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February 13, 2018

VIA ELECTRONIC MAIL & HAND DELIVERY

Office of the Secretary
Board of Public Utilities
44 South Clinton Ave.
3rd Floor, Suite 314
Trenton, New Jersey 08625-0350

Attn: Aida Camacho

Re: In the Matter of the Provision of Basic Generation Service for Year Two of the Post-Transition Period

-and-

In the Matter of the Provision of Basic Generation Service for the Period Beginning June 1, 2015

-and-

In the Matter of the Provision of Basic Generation Service for the Period Beginning June 1, 2016

-and-

In the Matter of the Provision of Basic Generation Service for the Period Beginning June 1, 2017

-and-

In the Matter of the Provision of Basic Generation Service for the Period Beginning June 1, 2018

BPU Docket Nos. EO03050394, ER14040370, ER15040482, ER16040337 & ER17040335

Compliance Tariff Filing Reflecting Changes to Schedule 12 Charges in PJM Open Access Transmission Tariff

Dear Ms. Camacho:

Enclosed for filing on behalf of Jersey Central Power & Light Company ("JCP&L"), Atlantic City Electric Company ("ACE"), Public Service Electric and Gas Company ("PSE&G"), and Rockland Electric Company ("RECO") (collectively, the "EDCs"), please find an original and ten copies of tariff sheets and supporting exhibits that reflect changes to the PJM Open Access Transmission Tariff ("OATT") made in response to the Federal Energy Regulatory Commission ("FERC") Orders issued on December 15, 2017, in Docket Nos. EL17-84-000 and EL17-90-000 ("HTP and Linden VFT Orders").

Purpose of Revised Tariff Sheet Filing

The attached updated tariff sheets and supporting exhibits listed below incorporate changes to the PJM Open Access Transmission Tariff ("OATT") pursuant to Federal Energy Regulatory Commission ("FERC") Orders issued on December 15, 2017, in Docket Nos. EL17-84-000 and EL17-90-000 ("HTP and Linden VFT Orders"). PJM implemented these changes in the OATT effective January 1, 2018. The changes to the PJM OATT were made as a result of a change in Hudson Transmission Partners' ("HTP") and Linden VFT's responsibility for certain transmission cost allocations resulting from the conversion of Firm to Non-Firm Transmission Withdrawal Rights.

The PJM tariff revisions remove HTP and Linden VFT as parties responsible for cost allocation under Schedule 12 of the PJM. The tariff revisions reallocate the HTP and Linden VFT transmission costs to other entities in PJM. As a result, the Transmission Enhancement Charges ("TEC") in Schedule 12 have been adjusted to reflect the revised cost allocation. This filing contains the updates to the TECs related to JCP&L transmission projects.

While FERC has ruled on these matters through the issuance of the HTP and Linden VFT Orders, the cost reallocation being implemented pursuant to the HTP and Linden VFT Orders are subject to ongoing challenges before FERC.

Updated Tariff Sheets

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

- Attachment 1 – Derivation of JCP&L Network Integration Transmission Service Charge
- Attachment 2a – Pro-forma JCP&L Tariff Sheets
- Attachment 2b – JCP&L Translation of NITS Charge Into Customer Rates
- Attachment 3a – Pro-forma PSE&G Tariff Sheets
- Attachment 3b – PSE&G Translation of JCP&L Schedule 12 (TEC) Charges into Customer Rates
- Attachment 4a – Pro-forma ACE Tariff Sheets
- Attachment 4b – ACE Translation of JCP&L Schedule 12 (TEC) Charges into Customer Rates
- Attachment 5a – Pro-forma RECO Tariff Sheets
- Attachment 5b – RECO Translation of JCP&L Schedule 12 (TEC) Charges into

Customer Rates

- Attachment 6 – PJM Schedule 12 (TEC) Charges – JCP&L Project Charges
- Attachment 7 – HTP FERC Order
- Attachment 8 – Linden VFT FERC Order

Request for Authority to Collect Adjusted Rate and to Pay Suppliers

The EDCs respectfully request approval to implement these revised tariff rates with a rate effective date of January 1, 2018. In support of this request, the EDCs have included pro-forma tariff sheets as noted above. The Basic Generation Service ("BGS") rates have been modified in accordance with the Board-approved methodology contained in each EDC's Company-Specific Addendum in the above-referenced BGS proceedings and in conformance with each EDC's Board-approved BGS tariff sheets.

The EDCs also respectfully request that the Board issue a waiver of the 30-day filing requirement that would otherwise apply to this submission, because BGS suppliers began paying these revised transmission charges for transmission service effective January 1, 2018 pursuant to the PJM OATT changes implementing the HTP and Linden VFT FERC Orders. The EDCs hereby also seek authority from the Board to remit payment to suppliers for the increased charges they incur.

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

We note that the HTP and Linden VFT rate adjustments in the attached tariffs are intended to implement adjustments to TECs rather than the Firm Transmission Rate. Thus, there will not be a FERC Final Order approving a Firm Transmission Rate.

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

We thank the Board for all courtesies extended.

Respectfully submitted,

Gregory Eisenstark
Attorney for JCP&L and on behalf of
PSE&G, ACE and RECO

Attachments
c: Thomas Walker, NJBPU
Stacy Peterson, NJBPU
Stefanie Brand, Division of Rate Counsel
Service List (via Electronic Mail)

Jersey Central Power & Light Company
Compliance Tariff Filing Reflecting Changes to Schedule
12 Charges in PJM Open Access Transmission Tariff
BPU Docket No. ____________

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Jersey Central Power & Light Company
Compliance Tariff Filing Reflecting Changes to Schedule
12 Charges in PJM Open Access Transmission Tariff
BPU Docket No. _____________

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Jersey Central Power & Light Company
Compliance Tariff Filing Reflecting Changes to Schedule
12 Charges in PJM Open Access Transmission Tariff
BPU Docket No. ______________

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Attachment 1

Derivation of JCP&L Network Integration Transmission Service Charge

Attachment 1 - JCP&L Network Integration Transmission Service Calculation

Updated 1/26/2018

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

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

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

Attachment 2 – JCP&L Tariffs and Rate Translation

Attachment 2a

Pro-forma JCP&L Tariff Sheets

Attachment 2b

JCP&L Translation of NITS Charge into Customer Rates

Updated 1/26/2018

Attachment 2a
Pro-forma JCP&L Tariff Sheets

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: $0.007973** 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: $2.97** per month
Supplemental Customer Charge: $1.55 per month Off-Peak/Controlled Water Heating

2) **Distribution Charge:**

June through September:
$0.016140 per KWH for the first 600 KWH (except Water Heating)
$0.063825 per KWH for all KWH over 600 KWH (except Water Heating)

October through May:
$0.026440 per KWH for all KWH (except Water Heating)

Water Heating Service:
$0.017645 per KWH for all KWH for Off-Peak Water Heating
$0.023242 per KWH for all KWH for Controlled Water Heating

Service Classification RT
Residential Time-of-Day Service

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

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

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

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

BASIC GENERATION SERVICE (default service):

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

2) **Transmission Charge: $0.007973** 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: $5.54** per month
Solar Water Heating Credit: $1.39 per month

2) **Distribution Charge:**
$ 0.049470 per KWH for all KWH on-peak for June through September
$ 0.036338 per KWH for all KWH on-peak for October through May
$ 0.023109 per KWH for all KWH off-peak

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

4) **Societal Benefits Charge (Rider SBC):**
$ 0.007189 per KWH for all KWH on-peak and off-peak

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

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

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

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:**
$0.007973 per KWH for all KWH on-peak and off-peak for June through September
$0.007973 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: $5.54** per month

2) **Distribution Charge:**

June through September:
$0.049470 per KWH for all KWH on-peak
$0.023109 per KWH for all KWH off-peak

October through May:
$0.026440 per KWH for all KWH

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:**
$ 0.007973 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:** **$ 3.32** per month single-phase
$11.90 per month three-phase

Supplemental Customer Charge: **$ 1.55** per month Off-Peak/Controlled Water Heating
$ 2.72 per month Day/Night Service
$12.36 per month Traffic Signal Service

2) **Distribution Charge:**

KW Charge: (Demand Charge)
$ 7.08 per maximum KW during June through September, in excess of 10 KW
$ 6.60 per maximum KW during October through May, in excess of 10 KW
$ 3.21 per KW Minimum Charge, in excess of 10 KW

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: $0.007973** 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: $31.89** per month single-phase
$45.52 per month three-phase

2) **Distribution Charge:**

KW Charge: (Demand Charge)
$ 7.50 per maximum KW during June through September
$ 7.01 per maximum KW during October through May
$ 3.26 per KW Minimum Charge

KWH Charge:
$0.004982 per KWH for all KWH on-peak
$0.004982 per KWH for all KWH off-peak

Service Classification GP
General Service Primary

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

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

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

BASIC GENERATION SERVICE (default service):

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

2) **Transmission Charge: $0.005393** per KWH for all KWH

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

1) **Customer Charge: $56.16** per month

2) **Distribution Charge:**

KW Charge: (Demand Charge)
$ 5.85 per maximum KW during June through September
$ 5.43 per maximum KW during October through May
$ 1.98 per KW Minimum Charge

KVAR Charge: (Kilovolt-Ampere Reactive Charge)
$0.37 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:
$0.003601 per KWH for all KWH on-peak and off-peak

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

4) **Societal Benefits Charge (Rider SBC):**
$ 0.007189 per KWH for all KWH on-peak and off-peak

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

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

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

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

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:** **$0.004970** per KWH for all KWH
$0.001214 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:** **$240.00** per month

3) **Distribution Charge:**

KW Charge: (Demand Charge)
$ 3.76 per maximum KW
$ 1.00 per KW High Tension Service Credit
$ 2.50 per KW DOD Service Credit

KW Minimum Charge: (Demand Charge)
$ 1.14 per KW Minimum Charge
$ 0.76 per KW DOD Service Credit
$ 0.48 per KW Minimum Charge Credit

KVAR Charge: (Kilovolt-Ampere Reactive Charge)
$0.36 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:
$0.002763 per KWH for all KWH on-peak and off-peak
$0.000981 per KWH High Tension Service Credit
$0.001796 per KWH DOD Service Credit

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

4) **Societal Benefits Charge (Rider SBC):**
$ 0.007189 per KWH for all KWH on-peak and off-peak

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	**$ 2.62**	Not Available
175	211	74	Not Available	**$ 2.62**	Not Available
70	99	35	**$10.92**	Not Available	Not Available
100	137	48	**$10.92**	Not Available	Not Available
150	176	62	Not Available	Not Available	**$12.82**
250	293	103	Not Available	Not Available	**$13.47**
400	498	174	Not Available	Not Available	**$13.82**

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

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

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

DELIVERY SERVICE (Distribution Charge includes Corporation Business Tax as provided in Rider CBT):
1) **Distribution Charge: $0.049226** per KWH
2) **Non-utility Generation Charge (Rider NGC): $0.001664** per KWH
3) **Societal Benefits Charge (Rider SBC): $0.007189** per KWH
4) **System Control Charge (Rider SCC): $0.000000** per KWH
5) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
6) **Storm Recovery Charge (Rider SRC): $0.003288** per KWH

Service Classification SVL
Sodium Vapor Street Lighting Service

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

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

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

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

Nominal Ratings					
Lamp Wattage	Lamp & Ballast Wattage	Billing Month KWH *	Company Fixture	Contribution Fixture	Customer Fixture
50	60	21	**$ 6.37**	**$ 1.78**	**$ 0.86**
70	85	30	**$ 6.37**	**$ 1.78**	**$ 0.86**
100	121	42	**$ 6.37**	**$ 1.78**	**$ 0.86**
150	176	62	**$ 6.37**	**$ 1.78**	**$ 0.86**
250	293	103	**$ 7.53**	**$ 1.78**	**$ 0.86**
400	498	174	**$ 7.53**	**$ 1.78**	**$ 0.86**

* 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: $0.049226** per KWH
2) **Non-utility Generation Charge (Rider NGC): $0.001664** per KWH
3) **Societal Benefits Charge (Rider SBC): $0.007189** per KWH
4) **System Control Charge (Rider SCC): $0.000000** per KWH
5) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
6) **Storm Recovery Charge (Rider SRC): $0.003288** per KWH

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

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	**$ 4.45**	**$ 1.68**	**$ 0.85**
175	211	74	**$ 4.45**	**$ 1.68**	**$ 0.85**
250	295	103	**$ 4.45**	**$ 1.68**	**$ 0.85**
400	468	164	**$ 4.82**	**$ 1.68**	**$ 0.85**
700	803	281	**$ 5.83**	**$ 1.68**	**$ 0.85**
1000	1135	397	**$ 5.83**	**$ 1.68**	**$ 0.85**

* 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: $0.049226** per KWH
2) **Non-utility Generation Charge (Rider NGC): $0.001664** per KWH
3) **Societal Benefits Charge (Rider SBC): $0.007189** per KWH
4) **System Control Charge (Rider SCC): $0.000000** per KWH
5) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
6) **Storm Recovery Charge (Rider SRC): $0.003288** per KWH

Service Classification 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	**$ 1.88**	**$ 0.85**
205	72	**$ 1.88**	**$ 0.85**
327	114	**$ 1.88**	**$ 0.85**
448	157	**$ 1.88**	**$ 0.85**
690	242	**$ 1.88**	**$ 0.85**
860	301	**$ 1.88**	**$ 0.85**

* 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: $0.049226** per KWH
2) **Non-utility Generation Charge (Rider NGC): $0.001664** per KWH
3) **Societal Benefits Charge (Rider SBC): $0.007189** per KWH
4) **System Control Charge (Rider SCC): $0.000000** per KWH
5) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
6) **Storm Recovery Charge (Rider SRC): $0.003288** per KWH

Service Classification LED
LED Street Lighting Service

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

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

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

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

(A) FIXTURE CHARGE:

Lamp Wattage	Type	Lumens	Billing Month KWH*	Company Fixture
50	Cobra Head	4000	18	**$ 6.80**
90	Cobra Head	7000	32	**$ 7.52**
130	Cobra Head	11500	46	**$ 8.96**
260	Cobra Head	24000	91	**$ 11.57**
50	Acorn	2500	18	**$ 16.29**
90	Acorn	5000	32	**$ 17.04**
50	Colonial	2500	18	**$ 9.32**
90	Colonial	5000	32	**$ 13.22**

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

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

BASIC GENERATION SERVICE (default service):

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

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

1) **Distribution Charge: $0.049226** per KWH
2) **Non-utility Generation Charge (Rider NGC): $0.001664** per KWH
3) **Societal Benefits Charge (Rider SBC): $0.007189** per KWH
4) **System Control Charge (Rider SCC): $0.000000** per KWH
5) **RGGI Recovery Charge (Rider RRC): See Rider RRC for rate** per KWH
6) **Storm Recovery Charge (Rider SRC): $0.003288** per KWH

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

Attachment 2b

JCP&L Translation of NITS Charge into Customer Rates

Updated 1/26/2018

Attachment 2b - JCP&L Translation of NITS Charge into BGS Customer Rates - RSCP and CIEP

NITS Charges for January 2018 - December 2018 - Settlement

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

Effective January 1, 2018:

BGS by Voltage Level	Transmission Obligation (MW)	Allocated Cost Recovery	BGS Eligible Sales (kWh)	Transmission Rate ($/kWh)	Transmission Rate w/SUT ($/kWh)
Secondary (excluding lighting)	4,934.8	$ 123,922,774	16,572,627,418	$ 0.007478	$ 0.007973
Primary	348.5	$ 8,751,537	1,730,276,418	$ 0.005058	$ 0.005393
Transmission @ 34.5 kV	293.5	$ 7,370,377	1,581,370,077	$ 0.004661	$ 0.004970
Transmission @ 230 kV	15.5	$ 389,236	341,655,635	$ 0.001139	$ 0.001214
Total	5,592.3	$ 140,433,925	20,225,929,548		

BGS-RSCP Supplier Payment Adjustment

Line No.			
1	BGS-RSCP Eligible Sales January through December @ Customer	15,159,224	MWH
2	BGS-RSCP Eligible Sales January through December @ Transmission Node	16,830,967	MWH
3	BGS-RSCP Eligible Transmission Obligation	4,688	MW
4	Change in Transmission Payment to RSCP Suppliers	$ 46,887,761	= Line 3 x $27.40 x 365
5	Change to Supplier Payment Rates $/MWH (rounded to 2 decimals)	$ 2.79	= Line 4 / Line 2

Attachment 3 – PSE&G Tariffs and Rate Translation

Attachment 3a

Pro-forma PSE&G Tariff Sheets

Attachment 3b

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

Attachment 3a

Pro-forma PSE&G Tariff Sheets

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

APPLICABLE TO:

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

BGS ENERGY CHARGES:

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

Charges per kilowatthour:

	For usage in each of the months of October through May		For usage in each of the months of June through September	
Rate Schedule	Charges	Charges Including SUT	Charges	Charges Including SUT
RS – first 600 kWh	$0.114744	$0.122346	$0.114798	$0.122403
RS – in excess of 600 kWh	0.114744	0.122346	0.123916	0.132125
RHS – first 600 kWh	0.092782	0.098929	0.087886	0.093708
RHS – in excess of 600 kWh	0.092782	0.098929	0.100078	0.106708
RLM On-Peak	0.195778	0.208748	0.207216	0.220944
RLM Off-Peak	0.054762	0.058390	0.050998	0.054377
WH	0.054424	0.058030	0.051835	0.055269
WHS	0.054891	0.058528	0.051426	0.054833
HS	0.092766	0.098912	0.093645	0.099849
BPL	0.051712	0.055138	0.046936	0.050046
BPL-POF	0.051712	0.055138	0.046936	0.050046
PSAL	0.051712	0.055138	0.046936	0.050046

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

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

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

BGS CAPACITY CHARGES:

Applicable to Rate Schedules GLP and LPL-Sec.

Charges per kilowatt of Generation Obligation:

Charge applicable in the months of June through September .... $ 5.7899
Charge including New Jersey Sales and Use Tax (SUT) .... $ 6.1735

Charge applicable in the months of October through May .... $ 5.7899
Charge including New Jersey Sales and Use Tax (SUT) .... $ 6.1735

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 .... $ 92,569.05 per MW per year
PJM Reallocation .... $ 0.00 per MW per year
PJM Seams Elimination Cost Assignment Charges .... $ 0.00 per MW per month
PJM Reliability Must Run Charge .... $ 2.82 per MW per month
PJM Transmission Enhancements
Trans-Allegheny Interstate Line Company .... $102.26 per MW per month
Virginia Electric and Power Company .... $ 84.08 per MW per month
Potomac-Appalachian Transmission Highline L.L.C. .... $ 11.32 per MW per month
PPL Electric Utilities Corporation .... $ 52.22 per MW per month
American Electric Power Service Corporation .... $ 28.18 per MW per month
Atlantic City Electric Company. .... $ 11.09 per MW per month
Delmarva Power and Light Company .... $ 0.33 per MW per month
Potomac Electric Power Company. .... $ 3.24 per MW per month
Baltimore Gas and Electric Company .... $ 6.91 per MW per month
Jersey Central Power and Light .... $ 68.84 per MW per month

Above rates converted to a charge per kW of Transmission
Obligation, applicable in all months .... $ 8.0853
Charge including New Jersey Sales and Use Tax (SUT) .... $ 8.6210

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

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

BGS TRANSMISSION CHARGES

Charges per kilowatt of Transmission Obligation:

Currently effective Annual Transmission Rate for Network Integration Transmission Service for the Public Service Transmission Zone as derived from the FERC Electric Tariff of the PJM Interconnection, LLC	$ 92,569.05 per MW per year
PJM Reallocation	$ 0.00 per MW per year
PJM Seams Elimination Cost Assignment Charges	$ 0.00 per MW per month
PJM Reliability Must Run Charge	$ 2.82 per MW per month
PJM Transmission Enhancements	
Trans-Allegheny Interstate Line Company	$102.26 per MW per month
Virginia Electric and Power Company	$ 84.08 per MW per month
Potomac-Appalachian Transmission Highline L.L.C.	$ 11.32 per MW per month
PPL Electric Utilities Corporation	$ 52.22 per MW per month
American Electric Power Service Corporation	$ 28.18 per MW per month
Atlantic City Electric Company.	$ 11.09 per MW per month
Delmarva Power and Light Company	$ 0.33 per MW per month
Potomac Electric Power Company.	$ 3.24 per MW per month
Baltimore Gas and Electric Company	$ 6.91 per MW per month
Jersey Central Power and Light	$ 68.84 per MW per month

Above rates converted to a charge per kW of Transmission Obligation, applicable in all months	$ 8.0853
Charge including New Jersey Sales and Use Tax (SUT)	$ 8.6210

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

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

Attachment 3b

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

Transmission Charge Adjustment - BGS-RSCP
PJM Schedule 12 - Transmission Enhancement Charges for January 2018 - December 2018
Calculation of costs and monthly PJM charges for JCP&L

TEC Charges for Jan 2018 - Dec 2018	$	7,903,305.53		
PSE&G Zonal Transmission Load for Effective Yr. (MW)		9,566.90		
Term (Months)		12		
OATT rate	$	68.84	/MW/month	all values show w/o NJ SUT
Resulting Increase in Transmission Rate	$	826.08	/MW/yr	

	RS	RHS	RLM	WH	WHS	HS	PSAL	BPL
Trans Obl - MW	3,892.6	25.5	73.1	0.0	0.0	2.8	0.0	0.0
Total Annual Energy - MWh	12,201,595.6	133,055.9	218,245.6	1,283.0	27.0	15,196.6	158,968.0	296,268.0
Change in energy charge								
in $/MWh	$ 0.2635	$ 0.1583	$ 0.2767	$ -	$ -	$ 0.1522	$ -	$ -
in $/kWh - rounded to 6 places	**$ 0.000264**	**$ 0.000158**	**$ 0.000277**	**$ -**	**$ -**	**$ 0.000152**	**$ -**	**$ -**

Line #						
1	Total BGS-RSCP Trans Obl		6,658.8	MW		= sum of BGS-RSCP eligible Trans Obl adjusted for migration
2	Total BGS-RSCP energy @ cust		23,949,599	MWh		= sum of BGS-RSCP eligible kWh @ cust adjusted for migration
3	Total BGS-RSCP energy @ trans nodes		25,728,145	MWh	unrounded	= (2) * loss expansion factor to trans node
4	Change in OATT rate * total Trans Obl	$	5,500,702		unrounded	= Change in OATT rate * Total BGS-RSCP eligible Trans Obl
5	Change in Average Supplier Payment Rate	$	0.2138	/MWh	unrounded	= (4) / (3)
6	Change in Average Supplier Payment Rate	$	0.21	/MWh	rounded to 2 decimal places	= (5) rounded to 2 decimal places
7	Proposed Total Supplier Payment	$	5,402,910		unrounded	= (6) * (3)
8	Difference due to rounding	$	(97,791)		unrounded	= (7) - (4)

Attachment 4 – ACE Tariffs and Rate Translation

Attachment 4a

Pro-forma ACE Tariff Sheets

Attachment 4b

ACE Translation of JCP&L Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 4a

Pro-forma ACE Tariff Sheets

RIDER (BGS) continued
Basic Generation Service (BGS)

CIEP Standby Fee $0.000160 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	0.000413	0.000344	0.000372	0.000228	0.000181	0.000175	-	0.000145
TrAILCo	0.000574	0.000480	0.000518	0.000317	0.000253	0.000244	-	0.000202
PSE&G	0.000581	0.000486	0.000525	0.000321	0.000257	0.000248	-	0.000204
PATH	(0.000049)	(0.000042)	(0.000045)	(0.000027)	(0.000021)	(0.000021)	-	(0.000017)
PPL	0.000244	0.000204	0.000220	0.000134	0.000108	0.000103	-	0.000085
PECO	0.000194	0.000162	0.000176	0.000108	0.000086	0.000083		0.000068
Pepco	0.000022	0.000019	0.000020	0.000013	0.000010	0.000010	-	0.000007
MAIT	0.000031	0.000026	0.000028	0.000017	0.000014	0.000013		0.000011
JCP&L	0.000003	0.000003	0.000003	0.000002	0.000001	0.000001	-	0.000001
Delmarva	0.000002	0.000001	0.000001	0.000001	0.000001	0.000001	-	0.000001
BG&E	0.000077	0.000064	0.000069	0.000043	0.000034	0.000033	-	0.000027
AEP - East	0.000128	0.000107	0.000115	0.000070	0.000057	0.000054	-	0.000045
Total	0.002220	0.001854	0.002002	0.001227	0.000981	0.000944	-	0.000779

Attachment 4b

ACE Translation of JCP&L Schedule 12 (Transmission Enhancement) Charges into Customer Rates

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

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

Rate Class	Col. 1 Transmission Obligation (MW)	Col. 2 Allocated Cost Recovery	Col. 3 BGS Eligible Sales Jan 2017 - Dec 2017 (kWh)	Col. 4 = Col. 2/Col. 3 Transmission Enhancement Charge ($/kWh)	Col. 5 = Col. 4 x 1/(1-.005) Transmission Enhancement Charge w/ BPU Assessment ($/kWh)	Col. 6 = Col. 5 x 1.06625 Transmission Enhancement Charge w/ SUT ($/kWh)
RS	1,553	$ 12,679	4,171,964,933	$ 0.000003	$ 0.000003	$ 0.000003
MGS Secondary	359	$ 2,928	1,152,950,462	$ 0.000003	$ 0.000003	$ 0.000003
MGS Primary	8	$ 67	24,456,016	$ 0.000003	$ 0.000003	$ 0.000003
AGS Secondary	393	$ 3,211	1,917,585,029	$ 0.000002	$ 0.000002	$ 0.000002
AGS Primary	94	$ 768	571,955,641	$ 0.000001	$ 0.000001	$ 0.000001
TGS	146	$ 1,193	920,786,585	$ 0.000001	$ 0.000001	$ 0.000001
SPL/CSL	-	$ -	73,240,385	$ -	$ -	$ -
DDC	2	$ 13	12,621,752	$ 0.000001	$ 0.000001	$ 0.000001
	2,554	$ 20,858	8,845,560,805			

Attachment 5 – RECO Tariffs and Rate Translation

Attachment 5a

Pro-forma RECO Tariff Sheets

Attachment 5b

RECO Translation of JCP&L Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Attachment 5a

Pro-forma RECO Tariff Sheets

SERVICE CLASSIFICATION NO. 1
RESIDENTIAL SERVICE (Continued)

RATE – MONTHLY (Continued)

(3) Transmission Charges

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

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

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

All kWh .... @	0.985 ¢ per kWh	0.985 ¢ per kWh

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

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

* Definition of Summer Billing Months - June through September

(Continued)

DRAFT

SERVICE CLASSIFICATION NO. 2
GENERAL SERVICE (Continued)

RATE – MONTHLY (Continued)

(3) Transmission Charges (Continued)

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

	Summer Months*	Other Months
Secondary Voltage Service Only		
All kWh ....@	0.593 ¢ per kWh	0.593 ¢ per kWh
Primary Voltage Service Only		
All kWh ....@	0.575 ¢ per kWh	0.575 ¢ per kWh

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

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

* Definition of Summer Billing Months - June through September

(Continued)

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

RATE – MONTHLY (Continued)

(3) Transmission Charge

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

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

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

All kWh .....@	0.624 ¢ per kWh	0.624 ¢ per kWh

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

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

* Definition of Summer Billing Months - June through September

(Continued)

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

RATE - MONTHLY (Continued)

(3) Transmission Charge

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

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

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

All kWh .... @	0.631 ¢ per kWh	0.631 ¢ per kWh

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

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

* Definition of Summer Billing Months - June through September

(Continued)

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

RATE– MONTHLY (Continued)

(3) Transmission Charges (Continued)

(a) (Continued)

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

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

		Primary	High Voltage Distribution
All Periods	All kWh @	0.368 ¢ per kWh	0.368 ¢ per kWh

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

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

(Continued)

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

SPECIAL PROVISIONS

(A) Space Heating

Customers who take service under this classification for 10 kW or more of permanently installed space heating equipment may elect to have the electricity for this service billed separately. All monthly use shall be billed at a Distribution Charge of 3.281 ¢ per kWh during the billing months of October through May and 5.304 ¢ per kWh during the summer billing months, a Transmission Charge of 0.421 ¢ per kWh and a Transmission Surcharge of 0.368 ¢ 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)

Attachment 5b

RECO Translation of JCP&L Schedule 12 (Transmission Enhancement) Charges into Customer Rates

Rockland Electric Company

Calculation of Transmission Surcharges reflecting changes in Transmission Enhancement Charges (JCP&L) effective January 1, 2018
To reflect FERC-approved JCP&L Project Schedule 12 Charges (Schedule 12 PJM OATT) for the period January 2018 to December 2018

2018 Average Monthly JCP&L-TEC Costs Allocated to RECO	$	27,195	(1)
2018 RECO Zone Transmission Peak Load (MW)		438.1	(2)
Transmission Enhancement Rate ($/MW-month)	$	62.08	
SUT		6.625%	

	Col. 1	Col. 2	Col.3=Col.2 x $27,195 x 12	Col. 4	Col. 5 = Col. 3/Col. 4	Col. 6 = Col. 5 x 1.07
Rate Class	BGS-Eligible Transmission Obligation (MW)	Transmission Obligation (Pct)	Allocated Cost Recovery (1)	BGS Eligible Sales January 2018 - December 2018 (kWh)	Transmission Enhancement Charge ($/kWh)	Transmission Enhancement Charge w/ SUT ($/kWh)
SC1	265.1	60.52%	$ 197,510	692,439,000	$ 0.00029	$ 0.00031
SC2 Secondary	122.2	27.89%	$ 91,003	528,990,000	$ 0.00017	$ 0.00018
SC2 Primary	14.5	3.32%	$ 10,821	65,159,000	$ 0.00017	$ 0.00018
SC3	0.1	0.02%	$ 50	275,000	$ 0.00018	$ 0.00019
SC4	0.0	0.00%	$ -	6,441,000	$ -	$ -
SC5	3.6	0.83%	$ 2,695	14,763,000	$ 0.00018	$ 0.00019
SC6	0.0	0.00%	$ -	5,550,000	$ -	$ -
SC7	32.6	7.43%	$ 24,259	227,701,000	$ 0.00011	$ 0.00012
Total	438.1 (2)	100.00%	$ 326,338	1,541,318,000		

(1) Attachment 2 - Cost Allocation of JCP&L Schedule 12 Charges to RECO Zone for January 2018 to December 2018
(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)		1,263,798	MWH
2	BGS-RSCP Eligible Sales Jan - Dec @ trans node (RECO Eastern Division)		1,176,362	MWH
3	BGS-RSCP Eligible Transmission Obligation		406	MW
4	Transmission Enhancement Costs to RSCP Suppliers	$	302,098.66	= Line 3 x $62.08 * 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 proposed changes effective January 1, 2018
To reflect: RMR Costs
FERC-approved ACE Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved AEP-East Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved BG&E Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved Delmarva Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved PATH Project Schedule 12 Charges (Schedule 12 PJM OATT
FERC-approved PEPCO Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved PPL Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved PSE&G Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved TrailCo Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved VEPCo Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved MAIT Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved JCP&L Project Schedule 12 Charges (Schedule 12 PJM OATT)
FERC-approved PECO Project Schedule 12 Charges (Schedule 12 PJM OATT)

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

Transmission Project	Note	SC1	SC2 Sec	SC2 Pri	SC3	SC4	SC5	SC6	SC7
Reliability Must Run	(1)	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001
ACE - TEC	(2)	0.00004	0.00002	0.00002	0.00002	0.00000	0.00002	0.00000	0.00001
AEP-East - TEC	(3)	0.00013	0.00008	0.00008	0.00008	0.00000	0.00008	0.00000	0.00005
BG&E- TEC	(4)	0.00003	0.00002	0.00002	0.00002	0.00000	0.00002	0.00000	0.00001
Delmarva - TEC	(5)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
PATH - TEC	(6)	(0.00004)	(0.00003)	(0.00003)	(0.00003)	0.00000	(0.00003)	0.00000	(0.00002)
PEPCO - TEC	(7)	0.00001	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00000
PPL - TEC	(8)	0.00022	0.00013	0.00013	0.00014	0.00000	0.00014	0.00000	0.00008
PSE&G - TEC	(9)	0.00770	0.00464	0.00448	0.00487	0.00000	0.00493	0.00000	0.00288
TrAILCo - TEC	(10)	0.00042	0.00026	0.00025	0.00027	0.00000	0.00027	0.00000	0.00016
VEPCo - TEC	(11)	0.00036	0.00021	0.00021	0.00023	0.00000	0.00023	0.00000	0.00013
MAIT -TEC	(12)	0.00002	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00001
JCP&L -TEC	(13)	0.00029	0.00017	0.00017	0.00018	0.00000	0.00018	0.00000	0.00011
PECO -TEC	(14)	0.00006	0.00003	0.00003	0.00004	0.00000	0.00004	0.00000	0.00002
Total ($/kWh and excl SUT)		$0.00925	$0.00556	$0.00539	$0.00585	$0.00001	$0.00591	$0.00001	$0.00345
Total (¢/kWh and excl SUT)		0.925 ¢	0.556 ¢	0.539 ¢	0.585 ¢	0.001 ¢	0.591 ¢	0.001 ¢	0.345 ¢

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

Transmission Project	Note	SC1	SC2 Sec	SC2 Pri	SC3	SC4	SC5	SC6	SC7
Reliability Must Run	(1)	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001	$0.00001
ACE - TEC	(2)	0.00004	0.00002	0.00002	0.00002	0.00000	0.00002	0.00000	0.00001
AEP-East - TEC	(3)	0.00014	0.00009	0.00009	0.00009	0.00000	0.00009	0.00000	0.00005
BG&E- TEC	(4)	0.00003	0.00002	0.00002	0.00002	0.00000	0.00002	0.00000	0.00001
Delmarva - TEC	(5)	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
PATH - TEC	(6)	(0.00004)	(0.00003)	(0.00003)	(0.00003)	0.00000	(0.00003)	0.00000	(0.00002)
PEPCO - TEC	(7)	0.00001	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00000
PPL - TEC	(8)	0.00023	0.00014	0.00014	0.00015	0.00000	0.00015	0.00000	0.00009
PSE&G - TEC	(9)	0.00821	0.00495	0.00478	0.00519	0.00000	0.00526	0.00000	0.00307
TrAILCo - TEC	(10)	0.00045	0.00028	0.00027	0.00029	0.00000	0.00029	0.00000	0.00017
VEPCo - TEC	(11)	0.00038	0.00022	0.00022	0.00025	0.00000	0.00025	0.00000	0.00014
MAIT -TEC	(12)	0.00002	0.00001	0.00001	0.00001	0.00000	0.00001	0.00000	0.00001
JCP&L -TEC	(13)	0.00031	0.00018	0.00018	0.00019	0.00000	0.00019	0.00000	0.00012
PECO -TEC	(14)	0.00006	0.00003	0.00003	0.00004	0.00000	0.00004	0.00000	0.00002
Total ($/kWh and incl SUT)		$0.00985	$0.00593	$0.00575	$0.00624	$0.00001	$0.00631	$0.00001	$0.00368
Total (¢/kWh and incl SUT)		0.985 ¢	0.593 ¢	0.575 ¢	0.624 ¢	0.001 ¢	0.631 ¢	0.001 ¢	0.368 ¢

Notes:

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

Attachment 6 – PJM Schedule 12 (Transmission Enhancement) Charges

JCP&L Project Charges

Attachment 6 - PJM Schedule 12 - Transmission Enhancement Charges for January 2018 - December 2018
Calculation of Costs and Monthly PJM charges for JCP&L Projects

Updated 1/26/2018

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

	(k)	(l)	(m)	(n)	(o)
Zonal Cost Allocation for New Jersey Zones	Average Monthly Impact on Zone Customers in 2018	2018 Trans. Peak Load [2]	Rate in \$/MW-mo. [1]	2018 Impact (12 months)	
PSE&G	$ 658,609	9,566.9	$ 68.84	$ 7,903,306	
JCP&L	$ 722,153	5,721.0	$ 126.23	$ 8,665,841	
ACE	$ 1,729	2,540.8	$ 0.68	$ 20,748	
RE	$ 27,195	401.7	$ 67.70	$ 326,338	
Total Impact on NJ Zones	**$ 1,409,686**	**18,230.4**		**$ 16,916,234**	
			= (k) / (l)	= (k) *12	

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

Attachment 6

Required Transmission Enhancements owned by: Jersey Central Power & Light (Transmission)

PJM Upgrade ID	Annual Revenue Requirement	Monthly Revenue Requirement (Jan - Dec 2018)	Responsible Customers'/Zones' allocation shares of monthly charges																						
			AE	AEP	APS	ATSI	BGE	ComEd	Dayton	Duke Energy OH/KY	Duquesne	Delmarva	Dominion	EKPC	HTP	JCPL	MetEd	Neptune	PECO	Penelec	PEPCO	PPL	PSEG	Rockland	East Coast Power
b0174	$ 1,273,748.00	$ 106,145.67														35.98%		5.76%					55.27%	2.99%	0.00%
			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 38,191.21	$ -	$ 6,113.99	$ -	$ -	$ -	$ -	$ 58,666.71	$ 3,173.76	$ -
b0268	$646,180	$ 53,848.33														62.43%		3.03%					33.08%	1.46%	0.00%
			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 33,617.51	$ -	$ 1,631.60	$ -	$ -	$ -	$ -	$ 17,813.03	$ 786.19	$ -
b0726	$846,872	$ 70,572.67	2.45%													97.55%									
			$ 1,729.03	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 68,843.64	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
b2015	$18,839,128	$ 1,569,927.33											0.00%			37.04%		24.40%					37.08%	1.48%	0.00%
			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 581,501.08	$ -	$ 383,062.27	$ -	$ -	$ -	$ -	$ 582,129.06	$23,234.92	$ -
b1374	$ -	$ -																		100.00%					
			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TOTAL	$ 21,605,928.00	$ 1,800,494.00	$ 1,729.03	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 722,153.45	$ -	$ 390,807.86	$ -	$ -	$ -	$ -	$ 658,608.79	$27,194.87	$ -

Attachment 7

HTP FERC Order

161 FERC ¶ 61,262
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Cheryl A. LaFleur, Neil Chatterjee,
Robert F. Powelson, and Richard Glick.

PJM Interconnection, L.L.C. Docket No. EL17-84-000

ORDER REQUIRING PJM TO PERMIT CONVERSION OF FIRM TO NON-FIRM TRANSMISSION WITHDRAWAL RIGHTS UNDER INTERCONNECTION SERVICE AGREEMENT

(Issued December 15, 2017)

1. On September 8, 2017, the Commission instituted a proceeding pursuant to section 206 of the Federal Power Act (FPA) directing PJM Interconnection, L.L.C. (PJM) and Public Service Electric and Gas Company (PSEG or Interconnected Transmission Owner) to show cause: (1) why the existing Interconnection Service Agreement (Existing ISA) between Hudson Transmission Partners, LLC (HTP), PSEG, and PJM is not unjust and unreasonable and unduly discriminatory to the extent it fails to allow HTP to convert Firm Transmission Withdrawal Rights (TWRs) to Non-Firm TWRs; and (2) why PSEG's failure to consent to an amendment to the Existing ISA reflecting the same is not unjust, unreasonable, and unduly discriminatory.[1] As discussed below, and based on the filings described herein, we find that the Existing ISA is unjust and unreasonable insofar as it does not permit HTP to convert its Firm TWRs to Non-Firm TWR.

I. Background

2. PJM's Open Access Transmission tariff (tariff or OATT) provides merchant transmission facilities with the right to elect TWRs in lieu of other transmission rights[2]

[1] *PJM Interconnection, L.L.C.*, 160 FERC ¶ 61,056 (2017) (Show Cause Order).

[2] Interconnection customers can elect TWRs in lieu of Incremental Deliverability Rights, Incremental Auction Revenue Rights, Incremental Capacity Transfer Rights, and Incremental Available Transfer Capability Revenue Rights. *See* PJM OATT § 232, Transmission Injection Rights and Transmission Withdrawal Rights.

and to request either Firm or Non-Firm TWRs. Firm TWRs allow the merchant transmission facility to schedule energy and capacity withdrawals from the PJM system.[3] In contrast, Non-Firm TWRs only allow the merchant transmission facility to schedule energy and, as such, are similar to Non-Firm Point-to-Point Transmission Service in that Non-Firm TWRs allow the merchant transmission facility to schedule transmission service on an as-available basis and are subject to curtailment.[4]

3. Once a merchant transmission facility has elected to obtain TWRs rather than another type of transmission right, PJM determines the necessary upgrades to support the Firm or Non-Firm TWRs requested through its interconnection process.[5] Upon receiving an interconnection request, PJM undertakes feasibility and system impact studies, and based on these costs, the merchant transmission facility decides the level of Firm or Non-Firm TWRs it wishes to obtain. The interconnecting merchant transmission facility is assigned the costs of the Merchant Network Upgrades that would not have been incurred "but for" the interconnection request.[6] The merchant transmission facility, PJM, and the transmission owner to which the facility will be interconnected enter into a three-party ISA establishing the costs and conditions of the interconnection. In addition, a merchant

[3] Firm TWRs have rights similar to those under Firm Point-to-Point Transmission Service. Firm TWRs are rights to schedule energy and capacity withdrawals between a Point of Interconnection of merchant transmission facility with the transmission system that can only be awarded to a merchant transmission facility, whereas Firm Point-to-Point Transmission Service is reserved or scheduled energy between specified Points of Receipt and Points of Delivery for transmission customers generally. *See* PJM OATT § I, OATT Definitions 1.13A, E-F, 5.0.1 and Definitions L-M-N, 14.0.0. *See also* PJM OATT § II, Point-to-Point Transmission Service.

[4] *See* PJM OATT § I, OATT Definitions L-M-N, 14.0.0, Non-Firm Transmission Withdrawal Rights.

[5] PJM OATT § 232.3, Determination of Transmission Injection Rights and Transmission Withdrawal Rights to be Provided to Interconnection Customer.

[6] *PJM Interconnection, L.L.C.*, 102 FERC ¶ 61,277, at P 4 (2003). Merchant Network Upgrades are additions or upgrades to, or replacement of, existing transmission system facilities by or on behalf of a merchant transmission facility developer. *See* PJM OATT, § I, OATT Definitions - L - M - N, 11.0.0. In exchange for their Merchant Network Upgrades, merchant transmission facilities receive Firm TWRs and Financial Transmission Rights. *See* PJM Filing, ER03-405-000 at 12 (identifying transmission-related rights to which merchant transmission facility developers may be entitled), PJM Interconnection, L.L.C./Intra-PJM Tariffs, OATT 206.5 Estimates of Certain Upgrade-Related Rights.

transmission facility is responsible, on an annual basis, for the costs of any post-interconnection network upgrades to the transmission system necessary to support the merchant transmission facility's Firm TWRs.[7]

Filing in Docket No. ER17-2073-000

4. The Existing ISA sets out the rights and responsibilities of PJM, HTP, and PSEG with respect to the interconnection to the PJM system of the Hudson Line,[8] a 660 MW high voltage direct current (HVDC) fully controllable merchant transmission facility that connects PJM in Northern New Jersey and the New York Independent System Operator, Inc. (NYISO) in New York City via a 345 kV undersea cable.[9] On July 10, 2017, at the request of HTP, PJM filed, under section 205 of the FPA, an unexecuted amended ISA (Amended ISA) among PJM, HTP, and PSEG, to be effective June 2, 2017.[10] PJM filed the Amended ISA unexecuted as PSEG, a party to the agreement, did not consent. Under the Amended ISA, HTP sought to convert its 320 megawatts (MW) of Firm TWRs to Non-Firm TWRs, resulting in 673 MW of Non-Firm TWRs and 0 MW of Firm TWRs. PJM stated that the proposed amendment to the Existing ISA comported with the 673 MW Nominal Rated Capability of the facility specified in the Existing ISA and that

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[7] *See* PJM OATT § Schedule 12 (b), and PJM OATT § 232.2, Right of Interconnection Customer to Transmission Injection Rights and Transmission Withdrawal Rights. *See also*, *PJM Interconnection, L.L.C.*, Opinion No. 503, 129 FERC ¶ 61,161 (2009) (finding that merchant transmission facilities should be responsible for the costs of maintaining network reliability, including costs for RTEP responsibility assignments, based on their Firm TWRs).

[8] HTP states that the Hudson Line, over which PJM has operational control, went into service in June of 2013. HTP Response, Docket No. EL14-84-000, at 5.

[9] HTP states that, pursuant to a long-term offtake contract, it transferred all of its Firm TWRs on the Hudson Line to the New York Power Authority (NYPA) for the purpose of exporting energy and capacity from PJM to NYISO. HTP states that NYPA pays for the rights that it receives under the long-term offtake contract, including costs of network upgrades required for the interconnection of the Hudson Line to PJM and for PJM RTEP transmission enhancement costs allocated to HTP under the existing Schedule 12 of the PJM OATT. Show Cause Order, 160 FERC ¶ 61,056 at P5; HTP Response, Docket No. EL14-84-000, at 5-6.

[10] PJM made this filing in Docket No. ER17-2073-000.

HTP's request would not adversely impact the operation or reliability of the PJM system.[11]

5. In the September 8, 2017 order, the Commission rejected the Amended ISA, finding that neither the Existing ISA nor PJM's tariff permitted PJM to file, under section 205, an unexecuted amended ISA with modifications requested by an interconnection customer.[12] While the Commission rejected PJM's filing, the Commission also found that, based on the evidence in the proceeding, the Existing ISA may be unjust and unreasonable and unduly discriminatory to the extent that it fails to permit HTP to convert Firm TWRs to Non-Firm and that PSEG's withholding of consent to the Amended ISA may also be unjust and unreasonable. Accordingly, the Commission instituted a proceeding, in Docket No. EL17-84-000, pursuant to section 206 of the FPA, requiring PSEG and PJM to show cause why the Existing ISA and PSEG's failure to consent to the Amended ISA is not unjust and unreasonable and unduly discriminatory.

6. In instituting the section 206 proceeding, the Commission stated that not permitting HTP to reduce the quality of its service from Firm TWRs to Non-Firm TWRs appeared to be unjust and unreasonable in these factual circumstances. The Commissioned reasoned that (1) HTP had fully paid for the network upgrades necessary for its Firm TWRs and therefore the reduction would not affect payments for previously constructed facilities;[13] (2) the conversion would not exceed the nominal rated capability of the Hudson Line and therefore system withdrawals would not increase; (3) HTP operates a DC line that is fully controllable by PJM, so PJM can shut off flows, consistent with applicable rules and procedures, in the event that a reliability or other operational

[11] Show Cause Order, 160 FERC ¶ 61,056 at P 5.

[12] The Commission found that, under PJM's tariff and the Existing ISA, without the consent of all parties to the Amended ISA, HTP was required to file under section 206 of the FPA to amend the Existing ISA. Show Cause Order, 160 FERC ¶ 61,056 at PP 34-40.

[13] *See* Opinion No. 503, 129 FERC ¶ 61,161 at P 80 & n.84 ("PJM would not need to incur the upgrades since it has *no obligation to plan for Non-Firm Transmission Withdrawal Rights in the RTEP process*") (emphasis added) and P 110 ("As the system changes for a variety of reasons (e.g., retirements and load growth), it may be necessary to construct additional facilities in order for PJM to be able to provide the level of *Firm Transmission Withdrawal Rights* to which the customers subscribed. In those circumstances, we find it just and reasonable and not unduly discriminatory or preferential for PJM to charge the Merchant Transmission Facilities for the costs of assuring their service.") (emphasis added).

problem arises; and (4) HTP's relinquishing of Firm TWRs would not adversely impact the operation or reliability of the PJM system.[14]

7. In response to a PSEG argument, the Commission also stated that requiring HTP to terminate the Existing ISA and disconnect an already constructed transmission line, rather than permitting an amendment of the Existing ISA to convert Firm TWRs to Non-Firm TWRs, appeared to be unjust and unreasonable. The Commission noted that Non-Firm TWRs impose less of a burden on the system than HTP's Firm TWRs and that PJM, as the system operator, finds that such a conversion will not have adverse reliability or operational impacts.[15]

8. The Commission also found that the protestors' arguments related to cost allocation were beyond the scope of the proceeding because such arguments challenged the justness and reasonableness of PJM's RTEP cost allocation method, not whether HTP should be able to convert its Firm TWRs to Non-Firm.[16]

9. On September 8, 2017, Linden VFT, L.L.C. (Linden) filed a request for rehearing of the Show Cause Order, which is still pending before the Commission.

II. Notice of Filing and Responsive Pleadings

10. Notice of the Show Cause Order was published in the *Federal Register*, 82 Fed. Reg. 43,535 (Sept. 18, 2017), with interventions due on or before September 29, 2017.

11. Timely motions to intervene were filed by Duke Energy Corporation; PPL Electric Utilities Corporation; Exelon Corporation; FirstEnergy Service Company (FirstEnergy), ITC Lake Erie Connector, LLC; American Electric Power Service Corporation; Monitoring Analytics, LLC, acting in its capacity as Independent Market Monitor for PJM (Market Monitor); NYPA; HTP; New Jersey Board of Public Utilities (NJBPU); and Consolidated Edison Energy, Inc. Out-of-time motions to intervene were filed by Consolidated Edison Company of New York (Con Edison); Long Island Power Authority and its operating subsidiary, Long Island Lighting Company d/b/a LIPA; City of New York, New York (New York City); and Linden VFT, L.L.C. (Linden).

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[14] Show Cause Order, 160 FERC ¶ 61,056 at P 43.

[15] *Id.* P 44.

[16] *Id.* P 45.

12. On October 25, 2017, and October 30, 2017, respectively, NYPA and HTP each filed answers to PSEG's response to the Show Cause Order. NJBPU filed comments on October 10, 2017 and on October 25, 2017, Linden filed an answer to PSEG's response to the Show Cause Order and NJBPU's comments. The Market Monitor filed comments on November 1, 2017. On November 3, 2017, Linden filed an answer to the Market Monitor's November 1st comments. On November 9, 2017, HTP filed an answer to the Market Monitor's November 1st comments. On November 10, 2017, the Market Monitor filed an answer to Linden's November 3rd and HTP's November 9th answers and a motion to lodge information in the related but non-consolidated complaint filed by Linden against PJM in order to provide a more complete record in that proceeding. On November 13, 2017, Linden filed an answer to the Market Monitor's November 10th comments and motion to lodge. On November 14, 2017, NYPA filed an answer to the Market Monitor's November 1st and 13th comments. On November 17, 2017, FirstEnergy, on behalf of the PJM Transmission Owners, filed comments in response to Linden's November 3rd and November 13th answers.

III. Show Cause Order Responses, Comments, and Answers

13. In its response, PJM agrees that, given the unique facts of this case, it is reasonable for the Commission to consider whether the Existing ISA is unjust and unreasonable and unduly discriminatory if HTP is not permitted to reduce the quality of its service from Firm to Non-Firm TWRs. As noted by the Commission, PJM states that those relevant facts include: (1) HTP has fully paid for the network upgrades required to receive Firm TWRs (therefore the reduction of service from Firm to Non-Firm TWRs will not affect HTP's responsibility to fund previously constructed facilities); (2) the conversion will not exceed the nominal rated capability of the Hudson Line (because system withdrawals will not increase); (3) HTP's line is fully controllable by PJM (so PJM can shut off flows in the event that a reliability or operational problem arises), and (4) allowing HTP to convert its Firm TWRs to Non-firm TWRs will not adversely impact the operation or reliability of the PJM transmission system. Should the Commission allow HTP to amend its ISA to convert its Firm TWRs to Non-Firm TWRs, PJM contends that the termination of the Firm TWRs should not relieve HTP of its cost responsibility obligations under Schedule 12 of the PJM tariff that were incurred prior to termination of its Firm TWRs and that any future cost responsibility obligations should terminate in accordance with existing tariff processes.

14. In its response, PSEG argues cost allocation is not beyond the scope of this proceeding, and the amendment to the Existing ISA will result in preferential rates for New York customers as HTP will avoid a share of cost responsibility that it caused. PSEG further argues that it reasonably relied upon the long-term duration of the Existing ISA, and permitting an unilateral amendment of ISAs will undermine the interconnection

process. PSEG adds that the provisions of the Existing ISA are protected by the *Mobile-Sierra* doctrine. [17] Finally, PSEG argues HTP's amendment to its Existing ISA raises issues of material fact that require that this matter be set for hearing and settlement procedures. NJBPU also filed comments arguing cost allocation is not beyond the scope of this proceeding.

15. In their answers, HTP, NYPA, and Linden argue that PSEG fails to provide a reasonable basis for PSEG's refusal to consent to HTP's request to reduce the quality of its service under the Existing ISA by converting its Firm TWRs to Non-Firm TWRs and therefore, PSEG's refusal to consent to amending the Existing ISA is unjust, unreasonable, and unduly discriminatory and preferential. They also argue that, regardless of PSEG's unreasonable refusal to consent, the Existing ISA is unjust and unreasonable and unduly discriminatory to the extent that it fails to permit HTP to reduce the quality of its service under the Existing ISA by relinquishing its Firm TWRs and retaining only Non-Firm TWRs. HTP also requests that the Commission act on the Show Cause Order and grant the relief requested by no later than December 15, 2017.

16. As further detailed below, the PJM Market Monitor and PJM Transmission Owners filed comments concerning the allocation of costs for RTEP projects to Firm Point-to-Point transmission customers as it may relate to a merchant transmission facility's request for Firm Point-to-Point transmission service.

A. Mobile Sierra

17. PSEG contends that the provisions of the Existing ISA are protected by the *Mobile-Sierra* doctrine. PSEG states that the Existing ISA was filed and accepted by the Commission and as such it has the force of a filed rate.[18] PSEG argues that the *Mobile-Sierra* doctrine requires that the Commission presume that the contract rates and terms contained in the Existing ISA are just and reasonable, unless otherwise shown to be contrary to the public interest.[19] PSEG states that the presumption may be overcome only if the Commission concludes that the contract seriously harms the public interest,[20] which

[17] *F.P.C. v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956); *United Gas Pipe Line Co. v. Mobile Gas Service Corp.*, 350 U.S. 344 (1956) (Mobile-Sierra).

[18] PSEG Response, Docket No. EL17-84-000 at 7 (citing *Town of Norwood v. F.E.R.C.*, 217 F.3d 24, 28 (1st Cir 2000), *cert. denied*, 532 U.S 993 (2001)).

[19] *Id.* (citing *NRG Power Mktg., LLC v. Me. Pub. Utils.Comm'n*, 558 U.S. 165, 167 (2010)).

[20] *Id.* (citing *Morgan Stanley Capital Group Inc. v. Pub. Util. Dist. No. 1 of Snohomish County*, 554 U.S. 527, 128 S.Ct. 2733, 2736 171 L.Ed.2d 607 (2008)).

generally requires "a finding that the existing rate or term 'might impair the financial ability of [a] public utility to continue its service,' or that the rate would 'cast upon other consumers an excessive burden, or be unduly discriminatory,' [or that there are] other 'circumstances of unequivocal public necessity.'"[21] PSEG states that is not the case here and the Existing ISA must not be disturbed.

18. HTP and Linden argue that the limited revisions in the Amended ISA are not protected by the *Mobile-Sierra* doctrine. Linden states that in order to determine whether the *Mobile-Sierra* presumption applies to a contract, the Commission considers whether a contract "embodies either: (1) individualized rates, terms, or conditions that apply only to sophisticated parties who negotiated them freely at arm's length; or (2) rates, terms, or conditions that are generally applicable or that arose in circumstances that do not provide the assurance of justness and reasonableness associated with arm's-length negotiations."[22] Linden states that contracts that have the characteristics of the first category may be eligible to qualify for the *Mobile-Sierra* presumption, but contracts that have the characteristics of the latter "constitute tariff rates, terms, or conditions to which the *Mobile-Sierra* presumption does not apply."[23] Linden states that the Commission has further explained that terms of an agreement that are "incorporated into the service agreements of all present and future customers…are properly classified as tariff rates and the *Mobile-Sierra* presumption would not apply."[24] Linden argues that the Existing ISA is a form agreement, the *pro forma* for which is attached to the PJM tariff as Attachment O. Thus, Linden concludes, it constitutes a tariff rate that is not eligible for the *Mobile-Sierra* presumption. Linden states that, as the relevant language is in the form agreement, the parties were not in a position to negotiate the terms and conditions of this agreement "freely at arm's length." HTP also points out that PSEG did not seek

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[21] *Id.* (citing *Wis. Pub. Power*, 493 F.3d at 271 (quoting Fed. Power Comm'n v. Sierra Pac. Power Co., 350 U.S. 348, 355, 76 S.Ct. 368, 100 L.Ed. 388 (1956); Permian Basin Area Rate Cases, 390 U.S. 747, 822, 88 S.Ct. 1344, 20 L.Ed.2d 312 (1968)).

[22] Linden Answer, Docket No. EL17-84-000, at 13 (citing *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214, at P 183 (2013) (PJM)).

[23] *Id.* (citing *PJM*, 142 FERC ¶ 61,214 at P 183 (citing *New England Power Generators Ass'n, Inc. v. FERC*, 707 F.3d 364 (D.C. Cir. 2013)).

[24] *Id.* (citing *PJM*, 142 FERC ¶ 61,214 at P 184 (citing *Carolina Gas Transmission Corp.*, 136 FERC ¶ 61,014 at P 17 (2011) (Carolina Gas)).

rehearing of the Commission's conclusion in the Show Cause Order that the changes in this proceeding are not contract rates and are instead "non-rate" terms of service.[25]

19. Linden and NYPA argue that, even if the *Mobile-Sierra* presumption were to apply, the Commission may overcome the Mobile-Sierra presumption by determining that the Existing ISA and PSEG's refusal to consent to the Amended ISA is not consistent with the public interest. Linden states that U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) has held that "a *Mobile-Sierra* contract will not automatically shield any and all discriminatory treatment from attack under Section 205(b) of the Federal Power Act. Rather, that section remains an independent force which must be accommodated."[26]

20. NYPA contends that the Commission has previously determined that any presumption of *Mobile-Sierra* protection created by inclusion of a *Mobile-Sierra* clause may be overcome by a reservation of rights provision and in such instances, the just and reasonable standard of review applies.[27] NYPA states that section 22.3 of the Existing ISA specifically reserves to all parties their rights "with respect to changes in applicable rates or charges under Section 205 of the Federal Power Act . . . or any of the rights of any Interconnection Party under Section 206 of the Federal Power Act." NYPA states that such language unambiguously preserves all parties' section 206 rights under the ordinary just and reasonable standard.

B. Cost Allocation

21. PSEG and NJBPU disagree with the Commission determination that cost allocation is beyond the scope of this proceeding. PSEG argues that allowing HTP to unilaterally change terms by converting its Firm TWRs to Non-Firm, so it can escape its cost responsibilities and continue to benefit from needed infrastructure investment while

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[25] HTP Answer, Docket No. EL17-84-000, at 18 (citing Show Cause Order, 160 FERC ¶ 61,056 at P 39).

[26] Linden Answer, Docket No. EL17-84-000, at 14 (citing *Town of Norwood*, 587 F.2d at 1311).

[27] NYPA Answer, Docket No. EL17-84-000, at 14 (citing *Ontelaunee Power Operating Co., LLC v. Metropolitan Edison Co.*, 119 FERC ¶ 61,181, at PP 21, 24- 25, n.19 (2007) (Ontelaunee Power) (citing *Kiowa Power Partners, LLC v. Pub. Serv. Co. of Okla.*, 110 FERC ¶ 61,118, at P 10 (2005)); *Duke Energy Hinds, LLC*, 102 FERC ¶ 61,068, at P 21 (2003); *PJM Interconnection, L.L.C.*, 117 FERC ¶ 61,168, at PP 8, 38-39 (2006)).

passing a portion of its legitimate transmission cost obligation on to New Jersey ratepayers would be unjust and unreasonable.

22. PSEG also argues that allowing amendment of the ISA will result in preferential rates for New York customers to the detriment of New Jersey ratepayers. PSEG states that both the New York Independent System Operator, Inc. (NYISO) and New York Public Service Commission (NYPSC) concede that there are benefits to New York ,such as operational, reliability, and resource adequacy support for the New York Control Area (NYCA). PSEG states that New York customers will continue to receive these benefits even after the conversion to Non-Firm TWRs without any responsibility for the continued costs which will then fall to New Jersey ratepayers. Further, PSEG states that HTP's withdrawal requirement has, in some instances, driven the need for RTEP projects in the Northern PSEG zone. Similarly, PSEG states that, but for HTP's Firm TWRs, some of these projects may not have been built or at the least may have been delayed for many years, or the system may have been planned in a different way.[28] PSEG contends that, if HTP is permitted to escape from the market and financial risks associated with its project and does not continue to bear its appropriate share of cost responsibility for PJM transmission facilities, then the cost allocation to customers in PJM will need to be increased to cover the costs, while HTP and the load that they are serving in New York unjustly and unreasonably get a "free ride."

23. PSEG also argues that opening the door to unilateral amendment of ISAs will undermine the entire RTO interconnection process. PSEG states that it reasonably relied upon the long-term duration of the Existing ISA. PSEG states that allowing HTP to circumvent the PJM documented interconnection procedures is prejudicial to other transmission customers seeking to interconnect, disruptive of the orderly nature of the PJM queue process and has absolutely no basis in the PJM Tariff. PSEG explains that the PJM transmission system is planned and designed to accommodate a planned MW quantity, both at the time of a facility's interconnection, and in subsequent studies to maintain the reliability of the transmission system.

24. With respect to PSEG's RTEP cost allocation arguments, HTP, NYPA, and Linden argue that PSEG's arguments do not provide a reasonable basis for PSEG's refusal to consent to the Amended ISA. Those arguments, they contend, reflect a challenge to the justness and reasonableness of PJM's cost allocation, which must be raised in a separate section 206 complaint. HTP states that Schedule 12 is not the subject of this proceeding and the existing cost allocation methodology in Schedule 12 is not modified or changed in any way by the Amended ISA. Similarly, HTP states that the Amended ISA does not propose any changes to PJM's existing transmission expansion

[28] PSEG Response, Docket No. EL17-84-000, at 13 (citing Khadr Affidavit at P 23).

planning methodology in the PJM Operating Agreement. HTP states that it will not continue to benefit from PJM transmission planning for new RTEP expansion projects because PJM will no longer plan for HTP in its RTEP transmission expansion planning.[29]

25. Linden also points out that PSEG made the same arguments in *New York Indep. Sys. Operator, Inc.*, 161 FERC ¶ 61,033 (2017) with respect to Con Edison and the Commission rejected PSEG's arguments. Linden states that PSEG's fear of cost reallocations to the New Jersey ratepayers resulting from the operation of the Schedule 12 reallocation process cannot be a just and reasonable basis for PSEG to refuse to consent to HTP reducing the service level of its Firm TWRs.

26. HTP also disputes PSEG's argument that permitting HTP to reduce the quality of its service in the Amended ISA would result in preferential rates for New York customers. HTP states that it has assumed the full market and financial risks for its project and has paid approximately $650 million in capital costs to construct the Hudson Line. HTP also states that it and NYPA have paid approximately $320 million for network upgrades to the PJM system for the interconnection of the Hudson Line to the PJM system. HTP states that, as a merchant transmission facility, HTP is not allowed to recover the costs for these transmission facilities through the PJM transmission rates. HTP states that, in addition, all HTP customers using the Hudson Line, including NYPA, are required by PJM to use Point-to-Point transmission service and pay PJM for it. HTP states that this includes ancillary services associated with Point-to-Point transmission service, including Scheduling service, Reactive Support and Voltage Control service, and Black Start service. For these reasons, HTP asserts that it and NYPA have paid, and will continue to pay, for the Hudson Line and use of the Hudson Line and the benefits that it provides. However, HTP notes that following a reduction in service level, it will no longer enjoy the right to schedule capacity withdrawals across the Hudson Line using Firm TWRs and PJM will no longer include HTP's Firm TWRs in its transmission expansion planning under the PJM Operating Agreement.

27. HTP and NYPA also argue that reducing the quality of its service in the Amended ISA will not open the door to unilateral amendment of ISAs or undermine the entire RTO interconnection process. HTP argues that this proceeding concerns a narrow, single issue that only applies to three merchant transmission facilities in PJM, two of which are parties to the proceeding. NYPA states that the anticompetitive behavior of

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[29] HTP Answer, Docket No. EL17-84-000, at 14 (citing PJM Operating Agreement, Schedule 6, Sect. 1.1. PJM Manual 14B: PJM Regional Transmission Expansion Planning Process, Att. C.7.3 (Rev. 39, Sept. 28, 2017) (Firm TWRs are included in the RTEP planning model); Opinion No. 503, 129 FERC ¶ 61,161 at P 80, n.84 ("PJM … has no obligation to plan for Non-Firm Transmission Withdrawal Rights in the RTEP process. Citing Tr. 278:5 – 280:15 (PJM Witness Herling)).

interconnecting transmission owners that refuse to consent to changes in interconnection service elections is what threatens to undermine the RTO interconnection process. Contrary to PSEG, HTP also asserts that, under the PJM Operating Agreement and PJM Manual 14-B, PJM performs its RTEP transmission expansion planning only for load and for Firm TWRs that are held by merchant transmission facilities. HTP states that under the terms of the PJM Operating Agreement and PJM Manual 14B, PJM will no longer perform its RTEP transmission expansion planning taking into account Firm TWRs held by HTP, and will no longer plan the PJM system to accommodate any such Firm TWRs.

28. HTP, NYPA, and Linden also dispute PSEG's claim that it relied on HTP's Firm TWRs being included in PJM's transmission planning and cost allocation for a "long-term duration." They contend that there is no reasonable basis for such reliance in light of the Existing ISA, the PJM tariff and the Commission's prior decisions. They argue that PSEG's claim is undercut by PSEG's acknowledgement that HTP is permitted to terminate the Existing ISA without the consent of PSEG, which would terminate all of HTP's interconnection rights, including the Firm TWRs. Linden states that, under Schedule 12 of the PJM tariff, cost allocation for regional transmission upgrades is based solely on firm use of an upgrade and shifts over time as different upgrade users change their firm service. Linden also claims that having a methodology that purports to update PJM-determined "beneficiaries" of RTEP projects each year was touted by the PJM Transmission Owners, including PSEG, as a primary benefit of the Solution-based DFAX methodology (as compared to its predecessor, Violation-based DFAX) because it theoretically allocates costs of projects to the use of those projects over time throughout their life, rather than only at the time of the upgrade.[30] Linden also asserts that there is nothing in the PJM tariff that requires or even suggests that merchant transmission facilities would or could be allocated costs for the life of an upgrade under Solution-based DFAX based on the number of Firm TWRs they hold when the RTEP project is first proposed.

29. NJBPU contends that the issue of cost allocation is not beyond the scope of this proceeding, as cost allocation is primarily what HTP and Linden seek to avoid. NJBPU states that the Amended ISA cannot be viewed in a vacuum. NJBPU states that HTP has conceded that the Amended ISA is an attempt to gain relief from RTEP costs in this matter, when such relief has not been granted in other proceedings. NJBPU states that indulging this collateral attack sets a dangerous precedent likely to inundate the

[30] Linden Answer, Docket No. EL17-84-000, at 12 (citing PJM Transmission Owners Filing, Transmittal Letter at 11, Docket No. ER13-90-000 (filed Oct. 11, 2012) ("because Solution-Based DFAX is based on the analysis of flows on the new facility, the analysis can be updated annually to capture changes in the distribution of the benefits of the new transmission facility")).

Commission with unwanted litigation from parties seeking a favorable decision by any means necessary. In addition, NJBPU argues that, if HTP is successful in avoiding its share of cost responsibility for PJM transmission facilities, then the cost allocation to customers in PJM will be increased to cover the costs as load in New York continues to receive the same benefits. NJBPU argues that it is unjust and unreasonable for load in New York to receive such benefit for nothing—and that is precisely what is sought.

30. In its answer, the Market Monitor addresses an alleged discrepancy in the allocation of costs for merchant transmission providers which hold firm point to point transmission contracts and those that hold Firm TWRs. The Market Monitor contends that Linden seeks to substitute Firm Point-to-Point Transmission service coupled with Non-Firm TWRs to maintain the ability to export capacity to the NYISO from PJM with the same level of transmission service they have with Firm TWRs. The Market Monitor asserts that this creates a discrepancy in cost allocation between section 232.2 and Schedule 12 of the tariff in that Schedule 12 omits any reference to merchant transmission facilities that hold both firm transmission service to the PJM border and Non-Firm TWRs. The Market Monitor concludes that it would not be just and reasonable to merchant transmission providers to retain the same capacity export though firm point-to-point transmission service and avoid RTEP cost allocation.

31. The PJM Transmission Owners also filed an answer clarifying that Schedule 12 defines customers with Firm Point-to-Point Transmission Service as customers responsible for the costs of RTEP projects.[31] The PJM Transmission Owners also state that Schedule 7 specifies that Firm Point-to-Point transmission customers should not be charged for the same RTEP costs under their applicable Point-to-Point service rate, and that Firm Point-to-Point customers can thus be assessed RTEP costs.[32]

C. <u>Reliability</u>

32. PSEG requests that the matter be set for hearing and settlement procedures, if not summarily dismissed. PSEG asserts that the issue of the operational and reliability impacts, as well as changes in locational marginal price (LMP) changes due to HTP converting its Firm TWRs to Non-Firm TWRs raises a multitude of disputed material facts that require that this matter be set for hearing and settlement procedures.

33. HTP, NYPA, and Linden oppose PSEG's request for a hearing. HTP argues that none of the claims made in the affidavit of PSEG's expert, Mr. Khadr, identified a

[31] PJM Transmission Owners Response, Docket No. EL17-84-000, at 4 (citing PJM OATT, Schedule 12 § (b)(viii)).

[32] *Id.* at 5 (citing PJM OATT, Schedule 7 § 7).

genuine issue of material fact that requires a hearing. Linden states that the NYISO Reliability Needs Assessment (RNA) upon which Mr. Khadr relies to support the claim that there is a genuine reliability issue represents a resource adequacy study used in conjunction with ensuring that a Loss of Load Expectation does not exceed one event in 10 years; it is not a transmission planning study and does not address whether a transmission system component requires upgrades.[33] Further, Linden states that NYISO's RNA is (and has been) based on the entire 660 MW capability of the HTP facility since HTP went into service, rather than HTP's 320 MW of Firm TWRs.[34] HTP, NYPA, and Linden also point out that PJM and NYISO are parties to this proceeding and neither has identified any reliability concerns with HTP reducing the quality of its serviced in the Amended ISA and converting its Firm TWRs to Non-Firm TWRs. Rather, Linden notes that PJM determined that HTP's conversion of Firm TWRs would not have adverse reliability or operational impacts.

34. HTP also disputes Mr. Khadr's assertions that after the reduction in the quality of HTP's service, the Hudson Line will remain used and useful to HTP and NYISO, and "all costs associated with HTP's existence will exclusively be borne by New Jersey ratepayers."[35] HTP states that it (and NYPA) is responsible for (1) approximately $650 million in capital costs for constructing the Hudson Line; (2) all of the costs to operate and maintain the Hudson Line and, because HTP is a merchant transmission facility; and (3) approximately $320 million to PJM for network upgrades in the Existing ISA. HTP also points out that all of HTP's customers using the Hudson Line, including NYPA, are required by the PJM tariff to use and pay for PJM Point-to-Point transmission service and PJM ancillary service charges, including PJM scheduling charges, PJM reactive support and voltage control charges, and PJM black start service charges.

35. HTP also argues that PSEG's and Mr. Khadr's assertion that HTP's Firm TWRs might have contributed to, or in some cases driven, the need for RTEP projects, and such projects may not have been built or may have been delayed, is speculation and even it were true, that is how PJM's transmission expansion planning process works.

36. HTP argues that, in order for PSEG's refusal to consent to the Amended ISA to be reasonable, it would have to be within the objective criteria established in section 205 of the PJM tariff for the study and evaluation of facility interconnections' impact on operation and reliability of the PJM system. HTP states that any refusal of the

[33] Linden Answer, Docket No. EL17-84-000, at 5-6.

[34] *Id.* at 5-6.

[35] HTP Answer, Docket No. EL17-84-000, at 29 (citing Khadr Affidavit at P 6).

interconnected transmission owner (i.e., PSEG) to refuse an interconnection request for reasons other than those objective criteria, as it has done here, is unjust, unreasonable, and unduly discriminatory, a violation of the PJM tariff, and a violation of open access transmission service under Order No. 888.[36] NYPA agrees the basis of PSEG's interference contradicts the role of transmission owners in party interconnection agreements, and emphasizes that the Commission, in Order No. 2003, clarified: "It is our intent that, while the Transmission Owner is a necessary part of interconnecting to a facility under the operational control of an RTO or ISO, its role in negotiating the agreement will be a limited one."[37]

37. HTP also contends that requiring HTP to terminate its ISA completely and, disconnect the Hudson Line from the PJM system, and reenter and restart the PJM interconnection process in order to permit HTP to reduce the quality of its service in the ISA, would be extraordinarily prejudicial to HTP. HTP contends that reentering the PJM interconnection queue process would require one to three years to complete, during which time the Hudson Line would be forcibly disconnected from the PJM system. Therefore, HTP asserts it would face the prospect of paying for interconnection upgrades twice for the same service under the PJM tariff.

38. HTP also argues that the Existing ISA should permit HTP to reduce the quality of its service under the Existing ISA by relinquishing its Firm TWRs and retaining only Non-Firm TWRs, and direct PJM to make the necessary changes to permit HTP to so reduce the quality of its service under the Existing ISA. HTP states that permitting HTP to reduce the quality of its service by relinquishing its Firm TWRs and retaining only Non-Firm TWRs is consistent with other provisions of the PJM tariff and the Existing

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[36] *Id.* at 32-34.

[37] NYPA Answer, Docket No. EL17-84-000, at 17 (citing *Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003-A, FERC Stats. & Regs., Regs. Preambles 2001-2005 ¶ 31,160, at PP 785-86 (2004) (emphasis added), *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs., Regs. Preambles 2001-2005 ¶ 31,171, *order on reh'g*, Order No. 2003-C, FERC Stats. & Regs., Regs. Preambles 2001-2005 ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), *cert. denied*, 552 U.S. 1230 (2008)).

ISA regarding interconnection rights.[38] For example, HTP states that section 232.7 of the PJM tariff allows PJM to unilaterally reduce the amount of HTP's TWRs without terminating the Existing ISA, and without the consent of PSEG or HTP. HTP states that, under section 232.7 of the PJM tariff, "Loss of … Transmission Withdrawal Rights," PJM has the unilateral right to make a partial reduction in the amount of TWRs in the Existing ISA, without the consent of PSEG (or HTP) and without termination of the ISA, in the event that the Hudson Line fails to operate or be capable of operating at the capacity level associated with the TWRs for any consecutive three-year period. HTP states that it is unduly discriminatory for the PJM Tariff to permit PJM to unilaterally reduce the quality of HTP's service under the Existing ISA without terminating the ISA and without the consent of PSEG, but not to permit HTP to reduce the quality if its service under the Existing ISA without terminating the ISA and without the consent of PSEG.

IV. <u>Discussion</u>

A. <u>Procedural Matters</u>

39. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure,[39] the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding. Pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedures,[40] the Commission will grant the late-filed motions to intervene given their interest in the proceeding, the early stages of the proceeding, and the absence of undue prejudice or delay.

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[38] HTP Answer, Docket No. EL17-84-000, at 36-41. HTP also cites section 230.3.3 of the PJM OATT (permitting an existing generator to replace its generating facility, using "a portion or all" of its existing capacity interconnection rights, without the consent of its Interconnected Transmission Owner and without terminating its interconnection agreement), section 16.1.2 of the Existing ISA (permitting HTP, at any time, to "unilaterally terminate the Interconnection Service Agreement" without the consent of PJM or PSEG, upon sixty days prior written notice), and section 3.1 of the Existing ISA (providing that HTP "may undertake modifications to its facilities" without the consent of PSEG, provided that the modifications do not have a permanent adverse impact on the Interconnection Transmission Owner's (i.e., PSEG's) facilities).

[39] 18 C.F.R. § 385.214 (2017).

[40] 18 C.F.R. § 385.214(d) (2017).

40. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure prohibits an answer to a protest or to an answer unless otherwise ordered by the decisional authority.[41] We will accept the answers filed in this docket because they provide information that assisted us in our decision-making process.

B. Substantive Matters

41. As discussed below, and based on the filings described herein, we find that the Existing ISA is unjust and unreasonable insofar as it does not permit HTP to convert its Firm TWRs to Non-Firm TWRs.[42] Accordingly, PJM shall make a compliance filing within 7 days of the date of this order amending the section 2.2 of Specifications for the Existing ISA to reflect the conversion of 320 MW Firm TWRs to a total of 0 MW of Firm TWRs and 673 MW Non-Firm TWRs, effective the date of this order.

42. We see no reasonable basis for barring HTP from converting from higher quality Firm TWRs to lower quality Non-Firm TWRs by amending the Existing ISA. ISAs establish the requirements and upgrades necessary for interconnection. Once a merchant transmission facility has elected to obtain Firm TWRs, PJM determines the necessary upgrades to support the Firm TWRs requested through its interconnection process. HTP already has satisfied the interconnection requirements, and we find that requiring it to maintain such Firm TWRs for the life of the merchant transmission facility is unjust and unreasonable in the absence of any operational or reliability basis for doing so.

43. Under the Existing ISA and PJM's tariff, PJM must guarantee that its transmission system is robust enough to permit HTP to use its Firm TWRs to export 320 MWs of power from its source in PJM across the river to New York at all times. Converting those Firm TWRs to Non-Firm TWRs imposes no additional obligation on PJM and, in fact, is less burdensome in that PJM will no longer have to guarantee that its transmission system can support such use. In terms of reliability, PJM states that "the conversion will not exceed the nominal rated capability of the HTP line (because system withdrawals will not

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[41] 18 C.F.R. § 385.213(a)(2) (2017).

[42] In the Show Cause Order, the Commission required PSEG and PJM to show cause (1) why the Existing ISA is not unjust and unreasonable and unduly discriminatory to the extent it fails to allow HTP to convert Firm TWRs to Non-Firm TWRs and (2) why PSEG's failure to consent to an amendment to the Existing ISA reflecting the same is not unjust, unreasonable, and unduly discriminatory. Because we have found that the Existing ISA is unjust and reasonable insofar as it does not permit HTP to convert its Firm TWRs to Non-Firm TWRs, we need not address whether PSEG acted unreasonably in withholding consent to an amendment to the Existing ISA reflecting the same.

increase,"[43] and no additional facilities would be necessary to support HTP's conversion from Firm TWRs to Non-Firm TWRs. In any case, HTP's line is fully controllable by PJM so that PJM can shut off flows if those flows jeopardize reliability or cause operational problems in New Jersey or elsewhere on the PJM system. PJM recognizes in its response to the Show Cause Order that for these reasons, the conversion to Non-Firm TWRs will not affect the operation or reliability of the PJM system, [44] and PSEG has offered no evidence to the contrary.

44. PSEG argues that, under section 16.1.2 and 16.2.1 of Appendix 2 of the Existing ISA,[45] HTP could effectuate such a reduction in Firm TWRs by exercising its unilateral right to terminate the Existing ISA and disconnecting its line. HTP could then reapply for Non-Firm TWRs. However, interpreting the Existing ISA, as PSEG did in its protest in Docket No. ER17-2073-000, to require that HTP terminate the Existing ISA and disconnect an already operational merchant transmission facility, rather than amending the Existing ISA to convert Firm TWRs to Non-Firm TWRs, would be unjust and unreasonable. As PJM states, "HTP has fully paid for the network upgrades required to receive Firm TWRs (therefore the reduction of service from Firm to Non-Firm TWRs

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[43] PJM Response, Docket No. EL17-84-000, at 3. *See also* PJM Transmittal, Docket No. ER17-2073-000, at 3-4 (PJM stated that the conversion "corresponds to the nominal rated capability of the facility of 673 MW").

[44] PJM Response, Docket No. EL17-84-000, at 3.

[45] Section 16.1.2 of Appendix 2 of the Existing ISA provides as follows:

> Interconnection Customer may unilaterally terminate the Interconnection Service Agreement pursuant to Applicable Laws and Regulations upon providing Transmission Provider and the Interconnected Transmission Owner sixty (60) days prior written notice thereof, provided that Interconnection Customer is not then in Default under the Interconnection Service Agreement.

Section 16.2.1 of Appendix 2 of the Existing ISA provides as follows:

> Disconnection: Upon termination of the Interconnection Service Agreement in accordance with this Section 16, Transmission Provider and/or the Interconnected Transmission Owner shall, in coordination with Interconnection Customer, physically disconnect the Customer Facility from the Transmission System, except to the extent otherwise allowed by this Appendix 2.

will not affect HTP's responsibility to fund previously constructed facilities)."[46] We also do not find, as PSEG alleges, that allowing HTP to convert its Firm TWRs to Non-Firm TWRs will undermine the interconnection process as HTP has already fulfilled its interconnection requirements. As discussed above, Non-Firm TWRs impose less of a burden on the transmission system than do Firm TWRs, and HTP's conversion of Firm TWRs to Non-Firm TWRs does not, as PJM points out, require any additional system upgrades as the Non-Firm TWRs do not increase system withdrawals.[47] Moreover, PJM, as the system operator, finds that such a conversion will not have adverse reliability or operational impacts, and HTP's amendment to the Existing ISA will not affect payments for previously constructed facilities.[48] Thus, we find that it is unjust and unreasonable not to allow HTP to amend the Existing ISA to convert its Firm TWRs to Non-Firm TWRs.[49]

45. PSEG makes three arguments against finding the Existing ISA unjust and unreasonable: that the Existing ISA is a bilateral contract governed by the public interest *Mobile-Sierra* standard; the issue of operational and reliability impacts raises a multitude of disputed material facts regarding the effect on the NYISO system warranting a hearing; and cost allocation is not beyond the scope of the proceeding. We address each of these arguments in turn.

1. Mobile-Sierra

46. As a threshold matter, we find that the Existing ISA is not eligible for the *Mobile-Sierra* "public interest" presumption. Aside from the fact that the Existing ISA was filed and accepted by the Commission, PSEG provides no other support for its contention that the Existing ISA is protected by the *Mobile-Sierra* doctrine.[50] As the Commission has explained, the *Mobile-Sierra* "public interest" presumption applies to an agreement only if the agreement has certain characteristics that justify the presumption. In ruling on

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[46] PJM Response, Docket No. EL17-84-000, at 3.

[47] *Id. See also* PJM Transmittal, Docket No. ER17-2073-000, at 3-4 (PJM stated that the conversion "corresponds to the nominal rated capability of the facility of 673 MW").

[48] Show Cause Order, 160 FERC ¶ 61,056 at P 43.

[49] *See, e.g., New York Indep. Sys. Operator, Inc.*, 150 FERC ¶ 61,116 at (2015) (requiring that ISO be the entity that makes the determination whether a specific generator is needed to ensure reliable transmission service).

[50] PSEG Response, Docket No. EL17-84-000, at 7.

whether the characteristics necessary to justify a *Mobile-Sierra* presumption are present, the Commission must determine whether the agreement at issue embodies either: (1) individualized rates, terms, or conditions that apply only to sophisticated parties who negotiated them freely at arm's length; or (2) rates, terms, or conditions that are generally applicable or that arose in circumstances that do not provide the assurance of justness and reasonableness associated with arm's-length negotiations. Unlike the latter, the former constitute contract rates, terms, or conditions that necessarily qualify for a *Mobile-Sierra* presumption.

47. We find that the terms and conditions of the Existing ISA at issue here are generally applicable and, therefore, are not protected by the *Mobile-Sierra* presumption. The granting of Firm and Non-Firm TWRs to a Transmission Interconnection Customer is governed by generally applicable provisions of the PJM tariff, namely section 232 of the PJM tariff.[51] Once determined by PJM following a System Impact Study, such rights become available to the Transmission Interconnection Customer (e.g., HTP) pursuant to execution of an ISA based on the *pro forma* ISA attached to the PJM tariff as Attachment O. The terms and conditions in the Existing ISA, including the terms related to Amendments, Termination, and Disconnection, were identical in relevant part to the terms and conditions set forth in the *pro forma* ISA in PJM's tariff.[52] The Commission has found that such generally applicable rates, terms and conditions are not the type of contract rates that qualify for the *Mobile-Sierra* presumption.[53]

48. Another, independent reason why the *Mobile-Sierra* presumption does not apply in these circumstances is that the Existing ISA contains the same standard *Memphis*

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[51] *See* PJM Tariff, Section 232.3 (Determination of Transmission Injection Rights and Transmission Withdrawal Rights to be Provided to Customer) ("The Office of Interconnection [PJM] shall determine the ... Transmission Withdrawal Rights ... to be provided to eligible Transmission Interconnection Customer(s)").

[52] Schedule F of the Existing ISA contains non-standard terms and conditions that set forth the terms and cost for HTP to acquire additional Firm TWRs above the 320 MW currently set forth in the Existing ISA.

[53] *Southwest Power Pool, Inc.*, 144 FERC ¶ 61,059 (2013), *on reh'g*, 149 FERC ¶ 61,048, at PP 100-104 (2014), *denying petition for review*, *Okla. Gas & Elec. Co. v. FERC*, 827 F.3d 75, 76 (D.C. Cir. 2016); *PJM*, 142 FERC ¶ 61,214 at P 184 (citing *Carolina Gas*, 136 FERC ¶ 61,014 at P 17 (holding that the terms of an agreement that are "incorporated into the service agreements of all present and future customers...are properly classified as tariff rates and the *Mobile-Sierra* presumption would not apply.").

clause[54] as in the *pro forma* ISA. That provision preserves for PJM and PSEG their section 205 filing rights and preserves the rights of any Interconnection Party to bring complaints under section 206. Specifically, section 22.3 of the Existing ISA states in pertinent part:

> This Interconnection Service Agreement may be amended or supplemented only by a written instrument duly executed by all Interconnection Parties. An amendment to the Interconnection Service Agreement shall become effective and a part of this Interconnection Service Agreement upon satisfaction of all Applicable Laws and Regulations. Notwithstanding the foregoing, nothing contained in this Interconnection Service Agreement shall be construed as affecting in any way any of the rights of any Interconnection Party with respect to changes in applicable rates or charges under Section 205 of the Federal Power Act and/or FERC's rules and regulations thereunder, or any of the rights of any Interconnection Party under Section 206 of the Federal Power Act and/or FERC's rules and regulations thereunder.

While section 22.3 states that the Existing ISA may be amended "only by a written instrument duly executed by all Interconnection Parties…", the second sentence of the provision protects the parties' unilateral filing rights. Consistent with court precedent, the Commission has found that such provisions apply the ordinary just and reasonable standard: "where provisions in an Interconnection Agreement allow either party to unilaterally request changes under FPA sections 205 or 206, the Commission has the authority to require changes to the contracts under the just and reasonable standard."[55]

2. **Cost Allocation**

49. PSEG and NJBPU argue that HTP should not be permitted to relinquish its Firm TWRs, because, under Schedule 12 of PJM's tariff, HTP would no longer be allocated costs for RTEP projects that PSEG alleges were caused by HTP's Firm TWRs and benefit HTP. However, as explained below, it is the cost allocation provisions in

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[54] *United Gas Co. v. Memphis Gas Div.*, 358 U.S. 103 (1958) (contracts can preserve the rights of parties to revise rates under ordinary just and reasonable standard).

[55] *Ontelaunee Power*, 119 FERC ¶ 61,181 at P 24 (citing *Duke Energy Hinds*, 102 FERC ¶ 61,068 at P 21). *See also Papago Tribal Util. Auth. v. FERC*, 723 F.2d 950, 954 (D.C. Cir. 1983) ("specific acknowledgment of the possibility of future rate change is virtually meaningless unless it envisions a just-and-reasonable standard").

Schedule 12 that provide that a Merchant Transmission Owner that does not own Firm TWRs does not receive cost responsibility assignments for RTEP projects.[56] Neither PSEG nor NJBPU have argued that those provisions are unjust and unreasonable. Accordingly, we find that their cost allocation argument does not provide a basis for precluding HTP from terminating its Firm TWRs under the Existing ISA.

50. Under Schedule 12 of the PJM tariff, a merchant transmission facility's cost responsibility assignments for RTEP projects are calculated based that facility's Firm TWRs.[57] As the Commission has explained, the reason that the costs of RTEP projects are allocated to merchant transmission facilities with Firm TWRs is that PJM is required to provide firm service to those facilities and therefore those facilities are responsible for contributing to facilities necessary to support that firm service:

> PJM is required to provide reliable service up to the Firm Transmission Withdrawal Rights held by these customers. In order to provide such rights, PJM must require the construction of RTEP upgrades. The Merchant Transmission Facilities can avoid these costs if instead of opting for Firm Transmission Withdrawal Rights, they opt only for Non-Firm Transmission Withdrawal Rights under the tariff.[58]

As of the effective date of HTP's conversion of its Firm TWRs to Non-Firm TWRs, PJM is no longer required to provide firm service and can curtail non-firm service whenever necessary to preserve reliability.[59] Under Schedule 12, therefore, RTEP upgrade costs would no longer be allocable to HTP. The cost responsibility assignments for RTEP projects are updated annually based on a range of inputs and values to determine beneficiaries of RTEP projects.[60] Thus, under Schedule 12, cost responsibility

[56] Although PJM implements the cost allocation provisions of Schedule 12 of the Tariff, the cost allocation method is determined by the PJM Transmission Owners, and it is the PJM Transmission Owners, not PJM, that have the section 205 filing rights for the PJM cost allocation method. *See Atlantic City Electric Co. v. FERC*, 295 F.3d 1 (D.C. Cir. 2002).

[57] *See* PJM OATT, Schedule 12 § (b)(i) (3.0.0).

[58] Opinion No. 503, 129 FERC ¶ 61,161 at P 80.

[59] *See* PJM OATT, Schedule 12 § (b)(i) (3.0.0). *See* PJM OATT § I, OATT Definitions L-M-N, 14.0.0, Non-Firm Transmission Withdrawal Rights. *See also* PJM OATT § II, Point-to-Point Transmission Service.

[60] *See* PJM OATT, Schedule 12 § (b)(iii)(H).

assignments for RTEP projects will shift over time as usage by transmission customers of a RTEP project changes over its lifespan.[61] For example, HTP's cost responsibility assignment increased as a direct result of the termination of Con Edison's transmission service agreements.[62] Contrary to PSEG's assertion, the PJM tariff does not require a merchant transmission facility, like HTP, to be allocated costs for an RTEP project over the life of that project based on the MWs of Firm TWRs the merchant transmission facility held at the time that the RTEP project was approved by PJM.[63] As noted, neither PSEG nor NJBPU has contended that these provisions are unjust and unreasonable.

51. Moreover, we also find unpersuasive PSEG's argument that it reasonably relied upon the long-term duration of the Existing ISA, and HTP maintaining its Firm TWRs, as providing for long-term cost responsibility assignments for RTEP projects to HTP. As PSEG itself acknowledged, HTP has the right unilaterally to terminate the Existing ISA, including its Firm TWRs, at any time.[64] As we explained earlier, requiring HTP to terminate its rights in order to convert its Firm TWRs to Non-Firm TWRs is unjust and unreasonable as making such changes will not result in reliability or operational difficulties for the PJM system.

52. Similarly, the PJM Market Monitor raises concerns with Schedule 12 and requests changes thereto in order to address an alleged discrepancy in the cost responsibility assignments for RTEP projects for merchant transmission providers that hold firm point-to-point transmission service and those that hold Firm TWRs. Those general concerns with Schedule 12 do not address whether HTP should be permitted to convert its Firm TWRs to Non-Firm TWRs. The PJM Transmission Owners also raise concerns regarding the cost responsibility assignments for RTEP projects to firm point-to-point transmission customers. We reject, as beyond the scope of this proceeding, these comments. The cost responsibility assignments for RTEP projects for firm point-to-point

[61] Schedule 12 updates cost allocations annually based on changes to the system's topology, load changes, and other events such as termination of service. *See* PJM OATT, Schedule 12 § (b).

[62] Show Cause Order, 160 FERC ¶ 61,056 at n.24.

[63] *See* PJM OATT, Schedule 12 § (b)(iii).

[64] Show Cause Order, 160 FERC ¶ 61,056 at P 6.

transmission customers under Schedule 12 are unrelated to the issue of whether HTP should be permitted to convert its Firm TWRs to Non-Firm TWRs.

3. **Reliability**

53. PSEG argues that allowing HTP to convert its Firm TWRs to Non-Firm TWRs will adversely affect the operation or reliability of the PJM transmission system, and raises a multitude of disputed material facts that require that the Commission set this matter for hearing and settlement procedures. In support of its contention, PSEG relies on the affidavit of Mr. Khadr, who asserts that there might be "critical reliability consequences" in NYISO as a result of HTP reducing the quality of its service under the Existing ISA and converting its Firm TWRs to Non-Firm TWR. Mr. Khadr bases his claim on NYISO's 2016 RNA. Mr. Khadr contends that because the 2016 RNA models 660 MW of flows from the HTP facility, 320 MW of which is firm, the 2016 RNA "shows great dependency on the PJM system and the PSE&G system in particular."[65] Mr. Khadr contends that if HTP is permitted to convert its Firm TWRs entirely to Non-Firm, "NYISO [will be] depending on an additional 320 MW across the Hudson Line that PJM will, properly, not be including in its planning assumption across the PJM/NYISO interface."[66]

54. PSEG, however, does not provide any evidence that the relinquishment of Firm TWRs would cause any reliability or operational problems for PJM, the region in which the service in dispute would actually be provided. With HTP's conversion of its Firm TWRs to Non-Firm TWRs, PJM, with its operational control over the Hudson Line, may curtail firm exports on the facility when necessary to support PJM's reliability or operational needs.[67] As to any potential effects on LMPs in PJM, such effects can result from any type of non-firm transmission service and are not a reason to require HTP to retain Firm TWRs.

55. Moreover, the studies cited by Mr. Khadr do not support that HTP's maintenance of its Firm TWRs is critical to NYISO's reliability. In his affidavit, Mr. Khadr references only a diagram of topology zones included in the RNA, which includes a reference to the capability of flowing 660 MW of flows from the Hudson Line into NYISO alongside other flows from PJM into NYISO. Contrary to Mr. Khadr's claims, however, the diagram makes no reference to the 320 MWs of Firm TWRs, nor does it assert that those MWs are critical to NYISO's reliability. Thus, the presence of Firm TWRs in PJM has

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[65] Khadr Affidavit at P 7.

[66] *Id.* P 8.

[67] PJM Response, Docket No. EL17-84-000, at 3.

not led to capacity that NYISO relies upon in serving its resource adequacy needs. NYISO has also asserted that reliability would be negatively impacted only if the Hudson Line is taken out of service. Since these issues can be resolved based on the written record, we find no material issues of disputed fact and see no need for a trial-type hearing.[68]

<u>The Commission orders</u>:

(A) As discussed in the body of this order, we find that the Existing ISA is unjust and unreasonable insofar as it does not permit HTP to convert its Firm TWRs to Non-Firm TWR.

(B) PJM shall make a compliance filing within 7 days of the date of this order amending section 2.2 of Specifications for the Existing ISA to reflect the conversion of 320 MW Firm TWRs to a total of 0 MWs Firm TWRs and 673 MW Non-Firm TWRs, effective the date of this order.

By the Commission. Chairman McIntyre is not participating.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

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[68] *See, e.g.*, *Pennsylvania Pub. Util. Comm'n v. FERC*, 881 F.2d 1123, 1126 (D.C. Cir. 1989); *Union Pacific Fuels, Inc. v. FERC*, 129 F.3d 157, 164 (D.C. Cir. 1997). ("FERC may resolve factual issues on a written record unless motive, intent, or credibility are at issue or there is a dispute over a past event"). "Mere allegations of disputed fact are insufficient to mandate a hearing; a petitioner must make an adequate proffer of evidence to support them." *Woolen Mill Ass'n v. FERC*, 917 F.2d 589, 592 (D.C. Cir. 1990) (citing *Pennsylvania Pub. Utility Comm'n v. FERC*, 881 F.2d 1123, 1126 (D.C.Cir.1989) and *Cerro Wire & Cable Co. v. FERC*, 677 F.2d 124, 124 (D.C.Cir.1982)).

Document Content(s)

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Attachment 8

Linden VFT FERC Order

161 FERC ¶ 61,264
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Cheryl A. LaFleur, Neil Chatterjee,
Robert F. Powelson, and Richard Glick.

Linden VFT, LLC
v.
Public Service Electric and Gas Company
and PJM Interconnection, L.L.C.

Docket No. EL17-90-000

ORDER GRANTING COMPLAINT, IN PART

(Issued December 15, 2017)

1. On September 18, 2017, Linden VFT, LLC (Linden),[1] pursuant to section 206 of the Federal Power Act (FPA),[2] filed a complaint (Complaint) contending that Public Service Electric and Gas Company (PSEG) is unreasonably withholding its consent to an amendment to the existing Linden interconnection service agreement (Existing ISA) between Linden, PJM Interconnection, L.L.C. (PJM), and PSEG to allow Linden to convert Firm Transmission Withdrawal Rights (Firm TWRs) to Non-Firm Transmission Withdrawal Rights (Non-Firm TWRs).[3] Additionally, or alternatively, Linden contends that the PJM Open Access Transmission Tariff (tariff or OATT) is unjust and unreasonable to the extent that it does not permit a merchant transmission facility

[1] Linden owns and operates a controllable alternating-current Merchant Transmission Facility that connects PJM Interconnection, L.L.C. (PJM) with New York Independent System Operator (NYISO).

[2] 16 U.S.C. §§ 824e (2012).

[3] *See* Service Agreement No. 3579, *PJM Interconnection, L.L.C.,* 144 FERC ¶ 61,070 (2013).

Owner to reduce all of its Firm TWRs to Non-Firm TWRs without an amendment to its ISA or the consent of the transmission owner that is party to that agreement.[4]

2. As discussed below, and based on the filings described herein, we find that the Existing ISA is unjust and unreasonable insofar as it does not permit Linden to convert its Firm TWRs to Non-Firm TWR.

I. Background

3. PJM's Open Access Transmission tariff (tariff or OATT) provides merchant transmission facilities with the right to elect TWRs in lieu of other transmission rights and to request either Firm or Non-Firm TWRs.[5] Firm TWRs allow the merchant transmission facility to schedule energy and capacity withdrawals from the PJM system.[6] In contrast, Non-Firm TWRs only allow the merchant transmission facility to schedule energy and, as such, are similar to Non-Firm Point-to-Point Transmission Service in that Non-Firm TWRs allow the merchant transmission facility to schedule transmission service on an as-available basis and are subject to curtailment.[7]

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[4] Firm Transmission Withdrawal Rights are defined as the rights to schedule energy and capacity withdrawals from a Point of Interconnection of a Merchant Transmission Facility with the Transmission System. Non-Firm Transmission Withdrawal Rights are defined as the rights to schedule energy withdrawals from a specified point on the Transmission System. *See* PJM OATT § I, OATT Definitions 1.13A,E-F, 5.0.1 and L-M-N, 14.0.0.

[5] Interconnection customers can elect TWRs in lieu of Incremental Deliverability Rights, Incremental Auction Revenue Rights, Incremental Capacity Transfer Rights, and Incremental Available Transfer Capability Revenue Rights. *See* PJM OATT § 232, Transmission Injection Rights and Transmission Withdrawal Rights.

[6] Firm TWRs have rights similar to those under Firm Point-to-Point Transmission Service. Firm TWRs are rights to schedule energy and capacity withdrawals between a point of interconnection of a merchant transmission facility with the transmission system that can only be awarded to a merchant transmission facility, whereas Firm Point-to-point Transmission Service is reserved or scheduled energy between specified Points of Receipt and Points of Delivery for transmission customers generally. *See* PJM OATT § I, OATT Definitions 1.13A, E-F, 5.0.1 and Definitions L-M-N, 14.0.0. *See also* PJM OATT § II, Point-to-Point Transmission Service.

[7] *See* PJM OATT § I, OATT Definitions L-M-N, 14.0.0, Non-Firm Transmission Withdrawal Rights.

4. Once a merchant transmission facility has elected to obtain TWRs rather than another type of transmission rights, PJM determines the necessary upgrades to support the Firm or Non-Firm TWRs requested through its interconnection process.[8] Upon receiving an interconnection request, PJM undertakes feasibility and system impact studies, and based on these costs, the merchant transmission facility decides the level of Firm TWRs it wishes to obtain. The interconnecting merchant transmission facility is assigned the costs of the Merchant Network Upgrades that would not have been incurred "but for" the interconnection request.[9] The merchant transmission facility, PJM, and the transmission owner to which the facility will be interconnected enter into a three-party ISA establishing the costs and conditions of the interconnection. In addition, a merchant transmission facility is responsible for the costs of any post-interconnection network upgrades that are included in the Regional Transmission Expansion Plan (RTEP) necessary to support the merchant transmission facility's Firm TWRs.[10]

5. The Existing ISA sets out the rights and responsibilities of PJM, Linden, and PSEG with respect to the interconnection to the PJM system of Linden's facility, a 315 megawatt (MW) merchant transmission project consisting of three 105 MW variable frequency transformers connected between the PSEG system and the Consolidated Edison Company of New York, Inc. system. On August 9, 2017, PJM, at the request of Linden, filed, under section 205 of the FPA,[11] an unexecuted, amended ISA between PJM, Linden, and PSEG. Linden sought to amend its Existing ISA to convert its

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[8] PJM OATT § 232.3, Determination of Transmission Injection Rights and Transmission Withdrawal Rights to be Provided to Interconnection Customer.

[9] *PJM Interconnection, L.L.C.*, 102 FERC ¶ 61,277, at P 4 (2003). Merchant Network Upgrades are additions or upgrades to, or replacement of, existing transmission system facilities by or on behalf of a merchant transmission facility developer. *See* PJM OATT§ I, OATT Definitions - L - M - N, 11.0.0. In exchange for their Merchant Network Upgrades, merchant transmission facilities receive Firm TWRs and Financial Transmission Rights. *See* PJM Filing, ER03-405-000 at 12 (identifying transmission-related rights to which merchant transmission facility developers may be entitled), PJM OATT, 206.5 Estimates of Certain Upgrade-Related Rights.

[10] *See* PJM OATT § Schedule 12 (b), and PJM OATT § 232.2, Right of Interconnection Customer to Transmission Injection Rights and Transmission Withdrawal Rights. *See also*, *PJM Interconnection, L.L.C.*, Opinion No. 503, 129 FERC ¶ 61,161 (2009) (finding that merchant transmission facilities should be responsible for the costs of maintaining network reliability, including RTEP costs, based on their Firm TWRs).

[11] 16 U.S.C. § 824d (2012).

330 MW of Firm TWRs to Non-Firm TWRs.[12] On October 5, 2017, the Commission rejected PJM's filing, finding that neither the Existing ISA nor PJM's tariff permitted PJM to file, under section 205, an unexecuted amended ISA with modifications requested by an interconnection customer, noting that subsequent to the filing of amendments to the Linden ISA, Linden filed its Complaint.[13] The Commission stated that it would address concerns related to Linden's request to convert its Firm TWRs to Non-Firm TWRs in proceedings related to the Complaint.

II. <u>Linden Complaint</u>

6. In its Complaint, Linden argues that PSEG is unreasonably withholding its consent to the amendment of the Existing ISA, which constitutes an abuse of power and violates principles of open access.[14] In support of its request that the Commission direct PSEG to consent to the amendment to the Existing ISA, Linden argues that PSEG has not identified a legitimate objection to Linden's request to amend the Existing ISA.[15] Linden also states that it has fully paid for the network upgrades necessary to support its Firm TWRs. Linden argues that there are no reliability concerns or operational issues raised as a result of its request to reduce the level of service from Firm TWRs to Non-Firm TWRs, and, because PJM is not obligated to plan to support Non-Firm TWRs, PJM will not need to plan any additional upgrades as of result of it request. Linden adds that its transmission facility will remain fully controllable by PJM, and in the event of a reliability or other operational issue, flow can be shut off consistent with applicable rules and procedures.[16]

7. Linden analogizes TWRs with Point-to-Point Transmission Service in which transmission service customers are free to select between firm and non-firm service without incurring additional non-firm transmission service charges or executing a new service agreement.[17] Linden specifically identifies that those entities owning and operating generation facilities are free to convert Firm Point-to-Point

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[12] PJM made this filing under Docket No. ER17-2267-000.

[13] *PJM Interconnection, L.L.C.*, 161 FERC ¶ 61,021 (2017).

[14] Complaint at 9-10.

[15] *Id.* at 11.

[16] *Id.* at 11-12.

[17] *Id.* at 12.

Transmission Service to non-firm transmission service without amending their interconnection agreements.[18]

8. Linden further contends that PSEG could not have reasonably relied on an allocation of costs to Linden for post-interconnection network upgrades.[19] Linden argues that, under the PJM tariff, cost responsibility assignments for RTEP projects are based on Firm TWRs, and are updated annually. Linden argues that there is nothing in the tariff that requires or even suggests that costs could be allocated for the life of an upgrade based on the Firm TWRs held by merchant transmission facilities when the project is included in the RTEP.[20] Linden notes that PSEG admits that Linden could unilaterally terminate the Existing ISA.[21] Linden contends that the Commission should not allow PSEG to withhold consent to the amendment to the Existing ISA for financial reasons. Linden further argues that concerns related to cost responsibility assignments are irrelevant to its request to reduce the level of service of its TWRs.

9. In addition, or alternatively, Linden requests that the Commission direct PJM to revise its tariff to permit merchant transmission facilities to unilaterally reduce the service level of their TWRs without requiring an amendment to the Existing ISA.[22] Linden maintains that the tariff establishes procedures in which a merchant transmission facility may request TWRs and elect the associated level of service; specifically, firm, non-firm, or some combination of the two. Linden contends that although the Commission may already interpret the tariff to provide merchant transmission facilities with the unilateral right to reduce their Firm TWRs to Non-Firm TWRs without requiring an amendment to an Existing ISA, this is not explicitly provided for in the tariff.[23]

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[18] *Id.* at 13.

[19] *Id.* at 14.

[20] *Id.* at 15.

[21] *Id.* at 16.

[22] *Id.* at 17. Linden requests that if an amendment is necessary, the tariff should be amended to specify that the merchant transmission facility has the right to file an unexecuted ISA. *Id.* at 21.

[23] *Id.* at 19.

III. Notice of Filing and Responsive Pleadings

10. Notice of the Complaint was published in the *Federal Register*, 82 Fed. Reg. 44,766 (2017), with interventions and protests due on or before October 10, 2017.

11. Notice of intervention was filed by New Jersey Board of Public Utilities (New Jersey Board). Timely motions to intervene were filed by FirstEnergy Service Company; Exelon Corporation; Monitoring Analytics;[24] Public Citizen, Inc.; Hudson Transmission Partners, LLC (HTP);[25] Consolidated Edison Company of New York, Inc.; Long Island Power Authority; PPL Electric Utilities Corporation; Brookfield Energy Marketing LP; American Electric Power Service Corporation; New York Power Authority; ITC Lake Erie Connector, LLC; and City of New York.

12. PJM filed an answer to the Complaint. PJM states that it will comply with any findings and directives that the Commission reasonably requires. PJM requests that should the Commission allow Linden to amend its Existing ISA to convert its Firm TWRs to Non-Firm TWRs, the Commission should grant the requested effective date with the understanding that such effective date shall not relieve Linden of its RTEP cost responsibility obligations under Schedule 12 of the tariff.[26]

13. PSEG filed a motion to dismiss, or in the alternative, an answer requesting that the Commission deny the Complaint. PSEG states that through the Complaint, Linden seeks to reduce Firm TWRs in an attempt to avoid cost responsibility assignments for RTEP projects, assignments that are the subject of other complaints and related proceedings that are currently pending before the Commission. PSEG argues that the Complaint is nothing more than a collateral attack on PJM's cost allocation method and an end run of those other proceedings. PSEG states that Linden's real grievance is the cost allocation method, and because the Complaint provides no new evidence, those other proceedings are the proper vehicle to address its concerns. Accordingly, PSEG requests that the Commission dismiss the Complaint.

14. In the alternative, PSEG requests that the Commission deny the Complaint. PSEG contends that Linden should not be allowed to amend its Existing ISA so that it can escape its cost responsibility assignments for RTEP projects. PSEG argues that it reasonably relied on Linden maintaining its Firm TWRs, and there is an expectation that

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[24] As the Independent Market Monitor for PJM (Market Monitor).

[25] In a separate proceeding, Linden sought to convert its Firm TWRs to Non-Firm TWRs. *See PJM Interconnection, L.L.C.,* 160 FERC ¶ 61,021 (2017).

[26] *See* PJM OATT, Schedule 12, §§ (b) (i), (iii).

the Linden facility will remain in service and will continue to be beneficial to New York. PSEG contends that if Linden is permitted to convert its Firm TWRs to Non-Firm TWRs, Linden and New York will continue to benefit from interconnection with the PJM transmission system at the expense of New Jersey ratepayers. PSEG states that the PJM transmission system is planned and designed to accommodate a planned megawatt quantity, both at the time of interconnection and in subsequent studies to maintain reliability. PSEG argues that the fact that a merchant transmission facility may not be using all of the Firm TWRs allotted to it under its existing ISA is irrelevant to the transmission planning process.

15. PSEG further argues that to allow for the unilateral amendment of existing ISAs because one party to the agreement is no longer satisfied accords unfair and undue preferential treatment, as well as compromises and introduces significant additional uncertainties into the interconnection queue process, potentially further inhibiting infrastructure development. PSEG adds that the *Mobile-Sierra* doctrine requires that the Commission presume that the contract rates and terms contained in the Existing ISA are just and reasonable unless otherwise shown to be contrary to the public interest, and that showing has not been made in this proceeding.[27]

16. New Jersey Board filed comments supporting PSEG's motion to dismiss, and argues that Linden's efforts to eliminate its cost allocation are intended to yield a preferential rate for customers in New York at the unjust and unreasonable expense of New Jersey ratepayers.

17. Linden filed an answer to PSEG reiterating that PJM has no obligation to plan its system for Non-Firm TWRs. Noting that PSEG's motion focuses largely on cost allocation issues, Linden answers that PSEG's challenge as it relates to the operation of the cost allocation provisions of the tariff represents a collateral attack on the Commission's order accepting provisions providing for a process that reallocates cost responsibilities assignments on an annual basis. Linden argues that the Commission should not in this proceeding address cost allocation issues already pending in other proceedings. Linden states that, where PJM's tariff permits cost responsibility assignments to shift over time as different users benefit from an upgrade, there is no reasonable basis for PSEG to rely on Linden maintaining its Firm TWRs over the long term. Further, Linden notes that PSEG acknowledges that Linden has the unilateral right to terminate its Existing ISA.

18. Addressing PSEG's *Mobile-Sierra* arguments, Linden answers that contracts that

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[27] PSEG Answer at 6. *See United Gas Pipe Line Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332 (1956); *FPC v. Sierra Pac. Power Co.*, 350 U.S. 348 (1956) (*Mobile-Sierra*).

apply generally applicable rates, terms, or conditions, such as the relevant language of Linden's Existing ISA, do not qualify for protections provided by the *Mobile-Sierra* doctrine. Linden states that, as the relevant language is in the form agreement, the parties were not in a position to negotiate the terms and conditions of this agreement "freely at arm's length." Linden states that, as the relevant language is in the form agreement, the parties were not in a position to negotiate the terms and conditions of this agreement "freely at arm's length." Furthermore, Linden argues that, where the existing rate or term might impair the financial ability of a public utility to continue its service, PSEG's actions are sufficient to meet the public interest standard and overcome the *Mobile-Sierra* presumptions.

19. The Market Monitor, noting that Linden has taken steps to obtain Firm Point-to-Point Transmission service coupled with Non-Firm TWRs, filed comments that address the responsibility for an allocation of transmission upgrade costs to transmission customers that have a point of delivery at the border where the transmission system interconnects with merchant transmission facilities. The Market Monitor contends that Linden seeks to substitute Firm Point-to-Point Transmission service coupled with Non-Firm TWRs to maintain the ability to export capacity to the NYISO from PJM with the same level of transmission service they have with Firm TWRs. The Market Monitor asserts that this creates a discrepancy in cost allocation between section 232.2 and Schedule 12 of the tariff in that Schedule 12 omits any reference to merchant transmission facilities that hold both firm transmission service to the PJM border and Non-Firm TWRs. The Market Monitor concludes that it would not be just and reasonable to require merchant transmission providers to retain the same capacity exports though firm point-to-point transmission service and avoid RTEP cost allocation.

20. The PJM Transmission Owners also filed an answer in response to Linden, to clarify that Schedule 12 defines customers with Firm Point-to-Point Transmission Service as customers responsible for the costs of RTEP projects. The PJM Transmission Owners also state that Schedule 7 specifies that Firm Point-to-Point transmission customers should not be charged for the same RTEP costs under their applicable Point-to-Point service rate, and that Firm Point-to-Point customers can thus be assessed RTEP costs.[28]

IV. Discussion

A. Procedural Matters

21. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure,[29] the notice of intervention and timely, unopposed motions to intervene serve to make

[29] 18 C.F.R. § 385.214 (2017).

the entities that filed them parties to this proceeding.

22. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure,[30] prohibits an answer to a protest and or answer unless otherwise ordered by the decisional authority. We will accept the answers and responsive pleadings because they have provided information that assisted us in our decision-making process.

B. Complaint

23. We grant the Complaint, in part. As discussed below, and based on the filings described herein, we find that the Existing ISA is unjust and unreasonable insofar as it does not permit Linden to convert its Firm TWRs to Non-Firm TWRs.[31] Accordingly, upon written notice from Linden, PJM shall make a compliance filing amending section 2.2 of Specifications for the Existing ISA to reflect the conversion of 330 MW Firm TWRs for a total of 0 MW Firm TWRs and 330 MW Non-Firm TWRs, to be effective on the date requested by Linden in its written notice, but no earlier than the date of that notice.[32] Because we find that Linden may convert its Firm TWRs to Non-Firm TWRs, we further find that revisions to the *pro forma* tariff are unnecessary. We reject the arguments that the Commission should dismiss the Complaint.

24. We see no reasonable basis for barring Linden from converting from higher quality Firm TWRs to lower quality Non-Firm TWRs by amending the Existing ISA. ISAs establish the requirements and upgrades necessary for interconnection. Once a merchant transmission facility has elected to obtain Firm TWRs, PJM determines the necessary upgrades to support the Firm TWRs requested through its interconnection process. Linden already has satisfied these interconnection requirements, and we find

[30] 18 C.F.R. § 385.213(a)(2) (2017).

[31] In the Complaint, Linden argues (1) the PJM tariff is unjust and unreasonable and unduly discriminatory to the extent it fails to allow Linden to convert Firm TWRs to Non-Firm TWRs and (2) PSEG's failure to consent to an amendment to the Existing ISA reflecting the same is unjust, unreasonable, and unduly discriminatory. Because we have found that the Existing ISA is unjust and reasonable insofar as it does not permit Linden to convert its Firm TWRs to Non-Firm TWRs, we need not address whether PSEG acted unreasonably in withholding consent to an amendment to the Existing ISA reflecting the same.

[32] Linden does not request a specific effective date for its amendment to the Existing ISA. Rather, Linden requests that the Commission act on its Complaint by December 15, 2017 in order for Linden to provide notice to PJM and PSEG of its amendment to the Existing ISA no later than December 31, 2017. Complaint at 2, 25-26.

that requiring it to maintain such Firm TWRs for the life of the merchant transmission facility is unjust and unreasonable in the absence of any operational or reliability basis for doing so.

25. Under the Existing ISA and PJM's tariff, PJM must guarantee that its transmission system is robust enough to permit Linden to use its Firm TWRs to export 330 MWs of power from its source in PJM across the river to New York at all times. Converting those Firm TWRs to Non-Firm TWRs imposes no additional obligation on PJM and, in fact, is less burdensome in that PJM will no longer have to guarantee that its transmission system can support such use. In terms of reliability, Linden supports that the conversion "will not exceed the nominal rated capability of Linden VFT's facility"[33], and no additional facilities would be necessary to support Linden's conversion from Firm TWRs to Non-Firm TWRs. In any case, the Linden facility is fully controllable by PJM so that PJM can shut off flows if those flows jeopardize reliability or cause operational problems in New Jersey or elsewhere on the PJM system.[34] PSEG has offered no evidence to the contrary.

26. PSEG argues that, under section 16.1.2 and 16.2.1 of Appendix 2 of the ISA, Linden could effectuate such a reduction in Firm TWRs by exercising its unilateral right to terminate the Existing ISA and disconnecting its line. Linden could then reapply for Non-Firm TWRs. However, interpreting the Existing ISA, as PSEG did in its protest in Docket No. ER17-2267-000, to require that Linden terminate the Existing ISA and disconnect an already operational merchant transmission facility, rather than amending the Existing ISA, to convert Firm TWRs to Non-Firm TWRs, would be unjust and unreasonable. Linden supports that it has "fully paid for the network upgrades necessary for its Firm [TWRs] and therefore the reduction will not affect payments for previously constructed facilities."[35] We also do not find, as PSEG alleges, that allowing Linden to convert its Firm TWRs to Non-Firm TWRs will undermine the interconnection process as Linden has already fulfilled its interconnection requirements. As discussed above, Non-Firm TWRs impose less of a burden on the transmission system than do Firm TWRs, and Linden's conversion of Firm TWRs to Non-Firm TWRs does not require any additional system upgrades as the Non-Firm TWRs do not increase system withdrawals.[36] Moreover, PJM, as the system operator, does not represent that such a conversion will have adverse reliability or operational impacts, and Linden's amendment to the Existing

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[33] Complaint at 11.

[34] Complaint at 11.

[35] Complaint at 11.

[36] Linden explains that it does not seek to expand the withdrawal capacity of its facilities, Complaint at 27.

ISA will not affect payments for previously constructed facilities.[37] Thus, we find that it is unjust and unreasonable not to allow Linden to amend the Existing ISA to convert its Firm TWRs to Non-Firm TWRs.

1. **Mobile-Sierra**

27. As a threshold matter, we find that the Existing ISA is not eligible for the *Mobile-Sierra* "public interest" presumption. Aside from the fact that the Existing ISA was filed and accepted by the Commission, PSEG provides no other support for its contention that the Existing ISA is protected by the *Mobile-Sierra* doctrine.[38] As the Commission has explained, the *Mobile-Sierra* "public interest" presumption applies to an agreement only if the agreement has certain characteristics that justify the presumption. In ruling on whether the characteristics necessary to justify a *Mobile-Sierra* presumption are present, the Commission must determine whether the agreement at issue embodies either: (1) individualized rates, terms, or conditions that apply only to sophisticated parties who negotiated them freely at arm's length; or (2) rates, terms, or conditions that are generally applicable or that arose in circumstances that do not provide the assurance of justness and reasonableness associated with arm's-length negotiations. Unlike the latter, the former constitute contract rates, terms, or conditions that necessarily qualify for a *Mobile-Sierra* presumption.

28. We find that the terms and conditions of the Existing ISA at issue here are generally applicable and, therefore, are not protected by the *Mobile-Sierra* presumption. The granting of Firm and Non-Firm TWRs to a Transmission Interconnection Customer is governed by generally applicable provisions of the PJM Tariff, namely section 232 of the PJM Tariff.[39] Once determined by PJM following a System Impact Study, such rights become available to the Transmission Interconnection Customer (e.g., Linden) pursuant to execution of an ISA based on the *pro forma* ISA attached to the PJM Tariff as Attachment O. The terms and conditions in the Existing ISA, including the terms related to Amendments, Termination, and Disconnection, were identical in relevant part to the

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[37] *See PJM Interconnection, L.L.C.,* 160 FERC ¶ 61,056, at P 43 (2017).

[38] PSEG Answer at 6.

[39] *See* PJM Tariff, Section 232.3 (Determination of Transmission Injection Rights and Transmission Withdrawal Rights to be Provided to Customer) ("The Office of Interconnection [PJM] shall determine the … Transmission Withdrawal Rights … to be provided to eligible Transmission Interconnection Customer(s)").

terms and conditions set forth in the *pro forma* ISA in PJM's Tariff.[40] The Commission has found that such generally applicable rates, terms and conditions are not the type of contract rates that qualify for the *Mobile-Sierra* presumption.[41]

29. Another, independent reason why the *Mobile-Sierra* presumption does not apply in these circumstances is that the Existing ISA contains the same standard *Memphis* clause[42] as in the *pro forma* ISA. That provision preserves for PJM and PSEG their section 205 filing rights and preserves the rights of any Interconnection Party to bring complaints under section 206. Specifically, section 22.3 of the Existing ISA states in pertinent part:

> This Interconnection Service Agreement may be amended or supplemented only by a written instrument duly executed by all Interconnection Parties. An amendment to the Interconnection Service Agreement shall become effective and a part of this Interconnection Service Agreement upon satisfaction of all Applicable Laws and Regulations. Notwithstanding the foregoing, nothing contained in this Interconnection Service Agreement shall be construed as affecting in any way any of the rights of any Interconnection Party with respect to changes in applicable rates or charges under Section 205 of the Federal Power Act and/or FERC's rules and regulations thereunder, or any of the rights of any

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[40] Section 2.1 of the Specifications and Schedule F of the Existing ISA contain non-standard terms and conditions. Schedule F of the Existing ISA sets forth the status of the construction and transfer of ownership of certain switchyard facilities and reserves certain rights with respect to the transfer of ownership of the switchyard facilities. The non-standard terms and conditions in Section 2.1 of the Specifications separates transmission injection rights by energy and capacity and makes capacity transmission injection rights contingent on completion of a certain RTEP upgrade.

[41] *Southwest Power Pool, Inc.*, 144 FERC ¶ 61,059 (2013), *on reh'g*, 149 FERC ¶ 61,048, at PP 100-104 (2014), *denying petition for review*, *Okla. Gas & Elec. Co. v. FERC*, 827 F.3d 75, 76 (D.C. Cir. 2016); *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214, at P 184 (2013) (citing *Carolina Gas Transmission Corp.*, 136 FERC ¶ 61,014, at P 17 (2011) (holding that the terms of an agreement that are "incorporated into the service agreements of all present and future customers…are properly classified as tariff rates and the *Mobile-Sierra* presumption would not apply.").

[42] *United Gas Co. v. Memphis Gas Div.*, 358 U.S. 103 (1958) (contracts can preserve the rights of parties to revise rates under ordinary just and reasonable standard).

Interconnection Party under Section 206 of the Federal Power Act and/or FERC's rules and regulations thereunder.

30. While section 22.3 states that the Existing ISA may be amended "only by a written instrument duly executed by all Interconnection Parties...", the second sentence of the provision protects the parties' unilateral filing rights. Consistent with court precedent, the Commission has found that such provisions apply the ordinary just and reasonable standard: "where provisions in an Interconnection Agreement allow either party to unilaterally request changes under FPA sections 205 or 206, the Commission has the authority to require changes to the contracts under the just and reasonable standard."[43]

2. Cost Allocation

31. PSEG and New Jersey Board also argue that Linden should not be permitted to relinquish its Firm TWRs, because, under Schedule 12 of PJM's tariff, Linden would no longer be allocated costs for RTEP projects that PSEG alleges were caused by Linden's Firm TWRs and benefit Linden. However, as explained below, it is the cost allocation provisions in Schedule 12 that provide that a Merchant Transmission Owner that does not own Firm TWRs does not receive cost responsibility assignments for RTEP projects.[44] Neither PSEG nor New Jersey Board have argued that those provisions are unjust and unreasonable. Accordingly, we find that their cost allocation argument does not provide a basis for precluding Linden from terminating its Firm TWRs under the Existing ISA.

32. Under Schedule 12 of the PJM tariff, a merchant transmission facility's cost responsibility assignments for RTEP projects are calculated based on that facility's Firm TWRs.[45] As the Commission has explained, the reason that the costs of RTEP projects are allocated to merchant transmission facilities with Firm TWRs is that PJM is required

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[43] *Ontelaunee Power Operating Co., LLC*, 119 FERC ¶ 61,181, at P 24 (2007) (citing *Duke Energy Hinds LLC*, 102 FERC ¶ 61,068, at P 21 (2003)). *See also Papago Tribal Util. Auth. v. FERC*, 723 F.2d 950, 954 (D.C. Cir. 1983) ("specific acknowledgment of the possibility of future rate change is virtually meaningless unless it envisions a just-and-reasonable standard").

[44] Although PJM implements the cost allocation provisions of Schedule 12 of the Tariff, the cost allocation method is determined by the PJM Transmission Owners, and it is the PJM Transmission Owners, not PJM, that have the section 205 filing rights for the PJM cost allocation method. *See Atlantic City Electric Co. v. FERC*, 295 F.3d 1 (D.C. Cir. 2002).

[45] *See* PJM OATT, Schedule 12, §§ (b)(i) (3.0.0).

to provide reliable service to those facilities and therefore those merchant transmission providers are responsible for contributing to facilities necessary to support that firm service:

> PJM is required to provide reliable service up to the Firm Transmission Withdrawal Rights held by these customers. In order to provide such rights, PJM must require the construction of RTEP upgrades. The Merchant Transmission Facilities can avoid these costs if instead of opting for Firm Transmission Withdrawal Rights, they opt only for Non-Firm Transmission Withdrawal Rights under the tariff.[46]

As of the effective date of Linden's conversion of its Firm TWRs to Non-Firm TWRs, PJM is no longer required to provide firm service and can curtail non-firm service whenever necessary to preserve reliability.[47] Under Schedule 12, therefore, RTEP project costs would no longer be allocable to Linden as of the effective date of Linden's conversion from Firm TWRs to Non-Firm TWRs. The cost responsibility assignments for RTEP projects are updated annually based on a range of inputs and values to determine beneficiaries of RTEP projects.[48] Thus, under Schedule 12, cost responsibility assignments for RTEP projects shift over time as usage by transmission customers of a RTEP project changes over its lifespan.[49] For example, Linden's cost responsibility assignment increased as a direct result of the termination of Con Edison's transmission service agreements.[50] Contrary to PSEG's assertion, the PJM tariff does not require a merchant transmission facility, like Linden, to be allocated costs for an RTEP project over the life of that project based on the MWs of Firm TWRs they held at the time that the RTEP project was approved by PJM.[51] As noted, neither PSEG nor New Jersey

[46] *PJM Interconnection, L.L.C.* Opinion No. 503, 129 FERC ¶ 61,161, at P 80 (2009).

[47] *See* PJM OATT, Schedule 12 § (b)(i) (3.0.0). *See* PJM OATT § I, OATT Definitions L-M-N, 14.0.0, Non-Firm Transmission Withdrawal Rights. *See also* PJM OATT § II, Point-to-Point Transmission Service.

[48] *See* PJM OATT, Schedule 12 § (b)(iii)(H).

[49] Schedule 12 updates cost allocations annually based on changes to the system's topology, load changes, and other events such as termination of service. *See* PJM OATT, Schedule 12 § (b).

[50] Complaint at 7-8, s*ee also* Mellana Affidavit at P 8.

[51] *See* PJM OATT, Schedule 12 § (b)(iii).

Board has contended that these provisions are unjust and unreasonable.

33. PSEG argues that the Complaint is a collateral attack on the PJM cost allocation method. We disagree. As discussed above, we find the Complaint appropriately raises concerns relating to Linden's request to convert Firm TWRs to Non-Firm TWRs. While PSEG identifies the potential for Linden's cost responsibility assignments for RTEP projects to change as a result of its request to convert its Firm TWRs to Non-Firm TWRs, this potential simply reflects the operation of the cost allocation method in the tariff, not a collateral attack of it.

34. Moreover, we are not persuaded by PSEG's arguments that the Commission should dismiss the Complaint because PSEG reasonably relied upon the long-term duration of the Existing ISA, and Linden maintaining its Firm TWRs, as providing for long-term cost responsibility assignments for RTEP projects to Linden. As PSEG itself acknowledged, Linden has the right unilaterally to terminate the Existing ISA, including its Firm TWRs, at any time.[52] As we explained earlier, requiring Linden to terminate its rights in order to convert its Firm TWRs to Non-Firm TWRs is unjust and unreasonable as making such changes will not result in reliability or operational difficulties for the PJM system.

35. Similarly, the Market Monitor raises concerns with Schedule 12 and requests changes thereto in order to address an alleged discrepancy in the cost responsibility assignments for RTEP projects for merchant transmission providers that hold firm point-to-point transmission service and those that hold Firm TWRs. Those general concerns with Schedule 12 do not address whether Linden should be permitted to convert its Firm TWRs to Non-Firm TWRs. The PJM Transmission Owners also raise concerns regarding the cost responsibility assignments for RTEP projects to firm point-to-point transmission customers. We reject, as beyond the scope of this proceeding, these comments. The cost responsibility assignments for RTEP projects for firm point-to-point transmission customers under Schedule 12 are unrelated to the issue of whether Linden should be permitted to convert its Firm TWRs to Non-Firm TWRs.

The Commission orders:

(A) We grant the Complaint in part, and based on the filings described herein, we find that the Existing ISA is unjust and unreasonable insofar as it does not permit Linden to convert its Firm TWRs to Non-Firm TWRs, as discussed in the body of this order.

(B) Upon written notice from Linden, PJM shall make a compliance filing amending the section 2.2 of Specifications for the Existing ISA to reflect the conversion

[52] Complaint at 16.

of 330 MW Firm TWRs for a total 0 MWs of Firm TWRs and 330 MW Non-Firm TWRs, to be effective on the date requested by Linden in its written notice, but no earlier than the date of that notice, as discussed in the body of this order.

By the Commission. Chairman McIntyre is not participating.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Document Content(s)

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