,776,276

PECO Energy Company

Attachment 4D - Intangible Plant Workpaper

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)
	Net Plant in Service	December Prior Year	January	February	March	April	May	June	July	August	September	October	November	December	Average	Transmission	Distribution	S&W Allocation	Total
	Gross Plant Minus Accumulated Depreciation														=average(b:n)				=sum(p:r)
43	Intangible - General	10,785,592	11,326,177	11,427,107	11,158,719	11,410,497	14,637,649	16,709,125	16,145,874	19,605,322	20,096,114	19,848,065	7,407,339	8,064,039	13,740,125			13,740,125	13,740,125
44	IT NERC CIP - Transmission	5,266,270	5,072,945	4,879,620	4,663,968	4,471,087	3,901,480	3,719,210	3,536,941	3,354,671	3,172,402	2,990,132	2,807,862	2,625,593	3,881,706	3,881,706			3,881,706
45	IT NERC CIP - Distribution	1,336,854	1,296,747	1,256,639	975,137	939,810	527,758	503,043	478,327	453,612	428,897	404,181	379,466	354,751	718,094		718,094		718,094
46	IT DSP - Distribution	649,778	10,736	7,669	4,601	1,534	-	-	-	-	-	-	-	-	51,871		51,871		51,871
47	IT Business Intelligence Data Analysis - Distribution	12,389,763	12,186,652	11,983,541	11,780,430	11,577,319	11,374,209	12,701,484	12,406,269	12,239,974	12,009,031	11,778,088	10,833,026	19,843,239	12,546,387		12,546,387		12,546,387
48	IT Post 2010 and Other - Distribution	2,752,327	2,645,919	2,507,662	2,370,432	2,233,202	5,436,144	5,919,444	7,364,713	7,221,830	7,012,040	6,763,008	18,566,469	9,818,288	6,200,883		6,200,883		6,200,883
49	IT Smart Meter - Distribution	14,330,566	13,997,210	13,663,855	13,330,499	12,997,143	12,663,787	12,353,378	12,065,915	11,779,133	11,510,146	11,261,035	11,014,683	10,768,330	12,441,206		12,441,206		12,441,206
50	IT Other - Transmission	4,449,841	4,202,628	3,955,415	3,708,201	3,460,988	3,424,916	3,161,461	2,898,006	2,634,551	2,371,096	2,107,641	1,844,185	1,580,730	3,061,512	3,061,512			3,061,512
51	IT Business Intelligence Data Analysis - Transmission	-	-	-	-	-	-	-	-	-	-	-	799,359	879,474	129,141	129,141	129,141		258,282
52		-	-	-	-	-	-	-	-	-	-	-	-	-					-
53		-	-	-	-	-	-	-	-	-	-	-	-	-					-
54		-	-	-	-	-	-	-	-	-	-	-	-	-					-
55		-	-	-	-	-	-	-	-	-	-	-	-	-					-
56		-	-	-	-	-	-	-	-	-	-	-	-	-					-
57		-	-	-	-	-	-	-	-	-	-	-	-	-					-
58		-	-	-	-	-	-	-	-	-	-	-	-	-					-
59		-	-	-	-	-	-	-	-	-	-	-	-	-					-
60		-	-	-	-	-	-	-	-	-	-	-	-	-					-
61	Total	51,960,992	50,739,013	49,681,506	47,991,989	47,091,580	51,965,942	55,067,146	54,896,045	57,289,092	56,599,725	55,152,150	53,652,390	53,934,444	52,770,924	7,072,359	32,087,581	13,740,125	52,900,065
62															Allocation Factor	100.00%	0.00%	9.45%	
63															Total Intangible - Transmission	7,072,359	-	1,298,316	8,370,675

	(a)	(b)	(c)	(d)	(e)	(f)
		Total	Transmission	Distribution	S&W Allocation	Total
	Depreciation Expense					=sum(c:e)
64	Intangible - General	4,026,332			4,026,332	4,026,332
65	IT NERC CIP - Transmission	2,012,206	2,012,206			2,012,206
66	IT NERC CIP - Distribution	99,119		99,119		99,119
67	IT DSP - Distribution	-		-		-
68	IT Business Intelligence Data Analysis - Distribution	645,830		645,830		645,830
69	IT Post 2010 and Other - Distribution	6,746,713		6,746,713		6,746,713
70	IT Smart Meter - Distribution	3,562,235		3,562,235		3,562,235
71	IT Other - Transmission	3,088,073	3,088,073			3,088,073
72	IT Business Intelligence Data Analysis - Transmission	20,459	20,459			20,459
73		-				-
74		-				-
75		-				-
76		-				-
77		-				-
78		-				-
79		-				-
80		-				-
81		-				-
82	Total	20,200,967	5,120,737	11,053,897	4,026,332	20,200,967
83		Allocation Factor	100.00%	0.00%	9.45%	
84		Total Intangible - Transmission	5,120,737	-	380,452	5,501,189

Attachment 12 PECO Formula Rate Updated

PECO Energy Company

Attachment 4E - Cost to Achieve Mergers (Note A)

	(a)	(b)	(c)	(d)	(e)	(…)	(x)
	O&M Cost To Achieve						
	FERC Account	Constellation Merger	PHI Merger				Total
1	923	0	$ 7,746				$ 7,746
2	926	0	$ -				$ -
3	920		$ -				$ -
4							$ -
5							$ -
6							$ -
7							$ -
8							$ -
9							$ -
10							$ -
11	Total	$ -	$ 7,746				$ 7,746

	Capital Cost To Achieve included in the Electric Portion of Common Plant						
	Gross Plant	Constellation Merger	PHI Merger				Total
12	December Prior Year	-	3,205,042				$ 3,205,042
13	January	-	3,205,042				$ 3,205,042
14	February	-	3,205,042				$ 3,205,042
15	March	-	3,205,042				$ 3,205,042
16	April	-	3,205,042				$ 3,205,042
17	May	-	3,205,042				$ 3,205,042
18	June	-	3,205,042				$ 3,205,042
19	July	-	3,205,042				$ 3,205,042
20	August	-	3,205,042				$ 3,205,042
21	September	-	3,205,042				$ 3,205,042
22	October	-	3,205,042				$ 3,205,042
23	November	-	3,205,042				$ 3,205,042
24	December	-	3,205,042				$ 3,205,042
25	Average	-	3,205,042				3,205,042

	Accumulated Depreciation	Constellation Merger	PHI Merger				Total
26	December Prior Year	-	706,297				$ 706,297
27	January	-	748,299				$ 748,299
28	February	-	793,736				$ 793,736
29	March	-	878,741				$ 878,741
30	April	-	936,610				$ 936,610
31	May	-	967,782				$ 967,782
32	June	-	1,020,130				$ 1,020,130
33	July	-	1,067,621				$ 1,067,621
34	August	-	1,125,911				$ 1,125,911
35	September	-	1,200,154				$ 1,200,154
36	October	-	1,229,865				$ 1,229,865
37	November	-	1,285,173				$ 1,285,173
38	December	-	1,329,143				$ 1,329,143
39	Average	-	1,022,266				1,022,266

PECO Energy Company

Attachment 4E - Cost to Achieve Mergers (Note A)

	(a)	(b)	(c)	(d)	(e)	(…)	(x)
	Net Plant = Gross Plant Minus Accumulated Depreciation from above	Constellation Merger	PHI Merger				Total
40	December Prior Year	-	2,498,744	-	-	-	$ 2,498,744
41	January	-	2,456,743	-	-	-	$ 2,456,743
42	February	-	2,411,306	-	-	-	$ 2,411,306
43	March	-	2,326,301	-	-	-	$ 2,326,301
44	April	-	2,268,432	-	-	-	$ 2,268,432
45	May	-	2,237,260	-	-	-	$ 2,237,260
46	June	-	2,184,911	-	-	-	$ 2,184,911
47	July	-	2,137,421	-	-	-	$ 2,137,421
48	August	-	2,079,131	-	-	-	$ 2,079,131
49	September	-	2,004,888	-	-	-	$ 2,004,888
50	October	-	1,975,177	-	-	-	$ 1,975,177
51	November	-	1,919,869	-	-	-	$ 1,919,869
52	December	-	1,875,899	-	-	-	$ 1,875,899
53	Average	-	2,182,775	-	-	-	2,182,775
	Depreciation (Monthly Change of Accumulated Depreciation from above)	Constellation Merger	PHI Merger				Total
54	January	-	42,001				$ 42,001
55	February	-	45,437				$ 45,437
56	March	-	85,005				$ 85,005
57	April	-	57,869				$ 57,869
58	May	-	31,172				$ 31,172
59	June	-	52,348				$ 52,348
60	July	-	47,490				$ 47,490
61	August	-	58,291				$ 58,291
62	September	-	74,243				$ 74,243
63	October	-	29,711				$ 29,711
64	November	-	55,308				$ 55,308
65	December	-	43,970				$ 43,970
66	Total	-	622,846				$ 622,846

Note:

A: Merger-related costs incurred during hold harmless period are to be excluded from rate unless approved by FERC order.

Attachment 5
Attachment H-7, Pages 3 and 4, Worksheet
PECO Energy Company

Line No.	Month	Transmission O&M Expenses	Account No. 566 (Misc. Trans. Expense)	Account No. 565	Accounts 561.4 and 561.8	Amortization of Regulatory Asset	Miscellaneous Transmission Expense (less amortization of regulatory asset)	Depreciation Expense - Transmission	Depreciation Expense - Common	Depreciation Expense - Transmission Intangible	Depreciation Expense - General Intangible	Depreciation Expense - Distribution
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Attachment H-7, Page 3, Line No.:	1	2	3		11	12	16				
	Form No. 1	321.112.b	321.97.b	321.96.b	321.88.b & 92.b	Portion of Account 566 (Attachment H-7 Notes T and Z)	Balance of Account 566	Attachment 8, Page 1, Line 11, Col J	Attachment 8, Page 2, Line 51, Col J	Attachment 8, Page 2, Line 10, Col J	Attachment 8, Page 2, Line 19, Col J	Attachment 8, Page 2, Line 22, Col J
1	Total	116,080,855	10,863,927	-	65,204,955	-	$ 10,863,927	$ 26,801,531	$ 32,943,973	$ 5,120,743	$ 4,026,335	$ 11,053,897

Line No.	Month	Depreciation Expense - General	Amortization of Abandoned Plant	Labor Related Taxes	Labor Related Taxes to be Excluded	Plant Related Taxes	Excluded Taxes Per Attachment 5C Line 5	Other Included Taxes	Plant Related Taxes to be Excluded	Amortized Investment Tax Credit Consistent with (266.8.f & 266.17.f) - Transmission	Excess Deferred Income Tax Amortization - Transmission	Tax Effect of Permanent Differences - Transmission
		(a)	(b)	(c)	(d) (Note F)	(e)	(f)	(g)	(h) (Note F)	(i)	(j)	(k)
	Attachment H-7, Page 3, Line Number	17	19	23	24	26	27	28	29	38	39	40
	Form No. 1	Attachment 8, Page 1, Line 25, Col J	(Note S)	Attachment 5C Line 2	Attachment 5C Line 9	Attachment 5C Line 1	Attachment 5C Line 5	Attachment 5C Line 3	Attachment 5C Line 10	(Note E)	(Attachment H-7 Note G)	(Attachment H-7 Note W)
2	Total	$ 18,971,738	$ -	$ 12,308,308	$ -	$ 12,835,970	$ 132,585,408	$ 450,022	$ -	$ 2,976	$ 3,250,820	$ 282,655

Attachment 5
Attachment H-7, Pages 3 and 4, Worksheet
PECO Energy Company

			$
3	Long Term Interest (117, sum of 62.c through 67.c), Excluding LVT Interest (Note G)		137,274,572
4	Preferred Dividends (118.29c) (positive number)		-
5	Proprietary Capital		4,070,854,964
6	Less Preferred Stock		-
7	Less Account 216.1 (enter negative) (Note D)		-
8	Less Account 219.1 (enter negative)		(1,843,551)
9	Common Stock	(Sum of Line 5 - Line 6 + Line 7 + Line 8)	4,069,011,413

			$	%	Cost	Weighted	
10	Long Term Debt (Note A)	(100% - Line 11, Col (%) - Line 12, Col (%))	3,409,418,609	45.59%	4.03%	1.84%	=WCLTD
11	Preferred Stock (Note B)	(Line 11, Col ($) / Line 13, Col ($))	-	-	-	0.00%	
12	Common Stock (Note C)	(Line 12, Col ($) / Line 13, Col ($))	4,069,011,413	54.41%	10.35%	5.63%	
13	Total	(Sum of Lines 10-12)	7,478,430,022			7.47%	=R

Notes:

A Long Term Debt balance will reflect the 13 month average of the balances, of which the 1st and 13th are found on page 112 lines 18.c & d to 21.c & d in the Form No. 1.

B Preferred Stock balance will reflect the 13 month average of the balances, of which the 1st and 13th are found on page 112 line 3.c & d in the Form No. 1

C Common Stock balance will reflect the 13 month average of the balances, of which the 1st and 13th are found on page 112 lines 3.c & d, 12.c & d, and 16.c & d in the Form No. 1 as shown on lines 10-12 above
A cap on the equity percentage of PECO's capital structure shall be 55.75%.
ROE will be supported in the original filing and no change in ROE may be made absent FERC authorization pursuant to a section 205 or section 206.

D The Account 216.1 balance is input only if positive number in the FERC Form No. 1 (112.12.c).

E Sum of transmission related electric and common amortized investment tax credit amounts. Total electric amount allocated to transmission as follows: (1) amounts solely related to transmission allocated 100% to transmission; (2) amounts solely related to distribution, gas or non-utility allocated 0% to transmission; (3) amounts related to electric general allocated using the wages and salaries allocator (Attachment H-7, p. 4, line 11, column (5)); (4) amount related to common plant allocated to transmission using the wages and salaries allocator (Attachment H-7, p. 4, line 11, column (5)), multiplied by common utility plant percent to electric (per FF1 page 356).

F Labor and Plant related taxes due to merger are to be excluded consistent with hold harmless commitment.

G All short-term interest related expense will be removed from the formula rate template.

Attachment 12 PECO Formula Rate Updated

PECO Energy Company
Attachment 5A - Revenue Credit Workpaper

	Account 454 - Rent from Electric Property		
1	Rent from Electric Property - Transmission Related, Subject to Sharing (Note 3)		8,608,297
2	Rent from Electric Property - Transmission Related, Pass to Customers (Note 3)		774,089
3	Total Rent Revenues	(Sum Lines 1 to 2)	9,382,385
	Account 456 & 456.1 - Other Electric Revenues (Note 1)		
4	Schedule 1A		$ 5,000,280
5	Firm Point to Point Service revenues for which the load is not included in the divisor received by transmission owner		$ 1,078,490
6	Revenues associated with transmission service not provided under the PJM OATT (Note 4)		-
7	Intercompany Professional Services		358,666
8	PJM Transitional Revenue Neutrality (Note 1)		-
9	PJM Transitional Market Expansion (Note 1)		-
10	Professional Services (Note 3)		-
11	Revenues from Directly Assigned Transmission Facility Charges (Note 2)		-
12	Rent or Attachment Fees associated with Transmission Facilities (Note 3)		-
13	Gross Revenue Credits	(Sum Lines 3, 4-12)	15,819,822
14	Less line 17g		(5,699,777)
15	Total Revenue Credits		10,120,044

<u>**Revenue Adjustment to determine Revenue Credit**</u>

16a	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 in line 2; provided, that the revenue credit on line 2 will not include revenues associated with transmission service the loads for which are included in the rate divisor in Attachment H-7, page 1, line 11.	-
16b	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.	
16c	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 and by department the revenues and costs associated with each secondary use (except for the cost of the associated income taxes). The cost associated with the secondary transmission use is 3/4 of the total department costs.	
17a	Revenues included in lines 1-11 which are subject to 50/50 sharing.	8,608,297
17b	Costs associated with revenues in line 17a	2,958,183
17c	Net Revenues (17a - 17b)	5,650,114
17d	50% Share of Net Revenues (17c / 2)	2,825,057
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.	83,463
17f	Net Revenue Credit (17d + 17e)	2,908,519
17g	Line 17f less line 17a	(5,699,777)
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.	-
19	Reserved	-
20	Total Account 454, 456 and 456.1	15,819,822
21	Reserved	

Attachment 5A - Revenue Credit Workpaper

Costs associated with revenues in line 17a

	Cost Item	Accounts booked to	Total Costs	Costs Allocation to Transmission (Note A)	Transmission Costs	S&W Allocation Factor	Costs Recovered Through A&G Costs
22a	Administrative and General Salaries	920000	635,681	75%	476,760	9.45%	60,066
22b	Employee Pensions and Benefits	926000	247,607	75%	185,705	9.45%	23,397
…							
23	Total Lines 22		$ 883,288		$ 662,466		$ 83,463

	FERC Account 454	Total Amount	Other	100% Transmission	Plant Related	Labor Related	Total
24a	Rent from Electric Distribution	$ 13,620,424	$ 13,620,424				
24b	Rent from Electric Transmission	264,492		264,492			
24c	Tower Rentals and Land Leasing - Transmission	8,608,297		8,608,297			
24d	Tower Rentals and Land Leasing - Distribution	3,175,581	3,175,581				
24e	Intercompany Rent	2,458,806			2,458,806		
24f	Intercompany Rent - Transmission	42,186		42,186			
…							
	Total Lines 24	$ 28,169,786	$ 16,796,006	$ 8,914,975	$ 2,458,806	$ -	
	Allocation Factors		0%	100%	19.01%	9.45%	
	Allocated Amount		$ -	$ 8,914,975	$ 467,411	$ -	$ 9,382,385

	FERC Account 456	Total Amount	Other	100% Transmission	Plant Related	Labor Related	Total
25a	Decommissioning remittances to Generation	$ (3,859,745)	$ (3,859,745)				
25b	Mutual Assistance	1,550,258	$ 1,550,258				
25c	Make Ready	8,613,547	$ 8,613,547				
25d	Intercompany Billings - Transmission	256,013		256,013			
25e	Intercompany Billings - Labor Related	557				557	
25f	Intercompany Billings - Other	1,080,486	1,080,486				
25g	Other	994,848	424,350	(59)	509,877	60,680	
…							
	Total Lines 25	$ 8,635,964	$ 7,808,896	$ 255,954	$ 509,877	$ 61,237	
	Allocation Factors		0%	100%	19.01%	9.45%	
	Allocated Amount		$ -	$ 255,954	$ 96,926	$ 5,786	$ 358,666

	FERC Account 456.1	Total Amount	Other	100% Transmission	Plant Related	Labor Related	Total
26a	Network Integration Credit	$ 142,255,073	$ 142,255,073				
26b	Transmission Owner Scheduling Credits	5,000,280		$ 5,000,280			
26c	Transmission Enhancement	33,519,816	$ 33,519,816				
26d	Revenue - Firm Point to Point	1,078,490		1,078,490			
26e	Other	2,597,170	2,597,170				
…							
	Total Lines 26	$ 184,450,830	$ 178,372,060	$ 6,078,770	$ -	$ -	
	Allocation Factors		0%	100%	19.01%	9.45%	
	Allocated Amount		$ -	$ 6,078,770	$ -	$ -	$ 6,078,770

Note A: Number of employees managing secondary transmission service contracts divided by number of employees managing transmission and distribution secondary service contracts.

PECO Energy Company
Attachment 5B - A&G Workpaper

			(a) 323.181.b to 323.196.b	(b)	(c)	(d)	(e)
			Total	S&W Allocation	Gross Plant Allocation	Non-Recoverable	Directly Assigned
1	Administrative and General Salaries	920.0	$ 27,667,179	$ 27,667,179		$ -	$ -
2	Office Supplies and Expenses	921.0	9,038,489	9,000,155		38,335	-
3	Administrative Expenses Transferred-Credit	922.0	-	-		-	-
4	Outside Service Employed (Note E)	923.0	74,403,755	73,736,716		667,039	-
5	Property Insurance	924.0	24,174		24,174	-	-
6	Injuries and Damages	925.0	13,844,910	13,844,910		-	-
7	Employee Pensions and Benefits	926.0	28,504,054	28,504,054		-	-
8	Franchise Requirements	927.0	-	-		-	-
9	Regulatory Commission Expenses (Note E)	928.0	8,049,891	-		7,714,062	335,829
10	Duplicate Charges-Credit	929.0	(2,859,505)	(2,859,505)		-	-
11	General Advertising Expenses (Note E)	930.1	2,643,003	-		2,643,003	-
12	Miscellaneous General Expenses (Note E)	930.2	3,076,972	2,445,200		631,772	-
13	Rents	931.0	-	-		-	-
14	Maintenance of General Plant	935	5,960,581	5,960,581		-	-
15	**Administrative & General - Total (Sum of lines 1-14)**		$ 170,353,503	$ 158,299,290	$ 24,174	$ 11,694,210	$ 335,829
16			Allocation Factor	9.45%	19.01%	0.00%	100.00%
17			Transmission A&G [1]	14,957,835	4,595	-	335,829
18						Total [2]	$15,298,260

Notes:

[1] Multiply total amounts on line 15, columns (b)-(e) by allocation factors on line 16.

[2] Sum of line 17, columns (b), (c), (d), (e).

PECO Energy Company
Attachment 5C - Taxes Other Than Income

	Taxes Other Than Income	**Page 263 Col (i)**
	Plant Related, Subject to Gross Plant Allocator	
1a	PA Real Estate Tax - 2019	7,579,064
1b	Property Tax Payable	5,256,906
1c		
…		
1	**Total Plant Related (Total Lines 1)**	12,835,970
	Labor Related, Subject to Wages & Salary Allocator	
2a	Federal Unemployment	49,816
2b	Social Security	11,940,482
2c	PA Unemployment	318,010
…		
2	**Total Labor Related (Total Lines 2)**	12,308,308
	Other Included, Subject to Gross Plant Allocator	
3a	State Use Taxes	446,333
3b	Miscellaneous Taxes	3,689
3c		
…		
3	**Total Other Included (Total Lines 3)**	450,022
4	**Total Included (Lines 1 to 3)**	25,594,300
	Taxes Other Than Income Excluded Per Notes A to E	
5a	PA Gross Receipts Tax - 2018	1,089,911
5b	PA Gross Receipts Tax - 2019	131,374,951
5c	Sales Tax Payable	120,546
…		
5	**Total Excluded Taxes Other Than Income (Total Lines 5)**	132,585,408
6	**Total Taxes Other Than Income, Included and Excluded (Lines 4 and 5)**	158,179,708
7	**Total Taxes Other Income from p115.14.g**	158,179,708
8	Difference (Line 6 - Line 7)	-
	Items Included in Line 4, that Are To Be Excluded from Formula Per Attachment 5-P3 Support Note F (Enter Negative)	
9a		
9b		
…		
9	Total Labor Related Taxes to be Excluded (Total Lines 9)	-
10a		
10b		
…		
10	Total Plant Related Taxes to be Excluded (Total Lines 10)	-

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 shall 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 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 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.

Attachment 12 PECO Formula Rate Updated

Attachment 6
True-Up Interest Rate
PECO Energy Company

	Month (Note A)	FERC Monthly Interest Rate
1	January	0.0036
2	February	0.0033
3	March	0.0036
4	April	0.0037
5	May	0.0038
6	June	0.0037
7	July	0.0040
8	August	0.0040
9	September	0.0039
10	October	0.0042
11	November	0.0041
12	December	0.0042
13	January	0.0044
14	February	0.0040
15	March	0.0044
16	April	0.0045
17	May	0.0046
18	Average of lines 1-17 above	0.0040

Note:

A The FERC Quarterly Interest Rate in column [A] is the interest applicable to the Month indicated.

19 Year 2019

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	A	B	C	D	E	F
	Project Name	RTO Project Number or Zonal	Amount	17 Months	Monthly Interest Rate	Interest
			Attachment 3, Col. G + Col H		Line 18 above	Col. C x Col D x Col E
21	Zonal	Zonal	(9,031,876)	17	0.0040	(614,168)
21a	Center Point 500-230 kV Substation A	b0269	398,375	17	0.0040	27,090
21b	Center Point 500-230 kV Substation A	b0269	(1,372,536)	17	0.0040	(93,332)
21c	Richmond-Waneeta 230 kV Line Re-cc	b1591	(809,654)	17	0.0040	(55,056)
21d	Richmond-Waneeta 230 kV Line Re-cc	b1398.8	72,349	17	0.0040	4,920
21e	Whitpain 500 kV Circuit Breaker Addi	b0269.6	(53,868)	17	0.0040	(3,663)
21f	Elroy-Hosensack 500 kV Line Rating I	b0171.1	(76,492)	17	0.0040	(5,201)
21g	Camden-Richmond 230 kV Line Rating	b1590.1 and b1590.2	323,871	17	0.0040	22,023
21h	Chichester-Linwood 230 kV Line Upgr	b1900	1,387,404	17	0.0040	94,343
21i	Bryn Mawr-Plymouth 138 kV Line Rel	b0727	(452,452)	17	0.0040	(30,767)
21j	Emilie 230-138 kV Transformer Additi	b2140	(351,059)	17	0.0040	(23,872)
21k	Chichester-Saville 138 kV Line Re-con	b1182	(336,000)	17	0.0040	(22,848)
21l	Waneeta 230-138 kV Transformer Add	b1717	(240,857)	17	0.0040	(16,378)
21m	Chichester 230-138 kV Transformer A	b1178	(152,157)	17	0.0040	(10,347)
21n	Bradford-Planebrook 230 kV Line Upg	b0790	(32,785)	17	0.0040	(2,229)
21o	North Wales-Hartman 230 kV Line Re-	b0506	(42,082)	17	0.0040	(2,862)
21p	North Wales-Whitpain 230 kV Line Re	b0505	(43,761)	17	0.0040	(2,976)
21q	Bradford-Planebrook 230 kV Line Upg	b0789	(44,780)	17	0.0040	(3,045)
21r	Planebrook 230 kV Capacitor Bank Ad	b0206	(54,068)	17	0.0040	(3,677)
21s	Newlinville 230 kV Capacitor Bank A	b0207	(73,586)	17	0.0040	(5,004)
21t	Chichester-Mickleton 230 kV Series R	b0209	(41,934)	17	0.0040	(2,851)
21u	Chichester-Mickleton 230 kV Line Re-	b0264	(36,871)	17	0.0040	(2,507)
21v	Buckingham-Pleasant Valley 230 kV L	b0357	(52,716)	17	0.0040	(3,585)
21w	Elroy 500 kV Dynamic Reactive Devic	b0287	237,345	17	0.0040	16,139
21x	Heaton 230 kV Capacitor Bank Additic	b0208	179,027	17	0.0040	12,174
21y	Peach Bottom 500-230 kV Transformer	b2694	-	17	0.0040	-
21z	Peach Bottom 500 kV Substation Upgr	b2766.2	-	17	0.0040	-
…						

Attachment 7
PBOPs
PECO Energy Company

Calculation of PBOP Expenses

	(a)		(b) PECO Total	(c) Portion not Capitalized	(d) Electric Col. (c) x Electric Labor in Note B
1	Total PBOP expenses allowed (Note A)		1,066,173	679,716	542,277
2	Total PBOP Expenses in A&G in the current year			815,434	650,553
3	PBOP Adjustment	Line 1 minus line 2			(108,275)

Notes:

A The source of the amounts from the Actuary Study supporting the amount in line 1, column (b) is the 3rd page of the attachment to the January 24, 2017 Willis Towers Watson report on PBOPs for PECO.

		$	%
B	Electric Labor (354.28.b)	166,589,129	79.78%
	Gas Labor sum (355.62.b)	42,221,639	20.22%
	Total	208,810,768	

C The Willis Towers Watson report on PBOPs does not breakout the amount related to construction labor that is capitalized. As a result, the portion not capitalized is calculated as labor expensed divided by total labor.

PECO Energy Company
Attachment 8 - Depreciation and Amortization

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
	Number	Plant Type	Estimated Life	Mortality Curve	Weighted Average Remaining Life	Depreciation / Amortization Rate	Gross Depreciable Plant (Year End Balance) $	Accumulated Depreciation $	Net Depreciable Plant $	Depreciation Expense $
			Note 1	Note 1	Note 2		Note 4	Note 4	(I)=(G)-(H)	(J)=(F)*(G)
1							**As of 12/31/2019**			**FY 2019**
2		**Electric Transmission**								
3	352	Structures and Improvements	N/A	N/A	N/A	1.7951%	84,648,186	22,075,677	62,572,509	1,519,520
4	353	Station Equipment	N/A	N/A	N/A	1.7406%	916,183,089	206,465,896	709,717,193	15,947,083
5	354	Towers and Fixtures	N/A	N/A	N/A	1.3697%	289,020,870	160,785,185	128,235,685	3,958,719
6	355	Poles and Fixtures	N/A	N/A	N/A	1.5768%	17,404,687	2,569,179	14,835,508	274,437
7	356	Overhead Conductors and Devices	N/A	N/A	N/A	1.5942%	200,291,092	84,403,607	115,887,485	3,193,041
8	357	Underground Conduit	N/A	N/A	N/A	1.6381%	16,205,140	4,253,018	11,952,122	265,456
9	358	Underground Conductors and Devices	N/A	N/A	N/A	1.5536%	103,883,450	45,482,089	58,401,361	1,613,933
10	359	Roads and Trails	N/A	N/A	N/A	1.1526%	2,545,719	2,087,014	458,705	29,342
11							**1,630,182,233**	**528,121,665**	**1,102,060,568**	**26,801,531**
12		**Electric General**								
13	390	Structures and Improvements	40	R1	26.62	2.9566%	49,534,157	11,870,358	37,663,799	1,464,527
14	391.1	Office Furniture and Equipment - Office Machines	10	SQ	2.50	10.6324%	83,462	65,786	17,676	8,874
15	391.2	Office Furniture and Equipment - Furnitures and Fixtures	15	SQ	10.93	6.8284%	509,566	147,907	361,659	34,795
16	391.3	Office Furniture and Equipment - Computers	5	SQ	3.25	19.7397%	28,616,027	13,187,765	15,428,262	5,648,718
17	391.4	Office Furniture and Equipment - Smart Meter Comp. Equip.	5	SQ	3.25	40.8577%	656,594	(76,065)	732,659	268,269
18	393	Stores Equipment	15	SQ	9.32	8.6809%	46,470	11,016	35,454	4,034
19	394	Tools, Shop, Garage Equipment	15	SQ	9.54	6.7951%	37,811,861	12,704,571	25,107,290	2,569,354
20	395.1	Laboratory Equipment - Testing	20	SQ	6.74	4.3016%	311,026	227,910	83,116	13,379
21	395.2	Laboratory Equipment - Meters	15	SQ	3.50	6.4687%	101,381	81,824	19,557	6,558
22	397	Communication Equipment	20	L3	14.46	5.0575%	128,734,058	32,489,484	96,244,574	6,510,725
23	397.1	Communication Equipment - Smart Meters	15	S2	9.47	6.6081%	36,350,171	13,922,355	22,427,816	2,402,056
24	398	Miscellaneous Equipment	15	SQ	0.54	156.6758%	25,817	3,845	21,972	40,449
25							**282,780,590**	**84,636,756**	**198,143,834**	**18,971,738**

PECO Energy Company
Attachment 8 - Depreciation and Amortization

1		**Electric Intangible**								
2	303	Software - Transmission 2-year Life (Note 10)	2	N/A	N/A	53.5078%	5,771,259	4,190,529	1,580,730	3,088,074
3	303	Software - Transmission 3-year Life (Note 10)	3	N/A	N/A	N/A	-	-	-	-
4	303	Software - Transmission 4-year Life (Note 10)	4	N/A	N/A	N/A	-	-	-	-
5	303	Software - Transmission 5-year Life (Note 10)	5	N/A	N/A	17.0410%	11,928,113	8,410,862	3,517,251	2,032,670
6	303	Software - Transmission 7-year Life (Note 10)	7	N/A	N/A	N/A	-	-	-	-
7	303	Software - Transmission 10-year Life (Note 10)	10	N/A	N/A	N/A	-	-	-	-
8	303	Software - Transmission 13-year Life (Note 10)	13	N/A	N/A	N/A	-	-	-	-
9	303	Software - Transmission 15-year Life (Note 10)	15	N/A	N/A	N/A	-	-	-	-
10							**17,699,372**	**12,601,391**	**5,097,981**	**5,120,743**
11	303	Software - Electric General 2-year Life (Note 10)	2	N/A	N/A	N/A	-	-	-	-
12	303	Software - Electric General 3-year Life (Note 10)	3	N/A	N/A	0.013887	245,411	3,408	242,003	3,408
13	303	Software - Electric General 4-year Life (Note 10)	4	N/A	N/A	N/A	-	-	-	-
14	303	Software - Electric General 5-year Life (Note 10)	5	N/A	N/A	23.0238%	17,472,905	9,813,804	7,659,101	4,022,927
15	303	Software - Electric General 7-year Life (Note 10)	7	N/A	N/A	N/A	-	-	-	-
16	303	Software - Electric General 10-year Life (Note 10)	10	N/A	N/A	N/A	-	-	-	-
17	303	Software - Electric General 13-year Life (Note 10)	13	N/A	N/A	N/A	-	-	-	-
18	303	Software - Electric General 15-year Life (Note 10)	15	N/A	N/A	N/A	-	-	-	-
19							**17,718,316**	**9,817,212**	**7,901,104**	**4,026,335**
20	303	Software - Electric Distribution	N/A	N/A	N/A	N/A	128,162,185	96,978,841	31,183,344	11,053,897
21	303	Regulatory Initiatives/Depr Charged to Reg Asset	N/A	N/A	N/A	N/A	18,781,412	9,192,331	9,589,081	Zero
22							**146,943,597**	**106,171,172**	**40,772,425**	**11,053,897**
23		**Common General - Electric**								
24	303	Software - 2-year Life (Note 10)	2	N/A	N/A	N/A	-	-	-	-
25	303	Software - 3-year Life (Note 10)	3	N/A	N/A	0.052207	332,272	17,347	314,925	17,347
26	303	Software - 4-year Life (Note 10)	4	N/A	N/A	N/A	-	-	-	-
27	303	Software - 5-year Life (Note 10)	5	N/A	N/A	8.4797%	229,959,380	161,634,363	68,325,017	19,499,866
28	303	Software - 7-year Life (Note 10)	7	N/A	N/A	N/A	-	-	-	-
29	303	Software - 10-year Life (Note 10)	10	N/A	N/A	N/A	-	-	-	-
30	303	Software - 13-year Life (Note 10)	13	N/A	N/A	N/A	-	-	-	-
31	303	Software - 15-year Life (Note 10)	15	N/A	N/A	N/A	-	-	-	-
32	303	Regulatory Initiatives/Depr Charged to Reg Asset	N/A	N/A	N/A	N/A	147,738	147,738	-	Zero
33	390	Structures and Improvements	50	R1	36.30	1.9364%	226,634,074	61,764,371	164,869,703	4,388,542
34	391.1	Office Furniture and Equipment - Office Machines	10	SQ	1.50	18.8194%	100,099	15,811	84,288	18,838
35	391.2	Office Furniture and Equipment - Furnitures and Fixtures	15	SQ	10.80	6.7577%	16,548,288	3,061,813	13,486,475	1,118,284
36	391.3	Office Furniture and Equipment - Computers	5	SQ	2.68	19.3400%	29,150,184	13,404,514	15,745,670	5,637,646
37	392.1	Transportation Equipment - Automobiles	6	L3	4.09	N/A	72,553	72,079	474	Zero
38	392.2	Transportation Equipment - Light Trucks	12	L4	7.37	N/A	26,839,337	12,378,794	14,460,543	Zero
39	392.3	Transportation Equipment - Heavy Trucks	14	R4	8.27	N/A	68,038,889	28,792,657	39,246,232	Zero
40	392.4	Transportation Equipment - Tractors	11	L2	2.36	N/A	216,441	217,544	(1,103)	Zero
41	392.5	Transportation Equipment - Trailers	15	R2	9.36	N/A	3,616,256	1,864,725	1,751,531	Zero
42	392.6	Transportation Equipment - Other Vehicles	15	R2	6.24	N/A	3,942,297	3,114,232	828,065	Zero
43	392.7	Transportation Equipment -Medium Trucks	N/A	N/A	7.28	N/A	13,310,723	1,876,790	11,433,933	Zero
44	393	Stores Equipment	15	SQ	8.91	7.4565%	1,111,086	314,348	796,738	82,848
45	394.1	Tools, Shop, Garage Equipment - Construction Tools	15	SQ	3.50	94.0451%	9,001	(16,243)	25,244	8,465
46	394.2	Tools, Shop, Garage Equipment - Common Tools	15	SQ	14.02	6.5410%	799,169	94,114	705,055	52,274
47	394.3	Tools, Shop, Garage Equipment - Garage Equipment	20	SQ	8.33	N/A	1,377,337	647,008	730,329	Zero
48	396	Power Operated Equipment	11	L2	2.70	N/A	143,389	141,445	1,944	Zero
49	397	Communication Equipment	20	L3	12.74	3.9345%	52,249,327	15,816,564	36,432,763	2,055,750
50	398	Miscellaneous Equipment	15	SQ	8.18	6.9008%	929,083	426,874	502,209	64,114
51							**675,526,923**	**305,786,888**	**369,740,035**	**32,943,973**

PECO Energy Company
Attachment 8 - Depreciation and Amortization

		Current Year Depr./Amor. Exp Per Formula Total Company (B)	Current Year Depr./Amor. Exp Per FF1 / Atta 4D for Intangible Total Company (C)	Current Year Difference Total Company (D)=(B)-(C)	Allocation % To Transmission (E)	Current Year Difference Allocated To Transmission (F)=(D)*(E)	Prior Year Total Cumulative Difference Total Company (G)	Prior Year Total Cumulative Difference Transmission (H)	Current Year Total Cumulative Difference Total Company (I)=(D)+(G)	Current Year Total Cumulative Difference Transmission (J)=(F)+(H)
1	Transmission	$ 26,801,531	$ 26,802,058	(527)	100.00%	(527)	(1,080)	(1,080)	(1,607)	(1,607)
2	Electric General	$ 18,971,738	$ 18,971,748	(10)	9.45%	(1)	54	5	44	4
3	Common - Electric	$ 32,943,973	$ 32,943,908	65	9.45%	6	(219)	(21)	(154)	(15)
4	Intangible - Transmission	$ 5,120,743	$ 5,120,737	6	100.00%	6	10	10	16	16
5	Intangible - General	$ 4,026,335	$ 4,026,332	2	9.45%	0	(7)	(1)	(4)	(0)
6	Intangible - Distribution	$ 11,053,897	$ 11,053,897	-	0.00%	-	-	-	-	-
7										
8	**Accumulative Depreciation**									

		Average Accumulative Depr./Amor. Per Book Total Company	Total Cumulative Adjustment Total Company	Adjusted Average Accumulative Depr./Amor. Total Company	Allocation % To Transmission	Adjusted Average Accumulative Depr./Amor. Transmission
9						
10	Transmission	$ 511,105,295	(1,344)	511,106,639	100.00%	511,106,639
11	Electric General	$ 78,730,021	49	78,729,972	9.45%	7,439,262
12	Common - Electric	$ 288,423,876	(186)	288,424,062	9.45%	27,253,436
13	Intangible - Transmission	$ 9,955,234	13	9,955,221	100.00%	9,955,221
14	Intangible - General	$ 8,689,115	(6)	8,689,120	9.45%	821,042
15	Intangible - Distribution	$ 100,632,356	$ -	100,632,356	0.00%	-
16	Total Intangible	$ 119,276,705	$ 8	$ 119,276,697		$ 10,776,263
17						
18						
19						
20						
21						
22						
23						
24						

Notes:

1 Columns (A), (B), (C), and (D) are fixed and cannot be changed absent Commission approval or acceptance. The depreciation / amortization expense is calculated separately for each row.

2 For Electric General and Common General plant, except FERC account 303, Column (E) is the remaining life of the assets in the account for each vintage (amount of plant added in each year is a vintage) weighted by the gross plant balance of each account or subaccount. The remaining life for each vintage is equal to the area under the Mortality Curve specified in Columns (C) and (D) using a half year convention for the first year placed in service. The weighted remaining life is calculated once a year at the beginning of the year.

3 For FERC accounts 303, 352 through 359 and 390 through 398, Column F is fixed and cannot be changed absent Commission approval or acceptance.

4 Column (G) is the depreciable amount of gross plant investment reported in the annual FERC Form No. 1 filing on pages 207 (Electric) and 356 (Common) by account or subaccount. Column (H) is the accumulated depreciation by account or subaccount.

5 Column (I) is the end of year depreciable net plant in the account or subaccount.

6 Reserved

7 Reserved

8 At least every 5 years, PECO Energy Company will file with the Commission a depreciation study supporting its existing Estimated Life and Mortality Curve for each account or subaccount.

9 The depreciation expense associated with Asset Retirement Obligations (booked to accounts 359.1 and 399.1) are not included in the tables above.

10 The life of each software or other intangible plant will be estimated at the time the plant is placed into service, and will not change over the life of the plant absent Commission approval or acceptance. The combined amortization expense for all intangible plant shall be the sum of each individual plant balance amortized over the life of each individual plant established in this manner.

11 The depreciation expenses related to Common General - Electric reflect electric common plant. The depreciation expenses associated with Transportation Equipment, Garage Equipment and Power Operated Tools are excluded from Account 403 and directly assigned to the functional O&M and capital accounts based on use.

Attachment 9
Excess / (Deficient) Deferred Income Taxes (Note B and Attachment H-7 Notes N, O and P)
PECO Energy Company

EDIT Amortization Amount (Note C)

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
			January	February	March	April	May	June	July	August	September	October	November	December	Total
1	**Protected Property**														
2	Transmission		$ 72,177	$ 72,177	$ 72,177	$ 72,177	$ 72,177	$ 72,177	$ 72,177	$ 72,177	$ 72,177	$ 72,177	$ 72,177	$ 72,177	$ 866,126
3	General		$ (2,833)	$ (2,833)	$ (2,833)	$ (2,833)	$ (2,833)	$ (2,833)	$ (2,833)	$ (2,833)	$ (2,833)	$ (2,833)	$ (2,833)	$ (2,833)	$ (33,994)
4	Transmission Allocation % (Att H-7 P4, L11, Col 5)		9.45%												
5	Allocated to Transmission		$ (268)	$ (268)	$ (268)	$ (268)	$ (268)	$ (268)	$ (268)	$ (268)	$ (268)	$ (268)	$ (268)	$ (268)	$ (3,212)
6	Common (To Be Split TDG)		$ 18,962	$ 18,962	$ 18,962	$ 18,962	$ 18,962	$ 18,962	$ 18,962	$ 18,962	$ 18,962	$ 18,962	$ 18,962	$ 18,962	$ 227,539
7	Transmission Allocation % (L 4 * Electric Factor in FERC Form 1 P356)		7.32%												
8	Allocated to Transmission		$ 1,388	$ 1,388	$ 1,388	$ 1,388	$ 1,388	$ 1,388	$ 1,388	$ 1,388	$ 1,388	$ 1,388	$ 1,388	$ 1,388	$ 16,659
9	**Total Protected Property**		$ 73,298	$ 73,298	$ 73,298	$ 73,298	$ 73,298	$ 73,298	$ 73,298	$ 73,298	$ 73,298	$ 73,298	$ 73,298	$ 73,298	$ 879,572
10	**Non-Protected Property (Note A)**		$ 201,938	$ 201,938	$ 201,938	$ 201,938	$ 201,938	$ 201,938	$ 201,938	$ 201,938	$ 201,938	$ 201,938	$ 201,938	$ 201,938	$ 2,423,256
11	**Non-Protected, Non-Property - Pension Asset (Note A)**		$ 74,045	$ 74,045	$ 74,045	$ 74,045	$ 74,045	$ 74,045	$ 74,045	$ 74,045	$ 74,045	$ 74,045	$ 74,045	$ 74,045	$ 888,540
12	**Non-Protected, Non-Property - Non-Pension Asset (Note A)**		$ (78,379)	$ (78,379)	$ (78,379)	$ (78,379)	$ (78,379)	$ (78,379)	$ (78,379)	$ (78,379)	$ (78,379)	$ (78,379)	$ (78,379)	$ (78,379)	$ (940,548)
13	**Total Non-Protected, Non-Property (Note A)**		$ (4,334)	$ (4,334)	$ (4,334)	$ (4,334)	$ (4,334)	$ (4,334)	$ (4,334)	$ (4,334)	$ (4,334)	$ (4,334)	$ (4,334)	$ (4,334)	$ (52,008)

EDIT Balance (Notes C and D)

		December Prior Year	January	February	March	April	May	June	July	August	September	October	November	December	Prior and Current December Average
14	**Protected Property**														
15	Transmission	$ 78,972,292	78,900,115	78,827,938	78,755,761	78,683,583	78,611,406	78,539,229	78,467,052	78,394,875	78,322,698	78,250,521	78,178,344	78,106,166	78,539,229
16	General	$ 1,463,764	1,466,597	1,469,430	1,472,263	1,475,095	1,477,928	1,480,761	1,483,594	1,486,427	1,489,260	1,492,092	1,494,925	1,497,758	1,480,761
17	Transmission Allocation %	9.45%													
18	Allocated to Transmission	$ 138,312	138,580	138,848	139,115	139,383	139,651	139,918	140,186	140,454	140,721	140,989	141,257	141,524	139,918
19	Common (To Be Split TDG)	$ 11,360,123	11,341,161	11,322,200	11,303,238	11,284,277	11,265,315	11,246,353	11,227,392	11,208,430	11,189,468	11,170,507	11,151,545	11,132,584	11,246,353
20	Transmission Allocation %	7.32%													
21	Allocated to Transmission	$ 831,692	830,304	828,915	827,527	826,139	824,751	823,363	821,974	820,586	819,198	817,810	816,422	815,033	823,363
22	**Total Protected Property**	$ 79,942,296	79,868,998	79,795,701	79,722,403	79,649,105	79,575,808	79,502,510	79,429,212	79,355,915	79,282,617	79,209,319	79,136,022	79,062,724	79,502,510
23	**Non-Protected Property (Note A)**	$ 14,539,561	14,337,623	14,135,685	13,933,747	13,731,809	13,529,871	13,327,933	13,125,995	12,924,057	12,722,119	12,520,181	12,318,243	12,116,305	13,327,933
24	**Non-Protected, Non-Property - Pension Asset (Note A)**	$ 3,554,162	3,480,117	3,406,072	3,332,027	3,257,982	3,183,937	3,109,892	3,035,847	2,961,802	2,887,757	2,813,712	2,739,667	2,665,622	3,109,892
25	**Non-Protected, Non-Property - Non-Pension Asset (Note A)**	$ (3,762,179)	(3,683,800)	(3,605,421)	(3,527,042)	(3,448,663)	(3,370,284)	(3,291,905)	(3,213,526)	(3,135,147)	(3,056,768)	(2,978,389)	(2,900,010)	(2,821,631)	(3,291,905)
26	**Total Non-Protected, Non-Property (Note A)**	$ (208,017)	(203,683)	(199,349)	(195,015)	(190,681)	(186,347)	(182,013)	(177,679)	(173,345)	(169,011)	(164,677)	(160,343)	(156,009)	(182,013)

Notes:

A EDIT data, including EDIT amortization amount and balance, for Protected, Non-Protected Property and Non-Protected, Non-Property shall reflect the Transmission portion of EDIT amounts. The amounts and categorization of these balances as of December 31, 2017 is: Protected Property - Transmission (Line 15): $79,726,712; Protected Property - Electric General to be allocated between Distribution and Transmission (Line 16): $1,683,749; Protected Property – Common to be allocated between Distribution, Transmission and Gas (Line 19): $11,901,494; Non-Protected Property (Line 23): $16,962,821; Non-Protected Non-Property (Line 26): ($260,021).

B The amortization schedule of the EDIT balance related to Tax Cuts and Job Act of 2017 shall be consistent with the following periods:

Protected:	ARAM
Non-Protected Property:	7 years
Non-Protected, Non-Property:	5 years

The Non-Protected Property EDIT balance shall be fully amortized by the end of 2024 and the Non-Protected, non-Property EDIT balance shall be fully amortized by the end of 2022.

C The data of the annual amortization amount and balance are from PECO's Tax Accounting records.

D EDIT balance was reclassified from ADIT to EDIT in December 2017.

Attachment 10
Pension Asset Discount Worksheet
PECO Energy Company

				Source
1	13 Month Average Pension Asset (Note A)		27,745,514	(Attachment 4, line 28(i))
	Net ADIT Balance			
2	Prior Year ADIT Related to Transmission Pension Asset		(8,756,446)	(Attachment 4B "PENSION EXPENSE PROVISION" times S&W Allocator)
3	Current Year ADIT Related to Transmission Pension Asset		(8,932,944)	(Attachment 4C "PENSION EXPENSE PROVISION" times S&W Allocator)
4	Average ADIT Balance Related to Transmission Pension Asset		(8,844,695)	(Average of Lines 2 and 3)
5	Net Unamortized EDIT Balance	$	(3,109,892)	(Attachment 9 line 24 "Average")
6	Net Pension Asset	$	15,790,927	(Line 1 plus Line 4 plus Line 5)
7	100% of ATRR on Net Pension Asset		1,540,431	(Line 6 times Attachment H-7 page 3, line 34, col (3) times (1+Attachment H-7 page 4, line 18, col (5))
8	Times Pension Discount %		60%	
9	ATRR Discount on Net Pension Asset	$	924,259	(Line 7 times Line 8)

Note:
A: PECO’s transmission-related Pension Asset balance is capped at $33 million. Such limit may only be changed pursuant to a section 205 or 206 filing.

Attachment 12 PECO Formula Rate Updated

Attachment 11
Cost of Capital
PECO Energy Company

Line		
	Long Term Interest (117, lines 62 through 67), Excluding LVT Interest	
1	Interest on Long-Term Debt (427)	122,359,442
2	Amort. of Debt Disc. and Expense (428)	2,310,300
3	Amortization of Loss on Reacquired Debt (428.1)	455,601
4	(Less) Amort. of Premium on Debt-Credit (429)	
5	(Less) Amortization of Gain on Reacquired Debt-Credit (429.1)	
6	Interest on Debt to Assoc. Companies (430)	12,149,229
7	(Less) Short-term Interest (5-P3 Support Note G)	
8	**Total Long Term Interest (Line 1 + Line 2 + Line 3 - Line 4 - Line 5 + Line 6 - Line 7)**	**$137,274,572**

13-Month Average Balance of Long-term Debt,

Line	**Long -term Debt (112, Lines 18 through 21)**	December Prior Year	January	February	March	April	May	June	July	August	September	October	November	December	13-Month Average
9	Bonds (221)	3,125,000,000	3,125,000,000	3,125,000,000	3,125,000,000	3,125,000,000	3,125,000,000	3,125,000,000	3,125,000,000	3,125,000,000	3,450,000,000	3,450,000,000	3,450,000,000	3,450,000,000	3,225,000,000
10	(Less) Reacquired Bonds (222)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Advances from Associated Companies (223)	184,418,609	184,418,609	184,418,609	184,418,609	184,418,609	184,418,609	184,418,609	184,418,609	184,418,609	184,418,609	184,418,609	184,418,609	184,418,609	184,418,609
12	Other Long-Term Debt (224)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	**Total (Line 9 - Line 10 + Line 11 + Line 12)**	**$ 3,309,418,609**	**$ 3,309,418,609**	**$ 3,309,418,609**	**$ 3,309,418,609**	**$ 3,309,418,609**	**$ 3,309,418,609**	**$ 3,309,418,609**	**$ 3,309,418,609**	**$ 3,309,418,609**	**$ 3,634,418,609**	**$ 3,634,418,609**	**$ 3,634,418,609**	**$ 3,634,418,609**	**$ 3,409,418,609**

Line	**Proprietary Capital (112, line 2 through 15)**	December Prior Year	January	February	March	April	May	June	July	August	September	October	November	December	13-Month Average
14	Common stock issued (201)	1,423,004,251	1,423,004,251	1,423,004,251	1,423,004,251	1,423,004,251	1,423,004,251	1,423,004,251	1,423,004,251	1,423,004,251	1,423,004,251	1,423,004,251	1,423,004,251	1,423,004,251	1,423,004,251
15	Preferred Stock (204) (112.3.c) (5-P3 Support Note B)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Capital Stock Subscribed (202, 205)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Stock Liability for Conversion (203, 206)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Premium on Capital Stock (207)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Other Paid-in Capital (208-211)	1,155,155,244	1,155,155,244	1,155,155,244	1,300,155,244	1,300,155,244	1,300,155,244	1,300,155,244	1,300,155,244	1,300,155,244	1,329,155,244	1,343,450,423	1,343,450,423	1,343,450,423	1,278,915,670
20	Installments Received on Capital Stock (212)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	(Less) Discount on Capital Stock (213)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	(Less) Capital Stock Expense (214)	86,742	86,742	86,742	86,742	86,742	86,742	86,742	86,742	86,742	86,742	86,742	86,742	86,742	86,742
23	Retained Earning s(215, 215.1, 216)	4,427,930,434	4,510,538,983	4,564,907,417	4,521,682,757	4,552,730,556	4,589,672,684	4,543,291,354	4,609,634,817	4,661,288,172	4,605,783,948	4,627,158,813	4,680,394,559	4,643,271,373	4,579,868,144
24	Unappropriated Undistributed Subsidiary Earnings (216.1)	(3,187,402,048)	(3,194,319,802)	(3,198,854,724)	(3,202,735,205)	(3,205,342,858)	(3,208,420,258)	(3,212,672,862)	(3,218,225,358)	(3,222,449,990)	(3,224,708,274)	(3,226,494,956)	(3,229,417,286)	(3,233,925,200)	(3,212,689,909)
25	(Less) Reacquired Capital Stock (217)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Noncorporate Proprietorship (Non-major only) (218)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Accumulated other Comprehensive Income (219)	1,674,806	1,630,458	1,630,180	1,742,674	1,742,953	1,742,953	1,769,513	1,725,165	1,725,165	2,094,739	2,094,739	2,094,739	2,298,082	1,843,551
28	Total Proprietary Capital (Line 14+ Line 15 + Line 16 + Line 17 + Line 18 + Line 19 + Line 20 - Line 21 - Line 22 + Line 23 + Line 24 - Line 25 + Line 26 + Line 27)	3,820,275,945	$3,895,922,391	$3,945,755,625	$4,043,762,979	$4,072,203,404	$4,106,068,132	$4,055,460,758	$4,116,207,377	$4,163,636,099	$4,135,243,165	$4,169,126,528	$4,219,439,943	$4,178,012,187	4,070,854,964
29	**Preferred Stock (line 15)**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
30	**Common Stock (line 28 - line 29)**	**$ 3,820,275,945**	**$ 3,895,922,391**	**$ 3,945,755,625**	**$ 4,043,762,979**	**$ 4,072,203,404**	**$ 4,106,068,132**	**$ 4,055,460,758**	**$ 4,116,207,377**	**$ 4,163,636,099**	**$ 4,135,243,165**	**$ 4,169,126,528**	**$ 4,219,439,943**	**$ 4,178,012,187**	**$ 4,070,854,964**

Appendix 2B
2019 True Up Adjustment Calculation – MDTAC

ATTACHMENT H-7B
MDTAC FORMULA RATE TEMPLATE

CALCULATION OF MONTHLY AMORTIZED REGULATORY ASSET TO BE RECOVERED			
1	Annual Revenue Requirement on Regulatory Asset Amortization	Attachment 1 - Revenue Requirement Line 3	$3,789,876
2	True-up Adjustment with Interest	Attachment 2 - True-Up Line 24	($1,622,571)
3	Net Annual Revenue Requirement on Regulatory Asset Amortization with True-up	Line 1 + line 2	$2,167,305
4	Net Monthly Revenue Requirement on Regulatory Asset Amortization with True-up	Line 3 / 12	$180,609

PECO Energy Company
Summary of Transmission SFAS 109 Regulatory Asset (Account 182.3) Amortization
For the 12 months ended 12/31/2019

1	SFAS 109 Reg Asset Amortization (Notes A and B)	$	3,923,411
2	Other Tax Adjustments (Note C)	$	(133,535)
3	**Adjusted Total**	$	3,789,876

Notes:
(A) All items are asssociated with ratemaking flow through requirements
(B) Additional detail is provided on page 2 of this exhibit
(C) Amortization of FAS 109 Regulatory Asset.

True-Up with Interest
PECO Energy Company

		Month (Note A)	FERC Monthly Interest Rate
1		January	0.0036
2		February	0.0033
3		March	0.0036
4		April	0.0037
5		May	0.0038
6		June	0.0037
7		July	0.0040
8		August	0.0040
9		September	0.0039
10		October	0.0042
11		November	0.0041
12		December	0.0042
13		January	0.0044
14		February	0.0040
15		March	0.0044
16		April	0.0045
17		May	0.0046
18	Average of lines 1-17 above		0.0040

Notes:

A The FERC Quarterly Interest Rate in column [A] is the interest applicable to the Month indicated.

19	Actual Revenue Requirement	880,221
20	Revenue Received	2,525,640
21	Net Under/(Over) Collection (Line 19 - Line 20)	(1,645,419)
22	17 Months	17
23	Interest (Line 18*Line 21*Line 22)	(111,888)
24	Total True-up	(1,757,308)

PECO Energy Company
Summary of Transmission SFAS 109 Regulatory Asset (Account 182.3)
December 31, 2018 through December 31, 2019

	12/31/2018	Activity	12/31/2019
TRANSMISSION ONLY			
Repair Allowance	7,627,294	(210,530)	7,416,764
Federal and State Flow Through	21,776,261	(819,226)	20,957,035
Excess Deferreds/pre-1981 Deferreds	17,057,254	(1,723,251)	15,334,003
Other	393,218	(13,122)	380,096
Total	46,854,027	(2,766,129)	44,087,898
COMMON (TO BE SPLIT TDG)			
Repair Allowance	-	-	-
Federal and State Flow Through	7,502,269	(59,629)	7,442,640
Excess Deferreds/pre-1981 Deferreds	2,789,109	(215,267)	2,573,842
Other	1,350,282	(78,933)	1,271,349
Total	11,641,660	(353,829)	11,287,831
Transmission Allocation %	7.32%	***(Attachment H-7A, page 4, line 11, column 5 * Common Allocation Factor in FERC Form 1 page 356)***	
Repair Allowance	-	-	-
Federal and State Flow Through	549,252	(4,366)	544,887
Excess Deferreds/pre-1981 Deferreds	204,195	(15,760)	188,435
Other	98,856	(5,779)	93,077
Total	852,304	(25,904)	826,399
ELECTRIC GENERAL (TO BE SPLIT TD)			
Repair Allowance	9,355	(240)	9,115
Federal and State Flow Through	848,578	27,532	876,110
Excess Deferreds/pre-1981 Deferreds	145,948	(4,019)	141,929
Other	2,581	(214)	2,367
Total	1,006,462	23,060	1,029,522
Transmission Allocation %	9.45%	***Source: Attachment H-7A, page 4, line 11, column 5***	
Repair Allowance	884	(23)	861
Federal and State Flow Through	80,183	2,602	82,784
Excess Deferreds/pre-1981 Deferreds	13,791	(380)	13,411
Other	244	(20)	224
Total	95,101	2,179	97,280
Transmission Summary			
Repair Allowance	7,628,178	(210,553)	7,417,625
Federal and State Flow Through	22,405,696	(820,990)	21,584,707
Excess Deferreds/pre-1981 Deferreds	17,275,240	(1,739,391)	15,535,849
Other	492,318	(18,921)	473,397
Total	**47,801,432**	**(2,789,855)**	**45,011,577**
Incl SFAS 109 + Gross-up	67,223,799	(3,923,411)	63,300,389
2010 Transmission Tax Adjustments b/f gross-up	(166,170)	94,954	(71,216)
2010 Transmission Tax Adjustments + gross-up	(233,687)	133,535	(100,152)
Total Transmission SFAS 109	66,990,112	(3,789,876)	63,200,237

Gross-up Factor

Federal Income Tax Rate	21.000%
State Income Tax Rate	9.990%
Composite Rate = F+S(1-F)	28.892%
Gross-up Factor = 1/(1-CR)	140.631%

Appendix 2C
2018 Actuals – NITS

ATTACHMENT H-7A
FORMULA RATE TEMPLATE

Attachment 12 PECO Formula Rate Updated

Attachment H-7
Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data
PECO Energy Company

For the 12 months ended 12/31/2018

Line No.	(1)	(2)	(3) Total	(4) Allocator		(5) Allocated Amount
1	GROSS REVENUE REQUIREMENT	(page 3, line 48)				189,044,343
2a	Additional Annual Refund (from 2018 to 2021)	Attachment 1, line 17, col 15a				850,000
2	REVENUE CREDITS	Attachment 5A, line 15	9,661,602	TP	100.00%	9,661,602
3	NET REVENUE REQUIREMENT	(line 1 minus lines 2 and 2a)				178,532,740
4	REGIONAL NET REVENUE REQUIREMENT	Attachment 1, line 18, col. 14 - Attachment 1, line 17a, col. 14				30,462,821
5	Regional True-up Adjustment with Interest	Attachment 1, line 18, col. 15 - Attachment 1, line 17a, col. 15				-
6	REGIONAL NET REVENUE REQUIREMENT with TRUE-UP	Attachment 1, line 18, col. 16 - Attachment 1, line 17a, col. 16				30,462,821
7	ZONAL NET REVENUE REQUIREMENT	Attachment 1, line 17a, col. 14 less line 2				148,069,920
8	Zonal True-up Adjustment with Interest	Attachment 1, line 17a, col. 15				-
9	ZONAL NET REVENUE REQUIREMENT with TRUE-UP	Line 7 + Line 8				148,069,920
10	Competitive Bid Concessions	Attachment 1, line 18, col. 13				-
11	Zonal Load	1 CP from PJM in MW				8,608
12	Network Integration Transmission Service rate for PECO Zone	(line 9/11)				$17,202

Attachment 12 PECO Formula Rate Updated

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data
PECO Energy Company

For the 12 months ended 12/31/2018

Line No.	(1)	(2) Source	(3) Company Total	Allocator	(4)	(5) Transmission (Col 3 times Col 4)
	RATE BASE:					
	GROSS PLANT IN SERVICE (Notes U and R)					
1	Production	205.46.g for end of year, records for other months	-	NA		-
2	Transmission	Attachment 4, Line 14, Col. (b)	1,568,082,823	TP	100.00%	1,568,082,823
3	Distribution	207.75.g for end of year, records for other months	6,155,245,145	NA	0.00%	-
4	General	Attachment 4, Line 14, Col. (c)	261,942,239	W/S	9.88%	25,881,521
5	Intangible	Attachment 4D, Line 19, Col. (s) and Line 21, Col. (s)	155,975,562	DA		15,185,839
6	Common	Attachment 4, Line 14, Col. (d)	564,826,965	W/S	9.88%	55,808,414
7	Costs To Achieve	(enter negative) Attach. 4E, Line 25, Col. (x)	(2,964,784)	W/S	9.88%	(292,939)
8	TOTAL GROSS PLANT	(Sum of Lines 1 through 7)	8,703,107,950	GP=	19.13%	1,664,665,657
9	ACCUMULATED DEPRECIATION (Notes U and R)					
10	Production	219.20-24.c for end of year, records for other months	-	NA		-
11	Transmission	Attachment 8, Page 3, Line 10, Col. (E)	495,660,234	TP	100.00%	495,660,234
12	Distribution	219.26.c for end of year, records for other months	1,697,405,628	NA	0.00%	-
13	General	Attachment 8, Page 3, Line 11, Col. (E)	69,920,764	W/S	9.88%	6,908,606
14	Intangible	Attachment 8, Page 3, Line 16, Col. (E) and Col. (G)	102,574,552	DA		6,030,271
15	Common	Attachment 8, Page 3, Line 12, Col. (E)	272,254,020	W/S	9.88%	26,900,389
16	Costs To Achieve	(enter negative) Attach. 4E, Line 39, Col. (x)	(406,500)	W/S	9.88%	(40,165)
17	TOTAL ACCUM. DEPRECIATION	(Sum of Lines 10 through 16)	2,637,408,698			535,459,335
18	NET PLANT IN SERVICE					
19	Production	(line 1 minus line 10)	-			-
20	Transmission	(line 2 minus line 11)	1,072,422,589			1,072,422,589
21	Distribution	(line 3 minus line 12)	4,457,839,517			-
22	General	(line 4 minus line 13)	192,021,475			18,972,915
23	Intangible	(line 5 minus line 14)	53,401,010			9,155,568
24	Common	(line 6 minus line 15)	292,572,945			28,908,025
25	Costs To Achieve	(line 7 minus line 16)	(2,558,283)			(252,774)
26	TOTAL NET PLANT	(Sum of Lines 19 through 25)	6,065,699,252	NP=	18.62%	1,129,206,322
27	ADJUSTMENTS TO RATE BASE (Note R)					
28	Account No. 281 (enter negative)	Attachment 4, Line 28, Col. (d) (Notes B and X)	Zero	NA	zero	-
29	Account No. 282 (enter negative)	Attachment 4A, Line 28, Col. (e) (Notes B and X)	(181,975,940)	TP	100.00%	(181,975,940)
30	Account No. 283 (enter negative)	Attachment 4A, Line 28, Col. (f) (Notes B and X)	(11,894,311)	TP	100.00%	(11,894,311)
31	Account No. 190	Attachment 4A, Line 28, Col. (g) (Notes B and X)	15,910,935	TP	100.00%	15,910,935
31a	Unamortized EDIT Balance - Protected Property (enter negative)	Attachment 9 - EDIT, Line 22, Col. (n)	(80,402,291)	TP	100.00%	(80,402,291)
31b	Unamortized EDIT Balance - Non-Protected Property (enter negative)	Attachment 9 - EDIT, Line 23, Col. (n)	(15,751,191)	TP	100.00%	(15,751,191)
31c	Unamortized EDIT Balance - Non-Protected, Non-Property (enter negative)	Attachment 9 - EDIT, Line 26, Col. (n)	234,019	TP	100.00%	234,019
32	Account No. 255 (enter negative)	Attachment 4, Line 28, Col. (h) (Notes B and X)	-	TP	100.00%	-
33	Unfunded Reserves (enter negative)	Attachment 4, Line 31, Col. (h) (Note Y)	(5,918,001)	DA	100.00%	(5,918,001)
34	CWIP	Attachment 4, Line 14, Col. (e)	-	DA	100.00%	-
35	Pension Asset	Attachment 4, Line 28, Col. (i)	27,945,369	DA	100.00%	27,945,369
36	Unamortized Regulatory Asset	Attachment 4, Line 28, Col. (b) (Note T)	-	DA	100.00%	-
37	Unamortized Abandoned Plant	Attachment 4, Line 28, Col. (c) (Note S)	-	DA	100.00%	-
38	Outstanding Network Credits	From PJM	-	DA	100.00%	-
39	Less Accum. Deprec. associated with Facilities with Outstanding Network Credits	From PJM	-	DA	100.00%	-
40	TOTAL ADJUSTMENTS	(Sum of Lines 28 through 39)	(251,851,410)			(251,851,410)
41	LAND HELD FOR FUTURE USE	Attachment 4, Line 14, Col. (f) (Note C)	685,204	TP	100.00%	685,204
42	WORKING CAPITAL	(Note D)				
43	CWC	1/8*(Page 3, Line 12 minus Page 3, Line 7)	30,999,118			8,716,172
44	Materials & Supplies	Attachment 4, Line 14, Col. (g)	13,305,123	TP	100.00%	13,305,123
45	Prepayments (Account 165)	Attachment 4, Line 14, Col. (h)	1,438,556	DA	100.00%	1,438,556
46	TOTAL WORKING CAPITAL	(Sum of Lines 43 through 45)	45,742,797			23,459,851
47	RATE BASE	(Sum of Lines 26, 40, 41 & 46)	5,860,275,843			901,499,967

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data
PECO Energy Company

For the 12 months ended 12/31/2018

Line No.	(1)	(2) Source	(3) Company Total	Allocator	(4)	(5) Transmission (Col 3 times Col 4)
	O&M					
1	Transmission	Attachment 5, Line 1, Col. (a)	188,583,461	TP	100.00%	188,583,461
2	Less Account 566 (Misc Trans Expense) (enter negative)	Attachment 5, Line 1, Col. (b)	(11,664,574)	TP	100.00%	(11,664,574)
3	Less Account 565 (enter negative)	Attachment 5, Line 1, Col. (c)	-	TP	100.00%	-
4	Less Accounts 561.4 and 561.8 (enter negative)	Attachment 5, Line 1, Col. (d)	(136,634,127)	TP	100.00%	(136,634,127)
5	A&G	Attachment 5B, Line 15, Col. (a) and Line 18, Col. (e)	195,655,730	DA		17,741,717
6	Account 566					
7	Amortization of Regulatory Asset	(Note T) Attachment 5, Line 1, Col. (e)	-	DA	100.00%	-
8	Miscellaneous Transmission Expense (less amortization of regulatory asset)	Attachment 5, Line 1, Col .(f)	11,664,574	TP	100.00%	11,664,574
9	Total Account 566	(Line 7 plus Line 8) Ties to 321.97.b	11,664,574			11,664,574
10	PBOP Adjustment	Attachment 7, line 3, Col. (d)	999,785	W/S	9.88%	98,785
11	Less O&M Cost to Achieve Included in O&M Above (enter negative)	Attachment 4E, Line 11, Col. (x)	(611,905)	W/S	9.88%	(60,460)
12	TOTAL O&M	(Sum of Lines 1 to 5, 9, 10 and 11)	247,992,943			69,729,376
13	DEPRECIATION EXPENSE (Note U)					
14	Transmission	Attachment 5, Line 1, Col. (g)	25,205,171	TP	100.00%	25,205,171
15	General	Attachment 5, Line 2, Col. (a)	16,933,417	W/S	9.88%	1,673,127
16	Intangible - Transmission	Attachment 5, Line 1, Col. (i)	3,401,047	TP	100.00%	3,401,047
16a	Intangible - General	Attachment 5, Line 1, Col. (j)	2,811,569	W/S	9.88%	277,800
16b	Intangible - Distribution	Attachment 5, Line 1, Col. (k)	12,591,808	NA	zero	-
17	Common - Electric	Attachment 5, Line 1, Col. (h)	25,075,521	W/S	9.88%	2,477,617
18	Common Depreciation Expense Related to Costs To Achieve	(enter negative) Attachment 4E, Line 66, Col (x)	(621,937)	W/S	9.88%	(61,451)
19	Amortization of Abandoned Plant	(Note S) Attachment 5, Line 2, Col. (b)	-	DA	100.00%	-
20	TOTAL DEPRECIATION	(Sum of Lines 14 through 19)	85,396,596			32,973,311
21	TAXES OTHER THAN INCOME TAXES	(Note F)				
22	LABOR RELATED					
23	Payroll	Attachment 5, Line 2, Col. (c)	12,636,392	W/S	9.88%	1,248,554
24	Labor Related Taxes to be Excluded	Attachment 5, Line 2, Col. (d)	-	W/S	9.88%	-
25	PLANT RELATED					
26	Property	Attachment 5, Line 2, Col. (e)	12,111,350	GP	19.13%	2,316,569
27	Excluded Taxes Per Attchment 5C Line 5	Attachment 5, Line 2, Col. (f)	131,044,354	NA	zero	-
28	Other	Attachment 5, Line 2, Col. (g)	440,813	GP	19.13%	84,315
29	Plant Related Taxes to be Excluded	Attachment 5, Line 2, Col. (h)	-	GP	19.13%	-
30	TOTAL OTHER TAXES	(Sum of Lines 23 through 29)	156,232,909			3,649,438
31	INTEREST ON NETWORK CREDITS	From PJM	-	DA	100.00%	-
32	INCOME TAXES	(Note G)				
33	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)}	WCLTD = Page 4, Line 19	0.2889			
34	CIT=(T/1-T) * (1-(WCLTD/R)) =	R = Page 4, Line 15	0.3020			
35	FIT & SIT & P	(Note G)				
36						
37	1 / (1 - T) = (T from line 33)		1.4063			
38	Amortized Investment Tax Credit (enter negative)	Attachment 5, Line 2, Col. (i)	(3,979)			
39	Excess Deferred Income Taxes (enter negative)	Attachment 5, Line 2, Col. (j)	(3,189,177)			
40	Tax Effect of Permanent Differences	Attachment 5, Line 2, Col. (k) (Note W)	296,018			
41	Income Tax Calculation	(Line 34 times Line 47)	132,125,657	NA		20,325,199
42	ITC adjustment	(Line 37 times Line 38)	(5,596)	TP	100.00%	(5,596)
43	Excess Deferred Income Tax Adjustment	(Line 37 times Line 39)	(4,484,983)	TP	100.00%	(4,484,983)
44	Permanent Differences Tax Adjustment	(Line 37 times Line 40)	416,294	TP	100.00%	416,294
45	Total Income Taxes	(Sum of Lines 41 through 44)	128,051,372			16,250,915
46	RETURN					
47	Rate Base times Return	(Page 2, Line 47 times Page 4, Line 18)	437,563,636	NA		67,311,440
48a	Net Pension Asset ATRR Discount (enter negative)	Attachment 10, Line 9	(870,137)	DA	100.00%	(870,137)
48	REVENUE REQUIREMENT	(Sum of Lines 12, 20, 30, 31, 45, 47)	1,054,367,320			189,044,343

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data
PECO Energy Company

For the 12 months ended 12/31/2018

SUPPORTING CALCULATIONS AND NOTES

Line No.	(1)	(2)	(3)		(4)		(5)	
	TRANSMISSION PLANT INCLUDED IN ISO RATES							
1	Total Transmission plant	(Page 2, Line 2, Column 3)					1,568,082,823	
2	Less Transmission plant excluded from PJM rates	(Note H)					-	
3	Less Transmission plant included in OATT Ancillary Services	(Note I)					-	
4	Transmission plant included in PJM rates	(Line 1 minus Lines 2 & 3)					1,568,082,823	
5	Percentage of Transmission plant included in PJM Rates	(Line 4 divided by Line 1)				TP=	100.00%	
6	WAGES & SALARY ALLOCATOR (W&S)							
		Form 1 Reference	$	TP	Allocation			
7	Electric Production	354.20.b	-	0.0%	-			
8	Electric Transmission	354.21.b	14,301,727	100.0%	14,301,727			
9	Electric Distribution	354.23.b	96,537,443	0.0%	-		W&S Allocator	
10	Electric Other	354.24,25,26.b	33,906,048	0.0%	-		($ / Allocation)	
11	Total (W& S Allocator is 1 if lines 7-10 are zero)	(Sum of Lines 7 through 10)	144,745,218		14,301,727	=	9.88%	= WS
12	RETURN (R)	(Note V)					$	
13					Cost			
14			$	%	(Notes K, Q, & R)		Weighted	
15	Long Term Debt	(Attachment 5, line 10 Notes Q & R)	3,126,726,301	46.39%	4.13%		1.92%	=WCLTD
16	Preferred Stock (112.3.c)	(Attachment 5, line 11 Notes Q & R)	-	0.00%	0.00%		0.00%	
17	Common Stock	(Attachment 5, line 12 Notes K, Q & R)	3,613,749,579	53.61%	10.35%		5.55%	
18	Total	(Attachment 5, line 13)	6,740,475,881				7.47%	=R

Formula Rate - Non-Levelized

Rate Formula Template
Utilizing FERC Form 1 Data
PECO Energy Company

For the 12 months ended 12/31/2018

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)

Notes:

A Reserved

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

C Reserved

D Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission at page 3, line 12, column 5 minus amortization of Regulatory Asset at page 3, line 7, column 5. For Prepayments, refer to Note K in Attachment 4.

E Page 3, Line 5: Attachment 5B, Line 4 - Exclude: (1) amortization of CAP Shopping and Seamless Moves; (2) amortization of DSP IV Admin Costs; (3) Miscellaneous Advertising; (4) SEPA Solar Power Study; (5) PSU Sponsorship; (6) EU IT Prepaid Meter Assess O&M; and (7) Customer Operations AMI/CI O&M. Include Communications, Public Advocacy and Corporate Relations and Government and Regulatory Affairs and Public Policy expenses listed in Account 923 found at Form 1 323.184.b.
Attachment 5B, Lines, 11, and 12 - Exclude EPRI Annual Membership Dues listed in Form 1 at 353.f, non-safety-related advertising included in Account 930.1 found at 323.191.b and Chamber of Commerce Dues and Civic Organization Expenses in Account 930.2 found at 323.192.b; include the costs related to Project Cancellation Fees and Remediation Expenditures (provided, that with regard to the Metal Bank Superfund, PECO must include as a credit any receipts received from the EPA and/or obtained through litigation with the remediation contractors related to Metal Bank Superfund).
Attachment 5B, Line 9- include Regulatory Commission Expenses directly related to transmission service, ISO filings, or transmission siting itemized at 351.h., and exclude all other Regulatory Commission Expenses itemized at 351.h.

F 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.

G 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 36). Excess Deferred Income Taxes reduce income tax expense by the amount of the expense multiplied by (T/1-T).

Inputs Required:	FIT =	21.00%	
	SIT=	9.99%	(State Income Tax Rate or Composite SIT)
	p =	0.00%	(percent of federal income tax deductible for state purposes)

H Removes transmission plant determined by Commission order to be state-jurisdictional according to the seven-factor test (until Form 1 balances are adjusted to reflect application of seven-factor test).

I Removes dollar amount of transmission plant to be 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.

J Reserved

K ROE will be supported in the original filing and no change in ROE may be made absent a Section 205 or Section 206 filing with FERC. The equity component of the capital structure will be capped at 55.75% and shall not be subject to change during the ROE Moratorium Period established under the Settlement Agreement in Docket No. ER17-1519. Thereafter, the cap shall be subject to change pursuant to sections 205 and 206 of the Federal Power Act.

L Reserved

M Reserved

N All items related to Contributions in Aid of Construction (CIAC), including investment in CIAC and CIAC related ADIT, excess/(deficient) ADIT and amortization of excess/(deficient) ADIT shall be excluded from the formula rate.

O Transmission-related ADIT, Excess/(Deficient) ADIT, and the amortization of Excess/(Deficient) ADIT shall be included in the formula rate except as noted in Notes N and P. For clarity of administration of the formula rate, this specifically includes (but is not limited to) transmission-related amounts related to Amortization of Book Premiums on Reacquired Debt, Pension Expense Provision, Loss on Reacquired Debt, FAS 112 and Electric Rate Case Expense – Regulatory Asset – Current.

P ADIT, Excess/(Deficient) ADIT and the amortizaiton of Excess/(Deficient) ADIT related to Accrued Benefits, Deferred Compensation, Vacation pay Change in Provision and Accrued Vacation shall be excluded from the formula rate.

Q All ADIT-190, ADIT-282, and ADIT-283 amounts reflected on Attachment 4C must be based on a timing difference between book expense recognition and expense recognition for tax purposes.

R Calculated using 13 month average balance, except ADIT.

S Unamortized Abandoned Plant and Amortization of Abandoned Plant will be zero until FERC explicitly approves recovery of the cost of abandoned plant pursuant to Section 205 of the FPA.

T Recovery of Regulatory Asset is permitted only as specifically authorized pursuant to Section 205 or 206 of the FPA by FERC. Recovery of any regulatory assets not specifically identified in the initial version of this formula rate template approved by FERC in Docket No. ER17-1519-000 will require specific authorization from FERC.

U Excludes Asset Retirement Obligation balances

V Company shall include only gains and losses on interest rate locks associated with debt issuances. Absent a Section 205 filing, Company shall not include in the Formula Rate, the gains, losses, or costs related to other hedges.

W The Tax Effect of Permanent Differences captures the differences in the income taxes due under the Federal and State calculations and the income taxes calculated in Attachment H that are not the result of a timing difference. Items that can be included in formula for recovery are AFUDC Equity, Meals & Entertainment (50%), Memberships & Dues Not Deductible, Additional Compensation to Employee Stock, and Life Insurance Premiums. Items that can not be included in formula for recovery are Dividend Received Deductions, Equity in Earnings of Unconsol. Subs, and Other Perms (Rabbi Trust). Commission authorization is required in order to include any other permanent difference as an adjustment to the income tax allowance computation in the Formula Rate Template.

X Calculated on Attachment 4A.

Y Unfunded Reserves are customer contributed capital such as when Injuries and Damages expense is accrued but not yet incurred. Also, pursuant to Special Instructions to Accounts 228.1 through 228.4, no amounts shall be credited to accounts 228.1 through 228.4 unless authorized by a regulatory authority or authorities to be collected in a utility’s rates.

Z Amortization of Regulatory Asset for Environmental Remediation of Manufactured Gas Plants shall be excluded from the formula rate.

Attachment 12 PECO Formula Rate Updated

Attachment 1
Project Revenue Requirement Worksheet
PECO Energy Company

To be completed in conjunction with Attachment H-7.

Line No.	(1)	(2) Attachment H-7 Page, Line, Col.	(3) Transmission	(4) Allocator
1	Gross Transmission Plant - Total	Attach H-7, p 2, line 2 col 5 (Note A)	1,568,082,823	
2	Net Transmission Plant - Total	Attach H-7, p 2, line 20 col 5 plus line 34 & 37 col 5 (Note B)	1,072,422,589	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Attach H-7, p 3, line 12 col 5	69,729,376	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1 col 3)	0.04	0.04
	GENERAL, INTANGIBLE AND COMMON (G&C) DEPRECIATION EXPENSE			
5	Total G, I & C Depreciation Expense	Attach H-7, p 3, lines 15 to 18, col 5 (Note H)	7,768,140	
6	Annual Allocation Factor for G, I & C Depreciation Expense	(line 5 divided by line 1 col 3)	0.00	0.00
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Attach H-7, p 3, line 30 col 5	3,649,438	
8	Annual Allocation Factor for Other Taxes	(line 7 divided by line 1 col 3)	0.00	0.00
9	Less Revenue Credits	Attach H-7, p 1, line 2 col 5	9,661,602	
10	Annual Allocation Factor Revenue Credits	(line 9 divided by line 1 col 3)	-	-
11	**Annual Allocation Factor for Expense**	**Sum of lines 4, 6, 8, and 10**		**0.05**
	INCOME TAXES			
12	Total Income Taxes	Attach H-7, p 3, line 45 col 5	16,250,915	
13	Annual Allocation Factor for Income Taxes	(line 12 divided by line 2 col 3)	0.02	0.02
	RETURN			
14	Return on Rate Base	Attach H-7, p 3, lines 47 and 48a col 5	66,441,302	
15	Annual Allocation Factor for Return on Rate Base	(line 14 divided by line 2 col 3)	0.06	0.06
16	**Annual Allocation Factor for Return**	**Sum of lines 13 and 15**	0.08	**0.08**

Attachment 12 PECO Formula Rate Updated

Attachment 1
Project Revenue Requirement Worksheet
PECO Energy Company

Line No.	(1) Project Name	(2) RTO Project Number or Zonal	(3) Project Gross Plant	(4) Annual Allocation Factor for Expense	(5) Annual Expense Charge	(6) Project Net Plant or CWIP Balance	(7) Annual Allocation Factor for Return	(8) Annual Return Charge	(9) Project Depreciation/Amortization Expense	(10) Annual Revenue Requirement	(11) Incentive Return in basis Points	(12) Incentive Return	(12a) Ceiling Rate	(13) Competitive Bid Concession	(14) Total Annual Revenue Requirement	(15) True-Up Adjustment	(15a) Additional Refund (Note Q)	(16) Net Rev Req
			(Note C)	(Page 1 line 11)	(Col. 3 * Col. 4)	(Notes D & I)	(Page 1 line 16)	(Col. 6 * Col. 7)	(Notes E & I)	(Sum Col. 5, 8 & 9)	(Note K)	(Attachment 2, Line 28 /100 * Col. 11 * Col. 6)	(Sum Col. 10 & 12)	(Note J)	(Sum Col. 10 & 12 Less Col. 13)	(Note F)	$ (850,000)	Sum Col. 14, 15 & 15(a) (Note G)
17a	Zonal	Zonal	$ 1,359,517,580	0.05	70,353,880	$ 878,447,780	0.08	67,735,233	20,354,820	158,443,933	-	-	158,443,933	-	158,443,933	-	(712,411)	[redacted]
17b	Center Point 500-230 kV Substation Addition	b0269	$ 34,380,669	0.05	1,779,170	$ 28,991,017	0.08	2,235,435	$ 670,819	4,685,425	-	-	4,685,425	-	4,685,425	-	(21,067)	4,664,358
17c	Center Point 500-230 kV Substation Addition	b0269	$ 17,190,335	0.05	889,585	$ 14,495,508	0.08	1,117,718	$ 335,410	2,342,712	-	-	2,342,712	-	2,342,712	-	(10,534)	2,332,179
17d	Richmond-Waneeta 230 kV Line Re-conductor	b1591	$ 4,605,741	0.05	238,343	$ 4,387,749	0.08	338,330	$ 110,157	686,830	-	-	686,830	-	686,830	-	(3,088)	683,742
17e	Richmond-Waneeta 230 kV Line Re-conductor	b1398.8	$ 1,535,247	0.05	79,448	$ 1,462,583	0.08	112,777	$ 36,719	228,943	-	-	228,943	-	228,943	-	(1,029)	227,914
17f	Whitpain 500 kV Circuit Breaker Addition	b0269.6	$ 3,258,302	0.05	168,614	$ 2,742,607	0.08	211,477	$ 63,904	443,995	-	-	443,995	-	443,995	-	(1,996)	441,999
17g	Elroy-Hosensack 500 kV Line Rating Increase	b0171.1	$ 4,456,731	0.05	230,632	$ 3,663,958	0.08	282,520	$ 85,372	598,524	-	-	598,524	-	598,524	-	(2,691)	595,833
17h	Camden-Richmond 230 kV Line Rating Increase	b1590.1 and b1590.2 (	$ 13,635,683	0.05	705,635	$ 12,618,060	0.08	972,952	$ 313,474	1,992,060	-	-	1,992,060	-	1,992,060	-	(8,957)	1,983,103
17i	Chichester-Linwood 230 kV Line Upgrades	b1900	$ 23,835,043	0.05	1,233,443	$ 31,631,855	0.08	2,439,065	$ 821,886	4,494,394	-	-	4,494,394	-	4,494,394	-	(20,208)	4,474,186
17j	Bryn Mawr-Plymouth 138 kV Line Rebuild	b0727	$ 18,039,324	0.05	933,520	$ 16,410,659	0.08	1,265,391	$ 487,432	2,686,342	-	-	2,686,342	-	2,686,342	-	(12,079)	2,674,264
17k	Emilie 230-138 kV Transformer Addition	b2140	$ 16,739,503	0.05	866,255	$ 15,912,693	0.08	1,226,994	$ 375,621	2,468,869	-	-	2,468,869	-	2,468,869	-	(11,101)	2,457,769
17l	Chichester-Saville 138 kV Line Re-conductor	b1182	$ 17,916,280	0.05	927,152	$ 15,695,976	0.08	1,210,283	$ 438,397	2,575,833	-	-	2,575,833	-	2,575,833	-	(11,582)	2,564,251
17m	Waneeta 230-138 kV Transformer Addition	b1717	$ 11,068,901	0.05	572,806	$ 10,606,952	0.08	817,879	$ 247,964	1,638,650	-	-	1,638,650	-	1,638,650	-	(7,368)	1,631,282
17o	Chichester 230-138 kV Transformer Addition	b1178	$ 8,327,907	0.05	430,962	$ 7,312,494	0.08	563,851	$ 170,395	1,165,208	-	-	1,165,208	-	1,165,208	-	(5,239)	1,159,969
17p	Bradford-Planebrook 230 kV Line Upgrades	b0790	$ 1,712,754	0.05	88,634	$ 1,585,530	0.08	122,257	$ 36,944	247,834	-	-	247,834	-	247,834	-	(1,114)	246,720
17q	North Wales-Hartman 230 kV Line Re-conductor	b0506	$ 2,229,232	0.05	115,361	$ 1,866,447	0.08	143,918	$ 52,028	311,306	-	-	311,306	-	311,306	-	(1,400)	309,906
17r	North Wales-Whitpain 230 kV Line Re-conductor	b0505	$ 2,546,903	0.05	131,800	$ 2,063,845	0.08	159,139	$ 57,530	348,469	-	-	348,469	-	348,469	-	(1,567)	346,902
17s	Bradford-Planebrook 230 kV Line Upgrades	b0789	$ 2,359,200	0.05	122,087	$ 2,163,071	0.08	166,790	$ 50,401	339,277	-	-	339,277	-	339,277	-	(1,525)	337,752
17u	Planebrook 230 kV Capacitor Bank Addition	b0206	$ 3,631,396	0.05	187,922	$ 2,748,576	0.08	211,937	$ 64,043	463,902	-	-	463,902	-	463,902	-	(2,086)	461,816
17v	Newlinville 230 kV Capacitor Bank Addition	b0207	$ 4,811,873	0.05	249,010	$ 3,742,282	0.08	288,559	$ 87,197	624,767	-	-	624,767	-	624,767	-	(2,809)	621,958
17w	Chichester-Mickleton 230 kV Series Reactor Addition	b0209	$ 2,699,444	0.05	139,694	$ 2,133,084	0.08	164,478	$ 49,702	353,873	-	-	353,873	-	353,873	-	(1,591)	352,282
17x	Chichester-Mickleton 230 kV Line Re-conductor	b0264	$ 2,221,241	0.05	114,947	$ 1,731,116	0.08	133,483	$ 48,255	296,685	-	-	296,685	-	296,685	-	(1,334)	295,351
17y	Buckingham-Pleasant Valley 230 kV Line Re-conductor	b0357	$ 1,723,078	0.05	89,168	$ 1,940,978	0.08	149,665	$ 58,719	297,551	-	-	297,551	-	297,551	-	(1,338)	296,213
17z	Elroy 500 kV Dynamic Reactive Device	b0287	$ 5,325,225	0.05	275,576	$ 4,711,735	0.08	363,312	$ 109,786	748,674	-	-	748,674	-	748,674	-	(3,366)	745,307
17aa	Heaton 230 kV Capacitor Bank Addition	b0208	$ 4,315,230	0.05	223,310	$ 3,356,034	0.08	258,777	$ 78,197	560,283	-	-	560,283	-	560,283	-	(2,519)	557,764
17ab																		-
18	Annual Totals		1,568,082,823			1,072,422,589		82,692,217	25,205,171	189,044,343		-	189,044,343	-	189,044,343	-	(850,000)	30,462,821

Notes:

A Gross Transmission Plant is that identified on page 2 line 2 of Attachment H
B Inclusive of any CWIP or unamortized abandoned plant included in rate base when authorized by FERC order less any prefunded AFUDC, if applicable.
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. This value includes subsequent capital investments required to maintain the facilities to their original capabilities.
Gross plant does not include Unamortized Abandoned Plant.
D Project Net Plant is the Project Gross Plant Identified in Column 3 less the associated Accumulated Depreciation. Net Plant includes CWIP and Unamortized Abandoned Plant and excludes any regulatory asset, which are to be entered as separate line items.
E Project Depreciation Expense is the actual value booked for the project and included in the Depreciation Expense in Attachment H, page 3, line 14. Project Depreciation Expense includes the amortization of Abandoned Plant
F True-Up Adjustment is calculated on the Attachment 3 Project True-up Schedule for the Rate Year
G The Net Rev Req is the value to be used in the rate calculation under the applicable Schedule 12 under the PJM OATT for each project.
H The Total General, Intangible and Common Depreciation Expense excludes any depreciation expense directly associated with a project and thereby included in page 2 column 9.
I The Unamortized Abandoned Plant balance is included in Net Plant, and Amortization of Abandoned Plant is included in Depreciation/Amortization Expense.
J The Competitive Bid Concession is the reduction in revenue, if any, that the company agreed to, for instance, to be selected to build facilities as the result of a competitive process and equals the amount by which the annual revenue requirement is reduced from the ceiling rate
K Requires approval by FERC of incentive return applicable to the specified project(s)
M All transmission facilities reflected in the revenue requirement on Attachment H-7, page 1 line 3 are to be included in this Attachment 1.
N Facilities that provide Wholesale Distribution Service are not to be listed as projects on lines 15, the revenue requirements associated with these facilities are calculated on Attachment 11
O When an updated projected net revenue requirement is posted due to an asset acquisition as provided for in the Protocols, the difference between the updated net revenue requirement in Col (16) and the revenues collected to date will be recovered
over the remaining months of the Rate Year.
P Zonal on line 17a refers to all projects not qualifying for regional recovery
Q Additional refund $850,00 per year for 2018-2021 and $0 for 2022 and beyond.

Attachment 2
Incentive ROE
PECO Energy Company

Line	Description	Reference	Note	$	%		Cost	$ Weighted	Total
1	Rate Base	Attachment H-7, Page 2 line 47, Col.5							901,499,967
2	100 Basis Point Incentive Return								
3	Long Term Debt	(Attachment H-7, Notes Q and R)		3,126,726,301	46.4%		4.13%	1.9%	
4	Preferred Stock	(Attachment H-7, Notes Q and R)		-	0.0%		0.00%	0.0%	
5	Common Stock	(Attachment H-7, Notes K, Q and R)	Cost = Attachment H-7, Page 4 Line 17, Cost plus .01	3,613,749,579	53.6%		11.35%	6.1%	
6	Total (sum lines 3-5)			6,740,475,881				8.0%	
7	100 Basis Point Incentive Return multiplied by Rate Base (line 1 * line 6)								72,144,622.35
8	INCOME TAXES								
9	T=1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =			28.8921%					
10	CIT=(T/1-T) * (1-(WCLTD/R)) =			30.8949%					
11	WCLTD = Line 3								
12	and FIT, SIT & p are as given in footnote K.								
13	1 / (1 - T) = (from line 9)			1.4063					
14	Amortized Investment Tax Credit (266.8f) (enter negative)		Attachment H-7, Page 3, Line 38	(3,979)					
15	Excess Deferred Income Taxes (enter negative)		Attachment H-7, Page 3, Line 39	(3,189,177)					
16	Tax Effect of Permanent Differences (Note B)		Attachment H-7, Page 3, Line 40	296,018					
17	Income Tax Calculation = line 10 * line 7			22,288,987		NA		22,288,987	
18	ITC adjustment (line 13 * line 14)			(5,596)		TP	100.0%	(5,596)	
19	Excess Deferred Income Tax Adjustment (line 13 * line 15)			(4,484,983)		TP	100.0%	(4,484,983)	
20	Permanent Differences Tax Adjustment (line 13 * 16)			416,294		TP	100.0%	416,294	
21	Total Income Taxes (sum lines 17 - 20)			18,214,702				18,214,702	18,214,702
22	Return and Income Taxes with 100 basis point increase in ROE		(Sum lines 7 & 21)						90,359,324
23	Return (Attach. H-7, page 3 line 47 col 5)								67,311,440
24	Income Tax (Attach. H-7, page 3 line 45 col 5)								16,250,915
25	Return and Income Taxes without 100 basis point increase in ROE		(Sum lines 23 & 24)						83,562,354
26	Incremental Return and Income Taxes for 100 basis point increase in ROE		(Line 22 - line 25)						6,796,970
27	Rate Base (line 1)								901,499,967
28	Incremental Return and Income Taxes for 100 basis point increase in ROE divided by Rate Base			(Line 26 / line 27)					0.0075

Notes:

A Line 5 includes a 100 basis point increase in ROE that is used only to determine the increase in return and income taxes associated with a 100 basis point increase in ROE. Any actual ROE incentive must be approved by the Commission.
For example, if the Commission were to grant a 137 basis point ROE incentive, the increase in return and taxes for a 100 basis point increase in ROE would be multiplied by 1.37 on Attachment 1 column 12.

B The Tax Effect of Permanent Differences captures the differences in the income taxes due under the Federal and State calculations and the income taxes calculated in Attachment H-7 that are not the result of a timing difference

Attachment 12 PECO Formula Rate Updated

Attachment 3
Project True-Up
PECO Energy Company

Line	A	B	C	D	E	F	G	H	I	J
1	Rate Year being Trued-Up		Revenue Requirement Projected For Rate Year		Revenue Received[3]	Actual Revenue Requirement (Note C)	Annual True-Up Calculation			
2										
	A	B	C	D	E	F	G	H	I	J
	Project Name	PJM Project Number or Zonal	Projected Net Revenue Requirement[1]	% of Total Revenue Requirement	Revenue Received	Actual Net Revenue Requirement[2]	Net Under/(Over) Collection (F)-(E)	Prior Period Adjustment [5]	Interest Income (Expense)[4]	Total True-Up (G) + (H) + (I)
3	Zonal	Zonal					-	-	-	-
3a	Center Point 500-230 kV Substation Addition	b0269					-	-	-	-
3b	Center Point 500-230 kV Substation Addition	b0269					-	-	-	-
3c	Richmond-Waneeta 230 kV Line Re-conductor	b1591					-	-	-	-
3d	Richmond-Waneeta 230 kV Line Re-conductor	b1398.8					-	-	-	-
3e	Whitpain 500 kV Circuit Breaker Addition	b0269.6					-	-	-	-
3f	Elroy-Hosensack 500 kV Line Rating Increase	b0171.1					-	-	-	-
3g	Camden-Richmond 230 kV Line Rating Increase	b1590.1 and b1590.2 (cancelled b1398.6)					-	-	-	-
3h	Chichester-Linwood 230 kV Line Upgrades	b1900					-	-	-	-
3i	Bryn Mawr-Plymouth 138 kV Line Rebuild	b0727					-	-	-	-
3j	Emilie 230-138 kV Transformer Addition	b2140					-	-	-	-
3k	Chichester-Saville 138 kV Line Re-conductor	b1182					-	-	-	-
3l	Waneeta 230-138 kV Transformer Addition	b1717					-	-	-	-
3m	Chichester 230-138 kV Transformer Addition	b1178					-	-	-	-
3o	Bradford-Planebrook 230 kV Line Upgrades	b0790					-	-	-	-
3p	North Wales-Hartman 230 kV Line Re-conductor	b0506					-	-	-	-
3q	North Wales-Whitpain 230 kV Line Re-conductor	b0505					-	-	-	-
3r	Bradford-Planebrook 230 kV Line Upgrades	b0789					-	-	-	-
3s	Planebrook 230 kV Capacitor Bank Addition	b0206					-	-	-	-
3u	Newlinville 230 kV Capacitor Bank Addition	b0207					-	-	-	-
3v	Chichester-Mickleton 230 kV Series Reactor Addition	b0209					-	-	-	-
3w	Chichester-Mickleton 230 kV Line Re-conductor	b0264					-	-	-	-
3x	Buckingham-Pleasant Valley 230 kV Line Re-conductor	b0357					-	-	-	-
3y	Elroy 500 kV Dynamic Reactive Device	b0287					-	-	-	-
3z	Heaton 230 kV Capacitor Bank Addition	b0208					-	-	-	-
4	Total Annual Revenue Requirements (Note A)		-	-	-	-	-		-	-

Monthly Interest Rate	-
Interest Income (Expense)	-

Notes:
1) From Attachment 1, line 17, col. 14 for the projection for the Rate Year.
2) From Attachment 1, line 17, col. 14, less col. 15(a) for each project and Attachment H-7, line 7 for zonal.
3) "Revenue Received" on line 3 Zonal, Col. (E), is the total amount of revenue received for the True-Up Year under PJM OATT Attachments 7, 8 and H-7 and "Revenue Received" on letter-denominated line 3 entries, Col. (E), is the amount of revenue received for the True-Up Year for the project designated in Cols. A and B under PJM OATT Schedule 12 PECO Appendix and PECO Appendix A as reported on pages 328-330 of the Form No 1. The Revenue Received in Col. E excludes any True-Up revenues

4) Interest from Attachment 6.
5) Prior Period Adjustment from line 5 is pro rata to each project, unless the error was project specific.

Prior Period Adjustments

	(a)	(b)	(c)	(d)
	Prior Period Adjustments (Note B)	Amount In Dollars	Interest (Note B)	Total Col. (b) + Col. (c)
5	-	-	-	-

Notes:

A For each project or Attachment H, the utility will populate the formula rate with the inputs for the True-Up Year. The revenue requirements, based on actual operating results for the True-Up Year, associated with the projects and Attachment H will then be entered in Col. (F) above. Column (E) above contains the actual revenues received associated with Attachment H and any Projects paid by the RTO to the utility during the True-Up Year. Then in Col. (G), Col. (E) is subtracted from Col. (F) to calculate the True-up Adjustment. The Prior Period Adjustment from Line 5 below is input in Col. (H). Column (I) is the applicable interest rate from Attachment 6. Column (I) adds the interest on the sum of Col.(G) and (H). Col. (J) is the sum of Col. (G), (H), and (I).

B Prior Period Adjustment is the amount of an adjustment to correct an error in a prior period. Interest will be calculated for the prior period adjustment based on the FERC Refund interest rate specified in 18 CFR 35.19(a) for the period up to the date the projected rates went into effect. PECO will provide the supporting worksheet for the interest calculation when prior period adjustment is needed.

C The Actual Revenue Requirement in the True-up Adjustment calculation for years 2020 and later shall use the depreciation and amortization rates approved for use by the Commission when PECO performs the True-Up Adjustment.

Attachment 12 PECO Formula Rate Updated

Attachment 4
Rate Base Worksheet
PECO Energy Company

Line No	Month	Gross Plant In Service			CWIP	LHFFU	Working Capital		Accumulated Depreciation		
	Month (a)	**Transmission (b)**	**General (c)**	**Common (d) (Note J)**	**CWIP in Rate Base (e)**	**Held for Future Use (f)**	**Materials & Supplies (g)**	**Prepayments (h) (Note K)**	**Transmission (i) (Note J)**	**General (j) (Note J)**	**Common (k) (Note J)**
	Attachment H, Page 2, Line No:	2	4	5	27	31	34	35	9	11	12
		207.58.g minus 207.57.g. Projected monthly balances that are the amounts expected to be included in 207.58.g for end of year and records for other months (Note I)	207.99.g minus 207.98.g for end of year, records for other months	Electric Only, Form No 1, page 356 for end of year, records for other months	(Note C)	214.16,d and 214.18,d for end of year, records for other months	227. 8. c + (227.16.c * Labor Ratio) + TLF for end of year, records for other months (Note L)	111.57.c for end of year, records for other months	Projected monthly balances that are expected to be included in 219.25.c for end of year and records for other months (Note I)	219.28.c for end of year, records for other months	Electric Only, Form No 1, page 356 for end of year, records for other months
1	December Prior Year	1,547,012,084	254,708,195	553,357,032	-	1,141,405	12,899,807	1,170,892	494,610,735	63,297,973	262,215,584
2	January	1,545,817,812	255,587,400	558,359,938	-	1,141,405	13,355,337	1,177,054	492,249,250	64,567,502	264,818,334
3	February	1,547,575,763	253,241,208	561,007,484	-	1,141,405	13,191,630	1,468,021	491,656,045	65,889,796	267,482,558
4	March	1,544,776,810	252,700,424	561,116,757	-	1,141,405	14,054,170	1,503,394	490,757,674	67,218,926	269,305,381
5	April	1,561,290,209	253,135,473	558,511,224	-	1,141,405	13,177,751	1,642,131	491,926,885	68,016,058	267,918,051
6	May	1,563,925,929	260,404,072	564,120,406	-	1,141,405	13,012,939	1,399,195	492,997,528	69,248,661	270,324,538
7	June	1,566,146,827	261,255,087	561,640,199	-	360,384	13,132,446	1,826,625	494,002,369	70,806,569	272,785,626
8	July	1,574,711,013	263,609,193	559,462,041	-	360,384	13,299,137	1,321,767	495,493,519	71,053,081	271,284,056
9	August	1,576,289,399	265,157,424	561,771,586	-	360,384	13,604,281	1,134,359	497,133,426	72,329,314	273,754,097
10	September	1,579,345,958	267,326,582	563,185,246	-	244,519	13,564,404	1,234,718	498,849,843	73,599,213	276,254,132
11	October	1,583,208,190	271,448,187	568,514,167	-	244,519	13,207,655	1,579,537	500,060,589	73,951,778	278,725,506
12	November	1,583,600,915	272,910,543	582,479,347	-	244,519	13,249,323	1,752,720	501,010,850	74,310,286	281,092,412
13	December	1,611,375,788	273,765,316	589,225,121	-	244,519	13,217,723	1,490,809	502,822,050	74,681,276	283,339,967
14	Average of the 13 Monthly Balances	1,568,082,823	261,942,239	564,826,965	-	685,204	13,305,123	1,438,556	495,659,290	69,920,803	272,253,865

Adjustments to Rate Base

Line No	Month (a)	Unamortized Regulatory Asset (b)	Unamortized Abandoned Plant (c)	Account No. 281 Accumulated Deferred Income Taxes (Note D) (d)	Account No. 282 Accumulated Deferred Income Taxes (Note D) (e)	Account No. 283 Accumulated Deferred Income Taxes (Note D) (f)	Account No. 190 Accumulated Deferred Income Taxes (Note D) (g)	Account No. 255 Accumulated Deferred Investment Credit (h)	Pension Asset (i)
	Attachment H, Page 2, Line No:	28	29	22	23	24	25	26	27a
		Notes A & E	**Notes B & F**	**Attachment 4A, line 20 for the projection and line 44 for the true-up**	**Attachment 4A, line 14 for the projection and line 38 for the true-up**	**Attachment 4A, line 17 for the projection and line 41 for the true-up**	**Attachment 4A, line 34 for the projection and line 47 for the true-up**	**Consistent with 266.8.b, 266.17.b, 267.8.h & 267.17.h**	**Transmission-Related Pension Asset booked to Account 186**
15	December Prior Year	-	-	[redacted]				-	26,927,375
16	January	-	-					-	28,643,301
17	February	-	-					-	28,546,635
18	March	-	-					-	28,432,559
19	April	-	-					-	28,313,623
20	May	-	-					-	28,190,629
21	June	-	-					-	28,067,635
22	July	-	-					-	27,953,863
23	August	-	-					-	27,835,217
24	September	-	-					-	27,708,455
25	October	-	-					-	27,587,206
26	November	-	-					-	27,468,755
27	December	-	-					-	27,614,546
28	Average of the 13 Monthly Balances	-	-	Zero	(181,975,940)	(11,894,311)	15,910,935	-	27,945,369

(except ADIT which is the amount shown on Attachment 4A)

Attachment 12 PECO Formula Rate Updated

Attachment 4
Rate Base Worksheet
PECO Energy Company

Unfunded Reserves (Notes G & H) | Page 2 of 2

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
				Enter 1 if NOT in a trust or reserved account, enter zero (0) if included in a trust or reserved account	Enter 1 if the accrual account is included in the formula rate, enter (0) if O if the accrual account is NOT included in the formula rate	Enter the percentage paid for by the transmission formula customers	Allocation (Plant or Labor Allocator)	Amount Allocated, col. c x col. d x col. e x col. f x col. g
29	List of all reserves:		Amount					
30a		Environmental Liab - Superfund	(1,280,525)	1.00	1.00	100%	9.88%	(126,524)
30b		Accrued Severance Plans	(173,263)	1.00	1.00	100%	9.88%	(17,119)
30c		Workers Compensation - short term	(1,172,299)	1.00	1.00	100%	9.88%	(115,830)
30d		Workers Compensation - long term	(9,929,165)	1.00	1.00	100%	9.88%	(981,063)
30e		Public claims - Short Term	(323,448)	1.00	1.00	100%	9.88%	(31,959)
30f		Public Claims - Long term	(19,748,313)	1.00	1.00	100%	9.88%	(1,951,256)
30g		Accrued Septa Railroad Rent - transmission	-	1.00	1.00	100%	100.00%	-
30h		AIP	(19,749,762)	1.00	1.00	100%	9.88%	(1,951,399)
30i		401 K Match	(1,521,411)	1.00	1.00	100%	9.88%	(150,325)
30j		Long-term Incentive Plans	(1,316,409)	1.00	1.00	100%	9.88%	(130,069)
30k		Mgmt. Retention Incentive Plan	(288,528)	1.00	1.00	100%	9.88%	(28,508)
30l		Stock Comp	(4,384,740)	1.00	1.00	100%	9.88%	(433,240)
30m		Severance - long term	(7,167)	1.00	1.00	100%	9.88%	(708)
30x		...	-	-				-
31		Total	(59,895,031)					(5,918,001)

Notes:

A Recovery of regulatory asset is limited to any regulatory assets authorized by FERC.

B Recovery of abandoned plant is limited to any abandoned plant recovery authorized by FERC.

C Includes only CWIP authorized by the Commission for inclusion in rate base. The annual report filed pursuant to Section 7 of the Protocols will include for each project under construction (i) the CWIP balance eligible for inclusion in rate base; (ii) the CWIP balance ineligible for inclusion in rate base; and (iii) a demonstration that AFUDC is only applied to the CWIP balance that is not included in rate base. The annual report will reconcile the project-specific CWIP balances to the total Account 107 CWIP balance reported on p. 216.b of the FERC Form 1. The demonstration in (iii) above will show that monthly debts and credits do not contain entries for AFUDC for each CWIP project in rate base.

D ADIT and Accumulated Deferred Income Tax Credits are computed using the average of the beginning of the year and the end of the year balances. The projection will use lines 16, 19 and 36 of Attachment 4A to populate the average ADIT balance on line 28 above.

E Recovery of a Regulatory Asset is permitted only for pre-commercial and formation expenses, and is subject to FERC approval before the amortization of the Regulatory Asset can be included in rates. Recovery of any other regulatory assets requires authorization from the Commission. A carrying charge equal to the weighted cost of capital will be applied to the Regulatory Asset prior to the rate year when costs are first recovered.

F Unamortized Abandoned Plant and Amortization of Abandoned Plant will be zero until the Commission accepts or approves recovery of the cost of abandoned plant.

G The Formula Rate shall include a credit to rate base for all unfunded reserves (funds collected from customers that (1) have not been set aside in a trust, escrow or restricted account; (2) whose balance are collected from customers through cost accruals to accounts that are recovered under the Formula Rate; and (3) exclude the portion of any balance offset by a balance sheet account). Each unfunded reserve will be included on lines 30 above. The allocator in Col. (g) will be the same allocator used in the formula for the cost accruals to the account that is recovered under the Formula Rate. Since reserves can be created by an offsetting balance sheet account, rather than through cost accruals, the amount to be deducted from rate base should exclude the portion offset by another balance sheet account.

H Calculate using 13 month average balance, except ADIT. SERP will not be included as an unfunded reserve in the formula rate.

I Projected balances are for the calendar year the revenue under this formula begins to be charged.

J Excludes ARO amounts.

K Total prepayments, including Fleet Activity, allocated to transmission as follows: (1) amounts solely related to transmission allocated 100% to transmission; (2) amounts solely related to distribution, gas or non-utility allocated 0% to transmission; (3) amounts related to electric general allocated using the wages and salaries allocator (Attachment H-7), p. 4, line 11, column (5)); (4) amounts related to common labor or plant allocated using the wages and salaries allocator (Attachment H-7, p. 4, line 11, column (5)), multiplied by either common labor percent to electric (Attachment 7-PBOP, Note B, Electric Labor) or by common utility plant percent to electric (per FF1 page 356) as applicable depending upon the nature of the prepayment item.

L TLF shall be equal to 50 percent of the lesser of (a) the transmission portion of FERC Form 1, page 227, line 5, column c per FERC Form No. 1) and (b) $9 million. The TLF recovery percentage and cap will be subject to modification only through Commission authorization under section 205 or section 206 of the Federal Power Act.

		Allocation	Prior Year End Total	Current Year End Total	Allocation Factor	Prior Year Allocated to T	Current Year Allocated to T	Allocation from Total To Electric (Note K)	Allocation from Electric to Transmission (Note K)
k1	Market Research	Other	$ 18,362	$ 20,335	0.00%	$ -	$ -	0.00%	0.00%
k2	Facilities	Allocation To Transmission	$ 38,233	$ 58,423	7.71%	$ 2,950	$ 4,507	78.08%	9.88%
k3	Land Leasing	Other	$ 25,621	$ 23,723	0.00%	$ -	$ -	0.00%	0.00%
k4	Fleet Activity	Allocation To Transmission	$ 310,312	$ 321,536	7.71%	$ 23,940	$ 24,806	78.08%	9.88%
k5	Membership dues	Other	$ 400,521	$ 400	0.00%	$ -	$ -	0.00%	0.00%
k6	IT Service Contracts	Allocation To Transmission	$ 588,153	$ 598,296	7.71%	$ 45,375	$ 46,157	78.08%	9.88%
k7	IT Service Contracts	Allocation To Transmission	$ 22,386	$ -	7.91%	$ 1,772	$ -	80.09%	9.88%
k8	IT Service Contracts	Other	$ 694,167	$ 1,317,780	0.00%	$ -	$ -	0.00%	0.00%
k9	Postage	Other	$ 583,032	$ 650,426	0.00%	$ -	$ -	0.00%	0.00%
k10	Prepaid Rent - T	100% Transmission	$ 949,730	$ 1,334,854	100.00%	$ 949,730	$ 1,334,854	100.00%	100.00%
k11	Prepaid Rent - D	Other	$ 238,112	$ 229,628	0.00%	$ -	$ -	0.00%	0.00%
k12	Prepaid Rent - G	Other	$ 52,410	$ 46,934	0.00%	$ -	$ -	0.00%	0.00%
k13	Prepaid gross receipts tax	Other	$ 6,399,988	$ -	0.00%	$ -	$ -	0.00%	0.00%
k14	Prepaid property tax	Allocation To Transmission	$ 1,886,145	$ -	7.71%	$ 145,512	$ -	78.08%	9.88%
k15	PUC Assessment	Other	$ 5,105,478	$ 4,635,979	0.00%	$ -	$ -	0.00%	0.00%
k16	Retention Incentive	Allocation To Transmission	$ 20,417	$ 13,000	7.91%	$ 1,616	$ 1,029	80.09%	9.88%
k17	Marketing	Other	$ 48,748	$ 236,261	0.00%	$ -	$ -	0.00%	0.00%
k18	VEBA	Allocation To Transmission	$ (12)	$ 834,281	7.91%	$ (1)	$ 66,022	80.09%	9.88%
k19	Equipment Maintenance	100% Transmission	$ -	$ 13,435	100.00%	$ -	$ 13,435	100.00%	100.00%
k20	Equipment Maintenance	Other	$ -	$ 126,509	0.00%	$ -	$ -	0.00%	0.00%
k21	New Business	Other	$ -	$ 173,775	0.00%	$ -	$ -	0.00%	0.00%
...									
Kxxx									
	Total Sum(lines K1 to Kxxx)		17,381,802	10,635,574		1,170,892	1,490,809		

Attachment 4A
PECO Energy Company
ADIT Worksheet for Projection

For Projection
Page 1 of 2

Projection for the 12 months ended 12/31/2018

ADIT for the Projection

	(a) Beginning Balance & Monthly Changes	(b) Month	(c) Year	(d) Weighting for Projection	(e) Beginning Balance/ Monthly Increment	(f) 100% Transmission	(g) 100% Allocator (f) x Allocator **100%**	(h) (Note A) Plant Related	(i) GP Allocator (h) x Allocator 0.1913 From Attach H Page 2, Line 18	(j) Labor Related	(k) S/W Allocator (j) x Allocator 0.0988 From Attach H Page 4, Line 16	(l) Total ADIT (d) x [(g)+(i)+(k)]
		ADIT- 282										
1	Balance	December	2018	100.00%	-	(189,143,729)	(189,143,729)	-	-	(30,828,318)	(3,046,029)	(192,189,758)
2	Increment	January	2019	91.78%	-	(144,634)	(144,634)	-	-	(78,958)	(7,802)	(139,906)
3	Increment	February	2019	84.11%	-	(144,634)	(144,634)	-	-	(78,958)	(7,802)	(128,213)
4	Increment	March	2019	75.62%	-	(144,634)	(144,634)	-	-	(78,958)	(7,802)	(115,266)
5	Increment	April	2019	67.40%	-	(144,634)	(144,634)	-	-	(78,958)	(7,802)	(102,737)
6	Increment	May	2019	58.90%	-	(144,634)	(144,634)	-	-	(78,958)	(7,802)	(89,791)
7	Increment	June	2019	50.68%	-	(144,634)	(144,634)	-	-	(78,958)	(7,802)	(77,262)
8	Increment	July	2019	42.19%	-	(144,634)	(144,634)	-	-	(78,958)	(7,802)	(64,315)
9	Increment	August	2019	33.70%	-	(144,634)	(144,634)	-	-	(78,958)	(7,802)	(51,369)
10	Increment	September	2019	25.48%	-	(144,634)	(144,634)	-	-	(78,958)	(7,802)	(38,840)
11	Increment	October	2019	16.99%	-	(144,634)	(144,634)	-	-	(78,958)	(7,802)	(25,893)
12	Increment	November	2019	8.77%	-	(144,634)	(144,634)	-	-	(78,958)	(7,802)	(13,364)
13	Increment	December	2019	0.27%	-	(144,634)	(144,634)	-	-	(78,958)	(7,802)	(418)
14	Sum Ties to December		2019	Balance	-	(190,879,334)	(190,879,334)	-	-	(31,775,814)	(3,139,648)	(193,037,131)
15	Increment	Not Subject to Proration	2019			(6,976,032)	(6,976,032)	-	-	-	-	(6,976,032)
16	Total					(197,855,366)	(197,855,366)	-	-	(31,775,814)	(3,139,648)	(200,013,163)
		ADIT-283										
17	Balance	December	2018		-	-	-	(5,581,934)	(1,067,671)	(108,797,636)	(10,749,882)	(11,817,553)
18	Balance	December	2019		-	-	-	(5,581,934)	(1,067,671)	(108,674,258)	(10,737,692)	(11,805,363)
19		Average			-	-	-	(5,581,934)	(1,067,671)	(108,735,947)	(10,743,787)	(11,811,458)
		ADIT-281										
20	Balance	December	2018		Zero	Zero	Zero	Zero	Zero	Zero	Zero	Zero
21	Balance	December	2019		Zero	Zero	Zero	Zero	Zero	Zero	Zero	Zero
22		Average			Zero	Zero	Zero	Zero	Zero	Zero	Zero	Zero
		ADIT-190										
23	Balance	December	2018	100.00%	-	-	-	13,690,676	2,618,650	131,938,478	13,036,341	15,654,992
24	Increment	January	2019	91.78%	-	-	-	-	-	-	-	-
25	Increment	February	2019	84.11%	-	-	-	-	-	-	-	-
26	Increment	March	2019	75.62%	-	-	-	-	-	-	-	-
27	Increment	April	2019	67.40%	-	-	-	-	-	-	-	-
28	Increment	May	2019	58.90%	-	-	-	-	-	-	-	-
29	Increment	June	2019	50.68%	-	-	-	-	-	-	-	-
30	Increment	July	2019	42.19%	-	-	-	-	-	-	-	-
31	Increment	August	2019	33.70%	-	-	-	-	-	-	-	-
32	Increment	September	2019	25.48%	-	-	-	-	-	-	-	-
33	Increment	October	2019	16.99%	-	-	-	-	-	-	-	-
34	Increment	November	2019	8.77%	-	-	-	-	-	-	-	-
35	Increment	December	2019	0.27%	-	-	-	13,690,676	2,618,650	125,601,855	12,410,244	15,028,894
36	Sum Ties to December		2019	Balance	-							15,341,943
	Line 36, If there are no items subject to proration, use average of lines 23 and 35											
37	Total ADIT											(196,482,678)

PECO Energy Company
ADIT Worksheet for True-Up

ADIT for True-Up

True-Up for the 12 months ended 12/31/2018

	(a) Balance	(b) Month	(c) Year	(d) Weighting for Projection	(e) Balance from ADIT BOY and ADIT EOY workpapers	(f) 100% Transmission	(g) 100% Allocator (f) x Allocator **100%**	(h) (Note A) Plant Related	(i) GP Allocator (h) x Allocator 0.1913 From Attach H Page 2, Line 18	(j) Labor Related	(k) S/W Allocator (j) x Allocator 0.0988 From Attach H Page 4, Line 16	(l) Total ADIT (d) x [(g)+(i)+(k)]
		ADIT- 282										
38	Balance	December	2017		(1,118,346,778)	(168,632,330)		-	-	(31,676,057)		
39	Balance	December	2018		(1,139,022,726)	(189,143,729)		-	-	(30,828,318)		
40		Average			(1,128,684,752)	(178,888,029)	(178,888,029)	-	-	(31,252,187)	(3,087,910)	(181,975,940)
		ADIT-283										
41	Balance	December	2017		(142,375,991)	-	-	(6,199,185)	(1,185,734)	(109,156,435)	(10,785,334)	
42	Balance	December	2018		(139,156,936)	-	-	(5,581,934)	(1,067,671)	(108,797,636)	(10,749,882)	
43		Average			(140,766,463)	-	-	(5,890,559)	(1,126,702)	(108,977,035)	(10,767,608)	(11,894,311)
		ADIT-281										
44	Balance	December	2017		Zero	Zero	Zero	Zero	Zero	Zero	Zero	Zero
45	Balance	December	2018		Zero	Zero	Zero	Zero	Zero	Zero	Zero	Zero
46		Average			Zero	Zero	Zero	Zero	Zero	Zero	Zero	Zero
		ADIT-190										
47	Balance	December	2017		185,826,860	-	-	7,420,671	1,419,371	149,256,889	14,747,508	16,166,879
48	Balance	December	2018		178,589,500	-	-	13,690,676	2,618,650	131,938,478	13,036,341	15,654,992
49		Average			182,208,180	-	-	10,555,673	2,019,011	140,597,683	13,891,925	15,910,935

Note:

A Plant Related ADIT reflects the total Electric plant related ADIT from Attachment 4B and 4C, which is allocated to transmission in Column (i) with GP allocation factor.

Attachment 4B
PECO Energy Company

ADIT BOY Worksheet

	A	B Total	C Gas, Prod, Retail Or Other Related	D Only Transmission Related	E Plant Related	F Labor Related	
a	*ADIT- 282*	(1,118,346,778)		(168,632,330)	-	(31,676,057)	(From line 17 for the column)
b	*ADIT-283*	(142,375,991)		-	(6,199,185)	(109,156,435)	(From line 29 for the column)
c	*ADIT-190*	185,826,860		-	7,420,671	149,256,889	(From line 5 for the column)
d	*Subtotal*	(1,074,895,909)		(168,632,330)	1,221,486	8,424,397	(Sum a - c)

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.

Line	A *ADIT-190 (Attachment H-7 Notes P and Q)*	B *Total*	C *Gas, Prod Retail Or Other Related*	D *Only Transmission Related*	E *Plant Related*	F *Labor Related*	G *Justification*
1	ACCRUED BENEFITS	849,467	849,467	-	-	-	Related to employer costs of benefits, such as health insurance, 401 (k), etc. The amounts are recorded to the liability and cleared through payments during each bi-weekly payroll. Any balance in the account at the end of the month would relate to the month-end accrual that is recorded at the end of the month and reversed on the first calendar day of the next month. As such, there is a book to tax timing difference.
1a	ADDBACK OF NQSO EXPENSE	1,877,516	-	-	-	1,877,516	No current book activity, tax deducts as distributions are made from the trust - employees in all functions.
1b	ADDBACK OF OTHER EQUITY COMP EXPENSE	1,247,830	-	-	-	1,247,830	Book expense recorded when stock is granted, tax expense when stock is issued at market price - employees in all functions.
1c	AMORT-ORGANIZATIONAL COSTS	-	-	-	-	-	Excluded because the underlying account(s) are not included in model
1d	BAD DEBT - CHANGE IN PROVISION	13,778,093	13,778,092	-	-	-	Retail bad debt. For book, expense taken as it's identified; tax deduction not taken until fully written-off and all collection efforts abandoned. Relates to retail operations.
1e	CHARITABLE CARRYFORWARD	1,570,195	1,570,195	-	-	-	Excluded because the underlying account(s) are not included in model
1f	CUSTOMER ADVANCES - CONSTRUCTION	158,593	158,593	-	-	-	Excluded because the underlying account(s) are not included in model
1g	DEFERRED COMPENSATION	2,077,910	2,077,910	-	-	-	Book records estimated accrued compensation; tax deducts only upon the retirement or other separation from service by the employees. Relates to all functions.
1h	DEFERRED REVENUE	220,916	220,916	-	-	-	Excluded because the underlying account(s) are not included in model
1i	FAS 112	207,942	-	-	-	207,942	Employer provided benefits to former employees but before retirement.
1j	FEDERAL NOL	1,141,419	-	-	1,141,419	-	PECO is in a net operating loss situation, therefore, losses are carried forward until such losses can be applied to taxable income.
1k	FIN 47 ARO	-	-	-	-	-	Accrual of future removal/retirements. Book recognized the expense estimate accrual, tax recognizes when paid. Related to all functions. ARO must be approved by FERC in order to include amounts.
1l	Gross Up-Bill E Credit	9,573,744	9,573,744	-	-	-	Excluded because the underlying account(s) are not included in model
1m	INCENTIVE PAY	9,947,772	-	-	-	9,947,772	Book records an accrual in filing year on estimated payouts; tax reverses the accrual and deducts the actual paid out. Relates to all functions.
1n	INJURIES AND DAMAGE PAYMENTS	-	-	-	-	-	Books records an estimated liability for injuries and damages; tax purposes a deduction is only taken when actual payments are made.
1o	MERGER COSTS NC	-	-	-	-	-	Excluded because the underlying account(s) are not included in model
1p	DEFFERRED CHARGES - TAX REPAIRS BILL CREDIT-DI	1,153,652	1,153,652	-	-	-	Excluded because the underlying account(s) are not included in model
1q	OBSOLETE MATERIALS PROVISION	429,796	429,796	-	-	-	Excluded because the underlying account(s) are not included in model
1r	OTHER CURRENT	0	0	-	-	-	
1s	FACILITY COMMITMENT FEES	10,794	-	-	10,794	-	Debt related
1t	FINES & OTHER	192,052	192,052	-	-	-	Excluded because the underlying account(s) are not included in model
1u	OTHER NONCURRENT- RAILROAD LIABILITY	83,758	-	-	83,758	-	Related to reserve for required maintenance on right of ways.
1v	OTHER UNEARNED REVENUE-DEFERRED RENTS	265,981	-	-	265,981	-	Rent expense deferred and amortized ratably for books, tax deduction when paid - used for all functions.
1w	PAYROLL TAXES	626,979	-	-	-	626,979	Book records a payroll tax accrual; tax reverses the accrual and deducts the actual amount paid out. Relates to all functions.
1x	PENNSYLVANIA NOL	6,078,222	-	-	6,078,222	-	PECO is in a net operating loss situation, therefore, losses are carried forward until such losses can be applied to taxable income.
1y	PENSION EXPENSE PROVISION	-	-	-	-	-	Book accrues and capitalizes anticipated Pension costs based on actuarial analysis. Tax deducts or capitalizes retirement benefits only when the amounts are paid. Related to all functions.
1z	POLE ATTACHMENT RESERVE	-	-	-	-	-	Excluded because the underlying account(s) are not included in model
1aa	POST RETIREMENT BENEFITS	77,957,835	-	-	-	77,957,835	Book accrues anticipated post retirement costs based on actuarial analysis. Tax deducts retirement benefits only when the amounts are paid or contributed to a fund.
1ab	RESERVE FOR EMPLOYEE LITIGATIONS Current	-	-	-	-	-	Related to reserves associated with ongoing and/or pending litigation. These are not legal service fees, but accrual for possible liability payments upon resolution of ongoing litigation matters. Since we have accrued, but not yet paid, we have to book the tax reserve.
1ac	SA UNBILLED RESERVE	3,827,688	3,827,688	-	-	-	Retail related
1ad	SECA REFUND	-	-	-	-	-	Retail related
1ae	SEPTA RAILROAD RENT	-	-	-	-	-	Reserve for potential transmission rent expense
1af	SEVERANCE PMTS CHANGE IN PROVISION	61,677	-	-	-	61,677	Book records an accrual; tax takes the deduction when actually paid. Relates to all functions.
1ag	VACATION PAY CHANGE IN PROVISION	1,004,916	1,004,916	-	-	-	Capitalized portion of vacation pay earned and expensed for books, tax takes the deduction when paid out. Related to all functions.
1ah	VEGETATION MGMT ACCRUAL	1,560,924	1,560,924	-	-	-	Excluded because the underlying account(s) are not included in model
1ai	WORKERS COMPENSATION RESERVE	10,806,431	-	-	-	10,806,431	These accounts are reserves for public claims, workers compensation and other third party incidents. For tax purposes these are not deductible until paid. Related to all functions.
1aj							
2	**Subtotal - p234.8.b**	146,712,102	36,397,945	-	7,580,174	102,733,982	
3	**Less FASB 109 Above if not separately removed**	(39,114,758)	7,248,646	-	159,503	(46,522,907)	
4	**Less FASB 106 Above if not separately removed**						
5	**Total**	185,826,860	29,149,299	-	7,420,671	149,256,889	

6 **Instructions for Account 190:**
7 **1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C**
8 **2. ADIT items related only to Transmission are directly assigned to Column D**
9 **3. ADIT items related to Plant other than general plant, intangible plant or common plant and not in Columns C & D are included in Column E**
10 **4. ADIT items related to labor, general plant, intangible plant, or common plant and not in Columns C & D are included in Column F**
11 **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,**
12 **the associated ADIT amount shall be excluded**

PECO Energy Company

ADIT BOY Worksheet

	A	B	C	D	E	F	G
	ADIT- 282 (Attachment H-7 Notes N and Q)	*Total*	*Gas, Prod Retail Or Other Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
13a	Property Related ADIT, Excl. ARO	-	-	-	-	-	
13b	Common	(28,709,490)	-	-	-	(28,709,490)	Included because plant in service is included in rate base.
13c	Distribution	(1,121,038,511)	(1,121,038,511)	-	-	-	Related to Distribution property.
13d	Electric General	(3,411,310)	-	-	-	(3,411,310)	Included because plant in service is included in rate base.
13e	Transmission	(213,299,037)	-	(213,299,037)	-	-	Included because plant in service is included in rate base.
13f							
13g							
13h							
…							
14	**Subtotal - p275.2.b**	(1,366,458,348)	(1,121,038,511)	(213,299,037)	-	(32,120,800)	
15	**Less FASB 109 Above if not separately removed**	(248,111,570)	(203,000,120)	(44,666,707)	-	(444,743)	
16	**Less FASB 106 Above if not separately removed**						
17	**Total (Line 14 - Line 15 - Line 16)**	(1,118,346,778)	(918,038,391)	(168,632,330)	-	(31,676,057)	

18 **Instructions for Account 282:**
19 **1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C**
20 **2. ADIT items related only to Transmission are directly assigned to Column D**
21 **3. ADIT items related to Plant other than general plant, intangible plant or common plant and not in Columns C & D are included in Column E**
22 **4. ADIT items related to labor, general plant, intangible plant, or common plant and not in Columns C & D are included in Column F**
23 **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,**
24 **the associated ADIT amount shall be excluded**

PECO Energy Company

ADIT BOY Worksheet

	A	B	C	D	E	F	G
	ADIT-283 (Attachment H-7 Notes O, P and Q)	*Total*	*Gas, Prod Retail Or Other Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
25	ACT 129 SMART METER	(6,674,279)	(6,674,279)	-	-	-	Retail related
25a	AEC RECEIVABLE	(1,172,108)	(1,172,108)	-	-	-	Retail related
25b	AMORT-BK-PREMIUMS ON REACQD DEBT-9.5%	(432,825)	-	-	(432,825)	-	Book recapitalizes costs incurred to retire or reacquire debt issuances. Tax deducts these costs when incurred.
25c	CAP FORGIVENESS REG ASSET	(2,105,889)	(2,105,889)	-	-	-	Retail related
25d	CAP SHOPPING REG ASSET	0	0	-	-	-	Retail related
25e	DSP 2 - REGULATORY ASSET	(74,577)	(74,577)	-	-	-	Retail related
25f	ELEC RATE CASE EXP - REG ASSET	(19,564)	(19,564)	-	-	-	Retail related
25g	ENERGY EFFICIENCY REG ASSET	(198,976)	(198,976)	-	-	-	Retail related
25h	Gross Up on State Def Tax Adj- AMR Reg Asset	(577,496)	(577,496)	-	-	-	Retail related
25i	HOLIDAY PAY CHANGE IN PROVISION	-	-	-	-	-	The book expense on Jan 1 of calendar year; accelerated tax expense taken in previous calendar year. Related to all functions.
25j	OCI-Def FIT & SIT	(568,355)	(568,355)	-	-	-	Excluded because the underlying account(s) are not included in model
25k	OTHER CURRENT REG ASSET:	-	-	-	-	-	0
25l	LOSS OF REAQUIRED DEBT	(153,763)	-	-	(153,763)	-	Book recapitalizes costs incurred to retire or reacquire debt issuances. Tax deducts these costs when incurred. Included in debt capitalization ratio on Appendix A, line 111.
25m	VACATION ACCRUAL	(1,461,442)	(1,461,442)	-	-	-	Current portion of vacation pay earned and expensed for books, tax takes the deduction when paid out. Related to all functions.
25n	SMART METER	(3,581,502)	(3,581,502)	-	-	-	Retail related
25o	CAP SHOPPING REG ASSET - CURRENT	(245,786)	(245,786)	-	-	-	Retail related
25p	CAP FORGIVENESS REG ASSET - CURRENT	(390,761)	(390,761)	-	-	-	Retail related
25q	FAS 112	(208,178)	-	-	-	(208,178)	Employer provided benefits to former employees but before retirement.
25r	ELEC RATE CASE EXP - REG ASSET - CURRENT	(127,943)	(127,943)	-	-	-	Property taxes. Book records on an accrual method based on the prior year; tax reverses the book accrual and deducts the actual payments made. . Relates to all functions.
25s	PURTA	4	4	-	-	-	Retail related
25t	SEAMLESS MOVES	(38,518)	(38,518)	-	-	-	Book accrues and capitalizes anticipated Pension costs based on actuarial analysis. Tax deducts or capitalizes retirement benefits only when the amounts are paid. Retail related.
25u	OTHER CURRENT REG ASSET	(2,217,430)	(2,217,430)	-	-	-	Gas Related
25v	PENSION EXPENSE PROVISION	(90,086,556)	-	-	-	(90,086,556)	Book accrues and capitalizes anticipated Pension costs based on actuarial analysis. Tax deducts or capitalizes retirement benefits only when the amounts are paid. Related to all functions.
25w	RATE CHANGE REG ASSET	(9,147,256)	(9,147,256)	-	-	-	Gross up related to non-property tax rate change/TCJA
25x	STATE TAX RESERVE	(3,254,291)	-	-	(3,254,291)	-	The state income tax is cash basis
25y							
25z							
25aa							
25ab							
25ac							
25ad							
25ae							
25af							
….							
….							
26	**Subtotal - p276.9.b**	(122,737,492)	(28,601,879)	-	(3,840,879)	(90,294,734)	
27	**Less FASB 109 Above if not separately removed**	19,638,499	(1,581,508)	-	2,358,306	18,861,701	
28	**Less FASB 106 Above if not separately removed**						
29	**Total**	(142,375,991)	(27,020,371)	-	(6,199,185)	(109,156,435)	

30 **Instructions for Account 283:**

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

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

33 **3. ADIT items related to Plant other than general plant, intangible plant or common plant and not in Columns C & D are included in Column E**

34 **4. ADIT items related to labor, general plant, intangible plant, or common plant and not in Columns C & D are included in Column F**

35 **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,**

36 **the associated ADIT amount shall be excluded**

Attachment 4C
PECO Energy Company

ADIT EOY Worksheet

	A	B	C	D	E	F	
			Gas, Prod	*Only*			
			Retail Or Other	*Transmission*	*Plant*	*Labor*	
		Total	*Related*	*Related*	*Related*	*Related*	
a	***ADIT- 282***	(1,139,022,726)		(189,143,729)	-	(30,828,318)	(From line 17 for the column)
b	***ADIT-283***	(139,156,936)		-	(5,581,934)	(108,797,636)	(From line 29 for the column)
c	***ADIT-190***	178,589,500		-	13,690,676	131,938,478	(From line 5 for the column)
d	***Subtotal***	(1,099,590,162)		(189,143,729)	8,108,741	(7,687,475)	(Sum a - c)

Line 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.

Line	A	B	C	D	E	F	G
	ADIT-190 (Attachment H-7 Notes P and Q)	***Total***	***Gas, Prod***	***Only***			
1			***Retail Or Other***	***Transmission***	***Plant***	***Labor***	
1a			***Related***	***Related***	***Related***	***Related***	***Justification***
1b							
1c	ACCRUED BENEFITS	237,053	237,053	-	-	-	Related to employer costs of benefits, such as health insurance, 401 (k), etc. The amounts are recorded to the liability and cleared through payments during each bi-weekly payroll. Any balance in the account at the end of the month would relate to the month-end accrual that is recorded at the end of the month and reversed on the first calendar day of the next month. As such, there is a book to tax timing difference.
1d	ADDBACK OF NQSO EXPENSE	1,773,851	-	-	-	1,773,851	No current book activity, tax deducts as distributions are made from the trust - employees in all functions.
1e	ADDBACK OF OTHER EQUITY COMP EXPENSE	1,863,208	-	-	-	1,863,208	Book expense recorded when stock is granted, tax expense when stock is issued at market price - employees in all functions.
1f	AMORT-ORGANIZATIONAL COSTS	-	-	-	-	-	Excluded because the underlying account(s) are not included in model
1g	BAD DEBT - CHANGE IN PROVISION	15,064,698	15,064,698	-	-	-	Retail bad debt. For book, expense taken as it's identified; tax deduction not taken until fully written-off and all collection efforts abandoned. Relates to retail operations.
1h	CHARITABLE CARRYFORWARD	1,013,502	1,013,502	-	-	-	Excluded because the underlying account(s) are not included in model
1i	CUSTOMER ADVANCES - CONSTRUCTION	335,650	335,650	-	-	-	Excluded because the underlying account(s) are not included in model
1j	DEFERRED COMPENSATION	1,698,133	1,698,133	-	-	-	Book records estimated accrued compensation; tax deducts only upon the retirement or other separation from service by the employees. Relates to all functions.
1k	DEFERRED REVENUE	225,134	225,134	-	-	-	Excluded because the underlying account(s) are not included in model
1l	FAS 112	18,627	-	-	-	18,627	Employer provided benefits to former employees but before retirement.
1m	FEDERAL NOL	-	-	-	-	-	PECO is in a net operating loss situation, therefore, losses are carried forward until such losses can be applied to taxable income.
1n	FIN 47 ARO	5,371,606	5,371,606	-	-	-	Accrual of future removal/retirements. Book recognized the expense estimate accrual, tax recognizes when paid. Related to all functions. ARO must be approved by FERC in order to include amounts.
1o	Gross Up-Bill E Credit	-	-	-	-	-	Excluded because the underlying account(s) are not included in model
1p	INCENTIVE PAY	9,990,749	-	-	-	9,990,749	Book records an accrual in filing year on estimated payouts; tax reverses the accrual and deducts the actual paid out. Relates to all functions.
1q	INJURIES AND DAMAGE PAYMENTS	-	-	-	-	-	Books records an estimated liability for injuries and damages; tax purposes a deduction is only taken when actual payments are made.
1r	MERGER COSTS NC	-	-	-	-	-	Excluded because the underlying account(s) are not included in model
1s	DEFFERRED CHARGES - TAX REPAIRS BILL CREDIT-DIST	67,489	67,489	-	-	-	Excluded because the underlying account(s) are not included in model
1t	OBSOLETE MATERIALS PROVISION	428,906	428,906	-	-	-	Excluded because the underlying account(s) are not included in model
1u	OTHER CURRENT	(15,328)	(15,328)	-	-	-	
1v	FACILITY COMMITMENT FEES	10,794	-	-	10,794	-	Debt related
1w	FINES & OTHER	192,052	192,052	-	-	-	Excluded because the underlying account(s) are not included in model
1x	OTHER NONCURRENT- RAILROAD LIABILITY	83,758	-	-	83,758	-	Related to reserve for required maintenance on right of ways.
1y	OTHER UNEARNED REVENUE-DEFERRED RENTS	262,092	-	-	262,092	-	Rent expense deferred and amortized ratably for books, tax deduction when paid - used for all functions.
1z	PAYROLL TAXES	-	-	-	-	-	Book records a payroll tax accrual; tax reverses the accrual and deducts the actual amount paid out. Relates to all functions.
1aa	PENNSYLVANIA NOL	13,825,356	-	-	13,825,356	-	PECO is in a net operating loss situation, therefore, losses are carried forward until such losses can be applied to taxable income.
1ab	PENSION EXPENSE PROVISION	-	-	-	-	-	Book accrues and capitalizes anticipated Pension costs based on actuarial analysis. Tax deducts or capitalizes retirement benefits only when the amounts are paid. Related to all functions.
1ac	POLE ATTACHMENT RESERVE	-	-	-	-	-	Excluded because the underlying account(s) are not included in model
1ad	POST RETIREMENT BENEFITS	71,389,972	-	-	-	71,389,972	Book accrues anticipated post retirement costs based on actuarial analysis. Tax deducts retirement benefits only when the amounts are paid or contributed to a fund.
1ae	RESERVE FOR EMPLOYEE LITIGATIONS Current	48,886	48,886	-	-	-	Related to reserves associated with ongoing and/or pending litigation. These are not legal service fees, but accrual for possible liability payments upon resolution of ongoing litigation matters. Since we have accrued, but not yet paid, we have to book the tax reserve.
1af	SA UNBILLED RESERVE	3,158,623	3,158,623	-	-	-	Retail related
1ag	SECA REFUND	-	-	-	-	-	Retail related
1ah	SEPTA RAILROAD RENT	132,515	132,515	-	-	-	Reserve for potential transmission rent expense
1ai	SEVERANCE PMTS CHANGE IN PROVISION	51,322	-	-	-	51,322	Book records an accrual; tax takes the deduction when actually paid. Relates to all functions.
1aj	VACATION PAY CHANGE IN PROVISION	1,145,678	1,145,678	-	-	-	Capitalized portion of vacation pay earned and expensed for books, tax takes the deduction when paid out. Related to all functions.
1ak	VEGETATION MGMT ACCRUAL	1,701,178	1,701,178	-	-	-	Excluded because the underlying account(s) are not included in model
1al	WORKERS COMPENSATION RESERVE	9,646,333	-	-	-	9,646,333	Related to all functions.
1am							
1an							
…		-					
2	**Subtotal - p234.8.c**	139,721,837	30,805,775	-	14,182,000	94,734,062	
3	**Less FASB 109 Above if not separately removed**	(38,867,663)	(2,154,571)	-	491,324	(37,204,416)	
4	**Less FASB 106 Above if not separately removed**						
5	**Total (Line 2 - Line 3 - Line 4)**	178,589,500	32,960,347	-	13,690,676	131,938,478	

6 **Instructions for Account 190:**
7 **1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C**
8 **2. ADIT items related only to Transmission are directly assigned to Column D**
9 **3. ADIT items related to Plant other than general plant, intangible plant or common plant and not in Columns C & D are included in Column E**
10 **4. ADIT items related to labor, general plant, intangible plant, or common plant and not in Columns C & D are included in Column F**
11 **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,**
12 **the associated ADIT amount shall be excluded**

Attachment 12 PECO Formula Rate Updated

PECO Energy Company

ADIT EOY Worksheet

	A	B	C	D	E	F	G
	ADIT- 282 (Attachment H-7 Notes N and Q)	*Total*	*Gas, Prod Retail Or Other Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
13a	Property Related ADIT, Excl. ARO	-	-	-	-	-	
13b	Common	(29,503,593)	-	-	-	(29,503,593)	Included because plant in service is included in rate base.
13c	Distribution	(1,188,168,321)	(1,188,168,321)	-	-	-	Related to Distribution property.
13d	Electric General	(3,041,661)	-	-	-	(3,041,661)	Included because plant in service is included in rate base.
13e	Transmission	(226,271,862)	-	(226,271,862)	-	-	Included because plant in service is included in rate base.
13f							
13g							
13h							
…							
14	**Subtotal - p275.2.k**	(1,446,985,437)	(1,188,168,321)	(226,271,862)	-	(32,545,254)	
15	**Less FASB 109 Above if not separately removed**	(307,962,711)	(269,117,641)	(37,128,133)	-	(1,716,937)	
16	**Less FASB 106 Above if not separately removed**						
17	**Total (Line 14 - Line 15 - Line 16)**	(1,139,022,726)	(919,050,680)	(189,143,729)	-	(30,828,318)	

18 **Instructions for Account 282:**
19 **1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C**
20 **2. ADIT items related only to Transmission are directly assigned to Column D**
21 **3. ADIT items related to Plant other than general plant, intangible plant or common plant and not in Columns C & D are included in Column E**
22 **4. ADIT items related to labor, general plant, intangible plant, or common plant and not in Columns C & D are included in Column F**
23 **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,**
24 **the associated ADIT amount shall be excluded**

PECO Energy Company

ADIT EOY Worksheet

	A	B	C	D	E	F	G
	ADIT-283 (Attachment H-7 Notes O, P and Q)	*Total*	*Gas, Prod Retail Or Other Related*	*Only Transmission Related*	*Plant Related*	*Labor Related*	*Justification*
25a	ACT 129 SMART METER	(3,337,244)	(3,337,244)	-	-	-	Retail related
25b	AEC RECEIVABLE	(848,268)	(848,268)	-	-	-	Retail related
25c	AMORT-BK-PREMIUMS ON REACQD DEBT-9.5%	(321,464)	-	-	(321,464)	-	Book recapitalizes costs incurred to retire or reacquire debt issuances. Tax deducts these costs when incurred.
25d	CAP FORGIVENESS REG ASSET	(417,587)	(417,587)	-	-	-	Retail related
25e	CAP SHOPPING REG ASSET	(1,350,453)	(1,350,453)	-	-	-	Retail related
25f	DSP 2 - REGULATORY ASSET	(68,443)	(68,443)	-	-	-	Retail related
25g	ELEC RATE CASE EXP - REG ASSET	(415,762)	(415,762)	-	-	-	Retail related
25h	ENERGY EFFICIENCY REG ASSET	(203,599)	(203,599)	-	-	-	Retail related
25i	Gross Up on State Def Tax Adj- AMR Reg Asset	(385,014)	(385,014)	-	-	-	Retail related
25j	HOLIDAY PAY CHANGE IN PROVISION	(242,518)	-	-	-	(242,518)	The book expense on Jan 1 of calendar year; accelerated tax expense taken in previous calendar year. Related to all functions.
25k	OCI-Def FIT & SIT	(575,647)	(575,647)	-	-	-	Excluded because the underlying account(s) are not included in model
25l	OTHER CURRENT REG ASSET:	-	-	-	-	-	0
25m	LOSS OF REAQUIRED DEBT	(111,361)	-	-	(111,361)	-	Book recapitalizes costs incurred to retire or reacquire debt issuances. Tax deducts these costs when incurred. Included in debt capitalization ratio on Appendix A, line 111.
25n	VACATION ACCRUAL	(1,595,005)	(1,595,005)	-	-	-	Current portion of vacation pay earned and expensed for books, tax takes the deduction when paid out. Related to all functions.
25o	SMART METER	(3,337,244)	(3,337,244)	-	-	-	Retail related
25p	CAP SHOPPING REG ASSET - CURRENT	(0)	(0)	-	-	-	Retail related
25q	CAP FORGIVENESS REG ASSET - CURRENT	(1,567,342)	(1,567,342)	-	-	-	Retail related
25r	FAS 112	(205,034)	-	-	-	(205,034)	Employer provided benefits to former employees but before retirement.
25s	ELEC RATE CASE EXP - REG ASSET - CURRENT	(0)	-	-	-	-	Property taxes. Book records on an accrual method based on the prior year; tax reverses the book accrual and deducts the actual payments made. . Relates to all functions.
25t	PURTA	-	-	-	-	-	Retail related
25u	SEAMLESS MOVES	(0)	-	-	-	(0)	Book accrues and capitalizes anticipated Pension costs based on actuarial analysis. Tax deducts or capitalizes retirement benefits only when the amounts are paid. Retail related.
25v	OTHER CURRENT REG ASSET	237,902	237,902	-	-	-	Gas Related
25w	PENSION EXPENSE PROVISION	(92,669,768)	-	-	-	(92,669,768)	Book accrues and capitalizes anticipated Pension costs based on actuarial analysis. Tax deducts or capitalizes retirement benefits only when the amounts are paid. Related to all functions.
25x	RATE CHANGE REG ASSET	(7,896,920)	(7,896,920)	-	-	-	Gross up related to non-property tax rate change/TCJA
25y	STATE TAX RESERVE	(3,278,057)	-	-	(3,278,057)	-	The state income tax is cash basis
25z	ARO- Reg Asset	(5,001,186)	(5,001,186)	-	-	-	
25aa							
….							
26	**Subtotal - p277.9.k**	(123,590,014)	(26,761,812)	-	(3,710,882)	(93,117,320)	
27	**Less FASB 109 Above if not separately removed**	15,566,922	(1,984,446)	-	1,871,052	15,680,316	
28	**Less FASB 106 Above if not separately removed**						
29	**Total**	(139,156,936)	(24,777,366)	-	(5,581,934)	(108,797,636)	

30 **Instructions for Account 283:**

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

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

33 **3. ADIT items related to Plant other than general plant, intangible plant or common plant and not in Columns C & D are included in Column E**

34 **4. ADIT items related to labor, general plant, intangible plant, or common plant and not in Columns C & D are included in Column F**

35 **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,**

36 **the associated ADIT amount shall be excluded**

Attachment 12 PECO Formula Rate Updated

PECO Energy Company

Attachment 4D - Intangible Plant Workpaper

Total Intangible Plant

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)
	Gross Plant	December Prior Year	January	February	March	April	May	June	July	August	September	October	November	December	Average	Transmission	Distribution	S&W Allocation	Total
															=average(b:n)				=sum(p:r)
1	Intangible - General	14,332,650	14,136,583	14,801,490	14,869,821	14,943,858	14,970,484	14,978,733	20,578,022	15,197,537	15,262,142	15,660,305	17,439,743	18,519,045	15,822,339			15,822,339	15,822,339
2	IT NERC CIP - Transmission	11,298,011	11,294,489	11,289,320	11,296,202	11,536,480	11,542,795	11,558,969	11,561,527	11,578,318	11,588,653	11,593,637	11,596,262	11,596,262	11,486,994	11,486,994			11,486,994
3	IT NERC CIP - Distribution	2,042,317	2,051,798	2,046,629	2,053,511	2,083,101	2,086,543	2,249,189	2,274,331	2,299,650	2,321,298	2,329,656	2,369,415	2,369,415	2,198,219		2,198,219		2,198,219
4	IT DSP - Distribution	2,231,384	2,231,384	2,255,383	2,262,909	2,231,384	2,231,384	2,231,384	2,231,384	2,231,384	2,231,384	2,231,384	2,231,384	2,872,703	2,284,987		2,284,987		2,284,987
5	IT Business Intelligence Data Analysis - Distribution	16,094,656	16,318,757	16,318,757	16,318,757	16,318,757	16,318,757	16,318,757	16,318,757	16,318,757	16,318,757	16,318,757	16,318,757	16,318,757	16,301,518		16,301,518		16,301,518
6	IT Post 2010 and Other - Distribution	19,638,254	19,638,254	19,638,254	19,638,254	19,638,254	19,638,254	19,638,254	19,638,254	19,638,254	19,638,254	19,638,254	19,638,254	19,607,929	19,635,921		19,635,921		19,635,921
7	IT Smart Meter - Distribution	86,110,084	86,110,084	86,110,084	86,110,084	86,110,084	86,110,084	86,110,084	86,110,084	86,110,084	86,110,084	86,110,084	86,110,084	86,110,084	86,110,084		86,110,084		86,110,084
8	IT Other - Transmission	-	-	-	-	-	-	-	-	5,552,297	5,552,297	5,552,297	5,552,297	5,552,297	2,135,499	2,135,499			2,135,499
9																			-
10																			-
11																			-
12																			-
13																			-
14																			-
15																			-
16																			-
17																			-
18																			-
19	Total	151,747,354	151,781,348	152,459,916	152,549,537	152,861,917	152,898,300	153,085,369	158,712,359	158,926,280	159,022,870	159,434,374	161,256,195	162,946,492	155,975,562	13,622,493	126,530,730	15,822,339	155,975,562
20															Allocation Factor	100.00%	0.00%	9.88%	
21															Total Intangible - Transmission	13,622,493	-	1,563,345	15,185,839

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)
	Accumulated Depreciation	December Prior Year	January	February	March	April	May	June	July	August	September	October	November	December	Average	Transmission	Distribution	S&W Allocation	Total
															=average(b:n)				=sum(p:r)
22	Intangible - General	4,923,132	5,132,603	5,345,563	5,587,710	5,807,851	6,028,078	6,248,564	6,510,788	6,774,640	6,998,926	7,226,657	7,470,595	7,733,452	6,291,428			6,291,428	6,291,428
23	IT NERC CIP - Transmission	4,031,408	4,219,675	4,407,875	4,596,093	4,786,380	4,978,743	5,171,299	5,364,011	5,556,885	5,749,989	5,943,229	6,136,668	6,329,993	5,174,788	5,174,788			5,174,788
24	IT NERC CIP - Distribution	586,795	621,373	655,997	690,638	725,599	760,850	797,490	835,695	874,332	913,377	952,691	992,453	1,032,561	803,065		803,065		803,065
25	IT DSP - Distribution	1,961,801	1,994,879	2,028,156	2,061,698	2,094,112	2,126,172	2,157,214	2,188,256	2,205,310	2,208,378	2,211,445	2,214,513	2,222,925	2,128,835		2,128,835		2,128,835
26	IT Business Intelligence Data Analysis - Distribution	1,493,220	1,694,774	1,897,885	2,100,996	2,304,107	2,507,218	2,710,329	2,913,440	3,116,551	3,319,661	3,522,772	3,725,883	3,928,994	2,710,449		2,710,449		2,710,449
27	IT Post 2010 and Other - Distribution	15,209,326	15,346,557	15,483,788	15,621,019	15,758,250	15,895,481	16,032,712	16,169,943	16,307,174	16,444,405	16,581,636	16,718,867	16,855,601	16,032,674		16,032,674		16,032,674
28	IT Smart Meter - Distribution	65,618,582	66,529,345	67,440,107	68,155,995	68,569,770	68,983,545	69,397,319	69,811,094	70,224,869	70,633,908	71,030,255	71,418,645	71,779,518	69,199,458		69,199,458		69,199,458
29	IT Other - Transmission	-	-	-	-	-	-	-	-	113,602	360,816	608,029	855,243	1,102,456	233,857	233,857			233,857
30																			-
31																			-
32																			-
33																			-
34																			-
35																			-
36																			-
37																			-
38																			-
39																			-
40	Total	93,824,262	95,539,205	97,259,372	98,814,149	100,046,069	101,280,086	102,514,927	103,793,227	105,173,364	106,629,461	108,076,715	109,532,866	110,985,499	102,574,554	5,408,646	90,874,481	6,291,428	102,574,554
41															Allocation Factor	100.00%	0.00%	9.88%	
42															Total Intangible - Transmission	5,408,646	-	621,632	6,030,278

PECO Energy Company

Attachment 4D - Intangible Plant Workpaper

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)
	Net Plant in Service	December Prior Year	January	February	March	April	May	June	July	August	September	October	November	December	Average	Transmission	Distribution	S&W Allocation	Total
	Gross Plant Minus Accumulated Depreciation														=average(b:n)				=sum(p:r)
43	Intangible - General	9,409,518	9,003,980	9,455,926	9,282,111	9,136,006	8,942,405	8,730,169	14,067,234	8,422,897	8,263,216	8,433,648	9,969,148	10,785,593	9,530,912			9,530,912	9,530,912
44	IT NERC CIP - Transmission	7,266,603	7,074,814	6,881,445	6,700,109	6,750,100	6,564,053	6,387,670	6,197,516	6,021,433	5,838,664	5,650,407	5,459,595	5,266,270	6,312,206	6,312,206			6,312,206
45	IT NERC CIP - Distribution	1,455,522	1,430,426	1,390,633	1,362,873	1,357,502	1,325,693	1,451,699	1,438,635	1,425,317	1,407,921	1,376,965	1,376,962	1,336,854	1,395,154		1,395,154		1,395,154
46	IT DSP - Distribution	269,583	236,506	227,226	201,211	137,272	105,212	74,170	43,128	26,074	23,006	19,939	16,871	649,778	156,152		156,152		156,152
47	IT Business Intelligence Data Analysis - Distribution	14,601,436	14,623,983	14,420,872	14,217,761	14,014,650	13,811,539	13,608,428	13,405,317	13,202,206	12,999,096	12,795,985	12,592,874	12,389,763	13,591,070		13,591,070		13,591,070
48	IT Post 2010 and Other - Distribution	4,428,928	4,291,697	4,154,466	4,017,235	3,880,004	3,742,773	3,605,542	3,468,311	3,331,080	3,193,849	3,056,617	2,919,386	2,752,327	3,603,247		3,603,247		3,603,247
49	IT Smart Meter - Distribution	20,491,501	19,580,739	18,669,976	17,954,088	17,540,314	17,126,539	16,712,764	16,298,990	15,885,215	15,476,176	15,079,829	14,691,439	14,330,566	16,910,626		16,910,626		16,910,626
50	IT Other - Transmission	-	-	-	-	-	-	-	-	5,438,695	5,191,482	4,944,268	4,697,055	4,449,841	1,901,642	1,901,642			1,901,642
51		-	-	-	-	-	-	-	-	-	-	-	-	-	-		-		-
52		-	-	-	-	-	-	-	-	-	-	-	-	-					-
53		-	-	-	-	-	-	-	-	-	-	-	-	-					-
54		-	-	-	-	-	-	-	-	-	-	-	-	-					-
55		-	-	-	-	-	-	-	-	-	-	-	-	-					-
56		-	-	-	-	-	-	-	-	-	-	-	-	-					-
57		-	-	-	-	-	-	-	-	-	-	-	-	-					-
58		-	-	-	-	-	-	-	-	-	-	-	-	-					-
59		-	-	-	-	-	-	-	-	-	-	-	-	-					-
60		-	-	-	-	-	-	-	-	-	-	-	-	-					-
61	Total	57,923,092	56,242,144	55,200,544	53,735,388	52,815,848	51,618,214	50,570,442	54,919,132	53,752,916	52,393,409	51,357,659	51,723,329	51,960,993	53,401,008	8,213,848	35,656,249	9,530,912	53,401,008
62															Allocation Factor	100.00%	0.00%	9.88%	
63															Total Intangible - Transmission	8,213,848	-	941,713	9,155,561

	(a)	(b)	(c)	(d)	(e)	(f)
		Total	Transmission	Distribution	S&W Allocation	Total
	Depreciation Expense					=sum(c:e)
64	Intangible - General	2,811,571			2,811,571	2,811,571
65	IT NERC CIP - Transmission	2,298,585	2,298,585			2,298,585
66	IT NERC CIP - Distribution	445,766		445,766		445,766
67	IT DSP - Distribution	-		-		-
68	IT Business Intelligence Data Analysis - Distribution	458,584		458,584		458,584
69	IT Post 2010 and Other - Distribution	5,526,523		5,526,523		5,526,523
70	IT Smart Meter - Distribution	6,160,935		6,160,935		6,160,935
71	IT Other - Transmission	1,102,456	1,102,456			1,102,456
72		-				-
73		-				-
74		-				-
75		-				-
76		-				-
77		-				-
78		-				-
79		-				-
80		-				-
81		-				-
82	Total	18,804,420	3,401,041	12,591,808	2,811,571	18,804,420
83		Allocation Factor	100.00%	0.00%	9.88%	
84		Total Intangible - Transmission	3,401,041	-	277,801	3,678,842

PECO Energy Company

Attachment 4E - Cost to Achieve Mergers (Note A)

	(a)	(b)	(c)	(d)	(e)	(…)	(x)
	O&M Cost To Achieve						
	FERC Account	Constellation Merger	PHI Merger				Total
1	923	0	$ 609,158				$ 609,158
2	926	0	$ -				$ -
3	920		$ 2,747				$ 2,747
4							$ -
5							$ -
6							$ -
7							$ -
8							$ -
9							$ -
10							$ -
11	Total	$ -	$ 611,905				$ 611,905

	Capital Cost To Achieve included in the Electric Portion of Common Plant						
	Gross Plant	Constellation Merger	PHI Merger				Total
12	December Prior Year	-	714,419				$ 714,419
13	January	-	2,779,127				$ 2,779,127
14	February	-	3,042,854				$ 3,042,854
15	March	-	3,132,688				$ 3,132,688
16	April	-	3,143,588				$ 3,143,588
17	May	-	3,181,867				$ 3,181,867
18	June	-	3,187,594				$ 3,187,594
19	July	-	3,198,607				$ 3,198,607
20	August	-	3,225,632				$ 3,225,632
21	September	-	3,240,064				$ 3,240,064
22	October	-	3,231,099				$ 3,231,099
23	November	-	3,234,787				$ 3,234,787
24	December	-	3,229,861				$ 3,229,861
25	Average	-	2,964,784				2,964,784

	Accumulated Depreciation	Constellation Merger	PHI Merger				Total
26	December Prior Year	-	89,830				$ 89,830
27	January	-	153,204				$ 153,204
28	February	-	203,767				$ 203,767
29	March	-	255,478				$ 255,478
30	April	-	304,640				$ 304,640
31	May	-	356,808				$ 356,808
32	June	-	407,269				$ 407,269
33	July	-	458,129				$ 458,129
34	August	-	510,101				$ 510,101
35	September	-	562,757				$ 562,757
36	October	-	608,211				$ 608,211
37	November	-	662,547				$ 662,547
38	December	-	711,767				$ 711,767
39	Average	-	406,500				406,500

PECO Energy Company

Attachment 4E - Cost to Achieve Mergers (Note A)

	(a)	(b)	(c)	(d)	(e)	(…)	(x)
	Net Plant = Gross Plant Minus Accumulated Depreciation from above	Constellation Merger	PHI Merger				Total
40	December Prior Year	-	624,589	-	-	-	$ 624,589
41	January	-	2,625,923	-	-	-	$ 2,625,923
42	February	-	2,839,087	-	-	-	$ 2,839,087
43	March	-	2,877,210	-	-	-	$ 2,877,210
44	April	-	2,838,948	-	-	-	$ 2,838,948
45	May	-	2,825,060	-	-	-	$ 2,825,060
46	June	-	2,780,325	-	-	-	$ 2,780,325
47	July	-	2,740,478	-	-	-	$ 2,740,478
48	August	-	2,715,532	-	-	-	$ 2,715,532
49	September	-	2,677,307	-	-	-	$ 2,677,307
50	October	-	2,622,889	-	-	-	$ 2,622,889
51	November	-	2,572,240	-	-	-	$ 2,572,240
52	December	-	2,518,094	-	-	-	$ 2,518,094
53	Average	-	2,558,283	-	-	-	2,558,283

	Depreciation (Monthly Change of Accumulated Depreciation from above)	Constellation Merger	PHI Merger				Total
54	January	-	63,374				$ 63,374
55	February	-	50,563				$ 50,563
56	March	-	51,712				$ 51,712
57	April	-	49,161				$ 49,161
58	May	-	52,168				$ 52,168
59	June	-	50,461				$ 50,461
60	July	-	50,860				$ 50,860
61	August	-	51,972				$ 51,972
62	September	-	52,656				$ 52,656
63	October	-	45,454				$ 45,454
64	November	-	54,336				$ 54,336
65	December	-	49,220				$ 49,220
66	Total	-	621,937				$ 621,937

Note:

A: Merger-related costs incurred during hold harmless period are to be excluded from rate unless approved by FERC order.

Attachment 5
Attachment H-7, Pages 3 and 4, Worksheet
PECO Energy Company

Line No.	Month	Transmission O&M Expenses	Account No. 566 (Misc. Trans. Expense)	Account No. 565	Accounts 561.4 and 561.8	Amortization of Regulatory Asset	Miscellaneous Transmission Expense (less amortization of regulatory asset)	Depreciation Expense - Transmission	Depreciation Expense - Common	Depreciation Expense - Transmission Intangible	Depreciation Expense - General Intangible	Depreciation Expense - Distribution
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
	Attachment H-7, Page 3, Line No.:	1	2	3		11	12	16				
	Form No. 1	321.112.b	321.97.b	321.96.b	321.88.b & 92.b	Portion of Account 566 (Attachment H-7 Notes T and Z)	Balance of Account 566	Attachment 8, Page 1, Line 11, Col J	Attachment 8, Page 2, Line 51, Col J	Attachment 8, Page 2, Line 10, Col J	Attachment 8, Page 2, Line 19, Col J	Attachment 8, Page 2, Line 22, Col J
1	Total	188,583,461	11,664,574	-	136,634,127	-	$ 11,664,574	$ 25,205,171	$ 25,075,521	$ 3,401,047	$ 2,811,569	$ 12,591,808

		Depreciation Expense - General	Amortization of Abandoned Plant	Labor Related Taxes	Labor Related Taxes to be Excluded	Plant Related Taxes	Excluded Taxes Per Attachment 5C Line 5	Other Included Taxes	Plant Related Taxes to be Excluded	Amortized Investment Tax Credit Consistent with (266.8.f & 266.17.f) - Transmission	Excess Deferred Income Tax Amortization - Transmission	Tax Effect of Permanent Differences - Transmission
		(a)	(b)	(c)	(d) (Note F)	(e)	(f)	(g)	(h) (Note F)	(i)	(j)	(k)
	Attachment H-7, Page 3, Line Number	17	19	23	24	26	27	28	29	38	39	40
	Form No. 1	Attachment 8, Page 1, Line 25, Col J	(Note S)	Attachment 5C Line 2	Attachment 5C Line 9	Attachment 5C Line 1	Attachment 5C Line 5	Attachment 5C Line 3	Attachment 5C Line 10	(Note E)	(Attachment H-7 Note G)	(Attachment H-7 Note W)
2	Total	$ 16,933,417	$ -	$ 12,636,392	$ -	$ 12,111,350	$ 131,044,354	$ 440,813	$ -	$ 3,979	$ 3,189,177	$ 296,018

Attachment 5
Attachment H-7, Pages 3 and 4, Worksheet
PECO Energy Company

		$
3	Long Term Interest (117, sum of 62.c through 67.c), Excluding LVT Interest (Note G)	129,261,613
4	Preferred Dividends (118.29c) (positive number)	-
5	Proprietary Capital	3,615,441,080
6	Less Preferred Stock	-
7	Less Account 216.1 (enter negative) (Note D)	-
8	Less Account 219.1 (enter negative)	(1,691,501)
9	Common Stock (Sum of Line 5 - Line 6 + Line 7 + Line 8)	3,613,749,579

			$	%	Cost	Weighted	
10	Long Term Debt (Note A)	(100% - Line 11, Col (%) - Line 12, Col (%))	3,126,726,301	46.39%	4.13%	1.92%	=WCLTD
11	Preferred Stock (Note B)	(Line 11, Col ($) / Line 13, Col ($))	-	-	-	0.00%	
12	Common Stock (Note C)	(Line 12, Col ($) / Line 13, Col ($))	3,613,749,579	53.61%	10.35%	5.55%	
13	Total	(Sum of Lines 10-12)	6,740,475,881			7.47%	=R

Notes:

A Long Term Debt balance will reflect the 13 month average of the balances, of which the 1st and 13th are found on page 112 lines 18.c & d to 21.c & d in the Form No. 1.

B Preferred Stock balance will reflect the 13 month average of the balances, of which the 1st and 13th are found on page 112 line 3.c & d in the Form No. 1

C Common Stock balance will reflect the 13 month average of the balances, of which the 1st and 13th are found on page 112 lines 3.c & d, 12.c & d, and 16.c & d in the Form No. 1 as shown on lines 10-12 above
A cap on the equity percentage of PECO's capital structure shall be 55.75%.
ROE will be supported in the original filing and no change in ROE may be made absent FERC authorization pursuant to a section 205 or section 206.

D The Account 216.1 balance is input only if positive number in the FERC Form No. 1 (112.12.c).

E Sum of transmission related electric and common amortized investment tax credit amounts. Total electric amount allocated to transmission as follows: (1) amounts solely related to transmission allocated 100% to transmission; (2) amounts solely related to distribution, gas or non-utility allocated 0% to transmission; (3) amounts related to electric general allocated using the wages and salaries allocator (Attachment H-7, p. 4, line 11, column (5)); (4) amount related to common plant allocated to transmission using the wages and salaries allocator (Attachment H-7, p. 4, line 11, column (5)), multiplied by common utility plant percent to electric (per FF1 page 356).

F Labor and Plant related taxes due to merger are to be excluded consistent with hold harmless commitment.

G All short-term interest related expense will be removed from the formula rate template.

PECO Energy Company
Attachment 5A - Revenue Credit Workpaper

	Account 454 - Rent from Electric Property		
1	Rent from Electric Property - Transmission Related, Subject to Sharing (Note 3)		7,551,396
2	Rent from Electric Property - Transmission Related, Pass to Customers (Note 3)		773,462
3	Total Rent Revenues	(Sum Lines 1 to 2)	8,324,858
	Account 456 & 456.1 - Other Electric Revenues (Note 1)		
4	Schedule 1A		$ 5,108,495
5	Firm Point to Point Service revenues for which the load is not included in the divisor received by transmission owner		$ 927,381
6	Revenues associated with transmission service not provided under the PJM OATT (Note 4)		-
7	Intercompany Professional Services		304,662
8	PJM Transitional Revenue Neutrality (Note 1)		-
9	PJM Transitional Market Expansion (Note 1)		-
10	Professional Services (Note 3)		-
11	Revenues from Directly Assigned Transmission Facility Charges (Note 2)		-
12	Rent or Attachment Fees associated with Transmission Facilities (Note 3)		-
13	Gross Revenue Credits	(Sum Lines 3, 4-12)	14,665,396
14	Less line 17g		(5,003,794)
15	Total Revenue Credits		9,661,602

Revenue Adjustment to determine Revenue Credit

16a	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 in line 2; provided, that the revenue credit on line 2 will not include revenues associated with transmission service the loads for which are included in the rate divisor in Attachment H-7, page 1, line 11.	-
16b	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.	
16c	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 and by department the revenues and costs associated with each secondary use (except for the cost of the associated income taxes). The cost associated with the secondary transmission use is 3/4 of the total department costs.	
17a	Revenues included in lines 1-11 which are subject to 50/50 sharing.	7,551,396
17b	Costs associated with revenues in line 17a	2,617,742
17c	Net Revenues (17a - 17b)	4,933,654
17d	50% Share of Net Revenues (17c / 2)	2,466,827
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.	80,775
17f	Net Revenue Credit (17d + 17e)	2,547,602
17g	Line 17f less line 17a	(5,003,794)
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.	-
19	Reserved	-
20	Total Account 454, 456 and 456.1	14,665,396
21	Reserved	

Attachment 12 PECO Formula Rate Updated

Attachment 5A - Revenue Credit Workpaper

Costs associated with revenues in line 17a

	Cost Item	Accounts booked to	Total Costs	Costs Allocation to Transmission (Note A)	Transmission Costs	S&W Allocation Factor	Costs Recovered Through A&G Costs
22a	Administrative and General Salaries	920000	678,532	75%	508,899	9.88%	67,043
22b	Employee Pensions and Benefits	926000	138,977	75%	104,233	9.88%	13,732
…							
23	Total Lines 22		$ 817,509		$ 613,132		$ 80,775

	FERC Account 454	Total Amount	Other	100% Transmission	Plant Related	Labor Related	Total
24a	Rent from Electric Distribution	$ 12,723,689	$ 12,723,689				
24b	Rent from Electric Transmission	264,492		264,492			
24c	Tower Rentals and Land Leasing - Transmission	7,551,396		7,551,396			
24d	Tower Rentals and Land Leasing - Distribution	3,410,228	3,410,228				
24e	Intercompany Rent	2,660,969			2,660,969		
…							
	Total Lines 24	$ 26,610,774	$ 16,133,917	$ 7,815,888	$ 2,660,969	$ -	
	Allocation Factors		0%	100%	19.13%	9.88%	
	Allocated Amount		$ -	$ 7,815,888	$ 508,970	$ -	$ 8,324,858

	FERC Account 456	Total Amount	Other	100% Transmission	Plant Related	Labor Related	Total
25a	Decommissioning remittances to Generation	$ (3,859,745)	$ (3,859,745)				
25b	Mutual Assistance	7,314,198	$ 7,314,198				
25c	Make Ready	6,138,390	$ 6,138,390				
25d	Intercompany Billings - Transmission	179,941		179,941			
25e	Intercompany Billings - Labor Related	3,022				3,022	
25f	Intercompany Billings - Other	2,377,641	2,377,641				
25g	Other	798,950	108,246	-	607,536	83,168	
…							
	Total Lines 25	$ 12,952,397	$ 12,078,730	$ 179,941	$ 607,536	$ 86,190	
	Allocation Factors		0%	100%	19.13%	9.88%	
	Allocated Amount		$ -	$ 179,941	$ 116,205	$ 8,516	$ 304,662

	FERC Account 456.1	Total Amount	Other	100% Transmission	Plant Related	Labor Related	Total
26a	Network Integration Credit	$ 150,520,913	$ 150,520,913				
26b	Transmission Owner Scheduling Credits	5,108,495		$ 5,108,495			
26c	Transmission Enhancement	31,755,664	$ 31,755,664				
26d	Revenue - Firm Point to Point	927,381		927,381			
26e	Other	2,620,527	2,620,527				
…							
	Total Lines 26	$ 190,932,980	$ 184,897,104	$ 6,035,876	$ -	$ -	
	Allocation Factors		0%	100%	19.13%	9.88%	
	Allocated Amount		$ -	$ 6,035,876	$ -	$ -	$ 6,035,876

Note A: Number of employees managing secondary transmission service contracts divided by number of employees managing transmission and distribution secondary service contracts.

PECO Energy Company
Attachment 5B - A&G Workpaper

			(a) 323.181.b to 323.196.b	(b)	(c)	(d)	(e)
			Total	S&W Allocation	Gross Plant Allocation	Non-Recoverable	Directly Assigned
1	Administrative and General Salaries	920.0	$ 27,642,490	$ 27,642,490			$ -
2	Office Supplies and Expenses	921.0	12,903,052	11,302,196		1,600,856	-
3	Administrative Expenses Transferred-Credit	922.0	-	-			-
4	Outside Service Employed (Note E)	923.0	90,787,879	76,332,080		14,455,799	-
5	Property Insurance	924.0	432,444		432,444		-
6	Injuries and Damages	925.0	14,565,488	14,565,488			-
7	Employee Pensions and Benefits	926.0	30,527,267	30,527,267			-
8	Franchise Requirements	927.0	-	-			-
9	Regulatory Commission Expenses (Note E)	928.0	9,438,542	-		8,262,295	1,176,247
10	Duplicate Charges-Credit	929.0	(2,308,136)	(2,308,136)			-
11	General Advertising Expenses (Note E)	930.1	2,188,999			2,188,999	-
12	Miscellaneous General Expenses (Note E)	930.2	3,736,404	3,016,329		720,075	-
13	Rents	931.0	-	-			-
14	Maintenance of General Plant	935	5,741,301	5,741,301			-
15	**Administrative & General - Total (Sum of lines 1-14)**		$ 195,655,730	$ 166,819,015	$ 432,444	$ 27,228,024	$ 1,176,247
16			Allocation Factor	9.88%	19.13%	0.00%	100.00%
17			Transmission A&G [1]	16,482,755	82,715	-	1,176,247
18						Total [2]	$17,741,717

Notes:

[1] Multiply total amounts on line 15, columns (b)-(e) by allocation factors on line 16.

[2] Sum of line 17, columns (b), (c), (d), (e).

PECO Energy Company
Attachment 5C - Taxes Other Than Income

	Taxes Other Than Income	**Page 263 Col (i)**
	Plant Related, Subject to Gross Plant Allocator	
1a	PA Real Estate Tax - 2018	6,629,663
1b	Property Tax Payable	5,481,687
1c		
…		
1	**Total Plant Related (Total Lines 1)**	12,111,350
	Labor Related, Subject to Wages & Salary Allocator	
2a	Federal Unemployment	63,037
2b	Social Security	12,168,172
2c	PA Unemployment	405,183
…		
2	**Total Labor Related (Total Lines 2)**	12,636,392
	Other Included, Subject to Gross Plant Allocator	
3a	State Use Taxes	436,519
3b	Miscellaneous Taxes	4,294
3c		
…		
3	**Total Other Included (Total Lines 3)**	440,813
4	**Total Included (Lines 1 to 3)**	25,188,555
	Taxes Other Than Income Excluded Per Notes A to E	
5a	PA Gross Receipts Tax - and prior	96,280
5b	PA Gross Receipts Tax - 2018	130,847,137
5c	Sales Tax Payable	100,937
…		
5	**Total Excluded Taxes Other Than Income (Total Lines 5)**	131,044,354
6	**Total Taxes Other Than Income, Included and Excluded (Lines 4 and 5)**	156,232,909
7	**Total Taxes Other Income from p115.14.g**	156,232,911
8	Difference (Line 6 - Line 7)	(2)
	Items Included in Line 4, that Are To Be Excluded from Formula Per Attachment 5-P3 Support Note F (Enter Negative)	
9a		
9b		
…		
9	Total Labor Related Taxes to be Excluded (Total Lines 9)	-
10a		
10b		
…		
10	Total Plant Related Taxes to be Excluded (Total Lines 10)	-

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 shall 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 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 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.

Attachment 12 PECO Formula Rate Updated

Attachment 6
True-Up Interest Rate
PECO Energy Company

	Month (Note A)	FERC Monthly Interest Rate
1	January	-
2	February	-
3	March	-
4	April	-
5	May	-
6	June	-
7	July	-
8	August	-
9	September	-
10	October	-
11	November	-
12	December	-
13	January	-
14	February	-
15	March	-
16	April	-
17	May	-
18	Average of lines 1-17 above	-

Note:
A The FERC Quarterly Interest Rate in column [A] is the interest applicable to the Month indicated.

19 Year 2018
20

	A	B	C	D	E	F
	Project Name	RTO Project Number or Zonal	Amount	17 Months	Monthly Interest Rate	Interest
			Attachment 3, Col. G + Col H		Line 18 above	Col. C x Col D x Col E
21	Zonal	Zonal	-	17	-	-
21a	Center Point 500-230 kV Substation A	b0269	-	17	-	-
21b	Center Point 500-230 kV Substation A	b0269	-	17	-	-
21c	Richmond-Waneeta 230 kV Line Re-c	b1591	-	17	-	-
21d	Richmond-Waneeta 230 kV Line Re-c	b1398.8	-	17	-	-
21e	Whitpain 500 kV Circuit Breaker Addi	b0269.6	-	17	-	-
21f	Elroy-Hosensack 500 kV Line Rating I	b0171.1	-	17	-	-
21g	Camden-Richmond 230 kV Line Rating	b1590.1 and b1590.2 (cancelle	-	17	-	-
21h	Chichester-Linwood 230 kV Line Upgr	b1900	-	17	-	-
21i	Bryn Mawr-Plymouth 138 kV Line Rel	b0727	-	17	-	-
21j	Emilie 230-138 kV Transformer Additi	b2140	-	17	-	-
21k	Chichester-Saville 138 kV Line Re-con	b1182	-	17	-	-
21l	Waneeta 230-138 kV Transformer Add	b1717	-	17	-	-
21m	Chichester 230-138 kV Transformer A	b1178	-	17	-	-
21n	Bradford-Planebrook 230 kV Line Upg	b0790	-	17	-	-
21o	North Wales-Hartman 230 kV Line Re-	b0506	-	17	-	-
21p	North Wales-Whitpain 230 kV Line Re	b0505	-	17	-	-
21q	Bradford-Planebrook 230 kV Line Upg	b0789	-	17	-	-
21r	Planebrook 230 kV Capacitor Bank Ad	b0206	-	17	-	-
21s	Newlinville 230 kV Capacitor Bank A	b0207	-	17	-	-
21t	Chichester-Mickleton 230 kV Series R	b0209	-	17	-	-
21u	Chichester-Mickleton 230 kV Line Re-	b0264	-	17	-	-
21v	Buckingham-Pleasant Valley 230 kV L	b0357	-	17	-	-
21w	Elroy 500 kV Dynamic Reactive Devic	b0287	-	17	-	-
21x	Heaton 230 kV Capacitor Bank Additic	b0208	-	17	-	-
...						

Attachment 7
PBOPs
PECO Energy Company

Calculation of PBOP Expenses

	(a)		(b) PECO Total	(c) Portion not Capitalized	(d) Electric Col. (c) x Electric Labor in Note B
1	Total PBOP expenses allowed (Note A)		1,066,173	679,716	544,398
2	Total PBOP Expenses in A&G in the current year			(568,579)	(455,386)
3	PBOP Adjustment	Line 1 minus line 2			999,785

Notes:

A The source of the amounts from the Actuary Study supporting the amount in line 1, column (b) is the 3rd page of the attachment to the January 24, 2017 Willis Towers Watson report on PBOPs for PECO.

		$	%
B	Electric Labor (354.28.b)	174,664,333	80.09%
	Gas Labor sum (355.62.b)	43,415,326	19.91%
	Total	218,079,659	

C The Willis Towers Watson report on PBOPs does not breakout the amount related to construction labor that is capitalized. As a result, the portion not capitalized is calculated as labor expensed divided by total labor.

PECO Energy Company
Attachment 8 - Depreciation and Amortization

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
	Number	Plant Type	Estimated Life	Mortality Curve	Weighted Average Remaining Life	Depreciation / Amortization Rate	Gross Depreciable Plant (Year End Balance) $	Accumulated Depreciation $	Net Depreciable Plant $	Depreciation Expense $
			Note 1	Note 1	Note 2		Note 4	Note 4	(I)=(G)-(H)	(J)=(F)*(G)
1							As of 12/31/2018			FY 2018
2		**Electric Transmission**								
3	352	Structures and Improvements	N/A	N/A	N/A	1.8720%	75,390,205	20,575,797	54,814,408	1,411,305
4	353	Station Equipment	N/A	N/A	N/A	1.7494%	854,998,094	195,819,068	659,179,026	14,957,337
5	354	Towers and Fixtures	N/A	N/A	N/A	1.2812%	286,188,012	157,330,075	128,857,937	3,666,641
6	355	Poles and Fixtures	N/A	N/A	N/A	1.5094%	17,313,544	2,740,693	14,572,851	261,331
7	356	Overhead Conductors and Devices	N/A	N/A	N/A	1.5664%	195,917,893	81,514,576	114,403,317	3,068,858
8	357	Underground Conduit	N/A	N/A	N/A	1.5793%	15,245,948	3,987,566	11,258,382	240,779
9	358	Underground Conductors and Devices	N/A	N/A	N/A	1.5723%	101,104,523	43,879,010	57,225,513	1,589,666
10	359	Roads and Trails	N/A	N/A	N/A	0.3715%	2,491,293	2,057,672	433,621	9,255
11							**1,548,649,512**	**507,904,457**	**1,040,745,055**	**25,205,171**
12		**Electric General**								
13	390	Structures and Improvements	40	R1	27.43	2.8378%	49,393,587	11,771,540	37,622,047	1,401,691
14	391.1	Office Furniture and Equipment - Office Machines	10	SQ	3.26	18.1220%	83,462	56,913	26,549	15,125
15	391.2	Office Furniture and Equipment - Furnitures and Fixtures	15	SQ	8.38	10.9890%	509,566	113,111	396,455	55,996
16	391.3	Office Furniture and Equipment - Computers	5	SQ	2.89	18.5040%	22,992,598	7,539,039	15,453,559	4,254,550
17	391.4	Office Furniture and Equipment - Smart Meter Comp. Equip.	5	SQ	2.89	11.8383%	2,902,800	1,901,872	1,000,928	343,642
18	393	Stores Equipment	15	SQ	11.32	8.6817%	46,470	6,982	39,488	4,034
19	394	Tools, Shop, Garage Equipment	15	SQ	9.99	6.7896%	34,588,353	10,806,819	23,781,534	2,348,411
20	395.1	Laboratory Equipment - Testing	20	SQ	8.58	4.4040%	311,026	214,531	96,495	13,698
21	395.2	Laboratory Equipment - Meters	15	SQ	5.50	6.4773%	101,381	75,266	26,115	6,567
22	397	Communication Equipment	20	L3	15.53	4.8407%	125,639,703	29,840,526	95,799,177	6,081,841
23	397.1	Communication Equipment - Smart Meters	15	S2	10.16	6.5693%	35,480,218	12,177,653	23,302,565	2,330,802
24	398	Miscellaneous Equipment	15	SQ	1.74	11.8064%	652,693	590,273	62,420	77,060
25							**272,701,857**	**75,094,525**	**197,607,332**	**16,933,417**

PECO Energy Company
Attachment 8 - Depreciation and Amortization

1		**Electric Intangible**								
2	303	Software - Transmission 2-year Life (Note 10)	2	N/A	N/A	19.8559%	5,552,297	1,102,456	4,449,841	1,102,459
3	303	Software - Transmission 3-year Life (Note 10)	3	N/A	N/A	N/A	-	-	-	-
4	303	Software - Transmission 4-year Life (Note 10)	4	N/A	N/A	N/A	-	-	-	-
5	303	Software - Transmission 5-year Life (Note 10)	5	N/A	N/A	19.8218%	11,596,263	6,329,993	5,266,270	2,298,588
6	303	Software - Transmission 7-year Life (Note 10)	7	N/A	N/A	N/A	-	-	-	-
7	303	Software - Transmission 10-year Life (Note 10)	10	N/A	N/A	N/A	-	-	-	-
8	303	Software - Transmission 13-year Life (Note 10)	13	N/A	N/A	N/A	-	-	-	-
9	303	Software - Transmission 15-year Life (Note 10)	15	N/A	N/A	N/A	-	-	-	-
10							**17,148,560**	**7,432,449**	**9,716,111**	**3,401,047**
11	303	Software - Electric General 2-year Life (Note 10)	2	N/A	N/A	N/A	-	-	-	-
12	303	Software - Electric General 3-year Life (Note 10)	3	N/A	N/A	N/A	-	-	-	-
13	303	Software - Electric General 4-year Life (Note 10)	4	N/A	N/A	N/A	-	-	-	-
14	303	Software - Electric General 5-year Life (Note 10)	5	N/A	N/A	15.3168%	18,356,110	7,733,452	10,622,658	2,811,569
15	303	Software - Electric General 7-year Life (Note 10)	7	N/A	N/A	N/A	-	-	-	-
16	303	Software - Electric General 10-year Life (Note 10)	10	N/A	N/A	N/A	-	-	-	-
17	303	Software - Electric General 13-year Life (Note 10)	13	N/A	N/A	N/A	-	-	-	-
18	303	Software - Electric General 15-year Life (Note 10)	15	N/A	N/A	N/A	-	-	-	-
19							**18,356,110**	**7,733,452**	**10,622,658**	**2,811,569**
20	303	Software - Electric Distribution	N/A	N/A	N/A	N/A	109,482,129	88,949,479	20,532,650	12,591,808
21	303	Regulatory Initiatives/Depr Charged to Reg Asset	N/A	N/A	N/A	N/A	17,796,758	6,870,119	10,926,639	Zero
22							**127,278,887**	**95,819,598**	**31,459,289**	**12,591,808**
23		**Common General - Electric**								
24	303	Software - 2-year Life (Note 10)	2	N/A	N/A	N/A			-	-
25	303	Software - 3-year Life (Note 10)	3	N/A	N/A	N/A	-	-	-	-
26	303	Software - 4-year Life (Note 10)	4	N/A	N/A	N/A	-	-	-	-
27	303	Software - 5-year Life (Note 10)	5	N/A	N/A	7.5644%	182,916,750	150,150,823	32,765,927	13,836,555
28	303	Software - 7-year Life (Note 10)	7	N/A	N/A	N/A	-	-	-	-
29	303	Software - 10-year Life (Note 10)	10	N/A	N/A	N/A	-	-	-	-
30	303	Software - 13-year Life (Note 10)	13	N/A	N/A	N/A	-	-	-	-
31	303	Software - 15-year Life (Note 10)	15	N/A	N/A	N/A	-	-	-	-
32	303	Regulatory Initiatives/Depr Charged to Reg Asset	N/A	N/A	N/A	N/A	148,882	120,346	28,536	Zero
33	390	Structures and Improvements	50	R1	36.62	1.9491%	215,979,871	60,401,682	155,578,189	4,209,664
34	391.1	Office Furniture and Equipment - Office Machines	10	SQ	2.95	24.7644%	70,521	45,123	25,398	17,464
35	391.2	Office Furniture and Equipment - Furnitures and Fixtures	15	SQ	7.92	7.2809%	12,284,023	2,668,489	9,615,533	894,387
36	391.3	Office Furniture and Equipment - Computers	5	SQ	2.73	16.6017%	24,952,515	11,022,999	13,929,517	4,142,542
37	392.1	Transportation Equipment - Automobiles	6	L3	4.58	N/A	73,115	72,503	612	Zero
38	392.2	Transportation Equipment - Light Trucks	12	L4	7.95	N/A	26,035,560	12,841,583	13,193,976	Zero
39	392.3	Transportation Equipment - Heavy Trucks	14	R4	9.13	N/A	61,724,127	28,073,053	33,651,074	Zero
40	392.4	Transportation Equipment - Tractors	11	L2	2.61	N/A	218,117	219,830	(1,712)	Zero
41	392.5	Transportation Equipment - Trailers	15	R2	10.00	N/A	3,848,912	1,894,613	1,954,299	Zero
42	392.6	Transportation Equipment - Other Vehicles	15	R2	7.27	N/A	3,959,867	2,995,334	964,533	Zero
43	392.7	Transportation Equipment -Medium Trucks	N/A	N/A	8.00	N/A	6,956,875	646,136	6,310,739	Zero
44	393	Stores Equipment	15	SQ	7.46	8.5151%	966,049	233,293	732,757	82,260
45	394.1	Tools, Shop, Garage Equipment - Construction Tools	15	SQ	5.50	94.1723%	9,071	(24,899)	33,969	8,542
46	394.2	Tools, Shop, Garage Equipment - Common Tools	15	SQ	10.25	2.5768%	805,358	42,164	763,194	20,752
47	394.3	Tools, Shop, Garage Equipment - Garage Equipment	20	SQ	8.00	N/A	2,089,954	1,190,818	899,136	Zero
48	396	Power Operated Equipment	11	L2	3.17	N/A	144,500	141,644	2,855	Zero
49	397	Communication Equipment	20	L3	10.02	4.5162%	39,280,679	13,867,388	25,413,291	1,773,994
50	398	Miscellaneous Equipment	15	SQ	7.69	9.5527%	935,457	376,200	559,257	89,361
51							**583,400,203**	**286,979,123**	**296,421,080**	**25,075,521**

PECO Energy Company
Attachment 8 - Depreciation and Amortization

		Current Year Depr./Amor. Exp Per Formula Total Company	Current Year Depr./Amor. Exp Per FF1 / Atta 4D for Intangible Total Company	Current Year Difference Total Company	Allocation % To Transmission	Current Year Difference Allocated To Transmission	Prior Year Total Cumulative Difference Total Company	Prior Year Total Cumulative Difference Transmission	Current Year Total Cumulative Difference Total Company	Current Year Total Cumulative Difference Transmission
		(B)	(C)	(D)=(B)-(C)	(E)	(F)=(D)*(E)	(G)	(H)	(I)=(D)+(G)	(J)=(F)+(H)
1	Transmission	$ 25,205,171	$ 25,205,442	(271)	100.00%	(271)	(809)	(809)	(1,080)	(1,080)
2	Electric General	$ 16,933,417	$ 16,933,386	31	9.88%	3	23	2	54	5
3	Common - Electric	$ 25,075,521	$ 25,075,648	(127)	9.88%	(13)	(92)	(8)	(219)	(21)
4	Intangible - Transmission	$ 3,401,047	$ 3,401,041	5	100.00%	5	5	5	10	10
5	Intangible - General	$ 2,811,569	$ 2,811,571	(2)	9.88%	(0)	(5)	(0)	(7)	(1)
6	Intangible - Distribution	$ 12,591,808	$ 12,591,808	-	0.00%	-	-	-	-	-
7										
8	**Accumulative Depreciation**									

		Average Accumulative Depr./Amor. Per Book Total Company	Total Cumulative Adjustment Total Company	Adjusted Average Accumulative Depr./Amor. Total Company	Allocation % To Transmission	Adjusted Average Accumulative Depr./Amor. Transmission
9						
10	Transmission	$ 495,659,290	(945)	495,660,234	100.00%	495,660,234
11	Electric General	$ 69,920,803	38	69,920,764	9.88%	6,908,606
12	Common - Electric	$ 272,253,865	(155)	272,254,020	9.88%	26,900,389
13	Intangible - Transmission	$ 5,408,646	8	5,408,638	100.00%	5,408,638
14	Intangible - General	$ 6,291,428	(6)	6,291,433	9.88%	621,633
15	Intangible - Distribution	$ 90,874,481	$ -	90,874,481	0.00%	-
16	Total Intangible	$ 102,574,554	$ 2	$ 102,574,552		$ 6,030,271
17						
18						
19						
20						
21						
22						
23						
24						

Notes:

1 Columns (A), (B), (C), and (D) are fixed and cannot be changed absent Commission approval or acceptance. The depreciation / amortization expense is calculated separately for each row.

2 For Electric General and Common General plant, except FERC account 303, Column (E) is the remaining life of the assets in the account for each vintage (amount of plant added in each year is a vintage) weighted by the gross plant balance of each account or subaccount. The remaining life for each vintage is equal to the area under the Mortality Curve specified in Columns (C) and (D) using a half year convention for the first year placed in service. The weighted remaining life is calculated once a year at the beginning of the year.

3 For FERC accounts 303, 352 through 359 and 390 through 398, Column F is fixed and cannot be changed absent Commission approval or acceptance.

4 Column (G) is the depreciable amount of gross plant investment reported in the annual FERC Form No. 1 filing on pages 207 (Electric) and 356 (Common) by account or subaccount. Column (H) is the accumulated depreciation by account or subaccount.

5 Column (I) is the end of year depreciable net plant in the account or subaccount.

6 Reserved

7 Reserved

8 At least every 5 years, PECO Energy Company will file with the Commission a depreciation study supporting its existing Estimated Life and Mortality Curve for each account or subaccount.

9 The depreciation expense associated with Asset Retirement Obligations (booked to accounts 359.1 and 399.1) are not included in the tables above.

10 The life of each software or other intangible plant will be estimated at the time the plant is placed into service, and will not change over the life of the plant absent Commission approval or acceptance. The combined amortization expense for all intangible plant shall be the sum of each individual plant balance amortized over the life of each individual plant established in this manner.

11 The depreciation expenses related to Common General - Electric reflect electric common plant. The depreciation expenses associated with Transportation Equipment, Garage Equipment and Power Operated Tools are excluded from Account 403 and directly assigned to the functional O&M and capital accounts based on use.

Attachment 9
Excess / (Deficient) Deferred Income Taxes (Note B and Attachment H-7 Notes N, O and P)
PECO Energy Company

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)
	EDIT Amortization Amount (Note C)	January	February	March	April	May	June	July	August	September	October	November	December	Total
1	**Protected Property**													
2	Transmission	$ 62,868	$ 62,868	$ 62,868	$ 62,868	$ 62,868	$ 62,868	$ 62,868	$ 62,868	$ 62,868	$ 62,868	$ 62,868	$ 62,868	$ 754,420
3	General	$ 18,332	$ 18,332	$ 18,332	$ 18,332	$ 18,332	$ 18,332	$ 18,332	$ 18,332	$ 18,332	$ 18,332	$ 18,332	$ 18,332	$ 219,985
4	Transmission Allocation % (Att H-7 P4, L11, Col 5)	9.88%												
5	Allocated to Transmission	$ 1,811	$ 1,811	$ 1,811	$ 1,811	$ 1,811	$ 1,811	$ 1,811	$ 1,811	$ 1,811	$ 1,811	$ 1,811	$ 1,811	$ 21,736
6	Common (To Be Split TDG)	$ 45,114	$ 45,114	$ 45,114	$ 45,114	$ 45,114	$ 45,114	$ 45,114	$ 45,114	$ 45,114	$ 45,114	$ 45,114	$ 45,114	$ 541,371
7	Transmission Allocation % (L 4 * Electric Factor in FERC Form 1 P356)	7.71%												
8	Allocated to Transmission	$ 3,480	$ 3,480	$ 3,480	$ 3,480	$ 3,480	$ 3,480	$ 3,480	$ 3,480	$ 3,480	$ 3,480	$ 3,480	$ 3,480	$ 41,766
9	**Total Protected Property**	$ 68,160	$ 68,160	$ 68,160	$ 68,160	$ 68,160	$ 68,160	$ 68,160	$ 68,160	$ 68,160	$ 68,160	$ 68,160	$ 68,160	$ 817,922
10	**Non-Protected Property (Note A)**	201,938	$ 201,938	$ 201,938	$ 201,938	$ 201,938	$ 201,938	$ 201,938	$ 201,938	$ 201,938	$ 201,938	$ 201,938	$ 201,938	$ 2,423,260
11	**Non-Protected, Non-Property - Pension Asset (Note A)**	$ 74,045	$ 74,045	$ 74,045	$ 74,045	$ 74,045	$ 74,045	$ 74,045	$ 74,045	$ 74,045	$ 74,045	$ 74,045	$ 74,045	$ 888,541
12	**Non-Protected, Non-Property - Non-Pension Asset (Note A)**	$ (78,379)	$ (78,379)	$ (78,379)	$ (78,379)	$ (78,379)	$ (78,379)	$ (78,379)	$ (78,379)	$ (78,379)	$ (78,379)	$ (78,379)	$ (78,379)	$ (940,545)
13	**Total Non-Protected, Non-Property (Note A)**	$ (4,334)	$ (4,334)	$ (4,334)	$ (4,334)	$ (4,334)	$ (4,334)	$ (4,334)	$ (4,334)	$ (4,334)	$ (4,334)	$ (4,334)	$ (4,334)	$ (52,004)

EDIT Balance (Notes C and D)

		December Prior Year	January	February	March	April	May	June	July	August	September	October	November	December	Prior and Current December Average
14	**Protected Property**														
15	Transmission	$ 79,726,712	79,663,844	79,600,975	79,538,107	79,475,239	79,412,370	79,349,502	79,286,634	79,223,765	79,160,897	79,098,029	79,035,160	78,972,292	79,349,502
16	General	$ 1,683,749	1,665,417	1,647,085	1,628,753	1,610,421	1,592,089	1,573,757	1,555,424	1,537,092	1,518,760	1,500,428	1,482,096	1,463,764	1,573,757
17	Transmission Allocation %	9.88%													
18	Allocated to Transmission	$ 166,365	164,554	162,742	160,931	159,120	157,308	155,497	153,686	151,874	150,063	148,252	146,440	144,629	155,497
19	Common (To Be Split TDG)	$ 11,901,494	11,856,380	11,811,266	11,766,151	11,721,037	11,675,923	11,630,809	11,585,694	11,540,580	11,495,466	11,450,352	11,405,237	11,360,123	11,630,809
20	Transmission Allocation %	7.71%													
21	Allocated to Transmission	$ 918,175	914,695	911,214	907,734	904,253	900,773	897,292	893,812	890,331	886,851	883,370	879,890	876,410	897,292
22	**Total Protected Property**	$ 80,811,252	80,743,092	80,674,932	80,606,772	80,538,612	80,470,451	80,402,291	80,334,131	80,265,971	80,197,811	80,129,651	80,061,491	79,993,331	80,402,291
23	**Non-Protected Property (Note A)**	$ 16,962,821	16,760,883	16,558,944	16,357,006	16,155,068	15,953,129	15,751,191	15,549,253	15,347,314	15,145,376	14,943,438	14,741,499	14,539,561	15,751,191
24	**Non-Protected, Non-Property - Pension Asset (Note A)**	$ 4,442,703	4,368,658	4,294,613	4,220,568	4,146,523	4,072,478	3,998,433	3,924,388	3,850,343	3,776,298	3,702,253	3,628,207	3,554,162	3,998,433
25	**Non-Protected, Non-Property - Non-Pension Asset (Note A)**	$ (4,702,724)	(4,624,345)	(4,545,967)	(4,467,588)	(4,389,209)	(4,310,830)	(4,232,452)	(4,154,073)	(4,075,694)	(3,997,315)	(3,918,937)	(3,840,558)	(3,762,179)	(4,232,452)
26	**Total Non-Protected, Non-Property (Note A)**	$ (260,021)	(255,687)	(251,354)	(247,020)	(242,686)	(238,353)	(234,019)	(229,685)	(225,352)	(221,018)	(216,684)	(212,350)	(208,017)	(234,019)

Notes:

A EDIT data, including EDIT amortization amount and balance, for Protected, Non-Protected Property and Non-Protected, Non-Property shall reflect the Transmission portion of EDIT amounts. The amounts and categorization of these balances as of December 31, 2017 is: Protected Property - Transmission (Line 15): $79,726,712; Protected Property - Electric General to be allocated between Distribution and Transmission (Line 16): $1,683,749; Protected Property – Common to be allocated between Distribution, Transmission and Gas (Line 19): $11,901,494; Non-Protected Property (Line 23): $16,962,821; Non-Protected Non-Property (Line 26): ($260,021).

B The amortization schedule of the EDIT balance related to Tax Cuts and Job Act of 2017 shall be consistent with the following periods:

Protected:	ARAM
Non-Protected Property:	7 years
Non-Protected, Non-Property:	5 years

The Non-Protected Property EDIT balance shall be fully amortized by the end of 2024 and the Non-Protected, non-Property EDIT balance shall be fully amortized by the end of 2022.

C The data of the annual amortization amount and balance are from PECO's Tax Accounting records.

D EDIT balance was reclassified from ADIT to EDIT in December 2017.

Attachment 10
Pension Asset Discount Worksheet
PECO Energy Company

				Source
1	13 Month Average Pension Asset (Note A)		27,945,369	(Attachment 4, line 28(i))
	Net ADIT Balance			
2	Prior Year ADIT Related to Transmission Pension Asset		(8,901,112)	(Attachment 4B "PENSION EXPENSE PROVISION" times S&W Allocator)
3	Current Year ADIT Related to Transmission Pension Asset		(9,156,349)	(Attachment 4C "PENSION EXPENSE PROVISION" times S&W Allocator)
4	Average ADIT Balance Related to Transmission Pension Asset		(9,028,730)	(Average of Lines 2 and 3)
5	Net Unamortized EDIT Balance	$	(3,998,433)	(Attachment 9 line 24 "Average")
6	Net Pension Asset	$	14,918,206	(Line 1 plus Line 4 plus Line 5)
7	100% of ATRR on Net Pension Asset		1,450,229	(Line 6 times Attachment H-7 page 3, line 34, col (3) times (1+Attachment H-7 page 4, line 18, col (5))
8	Times Pension Discount %		60%	
9	ATRR Discount on Net Pension Asset	$	870,137	(Line 7 times Line 8)

Note:
A: PECO’s transmission-related Pension Asset balance is capped at $33 million. Such limit may only be changed pursuant to a section 205 or 206 filing.

Attachment 11
Cost of Capital
PECO Energy Company

Line		
	Long Term Interest (117, lines 62 through 67), Excluding LVT Interest	
1	Interest on Long-Term Debt (427)	112,709,164
2	Amort. of Debt Disc. and Expense (428)	2,054,564
3	Amortization of Loss on Reacquired Debt (428.1)	650,246
4	(Less) Amort. of Premium on Debt-Credit (429)	
5	(Less) Amortization of Gain on Reacquired Debt-Credit (429.1)	
6	Interest on Debt to Assoc. Companies (430)	13,848,752
7	(Less) Short-term Interest (5-P3 Support Note G)	1,113
8	**Total Long Term Interest (Line 1 + Line 2 + Line 3 - Line 4 - Line 5 + Line 6 - Line 7)**	**$129,261,613**

13-Month Average Balance of Long-term Debt,

Line		December Prior Year	January	February	March	April	May	June	July	August	September	October	November	December	13-Month Average
	Long -term Debt (112, Lines 18 through 21)														
9	Bonds (221)	2,925,000,000	2,925,000,000	3,250,000,000	2,750,000,000	2,750,000,000	2,750,000,000	2,800,000,000	2,800,000,000	2,800,000,000	3,125,000,000	3,125,000,000	3,125,000,000	3,125,000,000	2,942,307,692
10	(Less) Reacquired Bonds (222)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Advances from Associated Companies (223)	184,418,609	184,418,609	184,418,609	184,418,609	184,418,609	184,418,609	184,418,609	184,418,609	184,418,609	184,418,609	184,418,609	184,418,609	184,418,609	184,418,609
12	Other Long-Term Debt (224)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	**Total (Line 9 - Line 10 + Line 11 + Line 12)**	**$ 3,109,418,609**	**$ 3,109,418,609**	**$ 3,434,418,609**	**$ 2,934,418,609**	**$ 2,934,418,609**	**$ 2,934,418,609**	**$ 2,984,418,609**	**$ 2,984,418,609**	**$ 2,984,418,609**	**$ 3,309,418,609**	**$ 3,309,418,609**	**$ 3,309,418,609**	**$ 3,309,418,609**	**$ 3,126,726,301**
	Proprietary Capital (112, line 2 through 15)														
14	Common stock issued (201)	1,423,004,251	1,423,004,251	1,423,004,251	1,423,004,251	1,423,004,251	1,423,004,251	1,423,004,251	1,423,004,251	1,423,004,251	1,423,004,251	1,423,004,251	1,423,004,251	1,423,004,251	1,423,004,251
15	Preferred Stock (204) (112.3.c) (5-P3 Support Note B)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Capital Stock Subscribed (202, 205)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Stock Liability for Conversion (203, 206)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Premium on Capital Stock (207)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Other Paid-in Capital (208-211)	1,066,200,303	1,066,200,303	1,066,200,303	1,066,200,303	1,066,200,303	1,066,200,303	1,107,200,303	1,107,200,303	1,107,200,303	1,137,051,226	1,137,051,226	1,155,155,244	1,155,155,244	1,100,247,359
20	Installments Received on Capital Stock (212)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	(Less) Discount on Capital Stock (213)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	(Less) Capital Stock Expense (214)	86,742	86,742	86,742	86,742	86,742	86,742	86,742	86,742	86,742	86,742	86,742	86,742	86,742	86,742
23	Retained Earning s(215, 215.1, 216)	4,227,597,761	4,299,291,661	4,357,045,986	4,066,950,505	4,105,090,464	4,139,722,925	4,166,509,310	4,224,779,300	4,275,044,606	4,298,806,792	4,339,234,910	4,397,663,092	4,427,930,434	4,255,820,596
24	Unappropriated Undistributed Subsidiary Earnings (216.1)	(3,140,935,576)	(3,148,411,599)	(3,154,451,283)	(3,153,419,426)	(3,157,227,753)	(3,160,609,577)	(3,163,332,757)	(3,168,962,835)	(3,173,812,612)	(3,176,205,267)	(3,179,661,758)	(3,183,634,004)	(3,187,402,048)	(3,165,235,884)
25	(Less) Reacquired Capital Stock (217)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Noncorporate Proprietorship (Non-major only) (218)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Accumulated other Comprehensive Income (219)	1,630,458	1,630,458	1,630,458	1,660,838	1,660,838	1,660,838	1,636,632	1,636,632	1,636,632	1,842,583	1,842,583	1,845,758	1,674,806	1,691,501
28	Total Proprietary Capital (Line 14+ Line 15 + Line 16 + Line 17 + Line 18 + Line 19 + Line 20 - Line 21 - Line 22 + Line 23 + Line 24 - Line 25 + Line 26 + Line 27)	3,577,410,455	$3,641,628,332	$3,693,342,973	$3,404,309,729	$3,438,641,361	$3,469,891,998	$3,534,930,997	$3,587,570,910	$3,632,986,437	$3,684,412,842	$3,721,384,469	$3,793,947,598	$3,820,275,945	3,615,441,080
29	**Preferred Stock (line 15)**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30	**Common Stock (line 28 - line 29)**	**$ 3,577,410,455**	**$ 3,641,628,332**	**$ 3,693,342,973**	**$ 3,404,309,729**	**$ 3,438,641,361**	**$ 3,469,891,998**	**$ 3,534,930,997**	**$ 3,587,570,910**	**$ 3,632,986,437**	**$ 3,684,412,842**	**$ 3,721,384,469**	**$ 3,793,947,598**	**$ 3,820,275,945**	**$ 3,615,441,080**

Appendix 2D
2018 Actuals – MDTAC

ATTACHMENT H-7B
MDTAC FORMULA RATE TEMPLATE

CALCULATION OF MONTHLY AMORTIZED REGULATORY ASSET TO BE RECOVERED			
1	Annual Revenue Requirement on Regulatory Asset Amortization	Attachment 1 - Revenue Requirement Line 3	$880,221
2	True-up Adjustment with Interest	Attachment 2 - True-Up Line 24	$0
3	Net Annual Revenue Requirement on Regulatory Asset Amortization with True-up	Line 1 + line 2	$880,221
4	Net Monthly Revenue Requirement on Regulatory Asset Amortization with True-up	Line 3 / 12	$73,352

PECO Energy Company
Summary of Transmission SFAS 109 Regulatory Asset (Account 182.3) Amortization
For the 12 months ended 12/31/2018

1	SFAS 109 Reg Asset Amortization (Notes A and B)	$	1,013,756
2	Other Tax Adjustments (Note C)	$	(133,535)
3	**Adjusted Total**	$	880,221

Notes:
(A) All items are asssociated with ratemaking flow through requirements
(B) Additional detail is provided on page 2 of this exhibit
(C) Amortization of FAS 109 Regulatory Asset.

True-Up with Interest
PECO Energy Company

		Month (Note A)	FERC Monthly Interest Rate
1		January	-
2		February	-
3		March	-
4		April	-
5		May	-
6		June	-
7		July	-
8		August	-
9		September	-
10		October	-
11		November	-
12		December	-
13		January	-
14		February	-
15		March	-
16		April	-
17		May	-
18	Average of lines 1-17 above		-

Notes:

A The FERC Quarterly Interest Rate in column [A] is the interest applicable to the Month indicated.

19	Actual Revenue Requirement	
20	Revenue Received	
21	Net Under/(Over) Collection (Line 19 - Line 20)	-
22	17 Months	17
23	Interest (Line 18*Line 21*Line 22)	-
24	Total True-up	-

PECO Energy Company
Summary of Transmission SFAS 109 Regulatory Asset (Account 182.3)
December 31, 2017 through December 31, 2018

		12/31/2017	Activity	12/31/2018
	TRANSMISSION ONLY			
	Repair Allowance	7,851,141	(223,847)	7,627,294
	Federal and State Flow Through	22,131,867	(355,606)	21,776,261
	Excess Deferreds/pre-1981 Deferreds	17,136,824	(79,570)	17,057,254
	Other	411,760	(18,542)	393,218
	Total	47,531,592	(677,565)	46,854,027
	COMMON (TO BE SPLIT TDG)			
	Repair Allowance	-	-	-
	Federal and State Flow Through	7,654,873	(152,604)	7,502,269
	Excess Deferreds/pre-1981 Deferreds	2,817,856	(28,747)	2,789,109
	Other	1,564,184	(213,902)	1,350,282
	Total	12,036,913	(395,253)	11,641,660
	Transmission Allocation %	7.71%	***(Attachment H-7A, page 4, line 11, column 5 * Common Allocation Factor in FERC Form 1 page 356)***	
	Repair Allowance	-	-	-
	Federal and State Flow Through	590,557	(11,773)	578,784
	Excess Deferreds/pre-1981 Deferreds	217,392	(2,218)	215,174
	Other	120,673	(16,502)	104,171
	Total	928,622	(30,493)	898,130
	ELECTRIC GENERAL (TO BE SPLIT TD)			
	Repair Allowance	10,143	(788)	9,355
	Federal and State Flow Through	972,815	(124,237)	848,578
	Excess Deferreds/pre-1981 Deferreds	149,788	(3,840)	145,948
	Other	3,289	(708)	2,581
	Total	1,136,035	(129,573)	1,006,462
	Transmission Allocation %	9.88%	***Source: Attachment H-7A, page 4, line 11, column 5***	
	Repair Allowance	1,002	(78)	924
	Federal and State Flow Through	96,120	(12,275)	83,845
	Excess Deferreds/pre-1981 Deferreds	14,800	(379)	14,421
	Other	325	(70)	255
	Total	112,247	(12,803)	99,445
	Transmission Summary			
	Repair Allowance	7,852,143	(223,925)	7,628,218
	Federal and State Flow Through	22,818,544	(379,654)	22,438,890
	Excess Deferreds/pre-1981 Deferreds	17,369,016	(82,167)	17,286,848
	Other	532,758	(35,114)	497,644
	Total	**48,572,462**	**(720,861)**	**47,851,601**
Incl	SFAS 109 + Gross-up	68,308,109	(1,013,756)	67,294,353
	2010 Transmission Tax Adjustments b/f gross-up	(261,124)	94,954	(166,170)
	2010 Transmission Tax Adjustments + gross-up	(367,222)	133,535	(233,687)
	Total Transmission SFAS 109	67,940,887	(880,221)	67,060,666

Gross-up Factor	
Federal Income Tax Rate	21.000%
State Income Tax Rate	9.990%
Composite Rate = F+S(1-F)	28.892%
Gross-up Factor = 1/(1-CR)	140.631%

Appendix 3
Additional Workpapers Required by the Protocols

Protocol F.3

Supporting documentation and workpapers for Attachment H-7A, Attachment 3 Project True-Up will include for each new Schedule 12 tariffed project listed individually on letter-denominated Line 3 entries documentation of:
(1) the month in which project construction began and the date upon which the project (or first operationally in service portion of the project) was placed in service,
(2) the current budgeted project costs as listed on the PJM website, and
(3) the costs cleared to plant in service as of December 31 of the True-Up Year.

For the True-Up Year plus the preceding December, supporting documentation in electronic spreadsheet format will also include end-of-month gross plant balances for:
(1) each Schedule 12 project listed individually on letter-denominated Line 3 entries and
(2) the sum of the non-Schedule 12 projects included in the Attachment H-7A, Attachment 3, Line 3 Zonal entry.

In addition, PECO will provide a workpaper that lists the original in-service cost for each Schedule 12 tariffed project that is 100% allocated to PECO;

New Schedule 12 tarriffed projects listed individually:

Line No.	Project Name	RTO Project Number	Construction start date	Placed in Service date	Budgeted costs per PJM website	12/31/19 Plant in service
17z	Peach Bottom 500-230 kV Transformer Rating Increase	b2694	September 2018	January 2019	$ 11,600,000	$ 2,231,763
17z	Peach Bottom 500-230 kV Transformer Rating Increase	b2694	March 2019	May 2019		$ 10,806,440
	Total				$ 11,600,000	$ 13,038,203
17aa	Peach Bottom 500 kV Substation Upgrades	b2766.2	October 2019	December 2019	$ 4,300,000	$ 985,461

Protocol F.3

End-of-month gross plant balances for the 13-month period December 2017 - December 2018:

Project Name	RTO Project Number or Zonal	Dec-17	Jan-18	Feb-18	Mar-18
Center Point 500 kV Substation Addition	b0269	34,380,669	34,380,669	34,380,669	34,380,669
Center Point 230 kV Substation Addition	b0269.10	17,190,335	17,190,335	17,190,335	17,190,335
Richmond-Waneeta 230 kV Line Re-conductor	b1591	4,605,741	4,605,741	4,605,741	4,605,741
Richmond-Waneeta 230 kV Line Re-conductor	b1398.8	1,535,247	1,535,247	1,535,247	1,535,247
Whitpain 500 kV Circuit Breaker Addition	b0269.6	3,258,302	3,258,302	3,258,302	3,258,302
Elroy-Hosensack 500 kV Line Rating Increase	b0171.1	4,456,731	4,456,731	4,456,731	4,456,731
Camden-Richmond 230 kV Line Rating Increase	b1590.1 and b1590.2 (cancelled b1398.6)	13,635,683	13,635,683	13,635,683	13,635,683
Chichester-Linwood 230 kV Line Upgrades	b1900	22,114,407	22,114,407	22,114,407	22,114,407
Bryn Mawr-Plymouth 138 kV Line Rebuild	b0727	18,039,324	18,039,324	18,039,324	18,039,324
Emilie 230-138 kV Transformer Addition	b2140	16,739,503	16,739,503	16,739,503	16,739,503
Chichester-Saville 138 kV Line Re-conductor	b1182	17,916,280	17,916,280	17,916,280	17,916,280
Waneeta 230-138 kV Transformer Addition	b1717	11,068,901	11,068,901	11,068,901	11,068,901
Chichester 230-138 kV Transformer Addition	b1178	8,327,907	8,327,907	8,327,907	8,327,907
Bradford-Planebrook 230 kV Line Upgrades	b0790	1,712,754	1,712,754	1,712,754	1,712,754
North Wales-Hartman 230 kV Line Re-conductor	b0506	2,229,232	2,229,232	2,229,232	2,229,232
North Wales-Whitpain 230 kV Line Re-conductor	b0505	2,546,903	2,546,903	2,546,903	2,546,903
Bradford-Planebrook 230 kV Line Upgrades	b0789	2,359,200	2,359,200	2,359,200	2,359,200
Planebrook 230 kV Capacitor Bank Addition	b0206	3,631,396	3,631,396	3,631,396	3,631,396
Newlinville 230 kV Capacitor Bank Addition	b0207	4,811,873	4,811,873	4,811,873	4,811,873
Chichester-Mickleton 230 kV Series Reactor Additior	b0209	2,699,444	2,699,444	2,699,444	2,699,444
Chichester-Mickleton 230 kV Line Re-conductor	b0264	2,221,241	2,221,241	2,221,241	2,221,241
Buckingham-Pleasant Valley 230 kV Line Re-conduc	b0357	1,723,078	1,723,078	1,723,078	1,723,078
Elroy 500 kV Dynamic Reactive Device	b0287	5,325,225	5,325,225	5,325,225	5,325,225
Heaton 230 kV Capacitor Bank Addition	b0208	4,315,230	4,315,230	4,315,230	4,315,230
	Zonal	1,432,723,509	1,432,087,532	1,433,935,786	1,431,107,831

Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18
34,380,669	34,380,669	34,380,669	34,380,669	34,380,669	34,380,669	34,380,669	34,380,669	34,380,669
17,190,335	17,190,335	17,190,335	17,190,335	17,190,335	17,190,335	17,190,335	17,190,335	17,190,335
4,605,741	4,605,741	4,605,741	4,605,741	4,605,741	4,605,741	4,605,741	4,605,741	4,605,741
1,535,247	1,535,247	1,535,247	1,535,247	1,535,247	1,535,247	1,535,247	1,535,247	1,535,247
3,258,302	3,258,302	3,258,302	3,258,302	3,258,302	3,258,302	3,258,302	3,258,302	3,258,302
4,456,731	4,456,731	4,456,731	4,456,731	4,456,731	4,456,731	4,456,731	4,456,731	4,456,731
13,635,683	13,635,683	13,635,683	13,635,683	13,635,683	13,635,683	13,635,683	13,635,683	13,635,683
23,791,616	23,848,391	23,864,295	23,866,899	23,875,318	23,875,318	23,835,043	23,835,043	23,835,043
18,039,324	18,039,324	18,039,324	18,039,324	18,039,324	18,039,324	18,039,324	18,039,324	18,039,324
16,739,503	16,739,503	16,739,503	16,739,503	16,739,503	16,739,503	16,739,503	16,739,503	16,739,503
17,916,280	17,916,280	17,916,280	17,916,280	17,916,280	17,916,280	17,916,280	17,916,280	17,916,280
11,068,901	11,068,901	11,068,901	11,068,901	11,068,901	11,068,901	11,068,901	11,068,901	11,068,901
8,327,907	8,327,907	8,327,907	8,327,907	8,327,907	8,327,907	8,327,907	8,327,907	8,327,907
1,712,754	1,712,754	1,712,754	1,712,754	1,712,754	1,712,754	1,712,754	1,712,754	1,712,754
2,229,232	2,229,232	2,229,232	2,229,232	2,229,232	2,229,232	2,229,232	2,229,232	2,229,232
2,546,903	2,546,903	2,546,903	2,546,903	2,546,903	2,546,903	2,546,903	2,546,903	2,546,903
2,359,200	2,359,200	2,359,200	2,359,200	2,359,200	2,359,200	2,359,200	2,359,200	2,359,200
3,631,396	3,631,396	3,631,396	3,631,396	3,631,396	3,631,396	3,631,396	3,631,396	3,631,396
4,811,873	4,811,873	4,811,873	4,811,873	4,811,873	4,811,873	4,811,873	4,811,873	4,811,873
2,699,444	2,699,444	2,699,444	2,699,444	2,699,444	2,699,444	2,699,444	2,699,444	2,699,444
2,221,241	2,221,241	2,221,241	2,221,241	2,221,241	2,221,241	2,221,241	2,221,241	2,221,241
1,723,078	1,723,078	1,723,078	1,723,078	1,723,078	1,723,078	1,723,078	1,723,078	1,723,078
5,325,225	5,325,225	5,325,225	5,325,225	5,325,225	5,325,225	5,325,225	5,325,225	5,325,225
4,315,230	4,315,230	4,315,230	4,315,230	4,315,230	4,315,230	4,315,230	4,315,230	4,315,230
1,445,977,157	1,449,837,453	1,451,898,462	1,461,033,231	1,468,021,833	1,471,449,116	1,476,329,717	1,478,425,224	1,507,057,720

Protocol F.3

End-of-month gross plant balances for the 12-month period January 2019- December 2019:

Project Name	RTO Project Number or Zonal	Jan-19	Feb-19	Mar-19
Center Point 500 kV Substation Addition	b0269	34,380,112	34,380,112	34,380,112
Center Point 230 kV Substation Addition	b0269.10	17,190,056	17,190,056	17,190,056
Richmond-Waneeta 230 kV Line Re-conductor	b1591	4,605,741	4,605,741	4,605,741
Richmond-Waneeta 230 kV Line Re-conductor	b1398.8	1,535,247	1,535,247	1,535,247
Whitpain 500 kV Circuit Breaker Addition	b0269.6	3,258,302	3,258,302	3,258,302
Elroy-Hosensack 500 kV Line Rating Increase	b0171.1	4,456,731	4,456,731	4,456,731
Camden-Richmond 230 kV Line Rating Increase	b1590.1 and b1590.2 (cancelled b1398.6)	13,634,041	13,634,041	13,634,041
Chichester-Linwood 230 kV Line Upgrades	b1900	23,835,043	23,835,043	23,835,043
Bryn Mawr-Plymouth 138 kV Line Rebuild	b0727	18,036,480	18,036,480	18,036,480
Emilie 230-138 kV Transformer Addition	b2140	16,739,503	16,739,503	16,739,503
Chichester-Saville 138 kV Line Re-conductor	b1182	17,916,132	17,916,132	17,916,132
Waneeta 230-138 kV Transformer Addition	b1717	11,068,177	11,068,177	11,068,177
Chichester 230-138 kV Transformer Addition	b1178	8,327,759	8,327,759	8,327,759
Bradford-Planebrook 230 kV Line Upgrades	b0790	1,712,754	1,712,754	1,712,754
North Wales-Hartman 230 kV Line Re-conductor	b0506	2,229,232	2,229,232	2,229,232
North Wales-Whitpain 230 kV Line Re-conductor	b0505	2,546,903	2,546,903	2,546,903
Bradford-Planebrook 230 kV Line Upgrades	b0789	2,359,200	2,359,200	2,359,200
Planebrook 230 kV Capacitor Bank Addition	b0206	3,631,396	3,631,396	3,631,396
Newlinville 230 kV Capacitor Bank Addition	b0207	4,811,873	4,811,873	4,811,873
Chichester-Mickleton 230 kV Series Reactor Addition	b0209	2,699,444	2,699,444	2,699,444
Chichester-Mickleton 230 kV Line Re-conductor	b0264	2,221,241	2,221,241	2,221,241
Buckingham-Pleasant Valley 230 kV Line Re-conductor	b0357	1,723,078	1,723,078	1,723,078
Elroy 500 kV Dynamic Reactive Device	b0287	5,325,225	5,325,225	5,325,225
Heaton 230 kV Capacitor Bank Addition	b0208	4,315,230	4,315,230	4,315,230
Peach Bottom 500-230 kV Transformer Rating Increase	b2694	4,240,916	4,240,916	4,240,916
Peach Bottom 500 kV Substation Upgrades	b2766.2	-	-	-
	Zonal	1,500,721,028	1,507,158,264	1,518,246,141

Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19
34,380,112	34,380,112	34,380,112	34,380,112	34,380,112	34,380,112	34,380,112	34,380,112	34,380,112
17,190,056	17,190,056	17,190,056	17,190,056	17,190,056	17,190,056	17,190,056	17,190,056	17,190,056
4,605,741	4,605,741	4,605,741	4,605,741	4,605,741	4,605,741	4,605,741	4,605,741	4,605,741
1,535,247	1,535,247	1,535,247	1,535,247	1,535,247	1,535,247	1,535,247	1,535,247	1,535,247
3,258,302	3,258,302	3,258,302	3,258,302	3,258,302	3,258,302	3,258,302	3,258,302	3,258,302
4,456,731	4,456,731	4,456,731	4,456,731	4,456,731	4,456,731	4,456,731	4,456,731	4,456,731
13,634,041	13,634,041	13,634,041	13,634,041	13,634,041	13,634,041	13,634,041	13,634,041	13,634,041
23,835,043	23,835,043	23,835,043	23,835,043	23,835,043	23,835,043	23,835,043	23,835,043	23,835,043
18,036,480	18,036,480	18,036,480	18,036,480	18,036,480	18,036,480	18,036,480	18,036,480	18,036,480
16,739,503	16,739,503	16,739,503	16,739,503	16,739,503	16,739,503	16,739,503	16,739,503	16,739,503
17,916,132	17,916,132	17,916,132	17,916,132	17,916,132	17,916,132	17,916,132	17,916,132	17,916,132
11,068,177	11,068,177	11,068,177	11,068,177	11,068,177	11,068,177	11,068,177	11,068,177	11,068,177
8,327,759	8,327,759	8,327,759	8,327,759	8,327,759	8,327,759	8,327,759	8,327,759	8,327,759
1,712,754	1,712,754	1,712,754	1,712,754	1,712,754	1,712,754	1,712,754	1,712,754	1,712,754
2,229,232	2,229,232	2,229,232	2,229,232	2,229,232	2,229,232	2,229,232	2,229,232	2,229,232
2,546,903	2,546,903	2,546,903	2,546,903	2,546,903	2,546,903	2,546,903	2,546,903	2,546,903
2,359,200	2,359,200	2,359,200	2,359,200	2,359,200	2,359,200	2,359,200	2,359,200	2,359,200
3,631,396	3,631,396	3,631,396	3,631,396	3,631,396	3,631,396	3,631,396	3,631,396	3,631,396
4,811,873	4,811,873	4,811,873	4,811,873	4,811,873	4,811,873	4,811,873	4,811,873	4,811,873
2,699,444	2,699,444	2,699,444	2,699,444	2,699,444	2,699,444	2,699,444	2,699,444	2,699,444
2,221,241	2,221,241	2,221,241	2,221,241	2,221,241	2,221,241	2,221,241	2,221,241	2,221,241
1,723,078	1,723,078	1,723,078	1,723,078	1,723,078	1,723,078	1,723,078	1,723,078	1,723,078
5,325,225	5,325,225	5,325,225	5,325,225	5,325,225	5,325,225	5,325,225	5,325,225	5,325,225
4,315,230	4,315,230	4,315,230	4,315,230	4,315,230	4,315,230	4,315,230	4,315,230	4,315,230
4,240,916	11,679,096	12,865,391	12,961,661	12,987,393	13,002,265	13,027,473	13,038,198	13,038,203
-	-	-	-	-	-	-	-	985,461
1,530,201,066	1,533,399,678	1,539,049,840	1,545,248,144	1,536,622,186	1,536,700,457	1,548,943,027	1,569,967,491	1,582,661,483

Protocol F.3

Schedule 12 tarriffed projects that are 100% allocated to PECO:

Project Description	RTO Number	Original In-Service Cost	Notes
Upgrade two 230 kV breakers at Whitpain #235 and #325	b0005	-	**A**
Upgrade Plymouth Meeting 230 kV breakers #215	b0022	-	**A**
Add capacitors in north Philadelphia - Buckingham	b0043.1	1,232,268	
Add capacitors in north Philadelphia - Woodburne	b0043.2	1,736,497	
Add capacitors in north Philadelphia - North Wales	b0043.3	1,525,973	
Replace Richmond 69KV breaker #20 with 40,000 A	b0044	-	**A**
Jumper out Richmond 69KV breaker #40	b0045	-	**A**
Replace Richmond 69KV breaker #120 with 40,000 A	b0047	-	**A**
Add a new Roxborough 69kV breaker (#215)	b0059	42,984	
Circuit Breaker Upgrades at Whitpain - 230kV bus breakers #125 and #215	b0175	-	**A**
Replace Whitpain 230kV circuit breaker #165	b0180	-	**A**
Replace Whitpain 230kV circuit breaker #J105	b0181	-	**A**
Upgrade Plymouth Meeting 230kV circuit breaker #125	b0182	-	**A**
Install three 28.8MVAR capacitors at Planebrook 35kV substation	b0205	3,631,396	
Replace two wave traps and ammeter at Peach Bottom, and two wave traps and ammeter at Newlinville 230kV substations	b0266	238,283	
Upgrade North Wales breaker #105	b0269.7	-	**A**
Upgrade Waneeta 230 kV breaker '285'	b0269.8	-	**A**
Install 161MVAR capacitor at Warrington 230 kV substation	b0280.1	2,784,541	
Install 161MVAR capacitor at Bradford 230 kV substation	b0280.2	3,506,480	
Install 28.8MVAR capacitor at Warrington 34kV substation	b0280.3	745,859	
Install 18MVAR capacitor at Waverly 13.8kV substation	b0280.4	-	**A**
Tunnel - Grays Ferry 230kV - Replace terminal equipment 220-89 line	b0351	26,751	
Tunnel - Parrish 230kV - Replace terminal equipment 220-27 line	b0352	25,452	
Install 3% reactors on both lines from Eddystone - Lianerch	b0353.1	1,274,337	
Install identical second 230/138kV transformer in parallel with existing transformer at Plymouth Meeting	b0353.2	8,251,051	
Replace Whitpain 230 kV breaker 135	b0353.3	752,100	
Replace Whitpain 230 kV breaker 145	b0353.4	752,100	
Eddystone - Island Rd Upgrade line terminal equipment(CB # 235, three disconnect switches and two CTs) - new emergency rating of 1411 MVA, same impedance data	b0354	-	**A**
Install SPS at Chichester	b0413	-	**A**
Whitpain PRA 500/230kV Transformer	b0438	1,026,041	
Peach Bottom PRA 500/230kV Transformer	b0443	-	**A**
Replace station cable at Hartman on the Warrington - Hartman 230 kV circuit	b0508.1	23,428	
Jarrett - Heaton - Upgrade 230kV line terminal equipment (220-51 line)	b0509	309,935	
Replace Plymouth Meeting 230 kV breaker '335'	b0829.5	-	**A**
Install a 2nd 230/138 kV XFMR and 35 MVAR CAP at Heaton 138 kV bus	b0842	10,850,110	
Replace Heaton 138kV breaker '150'	b0842.1	241,114	
Install a 75 MVAR CAP at Llanerch 138 kV bus	b0843	5,870,803	
Replace station cable at Whitpain and Jarrett substations on the Jarrett - Whitpain 230 kV circuit 220-52	b0920	87,808	
Replace Breaker #115 at Printz 230 kV substation	b1015.1	24,621	
Replace Breaker #125 at Printz 230 kV substation	b1015.2	24,621	
Install 2 new 230 kV breakers at Planebrook (on the 220-02 line terminal and on the 230 kV side of the #9 transformer)	b1073	2,359,200	
Upgrade Richmond 230 kV breaker '525'	b1156.1	36,862	
Replace Emilie 138 kV breaker '190'	b1156.12	913,027	

Upgrade Richmond 230 kV breaker '415'	b1156.2	-	**A**
Upgrade Richmond 230 kV breaker '475'	b1156.3	2,908	
Upgrade Richmond 230 kV breaker '575'	b1156.4	29,209	
Upgrade Richmond 230 kV breaker '185'	b1156.5	582	
Upgrade Richmond 230 kV breaker '285'	b1156.6	-	**A**
Upgrade Waneeta 230 kV breaker '85'	b1156.7	595,249	
Replace Waneeta 230 kV breaker '425'	b1156.8	1,482,474	
Replace Emilie 230 kV breaker '815'	b1156.9	443,960	
Replace terminal equipment at Eddystone and Saville. Replace underground section of the line	b1179	3,239,637	
Replace terminal equipment at Chichester	b1180.1	255,514	
Replace terminal equipment at Chichester	b1180.2	255,514	
Install 230/138 kV transformer at Eddystone	b1181	3,064,183	
Replace 230/69 kV transformer #6 at Cromby. Add two 50 MVAR 230 kV banks at Cromby	b1183	10,821,904	
Add 138 kV breakers at Cromby, Perkiomen, and North Wales. Add a 35 MVAR capacitor at Perkiomen 138 kV	b1184	4,990,213	
Upgrade Eddystone 230 kV breaker #365	b1185	-	**A**
Upgrade Eddystone 230 kV breaker #785	b1186	372,437	
Reconductor the PECO portion of the Burlington - Croydon circuit, replace some towers, and replace aerial wire at Croydon.	b1197	1,550,007	
Replace terminal equipment including station cable, disconnects and relay at Conowingo 230 kV station	b1198	282,071	
Upgrade Printz 230 kV breaker '225'	b1338	252,355	
Upgrade Printz 230 kV breaker '315'	b1339	617,757	
Upgrade Printz 230 kV breaker '215'	b1340	448,523	
Install a second Waneeta 230/138 kV transformer on a separate bus section	b1717	11,069,197	
Reconductor the Crescentville - Foxchase 138 kV circuit	b1718	1,095,241	
Reconductor the Foxchase - Bluegrass 138 kV circuit	b1719	1,067,669	
Increase the effective rating of the Eddystone 230/138 kV transformer by replacing a circuit breaker at Eddystone	b1720	255,349	
Increase the rating of the Waneeta - Tuna 138 kV circuit by replacing two 138 kV CTs at Waneeta	b1721	16,371	
Increase the normal rating of the Cedarbrook - Whitemarsh 69 kV circuit by changing the CT ratio and replacing station cable at Whitemarsh 69 kV	b1722	16,550	
Install 39 MVAR capacitor at Cromby 138 kV bus	b1768	4,809,675	
Replace Waneeta 138 kV breaker '15' with 63 kA rated breaker	b2130	668,084	
Replace Waneeta 138 kV breaker '35' with 63 kA rated breaker	b2131	522,525	
Replace Waneeta 138 kV breaker '895' with 63 kA rated breaker	b2133	417,640	
Install a 3rd Emilie 230/138 kV transformer	b2140	16,310,640	
Replace two sections of conductor inside Richmond substation	b2145	-	**A**
Install a second Eddystone 230/138 kV transformer	b2222	20,342,771	
Replace the Eddystone 138 kV #205 breaker with 63kA breaker	b2222.1	272,372	
Increase Rating of Eddystone #415 138kV Breaker	b2222.2	425,581	
50 MVAR reactor at Buckingham 230 kV	b2236	5,578,133	
Replace Whitpain 230 kV breaker '155' with 80kA breaker	b2527	509,794	
Replace Whitpain 230 kV breaker '525' with 80kA breaker	b2528	474,748	
Replace Whitpain 230 kV breaker '175' with 80kA breaker	b2529	463,898	
Replace terminal equipment inside Chichester substation on the 220-36 (Chichester – Eddystone) 230 kV line	b2549	306,063	
Replace terminal equipment inside Nottingham substation on the 220-05 (Nottingham – Daleville – Bradford) 230 kV line	b2550	12,913	
Replace terminal equipment inside Llanerch substation on the 130-45 (Eddystone to Llanerch) 138 kV line	b2551	249,700	
Replace the Peach Bottom 500 kV '#225' breaker with a 63kA breaker	b2572	772,840	
Reconductor the Emilie - Falls 138 kV line, and and replace station cable and relay	b2774	5,399,046	
Reconductor the Falls - U.S. Steel 138 kV line	b2775	95,316	

Replace the Waneeta 230kV "285" with 63kA breaker	b2850	-	**A**
Replace the Chichester 230kV "195" with 63kA breaker	b2852	-	**B**
Replace the North Philadelphia 230kV "CS 775" with 63kA breaker	b2854	2,123,320	
Replace the North Philadelphia 230kV "CS 885" with 63kA breaker	b2855	2,158,251	
Replace the Parrish 230kV "CS 715" with 63kA breaker	b2856	1,490,758	
Replace the Plymouth Meeting 230kV "215" with 63kA breaker	b2859	374,445	
Replace the Plymouth Meeting 230kV "235" with 63kA breaker	b2860	440,571	
Replace the Plymouth Meeting 230kV "325" with 63kA breaker	b2861	394,525	
Replace the Grays Ferry 230kV "985" with 63kA breaker	b2863	-	**A**
Replace the Chichester 230kV '215' breaker with 63kA breaker	b2926	1,720,636	
Replace the Plymouth Meeting 230kV '125' breaker with 63kA breaker	b2927	359,055	
Total		157,211,814	

Notes:

A: Work was completed and the cost included as part of another Schedule 12 tariffed project 100% allocated to PECO and as such, the cost for this project is not being presented separately.

B: No field work was required for this project.

Protocol F.4

Provide supporting documentation for Attachment H-7B that will include workpapers showing that the income tax/(credit) for excess deferred income taxes is only related to the current year and reconciling input balances to the appropriate FERC Form No. 1 data

Income Tax Expense
PECO Energy Company

Line	Title of Account	FERC Form 1 Reference	Transmission[1] (A)	TCJA Related FAS109 Amortization[2] (B)	MDTAC[3] (C)	AFUDC Equity[4] (D)	Total Transmission (Columns A+B+C+D) (E)	Distribution / Other[5] (F)	FERC Form 1[6] (Columns E+F) (G)
1	Income Taxes - Federal (409.1)	Pg. 114, Line 15	7,286,037	-	-	-	7,286,037	36,341,112	43,627,149
2	- Other (409.1)	Pg. 114, Line 16	-	-	-	-	-	68,415	68,415
3	Provision for Deferred Income Taxes (410.1)	Pg. 114, Line 17	11,066,446	-	2,789,855	226,974	14,083,275	70,894,184	84,977,459
4	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	Pg. 114, Line 18	69,817	3,250,820	94,954	362,403	3,777,994	43,138,208	46,916,202
5	Investment Tax Credit Adj. - Net (411.4)	Pg. 114, Line 19	(2,976)	-	-	-	(2,976)	(143,405)	(146,381)
6	**Total - Income Tax Expense / (Benefit)**		18,279,690	(3,250,820)	2,694,901	(135,429)	17,588,342	64,022,098	81,610,440

Notes:

1 Represents the income tax accrual attributable to transmission related activity.

2 Represents the current year amortization of excess deferred taxes attributable to the Tax Jobs & Cuts Act (TCJA).

3 Represents the current year reversal / amortization of income tax regulatory assets / liabilities (i.e. Excess Deferred Taxes [Non-TCJA]), Repair Allowance and Federal and State Flow Through).

4 Represents the current year origination and reversal of income tax regulatory asset / liabilities attributable to AFUDC Equity.

5 Represents income tax accrual attributable to distribution and other related activity.

6 Represents total income tax accrual reflected on the FERC Form 1.

Protocol F.14

Include a workpaper with a breakdown of all Service Company costs allocated to and incurred by PECO and recognized in its Annual FERC Form No. 1, including costs recorded in Account 923. This breakdown will show the Service Company costs allocated to and incurred at PECO by FERC Account and expense item, and will be reconciled to both Exelon Business Services Company (BSC)'s Annual Form 60, Schedule XVII – Analysis of Billing – Associate Companies (Account 457), Line 31 (or the equivalent line number should that line number change) in addition to the inputs included in the annual transmission formula rate template

PECO Energy
2019 Exelon Service Company Allocated Costs to PECO

FERC Account	Description	Cost Type	For the 12 months ended December 31, 2019	
BALANCE SHEET				
107*	Construction work in progress	General and Administrative	5,804,843	E
107*	Construction work in progress	IT and Telecommunications	82,057,780	H
107*	Construction work in progress	Security Services	216,957	F
107*	Construction work in progress	Supply Services	737,669	G
		Total	**88,817,250**	
108	Accumulated provision for depreciation of utility plant (Major only)	General and Administrative	(26)	E
108	Accumulated provision for depreciation of utility plant (Major only)	IT and Telecommunications	100,462	H
108	Accumulated provision for depreciation of utility plant (Major only)	Supply Services	47,928	G
		Total	**148,363**	
163	Stores expense undistributed (Major only)	Supply Services	1,921,161	G
182.3	Other regulatory assets	Contracting Expenses	(2,476,867)	J
INCOME STATEMENT				
408.1	Taxes other than income taxes, utility operating income	Supply Services	(28)	G
426.1*	Donations	Communication Services	895,110	B
426.1*	Donations	Financial Services	4,467	A
426.1*	Donations	General and Administrative	50,270	E
426.1*	Donations	HR Services	983	C
426.1*	Donations	IT and Telecommunications	1,009	H
426.1*	Donations	Legal Services	1,002	D
426.1*	Donations	Reg & Govt Affair Services	53,932	I
		Total	**1,006,774**	
426.3*	Penalties	Contracting Expenses	140	J
426.3*	Penalties	Supply Services	(191)	G
		Total	**(51)**	
426.4*	Expenditures for certain civic, political and related activities	Communication Services	90,516	B
426.4*	Expenditures for certain civic, political and related activities	Financial Services	17,676	A
426.4*	Expenditures for certain civic, political and related activities	General and Administrative	3,103	E
426.4*	Expenditures for certain civic, political and related activities	Legal Services	1,031	D
426.4*	Expenditures for certain civic, political and related activities	Reg & Govt Affair Services	144,644	I
		Total	**256,970**	
426.5*	Other deductions	Supply Services	441	G
557*	Other expenses	IT and Telecommunications	1,023,862	H
560	Operation supervision and engineering	General and Administrative	2,152,128	E
562	Station expenses (Major only)	Supply Services	2,748	G
563	Overhead line expense (Major only)	Supply Services	568	G
566	Miscellaneous transmission expenses (Major only)	General and Administrative	83,116	E
566	Miscellaneous transmission expenses (Major only)	IT and Telecommunications	5,932,307	H
566	Miscellaneous transmission expenses (Major only)	Security Services	382,576	F
566	Miscellaneous transmission expenses (Major only)	Supply Services	82	G
		Total	**6,398,082**	
569	Maintenance of structures (Major only)	Supply Services	15	G
569.1	Maintenance of computer hardware.	IT and Telecommunications	58,543	H
569.2	Maintenance of computer software.	IT and Telecommunications	58,543	H
569.2	Maintenance of computer software.	Supply Services	(60)	G
		Total	**58,483**	
569.3	Maintenance of communication equipment	IT and Telecommunications	58,543	H
570	Maintenance of station equipment (Major only)	IT and Telecommunications	7	H
570	Maintenance of station equipment (Major only)	Supply Services	15,990	G
		Total	**15,997**	
571	Maintenance of overhead lines (Major only)	Supply Services	1,562	G
572	Maintenance of underground lines (Major only)	Supply Services	2,380	G
573	Maintenance of miscellaneous transmission plant (Major only)	IT and Telecommunications	5	H
573	Maintenance of miscellaneous transmission plant (Major only)	Supply Services	9,213	G

		Total	9,218	
582*	Station expenses (Major only)	Supply Services	828	G
583*	Overhead line expenses (Major only)	General and Administrative	(11)	E
583*	Overhead line expenses (Major only)	IT and Telecommunications	5,532	H
583*	Overhead line expenses (Major only)	Supply Services	124,679	G
		Total	130,200	
584*	Underground line expenses (Major only)	IT and Telecommunications	2,766	H
584*	Underground line expenses (Major only)	Supply Services	11,753	G
		Total	14,519	
585*	Street lighting and signal system expenses	General and Administrative	(1)	E
585*	Street lighting and signal system expenses	Supply Services	158	G
		Total	157	
586*	Meter expenses	IT and Telecommunications	1,812,445	H
586*	Meter expenses	Supply Services	953	G
		Total	1,813,398	
587*	Customer installations expenses	IT and Telecommunications	5	H
587*	Customer installations expenses	Supply Services	35,967	G
		Total	35,972	
588*	Miscellaneous distribution expenses	General and Administrative	16,621	E
588*	Miscellaneous distribution expenses	IT and Telecommunications	31,184,083	H
588*	Miscellaneous distribution expenses	Supply Services	3,672	G
		Total	31,204,375	
591*	Maintenance of structures (Major only)	IT and Telecommunications	8,393	H
592*	Maintenance of station equipment (Major only)	IT and Telecommunications	9	H
592*	Maintenance of station equipment (Major only)	Supply Services	87,036	G
		Total	87,045	
593*	Maintenance of overhead lines (Major only)	IT and Telecommunications	47,031	H
593*	Maintenance of overhead lines (Major only)	Supply Services	244,846	G
		Total	291,878	
594*	Maintenance of underground lines (Major only)	IT and Telecommunications	24	H
594*	Maintenance of underground lines (Major only)	Supply Services	139,023	G
		Total	139,047	
595*	Maintenance of line transformers	IT and Telecommunications	1	H
595*	Maintenance of line transformers	Supply Services	3,249	G
		Total	3,250	
596*	Maintenance of street lighting and signal systems	Supply Services	1,039	G
598*	Maintenance of miscellaneous distribution plant	General and Administrative	228	E
598*	Maintenance of miscellaneous distribution plant	IT and Telecommunications	1,409,553	H
598*	Maintenance of miscellaneous distribution plant	Supply Services	66,335	G
		Total	1,476,117	
840*	Operation supervision and engineering	Supply Services	1	G
841*	Operation labor and expenses	Supply Services	22	G
843.1*	Maintenance supervision and engineering	Supply Services	43	G
843.2*	Maintenance of structures and improvements	IT and Telecommunications	2,245	H
843.2*	Maintenance of structures and improvements	Supply Services	25	G
		Total	2,270	
870*	Operation supervision and engineering	Supply Services	256	G
874*	Mains and services expenses	Supply Services	32,626	G
875*	Measuring and regulation station expenses - General	Supply Services	4,093	G
878*	Meter and house regulator expenses	IT and Telecommunications	65,331	H
878*	Meter and house regulator expenses	Supply Services	72	G
		Total	65,403	
879*	Customer installations expenses	Supply Services	13,747	G
880*	Other expenses	IT and Telecommunications	6,869,620	H
880*	Other expenses	Supply Services	(52)	G
		Total	6,869,568	
887*	Maintenance of mains	Supply Services	59,394	G
889*	Maintenance of measuring and regulating station equipment - General	Supply Services	3,189	G
892*	Maintenance of services	Supply Services	6,303	G

893*	Maintenance of meters and house regulators	Supply Services	1,435	G
894*	Maintenance of other equipment	IT and Telecommunications	153,750	H
894*	Maintenance of other equipment	Supply Services	8	G
		Total	**153,758**	
902*	Meter reading expenses	IT and Telecommunications	1,261,773	H
903*	Customer records and collection expenses	IT and Telecommunications	10,078,748	H
905*	Miscellaneous customer accounts expenses (Major only)	IT and Telecommunications	1,626,182	H
905*	Miscellaneous customer accounts expenses (Major only)	Supply Services	25	G
		Total	**1,626,208**	
908*	Customer assistance expenses (Major only)	General and Administrative	250,988	E
908*	Customer assistance expenses (Major only)	IT and Telecommunications	178,474	H
		Total	**429,462**	
920	Administrative and general salaries	Contracting Expenses	(1,041)	J
920	Administrative and general salaries	Supply Services	(210,783)	G
		Total	**(211,824)**	
923	Outside services employed	Communication Services	1,749,784	B
923	Outside services employed	Contracting Expenses	1,043,307	J
923	Outside services employed	Financial Services	16,146,258	A
923	Outside services employed	General and Administrative	14,107,752	E
923	Outside services employed	HR Services	6,497,571	C
923	Outside services employed	IT and Telecommunications	24,245,845	H
923	Outside services employed	Legal Services	7,831,738	D
923	Outside services employed	Other Miscellaneous Expenses	577,316	K
923	Outside services employed	Reg & Govt Affair Services	1,814,220	I
923	Outside services employed	Security Services	7,058,688	F
923	Outside services employed	Supply Services	253,752	G
		Total	**81,326,230**	
924	Property insurance	Financial Services	53,479	A
925	Injuries and damages	HR Services	3,006	C
925	Injuries and damages	Security Services	3,990	F
		Total	**6,996**	
926	Employee pensions and benefits	Supply Services	7	G
930.1*	General advertising expenses	Communication Services	908,127	B
930.1*	General advertising expenses	Financial Services	1,446	A
930.1*	General advertising expenses	General and Administrative	9,019	E
930.1*	General advertising expenses	HR Services	1,748	C
930.1*	General advertising expenses	IT and Telecommunications	1,286	H
930.1*	General advertising expenses	Legal Services	11,067	D
930.1*	General advertising expenses	Supply Services	393	G
		Total	**933,085**	
932	Maintenance of general plant	IT and Telecommunications	11	H
935	Maintenance of general plant	IT and Telecommunications	64	H
935	Maintenance of general plant	Supply Services	46	G
		Total	**110**	

Totals - 2019 Exelon Service Company Allocated Costs to PECO	
*Below Cost Type Totals agreed to FF1 on 'F.14 Reconciliation to FF1'	
Financial Services (A)	**16,223,326**
Communication Services (B)	**3,643,536**
HR Services (C)	**6,503,308**
Legal Services (D)	**7,844,838**
General and Administrative (E)	**22,478,030**
Security Services (F)	**7,662,211**
Supply Services (G)	**3,623,622**
IT and Telecommunications (H)	**168,244,230**
Reg & Govt Affair Services (I)	**2,012,796**
Contracting Expenses (J)	**(1,434,462)**
Other Miscellaneous Expenses (K)	**577,316**
Total BSC Costs	**237,378,752**

NOTE: The table above includes all costs charged to PECO by Exelon Business Services Company ("BSC") in 2019. Costs charged to PECO's balance sheet accounts by BSC are ultimately recorded to the appropriate income statement accounts in the periods in which those costs are realized.

***** Excluded from the formula

Protocol F.14

FERC Form 1 Page 429 - BSC Provided Costs Only from 'F.14 FF1 Page'

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Non-power Goods or Services Provided by Affiliate				
	Financial Services (Direct)	Exelon BSC	923, 924	4,244,669	A
	Financial Services (Indirect)	Exelon BSC	Various	11,978,657	A
	Communication Services (Direct)	Exelon BSC	923	5,681	B
	Communication Services (Indirect)	Exelon BSC	Various	3,637,855	B
	Human Resources Services (Direct)	Exelon BSC	923	6,231,269	C
	Human Resources Services (Indirect)	Exelon BSC	Various	272,040	C
	Legal Governance Services (Direct)	Exelon BSC	923	1,957,360	D
	Legal Governance Services (Indirect)	Exelon BSC	Various	5,887,479	D
	Executive Services (Direct)	Exelon BSC	Various	20,177	E
	Executive Services (Indirect)	Exelon BSC	Various	6,449,881	E
	BSC Commercial Operation Group Services (Direct)	Exelon BSC	Various	21,473	E
	BSC Commercial Operation Group Services (Indirect)	Exelon BSC	923	13,245	E
	Real Estate Services (Indirect)	Exelon BSC	923	577,316	K
	Security Services (Indirect)	Exelon BSC	Various	7,662,211	F
	BSC Exelon Utility (Direct)	Exelon BSC	566, 923	106,893	E
	BSC Exelon Utility (Indirect)	Exelon BSC	Various	15,866,361	E
	Supply Services (Direct)	Exelon BSC	Various	161,856	G
	Supply Services (Indirect)	Exelon BSC	Various	3,461,766	G
	IT Non Telecommunications Services (Direct)	Exelon BSC	Various	88,472,211	H
	IT Non Telecommunications Services (Indirect)	Exelon BSC	Various	79,224,386	H
	Regulatory and Government Affairs Services (Indirect)	Exelon BSC	Various	2,012,796	I
	BSC Other Services (Direct)	Exelon BSC	920	(1,041)	J
	BSC Other Services (Indirect)	Exelon BSC	Various	(1,433,420)	J
				236,831,119	To FERC Form 60

	From FF1	From F.14 Attachment	Difference	
Financial Services (A)	16,223,326	16,223,326	-	
Communication Services (B)	3,643,536	3,643,536	-	
HR Services (C)	6,503,308	6,503,308	-	
Legal Services (D)	7,844,838	7,844,838	(0)	
General and Administrative (E)	22,478,030	22,478,030	-	
Security Services (F)	7,662,211	7,662,211	(0)	
Supply Services (G)	3,623,622	3,623,622	0	
IT and Telecommunications (H)	167,696,597	168,244,230	(547,633)	L
Reg & Govt Affair Services (I)	2,012,796	2,012,796	-	
Contracting Expenses (J)	(1,434,462)	(1,434,462)	-	
Other Miscellaneous Expenses (K)	577,316	577,316	-	
	236,831,119	237,378,752	(547,633)	

L These BSC costs were incorrectly not reflected in PECO's FERC Form 1 Page 429 or BSC's FERC Form 60. The costs have no impact on the transmission formula rate.

Exelon Business Services Company
FERC Form 60
Schedule XVII

Line No.	Name of Associate Company	Account 457.1 Direct Costs Charged	Account 457.2 Indirect Costs Charged	Account 457.3 Compensation For Use of Capital	Total Amount Billed
1	Aerolab Enterprises, LLC	4,490,809	-	-	4,490,809
2	Atlantic City Electric Co.	9,466,757	53,140,949	121,779	62,729,485
3	Aquify	647,524	-	-	647,524
4	ATNP Finance Company	5,949	-	-	5,949
5	Baltimore Gas and Electric Company	153,580,930	128,516,364	380,097	282,477,391
6	BGE Home Products & Services, LLC	2,365,289	10,498	-	2,375,787
7	CER Generation LLC (Hillabee)	20,527	-	-	20,527
8	Cltn Battery Utility, LLC	35,663	-	-	35,663
9	Colorado Bend II Power, LLC.	9,485	-	-	9,485
10	Commonwealth Edison Company	134,671,134	276,286,333	929,025	411,886,492
11	Constellation Energy Comm Grp.	62,097,910	1,686,251	-	63,784,161
12	Constellation Energy Nuclear Group, LLC (dba CENG, LLC)	4,123,628	(1,129)	-	4,122,499
13	Constellation Mystic Pwr, LLC	522,104	-	-	522,104
14	Constellation NewEnergy, Inc	55,693,623	2,350,019	-	58,043,642
15	Constellation Power Source Gen.	101,928	-	-	101,928
16	Constellation Power, Inc.	-	73,460	-	73,460
17	Criterion Power Partners LLC	38,247	-	-	38,247
18	Data Center Enterprises, LLC	1,483,139	-	-	1,483,139
19	Delmarva Power & Light Co.	15,011,873	64,562,198	148,533	79,722,604
20	Distrigas of Massachusetts LLC	242,749	-	-	242,749
21	Exelon Corporation	625,908	9,168,292	98,253	9,892,453
22	Exelon Enterprises Company,LLC	5,400	-	-	5,400

23	Exelon Framingham, LLC	(12)	-	-	(12)	
24	Exelon Generation Company, LLC	258,229,018	256,614,354	2,171,261	517,014,633	
25	Exelon Generation Finance Company, LLC	5,816	-	-	5,816	
26	ExGen Handley Power, LLC	96,727	-	-	96,727	
27	Exelon New England Holdings, LLC	1	-	-	1	
28	Exelon PowerLabs, LLC	2,971	-	-	2,971	
29	Exelon Solar Chicago, LLC	44,894	-	-	44,894	
30	Exelon Transmission Company, LLC	(24,262)	-	-	(24,262)	
31	Exelon West Medway, LLC	2,084	-	-	2,084	
32	Exelon West Medway II, LLC	323,968			323,968	
33	Exelon Wind, LLC	2,358,260	-	-	2,358,260	
34	Exelon Wyman, LLC	18	-	-	18	
35	ExTex LaPorte Limited Partnership	23,758	-	-	23,758	
36	EZEV Enterprise, LLC	1,727,095	-	-	1,727,095	
37	Handsome Lake Energy, LLC	13,368	-	-	13,368	
38	PECO Energy Company	101,220,546	135,225,402	385,171	236,831,119	From FF1
39	PEPCO Holdings Inc.	175,620	5,478,287	63,196	5,717,103	
40	PHI Service Company.	6,960,388	24,823,124	65,041	31,848,553	
41	Potomac Electric Power Co.	22,234,280	105,717,295	250,477	128,202,052	
42	RITELine Transmission Development, LLC	1	-	-	1	
43	Steer	2,316,441	-	-	2,316,441	
44	Wolf Hollow II Power, LLC.	83	-	-	83	
		840,951,639	1,063,651,697	4,612,833	1,909,216,169	

Protocol F.14

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PECO Energy Company	(1) [X] An Original (2) [ ] A Resubmission	03/24/2020	End of 2019/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Financial Services (Direct)	Exelon BSC	923, 924	4,244,669
3	Financial Services (Indirect)	Exelon BSC	Various	11,978,657
4	Communication Services (Direct)	Exelon BSC	923	5,681
5	Communication Services (Indirect)	Exelon BSC	Various	3,637,855
6	Human Resources Services (Direct)	Exelon BSC	923	6,231,269
7	Human Resources Services (Indirect)	Exelon BSC	Various	272,040
8	Legal Governance Services (Direct)	Exelon BSC	923	1,957,360
9	Legal Governance Services (Indirect)	Exelon BSC	Various	5,887,479
10	Executive Services (Direct)	Exelon BSC	Various	20,177
11	Executive Services (Indirect)	Exelon BSC	Various	6,449,881
12	BSC Commercial Operation Group Services (Direct)	Exelon BSC	Various	21,473
13	BSC Commercial Operation Group Services (Indirect)	Exelon BSC	923	13,245
14	Real Estate Services (Indirect)	Exelon BSC	923	577,316
15	Security Services (Indirect)	Exelon BSC	Various	7,662,211
16	BSC Exelon Utility (Direct)	Exelon BSC	566, 923	106,893
17	BSC Exelon Utility (Indirect)	Exelon BSC	Various	15,866,361
18	Supply Services (Direct)	Exelon BSC	Various	161,856
19	Supply Services (Indirect)	Exelon BSC	Various	3,461,766
20	**Non-power Goods or Services Provided for Affiliate**			
21	Real Estate Services	Exelon BSC	454, 493	3,007,762
22	Real Estate Services	Exelon Generation	454	21,993
23	Information Technology	ACE	456, 495	24,838
24	Information Technology	BGE	454, 456, 493, 495	598,364
25	Information Technology	ComEd	454, 456, 493, 495	311,581
26	Information Technology	DPL	456, 495	33,259
27	Information Technology	Pepco	456, 495	45,938
28	Human Resources Services	Exelon Generation	456	78,740
29	Mutual Assistance	ComEd	456	1,878
30	Mutual Assistance	DPL	456	5,556
31	Claims Services	Exelon Generation	Various	1,009,111
32	Corrective, Predictive, and Preventative Maintenae	Exelon Generation	456	19,772
33	Supply	BGE	456, 495	4,433
34	Training Services	Exelon Generation	456, 493, 495	73,793
35	Legislative Service	Exelon Generation	456, 495	145,040
37	Transmission Line Agreements	ACE	456	29,448
38	Transmission Line Agreements	DPL	456	36,492
39	Transmission Line Agreements	Pepco	456	54,288
40	Accounting Services	BGE	456, 495	66,768
41	Accounting Services	Exelon BSC	456, 495	85,949
42	Operations Support	DPL	456	20,579
1	**Non-power Goods or Services Provided by Affiliated**			
2	IT Non Telecommunications Services (Direct)	Exelon BSC	Various	88,472,211

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PECO Energy Company	(1) [X] An Original (2) [ ] A Resubmission	03/24/2020	End of 2019/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
3	IT Non Telecommunications Services (Indirect)	Exelon BSC	Various	79,224,386
4	Regulatory and Government Affairs Services (Indir)	Exelon BSC	Various	2,012,796
5	BSC Other Services (Direct)	Exelon BSC	920	-1,041
6	BSC Other Services (Indirect)	Exelon BSC	Various	-1,433,420
7	Calibration Testing	Exelon Power Labs	593, 920	759,660
8	Inspection Services	Exelon Aero Labs	920	239
9	Information Technology	BGE	588, 920	690,825
10	Information Technology	ComEd	920, 930	411,467
11	Mutual Assistance	ACE	920	110,633
12	Mutual Assistance	BGE	583, 584, 593, 920	426,812
13	Mutual Assistance	ComEd	593, 920	3,083,147
14	Mutual Assistance	DPL	920	511,087
15	Supply	BGE	920	1,377
16	Rent	Exelon Generation	567	138,630
17	Transmission Line Agreements	DPL	920	287,052
18	Call Center Services	ComEd	920	11,988
19	Corrective, Predictive, and Preventative Maintenae	Exelon Generation	107, 108.1	33,591
20	**Non-power Goods or Services Provided for Affiliate**			

Protocol F.15

Include a workpaper that lists the original in-service cost for each new Schedule 12 tariffed project that is 100% allocated to PECO

New Schedule 12 tarriffed projects that are 100% allocated to PECO:

Project Description	RTO Number	Original In-Service Cost	In-Service Year
Replace terminal equipment inside Nottingham substation on the 220-05 (Nottingham – Daleville – Bradford) 230 kV line	b2550	$ 12,912.84	2019
Replace terminal equipment inside Llanerch substation on the 130-45 (Eddystone to Llanerch) 138 kV line	b2551	249,700	2019
Reconductor the Emilie - Falls 138 kV line, and and replace station cable and relay	b2774	5,399,046	2019
Reconductor the Falls - U.S. Steel 138 kV line	b2775	95,316	2019
Replace the North Philadelphia 230kV "CS 775" with 63kA breaker	b2854	2,123,320	2019
Replace the North Philadelphia 230kV "CS 885" with 63kA breaker	b2855	2,158,251	2019
Replace the Parrish 230kV "CS 715" with 63kA breaker	b2856	1,490,758	2019

Protocol F.16

Include a workpaper that identifies and describes the amount of book depreciation expense associated with AFUDC Equity and its impact on income tax expense. The work paper will be taken directly from PECO's tax accounting records, namely the widely-used PowerTax tax depreciation and deferred tax software

AFUDC Equity
PECO Energy Company

Line	Line of Business	2019 AFUDC Equity Originations[1] (A)	2019 AFUDC Equity Reversals[1] (B)	Total AFUDC Equity Activity (Columns A+B) (C)	Transmission Allocation (D)	Transmission Allocation (Originations) (Columns A * D) (E)	Transmission Allocation (Reversals) (Columns B * D) (F)
1	Common	-	99,428	99,428	7.32%	-	7,279
2	Distribution	(8,152,887)	3,248,816	(4,904,071)	0.00%	-	-
3	Electric General	-	11,414	11,414	9.45%	-	1,078
4	Gas	(3,553,726)	473,938	(3,079,789)	0.00%	-	-
5	Transmission	(1,254,331)	777,236	(477,095)	100%	(1,254,331)	777,236
6	**Total**	(12,960,944)	4,610,831	(8,350,113)		(1,254,331)	785,594
7	Marginal Tax Rate					28.89%	28.89%
8	**Income Tax Expense / (Benefit)**					(362,403)	226,974

Notes:

1 Represents 2019 AFUDC Equity Originations and Reversals (pre-tax) from PowerTax by Line of Business.

PECO M&S
As of 12/31/2019

Line #	Description		Transmission M&S Total	Capital Split	Capital Split with 50% recovery up to $9M (Note L)	O&M Split	Transmission M&S 13 Month Average to Attachment 4
1	December	2018	13,217,723	6,664,966	3,332,483	6,552,757	9,885,240
2	January	2019	13,257,628	7,085,333	3,542,666	6,172,295	9,714,961
3	February	2019	13,274,321	7,094,254	3,547,127	6,180,067	9,727,194
4	March	2019	13,126,282	7,015,137	3,507,568	6,111,145	9,618,713
5	April	2019	13,225,663	7,068,249	3,534,125	6,157,413	9,691,538
6	May	2019	13,497,507	7,213,532	3,606,766	6,283,974	9,890,741
7	June	2019	13,885,185	7,420,721	3,710,361	6,464,464	10,174,825
8	July	2019	14,039,476	7,503,179	3,751,590	6,536,297	10,287,886
9	August	2019	13,914,484	7,436,379	3,718,190	6,478,105	10,196,294
10	September	2019	14,688,636	7,850,113	3,925,056	6,838,523	10,763,580
11	October	2019	14,555,065	7,778,728	3,889,364	6,776,337	10,665,701
12	November	2019	13,691,021	7,316,953	3,658,476	6,374,068	10,032,544
13	December	2019	15,045,584	8,040,878	4,020,439	7,004,706	11,025,145
Total				Q4 2019 FF1 tab, line 5; see		Q4 2019 FF1 tab; line 8 of FF1	**10,128,797**

Note L From Attachment 4: TLF shall be equal to 50 percent of the lesser of (a) the transmission portion of FERC Form 1, page 227, line 5, column c per FERC Form No. 1) and (b) $9 million. The TLF recovery percentage and cap will be subject to modification only through Commission authorization under section 205 or section 206 of the Federal Power Act.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PECO Energy Company	(1) [X] An Original (2) [ ] A Resubmission	03/24/2020	End of 2019/Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	1,724,781	1,628,987	Gas
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)		24,099,796	Electric & Gas
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)			
8	Transmission Plant (Estimated)	13,217, From F.18 Summary	7,004,706	Electric
9	Distribution Plant (Estimated)	23,916,814	3,898,241	Electric & Gas
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)			
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	37,134,537	35,002,743	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)			
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	38,859,318	36,631,730	

Schedule Page: 227 Line No.: 5 Column: c

Assigned to Construction 2019:

Distribution		15,737,126
Transmission	From F.18 Summary	8,040,878
Gas		321,792
Total		24,099,796