Attachment 1a

Derivation of PSE&G Network Integration Transmission Service (NITS) Charge

Attachment 1a PSE&G Network Integration Service Calculation.

Derived Network Integration Service Rate Applicable to PSE&G customers - Effective January 1, 2021 through December 31, 2021

Line #	Description	Rate			Source
(1)	Transmission Service Annual Revenue Requirement	$	1,645,668,896.00		Page 4 of Attachment 8 -Line 164
(2)	Total Schedule 12 TEC Included in above	$	(580,472,351.00)		Attachment 6a Column (a)
(3)	PSE&G Customer Share of Schedule 12 TEC	$	318,585,591.80		Attachment 6a Column (h)
(4)	Total Transmission Costs Borne by PSE&G customers	$	1,383,782,136.80		=(1) +(2) +(3)
(5)	2021 PSE&G Network Service Peak		9,557.3	MW	Page 4 of Attachment 8 Line 165
(6)	2021 Derived Network Integration Transmission Service Rate	$	144,787.98	per MW-year	
	Resulting 2021 BGS Firm Transmission Service Supplier Rate	$	396.68	per MW-day	= (6)/365

Attachment 1b

Derivation of JCP&L Network Integration Transmission Service (NITS) Charge

Attachment 1b JCP&L Network Integration Transmission Service Calculation

Derived Network Integration Transmission Service Rate Applicable to JCP&L Customers - Effective January 1, 2021 through December 31, 2021

Line #	Description	Rate		Source
(1)	Network Integration Transmission Service	$165,360,691		Attachment 9, Page 2 (Attachment H-4A) Line 10
(2)	JCP&L Customer Share of Schedule 12 TEC	$8,535,622		Attachment 6b, Column g
(3)	Total Transmission Costs Borne by JCP&L Customers	$173,896,313		=(1) + (2)
(4)	2021 JCP&L Network Service Peak	5,903.2	MW	PJM network service peak loads for 2021
(5)	2021 Derived Network Integration Transmission Service Rate	$29,457.97	per MW-year	
	Resulting 2021 BGS Firm Transmission Service Supplier Rate	$80.71	per MW-day	= (6)/365

Per JCPL Filing, Docket No. ER20-227, dated November 2, 2020 re PJM OATT, Attachment H-4 Projected Transmission Revenue Requirement for Rate Year 2021

Attachment 2 – PSE&G Tariffs and Rate Translation

Attachment 2a
Pro-forma PSE&G Tariff Sheets

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

Attachment 2c
PSE&G Translation of JCP&L Schedule 12 Transmission Enhancement
Charges into Customer Rates

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

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

Attachment 2f
PSE&G Translation of MAIT Schedule 12 Transmission Enhancement
Charges into Customer Rates

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

Attachment 2h
PSE&G Translation of Silver Run Schedule 12 Transmission
Enhancement Charges into Customer Rates

Attachment 2i
PSE&G Translation of NIPSCo Schedule 12 Transmission Enhancement
Charges into Customer Rates

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

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 2**
Superseding
B.P.U.N.J. No. 16 ELECTRIC **XXX Original Sheet No. 2**

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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 & CAPACITY 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: Energy & Capacity Charges	For usage in each of the months of October through May: Charges Including SUT	For usage in each of the months of June through September: Energy & Capacity Charges	For usage in each of the months of June through September: Charges Including SUT
RS – first 600 kWh	$ 0.068462	$ 0.072998	$ 0.066623	$ 0.071037
RS – in excess of 600 kWh	0.068462	0.072998	0.075579	0.080586
RHS – first 600 kWh	0.060084	0.064065	0.054500	0.058111
RHS – in excess of 600 kWh	0.060084	0.064065	0.066476	0.070880
RLM On-Peak	0.095990	0.102349	0.104770	0.111711
RLM Off-Peak	0.046576	0.049662	0.041682	0.044443
WH	0.049048	0.052297	0.046716	0.049811
WHS	0.049903	0.053209	0.046816	0.049918
HS	0.066461	0.070864	0.066771	0.071195
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, and Ancillary Services (including PJM Interconnection, L.L.C. (PJM) Administrative Charges).

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. 76**
Superseding
B.P.U.N.J. No. 16 ELECTRIC **XXX Revised Sheet No. 76**

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

BGS TRANSMISSION 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 all months: Transmission Charges	For usage in all months: Charges Including SUT
RS	$ 0.052745	$ 0.056239
RHS	0.030420	0.032435
RLM On-Peak	0.129500	0.138079
RLM Off-Peak	(0.002263)	(0.002413)
WH	0.000000	0.000000
WHS	0.000000	0.000000
HS	0.045112	0.048101
BPL	0.000000	0.000000
BPL-POF	0.000000	0.000000
PSAL	0.000000	0.000000

The above charges shall recover all costs related to 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 allocated to the above Rate Schedules. 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).

BGS ENERGY CHARGES:

Applicable to Rate Schedules GLP and LPL-Sec.

Charges per kilowatt-hour:

Rate Schedule	For usage in each of the months of October through May: Charges	For usage in each of the months of October through May: Charges Including SUT	For usage in each of the months of June through September: Charges	For usage in each of the months of June through September: Charges Including SUT
GLP	$ 0.049686	$ 0.052978	$ 0.047808	$ 0.050975
GLP Night Use	0.046292	0.049359	0.041682	0.044443
LPL-Sec. under 500 kW				
On-Peak	0.052928	0.056434	0.052974	0.056484
Off-Peak	0.046292	0.049359	0.041682	0.044443

The above Basic Generation Service Energy Charges reflect costs for Energy and Ancillary Services (including PJM Administrative Charges).

Kilowatt thresholds noted above are 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 ..... $144,787.98 per MW per year
EL05-121…….. ..... $ 82.32 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 ..... $ 67.96 per MW per month
Potomac-Appalachian Transmission Highline L.L.C. ..... $ 13.14 per MW per month
PPL Electric Utilities Corporation ..... $ 212.69 per MW per month
American Electric Power Service Corporation ..... $ 16.74 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 ..... $ 68.10 per MW per month
Mid Atlantic Interstate Transmission ..... $ 18.32 per MW per month
PECO Energy Company……. ..... $ 20.97 per MW per month
Silver Run Electric, Inc.……. ..... $ 42.82 per MW per month
Northern Indiana Public Service Company…… . $ 0.85 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 ..... $ 11.8868
Charge including New Jersey Sales and Use Tax (SUT) ..... $ 12.6743

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

PUBLIC SERVICE ELECTRIC AND GAS COMPANY **XXX Revised Sheet No. 83**
Superseding
B.P.U.N.J. No. 16 ELECTRIC **XXX Revised Sheet No. 83**

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

BGS TRANSMISSION CHARGES

Charges per kilowatt of Transmission Obligation:

Currently effective Annual Transmission Rate for Network Integration Transmission Service for the Public Service Transmission Zone as derived from the FERC Electric Tariff of the PJM Interconnection, LLC	$144,787.98 per MW per year
EL05-121……	$ 82.32 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	$ 67.96 per MW per month
Potomac-Appalachian Transmission Highline L.L.C.	$ 13.14 per MW per month
PPL Electric Utilities Corporation	$ 212.69 per MW per month
American Electric Power Service Corporation	$ 16.74 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	$ 68.10 per MW per month
Mid Atlantic Interstate Transmission	$ 18.32 per MW per month
PECO Energy Company…….	$ 20.97 per MW per month
Silver Run Electric, Inc.……	$ 42.82 per MW per month
Northern Indiana Public Service Company…… .	$ 0.85 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	$ 11.8868
Charge including New Jersey Sales and Use Tax (SUT)	$ 12.6743

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

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

Network Integration Service Calculation - BGS-RSCP
NITS Charges for January 2021 - December 2021

PSE&G Annual Transmission Service Revenue Requirement	$	1,645,668,896.00							
Total Schedule 12 TEC Included in above	$	(580,472,351.00)							
PSE&G Customer Share of Schedule 12 NITS	$	318,585,591.80							
NITS Charges for Jan 2021 - Dec 2021	$	1,383,782,136.80							
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,557.30							
Term (Months)		12							
OATT rate	$	12,065.66	/MW/month						
converted to $/MW/yr =	$	144,787.98	/MW/yr	**Jan 21 - Dec 21 NITS Charge**					
	$	117,402.50	/MW/yr	**2018- 2020 Weighted Average of:**			**$ 110,695.46**	**$ 104,709.15**	**$ 137,042.42**
	$	129,034.06	/MW/yr	**2019- 2021 Weighted Average of:**			**$ 104,709.15**	**$ 137,042.42**	**$ 144,787.98**
	$	124,187.58	/MW/yr	**Jan 21 - Dec 21 Weighted Average**					
Resulting Increase in Transmission Rate	$	20,600.40	/MW/yr						
Resulting Increase in Transmission Rate	$	1,716.70	/MW/month						

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4,435.3	20.1	69.7	0.0	0.0	3.3	0.0	0.0
Total Annual Energy - MWh	12,003,418.6	94,499.9	78,559.3	658.0	16.0	10,469.4	146,959.0	296,606.0
Energy Charge								
in $/MWh	$ 7.6119	$ 4.3817	$ 18.2773	$ -	$ -	$ 6.4933	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.007612**	**$ 0.004382**	**$ 0.018277**	**$ -**	**$ -**	**$ 0.006493**	**$ -**	**$ -**

Line #						
1	Total BGS-RSCP Trans Obl		6,947.7	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust		23,787,455	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes		25,091,270	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	143,125,404		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl adjusted for migration
5	Change in Average Supplier Payment Rate	$	5.7042	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	5.70	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	143,020,237		unrounded	= (6) * (3)
8	Difference due to rounding	$	(105,167)		unrounded	= (7) - (4)

Network Integration Service Calculation - BGS-RSCP
Estimate of Transmission Costs Embedded in Previous Auction Results
all values show w/o NJ SUT

$	117,402.50	/MW/yr	**2018- 2020 Weighted Average of:**	**$ 110,695.46**	**$ 104,709.15**	**$ 137,042.42**
$	129,034.06	/MW/yr	**2019- 2021 Weighted Average of:**	**$ 104,709.15**	**$ 137,042.42**	**$ 144,787.98**
$	124,187.58	/MW/yr	**Jan 21 - Dec 21 Weighted Average**			

	RS	**RHS**	**RLM**	**WH**	**WHS**	**HS**	**PSAL**	**BPL**
Trans Obl - MW	4,435.3	20.1	69.7	0.0	0.0	3.3	0.0	0.0
Total Annual Energy - MWh	12,003,418.6	94,499.9	78,559.3	658.0	16.0	10,469.4	146,959.0	296,606.0
Energy Charge								
in $/MWh	$ 45.8877	$ 26.4145	$ 110.1827	$ -	$ -	$ 39.1443	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.045888**	**$ 0.026415**	**$ 0.110183**	**$ -**	**$ -**	**$ 0.039144**	**$ -**	**$ -**

BGS RSCP Auction Results Effective June 1, 2020
PSE&G B.P.U.N.J. No. 16 Electric Tariff XXX Revised Sheet Nos. 75 and 76

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	BGS Auction Results Effective June 1, 2020		**Estimated Transmission Portion of Previous Auction Results**	**BGS Auction Energy & Capacity Charges Tariff Sheet No. 75**				**TEC Adders (see below table for details)**	**NITS Docket No. ERXXXXXXXX**	**RMR Approved = 0**	**BGS Transmission Charges Tariff Sheet No. 76**	
	(w/o SUT)		(w/o SUT)	October - May		June - September		(w/o SUT)	(w/o SUT)	(w/o SUT)		
	October - May	June - September	January - December	Charges w/o SUT (1) - (3) = (4)	Charges with SUT (4) * 1.06625 = (5)	Charges w/o SUT (2) - (3) = (6)	Charges with SUT (6) * 1.06625 = (7)	January - December	January - December	January - December	Charges w/o SUT (3) + (8) + (9) + (10) = (11)	Charges with SUT (11) * 1.06625 = (12)
RS – first 600 kWh	0.114350	0.112511	0.045888	0.068462	0.072998	0.066623	0.071037	-0.000755	0.007612	0.000000	0.052745	0.056239
RS – in excess of 600 kWh	0.114350	0.121467	0.045888	0.068462	0.072998	0.075579	0.080586	-0.000755	0.007612	0.000000	0.052745	0.056239
RHS – first 600 kWh	0.086499	0.080915	0.026415	0.060084	0.064065	0.054500	0.058111	-0.000377	0.004382	0.000000	0.030420	0.032435
RHS – in excess of 600 kWh	0.086499	0.092891	0.026415	0.060084	0.064065	0.066476	0.070880	-0.000377	0.004382	0.000000	0.030420	0.032435
RLM On-Peak	0.206173	0.214953	0.110183	0.095990	0.102349	0.104770	0.111711	0.001040	0.018277	0.000000	0.129500	0.138079
RLM Off-Peak	0.046576	0.041682	0.000000	0.046576	0.049662	0.041682	0.044443	-0.002263	0.000000	0.000000	-0.002263	-0.002413
WH	0.049048	0.046716	0.000000	0.049048	0.052297	0.046716	0.049811	0.000000	0.000000	0.000000	0.000000	0.000000
WHS	0.049903	0.046816	0.000000	0.049903	0.053209	0.046816	0.049918	0.000000	0.000000	0.000000	0.000000	0.000000
HS	0.105605	0.105915	0.039144	0.066461	0.070864	0.066771	0.071195	-0.000525	0.006493	0.000000	0.045112	0.048101
BPL	0.047907	0.043293	0.000000	0.047907	0.051081	0.043293	0.046161	0.000000	0.000000	0.000000	0.000000	0.000000
BPL-POF	0.047907	0.043293	0.000000	0.047907	0.051081	0.043293	0.046161	0.000000	0.000000	0.000000	0.000000	0.000000
PSAL	0.047907	0.043293	0.000000	0.047907	0.051081	0.043293	0.046161	0.000000	0.000000	0.000000	0.000000	0.000000

TEC Adders	**TECs filed Docket No. ERXXXXXXXX on XX/XX/2020**	**TECs filed Docket No. ERXXXXXXXX on XX/XX/2020**	**TECs filed Docket No. ER20100672 on 12/02/2020**	**TECs filed Docket No. ERXXXXXXXX on XX/XX/2020**	**TECs filed Docket No. ER20100672 on 12/02/2020**	**TECs filed Docket No. ER20060446 on 06/22/2020**	**TECs filed Docket No. ER20100672 on 12/02/2020**	**TECs filed Docket No. ER20100672 on 12/02/2020**	**TECs filed Docket No. ER20100672 on 12/02/2020**	**TECs filed Docket No. ERXXXXXXXX on XX/XX/2020**	**TECs filed Docket No. ERXXXXXXXX on XX/XX/2020**	**TECs filed Docket No. ER20100672 on 12/02/2020**	**TECs filed Docket No. ERXXXXXXXX on XX/XX/2020**	**TECs filed Docket No. ERXXXXXXXX on XX/XX/2020**	**TECs filed Docket No. ERXXXXXXXX on XX/XX/2020**	**TECs filed Docket No. ER20060446 on 06/22/2020**	**TECs filed Docket No. ER20100672 on 12/02/2020**	
Rate Schedule	**VEPCO**	**Path**	**ACE**	**AEP**	**TRAILCO**	**DELMARVA**	**PEPCO**	**PPL**	**BG&E**	**JCP&L**	**MAIT**	**PECO**	**EL05-121**	**SILVER RUN**	**NIPSCO**	**CW EDISON**	**FERC 680 & 715**	**TEC TOTAL**
RS – first 600 kWh	0.000301	0.000058	$0.000038	$0.000074	$0.000218	$0.000004	$0.000012	$0.000926	$0.000010	$0.000302	$0.000081	$0.000091	$0.000365	$0.000190	$0.000004	$0.000001	-$0.003430	-$0.000755
RS – in excess of 600 kWh	0.000301	0.000058	0.000038	0.000074	0.000218	0.000004	0.000012	0.000926	0.000010	0.000302	0.000081	0.000091	0.000365	0.000190	0.000004	0.000001	-0.003430	-$0.000755
RHS – first 600 kWh	0.000173	0.000034	0.000021	0.000043	0.000120	0.000002	0.000007	0.000508	0.000006	0.000174	0.000047	0.000050	0.000210	0.000109	0.000002	0.000001	-0.001884	-$0.000377
RHS – in excess of 600 kWh	0.000173	0.000034	0.000021	0.000043	0.000120	0.000002	0.000007	0.000508	0.000006	0.000174	0.000047	0.000050	0.000210	0.000109	0.000002	0.000001	-0.001884	-$0.000377
RLM On-Peak	0.000724	0.000140	0.000040	0.000178	0.000231	0.000005	0.000013	0.000983	0.000011	0.000725	0.000195	0.000097	0.000876	0.000456	0.000009	0.000001	-0.003644	$0.001040
RLM Off-Peak	0.000000	0.000000	0.000040	0.000000	0.000231	0.000005	0.000013	0.000983	0.000011	0.000000	0.000000	0.000097	0.000000	0.000000	0.000000	0.000001	-0.003644	-$0.002263
WH	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	$0.000000
WHS	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	$0.000000
HS	0.000257	0.000050	0.000030	0.000063	0.000174	0.000003	0.000010	0.000738	0.000008	0.000258	0.000069	0.000073	0.000311	0.000162	0.000003	0.000001	-0.002735	-$0.000525
BPL	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	$0.000000
BPL-POF	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	$0.000000
PSAL	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	0.000000	$0.000000

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges for January 2021 - December 2021
Calculation of costs and monthly PJM charges for JCP&L

TEC Charges for Jan 2021 - Dec 2021	$ 7,810,414.21		
PSE&G Zonal Transmission Load for Effective Yr. (MW)	9,557.30		
Term (Months)	12		
OATT rate	$ 68.10	/MW/month	all values show w/o NJ SUT
converted to $/MW/yr =	$ 817.20	/MW/yr	

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4,435.3	20.1	69.7	0.0	0.0	3.3	0.0	0.0
Total Annual Energy - MWh	12,003,418.6	94,499.9	78,559.3	658.0	16.0	10,469.4	146,959.0	296,606.0
Energy Charge								
in $/MWh	$ 0.3020	$ 0.1738	$ 0.7250	$ -	$ -	$ 0.2576	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000302**	**$ 0.000174**	**$ 0.000725**	**$ -**	**$ -**	**$ 0.000258**	**$ -**	**$ -**

Line #					
1	Total BGS-RSCP Trans Obl	6,947.7	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust	23,787,455.5	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes	25,091,269.7	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 5,677,660		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$ 0.2263	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ 0.23	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ 5,770,992		unrounded	= (6) * (3)
8	Difference due to rounding	$ 93,332		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges for January 2021 - December 2021
Calculation of costs and monthly PJM charges for VEPCO Projects

TEC Charges for Jan 2021 - Dec 2021	$ 7,793,603.16		
PSE&G Zonal Transmission Load for Effective Yr. (MW)	9,557.3		
Term (Months)	12		
OATT rate	$ 67.96	/MW/month	all values show w/o NJ SUT
converted to $/MW/yr =	$ 815.52	/MW/yr	

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4,435.3	20.1	69.7	0.0	0.0	3.3	0.0	0.0
Total Annual Energy - MWh	12,003,418.6	94,499.9	78,559.3	658.0	16.0	10,469.4	146,959.0	296,606.0
Energy Charge								
in $/MWh	$ 0.3013	$ 0.1735	$ 0.7236	$ -	$ -	$ 0.2571	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000301**	**$ 0.000173**	**$ 0.000724**	**$ -**	**$ -**	**$ 0.000257**	**$ -**	**$ -**

Line #					
1	Total BGS-RSCP Trans Obl	6,947.7	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust	23,787,455.5	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes	25,091,269.7	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 5,665,988		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$ 0.2258	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ 0.23	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ 5,770,992		unrounded	= (6) * (3)
8	Difference due to rounding	$ 105,004		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges for January 2021 - December 2021
Calculation of costs and monthly PJM charges for PATH Project

TEC Charges for Jan 2021 - Dec 2021	$ 1,507,285.85		
PSE&G Zonal Transmission Load for Effective Yr. (MW)	9,557.3		
Term (Months)	12		
OATT rate	$ 13.14	/MW/month	all values show w/o NJ SUT
converted to $/MW/yr =	$ 157.68	/MW/yr	

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4,435.3	20.1	69.7	0.0	0.0	3.3	0.0	0.0
Total Annual Energy - MWh	12,003,418.6	94,499.9	78,559.3	658.0	16.0	10,469.4	146,959.0	296,606.0
Energy Charge								
in $/MWh	$ 0.0583	$ 0.0335	$ 0.1399	$ -	$ -	$ 0.0497	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000058**	**$ 0.000034**	**$ 0.000140**	**$ -**	**$ -**	**$ 0.000050**	**$ -**	**$ -**

Line #					
1	Total BGS-RSCP Trans Obl	6,947.7	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust	23,787,455.5	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes	25,091,269.7	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 1,095,513		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$ 0.0437	/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	$ 1,003,651		unrounded	= (6) * (3)
8	Difference due to rounding	$ (91,863)		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges for January 2021 - December 2021
Calculation of costs and monthly PJM charges for Mid Atlantic Interstate Transmission Projects

TEC Charges for Jan 2021 - Dec 2021	$ 2,101,029.13			
PSE&G Zonal Transmission Load for Effective Yr. (MW)	9,557.3			
Term (Months)	12			
OATT rate	$ 18.32	/MW/month		all values show w/o NJ SUT
converted to $/MW/yr =	$ 219.84	/MW/yr		

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4,435.3	20.1	69.7	0.0	0.0	3.3	0.0	0.0
Total Annual Energy - MWh	12,003,418.6	94,499.9	78,559.3	658.0	16.0	10,469.4	146,959.0	296,606.0
Energy Charge								
in $/MWh	$ 0.0812	$ 0.0468	$ 0.1950	$ -	$ -	$ 0.0693	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000081**	**$ 0.000047**	**$ 0.000195**	**$ -**	**$ -**	**$ 0.000069**	**$ -**	**$ -**

Line #					
1	Total BGS-RSCP Trans Obl	6,947.7	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust	23,787,455.5	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes	25,091,269.7	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 1,527,382		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$ 0.0609	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ 0.06	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ 1,505,476		unrounded	= (6) * (3)
8	Difference due to rounding	$ (21,906)		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges for January 2021 - December 2021
Calculation of costs and monthly PJM charges for AEP - East Projects

TEC Charges for Jan 2021 - Dec 2021	$ 1,919,518.52		
PSE&G Zonal Transmission Load for Effective Yr. (MW)	9,557.3		
Term (Months)	12		
OATT rate	$ 16.74	/MW/month	all values show w/o NJ SUT
converted to $/MW/yr =	$ 200.88	/MW/yr	

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4,435.3	20.1	69.7	0.0	0.0	3.3	0.0	0.0
Total Annual Energy - MWh	12,003,418.6	94,499.9	78,559.3	658.0	16.0	10,469.4	146,959.0	296,606.0
Energy Charge								
in $/MWh	$ 0.0742	$ 0.0427	$ 0.1782	$ -	$ -	$ 0.0633	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000074**	**$ 0.000043**	**$ 0.000178**	**$ -**	**$ -**	**$ 0.000063**	**$ -**	**$ -**

Line #						
1	Total BGS-RSCP Trans Obl	6,947.7	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust	23,787,455.5	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes	25,091,269.7	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 1,395,654		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$ 0.0556	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ 0.06	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ 1,505,476		unrounded	= (6) * (3)
8	Difference due to rounding	$ 109,822		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges for January 2021 - December 2021
Calculation of costs and monthly PJM charges for Silver Run Projects

TEC Charges for Jan 2021 - Dec 2021	$ 4,911,064.23		
PSE&G Zonal Transmission Load for Effective Yr. (MW)	9,557.3		
Term (Months)	12		
OATT rate	$ 42.82	/MW/month	all values show w/o NJ SUT
converted to $/MW/yr =	$ 513.84	/MW/yr	

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4,435.3	20.1	69.7	0.0	0.0	3.3	0.0	0.0
Total Annual Energy - MWh	12,003,418.6	94,499.9	78,559.3	658.0	16.0	10,469.4	146,959.0	296,606.0
Energy Charge								
in $/MWh	$ 0.1899	$ 0.1093	$ 0.4559	$ -	$ -	$ 0.1620	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000190**	**$ 0.000109**	**$ 0.000456**	**$ -**	**$ -**	**$ 0.000162**	**$ -**	**$ -**

Line #					
1	Total BGS-RSCP Trans Obl	6,947.7	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust	23,787,455.5	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes	25,091,269.7	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$ 3,570,006		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$ 0.1423	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$ 0.14	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$ 3,512,778		unrounded	= (6) * (3)
8	Difference due to rounding	$ (57,228)		unrounded	= (7) - (4)

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges for January 2021 - December 2021
Calculation of costs and monthly PJM charges for NIPSCO Projects

TEC Charges for Jan 2021 - Dec 2021	$	97,291.40	
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,557.3	
Term (Months)		12	
OATT rate	$	0.85	/MW/month
converted to $/MW/yr =	$	10.20	/MW/yr

all values show w/o NJ SUT

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4,435.3	20.1	69.7	0.0	0.0	3.3	0.0	0.0
Total Annual Energy - MWh	12,003,418.6	94,499.9	78,559.3	658.0	16.0	10,469.4	146,959.0	296,606.0
Energy Charge								
in $/MWh	$ 0.0038	$ 0.0022	$ 0.0090	$ -	$ -	$ 0.0032	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000004**	**$ 0.000002**	**$ 0.000009**	**$ -**	**$ -**	**$ 0.000003**	**$ -**	**$ -**

Line #						
1	Total BGS-RSCP Trans Obl		6,947.7	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust		23,787,455.5	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes		25,091,269.7	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	70,867		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.0028	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	-	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	-		unrounded	= (6) * (3)
8	Difference due to rounding	$	(70,867)		unrounded	= (7) - (4)

Incremental Network Integration Service Calculation - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges effective January 1, 2021
Summary of EL05-121 Settlement Adjustments for January 2021 - December 2021

Summary of EL05-121 Settlement Adjustments for Jan 2021 - [	$ 9,440,981.76		
PSE&G Zonal Transmission Load for Effective Yr. (MW)	9,557.30		
Term (Months)	12		
OATT rate	$ 82.32	/MW/month	all values show w/o NJ SUT
converted to $/MW/yr =	$ 987.83	/MW/yr	

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	4,435.3	20.1	69.7	0.0	0.0	3.3	0.0	0.0
Total Annual Energy - MWh	12,003,418.6	94,499.9	78,559.3	658.0	16.0	10,469.4	146,959.0	296,606.0
Energy Charge								
in $/MWh	$ 0.3650	$ 0.2101	$ 0.8764	$ -	$ -	$ 0.3114	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000365**	**$ 0.000210**	**$ 0.000876**	**$ -**	**$ -**	**$ 0.000311**	**$ -**	**$ -**

Line #						
1	Total BGS-RSCP Trans Obl		6,947.7	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust		23,787,455.5	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes		25,091,269.7	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	6,863,142		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.2735	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	0.27	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	6,774,643		unrounded	= (6) * (3)
8	Difference due to rounding	$	(88,499)		unrounded	= (7) - (4)

Attachment 3 – JCP&L Tariffs and Rate Translation

Attachment 3a
Pro-forma JCP&L Tariff Sheets

Attachment 3b
JCP&L Translation of NITS Charge into
Customer Rates

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

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

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

Attachment 3f
JCP&L Translation of MAIT Schedule 12 Transmission Enhancement
Charges into Customer Rates

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

Attachment 3h
JCP&L Translation of Silver Run Schedule 12 Transmission
Enhancement Charges into Customer Rates

Attachment 3i
JCP&L Translation of NIPSCo Schedule 12 Transmission Enhancement
Charges into Customer Rates

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

JERSEY CENTRAL POWER & LIGHT COMPANY

XX Rev. Sheet No. 3
BPU No. 13 ELECTRIC - PART III **Superseding XX Rev. Sheet No. 3**

Service Classification RS
Residential Service

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

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

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

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

BASIC GENERATION SERVICE (default service):

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

2) **Transmission Charge:** **$0.010234** 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

JERSEY CENTRAL POWER & LIGHT COMPANY

XX Rev. Sheet No. 6

BPU No. 13 ELECTRIC - PART III

Superseding XX Rev. Sheet No. 6

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:** **$0.010234** 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)**
See Rider NGC for rate per KWH for all KWH on-peak and off-peak

4) **Societal Benefits Charge (Rider SBC):**
See Rider SBC for rate 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

JERSEY CENTRAL POWER & LIGHT COMPANY

XX Rev. Sheet No. 8
BPU No. 13 ELECTRIC - PART III **Superseding XX Rev. Sheet No. 8**

Service Classification RGT
Residential Geothermal & Heat Pump Service

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

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

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

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

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

BASIC GENERATION SERVICE (default service):

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

2) **Transmission Charge:**
$0.010234 per KWH for all KWH on-peak and off-peak for June through September
$0.010234 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

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JERSEY CENTRAL POWER & LIGHT COMPANY

XX Rev. Sheet No. 10
BPU No. 13 ELECTRIC - PART III Superseding XX Rev. Sheet No. 10

Service Classification GS
General Service Secondary

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

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

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

BASIC GENERATION SERVICE (default service):

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

2) **Transmission Charge:**
$0.010234 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. 13 ELECTRIC - PART III

XX Rev. Sheet No. 15
Superseding XX Rev. Sheet No. 15

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:** **$0.010234** 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

JERSEY CENTRAL POWER & LIGHT COMPANY

XX Rev. Sheet No. 19

BPU No. 13 ELECTRIC - PART III

Superseding XX Rev. Sheet No. 19

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:** **$0.006066** 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):**
See Rider NGC for rate per KWH for all KWH on-peak and off-peak

4) **Societal Benefits Charge (Rider SBC)**:
See Rider SBC for rate 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

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BPU No. 13 ELECTRIC - PART III **Superseding XX Rev. Sheet No. 22**

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:** **$0.005709** per KWH for all KWH
$0.001574 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):**
See Rider NGC for rate per KWH for all KWH on-peak and off-peak – excluding High Tension Service
See Rider NGC for rate per KWH for all KWH on-peak and off-peak – High Tension Service

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

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BPU No. 13 ELECTRIC - PART III

Superseding XX Rev. Sheet No. 26

Service Classification OL
Outdoor Lighting Service

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

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

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

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

(A) FIXTURE CHARGE:

Nominal Ratings

Lamp Wattage	Lamp & Ballast Wattage	Billing Month KWH *	HPS Area Lighting	MV Area Lighting	SV Flood Lighting
100	121	42	Not Available	**$ 2.46**	Not Available
175	211	74	Not Available	**$ 2.46**	Not Available
70	99	35	**$10.21**	Not Available	Not Available
100	137	48	**$10.21**	Not Available	Not Available
150	176	62	Not Available	Not Available	**$12.00**
250	293	103	Not Available	Not Available	**$12.60**
400	498	174	Not Available	Not Available	**$12.93**

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

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

BASIC GENERATION SERVICE (default service):

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

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

1) **Distribution Charge: $0.046032** per KWH
2) **Non-utility Generation Charge (Rider NGC): See Rider NGC for rate** per KWH
3) **Societal Benefits Charge (Rider SBC): See Rider SBC for rate** per KWH
4) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
5) **Zero Emission Certificate Recovery Charge (Rider ZEC): See Rider ZEC for rate** per KWH
6) **Tax Act Adjustment (Rider TAA): See Rider TAA for rate** per KWH
7) **JCP&L Reliability Plus Charge (Rider RP): See Rider RP for rate** per Fixture

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XX Rev. Sheet No. 28

BPU No. 13 ELECTRIC - PART III **Superseding XX Rev. Sheet No. 28**

Service Classification SVL
Sodium Vapor Street Lighting Service

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

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

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

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

(A) FIXTURE CHARGE:

Nominal Ratings					
Lamp Wattage	Lamp & Ballast Wattage	Billing Month KWH *	Company Fixture	Contribution Fixture	Customer Fixture
50	60	21	**$ 5.96**	**$ 1.67**	**$ 0.81**
70	85	30	**$ 5.96**	**$ 1.67**	**$ 0.81**
100	121	42	**$ 5.96**	**$ 1.67**	**$ 0.81**
150	176	62	**$ 5.96**	**$ 1.67**	**$ 0.81**
250	293	103	**$ 7.05**	**$ 1.67**	**$ 0.81**
400	498	174	**$ 7.05**	**$ 1.67**	**$ 0.81**

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

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

BASIC GENERATION SERVICE (default service):

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

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

1) **Distribution Charge: $0.046032** per KWH
2) **Non-utility Generation Charge (Rider NGC): See Rider NGC for rate** per KWH
3) **Societal Benefits Charge (Rider SBC): See Rider SBC for rate** per KWH
4) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
5) **Zero Emission Certificate Recovery Charge (Rider ZEC): See Rider ZEC for rate** per KWH
6) **Tax Act Adjustment (Rider TAA): See Rider TAA for rate** per KWH
7) **JCP&L Reliability Plus Charge (Rider RP): See Rider RP for rate** per Fixture

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

JERSEY CENTRAL POWER & LIGHT COMPANY

XX Rev. Sheet No. 31

BPU No. 13 ELECTRIC - PART III

Superseding XX Rev. Sheet No. 31

Service Classification MVL
Mercury Vapor Street Lighting Service

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

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

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

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

Nominal Ratings					
Lamp Wattage	Lamp & Ballast Wattage	Billing Month KWH *	Company Fixture	Contribution Fixture	Customer Fixture
100	121	42	**$ 4.16**	**$ 1.58**	**$ 0.80**
175	211	74	**$ 4.16**	**$ 1.58**	**$ 0.80**
250	295	103	**$ 4.16**	**$ 1.58**	**$ 0.80**
400	468	164	**$ 4.51**	**$ 1.58**	**$ 0.80**
700	803	281	**$ 5.46**	**$ 1.58**	**$ 0.80**
1000	1135	397	**$ 5.46**	**$ 1.58**	**$ 0.80**

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

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

BASIC GENERATION SERVICE (default service):

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

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

1) **Distribution Charge: $0.046032** per KWH
2) **Non-utility Generation Charge (Rider NGC): See Rider NGC for rate** per KWH
3) **Societal Benefits Charge (Rider SBC): See Rider SBC for rate** per KWH
4) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
5) **Zero Emission Certificate Recovery Charge (Rider ZEC): See Rider ZEC for rate** per KWH
6) **Tax Act Adjustment (Rider TAA): See Rider TAA for rate** per KWH
7) **JCP&L Reliability Plus Charge (Rider RP): See Rider RP for rate** per Fixture

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XX Rev. Sheet No. 34

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Service Classification ISL
Incandescent Street Lighting Service

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

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

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

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

(A) FIXTURE CHARGE:

Nominal Ratings Lamp Wattage	Billing Month KWH *	Company Fixture	Customer Fixture
105	37	**$ 1.76**	**$ 0.80**
205	72	**$ 1.76**	**$ 0.80**
327	114	**$ 1.76**	**$ 0.80**
448	157	**$ 1.76**	**$ 0.80**
690	242	**$ 1.76**	**$ 0.80**
860	301	**$ 1.76**	**$ 0.80**

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

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

BASIC GENERATION SERVICE (default service):

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

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

1) **Distribution Charge: $0.046032** per KWH
2) **Non-utility Generation Charge (Rider NGC): See Rider NGC for rate** per KWH
3) **Societal Benefits Charge (Rider SBC): See Rider SBC for rate** per KWH
4) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
5) **Zero Emission Certificate Recovery Charge (Rider ZEC): See Rider ZEC for rate** per KWH
6) **Tax Act Adjustment (Rider TAA): See Rider TAA for rate** per KWH
7) **JCP&L Reliability Plus Charge (Rider RP): See Rider RP for rate** per Fixture

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JERSEY CENTRAL POWER & LIGHT COMPANY

XX Rev. Sheet No. 38

BPU No. 13 ELECTRIC - PART III

Superseding XX Rev. Sheet No. 38

Service Classification LED
LED Street Lighting Service

CONTRIBUTION FIXTURE (a)

Fixture Wattage	Type	Lumens	Billing Month KWH*	Fixture Charge	Contribution Fixture (a)
30	Cobra Head	2400	11	$ 2.65	$ 358.38
50	Cobra Head	4000	18	$ 2.65	$ 354.88
90	Cobra Head	7000	32	$ 2.65	$ 403.55
130	Cobra Head	11500	46	$ 2.65	$ 492.97
260	Cobra Head	24000	91	$ 2.65	$ 694.22
50	Acorn	2500	18	$ 2.65	$1,295.80
90	Acorn	5000	32	$ 2.65	$1,243.30
50	Colonial	2500	18	$ 2.65	$ 619.38
90	Colonial	5000	32	$ 2.65	$ 793.88

CONTRIBUTION FIXTURE (b)

Fixture Wattage	Type	Lumens	Billing Month KWH*	Fixture Charge	Contribution Fixture (b)
30	Cobra Head	2400	11	$ 4.24	$ 209.20
50	Cobra Head	4000	18	$ 4.24	$ 205.70
90	Cobra Head	7000	32	$ 4.24	$ 254.37
130	Cobra Head	11500	46	$ 4.24	$ 343.79
260	Cobra Head	24000	91	$ 4.24	$ 545.04
50	Acorn	2500	18	$ 4.24	$1,146.62
90	Acorn	5000	32	$ 4.24	$1,094.12
50	Colonial	2500	18	$ 4.24	$ 470.20
90	Colonial	5000	32	$ 4.24	$ 644.70

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

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

BASIC GENERATION SERVICE (default service):

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

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

1) **Distribution Charge: $0.046032** per KWH
2) **Non-utility Generation Charge (Rider NGC): See Rider NGC for rate** per KWH
3) **Societal Benefits Charge (Rider SBC): See Rider SBC for rate** per KWH
4) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
5) **Zero Emission Certificate Recovery Charge (Rider ZEC): See Rider ZEC for rate** per KWH
6) **Tax Act Adjustment (Rider TAA): See Rider TAA for rate** per KWH
7) **JCP&L Reliability Plus Charge (Rider RP): See Rider RP for rate** per Fixture

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XX Rev. Sheet No. 42
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Rider BGS-RSCP
Basic Generation Service – Residential Small Commercial Pricing
(Applicable to Service Classifications RS, RT, RGT, GS, GST, OL, SVL, MVL, ISL and LED)

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

Effective **September 1, 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
COMED-TEC surcharge of **$0.000001** Per KWH

Effective **December 15, 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:

TRAILCO-TEC surcharge of **$0.000245** per KWH
ACE-TEC surcharge of **$0.000084** 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
PECO-TEC surcharge of **$0.000067** per KWH
EL18-680FM715-TEC surcharge of (**$0.000002)** per KWH

Effective **January 1, 2021**, 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 **$0.003182** per KWH
VEPCO-TEC surcharge of **$0.000285** per KWH
PATH-TEC surcharge of **$0.000062** per KWH
AEP-East-TEC surcharge of **$0.000066** per KWH
MAIT-TEC surcharge of **$0.000084** per KWH
EL05-121-TEC surcharge of **$0.000240** per KWH
SRE-TEC surcharge of **$0.000193** per KWH
NIPSCO-TEC surcharge of **$0.000002** per KWH

3) BGS Reconciliation Charge per KWH: ($0.002759) (includes Sales and Use Tax as provided in Rider SUT)

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

Issued: **Effective:**

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

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

JERSEY CENTRAL POWER & LIGHT COMPANY

XX Rev. Sheet No. 44

BPU No. 13 ELECTRIC - PART III **Superseding XX Rev. Sheet No. 44**

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

3) BGS Transmission Charge per KWH: (Continued)

Effective **September 1, 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	COMED-TEC
GS and GST	**$0.000004**	**$0.000001**
GP	**$0.000003**	**$0.000000**
GT	**$0.000002**	**$0.000000**
GT – High Tension Service	**$0.000001**	**$0.000000**

Effective **December 15, 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:

	TRAILCO-TEC	ACE-TEC		
GS and GST	**$0.000245**	**$0.000084**		
GP	**$0.000156**	**$0.000053**		
GT	**$0.000141**	**$0.000048**		
GT – High Tension Service	**$0.000044**	**$0.000015**		
	PEPCO-TEC	PPL-TEC	BG&E-TEC	
GS and GST	**$0.000014**	**$0.000805**	**$0.000011**	
GP	**$0.000009**	**$0.000510**	**$0.000007**	
GT	**$0.000007**	**$0.000461**	**$0.000006**	
GT – High Tension Service	**$0.000002**	**$0.000144**	**$0.000002**	
	PECO-TEC	EL18-680Fm715-TEC		
GS and GST	**$0.000067**	**($0.000002)**		
GP	**$0.000043**	**($0.000001)**		
GT	**$0.000038**	**($0.000001)**		
GT – High Tension Service	**$0.000012**	**($0.000000)**		

Effective **January 1, 2021**, the following TEC surcharges (include Sales and Use Tax as provided in Rider SUT) will be added to the BGS Transmission Charge applicable to all KWH usage:

	PSEG-TEC	VEPCO-TEC	PATH-TEC	AEP-East-TEC
GS and GST	**$0.003182**	**$0.000285**	**$0.000062**	**$0.000066**
GP	**$0.001886**	**$0.000168**	**$0.000037**	**$0.000039**
GT	**$0.001774**	**$0.000159**	**$0.000035**	**$0.000037**
GT – High Tension Service	**$0.000489**	**$0.000044**	**$0.000010**	**$0.000011**
	MAIT-TEC	EL05-121-TEC	SRE-TEC	NIPSCO-TEC
GS and GST	**$0.000084**	**$0.000240**	**$0.000193**	**$0.000002**
GP	**$0.000050**	**$0.000142**	**$0.000114**	**$0.000001**
GT	**$0.000047**	**$0.000133**	**$0.000108**	**$0.000001**
GT – High Tension Service	**$0.000013**	**$0.000037**	**$0.000030**	**$0.000000**

4) BGS Reconciliation Charge per KWH: $0.000840 (includes Sales and Use Tax as provided in Rider SUT)
The above BGS Reconciliation Charge recovers the difference between the payments to BGS suppliers and the revenues from BGS customers for Basic Generation Service and is subject to quarterly true-ups.

Issued: **Effective:**

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Docket No. dated

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300 Madison Avenue, Morristown, NJ 07962-1911

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

NITS Charges for January 2021 through December 2021 -

JCP&L Annual NITS Revenue Requirement	165,360,691	
JCP&L Customer Share of Schedule 12 TEC	8,535,622	
NITS Charges for January 2021 - December 2021	173,896,313	
JCP&L Zonal Transmission Load for 2021	5,903.20	(MW)
2021 NITS Rate	$29,457.97	(per MW-yr)
Resulting BGS Firm Transmission Service Supplier Rate	$80.71	(per MW-day)
Change in BGS Firm Transmission Service Supplier Rate	$10.30	(per MW-day)

Effective January 1, 2021:

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)	5,166.2	$ 152,186,002	15,856,121,857	$0.009598	$0.010234
Primary	307.6	$ 9,060,236	1,592,600,859	$0.005689	$0.006066
Transmission @ 34.5 kV	265.9	$ 7,832,930	1,463,079,125	$0.005354	$0.005709
Transmission @ 230 kV	17.2	$ 507,444	343,689,514	$0.001476	$0.001574
Total	5,756.9	$ 169,586,612	19,255,491,356		

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	$18,773,084	= Line 3 x -$-10.3 x 366	
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$1.15	= Line 4 / Line 2	

Attachment 3c

Jersey Central Power & Light Company
Proposed PSEG Project Transmission Enhancement Charge (PSEG-TEC Surcharge) effective January 1, 2021
To reflect FERC-approved PSEG Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 2021 - December 2021

2021 Average Monthly PSEG-TEC Costs Allocated to JCP&L Zone	$4,505,277.83	(1)
2021 JCP&L Zone Transmission Peak Load (MW)	5,903.20	
PSEG-Transmission Enhancement Rate ($/MW-month)	$763.19	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	**Effective January 1, 2021** PSEG-TEC Surcharge ($/kWh)	PSEG-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5,166.2	$47,313,727	15,856,121,857	$0.002984	$0.003182
Primary	307.6	$2,816,774	1,592,600,859	$0.001769	$0.001886
Transmission @ 34.5 kV	265.9	$2,435,211	1,463,079,125	$0.001664	$0.001774
Transmission @ 230 kV	17.2	$157,761	343,689,514	$0.000459	$0.000489
Total	5,756.9	$52,723,473	19,255,491,356		

(1) Cost Allocation of PSEG Project Schedule 12 Charges to JCP&L Zone for 2021
(2) Based on 12 months PSEG Project costs from January 2021 through December 2021
(3) January 2021 through December 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	$45,621,239	= Line 3 x $763.19 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$2.79	= Line 4 / Line 2

Attachment 3d

Jersey Central Power & Light Company
Proposed VEPCO Project Transmission Enhancement Charge (VEPCO-TEC Surcharge) effective January 1, 2021
To reflect FERC-approved VEPCO Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 2021 - December 2021

2021 Average Monthly VEPCO-TEC Costs Allocated to JCP&L Zone	$402,542.13	(1)
2021 JCP&L Zone Transmission Peak Load (MW)	5,903.20	
VEPCO-Transmission Enhancement Rate ($/MW-month)	$68.19	

				Effective January 1, 2021	
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	VEPCO-TEC Surcharge ($/kWh)	VEPCO-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5,166.2	$4,227,435	15,856,121,857	$0.000267	$0.000285
Primary	307.6	$251,676	1,592,600,859	$0.000158	$0.000168
Transmission @ 34.5 kV	265.9	$217,584	1,463,079,125	$0.000149	$0.000159
Transmission @ 230 kV	17.2	$14,096	343,689,514	$0.000041	$0.000044
Total	5,756.9	$4,710,790	19,255,491,356		

(1) Cost Allocation of VEPCO Project Schedule 12 Charges to JCP&L Zone for 2021
(2) Based on 12 months VEPCO Project costs from January 2021 through December 2021
(3) January 2021 through December 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	$4,076,196	= Line 3 x $68.19 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$0.25	= Line 4 / Line 2

Attachment 3e

Jersey Central Power & Light Company
Proposed PATH Project Transmission Enhancement Charge (PATH-TEC Surcharge) effective January 1, 2021
To reflect FERC-approved PATH Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 2021 - December 2021

2021 Average Monthly PATH-TEC Costs Allocated to JCP&L Zone	$88,227.47	(1)
2021 JCP&L Zone Transmission Peak Load (MW)	5,903.20	
PATH-Transmission Enhancement Rate ($/MW-month)	$14.95	

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	**Effective January 1, 2021** PATH-TEC Surcharge ($/kWh)	PATH-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5,166.2	$926,551	15,856,121,857	$0.000058	$0.000062
Primary	307.6	$55,161	1,592,600,859	$0.000035	$0.000037
Transmission @ 34.5 kV	265.9	$47,689	1,463,079,125	$0.000033	$0.000035
Transmission @ 230 kV	17.2	$3,089	343,689,514	$0.000009	$0.000010
Total	5,756.9	$1,032,491	19,255,491,356		

(1) Cost Allocation of PATH Project Schedule 12 Charges to JCP&L Zone for 2021
(2) Based on 12 months PATH Project costs from January 2021 through December 2021
(3) January 2021 through December 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	PATH-Transmission Enhancement Costs to RSCP Suppliers	$893,667	= Line 3 x $14.95 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$0.05	= Line 4 / Line 2

Attachment 3f

Jersey Central Power & Light Company
Proposed MAIT Project Transmission Enhancement Charge (MAIT-TEC Surcharge) effective January 1, 2021
To reflect FERC-approved MAIT Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 2021 - December 2021

2021 Average Monthly MAIT-TEC Costs Allocated to JCP&L Zone	$119,891.00	(1)
2021 JCP&L Zone Transmission Peak Load (MW)	5,903.20	
MAIT-Transmission Enhancement Rate ($/MW-month)	$20.31	

				Effective January 1, 2021	
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)	5,166.2	$1,259,077	15,856,121,857	$0.000079	$0.000084
Primary	307.6	$74,958	1,592,600,859	$0.000047	$0.000050
Transmission @ 34.5 kV	265.9	$64,804	1,463,079,125	$0.000044	$0.000047
Transmission @ 230 kV	17.2	$4,198	343,689,514	$0.000012	$0.000013
Total	5,756.9	$1,403,037	19,255,491,356		

(1) Cost Allocation of MAIT Project Schedule 12 Charges to JCP&L Zone for 2021
(2) Based on 12 months MAIT Project costs from January 2021 through December 2021
(3) January 2021 through December 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	$1,214,072	= Line 3 x $20.31 x 12	
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$0.07	= Line 4 / Line 2	

Attachment 3g

Jersey Central Power & Light Company
Proposed AEP-East Project Transmission Enhancement Charge (AEP-East-TEC Surcharge) effective January 1, 2021
To reflect FERC-approved AEP-East Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 2021 - December 2021

2021 Average Monthly AEP-East-TEC Costs Allocated to JCP&L Zone	$94,002.06	(1)
2021 JCP&L Zone Transmission Peak Load (MW)	5,903.20	
AEP-East-Transmission Enhancement Rate ($/MW-month)	$15.92	

				Effective January 1, 2021	
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)	5,166.2	$987,195	15,856,121,857	$0.000062	$0.000066
Primary	307.6	$58,772	1,592,600,859	$0.000037	$0.000039
Transmission @ 34.5 kV	265.9	$50,810	1,463,079,125	$0.000035	$0.000037
Transmission @ 230 kV	17.2	$3,292	343,689,514	$0.000010	$0.000011
Total	5,756.9	$1,100,069	19,255,491,356		

(1) Cost Allocation of AEP-East Project Schedule 12 Charges to JCP&L Zone for 2021
(2) Based on 12 months AEP-East Project costs from January 2021 through December 2021
(3) January 2021 through December 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	$951,650	= Line 3 x $15.92 x 12	
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$0.06	= Line 4 / Line 2	

Attachment 3h

Jersey Central Power & Light Company
Proposed Silver Run Elec Project Transmission Enhancement Charge (Silver Run Elec-TEC Surcharge) effective January 1, 2021
To reflect FERC-approved Silver Run Elec Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 2021 - December 2021

2021 Average Monthly Silver Run Elec-TEC Costs Allocated to JCP&L Zone	$272,640.05	(1)
2021 JCP&L Zone Transmission Peak Load (MW)	5,903.20	
Silver Run Elec-Transmission Enhancement Rate ($/MW-month)	$46.19	

				Effective January 1, 2021	
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	Silver Run Elec-TEC Surcharge ($/kWh)	Silver Run Elec-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5,166.2	$2,863,223	15,856,121,857	$0.000181	$0.000193
Primary	307.6	$170,459	1,592,600,859	$0.000107	$0.000114
Transmission @ 34.5 kV	265.9	$147,369	1,463,079,125	$0.000101	$0.000108
Transmission @ 230 kV	17.2	$9,547	343,689,514	$0.000028	$0.000030
Total	5,756.9	$3,190,598	19,255,491,356		

(1) Cost Allocation of Silver Run Elec Project Schedule 12 Charges to JCP&L Zone for 2021
(2) Based on 12 months Silver Run Elec Project costs from January 2021 through December 2021
(3) January 2021 through December 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	Silver Run Elec-Transmission Enhancement Costs to RSCP Suppliers	$2,761,101	= Line 3 x $46.19 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$0.17	= Line 4 / Line 2

Attachment 3i

Jersey Central Power & Light Company
Proposed NIPSCo Project Transmission Enhancement Charge (NIPSCo-TEC Surcharge) effective January 1, 2021
To reflect FERC-approved NIPSCo Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 2021 - December 2021

2021 Average Monthly NIPSCo-TEC Costs Allocated to JCP&L Zone	$3,435.07	(1)
2021 JCP&L Zone Transmission Peak Load (MW)	5,903.20	
NIPSCo-Transmission Enhancement Rate ($/MW-month)	$0.58	

				Effective January 1, 2021	
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	NIPSCo-TEC Surcharge ($/kWh)	NIPSCo-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5,166.2	$36,075	15,856,121,857	$0.000002	$0.000002
Primary	307.6	$2,148	1,592,600,859	$0.000001	$0.000001
Transmission @ 34.5 kV	265.9	$1,857	1,463,079,125	$0.000001	$0.000001
Transmission @ 230 kV	17.2	$120	343,689,514	$0.000000	$0.000000
Total	5,756.9	$40,199	19,255,491,356		

(1) Cost Allocation of NIPSCo Project Schedule 12 Charges to JCP&L Zone for 2021
(2) Based on 12 months NIPSCo Project costs from January 2021 through December 2021
(3) January 2021 through December 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	NIPSCo-Transmission Enhancement Costs to RSCP Suppliers	$34,671		= Line 3 x $0.58 x 12
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$0.00		= Line 4 / Line 2

Attachment 3j

Jersey Central Power & Light Company
Proposed EL05-121 Project Transmission Enhancement Charge (EL05-121-TEC Surcharge) effective January 1, 2021
To reflect FERC-approved EL05-121 Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 2021 - December 2021

2021 Average Monthly EL05-121-TEC Costs Allocated to JCP&L Zone	$339,684.16	(1)
2021 JCP&L Zone Transmission Peak Load (MW)	5,903.20	
EL05-121-Transmission Enhancement Rate ($/MW-month)	$57.54	

				Effective January 1, 2021	
BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery ($) (2)	BGS Eligible Sales (kWh) (3)	EL05-121-TEC Surcharge ($/kWh)	EL05-121-TEC Surcharge w/ SUT($/kWh)
Secondary (excluding lighting)	5,166.2	$3,567,310	15,856,121,857	$0.000225	$0.000240
Primary	307.6	$212,376	1,592,600,859	$0.000133	$0.000142
Transmission @ 34.5 kV	265.9	$183,607	1,463,079,125	$0.000125	$0.000133
Transmission @ 230 kV	17.2	$11,895	343,689,514	$0.000035	$0.000037
Total	5,756.9	$3,975,189	19,255,491,356		

(1) Cost Allocation of EL05-121 Project Schedule 12 Charges to JCP&L Zone for 2021
(2) Based on 12 months EL05-121 Project costs from January 2021 through December 2021
(3) January 2021 through December 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	EL05-121-Transmission Enhancement Costs to RSCP Suppliers	$3,439,571	= Line 3 x $57.54 x 12	
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$0.21	= Line 4 / Line 2	

Attachment 4 – ACE Tariffs and Rate Translation

Attachment 4a
Pro-forma ACE Tariff Sheets

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

Attachment 4c
ACE Translation of JCP&L Schedule 12 Transmission Enhancement Charges into Customer Rates

Attachment 4d
ACE Translation of VEPCo Schedule 12 Transmission Enhancement Charges into Customer Rates

Attachment 4e
ACE Translation of PATH Schedule 12 Transmission Enhancement Charges into Customer Rates

Attachment 4f
ACE Translation of MAIT Schedule 12 Transmission Enhancement Charges into Customer Rates

Attachment 4g
ACE Translation of AEP East Schedule 12 Transmission Enhancement Charges into Customer Rates

Attachment 4h
ACE Translation of Silver Run Schedule 12 Transmission Enhancement Charges into Customer Rates

Attachment 4i
ACE Translation of NIPSCo Schedule 12 Transmission Enhancement Charges into Customer Rates

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

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

RIDER (BGS) continued
Basic Generation Service (BGS)

CIEP Standby Fee $0.000160 per kWh

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

Transmission Enhancement Charge

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

	Rate Class							
	RS	MGS Secondary	MGS Primary	AGS Secondary	AGS Primary	TGS	SPL/ CSL	DDC
VEPCo	0.000371	0.000269	0.000294	0.000189	0.000146	0.000134	-	0.000117
TrAILCo	0.000338	0.000245	0.000269	0.000172	0.000133	0.000122	-	0.000107
PSE&G	0.000669	0.000485	0.000532	0.000340	0.000263	0.000241	-	0.000211
PATH	0.000077	0.000057	0.000062	0.000039	0.000031	0.000028	-	0.000025
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	0.000034	0.000025	0.000027	0.000017	0.000014	0.000013	-	0.000011
JCP&L	0.000003	0.000002	0.000002	0.000002	0.000001	0.000001	-	0.000001
EL05-121	0.000019	0.000014	0.000016	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	0.000075	0.000054	0.000059	0.000038	0.000029	0.000027	-	0.000023
Silver Run	0.000317	0.000230	0.000253	0.000162	0.000125	0.000115	-	0.000100
NIPSCO	0.000003	0.000002	0.000002	0.000002	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	0.002304	0.001671	0.001832	0.001173	0.000908	0.000832	-	0.000728

Atlantic City Electric Company
Proposed PSE&G Projects Transmission Enhancement Charge (PSE&G-TEC Surcharge) effective January 1, 2021
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 1, 2021

Transmission Enhancement Costs Allocated to ACE Zone (2020)	$	331,653
	$	331,653
2021 ACE Zone Transmission Peak Load (MW)		2,635
Transmission Enhancement Rate ($/MW)	$	125.89

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	$	2,415,954	3,862,087,569	$	0.000626	$	0.000627	$	0.000669
MGS Secondary	380	$	574,191	1,263,645,888	$	0.000454	$	0.000455	$	0.000485
MGS Primary	8	$	12,825	25,772,485	$	0.000498	$	0.000499	$	0.000532
AGS Secondary	371	$	560,469	1,755,110,088	$	0.000319	$	0.000319	$	0.000340
AGS Primary	91	$	136,866	554,832,432	$	0.000247	$	0.000247	$	0.000263
TGS	156	$	235,108	1,039,312,955	$	0.000226	$	0.000226	$	0.000241
SPL/CSL	0	$	-	67,341,732	$	-	$	-	$	-
DDC	2	$	2,821	14,236,110	$	0.000198	$	0.000198	$	0.000211
	2,607	$	3,938,233	8,582,339,259						

Atlantic City Electric Company
Proposed JCP&L Projects Transmission Enhancement Charge (JCP&L-TEC Surcharge) effective January 1, 2021
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 1, 2021

Transmission Enhancement Costs Allocated to ACE Zone (2021)	$	1,658
	$	1,658
2021 ACE Zone Transmission Peak Load (MW)		2,635
Transmission Enhancement Rate ($/MW)	$	0.63

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	$ 12,078	3,862,087,569	$ 0.000003	$ 0.000003	$ 0.000003
MGS Secondary	380	$ 2,871	1,263,645,888	$ 0.000002	$ 0.000002	$ 0.000002
MGS Primary	8	$ 64	25,772,485	$ 0.000002	$ 0.000002	$ 0.000002
AGS Secondary	371	$ 2,802	1,755,110,088	$ 0.000002	$ 0.000002	$ 0.000002
AGS Primary	91	$ 684	554,832,432	$ 0.000001	$ 0.000001	$ 0.000001
TGS	156	$ 1,175	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	$ 19,688	8,582,339,259			

Atlantic City Electric Company
Proposed VEPCO Projects Transmission Enhancement Charge (VEPCO-TEC Surcharge) effective January 1, 2021
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 1, 2021

Transmission Enhancement Costs Allocated to ACE Zone (2021)	$	184,190
	$	184,190
2021 ACE Zone Transmission Peak Load (MW)		2,635
Transmission Enhancement Rate ($/MW)	$	69.91

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	$	1,341,751	3,862,087,569	$ 0.000347	$ 0.000348	$ 0.000371
MGS Secondary	380	$	318,889	1,263,645,888	$ 0.000252	$ 0.000252	$ 0.000269
MGS Primary	8	$	7,123	25,772,485	$ 0.000276	$ 0.000276	$ 0.000294
AGS Secondary	371	$	311,268	1,755,110,088	$ 0.000177	$ 0.000177	$ 0.000189
AGS Primary	91	$	76,011	554,832,432	$ 0.000137	$ 0.000137	$ 0.000146
TGS	156	$	130,572	1,039,312,955	$ 0.000126	$ 0.000126	$ 0.000134
SPL/CSL	0	$	-	67,341,732	$ -	$ -	$ -
DDC	2	$	1,567	14,236,110	$ 0.000110	$ 0.000110	$ 0.000117
	2,607	$	2,187,181	8,582,339,259			

Atlantic City Electric Company
Proposed PATH Projects Transmission Enhancement Charge (PATH-TEC Surcharge) effective January 1, 2021
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 1, 2021

Transmission Enhancement Costs Allocated to ACE Zone (2021)	$	38,407
	$	38,407
2021 ACE Zone Transmission Peak Load (MW)		2,635
Transmission Enhancement Rate ($/MW)	$	14.58

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	$ 279,778	3,862,087,569	$ 0.000072	$ 0.000072	$ 0.000077
MGS Secondary	380	$ 66,494	1,263,645,888	$ 0.000053	$ 0.000053	$ 0.000057
MGS Primary	8	$ 1,485	25,772,485	$ 0.000058	$ 0.000058	$ 0.000062
AGS Secondary	371	$ 64,905	1,755,110,088	$ 0.000037	$ 0.000037	$ 0.000039
AGS Primary	91	$ 15,850	554,832,432	$ 0.000029	$ 0.000029	$ 0.000031
TGS	156	$ 27,227	1,039,312,955	$ 0.000026	$ 0.000026	$ 0.000028
SPL/CSL	0	$ -	67,341,732	$ -	$ -	$ -
DDC	2	$ 327	14,236,110	$ 0.000023	$ 0.000023	$ 0.000025
	2,607	$ 456,065	8,582,339,259			

Atlantic City Electric Company
Proposed MAIT Projects Transmission Enhancement Charge (MAIT Project-TEC Surcharge) effective January 1, 2021
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 1, 2021

Transmission Enhancement Costs Allocated to ACE Zone (2021)	$	16,872
	$	16,872
2021 ACE Zone Transmission Peak Load (MW)		2,635
Transmission Enhancement Rate ($/MW-Month)	$	6.40

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	$ 122,904	3,862,087,569	$ 0.000032	$ 0.000032	$ 0.000034
MGS Secondary	380	$ 29,210	1,263,645,888	$ 0.000023	$ 0.000023	$ 0.000025
MGS Primary	8	$ 652	25,772,485	$ 0.000025	$ 0.000025	$ 0.000027
AGS Secondary	371	$ 28,512	1,755,110,088	$ 0.000016	$ 0.000016	$ 0.000017
AGS Primary	91	$ 6,963	554,832,432	$ 0.000013	$ 0.000013	$ 0.000014
TGS	156	$ 11,960	1,039,312,955	$ 0.000012	$ 0.000012	$ 0.000013
SPL/CSL	0	$ -	67,341,732	$ -	$ -	$ -
DDC	2	$ 144	14,236,110	$ 0.000010	$ 0.000010	$ 0.000011
	2,607	$ 200,346	8,582,339,259			

Atlantic City Electric Company
Proposed AEP Projects Transmission Enhancement Charge (AEP Project-TEC Surcharge) effective January 1, 2021
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 1, 2021

Transmission Enhancement Costs Allocated to ACE Zone (2021)	$	36,902
	$	36,902
2021 ACE Zone Transmission Peak Load (MW)		2,635
Transmission Enhancement Rate ($/MW-Month)	$	14.01

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	$ 268,813.75	3,862,087,569	$ 0.000070	$ 0.000070	$ 0.000075
MGS Secondary	380	$ 63,888	1,263,645,888	$ 0.000051	$ 0.000051	$ 0.000054
MGS Primary	8	$ 1,427	25,772,485	$ 0.000055	$ 0.000055	$ 0.000059
AGS Secondary	371	$ 62,361	1,755,110,088	$ 0.000036	$ 0.000036	$ 0.000038
AGS Primary	91	$ 15,228	554,832,432	$ 0.000027	$ 0.000027	$ 0.000029
TGS	156	$ 26,160	1,039,312,955	$ 0.000025	$ 0.000025	$ 0.000027
SPL/CSL	0	$ -	67,341,732	$ -	$ -	$ -
DDC	2	$ 314	14,236,110	$ 0.000022	$ 0.000022	$ 0.000023
	2,607	$ 438,192	8,582,339,259			

Atlantic City Electric Company
Proposed Silver Run Projects Transmission Enhancement Charge (Silver Run-TEC Surcharge) effective January 1, 2021
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 1, 2021

Transmission Enhancement Costs Allocated to ACE Zone (2021)	$	157,678
	$	157,678
2021 ACE Zone Transmission Peak Load (MW)		2,635
Transmission Enhancement Rate ($/MW)	$	59.85

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	$ 1,148,622	3,862,087,569	$ 0.000297	$ 0.000297	$ 0.000317
MGS Secondary	380	$ 272,989	1,263,645,888	$ 0.000216	$ 0.000216	$ 0.000230
MGS Primary	8	$ 6,097	25,772,485	$ 0.000237	$ 0.000237	$ 0.000253
AGS Secondary	371	$ 266,465	1,755,110,088	$ 0.000152	$ 0.000152	$ 0.000162
AGS Primary	91	$ 65,070	554,832,432	$ 0.000117	$ 0.000117	$ 0.000125
TGS	156	$ 111,778	1,039,312,955	$ 0.000108	$ 0.000108	$ 0.000115
SPL/CSL	-	$ -	67,341,732	$ -	$ -	$ -
DDC	2	$ 1,341	14,236,110	$ 0.000094	$ 0.000094	$ 0.000100
	2,607	$ 1,872,362	8,582,339,259			

Atlantic City Electric Company
Proposed NIPSCO Projects Transmission Enhancement Charge (NIPSCO-TEC Surcharge) effective January 1, 2021
To reflect FERC-approved ACE Project Transmission Enhancement Charge (Schedule 12 PJM OATT) effective January 1, 2021

Transmission Enhancement Costs Allocated to ACE Zone (2021)	$	1,607
	$	1,607
2021 ACE Zone Transmission Peak Load (MW)		2,635
Transmission Enhancement Rate ($/MW)	$	0.61

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	$	11,704	3,862,087,569	$ 0.000003	$ 0.000003	$ 0.000003
MGS Secondary	380	$	2,782	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	$	2,715	1,755,110,088	$ 0.000002	$ 0.000002	$ 0.000002
AGS Primary	91	$	663	554,832,432	$ 0.000001	$ 0.000001	$ 0.000001
TGS	156	$	1,139	1,039,312,955	$ 0.000001	$ 0.000001	$ 0.000001
SPL/CSL	-	$	-	67,341,732	$ -	$ -	$ -
DDC	2	$	14	14,236,110	$ 0.000001	$ 0.000001	$ 0.000001
	2,607	$	19,079	8,582,339,259			

Atlantic City Electric Company
Proposed EL05-121 Transmission Enhancement Charge effective January 1st, 2021

Transmission Enhancement Costs Allocated to ACE Zone (January 2021 - December 2021)	$	9,802
	$	9,802
2021 ACE Zone Transmission Peak Load (MW)		2,635
Transmission Enhancement Rate ($/MW)	$	3.72

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	$ 71,405	3,862,087,569	$ 0.000018	$ 0.000018	$ 0.000019
MGS Secondary	380	$ 16,971	1,263,645,888	$ 0.000013	$ 0.000013	$ 0.000014
MGS Primary	8	$ 379	25,772,485	$ 0.000015	$ 0.000015	$ 0.000016
AGS Secondary	371	$ 16,565	1,755,110,088	$ 0.000009	$ 0.000009	$ 0.000010
AGS Primary	91	$ 4,045	554,832,432	$ 0.000007	$ 0.000007	$ 0.000007
TGS	156	$ 6,949	1,039,312,955	$ 0.000007	$ 0.000007	$ 0.000007
SPL/CSL	-	$ -	67,341,732	$ -	$ -	$ -
DDC	2	83	14,236,110	$ 0.000006	$ 0.000006	$ 0.000006
	2,607	$ 116,397	8,582,339,259			

Attachment 5 – RECO Tariffs and Rate Translation

Attachment 5a
Pro-forma RECO Tariff Sheets

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

Attachment 5c
RECO Translation of JCP&L Schedule 12 Transmission Enhancement Charges into Customer Rates

Attachment 5d
RECO Translation of VEPCo Schedule 12 Transmission Enhancement Charges into Customer Rates

Attachment 5e
RECO Translation of PATH Schedule 12 Transmission Enhancement Charges into Customer Rates

Attachment 5f
RECO Translation of MAIT Schedule 12 Transmission Enhancement Charges into Customer Rates

Attachment 5g
RECO Translation of AEP East Schedule 12 Transmission Enhancement Charges into Customer Rates

Attachment 5h
RECO Translation of Silver Run Schedule 12 Transmission Enhancement Charges into Customer Rates

Attachment 5i
RECO Translation of NIPSCo Schedule 12 Transmission Enhancement Charges into Customer Rates

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

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

DRAFT

Revised Leaf No. 83
Superseding Leaf No. 83

SERVICE CLASSIFICATION NO. 1
RESIDENTIAL SERVICE (Continued)

RATE – MONTHLY (Continued)

(3) Transmission Charges

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

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

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

All kWh ..... @	1.348 ¢ per kWh	1.348 ¢ 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)

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

DRAFT

Revised Leaf No. 90
Superseding Leaf No. 90

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 .....@	0.838 ¢ per kWh	0.838 ¢ per kWh
Primary Voltage Service Only All kWh .....@	0.883 ¢ per kWh	0.883 ¢ 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)

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

Revised Leaf No. 96
Superseding Leaf No. 96

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 .....@	1.048 ¢ per kWh	1.048 ¢ 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)

ROCKLAND ELECTRIC COMPANY
B.P.U. NO. 3 – ELECTRICITY **DRAFT**

Revised Leaf No. 109
Superseding Leaf No. 109

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 …….. @	1.348 ¢ per kWh	1.348 ¢ 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)

ROCKLAND ELECTRIC COMPANY
B.P.U. NO. 3 – ELECTRICITY **DRAFT**

Revised Leaf No. 124
Superseding Leaf No. 124

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 @	0.404 ¢ per kWh	0.404 ¢ 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)

DRAFT

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 0.404 ¢ 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 January 1, 2021
To reflect FERC-approved PSE&G Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period January 2020 - December 2020

2021 Average Monthly PSE&G-TEC Costs Allocated to RECO	$	1,010,890	(1)
2021 RECO Zone Transmission Peak Load (MW)		439.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	2,298.60	
SUT		6.625%	

	Col. 1	Col. 2	Col.3=Col.2 x $1,010,890 x 12		Col. 4	Col. 5 = Col. 3/Col. 4		Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)		Allocated Cost Recovery (1)	BGS Eligible Sales January 2021 - December 2021 (kWh)		Transmission Enhancement Charge ($/kWh)		Transmission Enhancement Charge w/ SUT ($/kWh)
SC1/SC5	271.2	61.67%	$	7,480,858	684,650,000	$	0.01093	$	0.01165
SC2 Secondary	120.3	27.36%	$	3,319,368	490,909,000	$	0.00676	$	0.00721
SC2 Primary	16.9	3.85%	$	466,603	65,321,000	$	0.00714	$	0.00761
SC3	0.1	0.02%	$	2,982	355,000	$	0.00840	$	0.00896
SC4	0.0	0.00%	$	-	6,388,000	$	-	$	-
SC6	0.0	0.00%	$	-	5,500,000	$	-	$	-
SC7	31.2	7.10%	$	860,864	263,806,325	$	0.00326	$	0.00348
Total	439.8 (2)	100.00%	$	12,130,675	1,516,929,325				

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

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales Jan - Dec @ cust (RECO Eastern Division)		1,199,427	MWH
2	BGS-RSCP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)		1,116,240	MWH
3	BGS-RSCP Eligible Transmission Obligation		409	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	11,269,794.66	= Line 3 x $2298.6 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	10.10	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (JCP&L) effective January 1, 2021
To reflect FERC-approved JCP&L Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period January 2020 - December 2020

2021 Average Monthly JCP&L-TEC Costs Allocated to RECO	$	26,852	(1)
2021 RECO Zone Transmission Peak Load (MW)		439.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	61.06	
SUT		6.625%	

	Col. 1	Col. 2	Col.3=Col.2 x $26,852 x 12	Col. 4	Col. 5 = Col. 3/Col. 4	Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)	Allocated Cost Recovery (1)	BGS Eligible Sales January 2021 - December 2021 (kWh)	Transmission Enhancement Charge ($/kWh)	Transmission Enhancement Charge w/ SUT ($/kWh)
SC1/SC5	271.2	61.67%	$ 198,709	684,650,000	$ 0.00029	$ 0.00031
SC2 Secondary	120.3	27.36%	$ 88,170	490,909,000	$ 0.00018	$ 0.00019
SC2 Primary	16.9	3.85%	$ 12,394	65,321,000	$ 0.00019	$ 0.00020
SC3	0.1	0.02%	$ 79	355,000	$ 0.00022	$ 0.00023
SC4	0.0	0.00%	$ -	6,388,000	$ -	$ -
SC6	0.0	0.00%	$ -	5,500,000	$ -	$ -
SC7	31.2	7.10%	$ 22,867	263,806,325	$ 0.00009	$ 0.00010
Total	439.8 (2)	100.00%	$ 322,219	1,516,929,325		

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

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales Jan - Dec @ cust (RECO Eastern Division)		1,199,427	MWH
2	BGS-RSCP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)		1,116,240	MWH
3	BGS-RSCP Eligible Transmission Obligation		409	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	299,370.77	= Line 3 x $61.06 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.27	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (VEPCo) effective January 1, 2021
To reflect FERC-approved VEPCo Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period January 2020 - December 2020

2021 Average Monthly VEPCo-TEC Costs Allocated to RECO	$	26,182	(1)
2021 RECO Zone Transmission Peak Load (MW)		439.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	59.53	
SUT		6.625%	

	Col. 1	Col. 2	Col.3=Col.2 x $26,182 x 12	Col. 4	Col. 5 = Col. 3/Col. 4	Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)	Allocated Cost Recovery (1)	BGS Eligible Sales January 2021 - December 2021 (kWh)	Transmission Enhancement Charge ($/kWh)	Transmission Enhancement Charge w/ SUT ($/kWh)
SC1/SC5	271.2	61.67%	$ 193,754	684,650,000	$ 0.00028	$ 0.00030
SC2 Secondary	120.3	27.36%	$ 85,971	490,909,000	$ 0.00018	$ 0.00019
SC2 Primary	16.9	3.85%	$ 12,085	65,321,000	$ 0.00019	$ 0.00020
SC3	0.1	0.02%	$ 77	355,000	$ 0.00022	$ 0.00023
SC4	0.0	0.00%	$ -	6,388,000	$ -	$ -
SC6	0.0	0.00%	$ -	5,500,000	$ -	$ -
SC7	31.2	7.10%	$ 22,296	263,806,325	$ 0.00008	$ 0.00009
Total	439.8 (2)	100.00%	$ 314,183	1,516,929,325		

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

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales Jan - Dec @ cust (RECO Eastern Division)		1,199,427	MWH
2	BGS-RSCP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)		1,116,240	MWH
3	BGS-RSCP Eligible Transmission Obligation		409	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	291,869.34	= Line 3 x $59.53 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.26	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (PATH) effective January 1, 2021
To reflect FERC-approved PATH Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period January 2020 - December 2020

2021 Average Monthly PATH-TEC Costs Allocated to RECO	$	4,794	(1)
2021 RECO Zone Transmission Peak Load (MW)		439.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	10.90	
SUT		6.625%	

	Col. 1	Col. 2	Col.3=Col.2 x $4,794 x 12	Col. 4	Col. 5 = Col. 3/Col. 4	Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)	Allocated Cost Recovery (1)	BGS Eligible Sales January 2021 - December 2021 (kWh)	Transmission Enhancement Charge ($/kWh)	Transmission Enhancement Charge w/ SUT ($/kWh)
SC1/SC5	271.2	61.67%	$ 35,475	684,650,000	$ 0.00005	$ 0.00005
SC2 Secondary	120.3	27.36%	$ 15,741	490,909,000	$ 0.00003	$ 0.00003
SC2 Primary	16.9	3.85%	$ 2,213	65,321,000	$ 0.00003	$ 0.00003
SC3	0.1	0.02%	$ 14	355,000	$ 0.00004	$ 0.00004
SC4	0.0	0.00%	$ -	6,388,000	$ -	$ -
SC6	0.0	0.00%	$ -	5,500,000	$ -	$ -
SC7	31.2	7.10%	$ 4,082	263,806,325	$ 0.00002	$ 0.00002
Total	439.8 (2)	100.00%	$ 57,525	1,516,929,325		

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

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales Jan - Dec @ cust (RECO Eastern Division)		1,199,427	MWH
2	BGS-RSCP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)		1,116,240	MWH
3	BGS-RSCP Eligible Transmission Obligation		409	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	53,441.56	= Line 3 x $10.9 * 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 (MAIT) effective January 1, 2021
To reflect FERC-approved MAIT Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period January 2020 - December 2020

2021 Average Monthly MAIT-TEC Costs Allocated to RECO	$	6,309	(1)
2021 RECO Zone Transmission Peak Load (MW)		439.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	14.35	
SUT		6.625%	

	Col. 1	Col. 2	Col.3=Col.2 x $6,309 x 12	Col. 4	Col. 5 = Col. 3/Col. 4	Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)	Allocated Cost Recovery (1)	BGS Eligible Sales January 2021 - December 2021 (kWh)	Transmission Enhancement Charge ($/kWh)	Transmission Enhancement Charge w/ SUT ($/kWh)
SC1/SC5	271.2	61.67%	$ 46,687	684,650,000	$ 0.00007	$ 0.00007
SC2 Secondary	120.3	27.36%	$ 20,716	490,909,000	$ 0.00004	$ 0.00004
SC2 Primary	16.9	3.85%	$ 2,912	65,321,000	$ 0.00004	$ 0.00004
SC3	0.1	0.02%	$ 19	355,000	$ 0.00005	$ 0.00005
SC4	0.0	0.00%	$ -	6,388,000	$ -	$ -
SC6	0.0	0.00%	$ -	5,500,000	$ -	$ -
SC7	31.2	7.10%	$ 5,373	263,806,325	$ 0.00002	$ 0.00002
Total	439.8 (2)	100.00%	$ 75,707	1,516,929,325		

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

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales Jan - Dec @ cust (RECO Eastern Division)		1,199,427	MWH
2	BGS-RSCP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)		1,116,240	MWH
3	BGS-RSCP Eligible Transmission Obligation		409	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	70,356.54	= Line 3 x $14.35 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.06	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (AEP East) effective January 1, 2021
To reflect FERC-approved AEP-East Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period January 2020 - December 2020

2021 Average Monthly AEP-East-TEC Costs Allocated to RECO	$	6,478	(1)
2021 RECO Zone Transmission Peak Load (MW)		439.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	14.73	
SUT		6.625%	

	Col. 1	Col. 2	Col.3=Col.2 x $6,478 x 12	Col. 4	Col. 5 = Col. 3/Col. 4	Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)	Allocated Cost Recovery (1)	BGS Eligible Sales January 2021 - December 2021 (kWh)	Transmission Enhancement Charge ($/kWh)	Transmission Enhancement Charge w/ SUT ($/kWh)
SC1/SC5	271.2	61.67%	$ 47,940	684,650,000	$ 0.00007	$ 0.00007
SC2 Secondary	120.3	27.36%	$ 21,272	490,909,000	$ 0.00004	$ 0.00004
SC2 Primary	16.9	3.85%	$ 2,990	65,321,000	$ 0.00005	$ 0.00005
SC3	0.1	0.02%	$ 19	355,000	$ 0.00005	$ 0.00005
SC4	0.0	0.00%	$ -	6,388,000	$ -	$ -
SC6	0.0	0.00%	$ -	5,500,000	$ -	$ -
SC7	31.2	7.10%	$ 5,517	263,806,325	$ 0.00002	$ 0.00002
Total	439.8 (2)	100.00%	$ 77,738	1,516,929,325		

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

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales Jan - Dec @ cust (RECO Eastern Division)		1,199,427	MWH
2	BGS-RSCP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)		1,116,240	MWH
3	BGS-RSCP Eligible Transmission Obligation		409	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	72,219.64	= Line 3 x $14.73 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.06	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (Silver Run) effective January 1, 2021
To reflect FERC-approved Silver Run Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period January 2020 - December 2020

2021 Average Monthly Silver Run-TEC Costs Allocated to RECO	$	12,205	(1)
2021 RECO Zone Transmission Peak Load (MW)		439.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	27.75	
SUT		6.625%	

	Col. 1	Col. 2	Col.3=Col.2 x $12,205 x 12	Col. 4	Col. 5 = Col. 3/Col. 4	Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)	Allocated Cost Recovery (1)	BGS Eligible Sales January 2021 - December 2021 (kWh)	Transmission Enhancement Charge ($/kWh)	Transmission Enhancement Charge w/ SUT ($/kWh)
SC1/SC5	271.2	61.67%	$ 90,319	684,650,000	$ 0.00013	$ 0.00014
SC2 Secondary	120.3	27.36%	$ 40,076	490,909,000	$ 0.00008	$ 0.00009
SC2 Primary	16.9	3.85%	$ 5,633	65,321,000	$ 0.00009	$ 0.00010
SC3	0.1	0.02%	$ 36	355,000	$ 0.00010	$ 0.00011
SC4	0.0	0.00%	$ -	6,388,000	$ -	$ -
SC6	0.0	0.00%	$ -	5,500,000	$ -	$ -
SC7	31.2	7.10%	$ 10,394	263,806,325	$ 0.00004	$ 0.00004
Total	439.8 (2)	100.00%	$ 146,458	1,516,929,325		

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

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales Jan - Dec @ cust (RECO Eastern Division)		1,199,427	MWH
2	BGS-RSCP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)		1,116,240	MWH
3	BGS-RSCP Eligible Transmission Obligation		409	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	136,055.34	= Line 3 x $27.75 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.12	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (NIPSCO) effective January 1, 2021
To reflect FERC-approved NIPSCO Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period January 2020 - December 2020

2021 Average Monthly NIPSCO-TEC Costs Allocated to RECO	$	230	(1)
2021 RECO Zone Transmission Peak Load (MW)		439.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	0.52	
SUT		6.625%	

	Col. 1	Col. 2	Col.3=Col.2 x $230 x 12	Col. 4	Col. 5 = Col. 3/Col. 4	Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)	Allocated Cost Recovery (1)	BGS Eligible Sales January 2021 - December 2021 (kWh)	Transmission Enhancement Charge ($/kWh)	Transmission Enhancement Charge w/ SUT ($/kWh)
SC1/SC5	271.2	61.67%	$ 1,701	684,650,000	$ -	$ -
SC2 Secondary	120.3	27.36%	$ 755	490,909,000	$ -	$ -
SC2 Primary	16.9	3.85%	$ 106	65,321,000	$ -	$ -
SC3	0.1	0.02%	$ 1	355,000	$ -	$ -
SC4	0.0	0.00%	$ -	6,388,000	$ -	$ -
SC6	0.0	0.00%	$ -	5,500,000	$ -	$ -
SC7	31.2	7.10%	$ 196	263,806,325	$ -	$ -
Total	439.8 (2)	100.00%	$ 2,759	1,516,929,325		

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

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales Jan - Dec @ cust (RECO Eastern Division)		1,199,427	MWH
2	BGS-RSCP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)		1,116,240	MWH
3	BGS-RSCP Eligible Transmission Obligation		409	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	2,549.51	= Line 3 x $0.52 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	-	= Line 4/Line 2

Rockland Electric Company
Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (EL05-121 Project) effective January 1, 2021
To reflect FERC-approved EL05-121 Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period January 2020 - December 2020

2021 Average Monthly EL05-121-TEC Costs Allocated to RECO	$	29,203	(1)
2021 RECO Zone Transmission Peak Load (MW)		439.8	(2)
Transmission Enhancement Rate ($/MW-month)	$	66.40	
SUT		6.625%	

	Col. 1	Col. 2	Col.3=Col.2 x $29,203 x 12	Col. 4	Col. 5 = Col. 3/Col. 4	Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)	Allocated Cost Recovery (1)	BGS Eligible Sales January 2021 - December 2021 (kWh)	Transmission Enhancement Charge ($/kWh)	Transmission Enhancement Charge w/ SUT ($/kWh)
SC1/SC5	271.2	61.67%	$ 216,107	684,650,000	$ 0.00032	$ 0.00034
SC2 Secondary	120.3	27.36%	$ 95,890	490,909,000	$ 0.00020	$ 0.00021
SC2 Primary	16.9	3.85%	$ 13,479	65,321,000	$ 0.00021	$ 0.00022
SC3	0.1	0.02%	$ 86	355,000	$ 0.00024	$ 0.00026
SC4	0.0	0.00%	$ -	6,388,000	$ -	$ -
SC6	0.0	0.00%	$ -	5,500,000	$ -	$ -
SC7	31.2	7.10%	$ 24,869	263,806,325	$ 0.00009	$ 0.00010
Total	439.8 (2)	100.00%	$ 350,431	1,516,929,325		

(1) Attachment 6i - Cost Allocation of EL05-121 Project Schedule 12 Charges to RECO Zone for January 2020 - December 2020
(2) Includes RECO's Central and Western Divisions

BGS-FP Supplier Payment Adjustment

Line No.				
1	BGS-RSCP Eligible Sales Jan - Dec @ cust (RECO Eastern Division)		1,199,427	MWH
2	BGS-RSCP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)		1,116,240	MWH
3	BGS-RSCP Eligible Transmission Obligation		409	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	325,552.23	= Line 3 x $66.4 * 12
5	Change in Supplier Payment Rate $/MWH (rounded to 2 decimals)	$	0.29	= Line 4/Line 2

Rockland Electric Company Attachment 5

Calculation of Transmission Surcharges reflecting proposed changes effective January 1, 2021

To reflect: RMR Costs
FERC-approved ACE Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved AEP-East Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved BG&E Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved Delmarva Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved PATH Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved PEPCO Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved PPL Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved PSE&G Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved TrailCo Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
FERC-approved VEPCo Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved MAIT Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved JCP&L Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved PECO Project Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates
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)
FERC-approved Silver Run Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved NIPSCO Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved ER18-680 and Form 715 Projects Schedule 12 Charges (Schedule 12 PJM OATT) currently in RECO's rates

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

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	$0.00000
ACE - TEC	(2)	0.00003	0.00002	0.00002	0.00003	0.00000	0.00003	0.00000	0.00001
AEP-East - TEC	(3)	0.00007	0.00004	0.00005	0.00005	0.00000	0.00007	0.00000	0.00002
BG&E- TEC	(4)	0.00001	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00000
Delmarva - TEC	(5)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
PATH - TEC	(6)	0.00005	0.00003	0.00003	0.00004	0.00000	0.00005	0.00000	0.00002
PEPCO - TEC	(7)	0.00001	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00000
PPL - TEC	(8)	0.00091	0.00061	0.00065	0.00092	0.00000	0.00091	0.00000	0.00031
PSE&G - TEC	(9)	0.01093	0.00676	0.00714	0.00840	0.00000	0.01093	0.00000	0.00326
TrAILCo - TEC	(10)	0.00021	0.00014	0.00015	0.00021	0.00000	0.00021	0.00000	0.00007
VEPCo - TEC	(11)	0.00028	0.00018	0.00019	0.00022	0.00000	0.00028	0.00000	0.00008
MAIT -TEC	(12)	0.00007	0.00004	0.00004	0.00005	0.00000	0.00007	0.00000	0.00002
JCP&L -TEC	(13)	0.00029	0.00018	0.00019	0.00022	0.00000	0.00029	0.00000	0.00009
PECO -TEC	(14)	0.00008	0.00006	0.00006	0.00008	0.00000	0.00008	0.00000	0.00003
CW Edison-TEC	(15)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
EL05-121	(16)	0.00032	0.00020	0.00021	0.00024	0.00000	0.00032	0.00000	0.00009
Silver RunTEC	(17)	0.00013	0.00008	0.00009	0.00010	0.00000	0.00013	0.00000	0.00004
NIPSCO TEC	(18)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
ER18-680 & Form 715	(19)	(0.00073)	(0.00049)	(0.00053)	(0.00074)	0.00000	(0.00073)	0.00000	(0.00025)
Total ($/kWh and excl SUT)		$0.01266	$0.00787	$0.00831	$0.00984	$0.00000	$0.01266	$0.00000	$0.00379
Total (¢/kWh and excl SUT)		1.266 ¢	0.787 ¢	0.831 ¢	0.984 ¢	0.000 ¢	1.266 ¢	0.000 ¢	0.379 ¢

(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	$0.00000
ACE - TEC	(2)	0.00003	0.00002	0.00002	0.00003	0.00000	0.00003	0.00000	0.00001
AEP-East - TEC	(3)	0.00007	0.00004	0.00005	0.00005	0.00000	0.00007	0.00000	0.00002
BG&E- TEC	(4)	0.00001	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00000
Delmarva - TEC	(5)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
PATH - TEC	(6)	0.00005	0.00003	0.00003	0.00004	0.00000	0.00005	0.00000	0.00002
PEPCO - TEC	(7)	0.00001	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00000
PPL - TEC	(8)	0.00097	0.00065	0.00069	0.00098	0.00000	0.00097	0.00000	0.00033
PSE&G - TEC	(9)	0.01165	0.00721	0.00761	0.00896	0.00000	0.01165	0.00000	0.00348
TrAILCo - TEC	(10)	0.00022	0.00015	0.00016	0.00022	0.00000	0.00022	0.00000	0.00007
VEPCo - TEC	(11)	0.00030	0.00019	0.00020	0.00023	0.00000	0.00030	0.00000	0.00009
MAIT -TEC	(12)	0.00007	0.00004	0.00004	0.00005	0.00000	0.00007	0.00000	0.00002
JCP&L -TEC	(13)	0.00031	0.00019	0.00020	0.00023	0.00000	0.00031	0.00000	0.00010
PECO -TEC	(14)	0.00009	0.00006	0.00006	0.00009	0.00000	0.00009	0.00000	0.00003
CW Edison-TEC	(15)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
EL05-121	(16)	0.00034	0.00021	0.00022	0.00026	0.00000	0.00034	0.00000	0.00010
Silver Run TEC	(17)	0.00014	0.00009	0.00010	0.00011	0.00000	0.00014	0.00000	0.00004
NIPSCO TEC	(18)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
ER18-680 & Form 715	(19)	(0.00078)	(0.00052)	(0.00057)	(0.00079)	0.00000	(0.00078)	0.00000	(0.00027)
Total ($/kWh and incl SUT)		$0.01348	$0.00838	$0.00883	$0.01048	$0.00000	$0.01348	$0.00000	$0.00404
Total (¢/kWh and incl SUT)		1.348 ¢	0.838 ¢	0.883 ¢	1.048 ¢	0.000 ¢	1.348 ¢	0.000 ¢	0.404 ¢

Notes:

(1) RMR rates based on allocation by transmission zone.
(2) ACE-TEC rates pursuant to the Board's Order dated December 2, 2020 in Docket No. ER20100672.
(3) AEP-East-TEC rates calculated in attachment 5g of the joint filing.
(4) BG&E-TEC rates pursuant to the Board's Order dated December 2, 2020 in Docket No. ER20100672.
(5) Delmarva-TEC rates pursuant to the Board's Order dated August 12, 2020 in Docket No. ER20060446.
(6) PATH-TEC rates calculated in attachment 5e of the joint filing.
(7) PEPCO-TEC rates pursuant to the Board's Order dated December 2, 2020 in Docket No. ER20100672.
(8) PPL-TEC rates pursuant to the Board's Order dated December 2, 2020 in Docket No. ER20100672.
(9) PSE&G-TEC rates calculated in attachment 5b of the joint filing.
(10) TrAILCo-TEC rates pursuant to the Board's Order dated December 2, 2020 in Docket No. ER20100672.
(11) VEPCo-TEC rates calculated in attachment 5d of the joint filing.
(12) MAIT-TEC rates calculated in attachment 5f of the joint filing.
(13) JCP&L-TEC rates calculated in attachment 5c of the joint filing.
(14) PECO-TEC rates pursuant to the Board's Order dated December 2, 2020 in Docket No. ER20100672.
(15) CW Edison-TEC rates pursuant to the Board's Order dated August 12, 2020 in Docket No. ER20060446.
(16) EL05-121 rates calculated in attachment 5j of the joint filing.
(17) Silver Run-TEC rates calculated in attachment 5h of the joint filing.
(18) NIPSCO-TEC rates calculated in attachment 5i of the joint filing.
(19) ER18-680 & Form 715 rates pursuant to the Board's Order dated December 2, 2020 in Docket No. ER20100672.

Attachment 6 – PJM Schedule 12 (Transmission Enhancement) Charges

Attachment 6a
PSE&G Project Charges

Attachment 6b
JCP&L Project Charges

Attachment 6c
Virginia Electric Power Company Project Charges

Attachment 6d
Potomac-Appalachian Transmission Highline Project Charges

Attachment 6e
MAIT Project Charges

Attachment 6f
AEP East Project Charges

Attachment 6g
Silver Run Project Charges

Attachment 6h
NIPSCo Project Charges

Attachment 6i
EL05-121 Charges

Attachment 6a -PJM Schedule 12 - Transmission Enhancement Charges for January 2021 - December 2021 **Attachment 6a**
Calculation of costs and monthly PJM charges for PSE&G Projects

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				Estimated New Jersey EDC Zone Charges by Project				
Required Transmission Enhancement *per PJM website*	PJM Upgrade ID *per PJM spreadsheet*	Jan - Dec 2021 Annual Revenue Requirement *per PJM website*	ACE Zone Share	JCP&L Zone Share	PSE&G Zone Share1,2	RE Zone Share	ACE Zone Charges	JCP&L Zone Charges	PSE&G Zone Charges	RE Zone Charges	Total NJ Zones Charges
			per PJM Open Access Transmission Tariff								
Replace all derated Branchburg 500/230 kava transformers	b0130	$ 1,792,195.00	1.36%	47.76%	50.88%	0.00%	$24,374	$855,952	$911,869	$0	$1,792,195
Reconductor Kittatinny - Newtown 230 kV with 1590 ACSS	b0134	$ 733,602.00	0.00%	51.11%	45.96%	2.93%	$0	$374,944	$337,163	$21,495	$733,602
Build new Essex - Aldene 230 kV cable connected through phase angle regulator at Essex	b0145	$ 7,859,349.00	0.00%	73.45%	21.78%	4.77%	$0	$5,772,692	$1,711,766	$374,891	$7,859,349
Install 4th 500/230 kV transformer at New Freedom	b0411	$ 1,991,280.00	47.01%	7.04%	22.31%	0.00%	$936,101	$140,186	$444,255	$0	$1,520,541
Install 230-138kV transformer at Metuchen substation	b0161	$ 2,447,158.00	0.00%	0.00%	99.80%	0.20%	$0	$0	$2,442,264	$4,894	$2,447,158
Build a new 230 kV section from Branchburg - Flagtown and move the Flagtown - Somerville 230 kV circuit to the new section	b0169	$ 1,496,253.00	1.72%	25.94%	59.59%	0.00%	$25,736	$388,128	$891,617	$0	$1,305,481
Reconductor the Flagtown-Somerville-Bridgewater 230 kV circuit with 1590 ACSS	b0170	$ 653,554.00	0.00%	42.95%	38.36%	0.79%	$0	$280,701	$250,703	$5,163	$536,568
Replace wave trap at Branchburg 500kV substation	b0172.2	$ 1,280.50	1.72%	3.82%	6.15%	0.25%	$22	$49	$79	$3	$153
Replace wave trap at Branchburg 500kV substation	b0172.2_dfax	$ 1,280.50	4.49%	29.72%	48.90%	2.01%	$57	$381	$626	$26	$1,090
Branchburg 400 MVAR Capacitor	b0290	$ 3,922,718.50	1.72%	3.82%	6.15%	0.25%	$67,471	$149,848	$241,247	$9,807	$468,373
Branchburg 400 MVAR Capacitor	b0290_dfax	$ 3,922,718.50	4.49%	29.72%	48.90%	2.01%	$176,130	$1,165,832	$1,918,209	$78,847	$3,339,018
Inst Conemaugh 250 MVAR Cap	b0376	$ 61,314.00	1.72%	3.82%	6.15%	0.25%	$1,055	$2,342	$3,771	$153	$7,321
Inst Conemaugh 250 MVAR Cap	b0376_dfax	$ 61,314.00	0.00%	18.75%	24.11%	0.99%	$0	$11,496	$14,783	$607	$26,886
Saddle Brook - Athenia Upgrade Cable	b0472	$ 1,472,012.00	0.00%	0.00%	94.41%	3.53%	$0	$0	$1,389,727	$51,962	$1,441,689
Build new 500 kV transmission facilities from Pennsylvania - New Jersey border at Bushkill to Roseland (500kV and above elements of the project)	b0489	$ 40,992,943.50	1.72%	3.82%	6.15%	0.25%	$705,079	$1,565,930	$2,521,066	$102,482	$4,894,557
Build new 500 kV transmission facilities from Pennsylvania - New Jersey border at Bushkill to Roseland (500kV and above elements of the project)	b0489_dfax	$ 40,992,943.50	0.00%	39.21%	54.50%	2.24%	$0	$16,073,333	$22,341,154	$918,242	$39,332,729
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	$ 4,541,326.00	5.09%	32.73%	40.71%	1.52%	$231,153	$1,486,376	$1,848,774	$69,028	$3,635,331
Susquehanna Roseland Breakers (In-Service)	b0489.5	$ 308,258.50	1.72%	3.82%	6.15%	0.25%	$5,302	$11,775	$18,958	$771	$36,806
Susquehanna Roseland Breakers (In-Service)	b0489.5_dfax	$ 308,258.50	0.00%	39.21%	54.50%	2.24%	$0	$120,868	$168,001	$6,905	$295,774
Loop the 5021 circuit into New Freedom 500 kV substation	b0498	$ 1,268,127.50	1.72%	3.82%	6.15%	0.25%	$21,812	$48,442	$77,990	$3,170	$151,414

Attachment 6a -PJM Schedule 12 - Transmission Enhancement Charges for January 2021 - December 2021 **Attachment 6a**
Calculation of costs and monthly PJM charges for PSE&G Projects

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				Estimated New Jersey EDC Zone Charges by Project				
Required Transmission Enhancement *per PJM website*	PJM Upgrade ID *per PJM spreadsheet*	Jan - Dec 2021 Annual Revenue Requirement *per PJM website*	ACE Zone Share	JCP&L Zone Share	PSE&G Zone Share1,2	RE Zone Share	ACE Zone Charges	JCP&L Zone Charges	PSE&G Zone Charges	RE Zone Charges	Total NJ Zones Charges
			per PJM Open Access Transmission Tariff								
Loop the 5021 circuit into New Freedom 500 kV substation	b0498_dfax	$ 1,268,127.50	8.37%	25.68%	41.36%	1.70%	$106,142	$325,655	$524,498	$21,558	$977,853
Branchburg-Somerville-Flagtown Reconductor	b0664-b0665	$ 1,902,963.00	0.00%	36.35%	43.24%	1.61%	$0	$691,727	$822,841	$30,638	$1,545,206
Somerville -Bridgewater Reconductor	b0668	$ 656,622.00	0.00%	39.41%	38.76%	1.45%	$0	$258,775	$254,507	$9,521	$522,802
Reconductor Hudson - South Waterfront 230kV circuit	b0813	$ 904,290.00	0.00%	9.92%	83.73%	3.12%	$0	$89,706	$757,162	$28,214	$875,081
New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie	b0814	$ 2,405,850.00	0.00%	23.49%	67.03%	2.50%	$0	$565,134	$1,612,641	$60,146	$2,237,922
Reconductor South Mahwah 345 kV J-3410 Circuit	b1017	$ 2,059,544.00	0.00%	29.01%	64.85%	2.53%	$0	$597,474	$1,335,614	$52,106	$1,985,194
Reconductor South Mahwah 345 kV K-3411 Circuit	b1018	$ 2,138,829.00	0.00%	29.18%	64.68%	2.53%	$0	$624,110	$1,383,395	$54,112	$2,061,617
West Orange Conversion (North Central Reliability)	b1154	$ 38,698,829.00	0.00%	0.00%	96.18%	3.82%	$0	$0	$37,220,534	$1,478,295	$38,698,829
Branchburg-Middlesex Sw Rack	b1155	$ 6,629,733.00	0.00%	4.61%	91.75%	3.64%	$0	$305,631	$6,082,780	$241,322	$6,629,733
Conversion	b1156	$ 37,708,166.00	0.00%	0.00%	96.18%	3.82%	$0	$0	$36,267,714	$1,440,452	$37,708,166
Reconf Kearny Loop in P2216	b1589	$ 2,536,461.00	0.00%	0.00%	61.59%	2.46%	$0	$0	$1,562,206	$62,397	$1,624,603
230kV Lawrence Switching Station Upgrade	b1228	$ 2,276,611.00	0.00%	0.00%	95.83%	3.81%	$0	$0	$2,181,676	$86,739	$2,268,415
Ridge Rd 69kV Breaker Station	b1255	$ 4,979,816.00	0.00%	0.00%	96.18%	3.82%	$0	$0	$4,789,587	$190,229	$4,979,816
Northeast Grid Reliability Project	b1304.1-b1304.4	$ 69,228,973.00	0.23%	1.17%	70.16%	2.78%	$159,227	$809,979	$48,571,047	$1,924,565	$51,464,819
Mickleton-Gloucester-Camden	b1398	$ 47,766,219.00	0.00%	12.82%	31.46%	1.25%	$0	$6,123,629	$15,027,252	$597,078	$21,747,960
Aldene-Springfield Rd. Conv	b1399	$ 7,783,761.00	0.00%	0.00%	96.18%	3.82%	$0	$0	$7,486,421	$297,340	$7,783,761
Replace Salem 500 kV breakers	b1410-b1415	$ 841,178.00	1.72%	3.82%	6.15%	0.25%	$14,468	$32,133	$51,732	$2,103	$100,437
Replace Salem 500 kV breakers	b1410-b1415_dfax	$ 841,178.00	0.00%	0.00%	96.06%	3.94%	$0	$0	$808,036	$33,142	$841,178
Uprate Eagle Point-Gloucester 230 kV Circuit	b1588	$ 1,317,127.00	0.00%	10.31%	54.17%	2.16%	$0	$135,796	$713,488	$28,450	$877,733
Upgrade Camden Richmon 230kV	b1590	$ 1,217,983.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
New Cox's Corner-Lumberton 230kV Circuit	b1787	$ 3,525,655.00	4.96%	44.20%	48.08%	1.92%	$174,872	$1,558,340	$1,695,135	$67,693	$3,496,039
Build Mickleton-Gloucester Corridor Ultimate Design	b2139	$ 2,163,362.00	0.00%	0.00%	61.11%	2.44%	$0	$0	$1,322,031	$52,786	$1,374,817
Reconfigure Brunswick New 69kV	b2146	$ 19,224,371.00	0.00%	0.00%	96.16%	3.84%	$0	$0	$18,486,155	$738,216	$19,224,371
Convert Bergen Marion 138 kV to double circuit 345kV and Sub	b2436.10_dfax	$ 9,971,441.50	0.00%	0.00%	100.00%	0.00%	$0	$0	$9,971,442	$0	$9,971,442
Convert Bergen Marion 138 kV to double circuit 345kV and Sub	b2436.10	$ 9,971,441.50	1.72%	3.82%	6.15%	0.25%	$171,509	$380,909	$613,244	$24,929	$1,190,590
Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.21_dfax	$ 3,876,431.00	0.00%	0.00%	100.00%	0.00%	$0	$0	$3,876,431	$0	$3,876,431
Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.21	$ 3,876,431.00	1.72%	3.82%	6.15%	0.25%	$66,675	$148,080	$238,401	$9,691	$462,846
Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.22_dfax	$ 2,865,744.00	0.00%	0.00%	96.06%	3.94%	$0	$0	$2,752,834	$112,910	$2,865,744
Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.22	$ 2,865,744.00	1.72%	3.82%	6.15%	0.25%	$49,291	$109,471	$176,243	$7,164	$342,170

Attachment 6a -PJM Schedule 12 - Transmission Enhancement Charges for January 2021 - December 2021 **Attachment 6a**
Calculation of costs and monthly PJM charges for PSE&G Projects

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				Estimated New Jersey EDC Zone Charges by Project				
Required Transmission Enhancement *per PJM website*	PJM Upgrade ID *per PJM spreadsheet*	Jan - Dec 2021 Annual Revenue Requirement *per PJM website*	ACE Zone Share	JCP&L Zone Share	PSE&G Zone Share1,2	RE Zone Share	ACE Zone Charges	JCP&L Zone Charges	PSE&G Zone Charges	RE Zone Charges	Total NJ Zones Charges
			per PJM Open Access Transmission Tariff								
New 500 kV bay at Hope Creek (Expansion of Hope Creek sub)	b2633.4	$ 2,004,378.00	1.72%	3.82%	6.15%	0.25%	$34,475	$76,567	$123,269	$5,011	$239,323
New 500 kV bay at Hope Creek (Expansion of Hope Creek sub)	b2633.4_dfax	$ 2,004,378.00	8.01%	13.85%	20.79%	0.62%	$160,551	$277,606	$416,710	$12,427	$867,294
New 500/230 kV autotransformer at Hope Creek and a new Hope Creek 230 kV substation	b2633.5	$ 6,995,758.00	8.01%	13.85%	20.79%	0.62%	$560,360	$968,912	$1,454,418	$43,374	$3,027,064
Rebuild Aldene-Warinanco-Linden VFT 230kV Circuit	b2955	$ 11,789,355.00	0.00%	92.14%	0.00%	0.00%	$0	$10,862,712	$0	$0	$10,862,712
Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades	b2436.33	$ 18,246,726.00	0.00%	0.00%	96.06%	3.94%	$0	$0	$17,527,805	$718,921	$18,246,726
Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades (B2436.34)	b2436.34	$ 14,607,545.00	0.00%	0.00%	96.06%	3.94%	$0	$0	$14,032,008	$575,537	$14,607,545
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)	b2436.60	$ 4,959,375.00	0.00%	0.00%	96.06%	3.94%	$0	$0	$4,763,976	$195,399	$4,959,375
Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation	b2436.81_dfax	$ 3,447,733.00	0.00%	0.00%	96.06%	3.94%	$0	$0	$3,311,892	$135,841	$3,447,733
Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation	b2436.81	$ 3,447,733.00	1.72%	3.82%	6.15%	0.25%	$59,301	$131,703	$212,036	$8,619	$411,659
Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.83_dfax	$ 3,447,733.00	0.00%	0.00%	96.06%	3.94%	$0	$0	$3,311,892	$135,841	$3,447,733
Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades	b2436.83	$ 3,447,733.00	1.72%	3.82%	6.15%	0.25%	$59,301	$131,703	$212,036	$8,619	$411,659
Convert Bayway-Linden "W" to 138kV circuit to 345kV	b2436.84_dfax	$ 3,417,499.50	0.00%	0.00%	96.06%	3.94%	$0	$0	$3,282,850	$134,649	$3,417,500
Convert Bayway-Linden "W" to 138kV circuit to 345kV	b2436.84	$ 3,417,499.50	1.72%	3.82%	6.15%	0.25%	$58,781	$130,548	$210,176	$8,544	$408,049
Convert Bayway-Linden "M" to 138kV circuit to 345kV	b2436.85_dfax	$ 3,419,871.50	0.00%	0.00%	96.06%	3.94%	$0	$0	$3,285,129	$134,743	$3,419,872
Convert Bayway-Linden "M" to 138kV circuit to 345kV	b2436.85	$ 3,419,871.50	1.72%	3.82%	6.15%	0.25%	$58,822	$130,639	$210,322	$8,550	$408,333
Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades	b2436.90_dfax	$ 1,718,216.00	0.00%	0.00%	100.00%	0.00%	$0	$0	$1,718,216	$0	$1,718,216
Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades	b2436.90	$ 1,718,216.00	1.72%	3.82%	6.15%	0.25%	$29,553	$65,636	$105,670	$4,296	$205,155
New Linden 345/230 kV transformer and any associated substation upgrades	b2437.30	$ 5,282,609.00	0.00%	0.00%	96.06%	3.94%	$0	$0	$5,074,474	$208,135	$5,282,609
Install two 175 MVAR Re at Hptcg	b2702_dfax	$ 1,291,665.00	0.00%	0.00%	100.00%	0.00%	$0	$0	$1,291,665	$0	$1,291,665

Attachment 6a -PJM Schedule 12 - Transmission Enhancement Charges for January 2021 - December 2021 **Attachment 6a**
Calculation of costs and monthly PJM charges for PSE&G Projects

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				Estimated New Jersey EDC Zone Charges by Project				
Required Transmission Enhancement *per PJM website*	PJM Upgrade ID *per PJM spreadsheet*	Jan - Dec 2021 Annual Revenue Requirement *per PJM website*	ACE Zone Share	JCP&L Zone Share	PSE&G Zone Share1,2	RE Zone Share	ACE Zone Charges	JCP&L Zone Charges	PSE&G Zone Charges	RE Zone Charges	Total NJ Zones Charges
			per PJM Open Access Transmission Tariff								
Install two 175 MVAR Re at Hptcg	b2702	$ 1,291,665.00	1.72%	3.82%	6.15%	0.25%	$22,217	$49,342	$79,437	$3,229	$154,225
Convert R-1318 and Q1815 Circuits to 230kV	b2835.1	$ 10,450,746.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Convert R-1318 and Q1815 Circuits to 230kV	b2835.2	$ 6,622,614.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Convert R-1318 and Q1815 Circuits to 230kV	b2835.3	$ 1,021,376.00	0.00%	0.00%	57.49%	2.36%	$0	$0	$587,189	$24,104	$611,294
Convert the N-1340 and T-1372/D-1330 (Brunswick - Trenton) 138 kV circuits to 230 kV circuits	b2836.2	$ 9,294,426.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Convert the N-1340 and T-1372/D-1330 (Brunswick - Trenton) 138 kV circuits to 230 kV circuits	b2836.3	$ 6,060,893.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Convert the N-1340 and T-1372/D-1330 (Brunswick - Trenton) 138 kV circuits to 230 kV circuits	b2836.4	$ 11,618,974.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Convert F-1358/Z-1326 and K-1363/Y-1325 to Circuits to 230kV	b2837.1	$ 3,746,086.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Convert F-1358/Z-1326 and K-1363/Y-1325 to Circuits to 230kV	b2837.2	$ 1,284,500.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Convert F-1358/Z-1326 and K-1363/Y-1325 to Circuits to 230kV	b2837.3	$ 884,806.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Convert F-1358/Z-1326 and K-1363/Y-1325 to Circuits to 230kV	b2837.4	$ 3,094,144.00	0.00%	0.00%	88.71%	3.64%	$0	$0	$2,744,815	$112,627	$2,857,442
Convert F-1358/Z-1326 and K-1363/Y-1325 to Circuits to 230kV	b2837.5	$ 3,184,082.00	0.00%	0.00%	90.12%	3.70%	$0	$0	$2,869,495	$117,811	$2,987,306
Convert F-1358/Z-1326 and K-1363/Y-1325 to Circuits to 230kV	b2837.6	$ 3,733,025.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Convert F-1358/Z-1326 and K-1363/Y-1325 to Circuits to 230kV	b2837.7	$ 1,240,875.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Convert F-1358/Z-1326 and K-1363/Y-1325 to Circuits to 230kV	b2837.8	$ 884,806.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Convert F-1358/Z-1326 and K-1363/Y-1325 to Circuits to 230kV	b2837.9	$ 323,731.00	0.00%	0.00%	87.28%	3.58%	$0	$0	$282,552	$11,590	$294,142
Convert F-1358/Z-1326 and K-1363/Y-1325 to Circuits to 230kV	b2837.10	$ 2,761,938.00	0.00%	0.00%	88.85%	3.65%	$0	$0	$2,453,982	$100,811	$2,554,793
Convert F-1358/Z-1326 and K-1363/Y-1325 to Circuits to 230kV	b2837.11	$ 3,281,770.00	0.00%	0.00%	90.40%	3.71%	$0	$0	$2,966,720	$121,754	$3,088,474
Roseland-Branchburg 230kV corridor rebuild (Readington - Branchburg)	b2986.12	$ 32,139.00	0.00%	100.00%	0.00%	0.00%	$0	$32,139	$0	$0	$32,139
Branchburg-Pleasant Valley 230kV corridor rebuild (Branchburg - East Flemington)	b2986.21	$ 3,242,623.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Replace Transformers 203/138kV transformers at Roseland	b0274	$ 2,002,469.00	0.00%	0.00%	96.77%	0.00%	$0	$0	$1,937,789	$0	$1,937,789
Totals		**$ 580,472,351.00**					**$3,979,836**	**$54,063,334**	**$318,585,592**	**$12,130,674**	**$388,759,436**

Notes on calculations >>> = (a) * (b) = (a) * (c) = (a) * (d) = (a) * (e) = (f) + (g) +

	(k)	(l)	(m)	(n)	(o)	
						318585595
Zonal Cost	**Average Monthly**			**2021**		**-$3**

Attachment 6a -PJM Schedule 12 - Transmission Enhancement Charges for January 2021 - December 2021 **Attachment 6a**
Calculation of costs and monthly PJM charges for PSE&G Projects

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			Responsible Customers - Schedule 12 Appendix				Estimated New Jersey EDC Zone Charges by Project				
Required Transmission Enhancement *per PJM website*	PJM Upgrade ID *per PJM spreadsheet*	Jan - Dec 2021 Annual Revenue Requirement *per PJM website*	ACE Zone Share	JCP&L Zone Share	PSE&G Zone Share1,2	RE Zone Share	ACE Zone Charges	JCP&L Zone Charges	PSE&G Zone Charges	RE Zone Charges	Total NJ Zones Charges
			per PJM Open Access Transmission Tariff								

Allocation for New Jersey Zones	Impact on Zone Customers in 2021	2021 Trans. Peak Load [2]	Rate in $/MW-mo. [1]	Impact (12 months)
PSE&G	$ 26,548,799.32	9,557.3	$ 2,777.86	$ 318,585,592
JCP&L	$ 4,505,277.83	5,903.2	$ 763.19	$ 54,063,334
ACE	$ 331,652.99	2,634.5	$ 125.89	$ 3,979,836
RE	$ 1,010,889.52	397.5	$ 2,543.12	$ 12,130,674
Total Impact on NJ Zones	**$ 32,396,619.65**	**18,492.5**		**$ 388,759,436**

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

Notes:
1) Uncompressed rate - assumes implementation on January 1, 2021
2) Data on PJM website

Attachment 6b - PJM Schedule 12 - Transmission Enhancement Charges for January 2021 - December 2021
Calculation of Costs and Monthly PJM charges for JCP&L Projects

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Required Transmission Enhancement	PJM Upgrade ID	Jan - Dec 2021 Annual Revenue Requirement	Responsible Customers - Schedule 12 Appendix ACE Zone Share	JCP&L Zone Share	PSE&G Zone Share1,2	RE Zone Share	Estimated New Jersey EDC Zone Charges by Project ACE Zone Charges	JCP&L Zone Charges	PSE&G Zone Charges	RE Zone Charges	Total NJ Zones Charges
	per PJM spreadsheet	*Attachment H-4A, Attachment 11*	*PJM Website Transmission Enhancement Worksheet 9.11.2020*								
Upgrade the Portland - Greystone 230kV circuit	b0174	$1,284,859	0.00%	35.40%	54.37%	2.94%	$0	$454,840	$698,578	$37,775	$1,191,193
Reconductor the 8 mile Gilbert - Glen Gardner 230kV circuit	b0268	$635,153	0.00%	61.77%	32.73%	1.45%	$0	$392,334	$207,885	$9,210	$609,429
Add a 2nd Raritan River 230/115 kV transformer	b0726	$812,093	2.45%	97.55%	0.00%	0.00%	$19,896	$792,197	$0	$0	$812,093
Build a new 230kV circuit from Larrabee to Oceanview	b2015	$19,247,145	0.00%	35.83%	35.87%	1.43%	$0	$6,896,252	$6,903,951	$275,234	$14,075,437
Totals		**$21,979,249**					**$19,896**	**$8,535,622**	**$7,810,414**	**$322,219**	**$16,688,152**

	(k)	(l)	(m)	(n)	(o)
Zonal Cost Allocation for New Jersey Zones	Average Monthly Impact on Zone Customers in 2021	2021 Trans. Peak Load [2]	Rate in $/MW-mo. [1]	2021 Impact (12 months)	
PSE&G	$650,868	9,557.3	$68.10	$7,810,414	
JCP&L	$711,302	5,903.2	$120.49	$8,535,622	
ACE	$1,658	2,634.5	$0.63	$19,896	
RE	$26,852	397.5	$67.55	$322,219	
Total Impact on NJ Zones	**$1,390,679**	**18,492.5**		**$16,688,152**	
			= (k) / (l)	= (k) *12	

Notes:
1) Uncompressed rate - assumes implementation on January 1, 2021
2) Data on PJM website

Attachment 6c - PJM Schedule 12 - Transmission Enhancement Charges for January 2021 - December 2021 **Attachment 6c**
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 2021 Annual Revenue Requirement *per PJM website*	ACE Zone Share	JCP&L Zone Share	PSE&G Zone Share1	RE Zone Share	ACE Zone Charges	JCP&L Zone Charges	PSE&G Zone Charges	RE Zone Charges	Total NJ Zones Charges
			per PJM Open Access Transmission Tariff								
Upgrade Mt Storm - Doubs 500kV	b0217	$107,459.13	1.72%	3.82%	6.15%	0.25%	$1,848	$4,105	$6,609	$269	$12,831
Upgrade Mt Storm - Doubs 500kV	b0217_dfax	$107,459.13	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Loudoun 150 MVA capacitor @ 500 kV	b0222	$87,252.53	1.72%	3.82%	6.15%	0.25%	$1,501	$3,333	$5,366	$218	$10,418
Loudoun 150 MVA capacitor @ 500 kV	b0222_dfax	$87,252.53	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
500 kV breakers and bus work at Suffolk	b0231	$1,229,747.00	1.72%	3.82%	6.15%	0.25%	$21,152	$46,976	$75,629	$3,074	$146,832
500 kV breakers and bus work at Suffolk	b0231_dfax	$1,229,747.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Meadowbrook-Loudon 500kV circuit	b0328.1	$13,305,482.35	1.72%	3.82%	6.15%	0.25%	$228,854	$508,269	$818,287	$33,264	$1,588,675
Meadowbrook-Loudon 500kV circuit	b0328.1_dfax	$13,305,482.35	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Upgrade Mt. Storm 500 KV Substation	b0328.3	$821,599.84	1.72%	3.82%	6.15%	0.25%	$14,132	$31,385	$50,528	$2,054	$98,099
Upgrade Mt. Storm 500 KV Substation	b0328.3_dfax	$821,599.84	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Upgrade Loudoun 500 KV Substation	b0328.4	$183,661.61	1.72%	3.82%	6.15%	0.25%	$3,159	$7,016	$11,295	$459	$21,929
Upgrade Loudoun 500 KV Substation	b0328.4_dfax	$183,661.61	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	$9,729,928.15	1.72%	3.82%	6.15%	0.25%	$167,355	$371,683	$598,391	$24,325	$1,161,753
Carson – Suffolk 500 kV, Suffolk 500/230 kV transformer & build Suffolk – Trascher 230 kV circuit	B0329.2B_dfax	$9,729,928.15	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
500/230 KV transformer at Bristers, new 230 Bristers - Gainsville circuit	b0227	$2,247,808.06	0.71%	0.00%	0.00%	0.00%	$15,959	$0	$0	$0	$15,959
Rebuild Mt Storm-Doubs 500 KV circuit	b1507	$19,282,169.58	1.72%	3.82%	6.15%	0.25%	$331,653	$736,579	$1,185,853	$48,205	$2,302,291
Rebuild Mt Storm-Doubs 500 KV circuit	b1507_dfax	$19,282,169.58	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Replace wave traps on Dooms-Lexington 500KV circuit	b0457	$6,086.97	1.72%	3.82%	6.15%	0.25%	$105	$233	$374	$15	$727
Replace wave traps on Dooms-Lexington 500KV circuit	b0457_dfax	$6,086.97	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Morrisville H1T573	b1647	$930.36	1.72%	3.82%	6.15%	0.25%	$16	$36	$57	$2	$111
Morrisville H1T573	b1647_dfax	$930.36	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Morrisville H2T545	b1648	$930.36	1.72%	3.82%	6.15%	0.25%	$16	$36	$57	$2	$111
Morrisville H2T545	b1648_dfax	$930.36	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Morrisville H1T580	b1649	$49,088.36	1.72%	3.82%	6.15%	0.25%	$844	$1,875	$3,019	$123	$5,861
Morrisville H1T580	b1649_dfax	$49,088.36	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Morrisville H2T569	b1650	$49,088.36	1.72%	3.82%	6.15%	0.25%	$844	$1,875	$3,019	$123	$5,861
Morrisville H2T569	b1650_dfax	$49,088.36	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Replace wave traps on North Anna-Ladysmith 500KV circuit	b0784	$4,222.46	1.72%	3.82%	6.15%	0.25%	$73	$161	$260	$11	$504
Replace wave traps on North Anna-Ladysmith 500KV circuit	b0784_dfax	$4,222.46	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0

Attachment 6c - PJM Schedule 12 - Transmission Enhancement Charges for January 2021 - December 2021 **Attachment 6c**
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 2021 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share**	**JCP&L Zone Share**	**PSE&G Zone Share1**	**RE Zone Share**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
			per PJM Open Access Transmission Tariff								
Reconductor the Dickerson-Pleasant View 230 KV circuit	b0467.2	$612,201.16	1.75%	0.71%	0.00%	0.00%	$10,714	$4,347	$0	$0	$15,060
Install 500/230 kV transformer and two 230 kV breakers at Brambleton	b1188.6	$1,976,109.73	0.22%	0.00%	0.00%	0.00%	$4,347	$0	$0	$0	$4,347
New Brambleton 500 kV line, 3 ring bus, to Loudon to Pleasant View 500 kV	b1188	$78,523.29	1.72%	3.82%	6.15%	0.25%	$1,351	$3,000	$4,829	$196	$9,376
New Brambleton 500 kV line, 3 ring bus, to Loudon to Pleasant View 500 kV	b1188_dfax	$78,523.29	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	$241,509.97	1.72%	3.82%	6.15%	0.25%	$4,154	$9,226	$14,853	$604	$28,836
Install 2 500kV breakers at Chancellor 500 kV	b0756.1_dfax	$241,509.97	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Wreck and Rebuild 7 miles of Cloverdale - Lexington 500 kV Line	b1797	$1,072,292.63	1.72%	3.82%	6.15%	0.25%	$18,443	$40,962	$65,946	$2,681	$128,032
Wreck and Rebuild 7 miles of Cloverdale - Lexington 500 kV Line	b1797_dfax	$1,072,292.63	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	$6,579,724.98	1.72%	3.82%	6.15%	0.25%	$113,171	$251,345	$404,653	$16,449	$785,619
Build 450 MVAR SVC and 300 MVAR switched shunt at Loudoun 500 kV	b1798_dfax	$6,579,724.98	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Build 150 MVAR Switched Shunt at Pleasant View 500 kV Line	b1799	$1,552,673.35	1.72%	3.82%	6.15%	0.25%	$26,706	$59,312	$95,489	$3,882	$185,389
Build 150 MVAR Switched Shunt at Pleasant View 500 kV Line	b1799_dfax	$1,552,673.35	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Install 250 MVAR SVC at Mt. Storm 500 kV Substation	b1805	$2,190,380.10	1.72%	3.82%	6.15%	0.25%	$37,675	$83,673	$134,708	$5,476	$261,531
Install 250 MVAR SVC at Mt. Storm 500 kV Substation	b1805_dfax	$2,190,380.10	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
At Yadkin 500 kV, install six 500 kV Breakers	b1906.1	$607,744.13	1.72%	3.82%	6.15%	0.25%	$10,453	$23,216	$37,376	$1,519	$72,565
At Yadkin 500 kV, install six 500 kV Breakers	b1906.1_dfax	$607,744.13	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Rebuild Lexington-Dooms 500 kV Line	b1908	$7,634,119.71	1.72%	3.82%	6.15%	0.25%	$131,307	$291,623	$469,498	$19,085	$911,514
Rebuild Lexington-Dooms 500 kV Line	b1908_dfax	$7,634,119.71	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Surry 500 kV Station Work	b1905.2	$115,220.57	1.72%	3.82%	6.15%	0.25%	$1,982	$4,401	$7,086	$288	$13,757
Surry 500 kV Station Work	b1905.2_dfax	$115,220.57	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	$41,469.32	1.72%	3.82%	6.15%	0.25%	$713	$1,584	$2,550	$104	$4,951
Mt Storm - Replace MOD with breaker on 500kV side of Transformer	b0837_dfax	$41,469.32	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0

Attachment 6c - PJM Schedule 12 - Transmission Enhancement Charges for January 2021 - December 2021 **Attachment 6c**
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 2021 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share**	**JCP&L Zone Share**	**PSE&G Zone Share1**	**RE Zone Share**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
			per PJM Open Access Transmission Tariff								
Uprate Section between Possum and Dumfries Substation	b1328	$472,765.95	0.66%	0.00%	0.00%	0.00%	$3,120	$0	$0	$0	$3,120
Rebuild Loudoun - Brambleto 500kV	b1694	$2,875,277.01	1.72%	3.82%	6.15%	0.25%	$49,455	$109,836	$176,830	$7,188	$343,308
Rebuild Loudoun - Brambleto 500kV	b1694_dfax	$2,875,277.01	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
R/P Midlothian 500kV 3 breaker Ring Bus	b2471	$480,079.73	1.72%	3.82%	6.15%	0.25%	$8,257	$18,339	$29,525	$1,200	$57,322
R/P Midlothian 500kV 3 breaker Ring Bus	b2471_dfax	$480,079.73	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Surry to Skiffes Creek 500kV Line	b1905.1	$20,170,063.79	1.72%	3.82%	6.15%	0.25%	$346,925	$770,496	$1,240,459	$50,425	$2,408,306
Surry to Skiffes Creek 500kV Line	b1905.1_dfax	$20,170,063.79	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Install Breaker and half scheme with minimum of eight 230kV Breakers	b1696	($615,152.36)	0.46%	0.64%	0.00%	0.00%	-$2,830	-$3,937	$0	$0	-$6,767
Build a second Loudon - Brambleton 500kV line	b2373	$2,724,928.58	1.72%	3.82%	6.15%	0.25%	$46,869	$104,092	$167,583	$6,812	$325,356
Build a second Loudon - Brambleton 500kV line	b2373_dfax	$2,724,928.58	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Rebuild Carson Rogers 500kV Ckt	b2744	$3,179,908.97	1.72%	3.82%	6.15%	0.25%	$54,694	$121,473	$195,564	$7,950	$379,681
Rebuild Carson Rogers 500kV Ckt	b2744_dfax	$3,179,908.97	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Optimal Capacitors Configuaration	b2729	$887,355.38	1.96%	3.31%	7.29%	0.00%	$17,392	$29,371	$64,688	$0	$111,452
Rebuild Elmont-Cunningham 500 kV Ln	b2582	$5,764,473.87	1.72%	3.82%	6.15%	0.25%	$99,149	$220,203	$354,515	$14,411	$688,278
Rebuild Elmont-Cunningham 500 kV Ln	b2582_dfax	$5,764,473.87	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Rebuild Cunningham-Dooms 500 kV Ln	b2665	$5,219,738.87	1.72%	3.82%	6.15%	0.25%	$89,780	$199,394	$321,014	$13,049	$623,237
Rebuild Cunningham-Dooms 500 kV Ln	b2665_dfax	$5,219,738.87	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Rebuild Line#549 Dooms-Valley 500kV	b2758	$3,983,539.33	1.72%	3.82%	6.15%	0.25%	$68,517	$152,171	$244,988	$9,959	$475,635
Rebuild Line#549 Dooms-Valley 500kV	b2758_dfax	$3,983,539.33	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Rebld Line #550 Mt.Storm-Valley 500kV	b2759	$9,545,613.80	1.72%	3.82%	6.15%	0.25%	$164,185	$364,642	$587,055	$23,864	$1,139,746
Rebld Line #550 Mt.Storm-Valley 500kV	b2759_dfax	$9,545,613.80	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Inst 125 MVAR STCOMs at Clover Sub	b2978	$2,619,368.68	1.72%	3.82%	6.15%	0.25%	$45,053	$100,060	$161,091	$6,548	$312,753
Inst 125 MVAR STCOMs at Clover Sub	b2978_dfax	$2,619,368.68	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Rebuild 4 Structures Line#549	b2928	$2,021,016.76	1.72%	3.82%	6.15%	0.25%	$34,761	$77,203	$124,293	$5,053	$241,309
Rebuild 4 Structures Line#549	b2928_dfax	$2,021,016.76	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Replace Capacitors on Line#547	b2960.1	$983,956.48	1.72%	3.82%	6.15%	0.25%	$16,924	$37,587	$60,513	$2,460	$117,484
Replace Capacitors on Line#547	b2960.1_dfax	$983,956.48	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Replace Capacitors on Line#548	b2960.2	$1,134,142.92	1.72%	3.82%	6.15%	0.25%	$19,507	$43,324	$69,750	$2,835	$135,417
Replace Capacitors on Line#548	b2960.2_dfax	$1,134,142.92	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Totals		**$256,927,915.59**					**$2,210,286**	**$4,830,506**	**$7,793,603**	**$314,184**	**$15,148,578**
Notes on calculations >>>							= (a) * (b)	= (a) * (c)	= (a) * (d)	= (a) * (e)	= (f) + (g) + (h) + (i)

Attachment 6c - PJM Schedule 12 - Transmission Enhancement Charges for January 2021 - December 2021 **Attachment 6c**
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 2021 Annual Revenue Requirement *per PJM website*	ACE Zone Share	JCP&L Zone Share	PSE&G Zone Share1	RE Zone Share	ACE Zone Charges	JCP&L Zone Charges	PSE&G Zone Charges	RE Zone Charges	Total NJ Zones Charges
			per PJM Open Access Transmission Tariff								

	(k)	(l)	(m)	(n)
Zonal Cost Allocation for New Jersey Zones	Average Monthly Impact on Zone Customers in 2021	2021 Trans. Peak Load [2]	Rate in $/MW-mo. [1]	2021 Impact (12 months)
PSE&G	$ 649,466.93	9,557.3	$ 67.96	$ 7,793,603
JCP&L	$ 402,542.13	5,903.2	$ 68.19	$ 4,830,506
ACE	$ 184,190.49	2,634.5	$ 69.91	$ 2,210,286
RE	$ 26,181.96	397.5	$ 65.87	$ 314,184
Total Impact on NJ Zones	**$ 1,262,381.50**	**18,492.5**		**$ 15,148,578**

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

Attachment 6d PJM Schedule 12 - Transmission Enhancement Charges for January 2021 - December 2021
Calculation of costs and monthly PJM charges for PATH Project

			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
				Responsible Customers - Schedule 12 Appendix				Estimated New Jersey EDC Zone Charges by Project				
Required Transmission Enhancement *per PJM website*	**PJM Upgrade ID** *per PJM spreadsheet*		**Jan - Dec 2021 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share**	**JCP&L Zone Share**	**PSE&G Zone Share**[1]	**RE Zone Share**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
				per PJM Open Access Transmission Tariff								
Amos-Bedington 765 kV Circuit (AEP)	b0490 &b 0491	$	4,811,597.00	1.72%	3.82%	6.15%	0.25%	$82,759	$183,803	$295,913	$12,029	$574,505
Amos-Bedington 765 kV Circuit (AEP)	b0490 & b0491_dfax	$	4,811,597.00	5.01%	11.64%	15.86%	0.59%	$241,061	$560,070	$763,119	$28,388	$1,592,639
Bedington-Kemptown 500 kV Circuit	b0492 & b560	$	2,036,589.50	1.72%	3.82%	6.15%	0.25%	$35,029	$77,798	$125,250	$5,091	$243,169
Bedington-Kemptown 500 kV Circuit	b0492 & b560_dfax	$	2,036,589.50	5.01%	11.64%	15.86%	0.59%	$102,033	$237,059	$323,003	$12,016	$674,111
Totals		**$**	**13,696,373.00**					**$460,883**	**$1,058,730**	**$1,507,286**	**$57,525**	**$3,084,423**
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 2021**	**2021 Trans. Peak Load**[2]	**Rate in $/MW-mo.**[1]	**2021 Impact (12 months)**
PSE&G	$	125,607.15	9,557.3	$13.14	$ 1,507,286
JCP&L	$	88,227.47	5,903.2	$14.95	$ 1,058,730
ACE	$	38,406.91	2,634.5	$14.58	$ 460,883
RE	$	4,793.73	397.5	$12.06	$ 57,525
Total Impact on NJ Zones	**$**	**257,035.27**	**18,492.5**		**$ 3,084,423**
Notes on calculations >>>				= (k) / (l)	= (k) *12

Notes:
1) Uncompressed rate - assumes implementation on January 1, 2021
2) Data on PJM website

Attachment 6e - Transmission Enhancement Charges for January 2021 - December 2021 **Attachment 6e**
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 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]**	**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	$ 1,735,668.00	6.71%	16.85%	22.67%	0.34%	$116,463	$292,460	$393,476	$5,901	$808,301
Replace wave trap at Kestone 500kV Sub	b2688.1	$ 1,890,460.00	0.00%	0.00%	0.00%	0.12%	$0	$0	$0	$2,269	$2,269
Install 250 MVAR Capacitor at Keystone 500kV Sub	b0549	$ 227,707.50	1.72%	3.82%	6.15%	0.25%	$3,917	$8,698	$14,004	$569	$27,188
Install 250 MVAR Capacitor at Keystone 500kV Sub	b0549_dfax	$ 227,707.50	4.26%	15.53%	19.08%	0.78%	$9,700	$35,363	$43,447	$1,776	$90,286
Install 25 MVAR capacitor at Saxton 115 kV Sub	b0551	$ 185,856.00	8.58%	18.16%	26.13%	0.97%	$15,946	$33,751	$48,564	$1,803	$100,065
Install 50 MVAR capacitor at Altoona 230 kV Sub	b0552	$ 148,035.00	8.58%	18.16%	26.13%	0.97%	$12,701	$26,883	$38,682	$1,436	$79,702
Install 50 MVAR capacitor at Raystoon 230 kV Sub	b0553	$ 131,438.00	8.58%	18.16%	26.13%	0.97%	$11,277	$23,869	$34,345	$1,275	$70,766
Install 75 MVAR capacitor at East Towanda 230 kV Sub	b0557	$ 308,900.00	8.58%	18.16%	26.13%	0.97%	$26,504	$56,096	$80,716	$2,996	$166,312
Relocate the Erie South 345 kV Line Terminal	b1993	$ 1,557,950.00	0.00%	5.14%	12.10%	0.48%	$0	$80,079	$188,512	$7,478	$276,069
Conver Lewis Run-Farmers Valley to 230kV using 1033.5 Conductor	b1994	$ 9,136,526.00	0.00%	8.64%	13.55%	0.54%	$0	$789,396	$1,237,999	$49,337	$2,076,732
Loop the 2026 kV Line to Laushtown Substation	b2006.1.1	$ 346,103.00	1.72%	3.82%	6.15%	0.25%	$5,953	$13,221	$21,285	$865	$41,325
Loop the 2026 kV Line to Laushtown Substation	b2006.1.1_dfax	$ 346,103.00	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Rplce Switch at Portland 230kv	b0132.3	$ 38,615.00	0.00%	100.00%	0.00%	0.00%	$0	$38,615	$0	$0	$38,615
South Lebanon 230/69 kv Bank 1 - Upgrade 69 kv Terminal Facilities	b1364	$ 25,954.00	0.00%	100.00%	0.00%	0.00%	$0	$25,954	$0	$0	$25,954
Middletown Sub - 69 kv Capacitor Bank	b1362	$ 14,306.00	0.00%	100.00%	0.00%	0.00%	$0	$14,306	$0	$0	$14,306
							$202,462	**$1,438,692**	**$2,101,029**	**$75,706**	**$3,817,889**
		$ 16,321,329									
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 2021**	**2021TX Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2021 Impact (12 months)**
PSE&G	$ 175,085.76	9,557.3	$ 18.32	$ 2,101,029
JCP&L	$ 119,891.00	5,903.2	$ 20.31	$ 1,438,692
ACE	$ 16,871.84	2,634.5	$ 6.40	$ 202,462
RE	$ 6,308.82	397.5	$ 15.87	$ 75,706
Total Impact on NJ Zones	**$ 318,157.43**			**$ 3,817,889**
Notes on calculations >>>			= (k) * (l)	= (k) *12

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

Attachment 6f PJM Schedule 12 - Transmission Enhancement Charges for January 2021 - December 2021 **Attachment 6f**
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 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]	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	$ 371,854	1.72%	3.82%	6.15%	0.25%	$6,396	$14,205	$22,869	$930	$44,399
New 765 KV circuit breakers at Hanging Rock Sub	b0504_dfax	$ 371,854	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Rockport Reactor Bank	b1465.2	$ 884,796	1.72%	3.82%	6.15%	0.25%	$15,218	$33,799	$54,415	$2,212	$105,645
Rockport Reactor Bank	b1465.2_dfax	$ 884,796	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Transpose Rockport- Sullivan 765KV line	b1465.3	$ 1,157,756	1.72%	3.82%	6.15%	0.25%	$19,913	$44,226	$71,202	$2,894	$138,236
Transpose Rockport- Sullivan 765KV line	b1465.3_dfax	$ 1,157,756	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Switching changes Sullivan 765KV station	b1465.4	$ 328,801	1.72%	3.82%	6.15%	0.25%	$5,655	$12,560	$20,221	$822	$39,259
Switching changes Sullivan 765KV station	b1465.4_dfax	$ 328,801	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Sullivan Inst Baker 765kV Trnsf.	b1465.5	$ 543,215	1.72%	3.82%	6.15%	0.25%	$9,343	$20,751	$33,408	$1,358	$64,860
Sullivan Inst Baker 765kV Trnsf.	b1465.5_dfax	$ 543,215	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
765kV circuit breaker at Wyoming station	b1661	$ 124,222	1.72%	3.82%	6.15%	0.25%	$2,137	$4,745	$7,640	$311	$14,832
765kV circuit breaker at Wyoming station	b1661_dfax	$ 124,222	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Term Tsfmr #2 @ SW Lima - new bay position	b1957	$ 1,434,560	0.00%	0.00%	4.52%	0.18%	$0	$0	$64,842	$2,582	$67,424
Reconductor/Rebuild Sporn-Waterford-Muskingham River 345 kV Line	b2017	$ 10,422,198	0.00%	1.39%	2.00%	0.08%	$0	$144,869	$208,444	$8,338	$361,650
Add four 765 kV Breakers at Kammar	b1962	$ 1,317,192	1.72%	3.82%	6.15%	0.25%	$22,656	$50,317	$81,007	$3,293	$157,273
Add four 765 kV Breakers at Kammar	b1962_dfax	$ 1,317,192	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Ft. Wayne Relocate	b1659.14	$ 3,869,856	1.72%	3.82%	6.15%	0.25%	$66,562	$147,828	$237,996	$9,675	$462,061
Ft. Wayne Relocate	b1659.14_dfax	$ 3,869,856	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Sorenson 765/500kV Transformer	b1659	$ 6,415,449	0.00%	0.00%	0.92%	0.04%	$0	$0	$59,022	$2,566	$61,588
Sorenson Work 765kV	b1659.13	$ 3,055,256	1.72%	3.82%	6.15%	0.25%	$52,550	$116,711	$187,898	$7,638	$364,798
Sorenson Work 765kV	b1659.13_dfax	$ 3,055,256	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Baker Station 765/500kV Transformer	b1495	$ 4,200,649	0.41%	0.90%	1.48%	0.06%	$17,223	$37,806	$62,170	$2,520	$119,718
Cloverdale 765/500kV Transformer	b1660	$ 197,588	1.72%	3.82%	6.15%	0.25%	$3,399	$7,548	$12,152	$494	$23,592
Cloverdale 765/500kV Transformer	b1660_dfax	$ 197,588	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Cloverdale 500kV Station	b1660.1	$ 1,714,518	1.72%	3.82%	6.15%	0.25%	$29,490	$65,495	$105,443	$4,286	$204,713
Cloverdale 500kV Station	b1660.1_dfax	$ 1,714,518	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Jacksons-Ferry 765kV Breakers	b1663.2	$ 297,604	1.72%	3.82%	6.15%	0.25%	$5,119	$11,368	$18,303	$744	$35,534
Jacksons-Ferry 765kV Breakers	b1663.2_dfax	$ 297,604	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Reconductor Cloverdale-Lexington 500kV	b1797.1	$ 2,782,878	1.72%	3.82%	6.15%	0.25%	$47,865	$106,306	$171,147	$6,957	$332,276

Attachment 6f PJM Schedule 12 - Transmission Enhancement Charges for January 2021 - December 2021 **Attachment 6f**
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 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]	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
				per PJM Open Access Transmission Tariff								
Reconductor Cloverdale-Lexington 500kV	b1797.1_dfax	$	2,782,878	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Reconductor West Bellaire	b1970	$	-	0.00%	1.68%	2.88%	0.11%	$0	$0	$0	$0	$0
Add a 3rd 2250 MVA 765/345 kV transformer at Sullivan station	b1465.1	$	4,032,529	0.71%	1.58%	2.62%	0.10%	$28,631	$63,714	$105,652	$4,033	$202,030
Replace existing 150 MVAR reactor at Amos 765 kV sub	b2230	$	780,177	1.72%	3.82%	6.15%	0.25%	$13,419	$29,803	$47,981	$1,950	$93,153
Replace existing 150 MVAR reactor at Amos 765 kV sub	b2230_dfax	$	780,177	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	$	1,226,367	1.72%	3.82%	6.15%	0.25%	$21,094	$46,847	$75,422	$3,066	$146,428
Install a 300 MVAR shunt reactor at AEP's Wyoming 765 kV station	b2423_dfax	$	1,226,367	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	$	3,882,672	1.72%	3.82%	6.15%	0.25%	$66,782	$148,318	$238,784	$9,707	$463,591
Install a 450 MVAR SVC Jackson's Ferry 765kV Substation	b2687.1_dfax	$	3,882,672	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	$	544,739	1.72%	3.82%	6.15%	0.25%	$9,370	$20,809	$33,501	$1,362	$65,042
Install 300 MVAR shunt line reactor	b2687.2_dfax	$	544,739	0.00%	0.00%	0.00%	0.00%	$0	$0	$0	$0	$0
Totals								**$442,821**	**$1,128,025**	**$1,919,519**	**$77,738**	**$3,568,102**
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 2021**	**2021Tx Peak Load** *per PJM website*	**Rate in $/MW-mo.**	**2021 Impact (12 months)**
PSE&G	$ 159,959.88	9,557.3	$ 16.74	$ 1,919,519
JCP&L	$ 94,002.06	5,903.2	$ 15.92	$ 1,128,025
ACE	$ 36,901.73	2,634.5	$ 14.01	$ 442,821
RE	$ 6,478.15	397.5	$ 16.30	$ 77,738
Total Impact on NJ Zones	**$ 297,341.82**			**$ 3,568,102**
Notes on calculations >>>			= (k) * (l)	= (k) *12

Notes:

Attachment 6f PJM Schedule 12 - Transmission Enhancement Charges for January 2021 - December 2021 **Attachment 6f**
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 2021 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) 2020 allocation share percentages are from PJM OATT

Attachment 6g -PJM Schedule 12 - Transmission Enhancement Charges for January 2021 - December 2021 **Attachment 6g**
Calculation of costs and monthly PJM charges for Silver Run 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 2021 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share**	**JCP&L Zone Share**	**PSE&G Zone Share1,2**	**RE Zone Share**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
			per PJM Open Access Transmission Tariff								
Build a new 230kV Transmission Line between substation Hope Creek and new Silver Run 230 kV substation	b2633.1-b2633.2	$ 23,622,242.58	8.01%	13.85%	20.79%	0.62%	$1,892,142	$3,271,681	$4,911,064	$146,458	$10,221,344
Totals		**$ 23,622,242.58**					**$1,892,142**	**$3,271,681**	**$4,911,064**	**$146,458**	**$10,221,344**
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 2021**	**2021 Trans. Peak Load [2]**	**Rate in $/MW-mo. [1]**	**2021 Impact (12 months)**	
PSE&G	$ 409,255.35	9,557.3	$ 42.82	$ 4,911,064	
JCP&L	$ 272,640.05	5,903.2	$ 46.19	$ 3,271,681	
ACE	$ 157,678.47	2,634.5	$ 59.85	$ 1,892,142	
RE	$ 12,204.83	397.5	$ 30.70	$ 146,458	
Total Impact on NJ Zones	**$ 851,778.70**	**18,492.5**		**$ 10,221,344**	
Notes on calculations >>>			= (k) / (l)	= (k) *12	

Notes:
1) Uncompressed rate - assumes implementation on January 1, 2021
2) Data on PJM website

Attachment 6h - PJM Schedule 12 - Transmission Enhancement Charges for January 2021 - December 2021 **Attachment 6h**
Calculation of costs and monthly PJM charges for NIPSCO 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 2021 Annual Revenue Requirement** *per PJM website*	**ACE Zone Share**	**JCP&L Zone Share**	**PSE&G Zone Share1**	**RE Zone Share**	**ACE Zone Charges**	**JCP&L Zone Charges**	**PSE&G Zone Charges**	**RE Zone Charges**	**Total NJ Zones Charges**
			per PJM Open Access Transmission Tariff								
Reconfigure Munster 345 kV as ring bus	b2971	$946,413.00	0.97%	2.16%	5.08%	0.15%	$9,180	$20,443	$48,078	$1,420	$79,120
Reconductor Michigan City-Bosserman 138kV	b2973	$811,760.00	0.93%	1.92%	4.48%	0.12%	$7,549	$15,586	$36,367	$974	$60,476
Replace terminal equipment at Reynolds on Reynolds-Magnetation 138kV	b2974	$6,827.00	0.01%	0.00%	0.03%	0.00%	$1	$0	$2	$0	$3
Reconductor Roxana-Praxair 138kV	b2975	$910,973.00	0.28%	0.57%	1.41%	0.04%	$2,551	$5,193	$12,845	$364	$20,952
Totals		**$2,675,973.00**					**$19,281**	**$41,221**	**$97,291**	**$2,758**	**$160,551**
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 2021**	**2021 Trans Peak Load [2]**	**Rate in $/MW-mo. [1]**	**2021 Impact (12 months)**
PSE&G	$ 8,107.62	9,557.3	$ 0.85	$ 97,291
JCP&L	$ 3,435.07	5,903.2	$ 0.58	$ 41,221
ACE	$ 1,606.75	2,634.5	$ 0.61	$ 19,281
RE	$ 229.84	397.5	$ 0.58	$ 2,758
Total Impact on NJ Zones	**$ 13,379.28**	**18,492.5**		**$ 160,551**
Notes on calculations >>>			= (k) / (l)	= (k) *12

Attachment 6i Summary of EL05-121 Settlement Adjustments for January 2021 - December 2021

Total - January 2021 - December 2021	AE	JCPL	PSEG	Rockland
BLI-1108A - Current Aggregate Recovery Charge Transitional Period - Catch-up	$ -	$ -	$ -	$ -
BLI-1108A - Estimated Interest August 2018 - June 2019	$ -	$ -	$ -	$ -
BLI-1115 - Transmission Enhancement Charge Adjustments (Black Box) Transitional Period - Catch-up	$ -	$ -	$ -	$ -
BLI-1115 - Transmission Enhancement Charge Adjustments (Black Box)	$ 117,627.00	$ 4,076,209.92	$ 9,440,981.76	$ 350,431.44
BLI-1115 - Estimated Transmission Enhancement Charge Adjustment (Black Box) Interest August 2018 - June 2019	$ -	$ -	$ -	$ -
Total Adjustments Allocated to NJ Zones	$ 117,627.00	$ 4,076,209.92	$ 9,440,981.76	$ 350,431.44

Monthly Total - January 2021 - December 2021	AE	JCPL	PSEG	Rockland
BLI-1108A - Current Aggregate Recovery Charge Transitional Period - Catch-up	$ -	$ -	$ -	$ -
BLI-1108A - Estimated Interest August 2018 - June 2019	$ -	$ -	$ -	$ -
BLI-1115 - Transmission Enhancement Charge Adjustments (Black Box) Transitional Period - Catch-up	$ -	$ -	$ -	$ -
BLI-1115 - Transmission Enhancement Charge Adjustments (Black Box)	$ 9,802.25	$ 339,684.16	$ 786,748.48	$ 29,202.62
BLI-1115 - Estimated Transmission Enhancement Charge Adjustment (Black Box) Interest August 2018 - June 2019	$ -	$ -	$ -	$ -
Total Monthly Adjustments Allocated to NJ Zones	$ 9,802.25	$ 339,684.16	$ 786,748.48	$ 29,202.62

Attachment 7 – Cost Allocations

Attachment 7a – Responsible Customer Shares for PSE&G Schedule 12
Projects Source – PJM OATT
Attachment 7b – Responsible Customer Shares for JCP&L Schedule 12
Projects Source – PJM OATT
Attachment 7c – Responsible Customer Shares for VEPCO Schedule 12
Projects Source – PJM OATT
Attachment 7d – Responsible Customer Shares for PATH Schedule 12
Projects Source – PJM OATT
Attachment 7e – Responsible Customer Shares for MAIT Schedule 12
Projects Source – PJM OATT
Attachment 7f – Responsible Customer Shares for AEP Schedule 12
Projects Source – PJM OATT
Attachment 7g – Responsible Customer Shares for Silver Run Schedule 12
Projects Source – PJM OATT
Attachment 7h – Responsible Customer Shares for NIPSCo Schedule 12
Projects Source – PJM OATT

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

SCHEDULE 12 – APPENDIX

(12) Public Service Electric and Gas Company

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

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

Public Service Electric and Gas Company (cont.)

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

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**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%)

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0201	Branchburg substation: replace wave trap on Branchburg – Readington 230 kV circuit		PSEG (100%)
b0213.1	Replace New Freedom 230 kV breaker BS2-6		PSEG (100%)
b0213.3	Replace New Freedom 230 kV breaker BS2-8		PSEG (100%)
b0274	Replace both 230/138 kV transformers at Roseland		PSEG (96.77%) / ECP** (3.23%)
b0275	Upgrade the two 138 kV circuits between Roseland and West Orange		PSEG (100%)
b0278	Install 228 MVAR capacitor at Roseland 230 kV substation		PSEG (100%)
b0290	Install 400 MVAR capacitor in the Branchburg 500 kV vicinity		**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%)

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

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

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b489.1	Replace Athenia 230 kV breaker 31H		PSEG (100%)
b489.2	Replace Bergen 230 kV breaker 10H		PSEG (100%)
b489.3	Replace Saddlebrook 230 kV breaker 21P		PSEG (100%)
b0489.4	Install two Roseland 500/230 kV transformers as part of the Susquehanna – Roseland 500 kV project		AEC (5.09%) / ComEd (0.29%) / Dayton (0.03%) / DPL (1.76%) / JCPL (32.73%) / Neptune* (6.32%) / PECO (10.04%) / PENELEC (0.56%) / ECP** (0.95%) / PSEG (40.71%) / RE (1.52%) ††
b0489.5	Replace Roseland 230 kV breaker '42H' with 80 kA		**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.

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%)

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Public Service Electric and Gas Company (cont.)

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

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Public Service Electric and Gas Company (cont.)

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

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Public Service Electric and Gas Company (cont.)

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

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Public Service Electric and Gas Company (cont.)

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

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Public Service Electric and Gas Company (cont.)

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

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Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0829	Build Branchburg to Roseland 500 kV circuit as part of Branchburg – Hudson 500 kV project		AEC (1.72%) / 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%)

*Neptune Regional Transmission System, LLC

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%*)

*Neptune Regional Transmission System, LLC

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%)

*Neptune Regional Transmission System, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements	Annual Revenue Requirement		Responsible Customer(s)
b2437.10	New Bergen 345/230 kV transformer and any associated substation upgrades		PSEG (*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%)

*Neptune Regional Transmission System, LLC

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%)

*Neptune Regional Transmission System, LLC

Public Service Electric and Gas Company (cont.)

Required Transmission Enhancements	Annual Revenue Requirement		Responsible Customer(s)
b2712	Replace the Bergen 138 kV '40P'breaker with 80kA breaker		PSEG (100%)
b2713	Replace the Bergen 138 kV '90P' breaker with 80kA breaker		PSEG (100%)
b2722	Reconductor the 1 mile Bergen – Bergen GT 138 kV circuit (B-1302)		PSEG (100%)
b2755	Build a third 345 kV source into Newark Airport		PSEG (100%)
b2810.1	Install second 230/69 kV transformer at Cedar Grove		PSEG (100%)
b2810.2	Build a new 69 kV circuit from Cedar Grove to Great Notch		PSEG (100%)
b2811	Build 69 kV circuit from Locust Street to Delair		PSEG (100%)
b2812	Construct River Road to Tonnelle Avenue 69kV Circuit		PSEG (100%)
b2825.1	Install 2X50 MVAR shunt reactors at Kearny 230 kV substation		PSEG (100%)
b2825.2	Increase the size of the Hudson 230 kV, 2X50 MVAR shunt reactors to 2X100 MVAR		PSEG (100%)
b2825.3	Install 2X100 MVAR shunt reactors at Bayway 345 kV substation		PSEG (100%)
b2825.4	Install 2X100 MVAR shunt reactors at Linden 345 kV substation		PSEG (100%)
b2835	Convert the R-1318 and Q1317 (Edison – Metuchen) 138 kV circuits to one 230 kV circuit		*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 – Responsible Customer Shares for JCP&L Schedule 12
Projects Source – PJM OATT

SCHEDULE 12 – APPENDIX

(4) Jersey Central Power & Light Company

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

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

Jersey Central Power & Light Company (cont.)

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

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

Jersey Central Power & Light Company (cont.)

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

* Neptune Regional Transmission System, LLC

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

Jersey Central Power & Light Company (cont.)

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

Jersey Central Power & Light Company (cont.)

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

Jersey Central Power & Light Company (cont.)

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

Jersey Central Power & Light Company (cont.)

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

Jersey Central Power & Light Company (cont.)

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

Jersey Central Power & Light Company (cont.)

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

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

SCHEDULE 12 – APPENDIX A

(4) Jersey Central Power & Light Company

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

Jersey Central Power & Light Company (cont.)

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

Jersey Central Power & Light Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2633.6	Implement high speed relaying utilizing OPGW on Deans – East Windsor 500 kV		**Load-Ratio Share Allocation:** AEC (1.72%) / 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 – Responsible Customer Shares for VEPCO Schedule 12
Projects Source – PJM OATT

SCHEDULE 12 – APPENDIX

(20) Virginia Electric and Power Company

Required Transmission Enhancements	Annual Revenue Requirement***	Responsible Customer(s)	
b0217	Upgrade Mt. Storm - Doubs 500kV		***Load-Ratio Share Allocation:*** AEC (1.72%) / 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 Remingtion – Sowego 115 kV to 230 kV	APS (0.31%) / BGE (3.01%) / DPL (0.04%) / Dominion (92.75%) / ME (0.03%) / PEPCO (3.86%)
b0453.2	Add Sowego – Gainsville 230 kV	APS (0.31%) / BGE (3.01%) / DPL (0.04%) / Dominion (92.75%) / ME (0.03%) / PEPCO (3.86%)
b0453.3	Add Sowego 230/115 kV transformer	APS (0.31%) / BGE (3.01%) / DPL (0.04%) / Dominion (92.75%) / ME (0.03%) / PEPCO (3.86%)
b0454	Reconductor 2.4 miles of Newport News – Chuckatuck 230 kV	Dominion (100%)

* Neptune Regional Transmission System, LLC

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%)

* Neptune Regional Transmission System, LLC

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%)*

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0492.10	Replace Mount Storm 500 kV breaker G2T554		***Load-Ratio Share Allocation:*** AEC (1.72%) / 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%)*

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Virginia Electric and Power Company (cont.)

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

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Virginia Electric and Power Company (cont.)

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

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements	Annual Revenue Requirement	Responsible Customer(s)
b0776	Re-build Trowbridge – Winfall 115 kV		Dominion (100%)
b0777	Terminate the Thelma – Carolina 230 kV circuit into Lakeview 230 kV		Dominion (100%)
b0778	Install 29.7 MVAR capacitor at Lebanon 115 kV		Dominion (100%)
b0779	Build a new 230 kV line from Yorktown to Hayes but operate at 115 kV initially		Dominion (100%)
b0780	Reconductor Chesapeake – Yadkin 115 kV line		Dominion (100%)
b0781	Reconductor and replace terminal equipment on line 17 and replace the wave trap on line 88		Dominion (100%)
b0782	Install a new 115 kV capacitor at Dupont Waynesboro substation		Dominion (100%)
b0784	Replace wave traps on North Anna to Ladysmith 500 kV		***Load-Ratio Share Allocation:*** AEC (1.72%) / 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%)

* Neptune Regional Transmission System, LLC

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%)

* Neptune Regional Transmission System, LLC

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%)

* Neptune Regional Transmission System, LLC

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%)

* Neptune Regional Transmission System, LLC

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%)

* Neptune Regional Transmission System, LLC

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%)*

* Neptune Regional Transmission System, LLC

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%)

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Virginia Electric and Power Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b1905.1	Surry to Skiffes Creek 500 kV Line (7 miles overhead)		***Load-Ratio Share Allocation:*** AEC (1.72%) / 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 7d – Responsible Customer Shares for PATH Schedule 12
Projects Source – PJM OATT

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0460	Raise limiting structures on Albright – Bethelboro 138 kV to raise the rating to 175 MVA normal 214 MVA emergency		APS (100%)
b0491	Construct an Amos to Welton Spring to WV state line 765 kV circuit (APS equipment)	As specified under the procedures detailed in Attachment H-19B	**Load-Ratio Share Allocation:** AEC (1.72%) / 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)
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%)

*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

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%)

* Neptune Regional Transmission System, LLC

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

SCHEDULE 12 – APPENDIX

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

Required Transmission Enhancements	Annual Revenue Requirement	Responsible Customer(s)
b0215	Install 230Kv series reactor and 2- 100MVAR PLC switched capacitors at Hunterstown	AEC (6.71%) / 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%)

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(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%)

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(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%

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(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%)

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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%)

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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)
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%)

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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)
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%)

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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)
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%)

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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)
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%)

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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)
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%)

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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)
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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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%)

* Neptune Regional Transmission System, LLC
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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)
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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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 7f – Responsible Customer Shares for AEP Schedule 12
Projects Source – PJM OATT

SCHEDULE 12 – APPENDIX

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0318	Install a 765/138 kV transformer at Amos		AEP (99.00%) / PEPCO (1.00%)
b0324	Replace entrance conductors, wave traps, and risers at the Tidd 345 kV station on the Tidd – Canton Central 345 kV circuit		AEP (100%)
b0447	Replace Cook 345 kV breaker M2		AEP (100%)
b0448	Replace Cook 345 kV breaker N2		AEP (100%)
b0490	Construct an Amos – Bedington 765 kV circuit (AEP equipment)	As specified under the procedures detailed in Attachment H-19B	**Load-Ratio Share Allocation:** AEC (1.72%) / 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

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0490.2	Replace Amos 138 kV breaker 'B'		**Load-Ratio Share Allocation:** AEC (1.72%) / 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%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0490.3	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%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0490.4	Replace Amos 138 kV breaker 'C'		**Load-Ratio Share Allocation:** AEC (1.72%) / 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%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0490.5	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%)

* Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0490.6	Replace Amos 138 kV breaker 'D'		**Load-Ratio Share Allocation:** AEC (1.72%) / 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%)

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0490.7	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%)

* Neptune Regional Transmission System, LLC

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

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b0490.8	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%)

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SCHEDULE 12 – APPENDIX A

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

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

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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%)

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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%)

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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%)

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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%)

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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%)*

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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%)*

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)*
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%)

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)
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 7g – Responsible Customer Shares for Silver Run Schedule 12
Projects Source – PJM OATT

SCHEDULE 12 – APPENDIX A

(26) Silver Run Electric, LLC

Required Transmission Enhancements	Annual Revenue Requirement	Responsible Customer(s)	
b2633.1	Build a new 230 kV transmission line between substation Hope Creek and Silver Run		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%)
b2633.2	Construct a new Silver Run 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%)

Attachment 7h – Responsible Customer Shares for NIPSCo Schedule 12
Projects Source – PJM OATT

SCHEDULE 12 – APPENDIX A

(19) Northern Indiana Public Service Company

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2971	Reconfigure Munster 345 kV as ring bus		MISO (12.00%) / AEC (0.97%) / AEP (16.65%) / APS (4.94%) / ATSI (7.77%) / BGE (5.20%) / Dayton (1.85%) / DEOK (2.29%) / Dominion (15.20%) / DPL (1.75%) / DL (1.43%) / EKPC (0.60%) / JCPL (2.16%) / ME (1.72%) / PECO (4.32%) / PENELEC (4.98%) / PEPCO (5.80%) / PPL (4.74%) / PSEG (5.08%) / RE (0.15%) / NEPTUNE* (0.33%) / ECP** (0.05%) / HTP*** (0.02%)
b2973	Reconductor Michigan City - Bosserman 138 kV		MISO (10.00%) / AEC (0.93%) / AEP (26.02%) / APS (4.19%) / ATSI (5.95%) / BGE (4.38%) / Dayton (1.58%) / DEOK (2.30%) / Dominion (14.70%) / DPL (1.53%) / DL (1.26%) / EKPC (0.98%) / JCPL (1.92%) / ME (1.39%) / PECO (4.19%) / PENELEC (4.34%) / PEPCO (5.05%) / PPL (4.03%) / PSEG (4.48%) / RE (0.12%) / NEPTUNE* (0.56%) / ECP** (0.08%) / HTP*** (0.02%)
b2974	Replace terminal equipment at Reynolds on the Reynolds - Magnetation 138 kV		MISO (59.00%) / AEC (0.01%) / AEP (40.28%) / APS (0.13%) / ATSI (0.05%) / BGE (0.08%) / Dayton (0.03%) / DPL (0.01%) / ME (0.04%) / PENELEC (0.06%) / PPL (0.20%) / PSEG (0.03%) / NEPTUNE* (0.04%) / HTP*** (0.04%)

Northern Indiana Public Service Company (cont.)

Required Transmission Enhancements		Annual Revenue Requirement	Responsible Customer(s)
b2975	Reconductor Roxana - Praxair 138 kV		MISO (76.00%) / AEC (0.28%) / AEP (4.51%) / APS (1.31%) / ATSI (1.91%) / BGE (1.40%) / Dayton (0.49%) / DEOK (0.69%) / Dominion (4.35%) / DPL (0.46%) / DL (0.38%) / EKPC (0.27%) / JCPL (0.57%) / ME (0.43%) / PECO (1.25%) / PENELEC (1.34%) / PEPCO (1.53%) / PPL (1.23%) / PSEG (1.41%) / RE (0.04%) / NEPTUNE* (0.14%) / HTP*** (0.01%)

Attachment 8
PSE&G Formula Rate for January 1, 2021 to December 31, 2021

Public Service Electric and Gas Company

ATTACHMENT H-10A

	Formula Rate -- Appendix A	Notes	FERC Form 1 Page # or Instruction	12 Months Ended 12/31/2021
	Shaded cells are input cells			
	Allocators			
	Wages & Salary Allocation Factor			
1	Transmission Wages Expense	(Note O)	Attachment 5	37,389,490
2	Total Wages Expense	(Note O)	Attachment 5	208,105,351
3	Less A&G Wages Expense	(Note O)	Attachment 5	6,000,000
4	Total Wages Less A&G Wages Expense		(Line 2 - Line 3)	202,105,351
5	**Wages & Salary Allocator**		(Line 1 / Line 4)	**18.5000%**
	Plant Allocation Factors			
6	Electric Plant in Service	(Note B)	Attachment 5	25,461,808,189
7	Common Plant in Service - Electric		(Line 22)	248,986,792
8	Total Plant in Service		(Line 6 + 7)	25,710,794,981
9	Accumulated Depreciation (Total Electric Plant)	(Note B & J)	Attachment 5	4,532,681,464
10	Accumulated Intangible Amortization - Electric	(Note B)	Attachment 5	6,075,642
11	Accumulated Common Plant Depreciation - Electric	(Note B & J)	Attachment 5	50,554,202
12	Accumulated Common Amortization - Electric	(Note B)	Attachment 5	72,229,346
13	Total Accumulated Depreciation		(Line 9 + Line 10 + Line 11 + Line 12)	4,661,540,654
14	Net Plant		(Line 8 - Line 13)	21,049,254,328
15	Transmission Gross Plant		(Line 31)	14,777,415,275
16	**Gross Plant Allocator**		(Line 15 / Line 8)	**57.4755%**
17	Transmission Net Plant		(Line 43)	13,223,565,551
18	**Net Plant Allocator**		(Line 17 / Line 14)	**62.8220%**
	Plant Calculations			
	Plant In Service			
19	Transmission Plant In Service	(Note B)	Attachment 5	14,670,297,858
20	General	(Note B)	Attachment 5	337,061,626
21	Intangible - Electric	(Note B)	Attachment 5	13,443,636
22	Common Plant - Electric	(Note B)	Attachment 5	248,986,792
23	Total General, Intangible & Common Plant		(Line 20 + Line 21 + Line 22)	599,492,054
24	Less: General Plant Account 397 -- Communications	(Note B)	Attachment 5	10,757,529
25	Less: Common Plant Account 397 -- Communications	(Note B)	Attachment 5	41,888,660
26	General and Intangible Excluding Acct. 397		(Line 23 - Line 24 - Line 25)	546,845,865
27	Wage & Salary Allocator		(Line 5)	18.5000%
28	General and Intangible Plant Allocated to Transmission		(Line 26 * Line 27)	101,166,485
29	Account No. 397 Directly Assigned to Transmission	(Note B)	Attachment 5	5,950,932
30	Total General and Intangible Functionalized to Transmission		(Line 28 + Line 29)	107,117,417
31	**Total Plant In Rate Base**		(Line 19 + Line 30)	**14,777,415,275**
	Accumulated Depreciation			
32	Transmission Accumulated Depreciation	(Note B & J)	Attachment 5	1,505,296,497
33	Accumulated General Depreciation	(Note B & J)	Attachment 5	131,531,418
34	Accumulated Common Plant Depreciation & Amortization - Electric	(Note B & J)	Attachment 5	118,594,995
35	Less: Amount of General Depreciation Associated with Acct. 397	(Note B & J)	Attachment 5	24,113,568
36	Balance of Accumulated General Depreciation		(Line 33 + Line 34 - Line 35)	226,012,845
37	Accumulated Intangible Amortization - Electric	(Note B)	(Line 10)	6,075,642
38	Accumulated General and Intangible Depreciation Ex. Acct. 397		(Line 36 + 37)	232,088,486
39	Wage & Salary Allocator		(Line 5)	18.5000%
40	Subtotal General and Intangible Accum. Depreciation Allocated to Transmission		(Line 38 * Line 39)	42,936,370
41	Accumulated General Depreciation Associated with Acct. 397 Directly Assigned to Transmission	(Note B & J)	Attachment 5	5,616,857
42	**Total Accumulated Depreciation**		(Lines 32 + 40 + 41)	**1,553,849,724**
43	**Total Net Property, Plant & Equipment**		(Line 31 - Line 42)	**13,223,565,551**

Public Service Electric and Gas Company

ATTACHMENT H-10A

	Formula Rate -- Appendix A		Notes	FERC Form 1 Page # or Instruction	12 Months Ended 12/31/2021
	Shaded cells are input cells				
	Adjustment To Rate Base				
	Accumulated Deferred Income Taxes				
44	**ADIT net of FASB 106 and 109**		(Note Q)	Attachment 1	-2,009,471,467
	Regulatory Assets and Liabilities				
44a	Deficient Deferred Taxes Regulatory Asset (Account 182.	enter positive	(Note V)		0
44b	Excess Deferred Taxes Regulatory Liability (Account 254)	enter negative	(Note V)		-673,157,053
44c	**Deficient/Excess Deferred Taxes Regulatory Assets and Liabilities Allocated to Transmission**			(Line 44a + 44b)	**-673,157,053**
	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	20,881,499
	Prepayments				
47	Prepayments		(Note A & Q)	Attachment 5	467,498
	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	5,882,981
52	Total Materials & Supplies Allocated to Transmission			(Line 50 + Line 51)	5,882,981
	Cash Working Capital				
53	Operation & Maintenance Expense			(Line 80)	143,482,929
54	1/8th Rule			1/8	12.5%
55	Total Cash Working Capital Allocated to Transmission			(Line 53 * Line 54)	17,935,366
	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)**	**(2,637,461,176)**
58	**Rate Base**			(Line 43 + Line 57)	**10,586,104,375**
	Operations & Maintenance Expense				
	Transmission O&M				
59	Transmission O&M		(Note O)	Attachment 5	123,700,000
60	Plus Transmission Lease Payments		(Note O)	Attachment 5	0
61	**Transmission O&M**			(Lines 59 + 60)	**123,700,000**
	Allocated Administrative & General Expenses				
62	Total A&G		(Note O)	Attachment 5	104,867,700
63	Plus: Actual PBOP expense		(Note J)	Attachment 5	-42,325,481
64	Less: Actual PBOP expense		(Note O)	Attachment 5	-42,325,481
65	Less Property Insurance Account 924		(Note O)	Attachment 5	5,058,406
66	Less Regulatory Commission Exp Account 928		(Note E & O)	Attachment 5	10,718,936
67	Less General Advertising Exp Account 930.1		(Note O)	Attachment 5	2,576,107
68	Less EPRI Dues		(Note D & O)	Attachment 5	0
69	**Administrative & General Expenses**			Sum (Lines 62 to 63) - Sum (Lines 64 to 68)	86,514,251
70	Wage & Salary Allocator			(Line 5)	18.5000%
71	**Administrative & General Expenses Allocated to Transmission**			(Line 69 * Line 70)	**16,005,136**
	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)	5,058,406
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)	5,058,406
78	Net Plant Allocator			(Line 18)	62.8220%
79	**A&G Directly Assigned to Transmission**			(Line 77 * Line 78)	**3,177,793**
80	**Total Transmission O&M**			**(Lines 61 + 71 + 74 + 79)**	**143,482,929**

Public Service Electric and Gas Company

ATTACHMENT H-10A

	Formula Rate -- Appendix A		Notes	FERC Form 1 Page # or Instruction	12 Months Ended 12/31/2021
	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	348,684,591
81a	Amortization of Abandoned Plant Projects		(Note R)	Attachment 5	0
82	General Depreciation Expense Including Amortization of Limited Term Plant		(Note J & O)	Attachment 5	27,132,186
83	Less: Amount of General Depreciation Expense Associated with Acct. 397		(Note J & O)	Attachment 5	5,283,117
84	Balance of General Depreciation Expense			(Line 82 - Line 83)	21,849,069
85	Intangible Amortization		(Note A & O)	Attachment 5	16,484,348
86	Total			(Line 84 + Line 85)	38,333,417
87	Wage & Salary Allocator			(Line 5)	18.50%
88	General Depreciation & Intangible Amortization Allocated to Transmission			(Line 86 * Line 87)	7,091,682
89	General Depreciation Expense for Acct. 397 Directly Assigned to Transmission		(Note J & O)	Attachment 5	595,266
90	**General Depreciation and Intangible Amortization Functionalized to Transmission**			(Line 88 + Line 89)	**7,686,948**
91	**Total Transmission Depreciation & Amortization**			**(Lines 81 + 81a + 90)**	**356,371,539**
	Taxes Other than Income Taxes				
92	Taxes Other than Income Taxes		(Note O)	Attachment 2	14,144,611
93	**Total Taxes Other than Income Taxes**			(Line 92)	**14,144,611**
	Return \ Capitalization Calculations				
94	**Long Term Interest**			p117.62.c through 67.c	375,469,950
95	**Preferred Dividends**		enter positive	p118.29.d	0
	Common Stock				
96	Proprietary Capital		(Note P)	Attachment 5	11,445,990,245
97	Less Accumulated Other Comprehensive Income Account 219		(Note P)	Attachment 5	381,672
98	Less Preferred Stock			(Line 106)	0
99	Less Account 216.1		(Note P)	Attachment 5	196,890
100	**Common Stock**			(Line 96 - 97 - 98 - 99)	11,445,411,683
	Capitalization				
101	Long Term Debt		(Note P)	Attachment 5	9,559,323,502
102	Less Loss on Reacquired Debt		(Note P)	Attachment 5	45,429,390
103	Plus Gain on Reacquired Debt		(Note P)	Attachment 5	0
104	Less ADIT associated with Gain or Loss		(Note P)	Attachment 5	601,942
105	Total Long Term Debt			(Line 101 - 102 + 103 - 104)	9,513,292,170
106	Preferred Stock		(Note P)	Attachment 5	0
107	Common Stock			(Line 100)	11,445,411,683
108	**Total Capitalization**			(Sum Lines 105 to 107)	20,958,703,852
109	Debt %	Total Long Term Debt		(Line 105 / Line 108)	45.39%
110	Preferred %	Preferred Stock		(Line 106 / Line 108)	0.00%
111	Common %	Common Stock		(Line 107 / Line 108)	54.61%
112	Debt Cost	Total Long Term Debt		(Line 94 / Line 105)	0.0395
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)	0.0638
118	**Rate of Return on Rate Base (ROR)**			(Sum Lines 115 to 117)	**0.0817**
119	**Investment Return = Rate Base * Rate of Return**			**(Line 58 * Line 118)**	**864,868,529**

Public Service Electric and Gas Company

ATTACHMENT H-10A

	Formula Rate -- Appendix A		Notes	FERC Form 1 Page # or Instruction	12 Months Ended 12/31/2021
	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	-525,189
126	1/(1-T)			1 / (1 - Line 123)	139.10%
127	Net Plant Allocation Factor			(Line 18)	62.82%
128	**ITC Adjustment Allocated to Transmission**			(Line 125 * Line 126 * Line 127)	**-458,943**
	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)		1,521,949
128g	1/(1-T)			1 / (1 - Line 123)	139.10%
128h	**AFUDC Equity Permanent Difference Tax Adjustment**			(Line 128f * Line 128g)	**2,117,052**
129	**Income Tax Component =**	(T/1-T) * Investment Return * (1-(WCLTD/ROR)) =		[Line 124 * Line 119 * (1- (Line 115 / Line 118))]	**264,020,941**
130	**Total Income Taxes**			**(Lines 128 + 128e + 128h + 129)**	**261,429,998**
	Revenue Requirement				
	Summary				
131	Net Property, Plant & Equipment			(Line 43)	13,223,565,551
132	Total Adjustment to Rate Base			(Line 57)	-2,637,461,176
133	**Rate Base**			(Line 58)	**10,586,104,375**
134	Total Transmission O&M			(Line 80)	143,482,929
135	Total Transmission Depreciation & Amortization			(Line 91)	356,371,539
136	Taxes Other than Income			(Line 93)	14,144,611
137	Investment Return			(Line 119)	864,868,529
138	Income Taxes			(Line 130)	261,429,998
139	**Gross Revenue Requirement**			**(Sum Lines 134 to 138)**	**1,640,297,606**
	Adjustment to Remove Revenue Requirements Associated with Excluded Transmission Facilities				
140	Transmission Plant In Service			(Line 19)	14,670,297,858
141	Excluded Transmission Facilities		(Note B & M)	Attachment 5	0
142	Included Transmission Facilities			(Line 140 - Line 141)	14,670,297,858
143	Inclusion Ratio			(Line 142 / Line 140)	100.00%
144	Gross Revenue Requirement			(Line 139)	1,640,297,606
145	**Adjusted Gross Revenue Requirement**			(Line 143 * Line 144)	**1,640,297,606**
	Revenue Credits & Interest on Network Credits				
146	**Revenue Credits**		(Note O)	Attachment 3	26,068,107
147	**Interest on Network Credits**		(Note N & O)	Attachment 5	0
148	**Net Revenue Requirement**			**(Line 145 - Line 146 + Line 147)**	**1,614,229,499**
	Net Plant Carrying Charge				
149	Gross Revenue Requirement			(Line 144)	**1,640,297,606**
150	Net Transmission Plant, CWIP and Abandoned Plant			(Line 19 - Line 32 + Line 45 + Line 45a)	**13,165,001,361**
151	Net Plant Carrying Charge			(Line 149 / Line 150)	**12.4595%**
152	Net Plant Carrying Charge without Depreciation			(Line 149 - Line 81) / Line 150	**9.8110%**
153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes			(Line 149 - Line 81 - Line 119 - Line 130) / Line 150	**1.2557%**
	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)	**513,999,079**
155	Increased Return and Taxes			Attachment 4	**1,206,713,087**
156	Net Revenue Requirement per 100 Basis Point increase in ROE			(Line 154 + Line 155)	**1,720,712,165**
157	Net Transmission Plant, CWIP and Abandoned Plant			(Line 19 - Line 32 + Line 45 + Line 45a)	**13,165,001,361**
158	Net Plant Carrying Charge per 100 Basis Point increase in ROE			(Line 156 / Line 157)	**13.0704%**
159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation			(Line 156 - Line 81) / Line 157	**10.4218%**
160	**Net Revenue Requirement**			(Line 148)	**1,614,229,499**
161	True-up amount			Attachment 6	**25,202,660**
162	Plus any increased ROE calculated on Attachment 7 other than PJM Sch. 12 projects not paid by other PJM transmission zones			Attachment 7	**6,236,736**
163	Facility Credits under Section 30.9 of the PJM OATT			Attachment 5	**0**
164	**Net Zonal Revenue Requirement**			(Line 160 + 161 + 162 + 163)	**1,645,668,896**
	Network Zonal Service Rate				
165	1 CP Peak		(Note L)	Attachment 5	**9,557.3**
166	Rate ($/MW-Year)			(Line 164 / 165)	**172,189.67**
167	**Network Service Rate ($/MW/Year)**			**(Line 166)**	**172,189.67**

Public Service Electric and Gas Company

ATTACHMENT H-10A

Formula Rate -- Appendix A	**Notes**	**FERC Form 1 Page # or Instruction**	**12 Months Ended 12/31/2021**

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 31,2021

	Only Transmission Related	*Plant Related*	*Labor Related*	*Total ADIT*	
ADIT- 282 (Not Subject to Proration)	(711,426,851)	0	(4,633,723)		From Acct. 282 (Not Subject to Proration) total, below
ADIT-283	0	(2,924,517)	0		From Acct. 283 total, below
ADIT-190	0	0	2,554,532		From Acct. 190 total, below
Subtotal	(711,426,851)	(2,924,517)	(2,079,191)		
Wages & Salary Allocator			18.5000%		
Net Plant Allocator		62.8220%			
End of Year ADIT	(711,426,851)	(1,837,240)	(384,650)	**(713,648,742)**	
End of Previous Year ADIT (from Sheet 1A-ADIT)	(647,342,821)	(2,526,949)	(349,595)	**(650,219,365)**	
Average Beginning and End of Year ADIT	(679,384,836)	(2,182,095)	(367,123)	**(681,934,053)**	
ADIT- 282 (Subject to Proration)	(1,324,708,263)	0	(2,829,151)	**(1,327,537,414)**	From Acct. 282 (Subject to Proration) total, below
Total Accumulated Deferred Income Taxes				**(2,009,471,467)**	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
(2,924,517) < 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*
Vacation Pay	723,739	-	-	-	723,739	Vacation pay earned and expensed for books, tax deduction when paid. This includes the associated non-grossed-up excess deferred tax balance that resides in Account 254.
OPEB	75,645,474	-	-	-	75,645,474	FASB 106 - Post Retirement Obligation. labor related.
Deferred Compensation	1,830,793	-	-	-	1,830,793	Book estimate accrued and expensed, tax deduction when paid - employees in all functions
Gross-up on Excess Deferred Income Taxes	447,943,231	447,943,231	-	-	-	Represents gross-up on excess deferred tax balance that resides in Account 254
Casualty Ins Proceed	2,705,630	2,705,630	-	-	-	Receipt of casualty proceeds which is taxed via future depreciation
Contribution in Aid of Construction	11,956,405	11,956,405	-	-	-	Contribution in Aid of Construction
Customer Advances	12,525,915	12,525,915	-	-	-	The difference between Customer Advances for Construction and other services and refunded amount
Injuries and Damanges	4,350,945	4,350,945	-	-	-	Flow Through of the benefit of the payments vs and increases in the reserve
Bad Debts	19,989,234	19,989,234	-	-	-	Flow Through of the difference between write-off of bad debt reserve and increases in bad debt reserve
Subtotal - p234	**577,671,366**	**499,471,360**	**0**	**0**	**78,200,006**	
Less FASB 109 Above if not separately removed	-			0		
Less FASB 106 Above if not separately removed	75,645,474				75,645,474	
Total	**502,025,892**	**499,471,360**	**0**	**0**	**2,554,532**	

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 31,2021

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

		-186620216.3	-310533076.7	0	-4419366.415	
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)	(319,548,659)	-	(319,548,659)	-	-	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)	(613,153,310)	(216,641,395)	(391,878,192)	-	(4,633,723)	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	(179,987,886)	(107,908,119)	(71,619,689)	-	(460,078)	FASB 109 - deferred tax liability primarily associated with plant related items previously flowed through due to regulation
Subtotal - ADIT- 282 (Not Subject to Proration)	**(1,112,689,855)**	**(324,549,514)**	**(783,046,540)**	**0**	**(5,093,801)**	
Less FASB 109 Above if not separately removed	(179,987,886)	(107,908,119)	(71,619,689)	0	(460,078)	
Less FASB 106 Above if not separately removed						
Total ADIT- 282 (Not Subject to Proration)	**(932,701,969)**	**(216,641,395)**	**(711,426,851)**	**0**	**(4,633,723)**	

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)	(2,333,100,975)	(993,100,004)	(1,324,708,263)	-	(15,292,708)	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)	**(2,333,100,975)**	**(993,100,004)**	**(1,324,708,263)**	**0**	**(15,292,708)**	
Less FASB 109 Above if not separately removed						
Less FASB 106 Above if not separately removed						
Total ADIT- 282 (Subject to Proration)	**(2,333,100,975)**	**(993,100,004)**	**(1,324,708,263)**	**0**	**(15,292,708)**	

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 31,2021

A *ADIT- 283*	B *Total*	C *Gas, Prod Or Other Related*	D *Only Transmission Related*	E *Plant Related*	F *Labor Related*	G *Justification*
New Jersey Corporation Business Tax	(40,719,248)	(40,719,248)	-	-	-	New Jersey Corporate Income Tax - Plant Related- Contra Account of 190 NJCBT
Accelerated Activity Plan	(32,582,054)	(32,582,054)	-	-	-	Demand Side management and Associated Programs - Retail Related
Additional Pension Deduction	(111,662,750)	(111,662,750)	-	-	-	Associated with Pension Liability not in rates
Loss on Reacquired Debt	(2,924,517)	-	-	(2,924,517)	-	Tax deduction when reacquired, booked amortizes to expense
Deferred Gain	(37,962,417)	(37,962,417)	-	-	-	Deferred gain resulted from 2000 deregulation step up basis
Environmental Cleanup Costs	(1,441,487)	(1,441,487)	-	-	-	The difference between the book expense and tax deduction which is based on payments
Casualty Loss	(64,638,126)	(64,638,126)	-	-	-	Receipt of casualty proceeds which is taxed via future depreciation
Clause	(58,576,767)	(58,576,767)	-	-	-	The difference between the book over/(under) recovery vs tax realization event
Investment in NJ Properties	(1,628,277)	(1,628,277)	-	-	-	The difference between the book and tax in investment
Performance Incentive Plan Adj	(938,879)	(938,879)	-	-	-	The difference between the book expense and tax deduction which is based on payments
Real Estate Taxes	(2,815,981)	(2,815,981)	-	-	-	The difference between the book expense and tax deduction which is based on payments
Assessment by BPU of the State of NJ	(601,942)	(601,942)	-	-	-	BPU's assessment that were incurred and deducted in the current year based on all events test
OCI Rubbi Trust	(2,853,314)	(2,853,314)	-	-	-	Unrealized gains and losses on equity security investments
Service Company Charge Out	(2,222,884)	(2,222,884)	-	-	-	Allocable share of the Service Company tax reform adjustment
Miscellaneous	(1,086,941)	(1,086,941)	-	-	-	Miscellaneous Tax Adjustments
Accounting for Income Taxes (FAS109) - Federal	(86,117,584)	-	-	(86,117,584)	-	FASB 109 - deferred tax liability primarily non-plant related items previously flowed through due to regulation
Subtotal - p277	**(448,773,168)**	**(359,731,067)**	**0**	**(89,042,101)**	**0**	
Less FASB 109 Above if not separately removed	(86,117,584)			(86,117,584)		
Less FASB 106 Above if not separately removed						
Total	**(362,655,584)**	**(359,731,067)**	**0**	**(2,924,517)**	**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, 2020

	Only Transmission Related	*Plant Related*	*Labor Related*	*Total ADIT*	
ADIT- 282 (Not Subject to Proration)	(647,342,821)	0	(4,694,285)		From Acct. 282 (Not Subject to Proration) total, below
ADIT-283	0	(4,022,394)	0		From Acct. 283 total, below
ADIT-190	0	0	2,804,582		From Acct. 190 total, below
Subtotal	(647,342,821)	(4,022,394)	(1,889,703)		
Wages & Salary Allocator			18.5000%		
Net Plant Allocator		62.8220%			
End of Year ADIT	(647,342,821)	(2,526,949)	(349,595)	**(650,219,365)**	

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
(4,022,394) < 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*
Vacation Pay	573,742	0	0	0	573,742	Vacation pay earned and expensed for books, tax deduction when paid. This includes the associated non-grossed-up excess deferred tax balance that resides in Account 254.
OPEB	86,857,011	0	0	0	86,857,011	FASB 106 - Post Retirement Obligation, labor related.
Deferred Compensation	2,230,840	0	0	0	2,230,840	Book estimate accrued and expensed, tax deduction when paid - employees in all functions
Gross-up on Excess Deferred Income Taxes	477,500,944	477,500,944	0	0	0	Represents gross-up on excess deferred tax balance that resides in Account 254
Casualty Ins Proceed	2,705,630	2,705,630	0	0	0	Receipt of casualty proceeds which is taxed via future depreciation
Contribution in Aid of Construction	9,436,405	9,436,405	0	0	0	Contribution in Aid of Construction
Customer Advances	10,005,915	10,005,915	0	0	0	The difference between Customer Advances for Construction and other services and refunded amount
Injuries and Damages	4,590,960	4,590,960	0	0	0	Flow Through of the benefit of the payments vs and increases in the reserve
Bad Debts	20,003,703	20,003,703	0	0	0	Flow Through of the difference between write-off of bad debt reserve and increases in bad debt reserve
Subtotal - p234	**613,905,150**	**524,243,557**	**0**	**-**	**89,661,593**	
Less FASB 109 Above if not separately removed	-					
Less FASB 106 Above if not separately removed	86,857,011				86,857,011	
Total	**527,048,139**	**524,243,557**	**0**	**0**	**2,804,582**	

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, 2020

Attachment 1 - Accumulated Deferred Income Taxes (ADIT) Worksheet

A *ADIT- 282 (Not Subject to Proration)*	B *Total*	C *Gas, Prod Or Other Related*	D *Only Transmission Related*	E *Plant Related*	F *Labor Related*	G *Justification*
Depreciation - Liberalized Depreciation (Federal)	(301,979,009)	0	(301,979,009)	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)	(560,623,066)	(210,564,969)	(345,363,812)	0	(4,694,285)	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	(194,373,753)	(124,678,749)	(69,228,290)	0	(466,714)	FASB 109 - deferred tax liability primarily associated with plant related items previously flowed through due to regulation
Subtotal - ADIT- 282 (Not Subject to Proration)	**(1,056,975,828)**	**(335,243,718)**	**(716,571,111)**	**0**	**(5,160,999)**	
Less FASB 109 Above if not separately removed	(194,373,753)	(124,678,749)	(69,228,290)	0	(466,714)	
Less FASB 106 Above if not separately removed						
Total ADIT- 282 (Not Subject to Proration)	**(862,602,075)**	**(210,564,969)**	**(647,342,821)**	**0**	**(4,694,285)**	

A *ADIT- 282 (Subject to Proration)*	B *Total*	C *Gas, Prod Or Other Related*	D *Only Transmission Related*	E *Plant Related*	F *Labor Related*	G *Justification*
Depreciation - Liberalized Depreciation (Federal)	(2,255,834,796)	(941,897,011)	(1,298,617,023)	0	(15,320,762)	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)	**(2,255,834,796)**	**(941,897,011)**	**(1,298,617,023)**	**0**	**(15,320,762)**	
Less FASB 109 Above if not separately removed						
Less FASB 106 Above if not separately removed						
Total ADIT- 282 (Subject to Proration)	**(2,255,834,796)**	**(941,897,011)**	**(1,298,617,023)**	**0**	**(15,320,762)**	

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, 2020

A *ADIT- 283*	B *Total*	C *Gas, Prod Or Other Related*	D *Only Transmission Related*	E *Plant Related*	F *Labor Related*	G *Justification*
New Jersey Corporation Business Tax	(35,648,601)	(35,648,601)	0	0	0	New Jersey Corporate Income Tax - Plant Related- Contra Account of 190 NJCBT
Accelerated Activity Plan	(27,527,187)	(27,527,187)	0	0	0	Demand Side management and Associated Programs - Retail Related
Additional Pension Deduction	(105,183,661)	(105,183,661)	0	0	0	Associated with Pension Liability not in rates
Loss on Reacquired Debt	(4,022,394)	0	0	(4,022,394)	0	Tax deduction when reacquired, booked amortizes to expense
Deferred Gain	(38,328,713)	(38,328,713)	0	0	0	Deferred gain resulted from 2000 deregulation step up basis
Environmental Cleanup Costs	(1,441,487)	(1,441,487)	0	0	0	The difference between the book expense and tax deduction which is based on payments
Casualty Loss	(58,768,714)	(58,768,714)	0	0	0	Receipt of casualty proceeds which is taxed via future depreciation
Clause	(61,880,151)	(61,880,151)	0	0	0	The difference between the book over/(under) recovery vs tax realization event
Investment in NJ Properties	(1,628,277)	(1,628,277)	0	0	0	The difference between the book and tax in investment
Performance Incentive Plan Adj	(938,879)	(938,879)	0	0	0	The difference between the book expense and tax deduction which is based on payments
Real Estate Taxes	(2,815,981)	(2,815,981)	0	0	0	The difference between the book expense and tax deduction which is based on payments
Assessment by BPU of the State of NJ	(601,942)	(601,942)	0	0	0	BPU's assessment that were incurred and deducted in the current year based on all events test
OCI Rabbi Trust	(1,743,751)	(1,743,751)	0	0	0	Unrealized gains and losses on equity security investments
Service Company Charge Out	(2,222,884)	(2,222,884)	0	0	0	Allocable share of the Service Company tax reform adjustment
Miscellaneous	(1,496,119)	(1,496,119)	0	0	0	Miscellaneous Tax Adjustments
Accounting for Income Taxes (FAS109) - Federal	(86,245,446)	0	0	(86,245,446)	0	FASB 109 - deferred tax liability primarily non-plant related items previously flowed through due to regulation
Subtotal - p277	**(430,494,187)**	**(340,226,347)**	**0**	**(90,267,840)**	**0**	
Less FASB 109 Above if not separately removed	(86,245,446)			(86,245,446)		
Less FASB 106 Above if not separately removed						
Total	**(344,248,741)**	**(340,226,347)**	**0**	**(4,022,394)**	**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, 2021

	Other Taxes	*Page 263 Col (i)*	*Allocator*	*Allocated Amount*
	Plant Related			
1	Real Estate	25,030,000		
2	***Total Plant Related***	25,030,000	N/A	11,184,000
	Labor Related		***Wages & Salary Allocator***	
3	FICA	14,983,585		
4	Federal Unemployment Tax	83,242		
5	New Jersey Unemployment Tax	624,316		
6	New Jersey Workforce Development	312,158		
7				
8	***Total Labor Related***	16,003,301	18.5000%	2,960,611
	Other Included		***Net Plant Allocator***	
9		0		
10		0		
11		0		
12		0		
13	***Total Other Included***	0	62.8220%	0
14	***Total Included (Lines 8 + 14 + 19)***	41,033,301		14,144,611
	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)**	41,033,301		
24	**Total Other Taxes from p114.14.g - Actual**	41,033,301		
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, 2021

	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)		752,960
	Account 456 - Other Electric Revenues		
3	Transmission for Others		0
4	Schedule 1A		4,700,000
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		12,000,000
7	Professional Services (Note 2)		50,000
8	Revenues from Directly Assigned Transmission Facility Charges (Note 1)		7,342,216
9	Rent or Attachment Fees associated with Transmission Facilities (Note 2)		4,833,125
10	Gross Revenue Credits	(Sum Lines 1-9)	29,678,301
11	Less line 18	- line 18	(3,610,194)
12	Total Revenue Credits	line 10 + line 11	26,068,107

13	Revenues associated with lines 2, 7, and 9 (Note 2)	5,636,085
14	Income Taxes associated with revenues in line 13	1,584,303
15	One half margin (line 13 - line 14)/2	2,025,891
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	2,025,891
18	Line 13 less line 17	3,610,194

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	1,206,713,087
B	100 Basis Point increase in ROE			1.00%

Return Calculation

			Appendix A Line or Source	**Reference**
1	**Rate Base**		(Line 43 + Line 57)	10,586,104,375
2	**Long Term Interest**		p117.62.c through 67.c	375,469,950
3	**Preferred Dividends**	enter positive	p118.29.d	0
	Common Stock			
4	Proprietary Capital		Attachment 5	11,445,990,245
5	Less Accumulated Other Comprehensive Income Account 219		p112.15.c	381,672
6	Less Preferred Stock		(Line 106)	0
7	Less Account 216.1		Attachment 5	196,890
8	Common Stock		(Line 96 - 97 - 98 - 99)	11,445,411,683
	Capitalization			
9	Long Term Debt		Attachment 5	9,559,323,502
10	Less Loss on Reacquired Debt		Attachment 5	45,429,390
11	Plus Gain on Reacquired Debt		Attachment 5	0
12	Less ADIT associated with Gain or Loss		Attachment 5	601,942
13	Total Long Term Debt		(Line 101 - 102 + 103 - 104)	9,513,292,170
14	Preferred Stock		Attachment 5	0
15	Common Stock		(Line 100)	11,445,411,683
16	Total Capitalization		(Sum Lines 105 to 107)	20,958,703,852
17	Debt %	Total Long Term Debt	(Line 105 / Line 108)	45.4%
18	Preferred %	Preferred Stock	(Line 106 / Line 108)	0.0%
19	Common %	Common Stock	(Line 107 / Line 108)	54.6%
20	Debt Cost	Total Long Term Debt	(Line 94 / Line 105)	0.0395
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)	0.0692
26	**Rate of Return on Rate Base (ROR)**		**(Sum Lines 115 to 117)**	**0.0872**
27	**Investment Return = Rate Base * Rate of Return**		**(Line 58 * Line 118)**	**922,678,556**

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	-525,189
35	1/(1-T)		1 / (1 - Line 123)	139.10%
36	Net Plant Allocation Factor		(Line 18)	62.8220%
37	**ITC Adjustment Allocated to Transmission**		(Line 125 * Line 126 * Line 127)	**-458,943**
	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)	1,521,949
44	1/(1-T)		1 / (1 - Line 123)	139.10%
45	**AFUDC Equity Permanent Difference Tax Adjustment**		(Line 128f * Line 128g)	**2,117,052**
46	**Income Tax Component =**	CIT=(T/1-T) * Investment Return * (1-(WCLTD/R)) =		286,625,473
47	**Total Income Taxes**			**284,034,531**

Electric / Non-electric Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Previous Year Form 1Dec	Current Year - 2021 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	24,624,456,537	24,710,400,855	24,829,497,391	24,922,924,114	25,093,622,871	25,274,241,418	25,508,188,405	25,555,904,558	25,641,529,399	25,929,865,852	26,133,945,196	26,245,719,760	26,533,210,099	25,461,808,189	
7	Common Plant in Service - Electric	(Note B)	p356	222,613,510	221,820,366	221,018,348	221,040,055	234,767,210	243,942,260	250,617,756	255,666,760	260,802,063	266,622,666	273,159,312	278,377,702	286,380,293	248,986,792	
9	Accumulated Depreciation (Total Electric Plant)	(Note B & J)	p219.29c	4,328,085,234	4,361,411,057	4,393,856,994	4,426,160,379	4,459,885,702	4,494,108,841	4,530,054,778	4,566,792,270	4,603,931,579	4,638,667,879	4,673,662,153	4,708,558,576	4,739,683,591	4,532,681,464	
10	Accumulated Intangible Amortization	(Note B)	p200.21c	4,956,214	5,135,146	5,314,078	5,493,010	5,671,942	5,867,426	6,062,910	6,258,393	6,453,877	6,649,361	6,844,845	7,040,328	7,235,812	6,075,642	
11	Accumulated Common Plant Depreciation - Electric	(Note B & J)	p356	49,430,196	49,586,524	49,728,509	49,867,561	50,015,335	50,207,593	50,429,693	50,661,900	50,903,878	51,165,283	51,442,959	51,730,565	52,034,626	50,554,202	
12	Accumulated Common Amortization - Electric	(Note B)	p356	68,022,544	68,644,248	69,262,739	69,878,018	70,639,592	71,399,650	72,158,144	72,915,076	73,672,164	74,429,408	75,200,980	75,973,624	76,785,314	72,229,346	
	Plant In Service																	
19	Transmission Plant in Service (Excludes Asset Retirement Costs - ARC)	(Note B)	p207.58.g	14,048,172,475	14,093,988,808	14,183,744,141	14,254,065,474	14,402,646,807	14,542,982,140	14,716,734,473	14,737,732,806	14,791,764,139	15,052,202,472	15,215,120,805	15,230,252,138	15,444,465,471	14,670,297,858	
20	General (Excludes Asset Retirement Costs - ARC)	(Note B)	p207.99.g	338,648,398	338,285,130	337,441,923	336,526,336	335,631,907	336,113,821	337,428,668	337,399,464	337,057,353	336,763,125	336,492,282	336,351,723	337,661,003	337,061,626	
21	Intangible - Electric	(Note B)	p205.5.g	12,588,291	12,588,291	12,588,291	12,588,291	12,588,291	13,978,227	13,978,227	13,978,227	13,978,227	13,978,227	13,978,227	13,978,227	13,978,227	13,443,636	
22	Common Plant in Service - Electric	(Note B)	p356	222,613,510	221,820,366	221,018,348	221,040,055	234,767,210	243,942,260	250,617,756	255,666,760	260,802,063	266,622,666	273,159,312	278,377,702	286,380,293	248,986,792	
24	General Plant Account 397 -- Communications	(Note B)	p207.94g	11,012,966	10,970,394	10,927,821	10,885,248	10,842,675	10,800,102	10,757,529	10,714,957	10,672,384	10,629,811	10,587,238	10,544,665	10,502,093	10,757,529	
25	Common Plant Account 397 -- Communications	(Note B)	p356	39,413,491	39,413,491	39,413,491	39,413,491	39,413,491	43,435,641	43,435,641	43,435,641	43,435,641	43,435,641	43,435,641	43,435,641	43,435,641	41,888,660	
29	Account No. 397 Directly Assigned to Transmission	(Note B)	Company Records	5,930,237	5,933,686	5,937,135	5,940,585	5,944,034	5,947,483	5,950,932	5,954,381	5,957,830	5,961,280	5,964,729	5,968,178	5,971,627	5,950,932	
	Accumulated Depreciation																	
32	Transmission Accumulated Depreciation	(Note B & J)	p219.25.c	1,368,726,229	1,391,207,305	1,412,208,892	1,433,479,122	1,456,838,515	1,480,079,578	1,504,296,146	1,528,819,711	1,553,363,338	1,576,263,842	1,598,902,182	1,621,069,785	1,643,599,815	1,505,296,497	
33	Accumulated General Depreciation	(Note B & J)	p219.28.b	148,497,394	145,679,387	142,855,392	140,024,912	137,188,092	134,354,388	131,529,524	128,704,265	125,876,460	123,046,440	120,214,364	117,381,127	114,556,692	131,531,418	
34	Accumulated Common Plant Depreciation & Amortization - Electric	(Note B & J)	p356	113,264,187	114,042,219	114,802,695	115,557,026	116,466,374	117,418,689	118,399,284	119,388,423	120,387,489	121,406,138	122,455,386	123,515,635	124,631,386	118,594,995	
35	Accumulated General Depreciation Associated with Acct. 397	(Note B & J)	Company Records	22,252,297	22,548,340	22,844,028	23,139,361	23,434,340	23,762,482	24,090,268	24,417,701	24,744,778	25,071,501	25,397,868	25,723,882	26,049,540	24,113,568	
41	Acc. Deprec. Acct. 397 Directly Assigned to Transmission	(Note B & J)	Company Records	5,396,345	5,432,992	5,469,667	5,506,371	5,543,104	5,579,866	5,616,656	5,653,475	5,690,323	5,727,199	5,764,104	5,801,038	5,838,001	5,616,857	

Wages & Salary

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
2	Total Wage Expense	(Note A)	p354.28b	208,105,351
3	Total A&G Wages Expense	(Note A)	p354.27b	6,000,000
1	Transmission Wages		p354.21b	37,389,490

Transmission / Non-transmission Cost Support

Line #s	Descriptions	Notes	Page #'s & Instructions	Beginning Year Balance	End of Year	Average
	Plant Held for Future Use (Including Land)	(Note C & Q)	p214.47.d	20,771,176	21,982,176	21,376,676
46	Transmission Only			20,275,999	21,486,999	20,881,499

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	19,315,413	2,527,014	2,527,014	2,527,014	18.500%	467,498

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	5,684,040	6,081,923	5,882,981

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	123,700,000
60	Transmission Lease Payments		p321.96.b	-

Property Insurance Expenses

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
65	Property Insurance Account 924	(Note O)	p323.185b	5,058,406

Adjustments to A & G Expense

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
62	Total A&G Expenses		p323.197b	104,867,700
63	Actual PBOP expense	(Note J)	Company Records	(42,325,481)
64	Actual PBOP expense	(Note O)	Company Records	(42,325,481)

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	10,718,936	-
	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	2,576,107	-	2,576,107

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	2,576,107	-	2,576,107

Depreciation Expense

Line #s	Descriptions	Notes	Page #'s & Instructions	End of Year
	Depreciation Expense			
81	Depreciation-Transmission	(Note J & O)	p336.7.f	348,684,591
82	Depreciation-General & Common	(Note J & O)	p336.10&11.f	27,132,186
83	Depreciation-General Expense Associated with Acct. 397	(Note J & O)	Company Records	5,283,117
85	Depreciation-Intangible	(Note A & O)	p336.1.f	16,484,348
89	Transmission Depreciation Expense for Acct. 397	(Note J & O)	Company Records	595,266

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	25,030,000	11,184,000	13,846,000

PSE&G's real estate taxes detail is in an access database which contains a list of the towns PSE&G pays taxes to, which are billed on a quarterly basis for various parcels of property by major classification.
Every parcel is associated with a Lot & Block number. These Lot & Blocks are identified to a particular type of property and are labeled. This is the breakout of transmission real estate taxes from total electric.

Return \ Capitalization

Line #s		Descriptions	Notes	Page #'s & Instructions	2018 End of Year	2019 End of Year	Average
96		Proprietary Capital	(Note P)	p112.16.c,d	10,948,602,528	11,943,377,961	11,445,990,245
97		Accumulated Other Comprehensive Income Account 219	(Note P)	p112.15.c,d	(749,352)	1,512,696	381,672
99		Account 216.1	(Note P)	p119.53.c&d	271,890	121,890	196,890
101		Long Term Debt	(Note P)	p112.18.c,d thru 23.c,d	9,235,548,104	9,883,098,899	9,559,323,502
102		Loss on Reacquired Debt	(Note P)	p111.81.c,d	48,560,802	42,297,978	45,429,390
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)	601,942	601,942	601,942
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	525,189

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	9,557.3

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, 2021

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 adjustment.	1,191,163,080	
B	ATRR based on projected costs included for the previous calendar year but excludes the true-up adjustment.	1,167,126,032	
C	Difference (A-B)	24,037,048	<Note: for the first rate year, divide this
D	Future Value Factor (1+i)^24	1.04849	reconciliation amount by 12 and multiply
E	True-up Adjustment (C*D)	25,202,660	by the number of months and fractional months the rate was in effect.

Where:
i = average interest rate as calculated below

Interest on Amount of Refunds or Surcharges

Month	Yr	Month
January	Year 1	0.2400%
February	Year 1	0.2100%
March	Year 1	0.2400%
April	Year 1	0.2200%
May	Year 1	0.2200%
June	Year 1	0.2100%
July	Year 1	0.2100%
August	Year 1	0.2000%
September	Year 1	0.1800%
October	Year 1	0.1700%
November	Year 1	0.1500%
December	Year 1	0.1700%
January	Year 2	0.1500%
February	Year 2	
March	Year 2	
April	Year 2	0.2000%
May	Year 2	0.1800%
June	Year 2	0.2100%
July	Year 2	
August	Year 2	
September	Year 2	
Average Interest Rate		0.1975%

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2021

Estimated Additions - 2021

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
	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)	Roseland-Branchburg 230kV corridor rebuild (Readington - Branchburg) (b2986.12) (Monthly Additions)	Branchburg-Pleasant Valley 230kV corridor rebuild (Branchburg - East Flemington) (b2986.21) (Monthly Additions)	Convert the R-1318 and Q1317 (Edison - Metuchen) 138 kV circuits to one 230 kV circuit (Brunswick - Meadow Road) (b2835.1) (Monthly Additions)	Convert the R-1318 and Q1317 (Edison - Metuchen) 138 kV circuits to one 230 kV circuit (Meadow Road - Pierson Ave) (b2835.2) (Monthly Additions)	Convert the R-1318 and Q1317 (Edison - Metuchen) 138 kV circuits to one 230 kV circuit (Pierson Ave - Metuchen) (b2835.3) (Monthly Additions)	Convert the N-1340 and T-1372/D-1330 (Brunswick - Trenton) 138 kV circuits to 230 kV circuits (Hunterglen - Trenton) (b2836.2) (Monthly Additions)	Convert the N-1340 and T-1372/D-1330 (Brunswick - Trenton) 138 kV circuits to 230 kV circuits (Brunswick - Devils Brook) (b2836.3) (Monthly Additions)	Convert the N-1340 and T-1372/D-1330 (Brunswick - Trenton) 138 kV circuits to 230 kV circuits (Devils Brook - Trenton) (b2836.4) (Monthly Additions)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Trenton - Yardville K) (b2837.1) (Monthly Additions)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Yardville - Ward Ave K) (b2837.2) (Monthly Additions)
		(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)
Dec-20	13,399,554,522	13,613,262	54,005,474	94,977,621	0	0	87,918,636	55,736,445	8,574,693	77,065,300	50,370,301	96,455,259	22,010,124	8,102,219
Jan	32,827,635	(5,738)	2,695,738	833,749	0	0	287,825	183,613	24,053	383,036	222,092	470,243	782,546	284,535
Feb	33,761,359	112,258	362,742	835,293	0	0	74,305	47,401	8,509	46,986	23,802	56,312	5,283,879	1,429,117
Mar	68,823,401	257,834	19,166	762,621	0	0	37,620	23,999	5,839	41,319	22,313	50,080	0	0
Apr	118,972,325	26,739,431	320,569	225,037	0	0	75,231	47,992	8,577	39,767	24,526	49,398	168,544	58,915
May	84,288,275	271,095	277,905	130,197	0	0	0	0	3,100	32,069	19,441	39,703	5,708,193	1,483,344
Jun	126,162,700	214,699	223,301	51,248	487,694	46,068,010	0	0	3,100	0	0	0	18,258	36,237
Jul	17,850,764	134,864	130,020	0	2,169	1,192,088	0	0	3,100	82,281	56,703	104,547	90,881	62,114
Aug	51,147,270	148,768	74,232	0	0	1,189,880	0	0	3,100	44,782	30,861	56,900	109,621	28,267
Sep	257,560,799	141,807	67,338	0	0	1,178,857	0	0	3,100	13,522	9,319	17,181	153,115	39,483
Oct	160,036,260	130,628	55,990	0	0	1,162,668	0	0	3,100	13,395	9,231	17,019	157,734	40,674
Nov	12,864,668	33,290	33,238	0	0	657,795	5,680	3,623	3,512	13,395	9,232	17,019	157,717	40,669
Dec	211,967,927	19,589	19,536	0	0	657,561	0	0	0	32,003	22,055	40,664	156,073	40,243
Total	14,575,817,905	41,811,787	58,285,249	97,815,766	489,863	52,106,859	88,399,297	56,043,073	8,643,783	77,807,835	50,819,876	97,374,325	34,796,685	11,645,817

Estimated Transmission Enhancement Charges (Before True-Up) - 2021

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)
642,350,288	**1,789,054**	**730,880**	**7,830,196**	**1,983,919**	**2,526,766**	**2,437,967**	**1,490,638**	**651,110**	**1,994,950**	**2,552**	**900,866**	**2,051,721**	**2,131,453**

Actual Additions - 2021

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
	Other Projects PIS (monthly additions)													
		(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)
Dec-20														
Jan														
Feb														
Mar														
Apr														
May														
Jun														
Jul														
Aug														
Sep														
Oct														
Nov														
Dec														
Total	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Actual Transmission Enhancement Charges - 2019

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)
509,660,426	**1,640,158**	**667,195**	**7,148,079**	**1,813,349**	**2,299,437**	**2,215,398**	**1,354,920**	**592,552**	**1,813,000**	**2,328**	**816,044**	**1,856,673**	**1,926,706**

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)
18,968,050	**2,996**	**2,596**	**27,805**	**7,020**	**9,051**	**8,766**	**5,355**	**2,331**	**7,172**	**9**	**3,266**	**7,462**	**7,035**

Interest		1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849

True Up by Project (with interest) -2019

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)
3,382,775	**3,142**	**2,722**	**29,153**	**7,361**	**9,490**	**9,191**	**5,615**	**2,444**	**7,520**	**9**	**3,425**	**7,823**	**7,376**

Estimated Transmission Enhancement Charges (After True-Up) - 2021

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)
645,733,063	**1,792,195**	**733,602**	**7,859,350**	**1,991,280**	**2,536,256**	**2,447,159**	**1,496,253**	**653,554**	**2,002,469**	**2,561**	**904,290**	**2,059,545**	**2,138,829**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2021

Estimated Additions - 2021

(O)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)	(AB)
Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Ward Ave - Crosswicks Y) (b2837.3) (Monthly Additions)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Crosswicks - Bustleton Y) (b2837.4) (Monthly Additions)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Bustleton - Burlington Y) (b2837.5) (Monthly Additions)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Trenton - Yardville F) (b2837.6) (Monthly Additions)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Yardville - Ward Ave F) (b2837.7) (Monthly Additions)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Ward Ave - Crosswicks Z) (b2837.8) (Monthly Additions)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Crosswicks - Williams Z) (b2837.9) (Monthly Additions)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Williams - Bustleton Z) (b2837.10) (Monthly Additions)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Bustleton - Burlington Z) (b2837.11) (Monthly Additions)			Other Projects PIS	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)
(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)				(in service)	(in service)
5,242,150	10,411,094	9,442,026	21,878,630	7,719,449	5,242,150	1,935,515	8,475,579	9,442,026		**Dec-20**	13,399,554,522	13,613,262	54,005,474
251,063	1,120,094	1,210,178	782,546	284,535	251,063	69,779	1,050,315	1,807,433		**Jan**	13,432,382,157	13,807,524	56,701,212
1,173,580	9,329,333	10,070,082	5,283,879	1,429,117	1,173,580	442,238	8,741,499	10,070,082		**Feb**	13,466,143,516	13,719,782	57,063,954
0	0	0	0	0	0	0	0	277,141		**Mar**	13,534,966,917	13,977,616	57,083,120
49,800	377,582	400,494	168,544	58,915	49,800	13,679	363,904	368,303		**Apr**	13,653,939,242	40,717,047	57,403,689
1,202,304	8,918,248	10,345,051	5,708,193	1,483,344	1,202,304	477,823	8,440,425	10,304,319		**May**	13,738,227,517	40,988,142	57,681,594
29,405	74,198	113,118	18,258	36,237	29,405	9,707	64,490	112,268		**Jun**	13,864,390,217	41,202,841	57,904,895
50,499	225,208	259,043	90,881	62,114	50,499	20,200	205,009	325,349		**Jul**	13,882,240,981	41,337,705	58,034,915
22,981	170,752	186,149	109,621	28,267	22,981	9,193	311,559	336,149		**Aug**	13,933,388,251	41,486,473	58,109,147
32,100	238,500	260,007	153,115	39,483	32,100	12,840	225,660	260,007		**Sep**	14,190,949,050	41,628,280	58,176,485
33,068	245,695	267,850	157,734	40,674	33,068	13,227	232,468	267,850		**Oct**	14,350,985,310	41,758,908	58,232,475
33,064	245,668	267,822	157,717	40,669	33,064	13,226	232,443	267,822		**Nov**	14,363,849,978	41,792,198	58,265,713
32,720	243,106	278,614	156,072	40,244	32,720	13,086	230,018	231,102		**Dec**	14,575,817,905	41,811,787	58,285,249
8,152,734	31,599,478	33,100,434	34,665,190	11,263,048	8,152,734	3,030,513	28,573,369	34,069,851		**Total**	**180,386,835,563**	427,641,565	746,947,922
										Average 13 Month Balance	**13,875,910,428**	32,895,505	57,457,532
										Average 13 Month in service		**10.23**	**12.82**
										13 Month Average CWIP to Appendix A, line 45			

Estimated Transmission Enhancement Charges (Before True-Up) - 2021

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)
7,828,202	**1,466,391**	**1,895,700**	**654,111**	**2,393,133**	**1,675,986**	**2,268,369**	**6,614,992**	**7,755,021**	**1,213,273**	**613,058**	**4,515,511**	**81,530,281**	**37,563,509**

Actual Additions - 2021

(O)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)	(W)	(X)	(Y)	(Z)	(AA)	(AB)
						Other Projects PIS							
(in service)	(in service)	(in service)	(in service)				(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)
					Dec-20	-	0	0	0	0	0	0	0
					Jan	-	0	0	0	0	0	0	0
					Feb	-	0	0	0	0	0	0	0
					Mar	-	0	0	0	0	0	0	0
					Apr	-	0	0	0	0	0	0	0
					May	-	0	0	0	0	0	0	0
					Jun	-	0	0	0	0	0	0	0
					Jul	-	0	0	0	0	0	0	0
					Aug	-	0	0	0	0	0	0	0
					Sep	-	0	0	0	0	0	0	0
					Oct	-	0	0	0	0	0	0	0
					Nov	-	0	0	0	0	0	0	0
					Dec	-	0	0	0	0	0	0	0
0	0	0	0		**Total**	-	0	0	0	0	0	-	-
					Average 13 Month Balance	-	0	0	0	0	0	-	-
					Average 13 Month in service		-	-	-	-	-	-	-
				-	**CWIP to Appendix A, line 45**								

Actual Transmission Enhancement Charges - 2019

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)
7,072,218	**1,324,275**	**1,712,321**	**590,435**	**4,272,398**	**1,489,809**	**2,044,102**	**5,957,472**	**6,972,793**	**1,090,525**	**559,490**	**4,099,747**	**73,929,272**	**33,796,614**

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)
16,439	**5,362**	**6,928**	**2,395**	**12,129**	**6,076**	**7,861**	**14,059**	**27,412**	**4,492**	**3,299**	**24,622**	**434,545**	**137,970**

1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849

True Up by Project (with interest) -2019

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)
17,236	**5,622**	**7,264**	**2,511**	**12,717**	**6,370**	**8,242**	**14,741**	**28,741**	**4,710**	**3,459**	**25,816**	**455,617**	**144,661**

Estimated Transmission Enhancement Charges (After True-Up) - 2021

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)
7,845,438	**1,472,013**	**1,902,963**	**656,622**	**2,405,850**	**1,682,357**	**2,276,611**	**6,629,733**	**7,783,762**	**1,217,983**	**616,517**	**4,541,327**	**81,985,898**	**37,708,170**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2021

Estimated Additions - 2021

(AC)	(AD)	(AE)	(AF)	(AG)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)	(AN)	(AO)	(AP)
Rebuild Aldene-Warinanco-Linden VFT 230kV Circuit (b2955)	Roseland-Branchburg 230kV corridor rebuild (Readington - Branchburg) (b2986.12)	Branchburg-Pleasant Valley 230kV corridor rebuild (Branchburg - East Flemington) (b2986.21)	Convert the R-1318 and Q1317 (Edison - Metuchen) 138 kV circuits to one 230 kV circuit (Brunswick - Meadow Road) (b2835.1)	Convert the R-1318 and Q1317 (Edison - Metuchen) 138 kV circuits to one 230 kV circuit (Meadow Road - Pierson Ave) (b2835.2)	Convert the R-1318 and Q1317 (Edison - Metuchen) 138 kV circuits to one 230 kV circuit (Pierson Ave - Metuchen) (b2835.3)	Convert the N-1340 and T-1372/D-1330 (Brunswick - Trenton) 138 kV circuits to 230 kV circuits (Hunterglen - Trenton) (b2836.2)	Convert the N-1340 and T-1372/D-1330 (Brunswick - Trenton) 138 kV circuits to 230 kV circuits (Brunswick - Devils Brook) (b2836.3)	Convert the N-1340 and T-1372/D-1330 (Brunswick - Trenton) 138 kV circuits to 230 kV circuits (Devils Brook - Trenton) (b2836.4)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Trenton - Yardville K) (b2837.1)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Yardville - Ward Ave K) (b2837.2)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Ward Ave - Crosswicks Y) (b2837.3)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Crosswicks - Bustleton Y) (b2837.4)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Bustleton - Burlington Y) (b2837.5)
(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)
94,977,621	0	0	87,918,636	55,736,445	8,574,693	77,065,300	50,370,301	96,455,259	22,010,124	8,102,219	5,242,150	10,411,094	9,442,026
95,811,370	0	0	88,206,461	55,920,058	8,598,746	77,448,336	50,592,393	96,925,502	22,792,670	8,386,754	5,493,213	11,531,188	10,652,204
96,646,663	0	0	88,280,766	55,967,459	8,607,255	77,495,302	50,616,195	96,981,814	28,076,549	9,815,871	6,666,793	20,860,521	20,722,286
97,409,284	0	0	88,318,386	55,991,458	8,613,094	77,536,621	50,638,508	97,031,894	28,076,549	9,815,871	6,666,793	20,860,521	20,722,286
97,634,321	0	0	88,393,617	56,039,450	8,621,671	77,576,388	50,663,034	97,081,292	28,245,093	9,874,786	6,716,593	21,238,103	21,122,780
97,764,518	0	0	88,393,617	56,039,450	8,624,771	77,608,457	50,682,475	97,120,995	33,953,286	11,358,130	7,918,897	30,156,351	31,467,831
97,815,766	487,694	46,068,010	88,393,617	56,039,450	8,627,871	77,608,457	50,682,475	97,120,995	33,971,544	11,394,367	7,948,302	30,230,549	31,580,949
97,815,766	489,863	47,260,098	88,393,617	56,039,450	8,630,971	77,690,738	50,739,178	97,225,542	34,062,425	11,456,481	7,998,801	30,455,757	31,839,992
97,815,766	489,863	48,449,978	88,393,617	56,039,450	8,634,071	77,735,520	50,770,039	97,282,442	34,172,046	11,484,748	8,021,782	30,626,509	32,026,141
97,815,766	489,863	49,628,835	88,393,617	56,039,450	8,637,171	77,749,042	50,779,358	97,299,623	34,325,161	11,524,231	8,053,882	30,865,009	32,286,148
97,815,766	489,863	50,791,503	88,393,617	56,039,450	8,640,271	77,762,437	50,788,589	97,316,642	34,482,895	11,564,905	8,086,950	31,110,704	32,553,998
97,815,766	489,863	51,449,298	88,399,297	56,043,073	8,643,783	77,775,832	50,797,821	97,333,661	34,640,612	11,605,574	8,120,014	31,356,372	32,821,820
97,815,766	489,863	52,106,859	88,399,297	56,043,073	8,643,783	77,807,835	50,819,876	97,374,325	34,796,685	11,645,817	8,152,734	31,599,478	33,100,434
1,264,954,139	3,426,872	345,754,581	1,148,278,162	727,977,716	112,098,151	1,008,860,265	658,940,242	1,262,549,986	403,605,639	138,029,754	95,086,904	331,302,156	340,338,895
97,304,165	263,606	26,596,506	88,329,089	55,998,286	8,622,935	77,604,636	50,687,711	97,119,230	31,046,588	10,617,673	7,314,377	25,484,781	26,179,915
12.93	**7.00**	**6.64**	**12.99**	**12.99**	**12.97**	**12.97**	**12.97**	**12.97**	**11.60**	**11.85**	**11.66**	**10.48**	**10.28**

Estimated Transmission Enhancement Charges (Before True-Up) - 2021

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)
47,579,304	**38,556,871**	**68,933,172**	**39,155,285**	**19,975,383**	**7,511,002**	**5,552,878**	**18,246,726**	**14,607,545**	**7,550,479**	**4,959,375**	**9,406,987**	**6,261,073**	**6,261,073**

Actual Additions - 2021

(AC)	(AD)	(AE)	(AF)	(AG)	(AH)	(AI)	(AJ)	(AK)	(AL)
(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)	(in service)
0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0	0
-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-

Actual Transmission Enhancement Charges - 2019

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)
42,770,064	**34,749,401**	**62,002,045**	**35,184,820**	**17,892,091**	**6,720,163**	**4,967,498**	**16,310,281**	**13,059,503**	**6,797,498**	**4,341,924**	**8,403,848**	**5,600,110**	**5,600,110**

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)
178,275	**135,396**	**282,127**	**(530,283)**	**(30,997)**	**230,680**	**170,354**	**(559,653)**	**243,319**	**39,903**	**(617,389)**	**(682,673)**	**605,068**	**605,068**
1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849

True Up by Project (with interest) -2019

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)
186,920	**141,962**	**295,808**	**(555,997)**	**(32,501)**	**241,866**	**178,615**	**(586,792)**	**255,118**	**41,838**	**(647,328)**	**(715,778)**	**634,409**	**634,409**

Estimated Transmission Enhancement Charges (After True-Up) - 2021

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)
47,766,224	**38,698,833**	**69,228,980**	**38,599,288**	**19,942,882**	**7,752,868**	**5,731,493**	**17,659,934**	**14,862,664**	**7,592,318**	**4,312,047**	**8,691,210**	**6,895,482**	**6,895,482**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 6A - Project Specific Estimate and Reconciliation Worksheet - December 31, 2021

Estimated Additions-2021

(AQ)	(AR)	(AS)	(AT)	(AU)	(AV)
Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Trenton - Yardville F) (b2837.6)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Yardville - Ward Ave F) (b2837.7)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Ward Ave - Crosswicks Z) (b2837.8)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Crosswicks - Williams Z) (b2837.9)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Williams - Bustleton Z) (b2837.10)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Bustleton - Burlington Z) (b2837.11)
(in service)	(in service)	(in service)	(in service)	(in service)	(in service)
21,878,630	7,719,449	5,242,150	1,935,515	8,475,579	9,442,026
22,861,176	8,003,984	5,493,213	2,005,294	9,525,894	11,249,459
27,945,055	9,433,101	6,666,793	2,447,532	18,267,393	21,319,541
27,945,055	9,433,101	6,666,793	2,447,532	18,267,393	21,596,682
28,113,599	9,492,016	6,716,593	2,461,211	18,631,297	21,964,985
33,821,792	10,975,360	7,918,897	2,939,034	27,071,722	32,269,304
33,840,050	11,011,597	7,948,302	2,948,741	27,136,212	32,381,572
33,930,931	11,073,711	7,998,801	2,968,941	27,341,221	32,706,921
34,040,552	11,101,978	8,021,782	2,978,134	27,652,780	33,043,070
34,193,867	11,141,461	8,053,882	2,990,974	27,878,440	33,303,077
34,351,401	11,182,135	8,086,950	3,004,201	28,110,908	33,570,927
34,509,118	11,222,804	8,120,014	3,017,427	28,343,351	33,838,749
34,665,190	11,263,048	8,152,734	3,030,513	28,573,369	34,069,851
401,896,216	133,053,745	95,086,904	35,175,049	296,275,559	350,756,164
30,915,094	10,234,903	7,314,377	2,705,773	22,713,505	26,981,243
11.59	**11.81**	**11.66**	**11.61**	**10.33**	**10.30**

Estimated Transmission Enhancement Charges (Before True-Up) - 2021

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)
6,076,738	**6,226,970**	**3,487,278**	**2,783,988**	**3,098,783**	**3,098,783**	**1,011,904**	**1,011,877**	**3,875,267**	**1,684,861**	**1,311,307**	**2,129,718**	**4,937,384**	**3,511,965**

Actual Transmission Enhancement Charges - 2019

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)
5,438,154	**5,438,154**	**3,124,607**	**2,494,579**	**2,780,686**	**2,780,686**	**903,008**	**902,986**	**3,470,539**	**1,508,145**	**1,177,840**	**1,912,015**	**4,402,674**	**3,151,751**

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)
723,210	**584,447**	**(48,495)**	**11,134**	**16,953**	**16,953**	**(699,227)**	**(699,227)**	**1,342,287**	**81,609**	**5,551**	**32,089**	**40,471**	**13,057**

1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849

True Up by Project (with interest) -2019

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)
758,280	**612,788**	**(50,846)**	**11,674**	**17,775**	**17,775**	**(733,134)**	**(733,134)**	**1,407,378**	85,566	**5,820**	**33,645**	**42,433**	**13,690**

Estimated Transmission Enhancement Charges (After True-Up) - 2021

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)
6,835,018	**6,839,758**	**3,436,431**	**2,795,662**	**3,116,559**	**3,116,559**	**278,770**	**278,742**	**5,282,645**	**1,770,427**	**1,317,127**	**2,163,363**	**4,979,817**	**3,525,655**

Estimated Transmission Enhancement Charges (Before True-Up) - 2021														
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)	Roseland-Branchburg 230kV corridor rebuild (Readington - Branchburg) (b2986.12)	Branchburg-Pleasant Valley 230kV corridor rebuild (Branchburg - East Flemington) (b2986.21)	Convert the R-1318 and Q1317 (Edison - Metuchen) 138 kV circuits to one 230 kV circuit (Brunswick - Meadow Road) (b2835.1)	Convert the R-1318 and Q1317 (Edison - Metuchen) 138 kV circuits to one 230 kV circuit (Meadow Road - Pierson Ave) (b2835.2)	Convert the R-1318 and Q1317 (Edison - Metuchen) 138 kV circuits to one 230 kV circuit (Pierson Ave - Metuchen) (b2835.3)	Convert the N-1340 and T-1372/D-1330 (Brunswick - Trenton) 138 kV circuits to 230 kV circuits (Hunterglen - Trenton) (b2836.2)	Convert the N-1340 and T-1372/D-1330 (Brunswick - Trenton) 138 kV circuits to 230 kV circuits (Brunswick - Devils Brook) (b2836.3)
122,152	**2,548,254**	**18,228,728**	**2,580,144**	**4,008,756**	**6,995,758**	**11,789,355**	**32,139**	**3,242,623**	**10,450,746**	**6,622,614**	**1,021,376**	**9,294,426**	**6,060,893**

Actual Transmission Enhancement Charges - 2019

Install Conemaugh 250MVAR Cap Bank (B0376)	Reconfigure Kearny-Loop in P2216 Ckt (B1589)	Reconfigure Brunswick Sw-New 69kV/Ckt-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)	Roseland-Branchburg 230kV corridor rebuild (Readington - Branchburg) (b2986.12)	Branchburg-Pleasant Valley 230KV corridor rebuild (Branchburg - East Flemington) (b2986.21)	Convert the R-1318 and Q1317 (Edison - Metuchen) 138 kV circuits to one 230 kV circuit (Brunswick - Meadow Road) (b2835.1)	Convert the R-1318 and Q1317 (Edison - Metuchen) 138 kV circuits to one 230 kV circuit (Meadow Road - Pierson Ave) (b2835.2)	Convert the R-1318 and Q1317 (Edison - Metuchen) 138 kV circuits to one 230 kV circuit (Pierson Ave - Metuchen) (b2835.3)	Convert the N-1340 and T-1372/D-1330 (Brunswick - Trenton) 138 kV circuits to 230 kV circuits (Hunterglen - Trenton) (b2836.2)	Convert the N-1340 and T-1372/D-1330 (Brunswick - Trenton) 138 kV circuits to 230 kV circuits (Brunswick - Devils Brook) (b2836.3)
109,575	**2,277,763**	**16,283,381**	**2,305,492**	0	0	0	0	0	**5,203,531**	**3,364,016**	**504,244**	**1,539,666**	**1,335,462**

Reconciliation by Project (without interest)

Install Conemaugh 250MVAR Cap Bank (B0376)	Reconfigure Kearny-Loop in P2216 Ckt (B1589)	Reconfigure Brunswick Sw-New 69kV/Ckt-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)	Roseland-Branchburg 230kV corridor rebuild (Readington - Branchburg) (b2986.12)	Branchburg-Pleasant Valley 230KV corridor rebuild (Branchburg - East Flemington) (b2986.21)	Convert the R-1318 and Q1317 (Edison - Metuchen) 138 kV circuits to one 230 kV circuit (Brunswick - Meadow Road) (b2835.1)	Convert the R-1318 and Q1317 (Edison - Metuchen) 138 kV circuits to one 230 kV circuit (Meadow Road - Pierson Ave) (b2835.2)	Convert the R-1318 and Q1317 (Edison - Metuchen) 138 kV circuits to one 230 kV circuit (Pierson Ave - Metuchen) (b2835.3)	Convert the N-1340 and T-1372/D-1330 (Brunswick - Trenton) 138 kV circuits to 230 kV circuits (Hunterglen - Trenton) (b2836.2)	Convert the N-1340 and T-1372/D-1330 (Brunswick - Trenton) 138 kV circuits to 230 kV circuits (Brunswick - Devils Brook) (b2836.3)
455	**(11,247)**	**949,619**	**3,038**	0	0	0	0	0	**5,203,531**	**3,364,016**	**504,244**	**1,539,666**	**1,335,462**

1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849

True Up by Project (with interest) -2019

Install Conemaugh 250MVAR Cap Bank (B0376)	Reconfigure Kearny-Loop in P2216 Ckt (B1589)	Reconfigure Brunswick Sw-New 69kV/Ckt-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)	Roseland-Branchburg 230kV corridor rebuild (Readington - Branchburg) (b2986.12)	Branchburg-Pleasant Valley 230KV corridor rebuild (Branchburg - East Flemington) (b2986.21)	Convert the R-1318 and Q1317 (Edison - Metuchen) 138 kV circuits to one 230 kV circuit (Brunswick - Meadow Road) (b2835.1)	Convert the R-1318 and Q1317 (Edison - Metuchen) 138 kV circuits to one 230 kV circuit (Meadow Road - Pierson Ave) (b2835.2)	Convert the R-1318 and Q1317 (Edison - Metuchen) 138 kV circuits to one 230 kV circuit (Pierson Ave - Metuchen) (b2835.3)	Convert the N-1340 and T-1372/D-1330 (Brunswick - Trenton) 138 kV circuits to 230 kV circuits (Hunterglen - Trenton) (b2836.2)	Convert the N-1340 and T-1372/D-1330 (Brunswick - Trenton) 138 kV circuits to 230 kV circuits (Brunswick - Devils Brook) (b2836.3)
477	**(11,793)**	**995,668**	**3,185**	0	0	0	0	0					

Estimated Transmission Enhancement Charges (After True-Up) - 2021

Install Conemaugh 250MVAR Cap Bank (B0376)	Reconfigure Kearny-Loop in P2216 Ckt (B1589)	Reconfigure Brunswick Sw-New 69kV/Ckt-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)	Roseland-Branchburg 230kV corridor rebuild (Readington - Branchburg) (b2986.12)	Branchburg-Pleasant Valley 230KV corridor rebuild (Branchburg - East Flemington) (b2986.21)	Convert the R-1318 and Q1317 (Edison - Metuchen) 138 kV circuits to one 230 kV circuit (Brunswick - Meadow Road) (b2835.1)	Convert the R-1318 and Q1317 (Edison - Metuchen) 138 kV circuits to one 230 kV circuit (Meadow Road - Pierson Ave) (b2835.2)	Convert the R-1318 and Q1317 (Edison - Metuchen) 138 kV circuits to one 230 kV circuit (Pierson Ave - Metuchen) (b2835.3)	Convert the N-1340 and T-1372/D-1330 (Brunswick - Trenton) 138 kV circuits to 230 kV circuits (Hunterglen - Trenton) (b2836.2)	Convert the N-1340 and T-1372/D-1330 (Brunswick - Trenton) 138 kV circuits to 230 kV circuits (Brunswick - Devils Brook) (b2836.3)
122,628	**2,536,461**	**19,224,396**	**2,583,330**	**4,008,756**	**6,986,758**	**11,789,355**	**32,139**	**3,242,623**	**10,450,746**	**6,622,614**	**1,021,376**	**9,284,426**	**6,060,893**

Estimated Transmission Enhancement Charges (Before True-Up) - 2021												
Convert the N-1340 and T-1372/D-1330 (Brunswick - Trenton) 138 kV circuits to 230 kV circuits (Devils Brook - Trenton) (b2836.4)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Trenton - Yardville K) (b2837.1)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Yardville - Ward Ave K) (b2837.2)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Ward Ave - Crosswicks Y) (b2837.3)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Crosswicks - Bustleton Y) (b2837.4)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Bustleton - Burlington Y) (b2837.5)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Trenton - Yardville F) (b2837.6)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Yardville - Ward Ave F) (b2837.7)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Ward Ave - Crosswicks Z) (b2837.8)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Crosswicks - Williams Z) (b2837.9)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Williams - Bustleton Z) (b2837.10)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Bustleton - Burlington Z) (b2837.11)
11,618,974	**3,746,086**	**1,284,501**	**884,806**	**3,094,144**	**3,184,082**	**3,733,024**	**1,240,875**	**884,806**	**323,731**	**2,761,938**	**3,281,769**

Actual Transmission Enhancement Charges - 2019

Convert the N-1340 and T-1372/D-1330 (Brunswick - Trenton) 138 kV circuits to 230 kV circuits (Devils Brook - Trenton) (b2836.4)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Trenton - Yardville K) (b2837.1)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Yardville - Ward Ave K) (b2837.2)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Ward Ave - Crosswicks Y) (b2837.3)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Crosswicks - Bustleton Y) (b2837.4)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Bustleton - Burlington Y) (b2837.5)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Trenton - Yardville F) (b2837.6)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Yardville - Ward Ave F) (b2837.7)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Ward Ave - Crosswicks Z) (b2837.8)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Crosswicks - Williams Z) (b2837.9)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Williams - Bustleton Z) (b2837.10)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Bustleton - Burlington Z) (b2837.11)
2,240,121	**400,083**	**106,413**	**141,595**	**158,711**	**17,116**	**353,300**	**60,047**	**141,595**	**141,595**	**17,116**	**17,116**

Reconciliation by Project (without interest)

Convert the N-1340 and T-1372/D-1330 (Brunswick - Trenton) 138 kV circuits to 230 kV circuits (Devils Brook - Trenton) (b2836.4)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Trenton - Yardville K) (b2837.1)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Yardville - Ward Ave K) (b2837.2)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Ward Ave - Crosswicks Y) (b2837.3)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Crosswicks - Bustleton Y) (b2837.4)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Bustleton - Burlington Y) (b2837.5)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Trenton - Yardville F) (b2837.6)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Yardville - Ward Ave F) (b2837.7)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Ward Ave - Crosswicks Z) (b2837.8)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Crosswicks - Williams Z) (b2837.9)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Williams - Bustleton Z) (b2837.10)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Bustleton - Burlington Z) (b2837.11)
2,240,121	**400,083**	**106,413**	**141,595**	**158,711**	**17,116**	**353,300**	**60,047**	**141,595**	**141,595**	**17,116**	**17,116**

1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849	1.04849

True Up by Project (with interest) - 2019

Convert the N-1340 and T-1372/D-1330 (Brunswick - Trenton) 138 kV circuits to 230 kV circuits (Devils Brook - Trenton) (b2836.4)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Trenton - Yardville K) (b2837.1)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Yardville - Ward Ave K) (b2837.2)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Ward Ave - Crosswicks Y) (b2837.3)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Crosswicks - Bustleton Y) (b2837.4)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Bustleton - Burlington Y) (b2837.5)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Trenton - Yardville F) (b2837.6)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Yardville - Ward Ave F) (b2837.7)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Ward Ave - Crosswicks Z) (b2837.8)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Crosswicks - Williams Z) (b2837.9)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Williams - Bustleton Z) (b2837.10)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Bustleton - Burlington Z) (b2837.11)

Estimated Transmission Enhancement Charges (After True-Up) - 2021

Convert the N-1340 and T-1372/D-1330 (Brunswick - Trenton) 138 kV circuits to 230 kV circuits (Devils Brook - Trenton) (b2836.4)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Trenton - Yardville K) (b2837.1)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Yardville - Ward Ave K) (b2837.2)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Ward Ave - Crosswicks Y) (b2837.3)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Crosswicks - Bustleton Y) (b2837.4)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Bustleton - Burlington Y) (b2837.5)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Trenton - Yardville F) (b2837.6)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Yardville - Ward Ave F) (b2837.7)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Ward Ave - Crosswicks Z) (b2837.8)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Crosswicks - Williams Z) (b2837.9)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Williams - Bustleton Z) (b2837.10)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Bustleton - Burlington Z) (b2837.11)
11,618,974	**3,746,086**	**1,284,501**	**884,806**	**3,094,144**	**3,184,082**	**3,733,024**	**1,240,875**	**884,806**	**323,731**	**2,761,938**	**3,281,769**

Public Service Electric and Gas Company
ATTACHMENT H-10A
Attachment 7 - Transmission Enhancement Charges Worksheet (TEC) - December 31, 2021

New Plant Carrying Charge

Fixed Charge Rate (FCR) if if not a CIAC

		Formula Line		
A	152	Net Plant Carrying Charge without Depreciation	9.81%
B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.42%
C		Line B less Line A	0.61%

FCR if a CIAC

D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.26%

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.
Per FERC Order dated December 30, 2011 in Docket No. ER12-298, 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.
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 5a, and Line 19 will be number of months to be amortized in year plus one.

Details		Branchburg (B0130)			Kittatinny (B0134)			Essex Aldene (B0145)			New Freedom Trans.(B0411)		
"Yes" if a project under PJM OATT Schedule 12, otherwise "No"													
Schedule 12	(Yes or No)	Yes			Yes			Yes			Yes		
Useful life of the project	Life	42			42			42			42		
"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 20. Otherwise "No"	CIAC	(Yes or No)	No			No			No			No	
Input the allowed increase in ROE	Increased ROE (Basis Points)		0			0			0			0	
From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.81%			9.81%			9.81%			9.81%	
Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.81%			9.81%			9.81%			9.81%	
Service Account 101 or 106 if not yet classified - End of year balance	Investment		20,614,102			8,089,022			86,467,721			22,188,863	
	Annual Depreciation or Amort Exp		490,812			192,120			2,058,755			528,306	
Line 17 divided by line 12													
Months in service for depreciation expense from Year placed in Service (0 if CWIP)			13.00			13.00			13.00			13.00	
			2006			2007			2007			2007	

	Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
W 11.68 % ROE	2006	20,680,597	492,395	4,652,471									
W Increased ROE	2006	20,680,597	492,395	4,652,471									
W 11.68 % ROE	2007	20,188,202	492,395	4,553,422	8,089,022	80,050	1,703,202	86,565,629	858,786	18,272,191	22,188,863	484,281	4,947,757
W Increased ROE	2007	20,188,202	492,395	4,553,422	8,089,022	80,050	1,703,202	86,565,629	858,786	18,272,191	22,188,863	484,281	4,947,757
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
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
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
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
W 11.68 % ROE	2010	18,711,016	492,395	4,095,988	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
W Increased ROE	2010	18,711,016	492,395	4,095,988	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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
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
W 11.68 % ROE	2019	14,214,940	490,812	1,640,158	5,875,657	192,120	667,195	62,943,978	2,058,755	7,148,079	15,893,213	528,306	1,813,349
W Increased ROE	2019	14,214,940	490,812	1,640,158	5,875,657	192,120	667,195	62,943,978	2,058,755	7,148,079	15,893,213	528,306	1,813,349
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
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
W 11.68 % ROE	2021	13,232,566	490,812	1,789,054	5,491,418	192,120	730,880	58,826,467	2,058,755	7,830,196	14,836,601	528,306	1,983,919
W Increased ROE	2021	13,232,566	490,812	1,789,054	5,491,418	192,120	730,880	58,826,467	2,058,755	7,830,196	14,836,601	528,306	1,983,919

New Plant Carrying Charge

Fixed Charge Rate (FCR) if not a CIAC

		Formula Line		
A	152	Net Plant Carrying Charge without Depreciation	9.81%
B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.42%
C		Line B less Line A	0.61%

FCR if a CIAC

D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.26%

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.
Per FERC Order dated December 20, 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.
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. 8a, and Line 19 will be number of months to be amortized in year plus one.

	Details		New Freedom Loop (B0499)			Metuchen Transformer (B0161)			Branchburg-Flagtown-Somerville (B0169)			Flagtown-Somerville-Bridgewater (B0170)		
"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes			Yes			Yes			Yes		
Useful life of the project	Life		42			42			42			42		
"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 39, Otherwise "No"	CIAC	(Yes or No)	No			No			No			No		
Input the allowed increase in ROE	Increased ROE (Basis Points)		0			0			0			0		
From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.81%			9.81%			9.81%			9.81%		
Line 14 plus (line 5 times line 15/100	FCR for This Project		9.81%			9.81%			9.81%			9.81%		
Service Account 101 or 106 if not yet classified - End of year balance	Investment		27,005,248			25,654,455			15,731,554			6,961,495		
	Annual Depreciation or Amort Exp		642,982			610,820			374,561			165,750		
Line 17 divided by line 12														
Months in service for depreciation expense from Year placed in Service (0 if CWIP)			13.00			13.00			13.00			13.00		
			2008			2009			2009			2008		
		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
	W 11.68 % ROE	2006												
	W Increased ROE	2006												
	W 11.68 % ROE	2007												
	W Increased ROE	2007												
	W 11.68 % ROE	2008	24,921,237	88,646	837,584							6,961,495	25,372	239,734
	W Increased ROE	2008	24,921,237	88,646	837,584							6,961,495	25,372	239,734
	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
	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
	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
	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
	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
	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
	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
	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
	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
	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
	W 11.68 % ROE	2014	23,701,687	642,982	3,583,358	23,054,049	614,263	3,454,841	13,997,743	374,561	2,099,276	6,107,373	165,750	918,263
	W Increased ROE	2014	23,701,687	642,982	3,583,358	23,054,049	614,263	3,454,841	13,997,743	374,561	2,099,276	6,107,373	165,750	918,263
	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
	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
	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
	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
	W 11.68 % ROE	2017	21,772,741	642,982	3,084,762	21,086,812	610,820	2,973,452	12,874,060	374,561	1,818,367	5,610,124	165,750	794,917
	W Increased ROE	2017	21,772,741	642,982	3,084,762	21,086,812	610,820	2,973,452	12,874,060	374,561	1,818,367	5,610,124	165,750	794,917
	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
	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
	W 11.68 % ROE	2019	20,486,777	642,982	2,299,437	19,845,171	610,820	2,215,398	12,124,939	374,561	1,354,920	5,278,624	165,750	592,552
	W Increased ROE	2019	20,486,777	642,982	2,299,437	19,845,171	610,820	2,215,398	12,124,939	374,561	1,354,920	5,278,624	165,750	592,552
	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
	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
	W 11.68 % ROE	2021	19,200,813	642,982	2,526,766	18,623,530	610,820	2,437,967	11,375,817	374,561	1,490,638	4,947,124	165,750	651,110
	W Increased ROE	2021	19,200,813	642,982	2,526,766	18,623,530	610,820	2,437,967	11,375,817	374,561	1,490,638	4,947,124	165,750	651,110

New Plant Carrying Charge

Fixed Charge Rate (FCR) if if not a CIAC

		Formula Line		
A	152	Net Plant Carrying Charge without Depreciation	9.81%
B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.42%
C		Line B less Line A	0.61%

FCR if a CIAC

D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.26%

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.
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.
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		Roseland Transformers (B0274)			Wave Trap Branchburg (B0172.2)			Reconductor Hudson - South Waterfront (B0812)			Reconductor South Mahwah J-3410 Circuit (B1017)		
	"Yes" if a project under PJM OATT Schedule 12, otherwise "No"													
	Schedule 12	(Yes or No)	Yes			Yes			Yes			Yes		
	Useful life of the project	Life	42			42			42			42		
	"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	
	Input the allowed increase in ROE	Increased ROE (Basis Points)		0			0			0			0	
	From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.81%			9.81%			9.81%			9.81%	
	Line 14 plus (line 5 times line 15/100	FCR for This Project		9.81%			9.81%			9.81%			9.81%	
	Service Account 101 or 106 if not yet classified - End of year balance	Investment		21,014,433			27,988			9,158,918			20,826,991	
	Line 17 divided by line 12	Annual Depreciation or Amort Exp		500,344			666			218,069			491,119	
	Months in service for depreciation expense from Year placed in Service (0 if CWIP)			13.00			13.00			13.00			13.00	
				2009			2008			2010			2011	
		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
	W 11.68 % ROE	2006												
	W Increased ROE	2006												
	W 11.68 % ROE	2007												
	W Increased ROE	2007												
	W 11.68 % ROE	2008				36,369	577	5,114						
	W Increased ROE	2008				36,369	577	5,114						
	W 11.68 % ROE	2009	21,092,458	268,347	2,634,086	35,792	866	8,379						
	W Increased ROE	2009	21,092,458	268,347	2,634,086	35,792	866	8,379						
	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			
	W Increased ROE	2010	20,797,967	501,579	4,507,079	27,122	666	5,890	8,806,222	18,700	169,959			
	W 11.68 % ROE	2011	20,302,530	501,725	4,128,443	25,878	666	5,289	9,140,218	218,069	1,850,822	20,823,951	500,198	2,435,793
	W Increased ROE	2011	20,302,530	501,725	4,128,443	25,878	666	5,289	9,140,218	218,069	1,850,822	20,823,951	500,198	2,435,793
	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
	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
	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
	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
	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
	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
	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
	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
	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
	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
	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
	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
	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
	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
	W 11.68 % ROE	2019	16,234,731	500,344	1,813,000	20,548	666	2,328	7,395,662	218,069	816,044	16,888,961	491,119	1,856,673
	W Increased ROE	2019	16,234,731	500,344	1,813,000	20,548	666	2,328	7,395,662	218,069	816,044	16,888,961	491,119	1,856,673
	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
	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
	W 11.68 % ROE	2021	15,234,044	500,344	1,994,950	19,215	666	2,552	6,959,523	218,069	900,886	15,906,724	491,119	2,051,721
	W Increased ROE	2021	15,234,044	500,344	1,994,950	19,215	666	2,552	6,959,523	218,069	900,886	15,906,724	491,119	2,051,721

New Plant Carrying Charge

Fixed Charge Rate (FCR) if not a CIAC

		Formula Line		
A	152	Net Plant Carrying Charge without Depreciation	9.81%
B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.42%
C		Line B less Line A	0.61%

FCR if a CIAC

D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.26%

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.
Per FERC Order dated December 20, 2011 in Docket No. ER12-296, the ROE for the Northeast Grid Reliability Project is 11.35%,
which includes a 25 basis-point transmission ROE adder as authorized by FERC to become effective January 1, 2012.
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		Reconductor South Mahwah, K-3411 Circuit (B1918)			Branchburg 500 MVAR Capacitor (B3290)			Saddle Brook - Athenia Upgrade Cable (B0472)			Branchburg-Sommerville-Flagtown Reconductor (B0664 & B0665)		
"Yes" if a project under PJM OATT Schedule 12, otherwise "No"														
Schedule 12		(Yes or No)	Yes			Yes			Yes			Yes		
Useful life of the project	Life		42			42			42			42		
"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		
Input the allowed increase in ROE	Increased ROE (Basis Points)		0			0			0			0		
From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.81%			9.81%			9.81%			9.81%		
Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.81%			9.81%			9.81%			9.81%		
Service Account 101 or 106 if not yet classified - End of year balance	Investment		21,163,173			77,234,030			14,404,842			18,664,931		
	Annual Depreciation or Amort.Exp													
Line 17 divided by line 12			503,885			1,838,905			342,972			444,403		
Months in service for depreciation expense from Year placed in Service (0 if CWIP)			13.00			13.00			13.00			13.00		
			2011			2012			2012			2012		
		Invest Yr.	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
	W 11.68 % ROE	2006												
	W Increased ROE	2006												
	W 11.68 % ROE	2007												
	W Increased ROE	2007												
	W 11.68 % ROE	2008												
	W Increased ROE	2008												
	W 11.68 % ROE	2009												
	W Increased ROE	2009												
	W 11.68 % ROE	2010												
	W Increased ROE	2010												
	W 11.68 % ROE	2011	20,511,158	37,566	284,735									
	W Increased ROE	2011	20,511,158	37,566	284,735									
	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
	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
	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
	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
	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
	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
	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
	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
	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
	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
	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
	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
	W 11.68 % ROE	2018	18,108,382	504,054	2,300,157	66,583,714	1,838,905	8,441,111	12,479,568	342,972	1,580,774	16,125,813	444,403	2,043,862
	W Increased ROE	2018	18,108,382	504,054	2,300,157	66,583,714	1,838,905	8,441,111	12,479,568	342,972	1,580,774	16,125,813	444,403	2,043,862
	W 11.68 % ROE	2019	17,597,228	503,885	1,926,706	64,724,808	1,838,905	7,072,218	12,136,595	342,972	1,324,275	15,681,410	444,403	1,712,321
	W Increased ROE	2019	17,597,228	503,885	1,926,706	64,724,808	1,838,905	7,072,218	12,136,595	342,972	1,324,275	15,681,410	444,403	1,712,321
	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
	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
	W 11.68 % ROE	2021	16,589,288	503,885	2,131,453	61,046,997	1,838,905	7,828,202	11,450,650	342,972	1,466,391	14,792,603	444,403	1,895,700
	W Increased ROE	2021	16,589,288	503,885	2,131,453	61,046,997	1,838,905	7,828,202	11,450,650	342,972	1,466,391	14,792,603	444,403	1,895,700

New Plant Carrying Charge

Fixed Charge Rate (FCR) if if not a CIAC

		Formula Line		
A	152	Net Plant Carrying Charge without Depreciation	9.81%
B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.42%
C		Line B less Line A	0.61%

FCR if a CIAC

D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.26%

The FCR resulting from Formula is 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.
Per FERC Order dated December 30, 2011 in Docket No. ER12-298, 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.
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		Sewaren-Bridgewater Reconductor (B1669)			New Essex-Kearny 138 kV circuit and Kearny 138 kV bus tie (B2614)			Salem 500 kV breakers (B1410-B1415)			230kV Lawrence Switching Station Upgrade (B1228)		
"Yes" if a project under PJM OATT Schedule 12, otherwise "No"													
Schedule 12	(Yes or No)	Yes			Yes			Yes			Yes		
Useful life of the project	Life	42			42			42			42		
"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	
Input the allowed increase in ROE	Increased ROE (Basis Points)	0			0			0			0		
From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE	9.81%			9.81%			9.81%			9.81%		
Line 14 plus (line 5 times line 15)/100	FCR for This Project	9.81%			9.81%			9.81%			9.81%		
Service Account 101 or 106 if not yet classified - End of year balance	Investment	6,390,403			45,985,436			15,865,267			21,732,218		
	Annual Depreciation or Amort Exp	152,152			1,094,891			377,744			517,434		
Line 17 divided by line 12													
Months in service for depreciation expense from Year placed in Service (0 if CWIP)		13.00			13.00			13.00			13.00		
		2012			2012			2011			2013		

	Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
W 11.68 % ROE	2006												
W Increased ROE	2006												
W 11.68 % ROE	2007												
W Increased ROE	2007												
W 11.68 % ROE	2008												
W Increased ROE	2008												
W 11.68 % ROE	2009												
W Increased ROE	2009												
W 11.68 % ROE	2010												
W Increased ROE	2010												
W 11.68 % ROE	2011							2,840,253	9,537	73,000			
W Increased ROE	2011							2,840,253	9,537	73,000			
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			
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			
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
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
W 11.68 % ROE	2014	6,181,910	151,180	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
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
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
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
W 11.68 % ROE	2016	5,877,066	152,152	824,687	42,862,264	1,096,665	5,978,667	14,899,633	378,036	2,083,057	20,438,822	517,546	2,856,436
W Increased ROE	2016	5,877,066	152,152	824,687	42,862,264	1,096,665	5,978,667	14,899,633	378,036	2,083,057	20,438,822	517,546	2,856,436
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
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
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
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
W 11.68 % ROE	2019	5,420,608	152,152	590,435	39,298,917	1,094,891	4,272,398	13,753,841	377,744	1,489,809	18,881,596	517,434	2,044,102
W Increased ROE	2019	5,420,608	152,152	590,435	39,298,917	1,094,891	4,272,398	13,753,841	377,744	1,489,809	18,881,596	517,434	2,044,102
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
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
W 11.68 % ROE	2021	5,116,303	152,152	654,111	13,232,586	1,094,891	2,393,133	13,232,586	377,744	1,675,986	17,846,729	517,434	2,268,369
W Increased ROE	2021	5,116,303	152,152	654,111	13,232,586	1,094,891	2,393,133	13,232,586	377,744	1,675,986	17,846,729	517,434	2,268,369

New Plant Carrying Charge

Fixed Charge Rate (FCR) if if not a CIAC

		Formula Line		
A	152	Net Plant Carrying Charge without Depreciation	9.81%
B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.42%
C		Line B less Line A	0.61%

FCR if a CIAC

D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.26%

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.
Per FERC Order dated December 30, 2011 in Docket No. ER12-256, 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.
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 5a, and Line 19 will be number of months to be amortized in year plus one.

Details		Branchburg-Middlesex Switch Rack (B1158)			Aldene-Springfield Rd. Conversion (B1399)			Upgrade Camden-Richmond 230kV Circuit (B1990)			Susquehanna Roseland Breakers (b0488.1-b0488.10)		
"Yes" if a project under PJM OATT Schedule 12, otherwise "No"													
Schedule 12	(Yes or No)	Yes			Yes			Yes			Yes		
Useful life of the project	Life	42			42			42			42		
"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 75, Otherwise "No"	CIAC	(Yes or No)	No			No			No			No	
Input the allowed increase in ROE	Increased ROE (Basis Points)		0			0			0			125	
From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.81%			9.81%			9.81%			9.81%	
Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.81%			9.81%			9.81%			10.57%	
Service Account 101 or 106 if not yet classified - End of year balance	Investment		62,938,142			72,364,662			11,276,183			5,857,687	
	Annual Depreciation or Amort Exp		1,498,527			1,722,968			268,481			139,469	
Line 17 divided by line 12													
Months in service for depreciation expense from Year placed in Service (0 if CWIP)			13.00			13.00			13.00			13.00	
			2013			2014			2014			2010	

		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
W	11.68 % ROE	2006												
W	Increased ROE	2006												
W	11.68 % ROE	2007												
W	Increased ROE	2007												
W	11.68 % ROE	2008												
W	Increased ROE	2008												
W	11.68 % ROE	2009												
W	Increased ROE	2009												
W	11.68 % ROE	2010										2,662,585	7,802	70,915
W	Increased ROE	2010										2,662,585	7,802	70,915
W	11.68 % ROE	2011										5,849,885	116,061	666,188
W	Increased ROE	2011										5,849,885	116,061	1,014,845
W	11.68 % ROE	2012										5,733,823	139,469	1,000,541
W	Increased ROE	2012										5,733,823	139,469	1,453,531
W	11.68 % ROE	2013	20,876,286	101,812	695,908							5,594,354	139,469	916,713
W	Increased ROE	2013	20,876,286	101,812	696,908							5,594,354	139,469	967,947
W	11.68 % ROE	2014	60,374,266	1,499,907	8,878,863	68,405,611	556,909	3,438,903	7,389,782	37,992	234,599	5,454,886	139,469	811,586
W	Increased ROE	2014	60,374,269	1,499,907	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
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	782,575
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
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
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
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
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
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
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
W	11.68 % ROE	2019	55,147,554	1,498,527	5,957,472	64,929,028	1,722,968	6,972,793	10,166,926	268,481	1,090,525	4,757,542	139,469	524,139
W	Increased ROE	2019	55,147,554	1,498,527	5,957,472	64,929,028	1,722,968	6,972,793	10,166,926	268,481	1,090,525	4,757,542	139,469	559,490
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
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
W	11.68 % ROE	2021	52,150,500	1,498,527	6,614,992	61,482,799	1,722,968	7,755,021	9,629,965	268,481	1,213,273	4,478,605	139,469	578,863
W	Increased ROE	2021	52,150,500	1,498,527	6,614,992	61,482,799	1,722,968	7,755,021	9,629,965	268,481	1,213,273	4,478,605	139,469	613,058

New Plant Carrying Charge

Fixed Charge Rate (FCR) if if not a CIAC

		Formula Line		
A	152	Net Plant Carrying Charge without Depreciation	9.81%
B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.42%
C		Line B less Line A	0.61%

FCR if a CIAC

D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.26%

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.
Per FERC Order dated December 20, 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.
For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects, Line 17 is the
12 month average balance from Attach 8a, and Line 19 will be number of months to be amortized in year plus one.

	Details		Susquehanna Roseland < 500KV (B0659.4)			Susquehanna Roseland > 500KV (B0459)			Burlington - Camden 230kV Conversion (B1156)			Mickleton-Gloucester-Camden(B1398-B1398.7)		
"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes			Yes			Yes			Yes		
Useful life of the project	Life		42			42			42			42		
"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 26. Otherwise "No"	CIAC	(Yes or No)	No			No			No			No		
Input the allowed increase in ROE	Increased ROE (Basis Points)		125			125			0			0		
From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.81%			9.81%			9.81%			9.81%		
Line 14 plus (line 5 times line 15/100	FCR for This Project		10.57%			10.57%			9.81%			9.81%		
Service Account 101 or 106 if not yet classified - End of year balance	Investment		40,538,248			721,910,808			356,574,888			436,447,199		
	Annual Depreciation or Amort Exp		965,196			17,188,353			8,489,878			10,439,219		
Months in service for depreciation expense from Year placed in Service (0 if CWIP)			13.00			13.00			13.00			13.00		
			2011			2012			2011			2013		
		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
	W 11.68 % ROE	2006												
	W Increased ROE	2006												
	W 11.68 % ROE	2007												
	W Increased ROE	2007												
	W 11.68 % ROE	2008												
	W Increased ROE	2008												
	W 11.68 % ROE	2009												
	W Increased ROE	2009												
	W 11.68 % ROE	2010												
	W Increased ROE	2010												
	W 11.68 % ROE	2011	7,844,331	111,778	905,626				19,902,939	147,204	1,150,144			
	W Increased ROE	2011	7,844,331	111,778	952,449				19,902,939	147,204	1,150,144			
	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			
	W Increased ROE	2012	7,628,074	184,491	1,389,745	4,694,511	8,598	66,040	19,848,511	475,501	3,452,558			
	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
	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
	W 11.68 % ROE	2014	40,067,737	717,210	4,387,056	666,963,000	10,160,548	69,693,814	333,325,376	6,107,990	37,392,933	83,696,796	854,944	5,279,191
	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
	W 11.68 % ROE	2015	39,365,526	965,196	5,579,888	711,440,230	16,714,518	97,780,768	346,271,067	8,256,393	47,814,854	436,685,203	6,739,741	39,857,912
	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
	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
	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
	W 11.68 % ROE	2017	37,435,134	965,196	5,163,491	677,132,437	17,186,557	93,125,945	330,033,398	8,484,132	45,496,882	420,701,437	10,447,458	57,628,494
	W Increased ROE	2017	37,435,134	965,196	5,487,093	677,132,437	17,186,557	98,979,324	330,033,398	8,484,132	45,496,882	420,701,437	10,447,458	57,628,494
	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
	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
	W 11.68 % ROE	2019	35,504,741	965,196	3,835,926	642,728,147	17,185,754	69,153,419	313,061,875	8,484,055	33,796,614	399,770,548	10,446,691	42,770,064
	W Increased ROE	2019	35,504,741	965,196	4,060,747	642,728,147	17,185,754	73,029,272	313,061,875	8,484,055	33,796,614	399,770,548	10,446,691	42,770,064
	W 11.68 % ROE	2020	34,539,544	965,196	3,389,360	625,620,033	17,187,848	60,890,593	304,580,993	8,484,132	29,916,276	389,587,112	10,452,951	37,986,044
	W Increased ROE	2020	34,539,544	965,196	4,549,433	625,620,033	17,187,848	82,109,464	304,580,993	8,484,132	37,827,676	389,587,112	10,452,951	47,986,044
	W 11.68 % ROE	2021	33,574,348	965,196	4,259,162	608,463,891	17,188,353	76,884,501	296,338,286	8,489,878	37,563,509	378,557,093	10,439,219	47,579,304
	W Increased ROE	2021	33,574,348	965,196	4,515,511	608,463,891	17,188,353	81,530,281	296,338,286	8,489,878	37,563,509	378,557,093	10,439,219	47,579,304

New Plant Carrying Charge

Fixed Charge Rate (FCR) if if not a CIAC

		Formula Line		
A	152	Net Plant Carrying Charge without Depreciation	9.81%
B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.42%
C		Line B less Line A	0.61%

FCR if a CIAC

D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.26%

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.
Per FERC Order dated December 30, 2011 in Docket No. ER12-266, 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.
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		North Central Reliability (West Orange Conversion (B1154)			Northeast Grid Reliability Project (B1204.1-B1204.4)			Northeast Grid Reliability Project (B1204.5-B1204.21)			Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades (B2436.10)		
"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes			Yes			Yes			Yes		
Useful life of the project	Life		42			42			42			42		
"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		
Input the allowed increase in ROE	Increased ROE (Basis Points)		0			25			25			0		
From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.81%			9.81%			9.81%			9.81%		
Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.81%			9.96%			9.96%			9.81%		
Service Account 101 or 106 if not yet classified - End of year balance	Investment		369,946,472			625,130,258			392,930,285			179,505,240		
Annual Depreciation or Amort Exp														
Line 17 divided by line 12			8,808,249			14,884,054			8,355,483			4,273,934		
Months in service for depreciation expense from Year placed in Service (0 if CWIP)			13.00			13.00			13.00			13.00		
			2012			2013			2016			2016		
		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
	W 11.68 % ROE	2006												
	W Increased ROE	2006												
	W 11.68 % ROE	2007												
	W Increased ROE	2007												
	W 11.68 % ROE	2008												
	W Increased ROE	2008												
	W 11.68 % ROE	2009												
	W Increased ROE	2009												
	W 11.68 % ROE	2010												
	W Increased ROE	2010												
	W 11.68 % ROE	2011												
	W Increased ROE	2011												
	W 11.68 % ROE	2012	16,441,748	30,113	220,046									
	W Increased ROE	2012	16,441,748	30,113	220,046									
	W 11.68 % ROE	2013	257,640,264	6,135,009	41,929,935	23,466,022	86,647	592,253						
	W Increased ROE	2013	257,640,264	6,135,009	41,929,935	23,466,022	86,647	598,801						
	W 11.68 % ROE	2014	360,673,484	7,742,954	47,135,528	274,113,325	2,382,627	14,884,013						
	W Increased ROE	2014	360,673,484	7,742,954	47,135,528	274,113,325	2,382,627	14,884,013						
	W 11.68 % ROE	2015	355,885,266	8,777,921	50,370,637	433,597,024	7,852,675	46,296,391						
	W Increased ROE	2015	355,885,266	8,777,921	50,370,637	433,597,024	7,852,675	46,859,053						
	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
	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
	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
	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
	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
	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
	W 11.68 % ROE	2019	320,836,205	8,808,249	34,749,401	572,230,626	14,884,041	61,151,642	325,852,479	8,355,470	34,700,595	168,462,457	4,271,090	17,892,091
	W Increased ROE	2019	320,836,205	8,808,249	34,749,401	572,230,626	14,884,041	62,002,045	325,852,479	8,355,470	35,194,920	168,462,457	4,271,090	17,892,091
	W 11.68 % ROE	2020	312,087,386	8,809,699	38,876,415	557,383,451	14,884,917	68,583,626	317,512,936	8,356,346	38,945,705	164,165,674	4,270,952	20,086,787
	W Increased ROE	2020	312,087,386	8,809,699	38,876,415	557,383,451	14,884,917	69,412,039	317,512,936	8,356,346	39,417,609	164,165,674	4,270,952	20,086,787
	W 11.68 % ROE	2021	303,218,257	8,808,249	38,556,871	542,462,214	14,884,054	68,104,804	309,121,209	8,355,483	38,683,241	160,039,881	4,273,934	19,975,383
	W Increased ROE	2021	303,218,257	8,808,249	38,556,871	542,462,214	14,884,054	68,933,172	309,121,209	8,355,483	39,155,285	160,039,881	4,273,934	19,975,383

New Plant Carrying Charge

Fixed Charge Rate (FCR) if if not a CIAC

		Formula Line		
A	152	Net Plant Carrying Charge without Depreciation	9.81%
B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.42%
C		Line B less Line A	0.61%

FCR if a CIAC

D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.26%

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.
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.
For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects. Line 17 is the
13 month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

	Details		Convert the 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)		
"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes			Yes			Yes			Yes		
Useful life of the project	Life		42			42			42			42		
"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 79 "Otherwise "No"	CIAC	(Yes or No)	No			No			No			No		
Input the allowed increase in ROE	Increased ROE (Basis Points)		0			0			0			0		
From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.81%			9.81%			9.81%			9.81%		
Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.81%			9.81%			9.81%			9.81%		
Service Account 101 or 106 if not yet classified - End of year balance	Investment		66,220,634			49,862,238			158,366,737			136,395,227		
	Annual Depreciation or Amort Exp													
Line 17 divided by line 12			1,576,682			1,163,863			3,770,637			3,007,029		
Months in service for depreciation expense from Year placed in Service (0 if CWIP)			13.00			13.00			13.00			13.00		
			2016			2016			2015			2018		

		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
W 11.68 % ROE		2006												
W Increased ROE		2006												
W 11.68 % ROE		2007												
W Increased ROE		2007												
W 11.68 % ROE		2008												
W Increased ROE		2008												
W 11.68 % ROE		2009												
W Increased ROE		2009												
W 11.68 % ROE		2010												
W Increased ROE		2010												
W 11.68 % ROE		2011												
W Increased ROE		2011												
W 11.68 % ROE		2012												
W Increased ROE		2012												
W 11.68 % ROE		2013												
W Increased ROE		2013												
W 11.68 % ROE		2014												
W Increased ROE		2014												
W 11.68 % ROE		2015							225,037	412	2,441			
W Increased ROE		2015							225,037	412	2,441			
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			
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			
W 11.68 % ROE		2017	42,938,400	916,068	5,198,758	24,558,823	583,272	3,294,965	14,747,154	214,998	1,226,916			
W Increased ROE		2017	42,938,400	916,068	5,198,758	24,558,823	583,272	3,294,965	14,747,154	214,998	1,226,916			
W 11.68 % ROE		2018	63,528,886	1,341,837	6,824,760	47,639,887	913,654	4,848,728	164,431,353	3,052,775	#########	125,948,110	2,038,280	10,529,391
W Increased ROE		2018	63,528,886	1,341,837	6,824,760	47,639,887	913,654	4,848,728	164,431,353	3,052,775	#########	125,948,110	2,038,280	10,529,391
W 11.68 % ROE		2019	63,619,714	1,576,203	6,720,163	47,047,242	1,163,502	4,967,498	155,088,856	3,770,600	#########	124,311,424	3,008,326	13,059,503
W Increased ROE		2019	63,619,714	1,576,203	6,720,163	47,047,242	1,163,502	4,967,498	155,088,856	3,770,600	#########	124,311,424	3,008,326	13,059,503
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	#########	121,342,718	3,008,244	14,698,486
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	#########	121,342,718	3,008,244	14,698,486
W 11.68 % ROE		2021	60,486,638	1,576,682	7,511,002	44,735,840	1,163,863	5,552,878	147,550,184	3,770,637	#########	118,240,376	3,007,029	14,607,545
W Increased ROE		2021	60,486,638	1,576,682	7,511,002	44,735,840	1,163,863	5,552,878	147,550,184	3,770,637	#########	118,240,376	3,007,029	14,607,545

New Plant Carrying Charge

Fixed Charge Rate (FCR) if if not a CIAC

		Formula Line		
A	152	Net Plant Carrying Charge without Depreciation	9.81%
B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.42%
C		Line B less Line A	0.61%

FCR if a CIAC

D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.26%

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.
Per FERC Order dated December 30, 2011 in Docket No. ER12-298, 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.
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 5a, and Line 19 will be number of months to be amortized in year plus one.

	Details		Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50)			Relocate the underground portion of North Ave - Linden "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.60)			Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades (B2436.70)			Relocate the overhead portion of Linden - North Ave "T" 138 kV circuit to Bayway, convert it to 345 kV, and any associated substation upgrades (B2436.61)		
"Yes" if a project under PJM OATT Schedule 12, otherwise "No"														
Schedule 12		(Yes or No)	Yes			Yes			Yes			Yes		
Useful life of the project			42			42			42			42		
"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		
Input the allowed increase in ROE	Increased ROE (Basis Points)		0			0			0			0		
From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.81%			9.81%			9.81%			9.81%		
Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.81%			9.81%			9.81%			9.81%		
Service Account 101 or 106 if not yet classified - End of year balance	Investment		65,231,920			43,000,622			81,612,264			54,736,672		
	Annual Depreciation or Amort Exp		1,553,141			1,028,586			1,943,149			1,303,254		
Line 17 divided by line 12														
Months in service for depreciation expense from Year placed in Service (0 if CWIP)			13.00			13.00			13.00			13.00		
			2018			2015			2015			2015		
		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
W 11.68 % ROE		2006												
W Increased ROE		2006												
W 11.68 % ROE		2007												
W Increased ROE		2007												
W 11.68 % ROE		2008												
W Increased ROE		2008												
W 11.68 % ROE		2009												
W Increased ROE		2009												
W 11.68 % ROE		2010												
W Increased ROE		2010												
W 11.68 % ROE		2011												
W Increased ROE		2011												
W 11.68 % ROE		2012												
W Increased ROE		2012												
W 11.68 % ROE		2013												
W Increased ROE		2013												
W 11.68 % ROE		2014												
W Increased ROE		2014				225,037	412	2,441	225,037	412	2,441	225,037	412	2,441
W 11.68 % ROE		2015				225,037	412	2,441	225,037	412	2,441	225,037	412	2,441
W Increased ROE		2015				349,923	8,202	47,577	349,923	8,202	47,577	723,468	12,273	71,227
W 11.68 % ROE		2016				349,923	8,202	47,577	349,923	8,202	47,577	723,468	12,273	71,227
W Increased ROE		2016				14,747,154	214,966	1,226,916	14,747,154	214,966	1,226,916	31,239,305	465,743	2,658,611
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
W Increased ROE		2017				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
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
W Increased ROE		2018	65,344,588	975,261	5,038,025	41,230,429	1,008,245	4,341,924	79,917,459	1,942,136	8,403,848	53,142,652	1,303,271	5,600,110
W 11.68 % ROE		2019	64,723,840	1,564,264	6,797,498	41,230,429	1,008,245	4,341,924	79,917,459	1,942,136	8,403,848	53,142,652	1,303,271	5,600,110
W Increased ROE		2019	64,723,840	1,564,264	6,797,498	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
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
W Increased ROE		2020	63,125,038	1,563,429	7,644,939	40,065,281	1,028,586	4,959,375	76,076,534	1,943,149	9,406,987	50,533,472	1,303,254	6,261,073
W 11.68 % ROE		2021	61,128,965	1,553,141	7,550,479	40,065,281	1,028,586	4,959,375	76,076,534	1,943,149	9,406,987	50,533,472	1,303,254	6,261,073
W Increased ROE		2021	61,128,965	1,553,141	7,550,479	40,065,281	1,028,586	4,959,375	76,076,534	1,943,149	9,406,987	50,533,472	1,303,254	6,261,073

New Plant Carrying Charge

Fixed Charge Rate (FCR) if if not a CIAC

		Formula Line		
	A	152	Net Plant Carrying Charge without Depreciation	9.81%
	B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.42%
	C		Line B less Line A	0.61%

FCR if a CIAC

	D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.26%

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.
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.
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 5a, and Line 19 will be number of months to be amortized in year plus one.

	Details		Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.83)			Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.84)			Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades (B2436.85)			Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades (B2436.90)		
"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes			Yes			Yes			Yes		
Useful life of the project	Life		42			42			42			42		
"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 79, Otherwise "No"	CIAC	(Yes or No)	No			No			No			No		
Input the allowed increase in ROE	Increased ROE (Basis Points)		0			0			0			0		
From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.81%			9.81%			9.81%			9.81%		
Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.81%			9.81%			9.81%			9.81%		
Service Account 101 or 106 if not yet classified - End of year balance	Investment		54,736,672			53,301,490			53,301,490			31,275,395		
	Annual Depreciation or Amort Exp													
Line 17 divided by line 12			1,303,254			1,269,083			1,269,083			744,602		
Months in service for depreciation expense from Year placed in Service (0 if CWIP)			13.00			13.00			13.00			13.00		
			2015			2015			2015			2016		
		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
	W 11.68 % ROE	2006												
	W Increased ROE	2006												
	W 11.68 % ROE	2007												
	W Increased ROE	2007												
	W 11.68 % ROE	2008												
	W Increased ROE	2008												
	W 11.68 % ROE	2009												
	W Increased ROE	2009												
	W 11.68 % ROE	2010												
	W Increased ROE	2010												
	W 11.68 % ROE	2011												
	W Increased ROE	2011												
	W 11.68 % ROE	2012												
	W Increased ROE	2012												
	W 11.68 % ROE	2013												
	W Increased ROE	2013												
	W 11.68 % ROE	2014												
	W Increased ROE	2014												
	W 11.68 % ROE	2015	225,037	412	2,441	225,037	412	2,441	225,037	412	2,441			
	W Increased ROE	2015	225,037	412	2,441	225,037	412	2,441	225,037	412	2,441			
	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
	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
	W 11.68 % ROE	2017	31,239,305	465,743	2,658,611	43,917,206	652,295	3,723,670	43,917,206	652,295	3,723,870	30,818,452	697,633	3,942,807
	W Increased ROE	2017	31,239,305	465,743	2,658,611	43,917,206	652,295	3,723,670	43,917,206	652,295	3,723,870	30,818,452	697,633	3,942,807
	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
	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
	W 11.68 % ROE	2019	53,142,652	1,303,271	5,600,110	51,558,311	1,269,416	5,438,154	51,558,310	1,269,416	5,438,154	29,437,483	744,445	3,124,607
	W Increased ROE	2019	53,142,652	1,303,271	5,600,110	51,558,311	1,269,416	5,438,154	51,558,310	1,269,416	5,438,154	29,437,483	744,445	3,124,607
	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
	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
	W 11.68 % ROE	2021	50,533,472	1,303,254	6,261,073	49,002,904	1,269,083	6,076,738	50,534,172	1,269,083	6,226,970	27,955,217	744,602	3,487,278
	W Increased ROE	2021	50,533,472	1,303,254	6,261,073	49,002,904	1,269,083	6,076,738	50,534,172	1,269,083	6,226,970	27,955,217	744,602	3,487,278

New Plant Carrying Charge

Fixed Charge Rate (FCR) if not a CIAC

		Formula Line		
A	152	Net Plant Carrying Charge without Depreciation	9.81%
B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.42%
C		Line B less Line A	0.61%

FCR if a CIAC

D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.26%

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.
Per FERC Order dated December 30, 2011 in Docket No. ER12-256, 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.
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. 8a, and Line 19 will be number of months to be amortized in year plus one.

	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)
"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes	Yes	Yes
Useful life of the project	Life		42	42	42	42
"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
Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0	0	0
From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.81%	9.81%	9.81%	9.81%
Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.81%	9.81%	9.81%	9.81%
Service Account 101 or 106 if not yet classified - End of year balance	Investment		24,999,416	27,869,743	27,869,743	9,121,932
Line 17 divided by line 12	Annual Depreciation or Amort Exp		595,224	663,565	663,565	217,189
Months in service for depreciation expense from Year placed in Service (0 if CWIP)			13.00	13.00	13.00	13.00
			2016	2016	2016	2016

		Invest Yr.	Depreciation or Amortization Ending	Depreciation or Amortization	Revenue	Depreciation or Amortization Ending	Depreciation or Amortization	Revenue	Depreciation or Amortization Ending	Depreciation or Amortization	Revenue	Depreciation or Amortization Ending	Depreciation or Amortization	Revenue
W 11.68 % ROE		2006												
W Increased ROE		2006												
W 11.68 % ROE		2007												
W Increased ROE		2007												
W 11.68 % ROE		2008												
W Increased ROE		2008												
W 11.68 % ROE		2009												
W Increased ROE		2009												
W 11.68 % ROE		2010												
W Increased ROE		2010												
W 11.68 % ROE		2011												
W Increased ROE		2011												
W 11.68 % ROE		2012												
W Increased ROE		2012												
W 11.68 % ROE		2013												
W Increased ROE		2013												
W 11.68 % ROE		2014												
W Increased ROE		2014												
W 11.68 % ROE		2015										225,037	412	2,441
W Increased ROE		2015										225,037	412	2,441
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
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
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
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
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
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
W 11.68 % ROE		2019	23,492,880	595,067	2,494,579	26,176,377	664,200	2,780,686	26,176,377	664,200	2,780,686	8,493,462	216,271	903,008
W Increased ROE		2019	23,492,880	595,067	2,494,579	26,176,377	664,200	2,780,686	26,176,377	664,200	2,780,686	8,493,462	216,271	903,008
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
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
W 11.68 % ROE		2021	22,309,370	595,224	2,783,988	24,821,405	663,565	3,098,783	24,821,405	663,565	3,098,783	8,100,277	217,189	1,011,904
W Increased ROE		2021	22,309,370	595,224	2,783,988	24,821,405	663,565	3,098,783	24,821,405	663,565	3,098,783	8,100,277	217,189	1,011,904

New Plant Carrying Charge

Fixed Charge Rate (FCR) if if not a CIAC

		Formula Line		
A	152	Net Plant Carrying Charge without Depreciation	9.81%
B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.42%
C		Line B less Line A	0.61%

FCR if a CIAC

D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.26%

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.
Per FERC Order dated December 30, 2011 in Docket No. ER12-295, 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.
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		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)		
"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes			Yes			Yes			Yes		
Useful life of the project	Life		42			42			42			42		
"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 70 Otherwise "No"	CIAC	(Yes or No)	No			No			No			No		
Input the allowed increase in ROE	Increased ROE (Basis Points)		0			0			0			0		
From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.81%			9.81%			9.81%			9.81%		
Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.81%			9.81%			9.81%			9.81%		
Service Account 101 or 106 if not yet classified - End of year balance	Investment		9,121,932			33,717,092			14,557,847			12,087,910		
	Annual Depreciation or Amort Exp		217,189			802,788			346,615			287,800		
Line 17 divided by line 12														
Months in service for depreciation expense from Year placed in Service (0 if CWIP)			13.00			13.00			13.00			13.00		
			2015			2016			2018			2015		
		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
W 11.68 % ROE		2006												
W Increased ROE		2006												
W 11.68 % ROE		2007												
W Increased ROE		2007												
W 11.68 % ROE		2008												
W Increased ROE		2008												
W 11.68 % ROE		2009												
W Increased ROE		2009												
W 11.68 % ROE		2010												
W Increased ROE		2010												
W 11.68 % ROE		2011												
W Increased ROE		2011												
W 11.68 % ROE		2012												
W Increased ROE		2012												
W 11.68 % ROE		2013												
W Increased ROE		2013												
W 11.68 % ROE		2014												
W Increased ROE		2014												
W 11.68 % ROE		2015	225,037	412	2,441							11,980,348	216,491	1,282,387
W Increased ROE		2015	225,037	412	2,441							11,980,348	216,491	1,282,387
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
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
W 11.68 % ROE		2017	14,750,613	214,998	1,227,153	18,339,519	295,246	1,684,077				11,583,248	287,798	1,586,839
W Increased ROE		2017	14,750,613	214,998	1,227,153	18,339,519	295,246	1,684,077				11,583,248	287,798	1,586,839
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
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
W 11.68 % ROE		2019	8,493,184	216,271	902,986	32,978,842	804,041	3,470,539	14,358,538	347,188	1,508,145	11,007,878	287,800	1,177,840
W Increased ROE		2019	8,493,184	216,271	902,986	32,978,842	804,041	3,470,539	14,358,538	347,188	1,508,145	11,007,878	287,800	1,177,840
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
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
W 11.68 % ROE		2021	8,099,999	217,189	1,011,877	31,316,802	802,788	3,875,267	13,640,316	346,615	1,684,861	10,432,277	287,800	1,311,307
W Increased ROE		2021	8,099,999	217,189	1,011,877	31,316,802	802,788	3,875,267	13,640,316	346,615	1,684,861	10,432,277	287,800	1,311,307

New Plant Carrying Charge

Fixed Charge Rate (FCR) if if not a CIAC

		Formula Line		
A	152	Net Plant Carrying Charge without Depreciation	9.81%
B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.42%
C		Line B less Line A	0.61%

FCR if a CIAC

D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.26%

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.
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.
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 5a, and Line 19 will be number of months to be amortized in year plus one.

	Details		Mickleton-Gloucester 230kV Circuit (B2139)			Ridge Road 69kV Breaker Station (B1698)			Cox's Corner-Lumberton 230kV Circuit (B1787)			Sewaren Switch 230kV Conversion (B2276)		
"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes			Yes			Yes			Yes		
Useful life of the project	Life		42			42			42			42		
"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 39 (Otherwise "No"	CIAC	(Yes or No)	No			No			No			No		
Input the allowed increase in ROE	Increased ROE (Basis Points)		0			0			0			0		
From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.81%			9.81%			9.81%			9.81%		
Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.81%			9.81%			9.81%			9.81%		
Service Account 101 or 106 if not yet classified - End of year balance	Investment		19,515,077			43,352,771			32,029,640			0		
Line 17 divided by line 12	Annual Depreciation or Amort Exp.		464,645			1,029,828			762,610			0		
Months in service for depreciation expense from Year placed in Service (0 if CWIP)			13.00			13.00			13.00					
			2015			2016			2015			2015		
		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
W 11.68 % ROE		2006												
W Increased ROE		2006												
W 11.68 % ROE		2007												
W Increased ROE		2007												
W 11.68 % ROE		2008												
W Increased ROE		2008												
W 11.68 % ROE		2009												
W Increased ROE		2009												
W 11.68 % ROE		2010												
W Increased ROE		2010												
W 11.68 % ROE		2011												
W Increased ROE		2011												
W 11.68 % ROE		2012												
W Increased ROE		2012												
W 11.68 % ROE		2013												
W Increased ROE		2013												
W 11.68 % ROE		2014												
W Increased ROE		2014												
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
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
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
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
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
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
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
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
W 11.68 % ROE		2019	17,900,855	464,645	1,912,015	41,752,538	1,026,780	4,402,674	29,548,520	762,610	3,151,751	0	0	0
W Increased ROE		2019	17,900,855	464,645	1,912,015	41,752,538	1,026,780	4,402,674	29,548,520	762,610	3,151,751	0	0	0
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
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
W 11.68 % ROE		2021	16,971,565	464,645	2,129,718	39,828,478	1,029,828	4,937,384	28,023,299	762,610	3,511,965	0	0	0
W Increased ROE		2021	16,971,565	464,645	2,129,718	39,828,478	1,029,828	4,937,384	28,023,299	762,610	3,511,965	0	0	0

New Plant Carrying Charge

Fixed Charge Rate (FCR) if not a CIAC

		Formula Line		
A	152	Net Plant Carrying Charge without Depreciation	9.81%
B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.42%
C		Line B less Line A	0.61%

FCR if a CIAC

D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.26%

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.
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.
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. 8a, and Line 19 will be number of months to be amortized in year plus one.

	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)		
"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes			Yes			Yes			Yes		
Useful life of the project	Life		42			42			42			42		
"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		
Input the allowed increase in ROE	Increased ROE (Basis Points)		0			0			0			0		
From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.81%			9.81%			9.81%			9.81%		
Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.81%			9.81%			9.81%			9.81%		
Service Account 101 or 106 if not yet classified - End of year balance	Investment		1,108,058			22,983,708			157,750,572			22,307,024		
	Annual Depreciation or Amort Exp													
Line 17 divided by line 12			26,382			525,326			3,755,966			531,120		
Months in service for depreciation expense from Year placed in Service (0 if CWIP)			13.00			13.00			13.00			13.00		
			2016			2016			2017			2018		
				Depreciation or			Depreciation or			Depreciation or			Depreciation or	
		Invest Yr	Ending	Amortization	Revenue	Ending	Amortization	Revenue	Ending	Amortization	Revenue	Ending	Amortization	Revenue
	W 11.68 % ROE	2006												
	W Increased ROE	2006												
	W 11.68 % ROE	2007												
	W Increased ROE	2007												
	W 11.68 % ROE	2008												
	W Increased ROE	2008												
	W 11.68 % ROE	2009												
	W Increased ROE	2009												
	W 11.68 % ROE	2010												
	W Increased ROE	2010												
	W 11.68 % ROE	2011												
	W Increased ROE	2011												
	W 11.68 % ROE	2012												
	W Increased ROE	2012												
	W 11.68 % ROE	2013												
	W Increased ROE	2013												
	W 11.68 % ROE	2014												
	W Increased ROE	2014												
	W 11.68 % ROE	2015												
	W Increased ROE	2015												
	W 11.68 % ROE	2016	1,108,058	26,382	153,181									
	W Increased ROE	2016	1,108,058	26,382	153,181									
	W 11.68 % ROE	2017	1,081,675	26,382	147,691	2,060,982	3,775	21,554	75,384,047	433,473	2,475,231			
	W Increased ROE	2017	1,081,675	26,382	147,691	2,060,982	3,775	21,554	75,384,047	433,473	2,475,231			
	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
	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
	W 11.68 % ROE	2019	1,028,911	26,382	109,575	21,673,168	525,383	2,277,763	154,955,597	3,754,475	16,283,381	21,945,167	531,120	2,305,492
	W Increased ROE	2019	1,028,911	26,382	109,575	21,673,168	525,383	2,277,763	154,955,597	3,754,475	16,283,381	21,945,167	531,120	2,305,492
	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
	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
	W 11.68 % ROE	2021	976,146	26,382	122,152	20,619,056	525,326	2,548,254	147,516,268	3,755,966	18,228,728	20,885,059	531,120	2,580,144
	W Increased ROE	2021	976,146	26,382	122,152	20,619,056	525,326	2,548,254	147,516,268	3,755,966	18,228,728	20,885,059	531,120	2,580,144

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	9.81%
4		B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.42%
5		C		Line B less Line A	0.61%
6	**FCR if a CIAC**				
7		D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.26%
8				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.	
9				Per FERC Order dated December 30, 2011 in Docket No. ER12-256, 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. 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. 8a, and Line 19 will be number of months to be amortized in year plus one.	

				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 (B2950)			Roseland-Branchburg 230kV corridor rebuild (Readington - Branchburg) (b2866.12)		
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 39, 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		9.81%			9.81%			9.81%			9.81%		
16	Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.81%			9.81%			9.81%			9.81%		
17	Service Account 101 or 106 if not yet classified - End of year balance	Investment		41,811,787			58,285,249			97,815,766			489,663		
18	Line 17 divided by line 12	Annual Depreciation or Amort Exp		995,519			1,387,744			2,328,947			11,663		
19	Months in service for depreciation expense from Year placed in Service (0 if CWIP)			10.23			12.82			12.93			7.60		
20				2020			2020			2020			2021		
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												
48		W 11.68 % ROE	2019												
49		W Increased ROE	2019												
50		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			
51		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			
52		W 11.68 % ROE	2021	41,788,014	783,226	4,008,756	58,187,916	1,368,036	6,995,758	97,058,738	2,316,766	11,789,355	489,863	6,276	32,139
53		W Increased ROE	2021	41,788,014	783,226	4,008,756	58,187,916	1,368,036	6,995,758	97,058,738	2,316,766	11,789,355	489,863	6,276	32,139

New Plant Carrying Charge

Fixed Charge Rate (FCR) if if not a CIAC

		Formula Line		
A	152	Net Plant Carrying Charge without Depreciation	9.81%
B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.42%
C		Line B less Line A	0.61%

FCR if a CIAC

D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.26%

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.
Per FERC Order dated December 30, 2011 in Docket No. ER12-298, 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.
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 5a, and Line 19 will be number of months to be amortized in year plus one.

	Details		Branchburg-Pleasant Valley 230kV corridor rebuild (Branchburg - East Flemington) (b2866.21)			Convert the R-1318 and Q1317 (Edison - Metuchen) 138 kV circuits to one 230 kV circuit (Brunswick - Meadow Road) (b2835.1)			Convert the R-1318 and Q1317 (Edison - Metuchen) 138 kV circuits to one 230 kV circuit (Meadow Road - Pierson Ave) (b2835.2)			Convert the R-1318 and Q1317 (Edison - Metuchen) 138 kV circuits to one 230 kV circuit (Pierson Ave - Metuchen) (B2835.3)		
"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes			Yes			Yes			Yes		
Useful life of the project	Life		42			42			42			42		
"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		
Input the allowed increase in ROE	Increased ROE (Basis Points)		0			0			0			0		
From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.81%			9.81%			9.81%			9.81%		
Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.81%			9.81%			9.81%			9.81%		
Service Account 101 or 106 if not yet classified - End of year balance	Investment		52,106,859			88,399,297			56,043,073			8,643,783		
Line 17 divided by line 12	Annual Depreciation or Amort Exp		1,240,640			2,104,745			1,334,359			205,804		
Months in service for depreciation expense from Year placed in Service (0 if CWIP)			6.64			12.99			12.99			12.97		
			2021			2018			2018			2019		
		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
	W 11.68 % ROE	2006												
	W Increased ROE	2006												
	W 11.68 % ROE	2007												
	W Increased ROE	2007												
	W 11.68 % ROE	2008												
	W Increased ROE	2008												
	W 11.68 % ROE	2009												
	W Increased ROE	2009												
	W 11.68 % ROE	2010												
	W Increased ROE	2010												
	W 11.68 % ROE	2011												
	W Increased ROE	2011												
	W 11.68 % ROE	2012												
	W Increased ROE	2012												
	W 11.68 % ROE	2013												
	W Increased ROE	2013												
	W 11.68 % ROE	2014												
	W Increased ROE	2014												
	W 11.68 % ROE	2015												
	W Increased ROE	2015												
	W 11.68 % ROE	2016												
	W Increased ROE	2016												
	W 11.68 % ROE	2017												
	W Increased ROE	2017												
	W 11.68 % ROE	2018				2,659,068	37,193	192,131	2,659,068	37,193	192,131			
	W Increased ROE	2018				2,659,068	37,193	192,131	2,659,068	37,193	192,131			
	W 11.68 % ROE	2019				83,079,277	1,184,132	5,203,531	52,624,372	765,680	3,364,016	7,960,942	114,708	504,244
	W Increased ROE	2019				83,079,277	1,184,132	5,203,531	52,624,372	765,680	3,364,016	7,960,942	114,708	504,244
	W 11.68 % ROE	2020				84,517,903	2,025,164	10,102,188	53,589,876	1,284,705	6,405,834	7,975,324	191,040	953,080
	W Increased ROE	2020				84,517,903	2,025,164	10,102,188	53,589,876	1,284,705	6,405,834	7,975,324	191,040	953,080
	W 11.68 % ROE	2021	52,106,859	633,250	3,242,623	85,152,808	2,103,074	10,450,746	53,965,496	1,333,293	6,622,614	8,338,035	205,308	1,021,376
	W Increased ROE	2021	52,106,859	633,250	3,242,623	85,152,808	2,103,074	10,450,746	53,965,496	1,333,293	6,622,614	8,338,035	205,308	1,021,376

New Plant Carrying Charge

Fixed Charge Rate (FCR) if not a CIAC

		Formula Line		
A	152	Net Plant Carrying Charge without Depreciation	9.81%
B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.42%
C		Line B less Line A	0.61%

FCR if a CIAC

D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.26%

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.
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.
For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects. Line 17 is the
13-month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

	Details		Convert the N-1340 and T-1372/D-1330 (Brunswick - Trenton) 138 kV circuits to 230 kV circuits (Hunterglen - Trenton) (B2836.2)			Convert the N-1340 and T-1372/D-1330 (Brunswick - Trenton) 138 kV circuits to 230 kV circuits (Brunswick - Devila Brook) (B2836.3)			Convert the N-1340 and T-1372/D-1330 (Brunswick - Trenton) 138 kV circuits to 230 kV circuits (Devila Brook - Trenton) (B2836.4)			Convert the F-1368/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Trenton - Yardville K) (B2837.1)		
"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes			Yes			Yes			Yes		
Useful life of the project	Life		42			42			42			42		
"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 20, Otherwise "No"	CIAC	(Yes or No)	No			No			No			No		
Input the allowed increase in ROE	Increased ROE (Basis Points)		0			0			0			0		
From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.81%			9.81%			9.81%			9.81%		
Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.81%			9.81%			9.81%			9.81%		
Service Account 101 or 106 if not yet classified - End of year balance	Investment		77,607,835			50,859,876			97,374,335			34,796,685		
	Annual Depreciation or Amort Exp													
Line 17 divided by line 12			1,852,568			1,209,997			2,318,436			826,493		
Months in service for depreciation expense from Year placed in Service (0 if CWIP)			12.97			12.97			12.97			11.60		
			2018			2019			2019			2017		
		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
	W 11.68 % ROE	2006												
	W Increased ROE	2006												
	W 11.68 % ROE	2007												
	W Increased ROE	2007												
	W 11.68 % ROE	2008												
	W Increased ROE	2008												
	W 11.68 % ROE	2009												
	W Increased ROE	2009												
	W 11.68 % ROE	2010												
	W Increased ROE	2010												
	W 11.68 % ROE	2011												
	W Increased ROE	2011												
	W 11.68 % ROE	2012												
	W Increased ROE	2012												
	W 11.68 % ROE	2013												
	W Increased ROE	2013												
	W 11.68 % ROE	2014												
	W Increased ROE	2014												
	W 11.68 % ROE	2015												
	W Increased ROE	2015												
	W 11.68 % ROE	2016												
	W Increased ROE	2016												
	W 11.68 % ROE	2017										450,604	1,558	8,895
	W Increased ROE	2017										450,604	1,558	8,895
	W 11.68 % ROE	2018	572,884	8,389	43,336							449,046	10,729	55,268
	W Increased ROE	2018	572,884	8,389	43,336							449,046	10,729	55,268
	W 11.68 % ROE	2019	36,080,098	350,313	1,539,666	25,358,212	303,797	1,335,462	47,846,023	509,593	2,240,121	10,016,807	91,099	400,083
	W Increased ROE	2019	36,080,098	350,313	1,539,666	25,358,212	303,797	1,335,462	47,846,023	509,593	2,240,121	10,016,807	91,099	400,083
	W 11.68 % ROE	2020	67,121,246	1,348,583	6,776,955	44,907,790	911,361	4,574,715	86,829,603	1,756,235	8,821,825	23,872,589	343,139	1,725,514
	W Increased ROE	2020	67,121,246	1,348,583	6,776,955	44,907,790	911,361	4,574,715	86,829,603	1,756,235	8,821,825	23,872,589	343,139	1,725,514
	W 11.68 % ROE	2021	76,100,549	1,847,729	9,294,426	49,604,718	1,206,850	6,060,893	95,108,497	2,312,363	11,618,974	34,350,161	739,204	3,746,086
	W Increased ROE	2021	76,100,549	1,847,729	9,294,426	49,604,718	1,206,850	6,060,893	95,108,497	2,312,363	11,618,974	34,350,161	739,204	3,746,086

New Plant Carrying Charge

Fixed Charge Rate (FCR) if not a CIAC

		Formula Line		
A	152	Net Plant Carrying Charge without Depreciation	9.81%
B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.42%
C		Line B less Line A	0.61%

FCR if a CIAC

D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.26%

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.
Per FERC Order dated December 30, 2011 in Docket No. ER13-296, 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.
For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects. Line 17 is the
13-month average balance from Attach 6a, and Line 19 will be number of months to be amortized in year plus one.

	Details		Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Yardville - Ward Ave K) (B2837.2)			Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton – Burlington) 138 kV circuits to 230 kV circuits (Ward Ave - Crosswicks Y) (B2837.3)			Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton – Burlington) 138 kV circuits to 230 kV circuits (Crosswicks - Bustleton Y) (B2837.4)			Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton – Burlington) 138 kV circuits to 230 kV circuits (Bustleton - Burlington Y) (B2837.5)		
"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes			Yes			Yes			Yes		
Useful life of the project	Life		42			42			42			42		
"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		
Input the allowed increase in ROE	Increased ROE (Basis Points)		0			0			0			0		
From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.81%			9.81%			9.81%			9.81%		
Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.81%			9.81%			9.81%			9.81%		
Service Account 101 or 106 if not yet classified - End of year balance	Investment		11,645,817			8,152,734			31,599,476			33,160,434		
	Annual Depreciation or Amort Exp													
Line 17 divided by line 12			277,281			194,113			752,369			788,106		
Months in service for depreciation expense from Year placed in Service (0 if CWIP)			11.85			11.66			10.48			10.28		
			2017			2019			2019			2019		
				Depreciation or			Depreciation or			Depreciation or			Depreciation or	
		Invest Yr	Ending	Amortization	Revenue	Ending	Amortization	Revenue	Ending	Amortization	Revenue	Ending	Amortization	Revenue
	W 11.68 % ROE	2006												
	W Increased ROE	2006												
	W 11.68 % ROE	2007												
	W Increased ROE	2007												
	W 11.68 % ROE	2008												
	W Increased ROE	2008												
	W 11.68 % ROE	2009												
	W Increased ROE	2009												
	W 11.68 % ROE	2010												
	W Increased ROE	2010												
	W 11.68 % ROE	2011												
	W Increased ROE	2011												
	W 11.68 % ROE	2012												
	W Increased ROE	2012												
	W 11.68 % ROE	2013												
	W Increased ROE	2013												
	W 11.68 % ROE	2014												
	W Increased ROE	2014												
	W 11.68 % ROE	2015												
	W Increased ROE	2015												
	W 11.68 % ROE	2016												
	W Increased ROE	2016												
	W 11.68 % ROE	2017	450,604	1,558	8,895									
	W Increased ROE	2017	450,604	1,558	8,895									
	W 11.68 % ROE	2018	449,046	10,729	55,268									
	W Increased ROE	2018	449,046	10,729	55,268									
	W 11.68 % ROE	2019	1,267,006	24,388	106,413	1,452,159	32,211	141,595	3,578,094	36,104	158,711	2,125,935	3,894	17,116
	W Increased ROE	2019	1,267,006	24,388	106,413	1,452,159	32,211	141,595	3,578,094	36,104	158,711	2,125,935	3,894	17,116
	W 11.68 % ROE	2020	8,285,191	75,087	377,575	6,269,759	46,817	235,295	18,465,043	127,407	641,952	18,342,368	95,983	484,283
	W Increased ROE	2020	8,285,191	75,087	377,575	6,269,759	46,817	235,295	18,465,043	127,407	641,952	18,342,368	95,983	484,283
	W 11.68 % ROE	2021	11,534,055	252,802	1,284,501	8,073,707	174,152	884,806	31,435,966	606,781	3,094,144	33,000,558	623,331	3,184,082
	W Increased ROE	2021	11,534,055	252,802	1,284,501	8,073,707	174,152	884,806	31,435,966	606,781	3,094,144	33,000,558	623,331	3,184,082

New Plant Carrying Charge

Fixed Charge Rate (FCR) if if not a CIAC

	Formula Line		
A	152	Net Plant Carrying Charge without Depreciation	9.81%
B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.42%
C		Line B less Line A	0.61%

FCR if a CIAC

D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.26%

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.
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.
For abandoned plant lines 12, 14, 15, and 16 will be from Attachment 5 - Abandoned Transmission Projects. Line 17 is the
12 month average balance from Attach 8a, and Line 19 will be number of months to be amortized in year plus one.

	Details		Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Trenton - Yardville F) (B2837.6)			Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Yardville - Ward Ave F) (B2837.7)			Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Ward Ave - Crosswicks Z) (B2837.8)			Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Crosswicks - Williams Z) (B2837.9)		
"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes			Yes			Yes			Yes		
Useful life of the project	Life		42			42			42			42		
"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		
Input the allowed increase in ROE	Increased ROE (Basis Points)		0			0			0			0		
From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.81%			9.81%			9.81%			9.81%		
Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.81%			9.81%			9.81%			9.81%		
Service Account 101 or 106 if not yet classified - End of year balance	Investment		34,665,190			11,283,048			8,152,734			3,030,513		
Line 17 divided by line 12	Annual Depreciation or Amort Exp		825,362			268,168			194,113			72,155		
Months in service for depreciation expense from Year placed in Service (0 if CWIP)			11.59			11.81			11.66			11.61		
			2019			2019			2019			2019		
		Invest Yr	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue	Ending	Depreciation or Amortization	Revenue
	W 11.68 % ROE	2006												
	W Increased ROE	2006												
	W 11.68 % ROE	2007												
	W Increased ROE	2007												
	W 11.68 % ROE	2008												
	W Increased ROE	2008												
	W 11.68 % ROE	2009												
	W Increased ROE	2009												
	W 11.68 % ROE	2010												
	W Increased ROE	2010												
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	W Increased ROE	2014												
	W 11.68 % ROE	2015												
	W Increased ROE	2015												
	W 11.68 % ROE	2016												
	W Increased ROE	2016												
	W 11.68 % ROE	2017												
	W Increased ROE	2017												
	W 11.68 % ROE	2018												
	W Increased ROE	2018												
	W 11.68 % ROE	2019	9,578,489	80,370	353,300	828,688	13,660	60,047	1,452,159	32,211	141,595	1,452,159	32,211	141,595
	W Increased ROE	2019	9,578,489	80,370	353,300	828,688	13,660	60,047	1,452,159	32,211	141,595	1,452,159	32,211	141,595
	W 11.68 % ROE	2020	23,445,000	332,410	1,672,767	7,857,602	64,359	324,322	6,269,759	46,817	235,295	2,291,699	38,046	189,882
	W Increased ROE	2020	23,445,000	332,410	1,672,767	7,857,602	64,359	324,322	6,269,759	46,817	235,295	2,291,699	38,046	189,882
	W 11.68 % ROE	2021	34,252,410	736,074	3,733,024	11,185,030	243,688	1,240,875	8,073,707	174,152	884,806	2,960,257	64,423	323,731
	W Increased ROE	2021	34,252,410	736,074	3,733,024	11,185,030	243,688	1,240,875	8,073,707	174,152	884,806	2,960,257	64,423	323,731

New Plant Carrying Charge

Fixed Charge Rate (FCR) if if not a CIAC

		Formula Line		
A	152	Net Plant Carrying Charge without Depreciation	9.81%
B	159	Net Plant Carrying Charge per 100 Basis Point in ROE without Depreciation	10.42%
C		Line B less Line A	0.61%

FCR if a CIAC

D	153	Net Plant Carrying Charge without Depreciation, Return, nor Income Taxes	1.26%

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.
Per FERC Order dated December 30, 2011 in Docket No. ER12-286, 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.
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 5a, and Line 19 will be number of months to be amortized in year plus one.

	Details		Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Williams - Bustleton Z) (B2837.10)	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Bustleton - Burlington Z) (B2837.11)
"Yes" if a project under PJM OATT Schedule 12, otherwise "No"	Schedule 12	(Yes or No)	Yes	Yes
Useful life of the project	Life		42	42
"Yes" if the customer has paid a lumpsum payment in the amount of the investment on line 20, Otherwise "No"	CIAC	(Yes or No)	No	No
Input the allowed increase in ROE	Increased ROE (Basis Points)		0	0
From line 3 above if "No" on line 13 and From line 7 above if "Yes" on line 13	11.68% ROE		9.81%	9.81%
Line 14 plus (line 5 times line 15)/100	FCR for This Project		9.81%	9.81%
Service Account 101 or 106 if not yet classified - End of year balance	Investment		28,573,369	34,069,851
Line 17 divided by line 12	Annual Depreciation or Amort Exp		680,318	811,187
Months in service for depreciation expense from Year placed in Service (0 if CWIP)			10.33	10.30
			2019	2019

			Depreciation or			Depreciation or						
		Invest Yr	Ending	Amortization	Revenue	Ending	Amortization	Revenue	Total	Incentive Charged	Revenue Credit	
W 11.68 % ROE		2006										
W Increased ROE		2006										
W 11.68 % ROE		2007										
W Increased ROE		2007										
W 11.68 % ROE		2008										
W Increased ROE		2008										
W 11.68 % ROE		2009										
W Increased ROE		2009										
W 11.68 % ROE		2010										
W Increased ROE		2010										
W 11.68 % ROE		2011										
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W Increased ROE		2015										
W 11.68 % ROE		2016										
W Increased ROE		2016										
W 11.68 % ROE		2017										
W Increased ROE		2017										
W 11.68 % ROE		2018										
W Increased ROE		2018										
W 11.68 % ROE		2019	2,125,935	3,894	17,116	2,125,935	3,894	17,116	$ 503,250,771		$ 503,250,771	
W Increased ROE		2019	2,125,935	3,894	17,116	2,125,935	3,894	17,116	$ 509,660,426	$ 509,660,426		$ 6,409,655
W 11.68 % ROE		2020	16,173,343	89,362	450,867	16,342,368	95,983	484,283	$ 596,008,507		$ 596,008,507	
W Increased ROE		2020	16,173,343	89,362	450,867	16,342,368	95,983	484,283	$ 602,248,962	$ 602,248,962		$ 6,240,455
W 11.68 % ROE		2021	28,480,114	540,798	2,761,938	33,969,975	642,411	3,281,769	$ 636,113,552		$ 636,113,552	
W Increased ROE		2021	28,480,114	540,798	2,761,938	33,969,975	642,411	3,281,769	$ 642,350,288	$ 642,350,288		$ 6,236,736

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
ATTACHMENT H-10A
Attachment 9 - Excess/(Deficient) Deferred Income Taxes - FERC Order 864 Worksheet (4)

Line No.	Year	Description:	Vintage:		A	B	C	D=(C*Tax Gross-up rate) (1)	E=(C+D)	F	G	H	I	J	K=(I+J)	L=(K*Tax Gross-up rate) (1)	M=(K+L)	N=(C+K)	O=(E+M)
					Beginning of the Year Excess/(Deficient) ADIT Regulatory Liability/(Asset)					Amortization Period		Amount Amortized						End of the Year Balance	
					Protected Original Account 282	Unprotected Original Account 190/282/283	Total Excess/(Deficient) Deferred Taxes Account 254/ (Account 182.3)	Income Tax Gross-Up	Total Account 254/ (Account 182.3)	Protected	Unprotected	FERC Account No. (3)	Protected	Unprotected	Total Amortization	Income Tax Gross-Up	Total Amortization with Gross-up	Excess/(Deficient) DIT Account 254/ (Account 182.3)	Excess/(Deficient) DIT with Gross-Up Account 254/ (Account 182.3)
1	2021	Protected	2017 TCJA	(2)	674,572,091		674,572,091	263,767,165	**938,339,256**	ARAM		411.1	(3,054,643)		(3,054,643)	(1,194,408)	(4,249,051)	671,517,448	934,090,204
2	2021	Unprotected	2017 TCJA	(2)			-	-	-		1 Year	411.1			-	-	-	-	-
3		**Total Excess/(Deficient) DIT:**			**674,572,091**	**-**	**674,572,091**	**263,767,165**	**938,339,256**				**(3,054,643)**	**-**	**(3,054,643)**	**(1,194,408)**	**(4,249,051)**	**671,517,448**	**934,090,204**

Notes:

(1) The Tax Cuts and Jobs Act was enacted on December 22, 2017 ("TCJA"). The TCJA reduced the federal corporate income tax rate from 35% to 21%, effective January 1, 2018. The composite and gross-up rates used for the remeasurement of ADIT balances are:

	Pre TCJA	Post TCJA
Federal income tax rate	35.00%	21.00%
State income tax rate	9.00%	9.00%
Federal benefit of deduction for state income tax	-3.15%	-1.89%
Composite federal/state income tax rate	40.85%	28.11%
Composite federal/state tax gross-up factor	1.69062	1.39101

(2) These amounts represent the future refunds to customers of PSE&G's excess deferred income tax liabilities as a result of the TCJA reduction in the federal corporate income tax rate effective January 1, 2018 and as reflected in PSE&G's FERC-approved Section 205 filing in Docket No. ER19-204.

(3) Excess DIT is amortized to FERC Account 411.1 and Deficient DIT is amortized to FERC Account 410.1.

(4) 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
Projected Costs of Plant in Forecasted Rate Base and In-Service Dates
12 Months Ended December 31, 2021

Required Transmission Enhancements

Upgrade ID	RTEP Baseline Project Description	Estimated/Actual Project Cost (thru 2021) *	Anticipated/Actual In-Service Date *
b0130	Replace all derated Branchburg 500/230 kv transformers	$ 20,614,102	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	$ 21,163,173	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	$ 45,985,436	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	$ 72,364,662	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	$ 43,252,771	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	$ 22,063,708	May-18
b2146	Reconfigure Brunswick Sw-New 69kVCkt-T	$ 157,750,572	Oct-17
b2702	350 MVAR Reactor Hopatcong 500kV	$ 22,307,024	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)	$ 721,910,808	Mar-12
b1156	Burlington - Camden 230kV Conversion	$ 356,574,888	Oct-11
b1398 - b1398.7	Mickleton-Gloucester-Camden	$ 438,447,199	Jun-13
b1154	North Central Reliability (West Orange Conversion)	$ 369,946,472	Jun-12
b1304.1-b1304.4	Northeast Grid Reliability Project	$ 625,130,258	Jun-13
b1304.5-b1304.21	Northeast Grid Reliability Project	$ 350,930,285	Dec-16
b2436.10	Convert the Bergen - Marion 138 kV path to double circuit 345 kV and associated substation upgrades	$ 179,505,240	Jan-16
b2436.21	Convert the Marion - Bayonne "L" 138 kV circuit to 345 kV and any associated substation upgrades	$ 66,220,634	May-16
b2436.22	Convert the Marion - Bayonne "C" 138 kV circuit to 345 kV and any associated substation upgrades	$ 48,882,238	May-16
b2436.33	Construct a new Bayway - Bayonne 345 kV circuit and any associated substation upgrades	$ 158,366,737	Dec-15
b2436.34	Construct a new North Ave - Bayonne 345 kV circuit and any associated substation upgrades	$ 126,295,227	Apr-18

Upgrade ID	RTEP Baseline Project Description	Estimated/Actual Project Cost (thru 2021) *	Anticipated/Actual In-Service Date *
b2436.50	Construct a new North Ave - Airport 345 kV circuit and any associated substation upgrades (B2436.50)	$ 65,231,920	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	$ 43,200,622	Dec-15
b2436.70	Construct a new Airport - Bayway 345 kV circuit and any associated substation upgrades	$ 81,612,264	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	$ 54,736,672	Dec-15
b2436.83	Convert the Bayway - Linden "Z" 138 kV circuit to 345 kV and any associated substation upgrades	$ 54,736,672	Dec-15
b2436.84	Convert the Bayway - Linden "W" 138 kV circuit to 345 kV and any associated substation upgrades	$ 53,301,490	Dec-15
b2436.85	Convert the Bayway - Linden "M" 138 kV circuit to 345 kV and any associated substation upgrades	$ 53,301,489	Dec-15
b2436.90	Relocate Farragut - Hudson "B" and "C" 345 kV circuits to Marion 345 kV and any associated substation upgrades	$ 31,273,305	May-16
b2436.91	Relocate the Hudson 2 generation to inject into the 345 kV at Marion and any associated upgrades	$ 24,999,416	Jun-16
b2437.10	New Bergen 345/230 kV transformer and any associated substation upgrades	$ 27,869,743	May-16
b2437.11	New Bergen 345/138 kV transformer #1 and any associated substation upgrades	$ 27,869,743	Jun-16
b2437.20	New Bayway 345/138 kV transformer #1 and any associated substation upgrades	$ 9,121,932	Dec-15
b2437.21	New Bayway 345/138 kV transformer #2 and any associated substation upgrades	$ 9,121,932	Dec-15
b2437.30	New Linden 345/230 kV transformer and any associated substation upgrades	$ 33,717,092	Jul-16
b2437.33	New Bayonne 345/69 kV transformer and any associated substation upgrades	$ 14,557,847	Apr-18
b2633.4	New 500 kV bay at Hope Creek (Expansion of Hope Creek substation)	$ 41,811,787	Dec-20
b2633.5	New 500/230 kV autotransformer at Hope Creek and a new Hope Creek 230 kV substation	$ 58,285,249	Dec-20
b2955	Rebuild Aldene-Warinanco-Linden VFT 230kV Circuit	$ 97,815,766	Jun-20
b2986.12	Roseland-Branchburg 230kV corridor rebuild (Readington - Branchburg)	$ 489,863	Jun-21
b2986.21	Branchburg-Pleasant Valley 230kV corridor rebuild (Branchburg - East Flemington)	$ 52,106,859	Jun-21
b2835.1	Convert the R-1318 and Q1317 (Edison - Metuchen) 138 kV circuits to one 230 kV circuit (Brunswick - Meadow Road)	$ 88,399,297	May-18
b2835.2	Convert the R-1318 and Q1317 (Edison - Metuchen) 138 kV circuits to one 230 kV circuit (Meadow Road - Pierson Ave)	$ 56,043,073	May-18
b2835.3	Convert the R-1318 and Q1317 (Edison - Metuchen) 138 kV circuits to one 230 kV circuit (Pierson Ave - Metuchen)	$ 8,643,783	Mar-19
b2836.2	Convert the N-1340 and T-1372/D-1330 (Brunswick - Trenton) 138 kV circuits to 230 kV circuits (Hunterglen - Trenton)	$ 77,807,835	May-18
b2836.3	Convert the N-1340 and T-1372/D-1330 (Brunswick - Trenton) 138 kV circuits to 230 kV circuits (Brunswick - Devils Brook)	$ 50,819,876	May-19
b2836.4	Convert the N-1340 and T-1372/D-1330 (Brunswick - Trenton) 138 kV circuits to 230 kV circuits (Devils Brook - Trenton)	$ 97,374,325	Apr-19
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)	$ 34,796,685	Nov-17
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)	$ 11,645,817	Nov-17
b2837.3	Convert the F-1358/Z-1326 and K-1363/Y-1325 (Trenton - Burlington) 138 kV circuits to 230 kV circuits (Ward Ave - Crosswicks Y)	$ 8,152,734	Jan-19
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)	$ 31,599,478	Jan-19
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)	$ 33,100,434	Dec-19
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)	$ 34,665,190	Apr-19
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)	$ 11,263,048	Apr-19
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)	$ 8,152,734	Jan-19
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)	$ 3,030,513	Jan-19
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)	$ 28,573,369	Dec-19
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)	$ 34,069,851	Dec-19
	Total	**$ 5,883,560,161**	

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

Attachment 9
JCP&L Formula Rate for January 1, 2021 to December 31, 2021

FirstEnergy

76 South Main Street
Akron, Ohio 44308

P. Nikhil Rao
Senior Corporate Counsel

330-384-2422
Fax: 330-384-3875

November 2, 2020

To: Parties to FERC Docket No. ER20-227

Re: Jersey Central Power & Light Company
PJM Open Access Transmission Tariff, Attachment H-4
Projected Transmission Revenue Requirement for Rate Year 2021

Pursuant to section II.C of the Formula Rate Implementation Protocols ("Protocols") set forth in Attachment H-4B of the PJM Open Access Transmission Tariff ("PJM OATT"),[1] Jersey Central Power & Light Company ("JCP&L") is submitting its Projected Transmission Revenue Requirement ("PTRR") for Rate Year 2021 to PJM for posting.

The 2021 PTRR was developed pursuant to the JCP&L formula rate as set forth in Attachment H-4 of the PJM OATT. JCP&L has asked PJM to post a copy of the 2021 PTRR to the formula rates section of its internet site, located at:

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

A copy of the 2021 PTRR is attached. Pursuant to section II.H of the Protocols, JCP&L shall hold an open meeting among Interested Parties ("Annual Projected Rate Meeting") no earlier than ten (10) business days following this posting and no later than November 30. No fewer than seven (7) days prior to such Annual Projected Rate Meeting, JCP&L shall provide notice on PJM's website of the time, date, and webcast registration information of the Annual Projected Rate Meeting.

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/2021

Jersey Central Power & Light

Line No.	(1)	(2)	(3)	(4)	(5) Allocated Amount
1	GROSS REVENUE REQUIREMENT [page 3, line 42, col 5]				$ 188,422,254
	REVENUE CREDITS	(Note T)	Total	Allocator	
2	Account No. 451	(page 4, line 29)	-	TP 1.00000	-
3	Account No. 454	(page 4, line 30)	-	TP 1.00000	-
4	Account No. 456	(page 4, line 31)	1,082,314	TP 1.00000	1,082,314
5	Revenues from Grandfathered Interzonal Transactions		-	TP 1.00000	-
6	Revenues from service provided by the ISO at a discount		-	TP 1.00000	-
7	TEC Revenue	Attachment 11, Page 2, Line 3, Col. 12	21,979,249	TP 1.00000	21,979,249
8	TOTAL REVENUE CREDITS (sum lines 2-7)		23,061,563		23,061,563
9	True-up Adjustment with Interest	(Attachment 13, Line 28) enter negative			-
10	NET REVENUE REQUIREMENT	(Line 1 - Line 8 + Line 9)			$ 165,360,691
	DIVISOR				Total
11	1 Coincident Peak (CP) (MW)			(Note A)	5,903.2
12	Average 12 CPs (MW)			(Note CC)	3,998.3
			Total		
13	Annual Rate ($/MW/Yr)	(line 10 / line 11)	28,012.04		
			Peak Rate Total		Off-Peak Rate Total
14	Point-to-Point Rate ($/MW/Year)	(line 10 / line 12)	41,357.75		41,357.75
15	Point-to-Point Rate ($/MW/Month)	(line 14/12)	3,446.48		3,446.48
16	Point-to-Point Rate ($/MW/Week)	(line 14/52)	795.34		795.34
17	Point-to-Point Rate ($/MW/Day)	(line 16/5; line 16/7)	159.07		113.62
18	Point-to-Point Rate ($/MWh)	(line 14/4,160; line 14/8,760)	9.94		4.72

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/2021

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)	65,117,368	NA		
2	Transmission	Attachment 3, Line 14, Col. 2 (Notes U & X)	1,855,896,269	TP	1.00000	1,855,896,269
3	Distribution	Attachment 3, Line 14, Col. 3 (Notes U & X)	5,128,174,657	NA		
4	General & Intangible	Attachment 3, Line 14, Col. 4 & 5 (Notes U & X)	406,377,857	W/S	0.09941	40,399,098
5	Common	Attachment 3, Line 14, Col. 6 (Notes U & X)	-	CE	0.09941	-
6	TOTAL GROSS PLANT (sum lines 1-5)		7,455,566,152	GP=	25.435%	1,896,295,367
	ACCUMULATED DEPRECIATION					
7	Production	Attachment 4, Line 14, Col. 1 (Notes U & X)	23,238,118	NA		
8	Transmission	Attachment 4, Line 14, Col. 2 (Notes U & X)	433,069,282	TP	1.00000	433,069,282
9	Distribution	Attachment 4, Line 14, Col. 3 (Notes U & X)	1,583,196,841	NA		
10	General & Intangible	Attachment 4, Line 14, Col. 4 & 5 (Notes U & X)	207,340,135	W/S	0.09941	20,612,231
11	Common	Attachment 4, Line 14, Col. 6 (Notes U & X)	-	CE	0.09941	-
12	TOTAL ACCUM. DEPRECIATION (sum lines 7-11)		2,246,844,376			453,681,513
	NET PLANT IN SERVICE					
13	Production	(line 1- line 7)	41,879,250			
14	Transmission	(line 2- line 8)	1,422,826,988			1,422,826,988
15	Distribution	(line 3 - line 9)	3,544,977,816			
16	General & Intangible	(line 4 - line 10)	199,037,722			19,786,867
17	Common	(line 5 - line 11)	-			-
18	TOTAL NET PLANT (sum lines 13-17)		5,208,721,776	NP=	27.696%	1,442,613,854
	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)	(424,339,302)	DA	1.00000	(424,339,302)
21	Account No. 283 (enter negative)	Attachment 5, Line 1, Col. 3 (Notes C, F)	(6,969,085)	DA	1.00000	(6,969,085)
22	Account No. 190	Attachment 5, Line 1, Col. 4 (Notes C, F)	72,761,663	DA	1.00000	72,761,663
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)		(358,546,724)			(358,546,724)
29	LAND HELD FOR FUTURE USE	214.x.d (Attachment 14, Line 3, Col. 1) (Notes G & Y)	-	TP	1.00000	-
30	WORKING CAPITAL (Note H)					
31	CWC	1/8*(Page 3, Line 14 minus Page 3, Line 11)	7,559,611.82			4,723,061.75
32	Materials & Supplies (Note G)	227.8.c & .16.c (Attachment 14, Line 3, Col. 2) (Note Y)	-	TE	0.96034	-
33	Prepayments (Account 165)	111.57.c (Attachment 14, Line 3, Col. 3) (Notes B & Y)	1,639,485	GP	0.25435	416,997
34	TOTAL WORKING CAPITAL (sum lines 31 - 33)		9,199,097			5,140,059
35	RATE BASE (sum lines 18, 28, 29, & 34)		4,859,374,149			1,089,207,189

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/2021

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	37,257,538	TE	0.96034	35,779,874
2	Less LSE Expenses Included in Transmission O&M Accounts (Note W)		248,820	DA	1.00000	248,820
3	Less Account 565	321.96.b	5,760	DA	1.00000	5,760
4	Less Account 566	321.97.b	-$6,842,099	DA	1.00000	(6,842,099)
5	A&G	323.197.b	28,671,257	W/S	0.09941	2,850,286
6	Less FERC Annual Fees		-	W/S	0.09941	-
7	Less EPRI & Reg. Comm. Exp. & Non-safety Ad. (Note I)		5,114,701	W/S	0.09941	508,466
8	Plus Transmission Related Reg. Comm. Exp. (Note I)			TE	0.96034	-
9	PBOP Expense Adjustment in Year	Attachment 6, Line 11 (Note C)	(82,619)	DA	1.00000	(82,619)
10	Common	356.1	-	CE	0.09941	-
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		(6,842,099)	DA	1.00000	(6,842,099)
13	Total Account 566 (sum lines 11 & 12, ties to 321.97.b)		(6,842,099)			(6,842,099)
14	TOTAL O&M (sum lines 1, 5,8, 9, 10, 13 less 2, 3, 4, 6, 7)		60,476,895			37,784,494
	DEPRECIATION AND AMORTIZATION EXPENSE					
15	Transmission	336.7.b (Note U)	40,510,927	TP	1.00000	40,510,927
16	General & Intangible	336.1.f & 336.10.f (Note U)	23,125,495	W/S	0.09941	2,298,967
17	Common	336.11.b (Note U)	-	CE	0.09941	-
18	Amortization of Abandoned Plant	Attachment 16, Line 15, Col. 5 (Note BB)	-	DA	1.00000	-
19	TOTAL DEPRECIATION (sum lines 15 -18)		63,636,422			42,809,894
	TAXES OTHER THAN INCOME TAXES (Note J)					
	LABOR RELATED					
20	Payroll	263.i (Attachment 7, line 1z)	5,388,036	W/S	0.09941	535,639
21	Highway and vehicle	263.i (Attachment 7, line 2z)	7,055	W/S	0.09941	701
22	PLANT RELATED					
23	Property	263.i (Attachment 7, line 3z)	6,403,724	GP	0.25435	1,628,763
24	Gross Receipts	263.i (Attachment 7, line 4z)	-	NA		-
25	Other	263.i (Attachment 7, line 5z)	3,116	GP	0.25435	793
26	Payments in lieu of taxes	Attachment 7, line 6z	-	GP	0.25435	-
27	TOTAL OTHER TAXES (sum lines 20 - 26)		11,801,931			2,165,896
	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)) = where WCLTD=(page 4, line 22) and R= (page 4, line 25) and FIT, SIT & p are as given in footnote K.		27.34%			
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)		96,631			
33	(Excess)/Deficient Deferred Income Taxes (Attachment 15, Lines 2 & 3, Col. 3) (Note E)		(2,359,204)			
34	Income Tax Calculation = line 29 * line 39		104,269,196	NA		23,371,478
35	ITC adjustment (line 30 * line 31)		(182,500)	NP	0.27696	(50,545)
36	Permanent Differences and AFUDC Equity Tax Adjustment (line 30 * line 32)		134,415	DA	1.00000	134,415
37	(Excess)/Deficient Deferred Income Tax Adjustment (line 30 * line 33)		(3,281,687)	DA	1.00000	(3,281,687)
38	Total Income Taxes	sum lines 34 through 37	100,939,424			20,173,662
39	RETURN	[Rate Base (page 2, line 35) * Rate of Return (page 4, line 25, col. 6)]	381,396,377.48	NA		85,488,308
40	GROSS REV. REQUIREMENT (WITHOUT INCENTIVE)	(sum lines 14, 19, 27, 38, 39)	618,251,049			188,422,254
41	ADDITIONAL INCENTIVE REVENUE	Attachment 11, Line 4 (Note AA)	0			0
42	GROSS REV. REQUIREMENT	(line 40 + line 41)	618,251,049			188,422,254

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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)						1,855,896,269		
2	Less transmission plant excluded from ISO rates (Note M)						-		
3	Less transmission plant included in OATT Ancillary Services (Note N)						-		
4	Transmission plant included in ISO rates (line 1 less lines 2 & 3)						1,855,896,269		
5	Percentage of transmission plant included in ISO Rates (line 4 divided by line 1)					TP=	1.00000		
	TRANSMISSION EXPENSES								
6	Total transmission expenses (page 3, line 1, column 3)						37,257,538		
7	Less transmission expenses included in OATT Ancillary Services (Note L)						1,477,664		
8	Included transmission expenses (line 6 less line 7)						35,779,874		
9	Percentage of transmission expenses after adjustment (line 8 divided by line 6)						0.96034		
10	Percentage of transmission plant included in ISO Rates (line 5)					TP	1.00000		
11	Percentage of transmission expenses included in ISO Rates (line 9 times line 10)					TE=	0.96034		
	WAGES & SALARY ALLOCATOR (W&S)								
		Form 1 Reference	$	TP	Allocation				
12	Production	354.20.b	-	0.00	-				
13	Transmission	354.21.b	8,504,759	1.00	8,504,759				
14	Distribution	354.23.b	60,906,329	0.00	-		W&S Allocator		
15	Other	354.24, 354.25, 354.26.b	16,138,984	0.00	-		($ / Allocation)		
16	Total (sum lines 12-15)		85,550,072		8,504,759	=	0.09941	= WS	
	COMMON PLANT ALLOCATOR (CE) (Note O)								
			$		% Electric		W&S Allocator		
17	Electric	200.3.c	-		(line 17 / line 20)		(line 16, col. 6)		CE
18	Gas	201.3.d	-		1.00000	*	0.09941	=	0.09941
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)		1,919,497,980	49%	0.0480		0.0236	=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)		1,982,810,076	51%	0.1080		0.0549		
25	Total (sum lines 22-24)		3,902,308,055				0.0785	=R	
	REVENUE CREDITS								
	ACCOUNT 447 (SALES FOR RESALE)		(310-311)	(Note Q)					
26	a. Bundled Non-RQ Sales for Resale (311.x.h)						-		
27	b. Bundled Sales for Resale included in Divisor on page 1						-		
28	Total of (a)-(b)						-		
29	ACCOUNT 451 (MISCELLANEOUS SERVICE REVENUE) (Note S)		(300.17.b)				-		
30	ACCOUNT 454 (RENT FROM ELECTRIC PROPERTY) (Note R)		(300.19.b)				-		
31	ACCOUNT 456 (OTHER ELECTRIC REVENUE) (Note V)		(330.x.n)				1,082,314		

Formula Rate - Non-Levelized | Rate Formula Template Utilizing FERC Form 1 Data | For the 12 months ended 12/31/2021

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	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 not include revenues associated with FERC annual charges, gross receipts taxes, ancillary services, or facilities not included in this template (e.g., direct assignment facilities and GSUs) which are not recovered under this Rate Formula Template. The revenue on line 7 is supported by 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.

Schedule 1A Rate Calculation

1	$	1,477,664	Attachment H-4A, Page 4, Line 7
2	$	145,041	Revenue Credits for Sched 1A - Note A
3	$	1,332,624	Net Schedule 1A Expenses (Line 1 - Line 2)
4		21,756,014	Annual MWh in JCP&L Zone - Note B
5	$	0.0613	Schedule 1A rate $/MWh (Line 3/ Line 4)

Note:

A Revenues received pursuant to PJM Schedule 1A revenue allocation procedures for transmission service outside of JCP&L's zone during the year used to calculate rates under Attachment H-4A.

B Load expressed in MWh consistent with load used for billing under Schedule 1A for the JCP&L zone. Data from RTO settlement systems for the calendar year prior to the rate year.

Incentive ROE Calculation

				Source Reference	
Return Calculation					
1	Rate Base			Attachment H-4A, page 2, Line 35, Col. 5	1,089,207,189
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	3,788,093,582
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	-5,607,428
6	Less Account 216.1 & Goodwill			Attachment 8, Line 14, Col. 3 & 5	1,810,890,935
7	Common Stock			Attachment 8, Line 14, Col. 6	1,982,810,076
	Capitalization				
8	Long Term Debt			Attachment H-4A, page 4, Line 22, Col. 3	1,919,497,980
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	1,982,810,076
11	Total Capitalization			Attachment H-4A, page 4, Line 25, Col. 3	3,902,308,055
12	Debt %		Total Long Term Debt	Attachment H-4A, page 4, Line 22, Col. 4	49.1888%
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	50.8112%
15	Debt Cost		Total Long Term Debt	Attachment H-4A, page 4, Line 22, Col. 5	0.0480
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)	0.0236
19	Weighted Cost of Preferred		Preferred Stock	(Line 13 * Line 16)	0.0000
20	Weighted Cost of Common		Common Stock	(Line 14 * Line 17)	0.0549
21	Rate of Return on Rate Base (ROR)			(Sum Lines 18 to 20)	**0.0785**
22	Investment Return = Rate Base * Rate of Return			**(Line 1 * Line 21)**	**85,488,308**
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	27.34%
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	96,631.28
28	(Excess)/Deficient Deferred Income Taxes			Attachment H-4A, page 3, Line 33, Col. 3	(2,359,204.50)
29	Income Tax Calculation			(line 22 * line 24)	23,371,478.30
30	ITC adjustment			Attachment H-4A, page 3, Line 35, Col. 5	(50,545.42)
31	Permanent Differences and AFUDC Equity Tax Adjustment			Attachment H-4A, page 3, Line 36, Col. 5	134,415.47
32	(Excess)/Deficient Deferred Income Tax Adjustment			Attachment H-4A, page 3, Line 37, Col. 5	(3,281,686.60)
33	Total Income Taxes			Sum lines 29 to 32	20,173,661.76
Increased Return and Taxes					
34	Return and Income taxes with increase in ROE			(Line 22 + Line 33)	105,661,970.24
35	Return without incentive adder			Attachment H-4A, Page 3, Line 39, Col. 5	85,488,308.48
36	Income Tax without incentive adder			Attachment H-4A, Page 3, Line 38, Col. 5	20,173,661.76
37	Return and Income taxes without increase in ROE			Line 35 + Line 36	105,661,970.24
38	Return and Income taxes with increase in ROE			Line 34	105,661,970.24
39	Incremental Return and incomes taxes for increase in ROE			Line 38 - Line 37	-
40	Rate Base			Line 1	1,089,207,189.28
41	Incremental Return and incomes taxes for increase in ROE divided by rate base			Line 39 / Line 40	-

Notes:

Line 17 to include an incentive ROE that is used only to determine the increase in return and incomes taxes associated with a specific increase in ROE. Any actual ROE incentive must be approved by the Commission. Until an ROE incentive is approved, line 17 will reflect the current ROE.

Gross Plant Calculation

For the 12 months ended 12/31/2021

			[1] Production	[2] Transmission	[3] Distribution	[4] Intangible	[5] General	[6] Common	[7] Total
1	December	2020	64,818,945	1,804,538,481	5,066,267,751	147,162,930	250,412,061	-	7,333,200,167
2	January	2021	64,842,533	1,820,808,325	5,076,886,850	147,400,746	251,217,309	-	7,361,155,763
3	February	2021	64,863,834	1,823,041,192	5,086,574,125	147,672,142	253,595,613	-	7,375,746,907
4	March	2021	64,868,584	1,829,455,864	5,095,022,580	148,302,588	255,633,609	-	7,393,283,225
5	April	2021	64,873,314	1,834,884,201	5,104,089,884	148,678,638	256,356,053	-	7,408,882,090
6	May	2021	65,012,871	1,840,783,054	5,113,960,870	148,934,730	257,119,930	-	7,425,811,455
7	June	2021	65,152,426	1,862,068,115	5,127,224,519	149,182,797	257,332,185	-	7,460,960,042
8	July	2021	65,291,982	1,866,326,047	5,138,314,587	149,426,196	257,542,160	-	7,476,900,973
9	August	2021	65,325,655	1,872,178,517	5,149,121,620	149,665,611	257,735,350	-	7,494,026,753
10	September	2021	65,330,371	1,876,472,267	5,159,263,459	149,908,284	257,880,360	-	7,508,854,742
11	October	2021	65,335,090	1,879,721,130	5,170,092,446	150,258,960	258,045,003	-	7,523,452,630
12	November	2021	65,339,809	1,885,290,737	5,180,533,157	150,494,513	258,241,363	-	7,539,899,578
13	December	2021	65,470,375	1,931,083,572	5,198,918,693	155,874,241	268,838,772	-	7,620,185,653
14	**13-month Average**	**[A] [C]**	**65,117,368**	**1,855,896,269**	**5,128,174,657**	**149,458,644**	**256,919,213**	**-**	**7,455,566,152**

				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	2020		123,069,808	1,804,541,891	5,066,313,408	147,162,930	252,007,672		7,393,095,709
16	January	2021		123,093,397	1,820,811,735	5,076,932,507	147,400,746	252,812,920		7,421,051,305
17	February	2021		123,114,698	1,823,044,603	5,086,619,782	147,672,142	255,191,224		7,435,642,449
18	March	2021		123,119,448	1,829,459,274	5,095,068,237	148,302,588	257,229,220		7,453,178,767
19	April	2021		123,124,178	1,834,887,611	5,104,135,541	148,678,638	257,951,665		7,468,777,633
20	May	2021		123,263,735	1,840,786,465	5,114,006,526	148,934,730	258,715,541		7,485,706,997
21	June	2021		123,403,289	1,862,071,526	5,127,270,176	149,182,797	258,927,797		7,520,855,584
22	July	2021		123,542,846	1,866,329,457	5,138,360,244	149,426,196	259,137,771		7,536,796,515
23	August	2021		123,576,518	1,872,181,927	5,149,167,277	149,665,611	259,330,962		7,553,922,295
24	September	2021		123,581,235	1,876,475,678	5,159,309,116	149,908,284	259,475,972		7,568,750,284
25	October	2021		123,585,954	1,879,724,540	5,170,138,103	150,258,960	259,640,615		7,583,348,172
26	November	2021		123,590,673	1,885,294,147	5,180,578,814	150,494,513	259,836,974		7,599,795,120
27	December	2021		123,721,238	1,931,086,982	5,198,964,349	155,874,241	270,434,384		7,680,081,195
28	13-month Average			123,368,232	1,855,899,680	5,128,220,314	149,458,644	258,514,824	-	7,515,461,694

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	2020		58,250,864	3,410	45,657		1,595,611	
30	January	2021		58,250,864	3,410	45,657		1,595,611	
31	February	2021		58,250,864	3,410	45,657		1,595,611	
32	March	2021		58,250,864	3,410	45,657		1,595,611	
33	April	2021		58,250,864	3,410	45,657		1,595,611	
34	May	2021		58,250,864	3,410	45,657		1,595,611	
35	June	2021		58,250,864	3,410	45,657		1,595,611	
36	July	2021		58,250,864	3,410	45,657		1,595,611	
37	August	2021		58,250,864	3,410	45,657		1,595,611	
38	September	2021		58,250,864	3,410	45,657		1,595,611	
39	October	2021		58,250,864	3,410	45,657		1,595,611	
40	November	2021		58,250,864	3,410	45,657		1,595,611	
41	December	2021		58,250,864	3,410	45,657		1,595,611	
42	13-month Average			58,250,864	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

Accumulated Depreciation Calculation

For the 12 months ended 12/31/2021

				[1] Production	[2] Transmission	[3] Distribution	[4] Intangible	[5] General	[6] Common	[7] Total
1	December	2020		22,419,273	422,454,173	1,539,246,042	100,094,986	97,804,647	-	2,182,019,121
2	January	2021		22,558,314	423,326,353	1,546,469,259	101,082,186	98,009,841	-	2,191,445,954
3	February	2021		22,697,654	425,772,255	1,553,815,094	102,071,508	98,551,127	-	2,202,907,639
4	March	2021		22,838,858	427,759,278	1,561,315,711	103,064,588	99,132,647	-	2,214,111,083
5	April	2021		22,980,074	429,863,993	1,568,764,171	104,061,861	99,861,847	-	2,225,531,945
6	May	2021		23,106,450	431,924,114	1,576,141,209	105,061,769	100,587,258	-	2,236,820,800
7	June	2021		23,233,101	432,294,604	1,583,162,291	106,063,777	101,374,509	-	2,246,128,281
8	July	2021		23,360,025	434,585,749	1,590,446,842	106,940,694	102,162,260	-	2,257,495,569
9	August	2021		23,498,884	436,696,184	1,597,783,016	107,819,622	102,952,100	-	2,268,749,806
10	September	2021		23,640,998	438,986,556	1,605,212,416	108,700,560	103,747,478	-	2,280,288,008
11	October	2021		23,783,120	441,397,695	1,612,584,860	109,583,970	104,540,844	-	2,291,890,489
12	November	2021		23,925,252	443,556,661	1,620,020,119	110,469,822	105,330,883	-	2,303,302,738
13	December	2021		24,053,534	441,283,047	1,626,597,901	111,379,071	104,971,905	-	2,308,285,459
14	**13-month Average**		**[A] [C]**	**23,238,118**	**433,069,282**	**1,583,196,841**	**105,876,493**	**101,463,642**	**-**	**2,246,844,376**

				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	2020		80,670,136	422,455,771	1,539,274,841	100,094,986	98,517,556		2,241,013,291
16	January	2021		80,809,178	423,327,955	1,546,498,132	101,082,186	98,729,519		2,250,446,971
17	February	2021		80,948,518	425,773,861	1,553,844,041	102,071,508	99,277,574		2,261,915,502
18	March	2021		81,089,722	427,760,889	1,561,344,732	103,064,588	99,865,863		2,273,125,793
19	April	2021		81,230,938	429,865,607	1,568,793,265	104,061,861	100,601,831		2,284,553,502
20	May	2021		81,357,314	431,925,732	1,576,170,377	105,061,769	101,334,012		2,295,849,203
21	June	2021		81,483,965	432,296,226	1,583,191,532	106,063,777	102,128,031		2,305,163,531
22	July	2021		81,610,889	434,587,375	1,590,476,157	106,940,694	102,922,551		2,316,537,665
23	August	2021		81,749,747	436,697,814	1,597,812,405	107,819,622	103,719,160		2,327,798,749
24	September	2021		81,891,861	438,988,190	1,605,241,879	108,700,560	104,521,307		2,339,343,797
25	October	2021		82,033,984	441,399,333	1,612,614,396	109,583,970	105,321,442		2,350,953,125
26	November	2021		82,176,116	443,558,303	1,620,049,730	110,469,822	106,118,249		2,362,372,220
27	December	2021		82,304,398	441,284,693	1,626,627,586	111,379,071	105,766,040		2,367,361,788
28	13-month Average			81,488,982	433,070,904	1,583,226,083	105,876,493	102,217,164	-	2,305,879,626

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	2020		58,250,864	1,598	28,799		712,909	
30	January	2021		58,250,864	1,602	28,873		719,678	
31	February	2021		58,250,864	1,606	28,947		726,447	
32	March	2021		58,250,864	1,610	29,020		733,216	
33	April	2021		58,250,864	1,614	29,094		739,985	
34	May	2021		58,250,864	1,618	29,168		746,753	
35	June	2021		58,250,864	1,622	29,242		753,522	
36	July	2021		58,250,864	1,626	29,316		760,291	
37	August	2021		58,250,864	1,630	29,389		767,060	
38	September	2021		58,250,864	1,634	29,463		773,829	
39	October	2021		58,250,864	1,638	29,537		780,597	
40	November	2021		58,250,864	1,642	29,611		787,366	
41	December	2021		58,250,864	1,646	29,684		794,135	
42	13-month Average			58,250,864	1,622	29,242	-	753,522	-

Notes:

[A] Taken to Attachment H-4A, page 2, lines 7-11, Col. 3

[B] Reference for December balances as would be reported in FERC Form 1.

[C] Balance excludes reserve for depreciation of asset retirement costs

			[1]	[2]	[3]	[4]	[5]	[6]
			ADIT Transmission Total (including Plant & Labor Related Transmission ADITs and applicable transmission adjustments from notes below)					
			Acct. No. 281	**Acct. No. 282**	**Acct. No. 283**	**Acct. No. 190**	**Acct. No. 255**	**Total**
			(enter negative)	**(enter negative)**	**(enter negative)**		**(enter negative)**	
				[B]	[C]	[D]	[E]	
1	December 31	2021	-	(424,339,302)	(6,969,085)	72,761,663	-	(358,546,724)

				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	2021 [G]	-	319,046,748	(28,109,349)	76,912,253	1,392,551	369,242,203

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	2021	-	506,101	(114,727,199)		8,928,544

[C] FERC Account No. 283 is adjusted for the following items.

		FAS 143 - ARO	FAS 106	FAS 109	CIAC	Normalization [F]
4	2021		4,571,980	(39,987,299)		336,885

[D] FERC Account No. 190 is adjusted for the following items:

		FAS 143 - ARO	FAS 106	FAS 109	CIAC	Normalization [F]
5	2021	-	10,158,556	(16,920,292)	10,649,495	262,832

[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

Jersey Central Power & Light
Summary of Transmission ADIT (Prior to adjusted items)

Line	1	2	3	4
		Transmission Ending (Note F)	**End Plant & Labor Related Allocated to Transmission** (page 1, Col. K)	**Total Transmission Ending** (col. 2 + col. 3) (Note E)
1	**ADIT- 282 From Account Subtotal Below**	319,046,748	-	319,046,748
2	**ADIT-283 From Account Subtotal Below**	(28,109,349)	-	(28,109,349)
3	**ADIT-190 From Account Subtotal Below**	76,912,253	-	76,912,253
4	**ADIT-281 From Account Subtotal Below**	-	-	-
5	**ADIT-255 From Account Subtotal Below**	1,392,551	-	1,392,551
	Total (sum rows 1-5)	369,242,203	-	369,242,203

Jersey Central Power & Light
Summary of Transmission ADIT (Prior to adjusted items)

Line		A	B	C	D	E	F
		End Plant Related (Note A)	**End Labor Related** (Note B)	**Plant & Labor Subtotal** Col. A + Col. B	**Gross Plant Allocator** (Note C)	**Wages & Salary Allocator** (Note D)	**End Plant & Labor Related ADIT** (Col. A * Col. D) + (Col. B * Col. E)
1	ADIT- 282 From Account Total Below	-	-	-	25.43%	9.94%	-
2	ADIT-283 From Account Total Below	-	-	-	25.43%	9.94%	-
3	ADIT-190 From Account Total Below	-	-	-	25.43%	9.94%	-
4	ADIT-281 From Account Total Below	-	-	-	25.43%	9.94%	-
5	ADIT-255 From Account Total Below	-	-	-	25.43%	9.94%	-
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

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**
Capitalized Interest	8,453,940			8,453,940			
Contribution in Aid of Construction	10,649,495			10,649,495			
FAS109 Related to Property	(4,359,900)			(4,359,900)			
Accrued Taxes: FICA on Vacation Accrual	43,575			43,575			
Accrued Taxes: Tax Audit Reserves	25,824			25,824			
Accum Prov For Inj and Damage-Gen Liability	27,830			27,830			
Accum Prov For Inj and Damage-Workers Comp	141,141			141,141			
Company Debt - Issuance Discount	29,116			29,116			
FAS 112 - Medical Benefit Accrual	505,494			505,494			
FAS 123R - Restricted Stock	9,450			9,450			
FAS 123R - Restricted Stock Units	30,679			30,679			
Federal Long Term - Protected	11,304,627			11,304,627			
Federal Long Term - Unprotected	17,403,438			17,403,438			
General Business Credit Carryforward	52,659			52,659			
GR&F Tax Audit	120,546			120,546			
ITC FAS 109	544,507			544,507			
Lease ROU Asset & Liability	1,059,481			1,059,481			
NOL Deferred Tax Asset - LT NJ	13,844,553			13,844,553			
715 Credits	249,702			249,702			
Pension EDCP-SERP Payments	173,465			173,465			
Pensions Expense	13,134,934			13,134,934			
PJM Receivable	4,844,584			4,844,584			
PJM Unbilled Deferral	1,066,955			1,066,955			
Post Retirement Benefits SFAS 106 Accrual	10,158,556			10,158,556			
Vacation Pay Accrual	502,502			502,502			
FAS 109 Related to Non-Property	(13,104,899)			(13,104,899)			
Subtotal	76,912,253	-	-	76,912,253	-	-	

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.

Jersey Central Power & Light

A	B	C	D	E	F	G	
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	84,774,311			84,774,311			
Accelarated Depreciation	281,221,271			281,221,271			
AFUDC	7,635,541			7,635,541			
AFUDC Equity (FAS109)	3,624,659			3,624,659			
Capitalized Tree Trimming	3,868,753			3,868,753			
Casualty Loss	5,270,290			5,270,290			
OPEBs	506,101			506,101			
Other	592,878			592,878			
Pension and Capitalized Benefits	13,461,406			13,461,406			
Tax Repairs	36,445,418			36,445,418			
Sale of Property - Book/Tax Gain/Loss	(2,022)			(2,022)			
FAS109 Related to Property	(118,351,610)			(118,351,610)			
FAS 109 Related to Non-Property	(248)			(248)			
Subtotal	319,046,748	-	-	319,046,748	-	-	

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.

Jersey Central Power & Light

For the 12 months ended 12/31/2021

A	B	C	D	E	F	G	
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)	1,417,293			1,417,293			
Property FAS109	(44,572,360)			(44,572,360)			
Deferred Charge - EIB	92,573			92,573			
FAS 123R - Performance Shares	15,385			15,385			
FE Service Tax Interest Allocation	913			913			
FE Service Timing Allocation	5,474,486			5,474,486			
Post Retirement Benefits FAS 106	4,571,980			4,571,980			
State Income Tax Deductible	1,722,613			1,722,613			
FAS 109 Related to Non-Property	(1,406,409)			(1,406,409)			
FAS 109 Related to Non-Property (Gross-up)	4,574,177			4,574,177			
Subtotal	(28,109,349)	-	-	(28,109,349)	-	-	

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.

Jersey Central Power & Light

A	B	C	D	E	F	G	
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.

For the 12 months ended 12/31/2021

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	1,392,551			1,392,551			
				-			
				-			
				-			
				-			
				-			
				-			
				-			
				-			
Subtotal	1,392,551	-	-	1,392,551	-	-	

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.

Line		A	B	C	D	E	F	G	H	I
			2021 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	72,436,642	348,893	72,785,535	80,283	72,865,818	79,644	72,945,462	79,032	73,024,494
		Beginning 190 (including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
2	PTRR	**72,436,642**	**263,821**		**40,691**		**20,293**		**217**	
		Beginning 282 (including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
3	PTRR	413,298,120	11,852,128	425,150,247	2,727,256	427,877,503	2,705,560	430,583,063	2,684,783	433,267,846
		Beginning 282 (including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
4	PTRR	**413,298,120**	**8,962,157**		**1,382,308**		**689,362**		**7,356**	
		Beginning 283 Including adjustments)	Q1 Activity	**Ending Q1**	Q2 Activity	**Ending Q2**	Q3 Activity	**Ending Q3**	Q4 Activity	**Ending Q4**
5	PTRR	6,552,488	447,195	6,999,683	102,903	7,102,586	102,084	7,204,670	101,300	7,305,970
		Beginning 283 Including adjustments)	**Pro-rated Q1**		**Pro-rated Q2**		**Pro-rated Q3**		**Pro-rated Q4**	
6	PTRR	**6,552,488**	**338,153**		**52,156**		**26,010**		**278**	

					2021 PTRR				
			J	K	L	M	N	O	P
					Page 1, row 2,4,6 Column				
				Page 1, B+D+F+H	A+B+D+F+H	J-L		M-N	Line 7= J-N-O Lines 8-9= -J+N+O
Line		Account	Estimated Ending Balance (Before Adjustments)	Projected Activity	Prorated Ending Balance	Prorated - Estimated End (Before Adjustments)	Sum of end ADIT Adjustments	Normalization	Ending ADIT Balance Included in Formula Rate
7	PTRR	Total Account 190	76,912,253	587,852	72,761,663	4,150,590	3,887,758	**262,832**	**72,761,663**
8	PTRR	Total Account 282	319,046,748	19,969,726	424,339,302	(105,292,553)	(114,221,097)	**8,928,544**	**(424,339,302)**
9	PTRR	Total Account 283	(28,109,349)	753,482	6,969,085	(35,078,434)	(35,415,319)	**336,885**	**(6,969,085)**
10	PTRR	Total ADIT Subject to Normalization	(214,025,146)	(20,135,356)	(358,546,724)	144,521,578	(145,748,658)	9,528,261	(358,546,724)

Notes:
1. Attachment 5b will only be populated within the PTRR

Line		A	B	C	D	E	F	G	H	I
		2021 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**	

2021 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	-	-	-	-	-	-	-

2021 ATRR

		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

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	6,147,906	JCP&L Labor: Company Records
7	PBOP Expense for current year (line 5 * line 6)	-$404,558	
8	PBOP expense in Account 926 for current year, total company	(3,238,409)	JCP&L Account 926: Company Records
9	W&S Labor Allocator	9.941%	
10	Allocated Transmission PBOP (line 8 * line 9)	(321,939)	
11	PBOP Adjustment for Attachment H-4A, page 3, line 9 (line 7 - line 10)	(82,619)	

12 Lines 3-4 cannot change absent a Section 205 or 206 filing approved or accepted by FERC in a separate proceeding

For the 12 months ended 12/31/2021

Taxes Other than Income Calculation

			[A]	Dec 31, 2021
1	**Payroll Taxes**			
1a	FICA & unemployement taxes	263.i		5,388,036
1b		263.i		
1c		263.i		
1d		263.i		
1z	**Payroll Taxes Total**			5,388,036
2	**Highway and Vehicle Taxes**			
2a	Federal Excise Tax	263.i		7,055
2z	**Highway and Vehicle Taxes**			7,055
3	**Property Taxes**			
3a	New Jersey Property Tax	263.i		6,403,648
3b	PA PURTA Tax	263.i		76
3c		263.i		-
3d		263.i		-
3z	**Property Taxes**			6,403,724
4	**Gross Receipts Tax**			
4a	Gross Receipts Tax	263.i		-
4z	**Gross Receipts Tax**			-
5	**Other Taxes**			
5a	Sales & Use Tax	263.i		3,116
5b		263.i		
5c		263.i		
5d				-
5z	**Other Taxes**			3,116
6z	**Payments in lieu of taxes**			
7	Total other than income taxes (sum lines 1z, 2z, 3z, 4z, 5z, 6z) [tie to 114.14c]			$11,801,930.86

Notes:

[A] Reference for December balances as would be reported in FERC Form 1.

Capital Structure Calculation

For the 12 months ended 12/31/2021

			[1] Proprietary Capital	[2] Preferred Stock	[3] Account 216.1	[4] Account 219	[5] Goodwill	[6] Common Stock	[7] Long Term Debt
		[A]	112.16.c	112.3.c	112.12.c	112.15.c	233.5.f	(1) - (2) - (3) - (4) - (5)	112.24.c
1	December	2020	3,714,258,231	-	(45,190)	(5,586,832)	1,810,936,125	1,908,954,128	1,650,448,660
2	January	2021	3,726,941,347		(45,190)	(5,590,265)	1,810,936,125	1,921,640,676	1,650,418,418
3	February	2021	3,737,579,292		(45,190)	(5,593,697)	1,810,936,125	1,932,282,054	1,650,388,177
4	March	2021	3,732,104,812		(45,190)	(5,597,130)	1,810,936,125	1,926,811,007	1,650,357,935
5	April	2021	3,744,678,279		(45,190)	(5,600,563)	1,810,936,125	1,939,387,907	1,650,327,693
6	May	2021	3,760,095,130		(45,190)	(5,603,996)	1,810,936,125	1,954,808,190	1,650,297,452
7	June	2021	3,768,063,724		(45,190)	(5,607,428)	1,810,936,125	1,962,780,217	2,150,267,210
8	July	2021	3,802,973,069		(45,190)	(5,610,861)	1,810,936,125	1,997,692,995	2,150,236,969
9	August	2021	3,835,910,259		(45,190)	(5,614,294)	1,810,936,125	2,030,633,618	2,150,206,727
10	September	2021	3,838,987,621		(45,190)	(5,617,727)	1,810,936,125	2,033,714,413	2,150,176,486
11	October	2021	3,853,264,035		(45,190)	(5,621,159)	1,810,936,125	2,047,994,259	2,150,146,244
12	November	2021	3,865,259,835		(45,190)	(5,624,592)	1,810,936,125	2,059,993,493	2,150,116,003
13	December	2021	3,865,100,938		(45,190)	(5,628,025)	1,810,936,125	2,059,838,028	2,150,085,761
14	13-month Average		3,788,093,582	-	(45,190)	(5,607,428)	1,810,936,125	1,982,810,076	1,919,497,980

Notes:

[A] Reference for December balances as would be reported in FERC Form 1.

Stated Value Inputs

For the 12 months ended 12/31/2021

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.

Debt Cost Calculation

TABLE 1: Summary Cost of Long Term Debt

CALCULATION OF COST OF DEBT

YEAR ENDED 12/31/2021

	t=N	(a) Issue Date	(b) Maturity Date	(c) ORIGINAL ISSUANCE (table 2, col. cc)	(d) Net Proceeds At Issuance (table 2, col. hh)	(e) Net Amount Outstanding at t=N	(f) Months Outstanding at t=N	(g) Average Net Outstanding in Year* z* ((col e. * col. F)/12)	(h) Weighted Outstanding Ratios (col. g/col. g total)	(i) Effective Cost Rate (Table 2, Col. ll)	(j) Weighted Debt Cost at t = N (h) * (i)
Long Term Debt Cost at ' 12/31/2021											
First Mortgage Bonds:											
(1) 6.40% Series		5/12/2006	5/15/2036	$ 200,000,000	$ 196,437,127	$ 198,519,965	12	$ 198,519,964.73	10.26%	6.54%	0.67%
(2) 6.15% Series		5/16/2007	6/1/2037	$ 300,000,000	$ 295,979,779	$ 297,937,136	12	$ 297,937,136.46	15.40%	6.25%	0.96%
(3) 4.30% Series		2/8/2019	1/15/2026	$ 400,000,000	$ 402,287,000	$ 401,332,654	12	$ 401,332,653.77	20.75%	4.20%	0.87%
(4) 4.70% Series		8/21/2013	4/1/2024	$ 500,000,000	$ 493,197,650	$ 498,557,396	12	$ 498,557,396.36	25.78%	4.87%	1.25%
(5) 4.30% Series		8/18/2015	1/15/2026	$ 250,000,000	$ 247,086,512	$ 248,869,232	12	$ 248,869,232.48	12.87%	4.44%	0.57%
(6) 3.00% Series - Planned		6/1/2021	6/1/2031	$ 500,000,000	$ 495,000,000	$ 495,291,621	7	$ 288,920,112.27	14.94%	3.12%	0.47%
				$ 2,150,000,000		$ 2,140,508,005		$ 1,934,136,496	100.000%		4.80% **

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 12/31/2021

	Long Term Debt Issuanc 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%
(6)	3.00% Series - Planned	6/1/2021	6/1/2031	$ 500,000,000	$ -	$ 5,000,000			$ 495,000,000	99.0000	0.0300	$ 15,000,000	3.12%
	TOTALS			$ 2,150,000,000	(2,420,000)	$ 17,591,932	-	xxx	$ 2,129,988,068			$ 97,700,000	

* 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 $C_{t=1}$ equals Net Proceeds column (gg); Semi-annual (or other) interest cashflows ($C_{t=1}$, $C_{t=2}$, etc.).

Transmission Enhancement Charge (TEC) Worksheet
To be completed in conjunction with Attachment H-4A

Line No.	(1)	(2) Reference	(3) Transmission	(4) Allocator
1	Gross Transmission Plant - Total	Attach. H-4A, p. 2, line 2, col. 5 (Note A)	$ 1,855,896,269	
2	Net Transmission Plant - Total	Attach. H-4A, p. 2, line 14, col. 5 (Note B)	$ 1,422,826,988	
	O&M EXPENSE			
3	Total O&M Allocated to Transmission	Attach. H-4A, p. 3, line 14, col. 5	$ 37,784,494	
4	Annual Allocation Factor for O&M	(line 3 divided by line 1, col. 3)	2.035916%	2.035916%
	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	$ 2,298,967	
6	Annual allocation factor for G, I, & C depreciation expense	(line 5 divided by line 1, col. 3)	0.123874%	0.123874%
	TAXES OTHER THAN INCOME TAXES			
7	Total Other Taxes	Attach. H-4A, p. 3, line 27, col. 5	$ 2,165,896	
8	Annual Allocation Factor for Other Taxes	(line 7 divided by line 1, col. 3)	0.116704%	0.116704%
9	**Annual Allocation Factor for Expense**	**Sum of line 4, 6, & 8**		**2.276493%**
	INCOME TAXES			
10	Total Income Taxes	Attach. H-4A, p. 3, line 38, col. 5	$ 20,173,662	
11	Annual Allocation Factor for Income Taxes	(line 10 divided by line 2, col. 3)	1.417858%	1.417858%
	RETURN			
12	Return on Rate Base	Attach. H-4A, p. 3, line 39, col. 5	$ 85,488,308	
13	Annual Allocation Factor for Return on Rate Base	(line 12 divided by line 2, col. 3)	6.008342%	6.008342%
14	**Annual Allocation Factor for Return**	**Sum of line 11 and 13**		**7.426199%**

Columns 5-9 (page 1) only applies with incentive ROE project(s) (Note F)

Line No.	(5)	(6)	(7) Reference	(8) Transmission	(9) Allocator
		INCOME TAXES			
10b		Total Income Taxes	Attachment 2, line 33	$ 20,173,662	
11b		Annual Allocation Factor for Income Taxes	(line 10b divided by line 2, col. 3)	1.417858%	1.417858%
		RETURN			
12b		Return on Rate Base	Attachment 2, line 22	$ 85,488,308	
13b		Annual Allocation Factor for Return on Rate Base	(line 12b divided by line 2, col. 3)	6.008342%	6.008342%
14b		**Annual Allocation Factor for Return**	**Sum of line 11b and 13b**		**7.426199%**
15		**Additional Annual Allocation Factor for Return**	**Line 14 b, col. 9 less line 14, col. 4**		**0.00000%**

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	$ 12,588,193	2.276493%	$286,569	$ 9,297,673	7.426199%	$690,464	$ 307,826	$1,284,859	0	$1,284,859		$1,284,859
2b	Reconductor the 8 mile Gilbert – Glen Gardner 230 kV circuit	b0268	$ 5,983,501	2.276493%	$136,214	$ 4,744,594	7.426199%	$352,343	$ 146,596	$635,153	0	$635,153		$635,153
2c	Add a 2nd Raritan River 230/115 kV transformer	b0726	$ 7,324,741	2.276493%	$166,747	$ 6,293,318	7.426199%	$467,354	$ 177,991	$812,093	0	$812,093		$812,093
2d	Build a new 230 kV circuit from Larrabee to Oceanview	b2015	$ 171,850,384	2.276493%	$3,912,163	$ 157,309,098	7.426199%	$11,682,087	$3,652,895	$19,247,145	0	$19,247,145		$19,247,145
3	Transmission Enhancement Credit taken to Attachment H-4A Page 1, Line 7											$21,979,249		
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

TEC Worksheet Support
Net Plant Detail

For the 12 months ended 12/31/2021

Line No.	Project Name	RTEP Project Number	Project Gross Plant	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21
			(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	$ 12,588,193	$ 12,588,193	$ 12,588,193	$ 12,588,193	$ 12,588,193	$ 12,588,193	$ 12,588,193	$ 12,588,193	$ 12,588,193	$ 12,588,193	$ 12,588,193	$ 12,588,193	$ 12,588,193	$ 12,588,193
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	$ 171,850,384	$171,850,384	$171,850,384	$171,850,384	$171,850,384	$171,850,384	$171,850,384	$171,850,384	$171,850,384	$171,850,384	$171,850,384	$171,850,384	$171,850,384	$171,850,384

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

TEC Worksheet Support
Net Plant Detail

Accumulated Depreciation (Note B)	Dec-20 (Note D)	Jan-21 (Note D)	Feb-21 (Note D)	Mar-21 (Note D)	Apr-21 (Note D)	May-21 (Note D)	Jun-21 (Note D)	Jul-21 (Note D)	Aug-21 (Note D)	Sep-21 (Note D)	Oct-21 (Note D)	Nov-21 (Note D)	Dec-21 (Note D)	Project Net Plant (Note B & C)
$ 3,290,520	$ 3,136,607	$ 3,162,259	$ 3,187,911	$ 3,213,563	$ 3,239,215	$ 3,264,868	$ 3,290,520	$ 3,316,172	$ 3,341,824	$ 3,367,476	$ 3,393,128	$ 3,418,781	$ 3,444,433	$9,297,673
$ 1,238,907	$ 1,165,609	$ 1,177,826	$ 1,190,042	$ 1,202,258	$ 1,214,475	$ 1,226,691	$ 1,238,907	$ 1,251,124	$ 1,263,340	$ 1,275,556	$ 1,287,773	$ 1,299,989	$ 1,312,205	$4,744,594
$ 1,031,423	$ 942,428	$ 957,260	$ 972,093	$ 986,925	$ 1,001,758	$ 1,016,591	$ 1,031,423	$ 1,046,256	$ 1,061,088	$ 1,075,921	$ 1,090,754	$ 1,105,586	$ 1,120,419	$6,293,318
$ 14,541,286	$12,714,838	$13,019,246	$13,323,654	$13,628,062	$13,932,470	$14,236,878	$14,541,286	$14,845,694	$15,150,102	$15,454,509	$15,758,917	$16,063,325	$16,367,733	$157,309,098

NOTE

[B] Utilizing a 13-month average. [C] Taken to Attachment 11, Page 2, Col. 6 [D] Company records

TEC - True-up

To be completed after Attachment 11 for the True-up Year is updated using actual data

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
Line No.	**Project Name**	**RTEP Project Number**	**Actual Revenues for Attachment 11**	**Projected Annual Revenue Requirement**	**% of Total Revenue Requirement**	**Revenue Received**	**Actual Annual Revenue Requirement**	**True-up Adjustment Principal Over/(Under)**	**Applicable Interest Rate on Over/(Under)**	**Total True-up Adjustment with Interest Over(Under)**
				Projected Attachment 11 p 2 of 2, col. 14	Col d, line 2 / Col. d, line 3	Col c, line 1 * Col e	Actual Attachment 11 p 2 of 2, col. 14	Col. f - Col. G	Col. H line 2x / Col. H line 3 * Col. J line 4	Col. h + Col. i
1	[A] Actual RTEP Credit Revenues for true-up year		0							
2a	Project 1			-	-	-	-	-	#DIV/0!	#DIV/0!
2b	Project 2				-	-		-	#DIV/0!	#DIV/0!
2c	Project 3				-	-		-	#DIV/0!	#DIV/0!
3	Subtotal			-			-	-		#DIV/0!
4	Total Interest (Sourced from Attachment 13a, line 30)									-

NOTE

[A] Amount included in revenues reported on pages 328-330 of FERC Form 1.

Net Revenue Requirement True-up with Interest

	Reconciliation Revenue Requirement For Year 2019 Available June 10, 2020		2019 Revenue Requirement Collected by PJM Based on Forecast filed on Oct 31, 2018		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 2019, held for 2020 and returned prorate over 2021							
	Calculation of Interest					Monthly		
3	January	Year 2019	-	0.0000%	12	-		-
4	February	Year 2019	-	0.0000%	11	-		-
5	March	Year 2019	-	0.0000%	10	-		-
6	April	Year 2019	-	0.0000%	9	-		-
7	May	Year 2019	-	0.0000%	8	-		-
8	June	Year 2019	-	0.0000%	7	-		-
9	July	Year 2019	-	0.0000%	6	-		-
10	August	Year 2019	-	0.0000%	5	-		-
11	September	Year 2019	-	0.0000%	4	-		-
12	October	Year 2019	-	0.0000%	3	-		-
13	November	Year 2019	-	0.0000%	2	-		-
14	December	Year 2019	-	0.0000%	1	-		-
						-		-
						Annual		
15	January through December	Year 2020	-	0.0000%	12	-		-
	Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					Monthly		
16	January	Year 2021	-	0.0000%		-	-	-
17	February	Year 2021	-	0.0000%		-	-	-
18	March	Year 2021	-	0.0000%		-	-	-
19	April	Year 2021	-	0.0000%		-	-	-
20	May	Year 2021	-	0.0000%		-	-	-
21	June	Year 2021	-	0.0000%		-	-	-
22	July	Year 2021	-	0.0000%		-	-	-
23	August	Year 2021	-	0.0000%		-	-	-
24	September	Year 2021	-	0.0000%		-	-	-
25	October	Year 2021	-	0.0000%		-	-	-
26	November	Year 2021	-	0.0000%		-	-	-
27	December	Year 2021	-	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

TEC Revenue Requirement True-up with Interest

	TEC Reconciliation Revenue Requirement For Year 2019 Available June 10, 2020		TEC 2019 Revenue Requirement Collected by PJM Based on Forecast filed on Oct 31, 2018		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 2019, held for 2020 and returned prorate over 2021							
	Calculation of Interest					Monthly		
3	January	Year 2019	-	0.0000%	12	-		-
4	February	Year 2019	-	0.0000%	11	-		-
5	March	Year 2019	-	0.0000%	10	-		-
6	April	Year 2019	-	0.0000%	9	-		-
7	May	Year 2019	-	0.0000%	8	-		-
8	June	Year 2019	-	0.0000%	7	-		-
9	July	Year 2019	-	0.0000%	6	-		-
10	August	Year 2019	-	0.0000%	5	-		-
11	September	Year 2019	-	0.0000%	4	-		-
12	October	Year 2019	-	0.0000%	3	-		-
13	November	Year 2019	-	0.0000%	2	-		-
14	December	Year 2019	-	0.0000%	1	-		-
						-		-
						Annual		
15	January through December	Year 2020	-	0.0000%	12	-		-
	Over (Under) Recovery Plus Interest Amortized and Recovered Over 12 Months					Monthly		
16	January	Year 2021	-	0.0000%		-	-	-
17	February	Year 2021	-	0.0000%		-	-	-
18	March	Year 2021	-	0.0000%		-	-	-
19	April	Year 2021	-	0.0000%		-	-	-
20	May	Year 2021	-	0.0000%		-	-	-
21	June	Year 2021	-	0.0000%		-	-	-
22	July	Year 2021	-	0.0000%		-	-	-
23	August	Year 2021	-	0.0000%		-	-	-
24	September	Year 2021	-	0.0000%		-	-	-
25	October	Year 2021	-	0.0000%		-	-	-
26	November	Year 2021	-	0.0000%		-	-	-
27	December	Year 2021	-	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

For the 12 months ended 12/31/2021

Other Rate Base Items

			[1]	[2]	[3]	[4]	[5]	[6]
			Land Held for Future Use	**Materials & Supplies**	**Prepayments (Account 165)**		**Total**	
		[A]	214.x.d	227.8.c & .16.c	111.57.c [B]			
1	December 31	2019	-	-	1,639,485		1,639,485	
2	December 31	2020	-	-	1,639,485		1,639,485	
3	Begin/End Average		-	-	1,639,485		1,639,485	

			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

Income Tax Adjustments

	[1]	[2]	[3] Dec 31, 2021	Reference
1	Tax adjustment for Permanent Differences & AFUDC Equity	[A] [C]	96,631	JCP&L Company Records
2	Amortized Excess Deferred Taxes (enter negative)	[B] [C]	(2,359,204)	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

Line No.	COLUMN A Description	COLUMN B EDIT Transmission Allocation	COLUMN C Amortization Period	COLUMN D Years Remaining at Year End	COLUMN E Amortization of EDIT	COLUMN F Protected (P) Non-Protected (N)
1	Accrued Taxes: FICA on Vacation Accrual	8,680	10	6	868	N
2	Accrued Taxes: Tax Audit Reserves	6,238	10	6	624	N
3	Accum Prov For Inj and Damage-Gen Liability	15,386	10	6	1,539	N
4	Accum Prov For Inj and Damage-Workers Comp	50,817	10	6	5,082	N
5	Asset Retirement Obligation Liability	(1,647)	10	6	(165)	N
6	Company Debt - Issuance Discount	16,436	10	6	1,644	N
7	Deferred Charge-EIB	(15,677)	10	6	(1,568)	N
8	FAS 112 - Medical Benefit Accrual	165,849	10	6	16,585	N
9	FAS 158 OPEB OCI Offset	(22,157)	10	6	(2,216)	N
10	FAS 158 Pension OCI Offset	1,790	10	6	179	N
11	FE Service Tax Interest Allocation	(712)	10	6	(71)	N
12	FE Service Timing Allocation	(503,373)	10	6	(50,337)	N
13	Federal Long Term NOL	5,037,433	35	31	143,927	P
14	Federal Long Term NOL	6,981,827	10	6	698,183	N
15	GR&F Tax Audit	36,747	10	6	3,675	N
16	NOL Deferred Tax Asset - LT NJ	(106,781)	10	6	(10,678)	N
17	Pension/OPEB : Other Def Cr. or Dr.	2,289,854	10	6	228,985	N
18	Pensions Expense	2,716,133	10	6	271,613	N
19	PJM Receivable	(1,381,762)	10	6	(138,176)	N
20	Post Retirement Benefits SFAS 106 Accrual	3,107,222	10	6	310,722	N
21	Post Retirement Benefits SFAS 106 Payments	(1,090,624)	10	6	(109,062)	N
22	Sale of Property - Book Gain or (Loss)	89,727	10	6	8,973	N
23	Sale of Property - Tax Gain or (Loss)	(94,435)	10	6	(9,444)	N
24	State Income Tax Deductible	(680,043)	10	6	(68,004)	N
25	Storm Damage	(6,198,498)	10	6	(619,850)	N
26	Unamortized Gain on Reacquired Debt	1,606	10	6	161	N
27	Unamortized Loss on Reacquired Debt	(204,887)	10	6	(20,489)	N
28	Vacation Pay Accrual	95,018	10	6	9,502	N
29	Vegetation Management	(29,221)	10	6	(2,922)	N
30	2017 Return-to-Accrual True-ups to Deficient ADITs	21,144	7	6	3,021	N
31	**Total Non-Property Amortization (Total of lines 1 thru 30)**				**672,298**	
32	**Property Book-Tax Timing Difference [B] [C]**				(3,031,503)	N & P
33	**Total Non-Property & Property Amortization [A] [B] [C]**				**(2,359,204)**	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

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 2020	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 2021	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

			CWIP [A] 216.b
1	December	2020	
2	January	2021	
3	February	2021	
4	March	2021	
5	April	2021	
6	May	2021	
7	June	2021	
8	July	2021	
9	August	2021	
10	September	2021	
11	October	2021	
12	November	2021	
13	December	2021	
14	13-month Average		-

Notes:

[A] Includes only CWIP authorized by the Commission for inclusion in rate base.

Federal Income Tax Rate

Nominal Federal Income Tax Rate (entered on Attachment H-4A, page 5 of 5, Note K)	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%

Regulatory Asset

	[1]	[2]	[3]	[4]	[5]	[6]	[7]
1	**Monthly Balance**	Source	Months Remaining In Amortization Period	BegInning Balance	Amortization Expense (Company Records)	Additions (Deductions)	Ending Balance
2	December 2020	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 2021	p232 (and Notes)	1	-	-	-	-
15	**Ending Balance 13-Month Average**	(sum lines 2-14) /13			$0.00	-	$0.00

Operation and Maintenance Expenses

FF1 Page 321 Line No.	Account Reference	Description	Account Balance [A]
82		***Operation***	
83	560	Operation Supervision and Engineering	$200,556
84			
85	561.1	Load Dispatch-Reliability	$1,268,472
86	561.2	Load Dispatch-Monitor and Operate Transmission System	$209,192
87	561.3	Load-Dispatch-Transmission Service and Scheduling	
88	561.4	Scheduling, System Control and Dispatch Services	$241,860
89	561.5	Reliability, Planning and Standards Development	$515,347
90	561.6	Transmission Service Studies	$54,182
91	561.7	Generation Interconnection Studies	$182,634
92	561.8	Reliability, Planning and Standards Development Services	$6,960
93	562	Station Expenses	$2,626,980
94	563	Overhead Lines Expense	$855,188
95	564	Underground Lines Expense	
96	565	Transmission of Electricity by Others	$5,760
97	566	Miscellaneous Transmission Expense	-$6,842,099
98	567	Rents	$10,183,854
99		TOTAL Operation (Enter Total of Lines 83 thru 98)	$9,508,886
100		***Maintenance***	
101	568	Maintenance Supervision and Engineering	$2,848,227
102	569	Maintenance of Structures	
103	569.1	Maintenance of Computer Hardware	$27,139
104	569.2	Maintenance of Computer Software	$46,217
105	569.3	Maintenance of Communication Equipment	$71,973
106	569.4	Maintenance of Miscellaneous Regional Transmission Plant	
107	570	Maintenance of Station Equipment	$4,059,153
108	571	Maintenance of Overhead Lines	$20,685,208
109	572	Maintenance of Underground Lines	
110	573	Maintenance of Miscellaneous Transmission Plant	$10,735
111		TOTAL Maintenance (Total of lines 101 thru 110)	$27,748,652
112		**TOTAL Transmission Expenses (Total of lines 99 and 111)**	**$37,257,538**

Notes:

[A] December balances as would be reported in FERC Form 1

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	-$95,072
182	921	Office Supplies and Expenses	$169,377
183	Less 922	Administrative Expenses Transferred - Credit	
184	923	Outside Services Employed	$5,578,741
185	924	Property Insurance	$69,137
186	925	Injuries and Damages	$355,481
187	926	Employee Pensions and Benefits	-$4,531,051
188	927	Franchise Requirements	
189	928	Regulatory Commission Expense	$448,860
190	Less 929	(Less) Duplicate Charges-Cr.	
191	930.1	General Advertising Expenses	$59,606
192	930.2	Miscellaneous General Expenses	$269,497
193	931	Rents	$242,473
194		**Total Operation (Enter Total of lines 181 thru 193)**	$2,567,050
195		***Maintenance***	
196	935	Maintenance of General Plant	$283,235
197		**TOTAL A&G Expenses (Total of lines 194 and 196)**	**$2,850,286**

Notes:

[B] December balances as would be reported in FERC Form 1, transmission only