

Division 1-16

Request:

Section 5.5 of the Share Purchase Agreement indicates that 49,089 preferred shares of Narragansett are issued and outstanding. Please:

- a. Describe the features of any associated preferred dividends, including their rate (i.e. annual yield), distribution schedule and whether they are cumulative, convertible or callable.
- b. Indicate the current owners of those preferred shares;
- c. Indicate the intended disposition of those preferred shares at the close of the Transaction; and
- d. If ownership of the preferred shares will change as a result of Transaction, indicate the planned owners of those preferred shares.

Response:

PPL and PPL RI refer to the response of National Grid USA and The Narragansett Electric Company to data request Division 1-16.

Division 1-17

Request:

Paragraph 37 of the Petition states that “the PPL Foundation will identify and support key charitable, philanthropic or community initiatives and programs in Rhode Island through donations. PPL also will make a contribution to the PPL Foundation in support of these commitments.” Please:

- a. Provide a list of any potential charitable, philanthropic or community initiatives in Rhode Island that the PPL Foundation has identified to receive donations after the Transaction is completed;
- b. Explain the criteria process by which the PPL Foundation will identify any such causes to donate to; and
- c. Provide the anticipated dollar figures that PPL intends to contribute toward these commitments.

Response:

a. PPL and PPL RI (collectively, “PPL”) have not yet identified any specific charitable, philanthropic, or community initiatives in Rhode Island that the PPL Foundation has identified to receive donations after the Transaction is completed. As the Transaction and integration planning proceed, PPL will develop specific processes for the PPL Foundation to identify key community initiatives and programs to support in Rhode Island, consistent with the PPL Foundation's focus areas: education; sustainable communities; and diversity equity and inclusion.

b. Each year, PPL Foundation contributes millions of dollars to support nonprofit organizations working to improve lives in the communities PPL serves.

PPL Foundation has three primary sources of giving:

- **United Way matching contributions:** Each year, PPL Foundation provides a 100% match of employee contributions pledged during the company's annual United Way campaign.
- **Major grants:** Annually, the company conducts a major grant cycle, with grants awarded in the fall. Major grants are focused on major expansions of programming that align with

PPL Foundation's focus areas. Capital expenditures are considered where such expenditures will result in the expanded capacity to serve.

- **Sustaining grants:** Each year, the company also conducts a sustaining grant cycle. Sustaining grants can be used for operating funds and day-to-day management of programs that align with PPL Foundation's focus areas.

As part of the above grant cycles, organizations are invited to apply for grants during the application window for each grant cycle. Grant applications are evaluated by local review teams. Factors considered during these reviews include alignment with PPL Foundation's focus areas, whether the program addresses a priority need in the community, the scope of potential impact and audience reached, program goals and metrics, and program sustainability. Recommendations are provided for review by a Corporate Review Team, with ultimate approval by PPL Foundation's Board of Directors. The PPL Foundation guide describing the grant process and focus areas can be found at https://www.pplweb.com/wp-content/uploads/2021/02/PPL-Foundation_2021-Grant-Info-Booklet-1.pdf.

PPL Foundation's focus areas are:

- **Education** – with a special emphasis on early childhood initiatives and STEM programs.
- **Diversity, equity and inclusion** – supporting programs aimed at confronting racism and discrimination, advancing social justice and equity, improving multi-cultural relations and supporting minority-led organizations.
- **Sustainable communities** – fostering the development of safe, strong and vibrant communities through support of community development projects or programs, with emphasis on those that are key to community revitalization.

As PPL moves forward with the transaction and integration planning, PPL Foundation will evaluate the suitability of its existing processes for applications in Rhode Island.

More information about the PPL Foundation and its community support can be found at <https://www.pplweb.com/communities/ppl-foundation/>.

- c. PPL and PPL Foundation have not yet identified specific dollar figures that they intend to contribute toward these commitments in Rhode Island.

PPL CORPORATION, PPL RHODE ISLAND HOLDINGS, LLC,
NATIONAL GRID USA, and THE NARRAGANSETT ELECTRIC COMPANY
Docket No. D-21-09
PPL Corporation and PPL Rhode Island Holdings, LLC's
Responses to Division's First Set of Data Requests
Issued on June 8, 2021

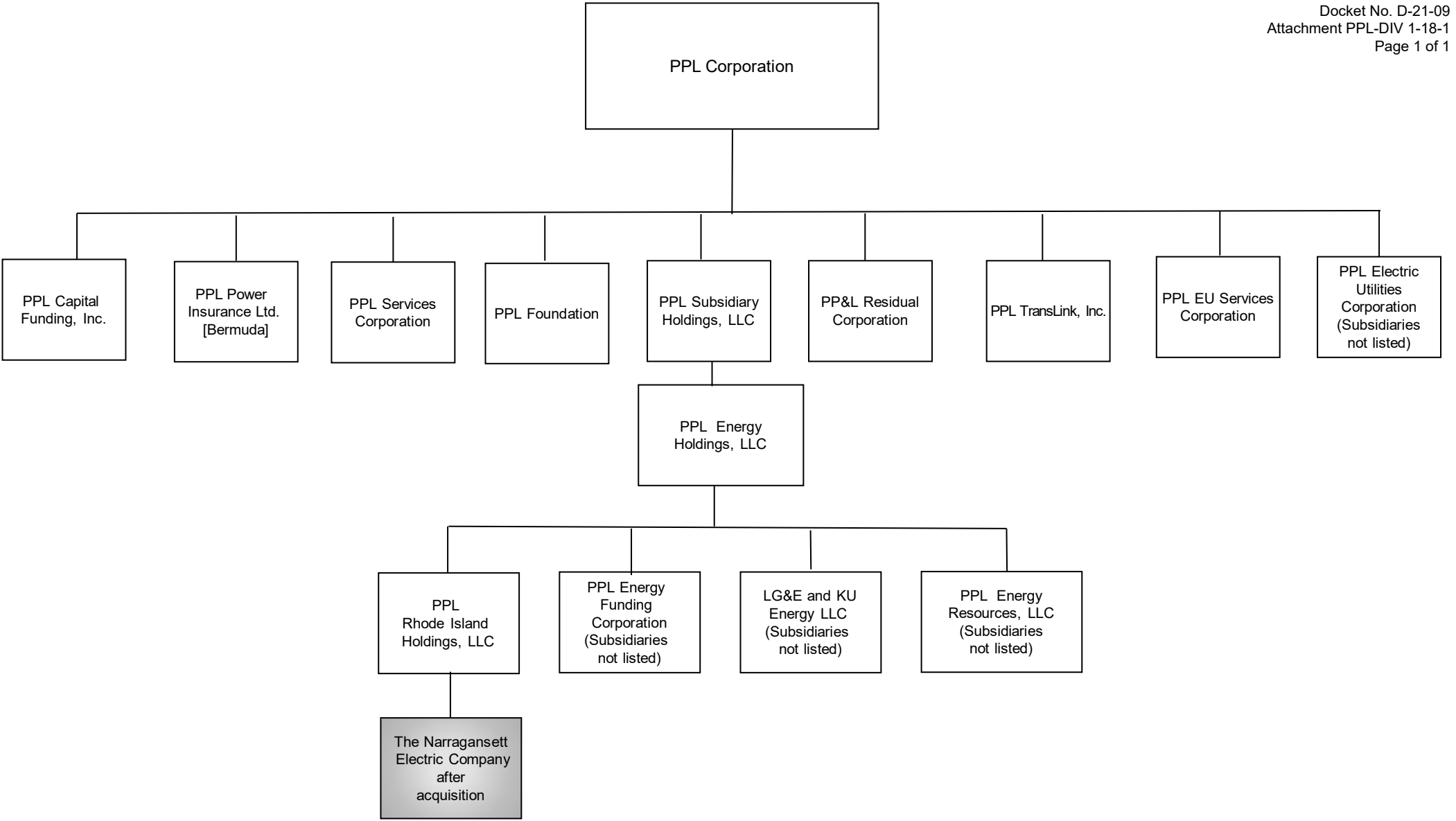
Division 1-18

Request:

Please provide an organizational chart for (a) PPL and (b) PPL RI.

Response:

Please see Attachment PPL-DIV-1-18-1.



Division 1-19

Request:

Paragraph 23 of the Petition states that “PPL will ensure that Narragansett has a Rhode Island-based President with responsibility for Narragansett’s operations and the necessary authority at PPL to ensure that Rhode Island has the resources and support to meet the needs of its customers.” With respect to this statement, please explain the reporting structure for the Narragansett President and:

- a. State to whom the President of PPL Rhode Island will report; and
- b. Describe the authority that the President of PPL Rhode Island will have to make decisions without authorization from PPL or PPL Utilities.

Response:

- a. The President of PPL RI will directly report to PPL’s Executive Vice President and Chief Operating Officer.
- b. The President of PPL RI will have decision-making authority to ensure the safe and reliable electric and gas service to customers. In addition, the President of PPL RI will work directly with the EVP and COO and other members of PPL’s Executive team, as necessary, to ensure that Narragansett has the resources and support necessary to provide this service to Rhode Island customers.

PPL CORPORATION, PPL RHODE ISLAND HOLDINGS, LLC,
NATIONAL GRID USA, and THE NARRAGANSETT ELECTRIC COMPANY

Docket No. D-21-09

PPL Corporation and PPL Rhode Island Holdings, LLC's
Responses to Division's First Set of Data Requests

Issued on June 8, 2021

Division 1-20

Request:

Please provide all Documents, including internal corporate guidelines or protocols, that govern the relationship between PPL, PPL RI, and Narragansett, presently or post-Transaction.

Response:

PPL and PPL RI refer to Attachment PPL-DIV 1-20-1, PPL Amended Services Agreement, dated July 21, 2016; Attachment PPL-DIV 1-20-2, PUC Approval – PPL Services Agreement, dated October 12, 2016; and Attachment PPL-DIV 1-20-3, PPL Standards of Integrity 2021.



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David B. MacGregor

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July 21, 2016

VIA ELECTRONIC FILING

Rosemary Chiavetta
Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street, 2nd Floor North
P.O. Box 3265
Harrisburg, PA 17105-3265

**Re: PPL Electric Utilities Corporation - Amended Services Agreement with PPL Corporation and Certain Subsidiaries
Docket No. G-2016-**

Dear Secretary Chiavetta:

Enclosed for filing on behalf of PPL Electric Utilities Corporation (“PPL Electric”), pursuant to Chapter 21 of the Public Utility Code, 66 Pa.C.S. Chapter 21, is a proposed Services Agreement between PPL Electric and PPL Corporation. This Services Agreement is intended to supersede and replace PPL Electric’s existing Services Agreement dated November 1, 2014, that was previously approved by the Pennsylvania Public Utility Commission (“Commission”).

PPL Electric is filing this Services Agreement primarily to add LG&E and KU Services Company, a PPL Corporation subsidiary, to the existing Services Agreement. This will allow PPL Electric to provide and receive services from LG&E and KU Services Company, and vice versa. The initial impetus for this Services Agreement is to accommodate the consolidation of certain information technology and related services among several PPL Corporation subsidiaries, but other services may be provided over time. Additionally, the proposed Services Agreement updates the list of current PPL Corporation subsidiaries, which is provided as Appendix A.

PPL Electric respectfully requests that the enclosed Services Agreement be considered as expeditiously as possible, consistent with the 30-day period for consideration of affiliate transactions set forth in Section 2102(b) of the Public Utility Code, 66 Pa.C.S. § 2102(b).

Rosemary Chiavetta
July 21, 2016
Page 2

Respectfully submitted,



David B. MacGregor
Principal

DBM/ctw
Enclosure

cc: Paul T. Diskin
Anthony J. Rametta

Services Agreement

This Agreement is made as of _____, by and between PPL Corporation, a Pennsylvania corporation ("PPL Corporation"), and PPL Electric Utilities Corporation, a Pennsylvania corporation ("PPL Electric"). This Services Agreement supersedes and replaces the Services Agreement between PPL Electric and PPL Corporation dated November 1, 2014.

WHEREAS, PPL Corporation is an energy and utility holding company and, under its Articles of Incorporation, may engage in any lawful act concerning any lawful business for which corporations may be incorporated under the Pennsylvania Business Corporation Law; and

WHEREAS, PPL Electric is a subsidiary of PPL Corporation and is engaged in providing electric distribution, transmission and default supply service to customers in portions of central eastern Pennsylvania subject to regulation by the Pennsylvania Public Utility Commission ("PaPUC") and the Federal Energy Regulatory Commission ("FERC"); and

WHEREAS, PPL Corporation and PPL Electric each possess knowledge and skill in various aspects of business operations; and

WHEREAS, the provision of certain services between PPL Corporation and PPL Electric will enable the parties to obtain these services effectively and efficiently; and

WHEREAS, PPL Corporation desires to procure services from PPL Electric on a non-exclusive basis, and PPL Electric is willing to provide these services; and

WHEREAS, PPL Electric desires to procure services from PPL Corporation on a non-exclusive basis, and PPL Corporation is willing to provide these services;

NOW, THEREFORE, in consideration of the agreements set forth herein and intending to be legally bound hereby, PPL Corporation and PPL Electric agree as follows:

A. Services

1. PPL Corporation agrees to provide, on an as-available basis, such services as may from time to time be requested by PPL Electric. These services may include management, supervisory, construction, engineering, accounting, legal, financial or similar services, as necessary and appropriate to the safe, efficient and/or cost effective operation of PPL Electric's business. A non-exclusive list of services that may be provided to PPL Electric includes, but is not limited to:

- Management services.
- Supervisory services.
- Construction services.
- Engineering services.
- Restoration of utility services.
- Information Technology services.
- External Affairs services.
- Human Resources services.
- Environmental Management services.
- Financial services.
- Auditing services.
- Risk Management services.
- Insurance services.

- Legal services.
- Call Center services.
- Billing services.
- Purchasing services.
- Supply Chain services.
- Real Estate services.
- Facilities Management services.
- Electronic data interchange ("EDI") services.
- Administrative services.
- Corporate Secretarial services.
- Other services that may be necessary for the safe, efficient and/or cost-effective operation of PPL Electric's business.

2. PPL Electric agrees to provide, on an as-available basis, such services as may from time to time be requested by PPL Corporation. These services may include management, supervisory, construction, engineering, accounting, legal, financial or similar services, as necessary and appropriate to the safe, efficient and/or cost effective operation of PPL Corporation's business, including, but not limited to, the non-exclusive list of services set forth in Paragraph A(1) above.

3. PPL Corporation and PPL Electric may obtain services of this nature from time to time on an as-needed basis. Neither PPL Corporation nor PPL Electric is under any obligation to procure a set amount of services pursuant to this Agreement.

B. Pricing

The price for services provided pursuant to Section A of this Agreement will be determined as set forth below; provided however that if a particular transaction is

subject to regulation by the FERC or another federal regulatory agency, and the rules of these agencies require a pricing mechanism that is different than provided herein, the Parties will follow the rules required by the federal agency, as applicable.

1. Direct Assignment

Pricing under this Agreement will be based on a direct assignment or attribution to the affiliate receiving the service to the extent reasonably possible.

2. Allocation

If pricing cannot be determined based on a direct assignment or attribution, it will be based on an allocation between the parties based on a reasonable approximation of the costs attributable to each party(ies).

If pricing cannot be determined as provided above, costs will be allocated using a three-factor methodology. The three factors are: (1) invested capital, (2) operation and maintenance expense, and (3) number of employees. The first factor will be calculated based upon each subsidiary's proportion of invested capital relative to its affiliates. The second factor will be based on each subsidiary's proportion of operation and maintenance expenses relative to its affiliates. The third factor will be based on each subsidiary's number of employees relative to its affiliates.

Each of the three factors will be weighted equally in importance. Therefore, the sum of the three factors will be divided by three to obtain the average multi-factor allocation percentage for each subsidiary. To reduce immaterial allocations, subsidiaries with a multi-factor average allocation rate of less than 1 percent will not receive an allocation.

PPL Corporation and/or its subsidiaries maintain Support Groups which may provide services to PPL Corporation and its subsidiaries. Support Groups will periodically analyze their indirect costs to determine which PPL Corporation subsidiaries do not receive a significant portion of their services. If these services and related costs are significant, the Support Groups will isolate them from other indirect costs to ensure that the PPL Corporation subsidiaries that do not receive a benefit from the costs are not allocated costs applicable to those services. Support Groups will identify either specific costs to be excluded or an appropriate percentage of services to be excluded based on the operation and the expenses incurred.

After the Support Groups determine which PPL subsidiaries benefit from their services (or a percentage of them if applicable), the allocation rate for each Support Group will be calculated. If all of a particular Support Group's costs benefit the same set of PPL Corporation subsidiaries equally, the appropriate allocation method for that Support Group will be obtained by using the average multi-factor allocation percentage for each subsidiary as discussed above. If, however, a portion of the costs only benefit certain subsidiaries, while the balance of the costs benefit another set of subsidiaries, then a Support Group blended multi-factor allocation factor will be calculated for that Support Group and used for allocating all the costs of that Support Group.

C. General

1. Subsidiary Participation

"PPL Corporation" as used in this Agreement includes all subsidiary and affiliated companies of PPL Corporation other than PPL Electric and LG&E and KU Energy, LLC's ("LKE") utility subsidiaries Louisville Gas and Electric Company and Kentucky

Utilities Company. A current list of PPL Corporation's subsidiaries is provided as Appendix A to this Agreement. PPL Electric will file an update of this list annually with the PaPUC. New PPL Corporation subsidiaries that are added before each annual update will be subject to this Agreement in the meantime. As set forth above, LKE's subsidiaries, Kentucky Utilities Company ("KU"), Kentucky Utilities Company d/b/a Old Dominion Power Company ("KU/ODP"), Louisville Gas and Electric Company ("LG&E") are not parties to this Agreement. This Agreement does not bind or otherwise obligate KU or LG&E. In the event that PPL Electric seeks to enter into a services contract with LKE's subsidiaries KU or LG&E, PPL Electric will file a separate affiliate agreement to cover those services.

2. Term

The term of this Agreement shall commence on the date first set forth above or the date on which the PaPUC approves this Agreement, whichever is later. Thereafter, this Agreement shall continue in full force and effect until terminated by either of the parties upon 15 days' written notice to the other party of its election to do so.

3. Billing

The party providing services under Section A of this Agreement shall bill on a monthly or more frequent basis the party receiving such services. Such bills shall reference the service provided and the associated prices, which shall be determined in accordance with Section B of this Agreement.

4. Governing Law

This Agreement shall be governed by and construed in accordance with the laws of the Commonwealth of Pennsylvania.

IN WITNESS WHEREOF, the parties have executed this Agreement as set forth
below.

PPL Corporation

By: Stephen K. Pappalardo

PPL Electric Utilities Corporation

By: Margaret C. Burns

Appendix A

PPL CORPORATION SUBSIDIARIES AND AFFILIATES

Airborne Clean Energy Ltd.	PPL EU Services Corporation
Airborne Pollution Control, Inc.	PPL Foundation
Aztec Insurance Limited	PPL Global, LLC
Central Networks Trustees Limited	PPL Infrastructure Services, LLC
CEP Commerce, LLC	PPL Island Limited
CEP Lending, Inc.	PPL Midlands Limited
CEP Reserves, Inc.	PPL Power Insurance Ltd.
DCUSA Limited	PPL Services Corporation
DHA, LLC	PPL Strategic Development, LLC
Downtown Commercial Loan Fund, LLC	PPL TransLink, Inc.
Ebusiness South West Limited	PPL UK Holdings, LLC
Electralink Limited	PPL UK Investments Limited
Electric Energy, Inc.	PPL UK Resources Limited
Electricity Association Services Limited	PPL UK Distribution Holdings Limited
Electricity Pensions Limited	PPL WEM Limited
Electricity Pensions Trustee Limited	PPL WPD Limited
Energy Networks Association Limited	Smart Energy Code Company Limited
FCD LLC	South Wales Electricity Share Scheme Trustees Limited
Gemserv Limited	South Western Helicopters Limited
Hyder Limited	Spinnaker Quay Management Company Limited
Hyder Profit Sharing Trustee Limited	Surf Telecoms Limited
Hyder Share Scheme Trustee (2) Limited	The Ombudsman Service Limited
Hyder Share Scheme Trustee Limited	Victory Park Management Company Limited
Indiana-Kentucky Electric Corporation	Western Kentucky Energy Corp.
Infralec 1992 Pension Trustee Limited	Western Power Distribution (East Midlands) plc
Joppa & Eastern Railroad Company	Western Power Distribution (West Midlands) plc
Kelston Properties Limited	Western Power Distribution (South Wales) plc
Kelston Properties 2 Limited	Western Power Distribution (South West) plc
Kentucky Utilities Company	Western Power Distribution Investments Limited
Lexington Utilities Company	Western Power Distribution pic
LG&E and KU Capital LLC	Western Power Generation Limited
LG&E and KU Energy LLC	Western Power Pension Trustee Limited
LG&E and KU Foundation Inc.	Willow Farm Management Company Limited
LG&E and KU Hydro I LLC	WPD Foundation
LG&E and KU Services Company	WPD Investments Limited
LG&E Energy Inc.	WPD Limited
LG&E Energy Marketing Inc.	WPD Limited (Guernsey)
Louisville Development Bancorp, Inc.	WPD Midlands Networks Contracting Limited
Louisville Gas and Electric Company	WPD Midlands Properties Limited
Merchants Landing (Amenities) Limited	WPD Distribution Networks Holdings Limited
Met-South, Inc.	WPD Property Developments Limited
Meter Operator Services Limited	WPD Property Investments Limited
Meter Reading Services Limited	WPD Property Limited
Metro Bank, Inc.	WPD Share Scheme Trustees Limited
Midwest Electric Power, Inc.	WPD Smart Metering Limited
MRA Service Company Limited	WW Share Schemes Trustees Limited
Northmere Limited	
Ohio Valley Electric Corporation	
PMDC Chile, LLC	
PMDC International Holdings, Inc.	
PP&L Residual Corporation	
PPL Capital Funding, Inc.	
PPL Cayman, LLC	
PPL Electric Utilities Corporation	
PPL Energy Funding Corporation	



COMMONWEALTH OF PENNSYLVANIA
PENNSYLVANIA PUBLIC UTILITY COMMISSION
400 NORTH STREET, HARRISBURG, PA 17120

October 12, 2016

IN REPLY PLEASE
REFER TO OUR FILE

G-2016-2557635
Utility Code: 110500

DAVID B MACGREGOR
POST & SCHELL
FOUR PENN CENTER
1600 JOHN F KENNEDY BOULEVARD
PHILADELPHIA PA 19103

Re: Affiliated Interest Agreement – PPL Electric Utilities Corporation – Services Agreement with PPL Corporation

Dear Mr. MacGregor:

On July 21, 2016, PPL Electric Utilities Corporation (PPL Electric) filed with the Pennsylvania Public Utility Commission (Commission), pursuant to 66 Pa. C.S. §§ 2102, *et seq.*, the above-referenced Affiliated Interest Agreement (Agreement). By Secretarial letter dated July 21, 2016, the Commission extended the statutory consideration period for this Agreement until further action of the Commission.

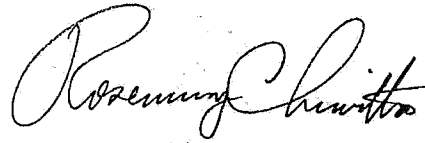
PPL Electric filed the proposed Agreement between PPL Electric and PPL Corporation, to supersede and replace PPL Electric's existing Services Agreement dated November 1, 2014, that was previously approved by the Commission at Docket No. G-2012-2323356.

PPL Electric is filing the Agreement primarily to add LG&E and KU Services Company, a PPL Corporation subsidiary, to the existing Services Agreement. This will allow PPL Electric to provide and receive services from LG&E and KU Services Company and vice versa. The proposed Agreement consolidates certain information technology and related services among several PPL Corporation subsidiaries and updates the list of current PPL Corporation subsidiaries, as provided in Appendix A.

Upon review of the filing, it does not appear that this Agreement is unreasonable or contrary to the public interest. Therefore, this filing is hereby approved. However, approval of this filing does not constitute a determination that the associated costs or expenses are reasonable or prudent for the purposes of determining just and reasonable rates. Furthermore, the Commission's approval is contingent upon the possibility that subsequent audits, reviews and inquiries in any Commission proceeding may be conducted, pursuant to 66 Pa. C.S. §§ 2102, *et seq.*

In addition, this approval will apply only to the agreement, services, matters and parties specifically and clearly defined under this instant proceeding as well as under any associated and previously filed filings.

Sincerely,

A handwritten signature in black ink, appearing to read "Rosemary Chiavetta". The signature is written in a cursive style with a large initial "R".

Rosemary Chiavetta
Secretary

cc: Yasmin Snowberger



PPL CORPORATION

Standards of Integrity

OUR VISION AND VALUES IN ACTION





Vince Sorgi



Steve Phillips

A Message from Vince Sorgi and Steve Phillips

Dear Colleague:

We are proud to be part of the highly skilled, intelligent and dedicated team that has made the PPL family of companies a top performer in the utility industry. To remain a top performer, we must continually overcome new challenges through innovation and determination to succeed. We know that meeting those challenges is critical, and meeting them in the right way is equally important.

Our Vision, Mission and Values along with our *Standards of Integrity* define how we conduct PPL's business. They set the foundation for our reputation as a company, our integrity as individuals, and the success of our operations. They apply in all situations, at all times, to all of us, guiding the decisions we make and the actions we take on behalf of PPL Corporation or any of its subsidiary companies.

Please join us in renewing and continuing our commitment to doing every job the right way.

A handwritten signature in black ink that reads "Vince Sorgi".

Vince Sorgi
President and Chief Executive Officer

A handwritten signature in black ink that reads "Steve Phillips".

Steve Phillips
*Vice President and
Global Chief Compliance Officer*

Our Vision, Mission and Values

Our Vision is empowering economic vitality and quality of life.

Our Mission is to provide safe, reliable, sustainable energy at a reasonable cost to our customers and superior, long-term returns to our shareowners.

Our Values are:

- Safety and Health: We do not compromise on safety and health.
- Customer Focus: We deliver customer service that is second to none.
- Diversity, Equity and Inclusion: We value each other and appreciate our differences.
- Performance Excellence and Innovation: We get the job done right, and we are always improving.
- Integrity and Openness: We do the right thing.
- Corporate Citizenship: We are environmentally conscious and invested in the communities we serve.

Standards of Integrity

The commitments stated in these *Standards of Integrity* (“Standards”) reflect our values and principles. These *Standards* apply to all directors, managers, officers, employees and agents, as appropriate, of PPL Corporation and its subsidiaries. All employees and others subject to these *Standards* are expected to read, understand and comply with them, as well as any other applicable policy of PPL Corporation (“Company” or “PPL”) or of any subsidiary company of PPL. In many cases, more detailed policies of PPL Corporation are referenced (and linked in the online version) to provide additional guidance on expectations. References to PPL Corporation policies should be read as referring to applicable subsidiary company policies as well.

COMMITMENT TO COMPLIANCE

We’re committed to complying fully with the letter and spirit of all applicable laws, rules and regulations. We abide by all applicable policies, procedures and guidelines, including those contained within these *Standards*. We understand that any violation of these *Standards* can result in disciplinary action including termination of employment.

WE SPEAK UP

We understand that our willingness to speak up and to speak truthfully is integral to our compliance and ethics commitment and that we are required to do so under these *Standards* and other applicable policies. We ask questions when we are unsure about a situation in the workplace. We promptly report workplace concerns. We never file reports or provide information that we know to be false or misleading, and we are forthright and cooperative in investigations that PPL or its subsidiary companies conduct.

GUIDELINES FOR DECISION-MAKING AND WHERE TO GO FOR ASSISTANCE

Occasionally, situations may arise that are not specifically covered by the *Standards* or other relevant policies. When faced with a decision regarding one of those situations, it may be helpful to ask yourself the following questions about your action or inaction, and to seek input from others qualified to help, as appropriate:

- Does it comply with the law?
- Does it comply with our rules, policies and procedures?
- Is it consistent with our Vision and Values?
- Who will be affected?
- Have I evaluated alternatives, and do I understand the consequences of each?

- How would my supervisor, co-workers, family or close friends view it?
- How would I feel if information about this were made public?
- Am I comfortable with it?

If you’re still unsure whether you are making the right decision, discuss your concerns with your supervisor, the manager to whom your supervisor reports, or any of the contacts listed at the end of these *Standards*.

REPORTING AND HANDLING OF VIOLATIONS

When reporting concerns, employees should provide the information that is available to them, and should not engage in their own investigation, or taking of videos, audio recordings or photographs. Instead, please allow those who are authorized to conduct all information gathering.

If reporting anonymously through the EthicsHelpline, be sure to provide enough information to allow the matter to be properly investigated. Our EthicsHelpline can protect your anonymity while interacting with you. Be sure to check back with the EthicsHelpline system to answer any questions posted requesting more information and to see the status of the matter.

NON-RETALIATION

PPL is committed to fostering an environment where employees feel comfortable speaking up. We do not tolerate any form of discrimination, harassment or retaliation against individuals raising a concern in good faith or toward employees who participate in the investigation of a concern. If you believe you have been retaliated against, promptly contact your Human Resources department or the department in your company responsible for ethics and compliance.



PEOPLE AND HUMAN RIGHTS

Workplace Health, Safety and Welfare

PPL is committed to the health, safety and welfare of its employees and of those with whom we do business. We promptly complete required training and immediately report unsafe situations. We follow applicable policies and guidelines on maintaining a workplace that is free from violence, weapons, dangerous conditions, smoking, drugs and alcohol.

Equal Employment Opportunity and Nondiscrimination

We treat all employees with fairness, respect and dignity and promote equal opportunity for all. We follow applicable policies and guidelines prohibiting discrimination, harassment, bullying or retaliation.

We want our employees to be fully engaged at work. We value individual differences and encourage different perspectives and ideas because we believe that diversity and inclusion are strengths that unlock our full potential and help us achieve our goals. We follow applicable guidelines on equal employment opportunity.

Human Rights

We respect the human rights of our employees and expect our suppliers to respect human rights as well, as described in subsidiary company policies required by our Supplier Code of Conduct. With respect to work-related matters, PPL recognizes and respects employees' freedom of association as well as the right to form or join a union, bargain collectively, or engage in union activities.

Privacy and Personal Information

We are committed to protecting personal information of employees and those with whom we do business. We are committed to complying with all applicable privacy and data protection laws and policies, including the PPL Enterprise Information Security Policy. We do not access personal information of our customers or co-workers without a legitimate business reason.

ENVIRONMENTAL COMMITMENT

We all have an obligation to carry out our business activities in ways that preserve and promote a clean, safe and healthy environment. We abide by the environmental laws and regulations of the locations in which we operate.

CONFLICTS OF INTEREST AND USE OF COMPANY ASSETS AND RESOURCES

We avoid conflicts between our personal interests and our work responsibilities. Our goal is to avoid even the appearance of conflict. We promptly disclose potential conflicts of interest to our supervisor or to any of the contacts listed at the end of these *Standards*.

We understand that we owe PPL (including its subsidiary companies) a duty to advance its legitimate interest when the opportunity to do so arises. We protect all company assets and resources and use all company information properly. We do not use any company assets, resources, information, or our position at work for improper personal gain, and we do not compete with any PPL company. If we learn of a business or investment opportunity through the use of any company assets, resources, information, or our position at work, we understand that this is an investment opportunity for our company. We do not participate in such an opportunity personally unless preapproved in writing by our company through approval at the senior manager level or above.

We comply with all applicable guidelines and policies that address conflicts of interest, including the following policies of PPL Corporation: Conflicts of Interest and External Board or Officer Service.

We also comply with applicable laws and policies on information protection and information security, including PPL's Enterprise Information Security Policy and we comply with our Insider Trading Policy and Guidelines.

Gifts and Entertainment

We make sure that offering or accepting gifts and entertainment to or from those with whom we do business does not result in a feeling or expectation of personal obligation or affect our business judgment, or even appear to do so. When offering or accepting gifts or entertainment, we never accept, offer or authorize gifts in the form of cash or certificates that can be exchangeable into cash. We use good judgment and act with moderation.

We comply with the Gifts and Entertainment provisions of the Conflicts of Interest Policy.

Community Activities and External Organizations

Volunteering our time in the communities we serve is an excellent way for us to make a difference and experience significant personal growth in areas such as leadership and communication skills, diversity awareness and team building. We may also serve as an officer or board member of external organizations. However, participation in external organizations can be time-consuming. We are careful to avoid conflicts of interest, and we follow these PPL Corporation policies: Political Activities and External Board or Officer Service.

IMPROPER INFLUENCE

We do not offer, give, solicit or receive any bribes or kickbacks. It is our goal to avoid even the appearance of improperly influencing others.

We offer no gifts or hospitality to government employees in the United States without approval from a company attorney, and we offer no gifts or entertainment to a foreign government official without approval from PPL's Office of General Counsel. We comply with the following PPL Corporation policies: Political Activities and Anti-Bribery/Anti-Corruption.

PROCURING GOODS AND SERVICES

We make procurement decisions in the best interests of our company. We comply with all applicable procurement and related policies, avoid conflicts of interest at all times in our procurement decisions, apply objective standards for evaluating supplier proposals, and select suppliers based on merit. We are also committed to compliance with any applicable laws related to supplier diversity, and we do not unlawfully discriminate in the identification and selection of qualified suppliers.

COMPETITIVE PRACTICES

Antitrust Laws

We compete fairly on the basis of price, service and value and comply with applicable laws and regulations that are intended to allow customers to freely make choices in the marketplace without obstruction from improper conduct or agreements that would affect price, restrict volumes or reduce the number of suppliers of goods and services. We comply with U.S. antitrust laws and anti-market manipulation rules of the Federal Energy Regulatory Commission and the Commodity Futures Trading Commission. We comply with PPL Corporation's Antitrust Policy.

Affiliate Relationships

We are subject to requirements that are meant to make sure that relationships and transactions among PPL subsidiaries do not disadvantage customers of PPL's public utility operations. We strictly follow these requirements, including appropriate accounting and cost allocation practices, and we comply with PPL Corporation's Affiliate Relationships Policy.

CONFIDENTIAL INFORMATION

We respect and protect confidential business information of our company, customers and vendors. We comply with laws and applicable policies dealing with disclosure of confidential information and with protecting confidential information. We do not access confidential business information without a legitimate business reason. We comply with PPL's Enterprise Information Security Policy.

FAIR DEALING

We deal fairly and honestly with governmental and regulatory bodies, customers, suppliers, competitors, peer companies, employees and anyone else with whom we have contact in our jobs. We never take unfair advantage of anyone through manipulation, concealment, abuse of privileged information, misrepresentation of material facts or any other unfair-dealing practice. We comply with laws when gathering competitive information and use such information only for legitimate business purposes. We comply with PPL Corporation's Fair Dealing Policy.

EMBARGOES AND TRADE SANCTIONS

We are committed to complying fully with the laws and regulations of the United States dealing with economic sanctions, including laws prohibiting transactions with certain countries, agencies and individuals.

GOVERNMENT RELATIONS

Communications in Contested Matters

In contested matters, we abide by applicable restrictions on communications with a government representative or regulator (such as a judge, commissioner, arbitrator, fact-finder, staff, etc.) without the other parties being present or knowing about it. We follow our Political Activities Policy.



Political Activities

We value and encourage citizenship. We are careful to comply with all laws on lobbying and political contributions. We do not use funds or assets of our company to make political contributions to candidates for public office or to political parties. We track and report lobbying time. We follow these PPL Corporation policies: Conflicts of Interest and Political Activities.

INTELLECTUAL PROPERTY

We are aware of others' intellectual property rights, including patents, trademarks, copyrights and trade secrets. We make sure we have the owner's permission before we reproduce copyrighted material, share a copy of an electronic or other subscription with unlicensed users, use logos or other trademarks or disclose proprietary information.

ACCURATE RECORDS

We maintain complete and accurate records of all business transactions. We make full, fair and accurate disclosure in compliance with all applicable laws and regulations in all documents that we submit to the government or regulator, or that we communicate to the public. We retain records in accordance with applicable policy and law, including data protection laws.

RESPONDING TO EXTERNAL INQUIRIES

Media Inquiries

Each of our companies has designated certain people who are authorized to speak on its behalf to the news media. We follow applicable policies on media inquiries and refer all media inquiries to our company's communications department.

Financial Inquiries

We direct all requests for information from the financial community and investors as follows:

- Requests from securities analysts, brokers or institutional investors are directed to PPL's Investor Relations department.
- Requests for information from the U.S. Securities and Exchange Commission or other regulators are directed to PPL's Office of General Counsel.
- Requests for information from individual shareowners are directed to Equiniti Trust Company, EQ Shareowner Services at 1-800-345-3085 or online at: shareowneronline.com.

SOCIAL MEDIA

We understand that our use of social media can pose risks to the confidential and proprietary information, reputation and brand of PPL Corporation or its subsidiary companies. We comply with PPL's Social Media Policy.



USE OF PPL'S INDEPENDENT AUDITOR

We are committed to making sure that PPL's independent auditor is independent in both fact and appearance. We obtain pre-approval from PPL's controller and head of audit services prior to using PPL's independent auditor, and we comply with PPL's policy on Use of the Company's Independent Auditor.

WAIVERS AND AMENDMENTS OF THE STANDARDS

It is not our practice to grant waivers of the *Standards*. For executive officers and directors of PPL, any waiver of the *Standards* may be made only by the board or by a board committee. We may periodically amend the *Standards* to enhance them or to ensure compliance with applicable law. We will promptly disclose significant amendments and waivers of the *Standards* as required by law.

Contact Information for Inquiries, Concerns and Allegations

ALL PPL CORPORATION SUBSIDIARIES

EthicsHelpline

1-800-550-9418

<https://pplethicshelpline.alertline.com>

Global Chief Compliance Officer

610-774-6525

Corporate Human Resources

610-774-6387

LG&E AND KU ENERGY

LG&E/KU HelpLine

1-800-407-7185

All helpline reports can be made anonymously.



PPL CORPORATION, PPL RHODE ISLAND HOLDINGS, LLC,
NATIONAL GRID USA, and THE NARRAGANSETT ELECTRIC COMPANY
Docket No. D-21-09
PPL Corporation and PPL Rhode Island Holdings, LLC's
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Issued on June 8, 2021

Division 1-21

Request:

Please provide all Documents pertaining to PPL's capital investment allocation and approval processes.

Response:

Counsel for PPL, PPL RI, National Grid USA ("National Grid"), The Narragansett Electric Company ("Narragansett"), and The Rhode Island Division of Public Utilities and Carriers Advocacy Section (the "Division Advocacy Section") met and conferred regarding the breadth and scope of certain data requests. After that meet and confer, the Division Advocacy Section sent a letter, dated June 22, 2021, advising that PPL, PPL RI, National Grid, and Narragansett can "use sound judgment and the rule of reason in crafting responses and providing responsive documents." The Division Advocacy Section also advised in the June 22, 2021 letter PPL, PPL RI, National Grid, and Narragansett to "consider the Advocacy Section's goal of protecting ratepayers when determining scope and relevancy." Based on the scope and breadth of this request, PPL and PPL RI have applied the rule of reason and used sound judgment in limiting the breadth and scope of documents produced in response to this request, and have considered the Division Advocacy Section's goal of protecting ratepayers in determining which documents it will produce.

Each year, PPL's electric utility subsidiaries formulate business plans that include, among other things, the proposed capital investments for the following year. The business plan for each electric utility subsidiary, including the cost allocation to the each one, is ultimately approved by PPL's Board of Directors. There are no documents reflecting this process.

PPL CORPORATION, PPL RHODE ISLAND HOLDINGS, LLC,
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PPL Corporation and PPL Rhode Island Holdings, LLC's
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Issued on June 8, 2021

Division 1-22

Request:

Please provide the credit ratings for PPL and each of its subsidiaries.

Response:

PPL and PPL RI refer to the table below for the requested information:

PPL Corporation & Subsidiary Companies - Credit Ratings		
Issuer	Moody's	Standard & Poor's
PPL Corporation		
Issuer Rating	Baa2	A-
Short-term Issuer Rating		A-2
Outlook	Positive	Stable
PPL Capital Funding		
Issuer Rating		A-
Senior Unsecured	Baa2	BBB+
Junior Subordinated Notes	Baa3	BBB
Short-term/Commercial Paper	P-2	A-2
Outlook	Positive	Stable
PPL Electric Utilities		
Issuer Rating	A3	A-
Senior Secured/First Mortgage Bonds	A1	A
Tax Exempt Bonds ⁽¹⁾	A1/A3	A
Short-term/Commercial Paper	P-2	A-2
Outlook	Stable	Positive
LG&E and KU Energy LLC		
Issuer Rating	Baa1	A-
Senior Unsecured	Baa1	BBB+
Outlook	Stable	Stable
LG&E		
Issuer Rating	A3	A-
Senior Secured/First Mortgage Bonds	A1	A
Tax Exempt Bonds ⁽¹⁾	A1/P-2	A/A-2
Short-term/Commercial Paper	P-2	A-2
Outlook	Stable	Stable
Kentucky Utilities		
Issuer Rating	A3	A-
Senior Secured/First Mortgage Bonds	A1	A
Tax Exempt Bonds ⁽¹⁾	A1/P-2	A/A-2
Short-term/Commercial Paper	P-2	A-2
Outlook	Stable	Stable

Prepared by or under the supervision of: Tadd J. Heninger

PPL CORPORATION, PPL RHODE ISLAND HOLDINGS, LLC,
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REDACTED

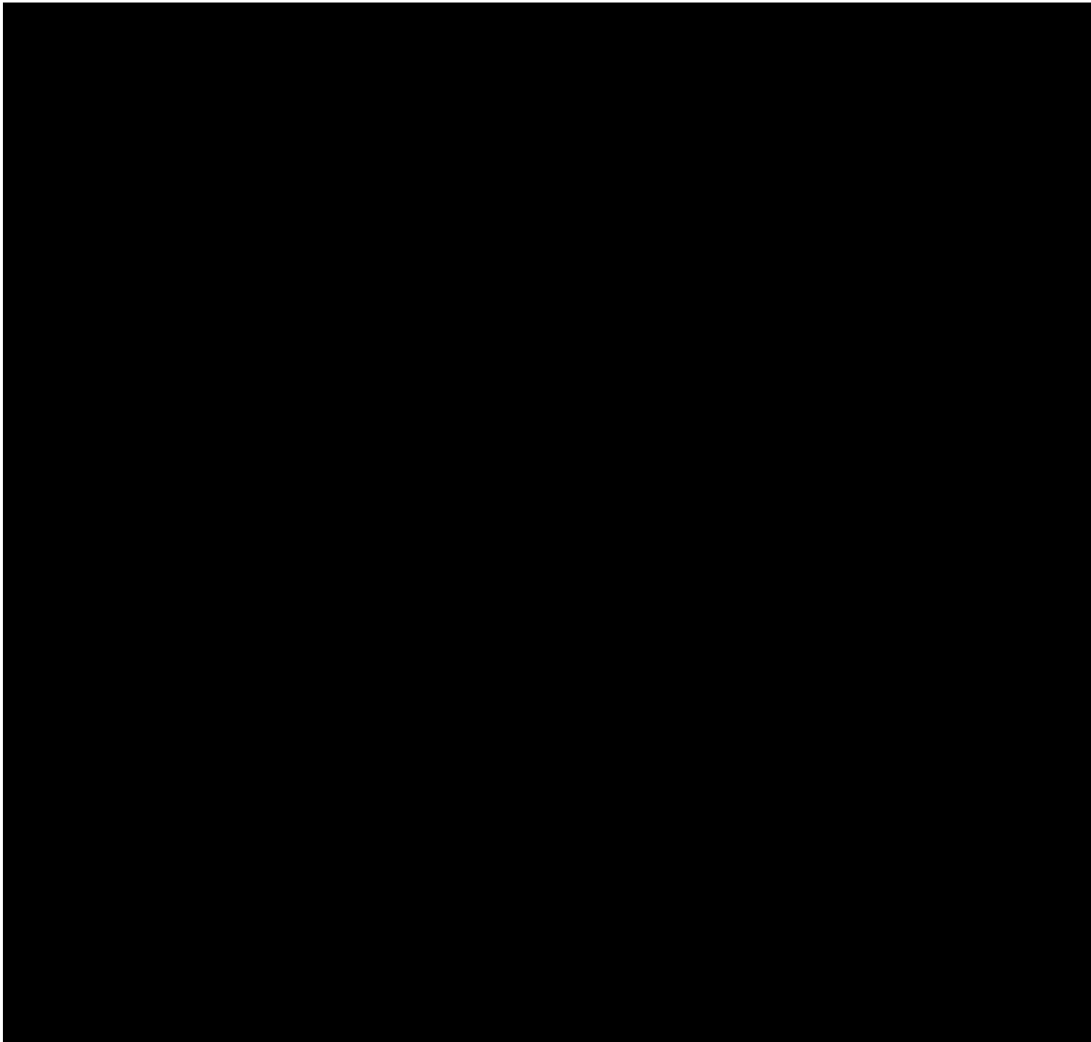
Division 1-23

Request:

Please provide a list of all outstanding loans made by any PPL subsidiary to another PPL subsidiary.

Response:

PPL and PPL RI refer to the below table for a list of all outstanding loans made between PPL subsidiaries.

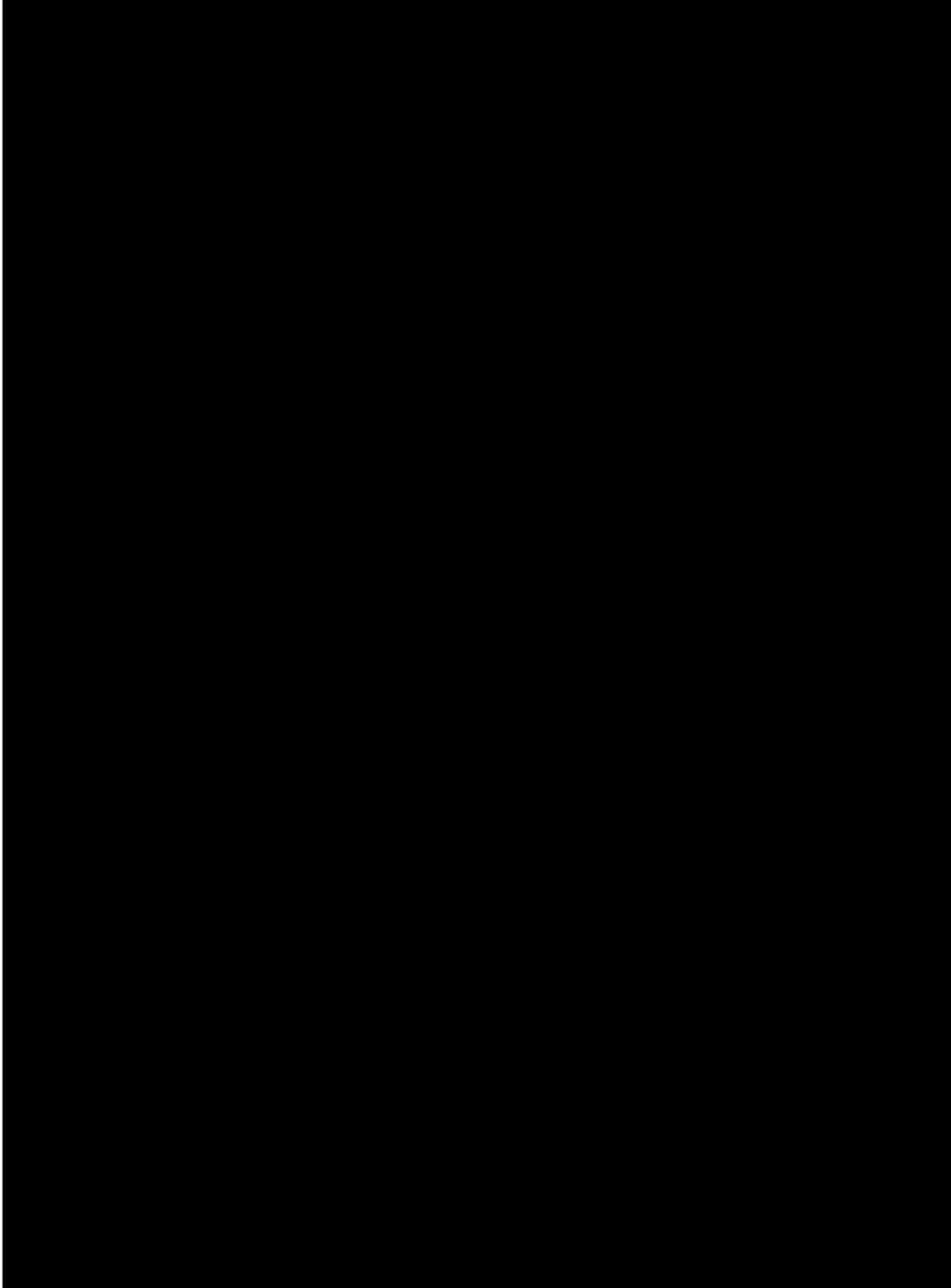


PPL CORPORATION, PPL RHODE ISLAND HOLDINGS, LLC,
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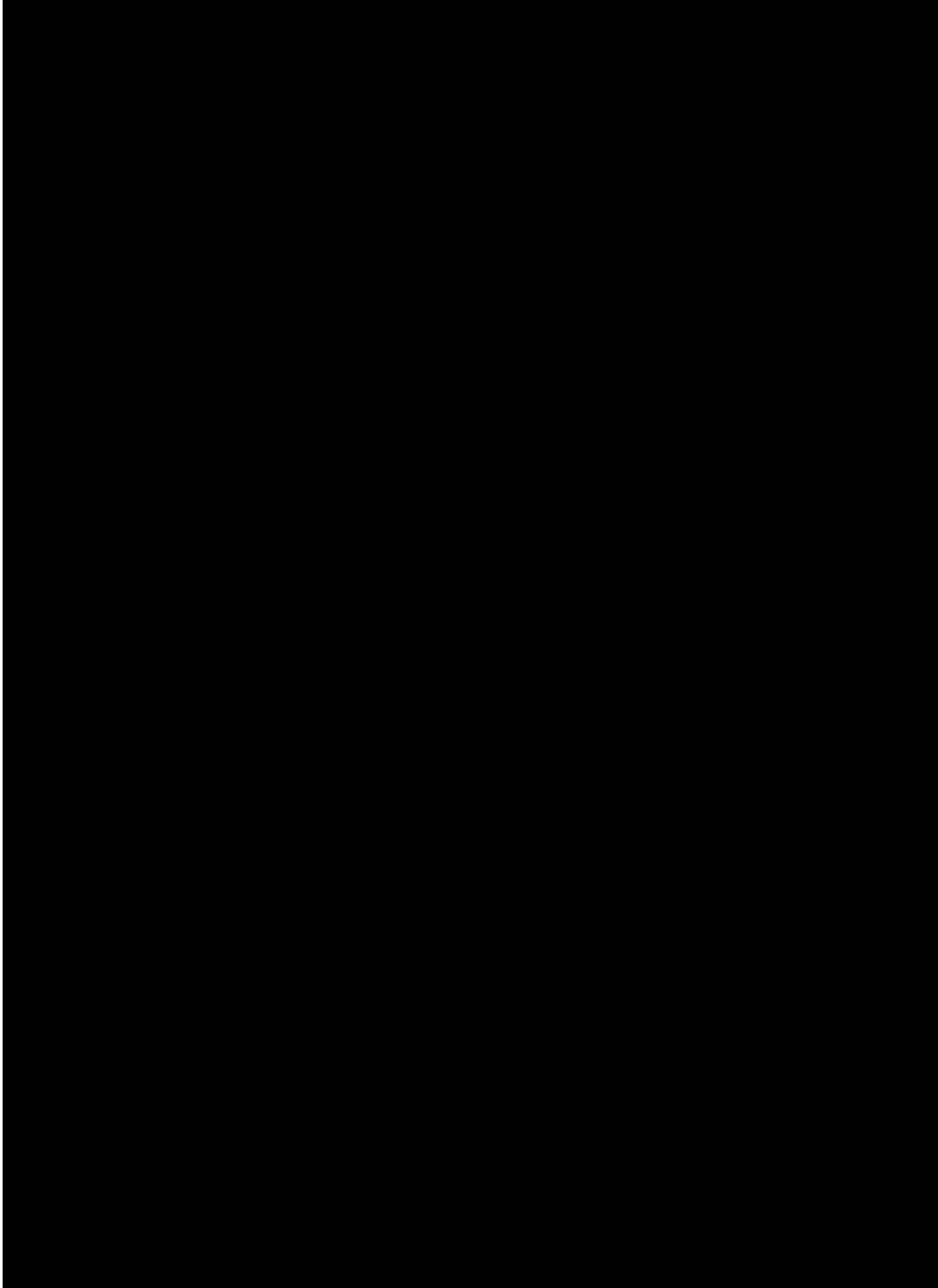


PPL CORPORATION, PPL RHODE ISLAND HOLDINGS, LLC,
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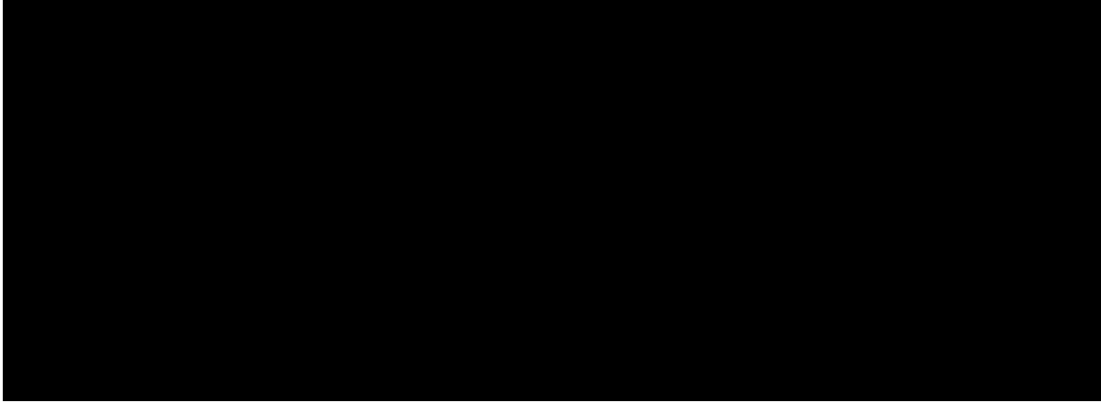


PPL CORPORATION, PPL RHODE ISLAND HOLDINGS, LLC,
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REDACTED
Division 1-24

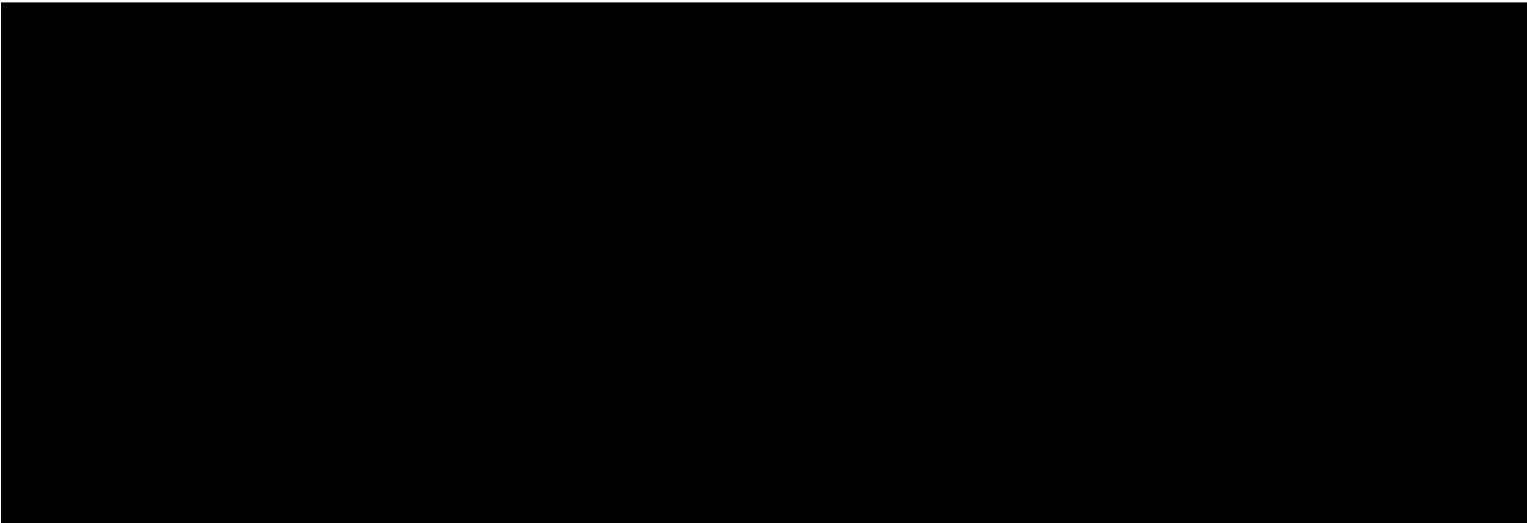
Request:

Please provide a list of outstanding debt owed by a PPL subsidiary to a third-party that is guaranteed by another PPL subsidiary.

Response:

PPL and PPL RI refer to the table below in response to the Request.

LONG-TERM DEBT MATURITY SCHEDULE
06/08/2021



PPL CORPORATION, PPL RHODE ISLAND HOLDINGS, LLC,
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Division 1-25

Request:

Please indicate whether PPL intends to pledge the assets of PPL RI as collateral for any loans by third-parties to another PPL subsidiary.

Response:

At this time, PPL does not intend to pledge assets of PPL RI as collateral for any loans by third parties to another PPL subsidiary.

PPL CORPORATION, PPL RHODE ISLAND HOLDINGS, LLC,
NATIONAL GRID USA, and THE NARRAGANSETT ELECTRIC COMPANY

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PPL Corporation and PPL Rhode Island Holdings, LLC's
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Division 1-26

Request:

Please provide the capital structures of PPL, PPL RI, and all other PPL regulated utility subsidiaries

Response:

PPL and PPL RI refer to the table below in response to the Request. The table references the following entities: PPL; Electric Utilities – Pennsylvania Public Utility Commission (“EU-PA PUC”); Electric Utilities – Federal Energy Regulatory Commission (“EU-FERC”); Kentucky Utilities Company (“KU”); Louisville Gas & Electric (“LG&E”); LG&E and KU Energy, LLC (“LKE”); and PPL Rhode Island Holdings, Inc. (“RI”).

PPL Utilities Cap Structure						
	<u>Debt</u>	<u>Equity</u>	<u>Total Cap</u>	<u>Equity/Cap</u>	<u>As of</u>	<u>Notes</u>
PPL	14,714	14,217	28,932	49.1%		Includes \$3B of debt paydown that was tendered or called via make-whole on 6/30 and 7/15, respectively.
EU-PA PUC	4,450	5,184	9,634	53.8%	5/31/2021	
EU- FERC	4,237	5,184	9,421	55.0%	5/31/2021	EU Regulatory cap structure does not include STD
KU	2,821	3,231	6,052	53.4%	5/31/2021	Exlcudes \$607M of goodwill from equity
LG&E	2,290	2,595	4,885	53.1%	5/31/2021	Exlcudes \$389M of goodwill from equity
LKE	6,774	4,244	11,018	38.5%	5/31/2021	Exlcudes \$996M of goodwill from equity
RI	1,510	1,666	3,177	52.4%	3/31/2021	Exlcudes \$725M of goodwill from equity

PPL CORPORATION, PPL RHODE ISLAND HOLDINGS, LLC,
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Division 1-27

Request:

Please explain and provide all related analysis, plans, and studies that form the basis for the proposed two year transition period.

Response:

No specific analysis or study was prepared concerning the two-year time period. The two-year time period was reached after negotiations among the parties, taking into account the transition periods for similar transactions in the industry.

Division 1-28

Request:

Please provide the status of efforts to “identify[] and negotiat[e] the nature and duration of the specific services to be provided by Service Company that will be set forth in an exhibit to the TSA.” Petition ¶ 19. If the referenced exhibit to the TSA has been completed, please provide a copy of that exhibit.

Response:

As provided for in the testimony of Gregory N. Dudkin, PPL and National Grid have assembled a group of officers, managers, and other employees from both companies to plan, execute, and coordinate the business integration and organizational separation efforts for the transaction. Mr. Dudkin leads the Integration Management Office ("IMO") for PPL that is responsible for defining the overall integration process and developing the schedules and workplans to effectively operate Narragansett upon legal close. The IMO is supported by core PPL functional teams responsible for defining and developing the Day-1 implementation efforts. Mr. Dudkin's counterpart at National Grid, Dan Davies, leads the Transition Management Office ("TMO") that is responsible for defining the transition plan and developing the schedules and workplans to effectively separate Narragansett from National Grid. The TMO is supported by National Grid functional teams responsible for defining and developing the Day-1 transition efforts. The IMO and TMO continue to work together to plan and guide the integration effort and are dedicated to its successful completion. The meetings have been occurring on a weekly basis to discuss progress against the schedule and workplans and coordinate across integration and transition topics, and are anticipated to continue until all services are transitioned.

The TSA services to be provided by National Grid are not yet fully identified and defined and at this time, PPL has not identified any TSA services National Grid will provide Narragansett. Please see Attachment NG-DIV 1-28-1, “Rhode Island Transition: TSA Directory,” for a listing of potential TSA services under consideration at this time. Please also see the following attachments to the response of National Grid and Narragansett, which consist of the indicative draft schedules by function current as of June 25, 2021:

- Billing & Collections – Attachment NG-DIV 1-28-2-1
- Customer Services – Attachment NG-DIV 1-28-2-2
- Energy Procurement – Attachment NG-DIV 1-28-2-3
- Gas Operations & Engineering – Attachment NG-DIV 1-28-2-4
- Electric Operations & Engineering – Attachment NG-DIV 1-28-2-5

PPL CORPORATION, PPL RHODE ISLAND HOLDINGS, LLC,
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- Business Services: Balance Sheet Account Reconciliations – Attachment NG-DIV 1-28-2-6
- Business Services: Supply Chain Master Data Management – Attachment NG-DIV 1-28-2-7
- Business Services: Employee Services – Attachment NG-DIV 1-28-2-8
- Facilities – Attachment NG-DIV 1-28-2-9
- Finance & Accounting – Attachment NG-DIV 1-28-2-10
- Human Resources – Attachment NG-DIV 1-28-2-11
- Health & Safety, Monitoring & Compliance – Attachment NG-DIV 1-28-2-12
- Regulatory – Attachment NG-DIV 1-28-2-13
- Supply Chain Management – Attachment NG-DIV 1-28-2-14

As the planning process progresses, PPL and National Grid integration teams will continue to refine TSA services required to operate Narragansett as of Day 1.

Division 1-29

Request:

Please provide all correspondence and Documents related to the TSA between PPL, its affiliates, and National Grid.

Response:

Counsel for PPL, PPL RI, National Grid USA ("National Grid"), The Narragansett Electric Company ("Narragansett"), and The Rhode Island Division of Public Utilities and Carriers Advocacy Section (the "Division Advocacy Section") met and conferred regarding the breadth and scope of certain data requests. After that meet and confer, the Division Advocacy Section sent a letter, dated June 22, 2021, advising that PPL, PPL RI, National Grid, and Narragansett can "use sound judgment and the rule of reason in crafting responses and providing responsive documents." The Division Advocacy Section also advised in the June 22, 2021 letter PPL, PPL RI, National Grid, and Narragansett to "consider the Advocacy Section's goal of protecting ratepayers when determining scope and relevancy." Based on the scope and breadth of this request, PPL and PPL RI have applied the rule of reason and used sound judgment in limiting the breadth and scope of documents produced in response to this request, and have considered the Division Advocacy Section's goal of protecting ratepayers in determining which documents it will produce.

PPL, PPL RI, and National Grid are actively engaged in constant communications on a daily basis to negotiate and plan for transition and integration of Narragansett's operations into PPL RI's ownership and PPL's operational systems. In consultation with National Grid, PPL and PPL RI have identified certain key documents reflecting the status of those efforts and will provide supplements with additional documents reflecting substantial developments in the transition and integration process.

PPL and PPL RI refer to Attachment NG-DIV 1-29-2, Joint TSA Readout & Day 1 Readiness Launch, dated May 26, 2021; and Attachment NG-DIV 1-29-3, Joint IMO / TMO Kickoff, dated April 7, 2021.

PPL and PPL RI also refer to Attachment NG-DIV 1-29-1, Separation Blueprint, dated January 2021, which is a working document that arose out of the series of joint workshop sessions between PPL and National Grid USA and details how Narragansett would be separated from National Grid USA post-closing.

PPL and PPL RI also refer to Attachments NG-DIV 1-28-2-1 through NG-DIV 1-28-2-14.

PPL CORPORATION, PPL RHODE ISLAND HOLDINGS, LLC,
NATIONAL GRID USA, and THE NARRAGANSETT ELECTRIC COMPANY

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PPL Corporation and PPL Rhode Island Holdings, LLC's
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Division 1-30

Request:

Please explain the meaning of the statement in the testimony of Mr. Dudkin (at 29:19-20) that “[a]s a practical matter, the transition services will not impact the cost structure to customers.”

Response:

PPL and PPL RI understand The Narragansett Electric Company's ("Narragansett") current cost structure. PPL will incur costs for operations and services provided by National Grid USA and National Grid USA Service Company, Inc. under the Transition Services Agreement. Additionally, PPL and PPL RI will incur costs related to setting up their organization to serve Narragansett's customers. PPL will track these transition costs (including internal costs of employees spending time working on transition issues, and external costs paid to consultants to reorganize and consolidate functions) and will not pass these costs on to Narragansett customers. Instead, such costs will remain at the PPL corporate level. PPL expects that it will serve Narragansett customers with an improved cost structure after the transition is complete.

PPL CORPORATION, PPL RHODE ISLAND HOLDINGS, LLC,
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PPL Corporation and PPL Rhode Island Holdings, LLC's
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Division 1-31

Request:

Referencing the testimony of Mr. Dudkin at 30:2-5, please explain how "PPL will ensure that the costs paid to the Service Company will not result in increased rates for Narragansett's customers."

Response:

PPL and PPL RI refer to the response to data request Division 1-30.

PPL CORPORATION, PPL RHODE ISLAND HOLDINGS, LLC,
NATIONAL GRID USA, and THE NARRAGANSETT ELECTRIC COMPANY

Docket No. D-21-09

PPL Corporation and PPL Rhode Island Holdings, LLC's
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Division 1-32

Request:

Please provide an accounting of all costs PPL and its affiliates anticipate incurring to achieve this Transaction.

Response:

Through the end of May 2021, PPL and its affiliates have spent approximately \$9 million in its effort to acquire The Narragansett Electric Company ("Narragansett"). These external costs include fees related to financing, legal, due diligence and consulting. PPL anticipates incurring additional fees for continued legal and consulting services, as well as costs to separate various Information Technology and other systems, but it does not currently have an estimate of what those total costs may be.

PPL CORPORATION, PPL RHODE ISLAND HOLDINGS, LLC,
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Docket No. D-21-09
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Issued on June 8, 2021

Division 1-33

Request:

Please confirm that PPL will not seek recovery of merger-related costs, including any acquisition premium, in Narragansett's base electric or gas rates.

Response:

PPL and PPL RI (collectively, "PPL") confirm that they will not seek recovery of merger-related costs, including any acquisition premium, that would result in increases in The Narragansett Electric Company's ("Narragansett") base electric or gas rates. In the event that any merger-related costs, such as system implementation costs, result in the potential for lower base electric or gas rates, PPL may consult with the Rhode Island Division of Public Utilities and Carriers or the Public Utilities Commission on these costs as mentioned in the Federal Energy Regulatory Commission's Policy Statement issued on May 19, 2016 to provide guidance regarding future implementation of hold harmless commitments offered by applicants as ratepayer protection mechanisms to mitigate adverse effects on rates. See Attachment PPL-DIV 1-33-1.

155 FERC ¶ 61,189
DEPARTMENT OF ENERGY
Federal Energy Regulatory Commission

[Docket No. PL15-3-000]

(Issued May 19, 2016)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Policy Statement

SUMMARY: The Commission adopts the following policies regarding future implementation of hold harmless commitments offered by applicants as ratepayer protection mechanisms to mitigate adverse effects on rates that may result from transactions subject to section 203 of the Federal Power Act (FPA). First, the Commission clarifies the scope and definition of the costs that should be subject to hold harmless commitments. Second, the Commission adopts the proposal that applicants offering hold harmless commitments should implement controls and procedures to track the costs from which customers will be held harmless. The Commission identifies the types of controls and procedures that applicants offering hold harmless commitments should implement. Third, the Commission declines to adopt its proposal to no longer accept hold harmless commitments that are limited in duration. Fourth, the Commission clarifies that, in connection with certain types of FPA section 203 transactions, an applicant may be able to demonstrate that the transaction will not have an adverse effect on rates without the need to make any hold harmless commitment.

Docket No. PL15-3-000

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EFFECTIVE DATE: This policy statement will become effective **[90 days after**

publication in the FEDERAL REGISTER]

FOR FURTHER INFORMATION CONTACT:

Eric Olesh (Technical Information)
Office of Energy Market Regulation
888 First Street, NE
Washington, DC 20426
(202) 502-6524
eric.olesh@ferc.gov

Noah Monick (Legal Information)
Office of the General Counsel
888 First Street, NE
Washington, DC 20426
(202) 502-8299
noah.monick@ferc.gov

Olga Anguelova (Accounting Information)
Office of Enforcement
888 First Street, NE
Washington, DC 20426
(202) 502-8098
olga.anguelova@ferc.gov

SUPPLEMENTARY INFORMATION

155 FERC ¶ 61,189
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Cheryl A. LaFleur, Tony Clark,
and Colette D. Honorable.

Policy Statement on Hold Harmless Commitments

Docket No. PL15-3-000

POLICY STATEMENT

(Issued May 19, 2016)

1. The Commission issues this Policy Statement to provide guidance regarding future implementation of hold harmless commitments offered by applicants as ratepayer protection mechanisms to mitigate adverse effects on rates that may result from transactions that are subject to section 203 of the Federal Power Act (FPA).¹
2. On January 22, 2015, the Commission proposed guidance in four areas pertaining to hold harmless commitments: (1) the scope and definition of the costs that should be subject to hold harmless commitments; (2) controls and procedures to track the costs from which customers will be held harmless; (3) whether to no longer accept hold harmless commitments that are limited in duration; and (4) clarification that, in certain cases, an applicant may be able to demonstrate that a proposed transaction will not have an adverse effect on rates without the need to make any hold harmless commitment or

¹ 16 U.S.C. 824b (2012).

Docket No. PL15-3-000

- 2 -

offer any other form of ratepayer protection mechanism.² We adopt, clarify, and withdraw, in part, the proposals in the Proposed Policy Statement as explained in further detail below.

3. First, we adopt, as general guidance, the lists of transaction-related costs and transition costs that should be subject to any hold harmless commitment, as proposed in the Proposed Policy Statement, and provide additional clarifications regarding transition costs, capital costs, labor costs, and the costs of transactions that are not consummated. Second, we adopt, in part, the proposal regarding establishing controls and procedures for transaction-related costs subject to any hold harmless commitment. Third, we withdraw our proposal to no longer accept hold harmless commitments that are limited in duration and clarify that we will continue to accept hold harmless commitments that are time limited to support a Commission finding that a proposed transaction will have no adverse effect on rates. Fourth, we clarify that consistent with the Merger Policy Statement, a hold harmless commitment is one of several forms of ratepayer protection that an applicant can offer to address any potential adverse effect on rates, and that hold harmless commitments may be unnecessary for some categories of transactions if an applicant can otherwise demonstrate that a proposed transaction will have no adverse effect on rates.

² *Policy Statement on Hold Harmless Commitments*, Proposed Policy Statement, 80 FR 4231 (Jan. 27 2015), 150 FERC ¶ 61,031 (2015) (Proposed Policy Statement).

I. Background

A. The Commission's Analysis of Proposed Transactions Under FPA Section 203

4. FPA section 203(a)(4) requires the Commission to approve proposed dispositions, consolidations, acquisitions, or changes in control if it determines that the proposed transaction will be consistent with the public interest.³ The Commission's analysis of whether a transaction will be consistent with the public interest generally involves consideration of three factors: (1) the effect on competition; (2) the effect on rates; and (3) the effect on regulation.⁴ Before granting authorization, FPA section 203(a)(4) also requires the Commission to find that the transaction "will not result in cross-subsidization of a non-utility associate company or the pledge or encumbrance of utility assets for the

³ 16 U.S.C. 824b(a)(4) (2012).

⁴ See *Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, Order No. 592, 61 FR 68595 (Dec. 30, 1996), FERC Stats. & Regs. ¶ 31,044, at 30,111 (1996) (Merger Policy Statement), *reconsideration denied*, Order No. 592-A, 79 FERC ¶ 61,321 (1997). See also *FPA Section 203 Supplemental Policy Statement*, 72 FR 42277 (Aug. 2, 2007), FERC Stats. & Regs. ¶ 31,253 (2007). See also *Revised Filing Requirements Under Part 33 of the Commission's Regulations*, Order No. 642, 65 FR 70983 (Nov. 28, 2000), FERC Stats. & Regs. ¶ 31,111 (2000), *order on reh'g*, Order No. 642-A, 94 FERC ¶ 61,289 (2001). See also *Transactions Subject to FPA Section 203*, Order No. 669, 71 FR 1348 (Jan. 6, 2006), FERC Stats. & Regs. ¶ 31,200 (2005), *order on reh'g*, Order No. 669-A, 71 FR 28422 (May 16, 2006), FERC Stats. & Regs. ¶ 31,214, *order on reh'g*, Order No. 669-B, 71 FR 42579 (July 27, 2006), FERC Stats. & Regs. ¶ 31,225 (2006).

benefit of an associate company, unless the Commission determines that the cross-subsidization, pledge, or encumbrance will be consistent with the public interest.”⁵

5. The Proposed Policy Statement focused on the second prong of the Commission’s FPA section 203 analysis, specifically, the effect of a proposed transaction on rates. As explained in the Proposed Policy Statement, the Commission has stated that, when considering a proposed transaction’s effect on rates, the Commission’s focus “is on the effect that a proposed transaction itself will have on rates, whether that effect is adverse, and whether any adverse effect will be offset or mitigated by benefits that are likely to result from the proposed transaction.”⁶ As relevant here, the Commission considers whether the transaction could result in an adverse effect on rates to wholesale requirements or transmission customers.

6. Generally, the Commission may find that a transaction will have no adverse effect on rates if an applicant demonstrates that there is no mechanism that would enable the applicant to recover costs related to the transaction in wholesale power or transmission rates, either because existing contracts would not allow such costs to be passed through to customers or, in the case of market-based rates, the transaction can have no adverse

⁵ 16 U.S.C. 824b(a)(4). The Commission’s regulations establish verification and information requirements for applicants that seek a determination that a transaction will not result in inappropriate cross-subsidization or a pledge or encumbrance of utility assets. *See* 18 CFR 33.2(j).

⁶ Proposed Policy Statement, 150 FERC ¶ 61,031 at P 3 (quoting *ITC Midwest LLC*, 140 FERC ¶ 61,125, at P 19 (2012)).

impact on wholesale rates.⁷ In addition, in cases in which the proposed transaction may have an effect on rates, the Commission may nevertheless be able to find that the transaction will not have an adverse effect on rates if the applicant has demonstrated that there are offsetting benefits. Finally, the Commission may base its finding that a transaction will not have an adverse effect on rates in whole or in part on an applicant's offer of specific ratepayer protections, such as a hold harmless commitment.

7. If an applicant's only customers are wholesale power sales customers served under market-based rates, then the transaction will have no adverse effect on rates for such customers.⁸ Similarly, if an applicant is unable to pass through transaction-related costs because its existing contracts do not allow for such pass through, then the transaction will have no adverse effect on rates for such customers.⁹ If, however, the transaction could result in an increase in rates and the wholesale power sales customers of the applicants are not served exclusively under market-based rates, or if the applicants have wholesale requirements or transmission customers, the Commission evaluates whether there are sufficient benefits to ratepayers that would offset any potential rate impact. If such

⁷ See *Exelon Corp.*, 149 FERC ¶ 61,148, at P 105 (2014).

⁸ *Cinergy Corp.*, 140 FERC ¶ 61,180, at P 41 (2012) (citing *Duquesne Light Holdings, Inc.*, 117 FERC ¶ 61,326, at P 25 (2006)) (“The Commission has previously stated that, when there are market-based rates, the effect on rates is not of concern. The effect on rates is not of concern in these circumstances because market-based rates will not be affected by the seller's cost of service and, thus, will not be adversely affected by the Proposed Transaction.”).

⁹ See, e.g., *Public Service Co. of New Mexico*, 153 FERC ¶ 61,377, at P 39 (2015); *NRG Energy Holdings, Inc.*, 146 FERC ¶ 61,196, at P 87 (2014).

benefits exist, the analysis of the effect on rates ends with a finding that there is no adverse effect on rates because of those offsetting economic benefits.¹⁰

8. If a proposed transaction has the potential to increase wholesale rates, but there is no showing of quantifiable offsetting economic benefits, the Commission must determine whether ratepayers are sufficiently protected from the potential rate increase, or whether there are other non-quantifiable, offsetting benefits that would, nevertheless, support a finding that the proposed transaction is consistent with the public interest, regardless of the potential for a rate increase.¹¹ When the Commission has considered such non-quantifiable offsetting benefits, it has often been in the context of transactions that increase competition or enable more competitive markets, such as transactions resulting

¹⁰ The Commission has found that there is no adverse effect on rates where, although costs may increase in one area of the utility's operations, lower costs are expected elsewhere. *See, e.g., Bluegrass Generation Co., L.L.C.*, 139 FERC ¶ 61,094, at P 41 (2012) (finding no adverse effect on rates because increases in capacity charges would be offset by a savings in energy rates).

¹¹ An increase in rates "can still be consistent with the public interest if there are countervailing benefits that derive from the merger." Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 30,114; *see also ALLETE, Inc.*, 129 FERC ¶ 61,174, at P 19 (2009) ("Our focus here is on the effect that the Proposed Transaction itself will have on rates, whether that effect is adverse, and whether any adverse effect will be offset or mitigated by benefits likely to result from the Proposed Transaction.").

in the expansion of regional transmission organizations or the increase in transmission ownership by independent transmission companies.¹²

9. Prior to the issuance of the Merger Policy Statement, the Commission had required applicants and intervenors to estimate the future costs and benefits of a transaction and then litigate the validity of those estimates. The Commission, however, eliminated those requirements in the Merger Policy Statement and, instead, established various ratepayer protection mechanisms that an applicant could offer to insulate customers from any possible rate effects attributable to a proposed transaction.¹³

10. The Commission then explained that it had previously accepted “a variety of hold harmless provisions,” and that parties could consider those as well as “other mechanisms if they appropriately address ratepayer concerns.”¹⁴ Among the types of protection the

¹² See, e.g., *ITC Midwest LLC*, 133 FERC ¶ 61,169, at P 23 (2010) (finding offsetting benefits because of the transfer of transmission assets to a standalone transmission company); *ALLETE*, 129 FERC ¶ 61,174 at P 20 (finding that the advantages created in joining a regional transmission organization outweighed potential rate increase created by the different tax treatment of the assets after transfer); *Ameren Servs. Co.*, 103 FERC ¶ 61,121, at P 23 (2003) (finding that increasing a regional transmission organization’s footprint would offset a rate increase); *Rockland Elec. Co.*, 97 FERC ¶ 61,357, at 62,651 (2001) (finding that attracting more bidders and encouraging more competition offset a potential rate increase for locational marginal prices along a seam at times of peak demand).

¹³ Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 30,111 (“[I]n assessing the effect of a proposed merger on rates, we will no longer require applicants and intervenors to estimate the future costs and benefits of a merger and then litigate the validity of those estimates. Instead, we will require applicants to propose appropriate rate protection for customers.”).

¹⁴ *Id.* at 30,124.

Commission stated applicants could propose were the following:

- Open season for wholesale customers—applicants agree to allow existing wholesale customers a reasonable opportunity to terminate their contracts (after notice) and switch suppliers. This allows customers to protect themselves from merger-related harm.
- General hold harmless provision—a commitment from the applicant that it will protect wholesale customers from any adverse rate effects resulting from the merger for a significant period of time following the merger. Such a provision must be enforceable and administratively manageable.
- Moratorium on increases in base rates (rate freeze)—applicants commit to freezing their rates for wholesale customers under certain tariffs for a significant period of time.
- Rate reduction—applicants make a commitment to file a rate decrease for their wholesale customers to cover a significant period of time.¹⁵

11. The Commission concluded that, although each mechanism would provide some benefit to ratepayers, in the majority of circumstances the most meaningful (and the most likely to give wholesale customers the earliest opportunity to take advantage of emerging competitive wholesale markets) was an open season provision.¹⁶

12. Subsequently, in Order No. 642, the Commission promulgated regulations governing FPA section 203 applications and described the information applicants must submit regarding the effect of a proposed transaction on rates. In relevant part, the Commission stated:

In the [Merger] Policy Statement, we determined that ratepayer protection mechanisms (e.g., open seasons to allow early termination of existing service contracts or rate freezes) may be necessary to protect the wholesale customers of merger applicants. ...

Thus, in the [Notice of Proposed Rulemaking] we proposed that all merger

¹⁵ *Id.* (footnotes omitted).

¹⁶ *Id.*

applicants demonstrate how wholesale ratepayers will be protected and that applicants will have the burden of proving that their proposed ratepayer protections are adequate. Specifically, we proposed that applicants must clearly identify what customer groups are covered (e.g., requirements customers, transmission customers, formula rate customers, etc.), what types of costs are covered, and the time period for which the protection will apply.¹⁷

13. The Commission adopted the proposals set forth in the Notice of Proposed Rulemaking and emphasized that if applicants did not offer any ratepayer protection mechanisms, they must explain how the proposed merger would provide adequate ratepayer protection.¹⁸

B. Current Commission Practice Regarding Hold Harmless Commitments

14. Over the last decade hold harmless commitments have become a common feature of FPA section 203 applications involving mergers of traditional franchised utilities or their upstream holding companies.¹⁹ More recently, hold harmless commitments have been made in connection with transactions by traditional franchised utilities to acquire

¹⁷ Order No. 642, FERC Stats. & Regs. ¶ 31,111 at 31,914.

¹⁸ *Id.*

¹⁹ The Commission has also accepted other forms of ratepayer protection in lieu of or in addition to hold harmless commitments. *See, e.g., Cinergy Services, Inc.*, 102 FERC ¶ 61,128, at P 33 (2003) (accepting rate freeze as rate mitigation); *Vermont Yankee Nuclear Power Corp.*, 91 FERC ¶ 61,325, at 62,125 (2000) (accepting rate cap and an open season provision as mitigation); *Cajun Elec. Power Coop., Inc.*, 90 FERC ¶ 61,309, at 62,005-06 (2000) (approving a transaction where current customers were allowed to keep their current contracts or choose from three different power purchasing agreements).

jurisdictional facilities in order to satisfy resource adequacy requirements at the state level, to improve system reliability and/or meet other regulatory requirements.²⁰

15. The Commission has consistently accepted hold harmless commitments in which FPA section 203 applicants commit not to seek recovery of transaction-related costs in jurisdictional rates except to the extent that such costs are offset by transaction-related savings.²¹ Thus, hold harmless commitments typically focus on preventing recovery in rates of the costs incurred that are “related” to the transaction.²² Although the Commission has relied on commitments to hold customers harmless from transaction-

²⁰ See, e.g., *FirstEnergy Generation Corp.*, 141 FERC ¶ 61,239, at PP 1, 16, 27-30 (2012) (*FirstEnergy*) (accepting a hold harmless commitment in an asset transaction where generation assets would be turned into assets to support transmission system upgrades in order to meet needs identified in a study by PJM Interconnection, L.L.C. following the retirement of other generating facilities); *ITC Midwest*, 140 FERC ¶ 61,125 at P 15; *Int’l Transmission Co.*, 139 FERC ¶ 61,003, at P 16 (2012).

²¹ *NSTAR Advanced Energy Sys., Inc.*, 131 FERC ¶ 61,098, at P 24 (2010) (“The Commission looks for assurances from public utilities that they hold customers harmless from these transaction-related costs, to the extent they are not exceeded by cost savings arising from the transaction, for a significant period of time following the merger, not an indefinite period of time.”) (internal citation omitted); see also *Cinergy*, 140 FERC ¶ 61,180 at P 42; *ITC Midwest*, 140 FERC ¶ 61,125 at PP 21-22; *Int’l Transmission*, 139 FERC ¶ 61,003 at P 17; *BHE Holdings Inc.*, 133 FERC ¶ 61,231, at P 37 (2010); cf. *Sierra Pacific Power Co.*, 133 FERC ¶ 61,017, at P 14 (2010) (accepting a commitment not to include any transaction-related costs in its Commission-accepted open access transmission tariff).

²² An applicant may seek to recover transaction-related costs incurred prior to consummating a proposed transaction or those transaction-related costs incurred within the time period during which the hold harmless commitment applies by making certain filings. Specifically, an applicant must submit a new filing under FPA section 205 and a concurrent informational filing in the relevant FPA section 203 docket. In the FPA section 205 filing, an applicant must: (1) specifically identify the transaction-related costs they are seeking to recover; and (2) demonstrate that those costs are exceeded by the savings produced by the transaction. *Exelon Corp.*, 149 FERC ¶ 61,148 at PP 105-107.

related costs to support findings of no adverse effects on rates, these commitments generally have not included detailed definitions of the transaction-related costs that are covered by the applicant's hold harmless commitment or identified the categories of savings that the transaction is expected to produce.²³

C. Proposed Policy Statement

16. On January 22, 2015, the Commission issued a Proposed Policy Statement on Hold Harmless Commitments to attempt to address: (1) concerns of parties that may believe hold harmless commitments offer insufficient protection; (2) instances in which hold harmless commitments may not be necessary; and (3) confusion over the scope and coverage of hold harmless commitments.

17. The Proposed Policy Statement focused on the matter of what should constitute an acceptable hold harmless commitment to demonstrate that ratepayers will be adequately protected from any rate effects of a transaction. The Commission identified several general areas to address including: (1) the scope and definition of the costs that should be subject to hold harmless commitments; (2) controls and procedures to track the costs from which customers will be held harmless; (3) the acceptance of hold harmless commitments that are limited in duration; and (4) clarification that, if applicants are

²³ See, e.g., *Puget Energy*, 123 FERC ¶ 61,050 at P 27 (“We accept Applicants’ hold harmless commitment, which we interpret to include all merger-related costs, not only costs related to consummating the transaction. If Applicants seek to recover any merger-related costs in a subsequent section 205 filing, they must show quantifiable offsetting benefits.”) (citations and footnotes omitted); *National Grid plc*, 117 FERC ¶ 61,080, at P 54 (2006) (“Applicants have committed to hold ratepayers harmless from transaction-related costs in excess of transaction savings for a period of five years.”).

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otherwise able to demonstrate that a proposed transaction will not have an adverse effect on rates, then there is no need for applicants to make hold harmless commitments or offer other ratepayer protection mechanisms. The Proposed Policy Statement did not propose to provide guidance on what categories of savings related to a proposed transaction may be used in a subsequent section 205 filing to justify recovery of transaction-related costs. These issues will be considered on a case-by-case basis.

D. Comments

18. Comments were filed by American Electric Power Company, Inc. (AEP); American Public Power Association and the National Rural Electric Cooperative Association (collectively, APPA and NRECA); Edison Electric Institute (EEI); Electric Power Supply Association (EPSA); Louisville Gas and Electric Company and Kentucky Utilities Company (collectively, Kentucky Utilities); South Central MCN, LLC and Midcontinent MCN, LLC (collectively, Transmission-Only Companies); Southern Company Services, Inc. as agent for Alabama Power Company, Georgia Power Company, Gulf Power Company, and Mississippi Power Company (collectively, Southern Company); Transmission Access Policy Study Group; and Transmission Dependent Utility Systems (Transmission Dependent Utilities).
19. We discuss specific concerns raised by commenters below.

II. Discussion

A. Scope and Definition of Transaction-Related Costs

1. Proposal

20. The Commission's experience has been that applicants generally do not attempt to define what costs are subsumed in the term "transaction-related costs," and that this may lead to later disagreement over which costs are or are not covered by the applicant's hold harmless commitment. In the Proposed Policy Statement, therefore, the Commission set forth guidelines for costs subject to hold harmless commitments offered by FPA section 203 applicants.²⁴ Specifically, the Commission proposed that the costs set out below are those transaction-related costs from which customers must be held harmless and that may not be recovered from customers except to the extent exceeded by demonstrated transaction-related savings.²⁵ The Commission proposed to provide guidance in the Proposed Policy Statement regarding how to identify transaction-related costs, and acknowledged that attempts to precisely articulate all such costs are not feasible.

21. First, the Commission proposed that transaction-related costs include, but are not limited to, the following costs incurred to explore, agree to, and consummate a transaction:

²⁴ See Proposed Policy Statement, 150 FERC ¶ 61,031 at PP 21-28.

²⁵ We expect that applicants proposing to recover these costs would track and record them pursuant to the procedures established below. See *infra* PP 66-69.

- the costs of securing an appraisal, formal written evaluation, or fairness opinions related to the transaction;
- the costs of structuring the transaction, negotiating the structure of the transaction, and obtaining tax advice on the structure of the transaction;
- the costs of preparing and reviewing the documents effectuating the transaction (e.g., the costs to transfer legal title of an asset, building permits, valuation fees, the merger agreement or purchase agreement and any related financing documents);
- the internal labor costs of employees²⁶ and the costs of external, third-party, consultants and advisors to evaluate potential merger transactions, and once a merger candidate has been identified, to negotiate merger terms, to execute financing and legal contracts, and to secure regulatory approvals;²⁷
- the costs of obtaining shareholder approval (e.g., the costs of proxy solicitation and special meetings of shareholders);
- professional service fees incurred in the transaction (e.g., fees for accountants, surveyors, engineers, and legal consultants); and

²⁶ If the duties of employees are not solely dedicated to activities related to a transaction, internal labor costs deemed merger-related should be determined in a manner that is proportionally equal to the amount of time spent on the merger compared to other activities of the utility and tracked accordingly.

²⁷ Some of these costs are typically incurred prior to the announcement of a merger.

- installation, integration, testing, and set up costs related to ensuring the operability of facilities subject to the transaction.

22. Moreover, the Commission stated that, for transactions that are pursued but never completed (transactions that ultimately fail), transaction-related costs should not be recovered from ratepayers. The Commission also recognized that not every cost listed above will be found in every transaction,²⁸ and that the final determination of what transaction-related costs may be recovered by applicants will remain subject to case-by-case analysis.

23. The Commission stated that there is a second category of transaction-related costs related to mergers, where, in addition to the costs to consummate the transaction described above, parties typically also incur costs to integrate the operations and assets of the merging companies in order to achieve merger synergies.²⁹ These costs, which are sometimes referred to collectively as “transition” costs, are incurred after the transaction is consummated, often over a period of several years. These costs include both the internal costs of employees spending time working on transition issues, and external costs paid to consultants and advisers to reorganize and consolidate functions of the merging entities to achieve merger synergies. These costs may also include both capital items (e.g., a new computer system or software, or costs incurred to carry out mitigation

²⁸ Proposed Policy Statement, 150 FERC ¶ 61,031 at P 23.

²⁹ Entities engaging in certain internal corporate restructuring and reorganizations, unrelated to complying with state law restructuring requirements, may seek to achieve similar cost savings or increased efficiencies as merging entities.

commitments accepted by the Commission in approving the transaction to address competition issues, such as the cost of constructing new transmission lines) and expense items (e.g., costs to eliminate redundancies, combine departments, or maximize contracting efficiencies). The Commission proposed that such transition costs incurred to integrate the operations of merging companies include, but are not limited to, the following:

- engineering studies needed both prior to and after closing the merger;
- severance payments;
- operational integration costs;
- accounting and operating systems integration costs;
- costs to terminate any duplicative leases, contracts, and operations; and
- financing costs to refinance existing obligations in order to achieve operational and financial synergies.³⁰

24. The Commission stated that this list of transition costs is not exhaustive, and may include other categories of costs incurred or paid in connection with the integration of two utilities after a merger. Thus, the Commission proposed to consider transition costs as transaction-related costs that should be subject to hold harmless commitments on a case-by-case basis and that such transaction-related costs should be covered under hold harmless protection, although noting that applicants will have an opportunity to show why certain of those costs should not be considered transaction-related costs under their

³⁰ Proposed Policy Statement, 150 FERC ¶ 61,031 at P 24.

hold harmless commitment based on their particular circumstances. Also, the Commission proposed to consider, on a case-by-case basis, whether other costs not discussed herein should be subject to hold harmless commitments.

25. Additionally, the Commission noted that accounting journal entries related to a merger transaction may affect expense, asset, liability, or proprietary capital accounts used in the development of a public utility's rates.³¹ These accounting journal entries may originate from transaction-related costs recorded as an expense or capitalized as an asset. Additional accounting journal entries may originate from goodwill and fair value adjustments related to the purchase price paid for the acquired company. Merger transactions are accounted for by applying purchase accounting, which adjusts the assets and liabilities of the acquired entity to fair value and recognizes goodwill for the amount paid in excess of fair value.³² If the acquired company is a holding company, purchase accounting also provides for the fair value adjustments and goodwill to be recorded on the books of some, or all, of the acquired holding company's subsidiaries, which is commonly referred to as "push-down" accounting. Under appropriate circumstances, the Commission has allowed the fair value accounting adjustments and goodwill to be

³¹ *Id.* P 26.

³² Purchase accounting is also commonly referred to as acquisition accounting under generally accepted accounting principles in the United States. Purchase accounting is a formal accounting method for merger transactions which measures the assets and liabilities of the acquired entity at fair value and establishes goodwill for amounts paid in excess of fair value. *See* Accounting Standard Codification Section 805-10 (Fin. Accounting Standards Bd. 2014), <http://asc.fasb.org>.

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recorded on a public utility's books and reported in the FERC Form No. 1. Additionally, the Commission has required public utilities to maintain detailed accounting records and disclosures associated with such amounts so as to facilitate the evaluation of the effects of the transaction on common equity and other accounts in future periods if needed for ratemaking purposes.³³ The Commission stated that it believed that ratepayers should continue to be protected from adverse effects on rates stemming from accounting entries recording goodwill and fair value adjustments on a public utility's books and reported in FERC Form Nos. 1 or 1-F. This is consistent with our long-standing policy that acquisition premiums, including goodwill, must be excluded from jurisdictional rates absent a filing under FPA section 205 and Commission authorization granting recovery of specific costs.

26. Finally, the Commission stated, in the context of FPA section 203 transactions involving the acquisition of discrete assets (e.g., an existing power plant) by a utility, under the Commission's accounting regulations and rate precedent the excess purchase cost of utility plant over its depreciated original cost is an acquisition premium and is excluded from recovery through rates unless a showing of offsetting benefits is demonstrated in an FPA section 205 filing.³⁴ The Commission stated that it has not, and does not, consider acquisition premiums to be part of transaction-related costs and, as

³³ *PPL Corp.*, 133 FERC ¶ 61,083, at P 39 (2010); *Michigan Electric Transmission Co., LLC*, 116 FERC ¶ 61,164, at PP 29-30 (2006); *Niagara Mohawk Holdings Inc.*, 95 FERC ¶ 61,381, at 62,415, *reh'g denied*, 96 FERC ¶ 61,144 (2001).

³⁴ Proposed Policy Statement, 150 FERC ¶ 61, 031 at P 27.

such, it did not believe that the proposed treatment of transaction-related costs required a change in the Commission's current practice with respect to acquisition premiums. Therefore, the Commission stated it will continue to preclude recovery of acquisition premiums as part of transaction-related costs, and reminded applicants that a showing of "specific, measurable, and substantial benefits to ratepayers" must be made in a subsequent FPA section 205 proceeding in order to recover an acquisition premium, whether or not a hold harmless commitment has been made.³⁵

2. Comments

a. General Comments

27. As a general matter, many commenters support the Commission's intent to provide additional guidance and clarity to the costs covered by hold harmless commitments.³⁶ For example, EEI generally supports the list of costs that the Commission proposes to consider as transaction-related costs covered by a hold harmless commitment as long as individual applicants continue to have the flexibility to tailor what

³⁵ *Id.* (citing *Duke Energy Progress, Inc.*, 149 FERC ¶ 61,220, at PP 67-68 (2014) (reviewing Commission precedent requiring that acquisition adjustments may be recovered if the acquisition provides "measurable benefits" that are "tangible and nonspeculative," and allowing recovery of an acquisition adjustment where "the acquisition provides specific, measurable, and substantial benefits to ratepayers") (internal citations omitted)).

³⁶ See AEP Comments at 2; APPA and NRECA Comments at 8; EEI Comments at 2; Kentucky Utilities Comments at 2; Southern Company Comments at 5; Transmission Access Policy Study Group Comments at 1; Transmission Dependent Utilities Comments at 3.

is covered by the hold harmless commitment to their individual circumstances.³⁷ EEI also states that the Commission should explicitly confirm that hold harmless commitments only apply to transaction-related costs.³⁸

28. Several commenters support the full list of transaction-related costs the Commission enumerated.³⁹ For example, APPA and NRECA support the scope of the costs outlined in the Proposed Policy Statement. APPA and NRECA list the following benefits likely to emerge from the Commission's clarifications including: (1) fewer protests of FPA section 203 applications; (2) more streamlined FPA section 203 proceedings; (3) improved ratepayer protections; (4) more consistent Commission orders; (5) easier enforcement and administration in Commission orders; (6) fewer compliance issues and complaints regarding cost recovery; (7) greater assurance of recovery of costs; and (8) lower financing costs due to more regulatory certainty.⁴⁰

29. At the same time, APPA and NRECA agree that the proposed list of costs is not definitive or determinative and that "because each transaction is unique, the final determination of what transaction-related costs may be recovered by applicants will

³⁷ EEI Comments at 13.

³⁸ *Id.*

³⁹ APPA and NRECA Comments at 9; Transmission Access Policy Study Group Comments at 3; Transmission Dependent Utilities Comments at 3-4.

⁴⁰ APPA and NRECA Comments at 7-8.

remain subject to a case-by-case analysis.”⁴¹ APPA and NRECA and the Transmission Dependent Utilities suggest that applicants should bear the ultimate burden to show the adequacy of their hold harmless commitment.⁴² The Transmission Dependent Utilities request that the Commission confirm that, in making its case-by-case determinations as to additional costs that will be subject to particular hold harmless commitments, the Commission will not limit its consideration only to consummation and transition costs but it will consider “any rate increase that results from a transaction.”⁴³

30. APPA and NRECA also state that they remain skeptical that utility mergers benefit customers in the form of lower wholesale energy prices or lower transmission rates and assert that empirical evidence supports their view.⁴⁴ They state that the evidence for the electric industry mergers is mixed at best and shows that merger benefits do not pan out and are not passed on to consumers.⁴⁵ Therefore, APPA and NRECA state that the Commission should be vigilant in enforcing hold harmless commitments.⁴⁶

⁴¹ *Id.* at 8 (citing Proposed Policy Statement, 150 FERC ¶ 61,031 at P 21). *See also* Transmission Dependent Utilities Comments at 4.

⁴² APPA and NRECA Comments at 9; Transmission Dependent Utilities Comments at 4.

⁴³ Transmission Dependent Utilities Comments at 4.

⁴⁴ APPA and NRECA Comments at 6-7 (citing JOHN KWOKA, MERGER CONTROL, AND REMEDIES: A RETROSPECTIVE ANALYSIS OF U.S. POLICY 104, 126, 148, 155-56, 231 (2015)).

⁴⁵ *Id.*

⁴⁶ *Id.* at 7.

31. Other commenters suggest the Commission take a different approach than an enumerated list of transaction-related and transition costs. For example, the Kentucky Utilities state that the Proposed Policy Statement should utilize “a more neutral” approach in its guidance as to whether transaction-related costs should be subject to a hold harmless commitment and that, if the transaction meets direct operating or regulatory compliance needs, any offered hold harmless commitment should not be assumed to cover “nearly all” transaction/transition costs.⁴⁷ Instead, the Kentucky Utilities suggest that the Commission should recognize that covered costs should be based on a fair and reasonable analysis of the specific facts or circumstances of the transaction.⁴⁸

32. Several commenters support the Commission’s current policy regarding treatment of acquisition premiums.⁴⁹ Finally, Transmission Access Policy Study Group states that the Commission should not be dissuaded from adopting its proposal based on speculative contentions that these measures will chill investment.⁵⁰

⁴⁷ Kentucky Utilities Comments at 6.

⁴⁸ *Id.*

⁴⁹ APPA and NRECA Comments at 9; Transmission Access Policy Study Group Comments at 3-4; Transmission Dependent Utilities Comments at n.8.

⁵⁰ Transmission Access Policy Study Group Comments at 4.

b. Transition Costs

33. EEI and AEP request that the Commission provide greater clarity as to the scope and definition of transition costs. Both caution that the Proposed Policy Statement does not distinguish transition costs from other ongoing business activities that merging entities may undergo that are unrelated to the merger but are also seeking to increase efficiency.⁵¹ EEI notes that the lack of distinction could lead companies to postpone otherwise beneficial investments to avoid those investments being viewed as transaction-related costs.⁵²

34. Furthermore, AEP states that over time the costs of ongoing business as a public utility and transition costs will become harder to differentiate,⁵³ and EEI cautions that a broad definition risks creating uncertainty about recovery of prudently-incurred costs.⁵⁴

Both are specifically concerned that post-integration engineering studies will be included

⁵¹ AEP Comments at 5-6 (giving the examples of “engineering studies,” “operating systems integration costs,” and “operational integration costs”); EEI Comments at 13-14 (giving the example of investments in new information technology systems, which could be timed coincidentally with a merger and not incurred primarily for the purpose of integration, and, therefore, should not be considered subject to a hold harmless commitment). *See also* Kentucky Utilities Comments at 7 (cautioning that entities may also engage in non-transaction related refinancing and renegotiation of vendor contracts that could be considered transition costs under a broad definition and that only an incremental or non-utility component of those costs should be considered a transaction-related cost).

⁵² EEI Comments at 14.

⁵³ *See* AEP Comments at 5 (stating that over time these costs “will have an increasingly diminished nexus to the merger itself”).

⁵⁴ *See* EEI Comments at 14.

as transition costs and they assert that doing so will discourage utilities from undertaking studies that are prudent or beneficial to ratepayers.⁵⁵ Finally, AEP questions the Commission's basis for generally including transition costs as transaction-related costs because: (1) applicants generally commit to hold customers harmless from costs directly incurred to effectuate the transaction and (2) the Proposed Policy Statement does not cite a case in which the Commission has formally adopted a rule requiring the inclusion of transition costs as transaction-related costs.⁵⁶

c. Capital Costs

35. AEP and EEI assert that the costs of any assets used to provide utility service on an ongoing basis belong in rate base and should not be excluded from the rate base because they may be a transaction cost.⁵⁷ Both assert that capital assets could be built to increase efficiencies, they will benefit customers, and the costs should be fully recoverable.⁵⁸ AEP asserts that the test for whether these capital costs should be included should be the same as it has always been: "are the facilities used and useful by the utility's customers and were the costs of the facilities prudently incurred in connection

⁵⁵ See AEP Comments at 6; EEI Comments at 18.

⁵⁶ See AEP Comments at 4-5.

⁵⁷ See *id.* at 7; EEI Comments at 16.

⁵⁸ See AEP Comments at 7 (giving the example of new more efficient facilities enabled by the combined entities' larger size); EEI Comments at 16-17 (giving the example of a new operations center).

with the provision of utility service.”⁵⁹ AEP states that this is consistent with the general principle that ratepayers should bear the cost of utility service.⁶⁰

36. AEP states that making capital costs subject to a hold harmless commitment raises further issues of how the policy will be implemented, including tracking and recovery of costs and future interconnection of generating facilities.⁶¹ AEP states that the Commission has approved settlements in the past that did not include new transmission as a transition cost; instead, the Commission waited to address it in a future proceeding, which AEP asserts is the appropriate course for capital costs.⁶²

37. Furthermore, EEI and AEP state that hold harmless commitments should not apply to costs related to new facilities that are constructed at the Commission’s direction or approval to mitigate market power concerns raised by a merger transaction.⁶³ Both assert that these assets provide utility service, and therefore benefits, to customers and should not be excluded from recovery as transaction costs just because the assets were included in mitigation strategies.⁶⁴ EEI suggests that new facilities that raise competition or rate concerns may be addressed through protection mechanisms other than a hold harmless

⁵⁹ AEP Comments at 7.

⁶⁰ *Id.* (citing Proposed Policy Statement, 150 FERC ¶ 61,031 at P 39).

⁶¹ *Id.* at 8, n.1.

⁶² *Id.* at 8 (citing *Pub. Serv. Co. of Colo.*, 78 FERC ¶ 61,267, at 62,139 (1997)).

⁶³ *See id.*; EEI Comments at 11, 17.

⁶⁴ *See* AEP Comments at 8; EEI Comments at 16.

commitment and that doing so would reduce implementation problems regarding the tracking of costs and recovery of related costs.⁶⁵

38. EEI asserts that the Commission should recognize that costs related to transactions undertaken as part of normal operations, such as to align ownership of an asset with a maintenance or reliability compliance obligation, or a transaction involving acquisition of a small, discrete transmission asset from a distribution-only entity, should not be subject to exclusion from rates under a hold harmless commitment.⁶⁶

d. Internal Labor Costs

39. AEP, EEI, and Southern Company all suggest that the Commission should clarify that internal labor costs that are subject to a hold harmless commitment should include only incremental costs caused by the merger that would not otherwise be incurred.⁶⁷ They contend that, if an employee was already employed by the merging or acquiring entities at the time the transaction was announced, the employee's salary should not be

⁶⁵ EEI Comments at 17-18 (suggesting providing customers with a first call right on the increased available transmission capacity).

⁶⁶ *Id.* at 17.

⁶⁷ *See* AEP Comments at 11; EEI Comments at 15-16; Southern Company Comments at 6-8. *See also* Kentucky Utilities Comments at 7 (cautioning that hold harmless commitments should only apply to incremental costs in general).

treated as a transaction-related cost because any assignments related to the transaction would be performed in addition to other duties, with no additional compensation.⁶⁸

Furthermore, EEI contends that the full cost of an employee's salary should continue be fully recoverable because the salary is prudently incurred to serve existing customers.⁶⁹

AEP and Southern Company assert that excluding non-incremental employee costs would result in unmerited rate reductions for customers of merging entities⁷⁰ and state that tracking labor costs will be burdensome and subject employees to endless tracking requirements.⁷¹ Finally, AEP and Southern Company both state that the Proposed Policy Statement cites no precedent to support including non-incremental internal labor costs as transaction-related costs subject to a hold harmless commitment.⁷² AEP asserts that Commission precedent can reasonably be read to mean that hold harmless commitments only apply to incremental internal costs.⁷³

⁶⁸ See AEP Comments at 11-12; EEI Comments at 16; Southern Company Comments at 7. Southern Company recognizes that some employees may receive additional compensation due to a merger and does not object to incremental compensation or the costs of new staff brought on to effectuate the transaction being treated as incremental transaction costs. Southern Company Comments at 7-8.

⁶⁹ EEI Comments at 16.

⁷⁰ See AEP Comments at 11-12; Southern Company Comments at 7.

⁷¹ See AEP Comments at 13; Southern Company Comments at 9.

⁷² AEP Comments at 12; Southern Company Comments at 8.

⁷³ AEP Comments at 12 (citing *Ameren Energy Generating Co.*, 145 FERC ¶ 61,034, at P 97 n.99 (2013) (*Ameren*)).

e. **Costs of Transactions That Are Not Completed and Costs Incurred Prior to Announcement**

40. AEP and EEI do not agree with the Commission's statement that costs related to transactions that are never completed should not be recovered from ratepayers.⁷⁴ Both assert that there are sound business reasons that a firm may choose not to pursue a transaction and that excluding recovery of such costs may improperly punish a firm for abandoning a transaction that was not ultimately in the best interest of its customers or discourage a firm from exploring transactions.⁷⁵ EEI asserts that past Commission policy did not exclude recovery of such costs and that it is difficult to ascertain when "normal business decisions" become transactions that are being "pursued."⁷⁶ Furthermore, EEI asserts that the proposal will require tracking of costs with more specificity than is required by the Commission's current accounting rules.⁷⁷

41. Southern Company asks for a clarification of the treatment of costs related to failed acquisitions. It states that a clarification that this statement is applicable only to the merger context would be useful because transaction-related costs relating to failed

⁷⁴ *Id.* at 14 (citing Proposed Policy Statement, 150 FERC ¶ 61,031 at P 23); EEI Comments at 15.

⁷⁵ *See* AEP Comments at 14-15 (stating that a utility may not have completed a transaction for which it incurred preliminary costs: (1) because the current owner decides to abandon the transaction; (2) based on the results of due diligence review; (3) because it determined a self-built project could be built at lower cost; or (4) because a lower-cost option becomes available from another seller); EEI Comments at 15.

⁷⁶ EEI Comments at 15.

⁷⁷ *Id.*

attempts to acquire specific generation and transmission facilities to fulfill a need, such as a need to serve load reliably, should be recoverable in a utility's cost-of-service.⁷⁸

Southern Company provides an example of a Request For Proposals (RFP) for long-term capacity that results in ten bidders and negotiations are pursued with two of the bidders, one offering a 20-year power purchase agreement and another offering to sell an existing generating unit. If negotiations fail with the bidder that happens to be an existing generator, Southern states that transaction-related costs associated with the potential purchase should not be deemed "unrecoverable," as the threat of such an action could skew the RFP results.⁷⁹ Southern states that such costs are merely the routine costs of capacity procurement efforts. Therefore, Southern Company states that "[t]he Commission should clarify that such costs, to the extent prudently-incurred, are permitted to be recovered in wholesale power rates."⁸⁰

42. EEI and EPSA contend that the Commission should not require inclusion of costs incurred prior to the announcement of a transaction because doing so would be premature, burdensome, and costly.⁸¹ EEI states that long-term strategic planning, including investigating potential transactions, is part of the routine daily operations of

⁷⁸ Southern Company Comments at 4-5.

⁷⁹ *Id.* at 5.

⁸⁰ *Id.*

⁸¹ *See* EEI Comments at 14; EPSA Comments at 4-6 ("Such a requirement is tantamount to asking a couple who are only on a second date to pick out their wedding china pattern.").

any company and should not be singled out for separate tracking, which it asserts would be unwieldy and misleading because staff would conceivably have to bill their time separately for every potential project or transaction they analyze, just in case that project or transaction came to fruition.⁸² EEI states that the burden of this proposal exceeds the benefits due to the number of transactions that may be explored and could provide a disincentive for companies to investigate transactions that could ultimately benefit customers.⁸³

f. Request for Guidance on Savings

43. EEI suggests that the Commission should provide useful guidance by adding some discussion to the Policy Statement regarding the scope and definition of transaction-related savings or benefits.⁸⁴ EEI states that, as part of this guidance, the Commission should specify “that hold harmless costs from a purchase can be netted against benefits from a future sale, so that if the future sale produces net benefits those can be used to offset the prior purchase’s costs, thereby reducing or eliminating costs to be tracked under a hold harmless commitment for the prior sale.”⁸⁵ EEI states that “[t]his would

⁸² EEI Comments at 14.

⁸³ *Id.* at 14-15.

⁸⁴ *Id.* at 18.

⁸⁵ *Id.*

allow companies that engage in multiple transactions over time to ensure that customers are not charged the costs net of the benefits of [multiple] transactions taken together.”⁸⁶

3. Commission Determination

44. We adopt in part the policy set forth in the Proposed Policy Statement regarding what kinds of costs are typically transaction-related costs covered by a hold harmless commitment. As described above, comments received in response to the Proposed Policy Statement were generally supportive of the Commission’s proposals. Accordingly, we adopt, and will consider, as general guidance, the proposed list of transaction-related costs including:

- the costs of securing an appraisal, formal written evaluation, or fairness opinions related to the transaction;
- the costs of structuring the transaction, negotiating the structure of the transaction, and obtaining tax advice on the structure of the transaction;
- the costs of preparing and reviewing the documents effectuating the transaction (e.g., the costs to transfer legal title of an asset, building permits, valuation fees, the merger agreement or purchase agreement and any related financing documents);

⁸⁶ *Id.*

- the internal labor costs of employees⁸⁷ and the costs of external, third-party, consultants and advisors to evaluate potential merger transactions, and once a merger candidate has been identified, to negotiate merger terms, to execute financing and legal contracts, and to secure regulatory approvals;⁸⁸
- the costs of obtaining shareholder approval (e.g., the costs of proxy solicitation and special meetings of shareholders);
- professional service fees incurred in the transaction (e.g., fees for accountants, surveyors, engineers, and legal consultants); and
- installation, integration, testing, and set up costs related to ensuring the operability of facilities subject to the transaction.

45. Further, we will adopt, and will consider, as general guidance, the proposed subset of transaction-related costs – transition costs – to include the following when incurred to integrate operations:

- engineering studies needed both prior to and after closing the merger;
- severance payments;
- operational integration costs;
- accounting and operating systems integration costs;

⁸⁷ If the duties of employees are not solely dedicated to activities related to a transaction, internal labor costs deemed merger-related should be determined in a manner that is proportionally equal to the amount of time spent on the merger compared to other activities of the utility and tracked accordingly.

⁸⁸ Some of these costs are typically incurred prior to the announcement of a merger.

- costs to terminate any duplicative leases, contracts, and operations; and
- financing costs to refinance existing obligations in order to achieve operational and financial synergies.

46. We will continue to consider hold harmless commitments on a case-by-case basis and, as such, applicants may propose that their hold harmless commitment cover specific transaction-related costs in addition to those listed above, if they can demonstrate that those certain cost categories may be properly included or excluded from their hold harmless commitment without an adverse effect on rates. The burden remains on applicants to show that any offered hold harmless commitment will meet the Commission's standard that the proposed transaction does not have an adverse effect on rates.

47. We decline to adopt the Transmission Dependent Utilities' request that we consider any rate increase that results from a transaction to be a transaction-related cost subject to an applicant's hold harmless commitment. This goes beyond our standard on adverse effects on rates as an increase in rates "can still be consistent with the public interest if there are countervailing benefits that derive from the merger."⁸⁹ The adoption of the Transmission Dependent Utilities request would curtail an applicant's ability to craft suitable ratepayer protection mechanisms and limit the Commission's ability to

⁸⁹ Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 30,114; *see, e.g., Bluegrass Generation Co., L.L.C.*, 139 FERC ¶ 61,094 at P 41 (finding no adverse effect on rates because increases in capacity charges would be offset by a savings in energy rates).

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authorize transactions where rate increases are offset by the benefits of the transaction.

We continue to believe that the guidance related to transaction-related costs set out in this Policy Statement does not require a change in the Commission's current practice with respect to acquisition premiums. Therefore, we will continue to preclude recovery of acquisition premiums as part of transaction-related costs, and remind applicants that a showing of "specific, measurable, and substantial benefits to ratepayers" must be made in a subsequent FPA section 205 proceeding in order to recover an acquisition premium, whether or not a hold harmless commitment has been made.

48. To provide further clarity, we discuss below, in detail, the following topics: (a) transition costs; (b) capital costs; (c) internal labor costs; (d) costs of transactions that are not completed and costs incurred prior to announcement; and (e) requests for guidance on savings.

a. Transition Costs

49. We will continue to consider transition costs as a subset of transaction-related costs. We are unconvinced by commenters' assertions that the line distinguishing costs incurred in connection with the normal business activities of a public utility and costs incurred to integrate operations and assets of two previously unaffiliated companies is difficult to discern or too burdensome to track. We acknowledge that the classification of a specific cost is fact specific and requires judgment in some cases. Nevertheless, to the extent there are categories of transition costs listed herein that applicants do not consider transaction-related based on transaction specific circumstances, applicants are free to demonstrate in the FPA section 203 proceeding that these costs should not be considered

transaction-related. We acknowledge AEP's concern that the Commission has not adopted a formal rule regarding the treatment and definition of transition costs for purposes of a hold harmless commitment. However, the Commission has stated that transaction-related costs, in the context of a hold harmless commitment, include transition costs.⁹⁰ In this Policy Statement, we provide additional guidance as to what those costs are. Further, if an applicant categorizes costs as transaction-related out of an abundance of caution because there is uncertainty regarding the nexus between the cost and the transaction, the Commission's policy provides for the recovery of such costs with a demonstration of offsetting benefits should the transaction produce savings or other synergies.⁹¹ This policy should not discourage beneficial investment by applicants following completion of a Commission-authorized transaction, but rather should encourage documentation and tracking of those costs and related savings.

⁹⁰ See, e.g., *Union Power Partners, L.P.*, 154 FERC ¶ 61,149, at P 63 (2016) (“We interpret Purchaser’s hold harmless commitment to apply to *all transaction-related costs, including* costs related to consummating the Proposed Transaction and *transition costs*, incurred prior to the consummation of the Proposed Transaction, or in the five years after the Proposed Transaction’s consummation.”) (emphasis added); *Exelon Corp.*, 138 FERC ¶ 61,167, at P 118 (2012) (“We interpret Applicants’ hold harmless commitment to *apply to all transaction-related costs, including* costs related to consummating the Proposed Transaction and *transition costs* (both capital and operating) incurred to achieve merger related synergies.”) (emphasis added).

⁹¹ Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 30,123 (noting that an increase in rates “can be consistent with the public interest if there are countervailing benefits that derive from the transaction”); *Pennsylvania Electric Co.*, 154 FERC ¶ 61,109 at P 48 (“The Commission has established that, where applicants make hold harmless commitments in the context of FPA section 203 transactions, in order to recover transaction-related costs, applicants must demonstrate offsetting benefits at the time they apply to recover those costs.”).

b. Capital Costs

50. We also clarify that whether or not capital costs, including capital costs related to mitigation, should be considered transaction-related costs that should be subject to an applicant's hold harmless commitment can be considered on a case-by-case basis either upfront in the FPA section 203 proceeding, or when an applicant seeks to recover such costs in an FPA section 205 proceeding.⁹² In this regard, we recognize that it would be inappropriate to adopt a general policy that all capital costs, including capital costs related to mitigation, are subject to an applicant's hold harmless commitment. Applicants may incur capital costs for facilities that are used and useful and provide service to customers. Conversely, applicants may also incur capital costs as a direct requirement of the transaction, which are not used and useful until a later point in time. An inquiry into whether these costs are used and useful or otherwise prudently incurred would require a fact specific inquiry, which is more appropriately handled on a case-by-case basis rather than under a generally applicable policy.

51. In general, capital costs unrelated to the transaction are not subject to an applicant's hold harmless commitment. For example, applicants may be able to demonstrate that certain capital projects were already in the preliminary stages of construction or development prior to the merger announcement and would be completed whether or not the transaction is ever consummated. If adequately documented, we agree that such capital costs should not be subject to an applicant's hold harmless commitment.

⁹² Proposed Policy Statement, 150 FERC ¶ 61,031 at PP 21-25.

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52. As guidance, we are principally concerned about three categories of capital costs directly tied to the transaction that may negatively impact customer rates: (1) the capital costs of facilities that are constructed as part of an applicant's commitment to mitigate competition concerns that have been identified in the Commission's authorization; (2) the costs of replacing any equipment or facility of merging companies, prior to the end of its useful life, if such action was the direct consequence of a transaction; and (3) the transition costs of integrating the previously separate systems. Generally, these costs will be considered transaction-related costs subject to an applicant's hold harmless commitment unless applicants demonstrate offsetting benefits, or offer ratepayer protections other than a hold harmless commitment, in their FPA section 203 application.

53. While applicants may present their case-by-case analysis when they seek to recover capital costs in an FPA section 205 proceeding, we advise applicants to present a clear case in their FPA section 203 application to avoid uncertainty when possible. Therefore, we advise applicants to clearly state which known capital costs related to the transaction will be included or excluded from a hold harmless commitment at the time of their FPA section 203 application. Further, we advise applicants to clearly explain a process for determining which capital costs—that may be unknown at the time of the application but are related to the transaction and determined at a future date—will be included or excluded from a hold harmless commitment at the time of their FPA section 203 application. Similarly, we advise applicants to explain the treatment of operation and maintenance costs incurred in relation to transaction-related capital costs if the related plant asset meets the used and useful criterion in providing utility service, the

Commission may consider exclusion of such costs from the hold harmless commitment. A clear explanation in the FPA section 203 application of the treatment of capital costs will aid the Commission and third parties in understanding how a transaction will not have an adverse effect on rates both in considering the application and in future related proceedings, including any future FPA section 205 filing to show transaction-related savings.

54. Finally, we note that capital costs incurred for documented utility need, including those for reliability, such as transmission upgrades, that are related to a transaction may offer similar benefits to the transactions discussed below where a hold harmless commitment may not be necessary for a showing of no adverse effect on rates.⁹³ In such cases, applicants may demonstrate that such capital costs are not transaction-related costs subject to their hold harmless commitment by showing such costs have offsetting benefits or otherwise showing that these capital costs have no adverse effect on rates.

c. Internal Labor Costs

55. We will adopt the proposal to include both internal and external labor costs related to a transaction as transaction-related costs. The Commission's concern is that an applicant will use its existing employees to both perform normal utility activities as well as transaction-related activities and not make a distinction between the two activities. As a result, the applicant would recover transaction-related labor costs without demonstrating that they are offset by benefits. Thus, an appropriate labor cost allocation

⁹³ See *infra* PP 92-95.

is needed to ensure the applicant's ratepayers are not paying for transaction-related activities without a showing of offsetting benefits.

56. The Commission declines to adopt AEP's reading of Commission precedent in *Ameren* as limiting transaction-related internal labor costs to incremental internal labor costs.⁹⁴ In *Ameren* the Commission stated that the applicant must file its accounting for any costs incurred to effectuate the transaction which "may include, but are not limited to, internal labor costs, legal, consulting, and professional services incurred to effectuate the transaction."⁹⁵ This statement directing accounting entries to be filed does not impact the scope of transaction-related costs subject to the applicant's hold harmless commitment, and thus, cannot be construed to mean that hold harmless commitments only apply to incremental labor costs.

57. Commenters' arguments that labor costs for existing employees that perform additional transaction-related tasks but receive no additional incremental salary should not be subject to hold harmless commitment are misplaced. Imposing additional transaction-related tasks on existing employees without additional compensation does not relieve applicants from general ratemaking principles, which require that employee costs

⁹⁴ *Ameren*, 145 FERC ¶ 61,034 at P 97, n.99.

⁹⁵ *Id.*

follow the employees' assigned tasks.⁹⁶ Employees' time should be allocated in proportion to the tasks performed. Otherwise, ratepayers will bear transaction-related costs without offsetting benefits. Therefore, it is the Commission's policy that applicants support the allocation of the labor costs for salaried employees who work on both normal business activities in providing utility service and on transaction-related activities with appropriate supporting documentation (e.g., approved time sheets detailing the allocation of actual time worked on utility, transaction, and other non-utility activities). To the extent applicants are unable or unwilling to track internal employees time related to a transaction, applicants should consider and propose other ratepayer protection mechanisms.

d. Costs of Transactions That Are Not Completed and Costs Incurred Prior to Announcement

58. As for costs related to transactions that are pursued but never completed, we clarify our statement that such "costs should not be recovered from ratepayers."⁹⁷ Instead those costs are subject to the Commission's general rate-making principles under FPA

⁹⁶ See, e.g., Final Audit Report: Audit of Formula Rates, Transmission Incentives, and Demand Response at Baltimore Gas and Electric Company, Docket No. FA13-13-000 at 17-18 (2015) (noting inappropriate recovery of internal labor costs in transmission rates).

⁹⁷ Proposed Policy Statement, 150 FERC ¶ 61,031 at P 23.

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sections 205 and 206 and the Commission's accounting precedent.⁹⁸ With respect to EEI's comment regarding activities in the early stages of a transaction that are undertaken in the course of normal business, we note that only those activities related to the transaction for which the hold harmless commitment was made necessitate separate tracking. In terms of tracking expenses prior to the announcement of a transaction, we note that a hold harmless commitment only applies where the Commission issues an order accepting such a commitment. Expenses for transactions that do not reach that point are subject to the Commission's ordinary ratemaking principles. Moreover, if a transaction that is the subject of a hold harmless commitment is not consummated, there would presumably never be any transaction-related savings that could offset transaction-related costs.

59. In addition, we clarify that while all costs related to the acquisition of an existing facility required to serve load or transmission customers, including costs associated with bids for other facilities that were incurred as a part of routine capacity procurement efforts, will be considered transaction-related costs if an applicant makes a hold harmless commitment, as we have noted in the preceding paragraphs, capital costs of facilities that are used and useful and provide service to customers would normally be recoverable in rates under general ratemaking principles,

⁹⁸ The costs incurred to consummate a merger transaction are considered to be nonoperational in nature and, to the extent recorded on a jurisdictional entity's books, should be included in a non-operating expense account - Account 426.5, Other Deductions. 18 CFR pt. 101 (2015).

unless the capital costs fall within one of the categories discussed above (e.g., capital costs related to mitigation measures), in which case they would be subject to the applicant's hold harmless commitment. Moreover, under our accounting rules, when electric plant constituting an operating system is purchased, the costs of acquisition, including expenses incidental thereto, are properly includible in electric plant and charged to Account 102, Electric Plant Purchased or Sold.⁹⁹ Thus, in the situation Southern Company posits, the real question is what portion of the costs associated with an RFP process, including costs incurred pursuing bids that are ultimately unsuccessful, would be properly includible in the costs of the facility that is acquired. To the extent all or some portion of those costs are included in the cost of the facility that is acquired, and assuming that the facility is used and useful and provides service to customers, they would normally be recoverable as capital costs associated with that facility and, therefore, not be subject to any hold harmless commitment that is made.

e. Request for Guidance on Savings

60. Regarding transaction-related savings, we decline to allow the netting of benefits from future transactions against the transaction-related costs of past transactions, as EEI suggests. The Commission has previously confined its analysis regarding the effect on rates to the transaction that is the subject of the application.¹⁰⁰ Applicants are not

⁹⁹ 18 CFR pt. 101 (2015).

¹⁰⁰ See *BHE Holdings, Inc.*, 133 FERC ¶ 61,231 at P 40 (focusing on “costs related to the instant transaction for purposes of the Commission’s section 203 analysis”).

required to create separate records to measure savings if they do not intend to recover transaction-related costs from ratepayers. Furthermore, we decline to speculate on the scope and definition of transaction-related savings that applicants may offer in a subsequent FPA section 205 filing in order to recover transaction-related costs covered by a hold harmless commitment given that we have received a limited number of FPA section 205 filings seeking to recover transaction-related costs by showing offsetting savings. Applicants may choose the most appropriate method to calculate savings so long as the savings can be shown to result from the transaction. We will review these filings on a case-by-case basis.

B. Controls and Procedures to Track and Record Costs Related to Hold Harmless Commitments

1. Proposal

61. In the Proposed Policy Statement the Commission proposed to clarify that all applicants offering hold harmless commitments should implement appropriate internal controls and procedures to ensure the proper identification, accounting, and rate treatment of all transaction-related costs incurred prior to and subsequent to the announcement of a proposed transaction, including all transition costs.¹⁰¹

62. Specifically, the Commission noted that applicants are required to describe in their FPA section 203 applications how they intend to protect ratepayers from transaction-related costs, consistent with their obligation to show that their transaction is consistent

¹⁰¹ Proposed Policy Statement, 150 FERC ¶ 61,031 at P 29.

with the public interest.¹⁰² As contemplated in the Merger Policy Statement, a hold harmless commitment offered by applicants must be “enforceable and administratively manageable.”¹⁰³ Therefore the Commission proposed that in creating an enforceable and administratively manageable commitment, applicants should provide assurances that transaction-related costs will be quantified, documented, and verified, and may not be recovered from ratepayers until applicants can demonstrate that savings, if any, offset the transaction-related costs they seek to recover. To this end, the Commission has required that applicants offering hold harmless commitments establish internal controls and/or tracking mechanisms.¹⁰⁴ In the Proposed Policy Statement, the Commission proposed the following additional guidance regarding these requirements.

63. First, the Commission proposed to clarify that all applicants offering hold harmless commitments should implement appropriate internal controls and procedures to ensure the proper identification, accounting, and rate treatment of all transaction-related costs incurred prior to and subsequent to the announcement of a proposed transaction, including all transition costs.¹⁰⁵

¹⁰² See Order No. 642, FERC Stats. & Regs. ¶ 31,111 at 31,914.

¹⁰³ Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 30,124.

¹⁰⁴ See *Silver Merger Sub, Inc.*, 145 FERC ¶ 61,261, at P 78 (2013); *ITC Holdings Corp.*, 143 FERC ¶ 61,256, at P 168 (2013).

¹⁰⁵ Proposed Policy Statement, 150 FERC ¶ 61,031 at P 30.

64. Second, the Commission proposed that applicants offering hold harmless commitments should include, as part of their FPA section 203 applications and any separate FPA section 205 filings seeking to recover transaction-related costs, a detailed description of how they define, designate, accrue, and allocate transaction-related costs, and explain the criteria used to determine which costs are transaction-related. Applicants should specifically identify and describe their direct and indirect cost classifications, and the processes they use to functionalize, classify and allocate transaction-related costs. In addition, applicants should explain the types of transaction-related costs that will be recorded on their public utilities' books; how they determined the portion of these costs assigned to their public utilities; and how they classify these costs as non-operating, transmission, distribution, production, and other. Applicants should also describe their accounting procedures and practices, and how they maintain the underlying accounting data so that the allocation of transaction-related costs to the operating and non-operating accounts of their public utilities is readily available and easily verifiable.¹⁰⁶

65. The Commission noted that it had, in the past, required applicants to submit their final accounting entries associated with transactions within six months of the date that the transaction is consummated.¹⁰⁷ The Commission proposed to require applicants subject to the Commission's accounting regulations to provide, as a part of this accounting filing,

¹⁰⁶ *Id.* P 31.

¹⁰⁷ See, e.g., *Central Vermont Public Service Corp.*, 138 FERC ¶ 61,161, at P 55 (2012).

the accounting entries and amounts related to all transaction-related costs incurred as of the date of the accounting filing, along with narrative explanations describing the entries.¹⁰⁸

2. Comments

66. EEI requests clarifications and changes related to the Commission's proposed accounting treatment. EEI encourages the Commission to have applicants "simply identify succinctly how they plan to categorize and handle the costs, in conformance with the Uniform System of Accounts" ¹⁰⁹ EEI asserts that applicants should be able to rely on the accounting systems they already have in place without having to explain the design and use of those systems, as their accounting practices are already overseen by the Commission. ¹¹⁰ EEI asserts the Commission should specify that if transaction costs are reasonably projected to be minor or below a certain threshold, the costs need not be tracked, as the cost of tracking them would exceed the benefit. ¹¹¹ EEI also encourages the Commission to extend the deadline for submitting accounting to one year rather than six months as the information may take more than six months to be verified and the extra time would lead to a more complete filing. ¹¹²

¹⁰⁸ Proposed Policy Statement, 150 FERC ¶ 61,031 at P 32.

¹⁰⁹ EEI Comments at 19.

¹¹⁰ *Id.*

¹¹¹ *Id.*

¹¹² *Id.*

67. Noting that the Commission seeks to require applicants to track and record costs that may be incurred even prior to a public announcement of any proposed transaction, EPSA states it does not understand how the Commission can recognize that it can be challenging to accurately track, record and categorize all transaction-related costs but also require applicants to keep accurate accounting of such information, particularly in the early stages of a negotiation.¹¹³ EPSA states the proposed requirement is not only premature, but extremely difficult to implement, administratively burdensome, and costly.¹¹⁴ EPSA states that this requirement is more appropriate after a public announcement of a transaction. Therefore, EPSA requests that the Commission not require tracking of transaction-related costs incurred prior to the announcement of a transaction.¹¹⁵

68. APPA and NRECA, Transmission Access Policy Study Group, and Transmission Dependent Utilities support the Commission's proposed tracking requirements.¹¹⁶ Specifically, APPA and NRECA support the Commission's proposal that the internal controls and procedures should be detailed in the FPA section 203 applications and any

¹¹³ EPSA Comments at 6.

¹¹⁴ *Id.*

¹¹⁵ *Id.*

¹¹⁶ APPA and NRECA Comments at 10-11; Transmission Access Policy Study Group Comments at 1, 4; Transmission Dependent Utilities Comments at 7.

related FPA section 205 rate filing.¹¹⁷ Transmission Access Policy Study Group states that internal controls are both feasible and essential and are good housekeeping, consistent with the practice of regulated utilities to operate pursuant to systems of accounts and fundamental to honoring hold harmless commitments.¹¹⁸ Transmission Dependent Utilities support the tracking requirements because the clarifications will help ensure that transaction-related costs will be quantified, documented, and verified and ensure that transaction-related costs will not be recovered from ratepayers until applicants demonstrate offsetting savings.¹¹⁹ Transmission Dependent Utilities assert that these requirements will result in fewer compliance difficulties, will reduce disputes about cost recovery, and will simplify the Commission's administration of hold harmless conditions by providing a clearer picture of each public utility's compliance efforts.¹²⁰

3. Commission Determination

69. We will withdraw the Commission's proposal requiring applicants to describe their accounting procedures and practices, and how they maintain the underlying accounting data for the transaction. As EEI suggested, applicants should be able to rely on their accounting systems without having to explain the design and use of those systems in the FPA section 203 filing. However, we will adopt the Commission's

¹¹⁷ APPA and NRECA Comments at 10.

¹¹⁸ Transmission Access Policy Study Group Comments at 4.

¹¹⁹ Transmission Dependent Utilities Comments at 7.

¹²⁰ *Id.*

proposal regarding establishing controls and procedures for transaction-related costs subject to the hold harmless commitment, regardless of the projected amount of the costs of the transaction. We will also adopt the proposal that applicants offering hold harmless commitments should include in the FPA section 203 application a description of how they define, designate, accrue, and allocate transaction-related costs. Applicants should also explain the criteria used to determine which costs are transaction-related.

70. Applicants that make a hold harmless commitment must make clear, at minimum, what they are committing to and have the ability to record and track such costs. A well-documented methodology and system to account for such costs also facilitates uniformity in practice and reduces confusion in how the hold harmless commitments are applied. Additionally, if applicants choose to seek recovery of those costs in a separate FPA section 205 filing, proper documentation is necessary for determining the appropriateness of the recovery. Moreover, proper documentation of these costs will provide for the avoidance of ongoing litigation which has been voiced as a concern by commenters.¹²¹

71. We will continue to require that applicants submit their final accounting entries associated with transactions within six months of the date that the transaction is consummated. We will also adopt the Commission's proposal to require applicants subject to the Commission's accounting regulations to provide, as a part of this accounting filing, the amounts related to all transaction-related costs incurred as of the

¹²¹ See, e.g., AEP Comments at 10; EEI Comments at 7, 10; Southern Company Comments at 9, 12.

date of the accounting filing. The final accounting entries and amounts related to transaction-related costs allow the Commission to scrutinize how applicants record the transaction at the time of consummation and apply the criteria to identify transaction-related costs as of the accounting filing date. The filing does not necessarily reflect all transaction-related costs as they typically continue to be incurred well after the merger. Given that applicants should have controls and procedures in place to track these costs in a timely manner, six months should be adequate for filing the accounting entries. If additional time is needed, applicants may file a request for extension including the reasons for the requested additional time.

72. We clarify that irrespective of the date that a transaction is announced, companies required to follow the Commission's accounting regulations must have appropriate controls and procedures in place to track transaction-related costs to ensure compliance. Specifically, the Commission's long-standing policy is that costs incurred to effectuate a merger are non-operating in nature, and they should be recorded in Account 426.5, Other Deductions. Accordingly, absent a change in the Commission's accounting requirements, these costs should be tracked when they are incurred.

C. Time Limits on Hold Harmless Commitments

1. Proposed Policy Statement Recommendations

73. The Commission proposed to reconsider whether a hold harmless commitment that is limited to five years or another specified time period adequately protects

ratepayers from an adverse effect on rates.¹²² Specifically, in light of the proposed treatment of certain categories of costs as transaction-related for purposes of any hold harmless commitment, the Commission's experience auditing utilities that have made hold harmless commitments, and concerns of protestors in previous FPA section 203 applications,¹²³ the Commission proposed to reconsider whether hold harmless commitments that are limited to five years (or another specified period) adequately protect ratepayers from any adverse effect on rates. As part of this reconsideration, the Commission stated that it believed that time-limited hold harmless commitments may not adequately protect ratepayers from transaction-related costs. Therefore, the Commission proposed that there be no time limit on hold harmless commitments and that costs subject to hold harmless commitments cannot be recovered from ratepayers at any time (regardless of when such costs are incurred), absent a showing of offsetting savings in order to demonstrate no adverse effect on rates.¹²⁴ The Commission stated that this revised approach is consistent with the Merger Policy Statement, which emphasized that the burden of proof to demonstrate that customers will be protected should be on

¹²² Proposed Policy Statement, 150 FERC ¶ 61,031 at P 34.

¹²³ See, e.g., *PNM Resources, Inc.*, 124 FERC ¶ 61,019, at P 36 (2008) (protestor alleging that the five-year limitation on recovery will simply result in the deferred recovery of transaction-related costs).

¹²⁴ Evidence of offsetting merger-related savings cannot be based on estimates or projections of future savings, but must be based on a demonstration of actual merger-related savings realized by jurisdictional customers. *Exelon Corp.*, 149 FERC ¶ 61,148 at P 107 (citing *Audit Report of National Grid, USA*, Docket No. FA09-10-000 (Feb. 11, 2011) at 55; *Ameren Corp.*, 140 FERC ¶ 61,034, at PP 36-37 (2012)).

applicants, and that applicants should also bear the risk that benefits will not materialize.¹²⁵

2. Comments

74. Many commenters suggest that the Commission should continue to accept time limited hold harmless commitments.¹²⁶ They contend that the Commission has not shown that there is any evidence that applicants have purposely deferred costs past the end of the five-year period or otherwise evaded review that requires a change in current policy.¹²⁷ Furthermore, they assert that, if the Commission is concerned that time-limited hold harmless commitments may lead an applicant to delay incurring or recovering a transaction's costs until after the hold harmless period expires, the Commission already has tools and protections to adequately protect customers.¹²⁸ Furthermore, AEP states that the change in policy would be a reversal of the Merger Policy Statement and put the Commission back in the position of weighing the costs and benefits of mergers.¹²⁹

¹²⁵ Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 30,123.

¹²⁶ See EEI Comments at 6; EPSA Comments at 4; Kentucky Utilities Comments at 3-4; Southern Company Comments at 9.

¹²⁷ See generally AEP Comments at 8-9; EEI Comments at 6; Southern Company Comments at 9-10.

¹²⁸ See generally AEP Comments at 9 (asserting current accounting, auditing, and ratemaking practices are adequate); EEI Comments at 9-10 (stating that current accounting rules address the Commission's concerns regarding deferral of recovery); Southern Company Comments at 11 (suggesting that the Commission's policy related to the recovery of regulatory assets is sufficient).

¹²⁹ See AEP Comments at 11.

Commenters contend that the Commission should not adopt this policy, which will unnecessarily burden applicants at the expense of transactions that benefit customers.¹³⁰

They generally assert that the change in policy will discourage mergers, which they believe will harm customers and deter infrastructure investment.¹³¹

75. Commenters explain that the Commission's concerns are unwarranted because it is in the applicant's financial interest to complete integration as soon as possible to ensure a quick transition and capture synergies.¹³² Furthermore, they assert that the integration of the operations of merging utilities generally occurs in the first few years after a merger.¹³³ They also assert that the costs associated with tracking these costs indefinitely will be burdensome and significant.¹³⁴ Commenters caution that an indefinite hold harmless commitment could incentivize entities to not pursue elimination of duplicative services and costs, which would reduce benefits to ratepayers, because the costs of such activity may be considered transition costs in perpetuity and, therefore, be unrecoverable.¹³⁵

¹³⁰ See EEI Comments at 6; EPSA Comments at 4.

¹³¹ See EEI Comments at 10-11; EPSA Comments at 4.

¹³² See generally AEP Comments at 9; EEI Comments at 8, 10.

¹³³ AEP Comments at 9; Southern Company at 10-11.

¹³⁴ EPSA Comments at 4; Southern Company Comments at 12 (stating that in addition to the cost of new systems, all current and future employees would have to be trained to recognize and track the costs).

¹³⁵ See EEI Comments at 8; EPSA Comments at 5.

76. Commenters also state that any change to the Commission's practice of accepting hold harmless commitments that are limited in duration will undermine regulatory certainty.¹³⁶ They state that without a time limit the Commission creates the unnecessary risk of future litigation in which there may be attempts by protesters or the Commission to link future costs back to a previous transaction, no matter how unrelated to a transaction, and that any entity that had a merger or transaction would then need to disprove that assertion.¹³⁷ Commenters assert that without regulatory certainty investors will be unwilling to commit funds or will increase the costs of the funds they do commit, which will have an adverse effect on the costs and on the viability of transactions and utility valuations.¹³⁸ As to transaction-related capital costs, Southern Company also asserts that one would expect that at some point in time, used and useful investments should and would be included in rates, and if the Commission wishes to exclude certain assets from recovery it should use a more targeted approach than extending the hold harmless period for all transaction-related costs.¹³⁹ Others state that a transaction must be considered closed at some point in order for there to be closure for both accounting and

¹³⁶ EEI Comments at 6.

¹³⁷ See AEP Comments at 10 (worrying that an open-ended commitment will spawn multiple look back proceedings); EEI Comments at 7, 10 (asserting that this will create an inappropriate evidentiary burden on applicants that may also be impossible to overcome); Kentucky Utilities Comments at 3; Southern Company Comments at 10, 12-13.

¹³⁸ See AEP Comments at 10, n.3; EEI Comments at 7.

¹³⁹ See Southern Company Comments at 11-12.

ratemaking purposes¹⁴⁰ and requiring an open ended hold harmless commitment could deter “beneficial consolidation.”¹⁴¹ EEI states that the Commission’s current standard provides ample protection for customers while also providing regulatory certainty, which is essential in a constantly changing industry.¹⁴²

77. Commenters further explain that it will be difficult to determine if costs are transaction-related the further in time entities get from the transaction because of intervening events¹⁴³ and a changing regulatory and technological environment,¹⁴⁴ and that it will be difficult to untangle these costs in rates from the entity’s general ongoing operations.¹⁴⁵ They caution that the further in time one gets from a transaction the more difficult it will become to determine what is and is not a transition cost.¹⁴⁶ AEP suggests that the Commission could remedy this problem either by accepting time-limited hold harmless provisions or limiting the scope of transition costs to the activities required to integrate the companies once their merger is consummated.¹⁴⁷

¹⁴⁰ See AEP Comments at 10; Southern Company Comments at 12.

¹⁴¹ Southern Company Comments at 12.

¹⁴² EEI Comments at 7.

¹⁴³ See *id.* at 6.

¹⁴⁴ See Kentucky Utilities Comments at 3.

¹⁴⁵ See AEP Comments at 10; EEI Comments at 7.

¹⁴⁶ See Kentucky Utilities Comments at 3; Southern Company Comments at 13.

¹⁴⁷ AEP Comments at 10.

78. AEP also notes that a hold harmless commitment with no limit on duration raises questions like: (1) how do you measure how much of a cost incurred 15 years after a merger was attributable to merger “integration” as opposed to normal utility operations; (2) if merger “integration” costs can still be incurred decades after the transaction closed, can merger “savings” still be accruing over that same period; (3) how do you measure those savings; and (4) would companies need to maintain shadow books for the unmerged companies for the rest of time to prove the savings that resulted from the merger?¹⁴⁸

79. EEI asserts that a time-limited commitment is consistent with U.S. generally accepted accounting principles, which recognize that transactions end when all costs, assets, and liabilities have been recorded.¹⁴⁹ EEI states that the Commission should recognize that there is a finite transition period following a transaction and five years is a reasonable time frame in which one could expect that a company would complete its transition and integration.¹⁵⁰ EEI asserts that the Commission should also recognize a commitment of less than five years may be appropriate for “relatively minor” transactions and that an indefinite hold harmless commitment is simply unreasonable.¹⁵¹

¹⁴⁸ *Id.*

¹⁴⁹ EEI Comments at 8.

¹⁵⁰ *Id.* at 9.

¹⁵¹ *Id.*

80. APPA and NRECA, Transmission Access Policy Study Group, and the Transmission Dependent Utilities support the Commission's proposal not to accept time-limited hold harmless commitments.¹⁵² These commenters state that the Commission should focus on whether a cost is transaction-related, not on when it was incurred or when recovery is sought.¹⁵³

81. APPA and NRECA state that unlimited duration hold harmless commitments will not impose a significant additional burden on applicants because most transition costs are incurred in the first few years after the merger is consummated.¹⁵⁴ Furthermore, to the extent that a longer commitment may lead to an additional burden on applicants, APPA and NRECA state that this burden is reasonable because it would mean that transaction-related costs continued to be incurred and offsetting merger savings failed to materialize.¹⁵⁵ Transmission Dependent Utilities state that time-limited commitments provide incentives for utilities to make inefficient spending and rate recovery decisions while failing to provide full protection to ratepayers.¹⁵⁶ Therefore, Transmission Dependent Utilities assert that eliminating any time limit on a hold harmless commitment

¹⁵² APPA and NRECA Comments at 11; Transmission Access Policy Study Group Comments at 2; Transmission Dependent Utilities Comments at 8.

¹⁵³ APPA and NRECA Comments at 11; Transmission Dependent Utilities Comments at 7-8.

¹⁵⁴ APPA and NRECA Comments at 11.

¹⁵⁵ *Id.*

¹⁵⁶ Transmission Dependent Utilities Comments at 7.

is in the public interest because it will bring greater certainty to the electric markets regarding costs subject to recovery in the future.¹⁵⁷

3. Commission Determination

82. After careful consideration of the comments, we withdraw our proposal to no longer accept time-limited hold harmless commitments and will continue to accept hold harmless commitments that are time limited as a method to show no adverse effect on rates. We agree with certain commenters that there is a tradeoff between the articulation of transaction-related costs adopted in section II.A above¹⁵⁸ and the duration of a hold harmless commitment, as there is less of a nexus between activities that are identified as transition costs and the transaction as time passes. While the Commission intends to ensure that ratepayers are adequately protected from potential adverse effects on rates, a hold harmless commitment must also be administratively manageable.

83. As some commenters note, as time passes, it becomes more difficult to distinguish actions taken, and related expenditures, to integrate the operations and assets of newly-merged companies from the conduct of an applicant's normal business activities, and it becomes more difficult to determine which costs share a nexus with the transaction and should thus be subject to an offered hold harmless commitment. Future actions, such as engineering studies, taken in the normal course of business need to be distinguished from those undertaken to effectuate the transaction for the duration of the hold harmless

¹⁵⁷ *Id.*

¹⁵⁸ *See supra* PP 44-58.

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commitment. If we were to adopt the proposal to no longer accept time-limited hold harmless commitments, applicants may be required to make these distinctions years removed from a transaction. As both commenters who support and oppose time limits on any hold harmless commitment recognize, the majority of these costs are incurred in the first five years after the closing of the transaction. At this time we do not find that there is sufficient evidence to conclude that applicants are indeed incurring substantial transaction-related costs after five years.

84. Therefore, we find that the articulation of transaction-related costs set forth in section II.A above, paired with the incentive of applicants to achieve integration and transaction related synergies as soon as possible, adequately protect ratepayers while providing applicants with regulatory certainty that a time-limited hold harmless commitment will not result in endless litigation regarding costs incurred after a transaction is consummated. We intend hold harmless commitments to avoid protracted litigation while at the same time protecting customers from the uncertain costs incurred to complete transactions.

85. In response to EEI's view that a commitment of less than five years may be appropriate for what EEI terms "relatively minor" transactions, as we stated in the Proposed Policy Statement, the Commission has found hold harmless commitments under which applicants commit not to seek to recover transaction-related costs except to the extent that such costs are exceeded by demonstrated transaction-related savings for a

period of five years to be “standard.”¹⁵⁹ While applicants may nevertheless propose hold harmless commitments of any number of years, we caution that applicants retain the burden of demonstrating that proposed ratepayer protections are adequate.¹⁶⁰ Applicants must adequately support and demonstrate that any commitment they propose provides adequate ratepayer protection when compared to other ratepayer protection mechanisms, including the offer of a five year hold harmless period that has become the norm in the industry.

D. Transactions Without An Adverse Effect on Rates

1. Proposed Policy Statement Recommendations

86. The Commission noted in the Proposed Policy Statement that some applicants have made hold harmless commitments in connection with transactions involving the acquisition of existing jurisdictional facilities where the acquiring entity is a traditional franchised utility and is entering into the transaction in order to satisfy resource adequacy requirements at the state level, to improve system reliability, and/or meet other regulatory

¹⁵⁹ Proposed Policy Statement, 150 FERC ¶ 61,031 at P 12 (citing *ITC Holdings Corp.*, 121 FERC ¶ 61,229, at P 128 (2007)). Although five-year hold harmless commitments are most common, the Commission has also accepted three-year hold harmless commitments. *Id.* n.21 (citing *Westar Energy, Inc.*, 104 FERC ¶ 61,170, at PP 16-17 (2003); *Long Island Lighting Co.*, 82 FERC ¶ 61,129, at 61,463-65 (1998)).

¹⁶⁰ Order No. 642, FERC Stats. & Regs. ¶ 31,111 at 31,914.

requirements.¹⁶¹ Furthermore, the Commission noted that, while customers in these examples may experience a rate increase due to the costs of the facilities, such rate effect may not necessarily be adverse because those costs were incurred to meet a governmental regulatory requirement. The Commission stated that it has held that, as a general matter of policy, ratepayers should bear the cost of utility service.¹⁶²

87. The Commission proposed to clarify that applicants undertaking certain types of transactions to fulfill documented utility service needs may not need to offer a hold harmless commitment in order to show that the transaction does not have an adverse effect on rates.¹⁶³ Specifically, the Commission stated that it believed that applicants engaging in these types of transactions can make the requisite showing that, even though the proposed transaction may have an effect on rates, such effect on rates is not adverse.

88. The Commission noted several examples of transactions in which applicants may demonstrate no adverse effect on rates without offering a hold harmless commitment or other ratepayer protection mechanism, including the purchase of an existing generating

¹⁶¹ Proposed Policy Statement, 150 FERC ¶ 61,031 at P 39. *See, e.g., FirstEnergy*, 141 FERC ¶ 61,239 at PP 1, 16, 27-30 (accepting a hold harmless commitment in an asset transaction where generation assets would be turned into assets to support transmission system upgrades in order to meet needs identified in a study by PJM Interconnection, L.L.C. following the retirement of other generating facilities); *ITC Midwest*, 140 FERC ¶ 61,125 at P 15; *Int'l Transmission Co.*, 139 FERC ¶ 61,003 at P 16.

¹⁶² *See, e.g., Old Dominion Elec. Cooperative and N.C. Elec. Membership Corp. v. Va. Elec. and Power Co.*, 146 FERC ¶ 61,200 (2014).

¹⁶³ Proposed Policy Statement, 150 FERC ¶ 61,031 at P 40.

plant or transmission facility that is needed to serve the acquiring company's customers or forecasted load within a public utility's existing footprint, in compliance with a resource planning process, or to meet specified North American Electric Reliability Corporation (NERC) standards. The Commission proposed that applicants seeking to demonstrate that a transaction will not have an adverse effect on rates for these or other reasons should provide supporting evidence and documentation which could include an explanation that the transaction is intended to serve existing customers or forecasted load within an existing footprint; to address a state commission order or directive requiring acquisition of specific assets; to address a need for a transmission facility, as established through a regional transmission planning process or as required to satisfy a NERC standard; or to address other state or federal regulatory requirements.¹⁶⁴ Under the clarification proposed therein, however, the Commission stated that a hold harmless commitment would not need to be offered in order to show that the transaction would not have an adverse effect on rates.

89. The Commission proposed that applicants may make a showing that a particular transaction does not have an adverse effect on rates based on other grounds, but the burden remains on applicants to show in their application for authorization under FPA section 203 that the costs, or a portion of the costs, related to such a transaction should be passed on to ratepayers. Further, the Commission proposed that applicants may provide the Commission with information to show the need to meet other regulatory requirements

¹⁶⁴ *Id.* P 41.

as a means to demonstrate that the effect on rates due to the transaction is not adverse.

The Commission proposed that it would carefully review such a showing before determining that a proposed transaction without any proposed ratepayer protection mechanism has no adverse effect on rates.

2. Comments

90. Several commenters support the Commission's proposal that hold harmless commitments may not be necessary for certain categories of transactions when undertaken to provide utility service for which ratepayers should bear cost responsibility.¹⁶⁵ Several parties recommend that the Commission more directly and clearly acknowledge that hold harmless commitments are not always necessary and that the Proposed Policy Statement does not mandate their inclusion in every FPA section 203 application.¹⁶⁶ EEI states that each transaction is unique and suggests that the need for and role of a hold harmless commitment will vary.¹⁶⁷ Additionally, commenters request that the Commission clarify that the circumstances articulated in the Proposed Policy Statement for when a hold harmless commitment may not be necessary are not exclusive

¹⁶⁵ See AEP Comments at 13; EEI Comments at 12; EPSA Comments at 3; Kentucky Utilities Comments at 4; Southern Company Comments at 3; Transmission-Only Companies Comments at 1.

¹⁶⁶ See EEI Comments at 11 (contending that it is not clear how the different sections of the document interact); Kentucky Utilities Comments at 5.

¹⁶⁷ EEI Comments at 11-12 (suggesting additional exemptions such as a transaction where the benefits outweigh any potential negative effects, or those negative effects may be *de minimis*).

or comprehensive,¹⁶⁸ and that the examples given were intended to be illustrative and will be interpreted broadly.¹⁶⁹

91. Other commenters request that the Commission clarify that it does not intend to identify certain categories of transactions that do not have an adverse effect on rates or transactions that do not require ratepayer protection mechanisms.¹⁷⁰ These commenters seek confirmation that the Commission is stating only that applicants may make a showing for any FPA section 203 transaction that there is no adverse effect on rates based on case-specific evidence, and as such those applicants need not offer a hold harmless commitment if they have otherwise met their burden of proof to make such a demonstration.¹⁷¹ Furthermore, APPA and NRECA urge the Commission to proceed with caution and avoid reducing the requirement of showing no adverse effect on rates to an exercise where any claimed, non-quantifiable benefits from a transaction are determined to outweigh rate increases.¹⁷²

92. Similarly, the Transmission Dependent Utilities also urge the Commission not to exempt certain transactions from the requirement to adopt ratepayer protection

¹⁶⁸ EPSA Comments at 3; Southern Company Comments at 4.

¹⁶⁹ Kentucky Utilities Comments at 5.

¹⁷⁰ See APPA and NRECA Comments at 12; Transmission Access Policy Study Group Comments at 6.

¹⁷¹ See APPA and NRECA Comments at 12-13; Transmission Access Policy Study Group Comments at 8-9.

¹⁷² APPA and NRECA Comments at 14.

mechanisms and state that the proposal undercuts the other ratepayer protection mechanisms proposed in the Proposed Policy Statement.¹⁷³ They assert that the Commission should not adopt the proposal because: (1) practically any asset transaction could meet the Commission's proposed standard as nearly any such transaction could be deemed necessary to serve existing or forecasted load or to satisfy at least one federal or state regulatory requirement; (2) wholesale customers may derive no benefits from transactions that satisfy state resource adequacy requirements; (3) FPA section 215¹⁷⁴ prohibits reliability standards from including any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity and therefore, the Commission should not grant a special exemption from adopting ratepayer protection mechanisms to utilities that purchase facilities in order to comply with NERC standards; and (4) the premise that an increase in rates may not be adverse because of the reason for the transaction is flawed.¹⁷⁵ The Transmission Dependent Utilities state that no such exemption is needed because to the extent that such a transaction provides for benefits to wholesale ratepayers, applicants should be able to demonstrate such benefits or savings exceed the transaction-related costs.¹⁷⁶

¹⁷³ See Transmission Dependent Utilities Comments at 8-9.

¹⁷⁴ 16 U.S.C. § 824o(a)(3) (2012).

¹⁷⁵ See Transmission Dependent Utilities Comments at 9-10.

¹⁷⁶ See *id.* at 11.

93. Some commenters also identified other types of transactions that may have a rate impact, but not one that is adverse, and therefore should not require any additional ratepayer protection. These commenters request that the Commission clarify that, in addition to transactions involving purchases of existing generation facilities, a hold harmless commitment may also be unnecessary in connection with: (1) purchases of existing transmission facilities that provide benefits, such as added capacity or increased reliability;¹⁷⁷ (2) transactions consummated under a blanket authorization;¹⁷⁸ (3) transactions that involve necessary contract rights or other jurisdictional assets, rather than physical facilities;¹⁷⁹ (4) transactions undertaken in order to comply with any other federal or state regulatory framework;¹⁸⁰ (5) transactions with “no identified or reasonably *de minimis* costs, such as internal reorganizations or restructurings;”¹⁸¹ (6) transactions involving the transfer of non-energized turn-key facilities;¹⁸² and (7) acquisitions of non-jurisdictional transmission assets by a transmission-only company.¹⁸³

¹⁷⁷ Southern Company Comments at 3.

¹⁷⁸ EEI Comments at 12.

¹⁷⁹ Kentucky Utilities Comments at 5.

¹⁸⁰ *Id.* at 5-6 (including environmental, antitrust, market power regulation, energy efficiency standards, or portfolio standards).

¹⁸¹ *Id.* at 6.

¹⁸² *See* AEP Comments at 14; Southern Company Comments at 4.

¹⁸³ Transmission-Only Companies Comments at 1. The Transmission-Only Companies explain that their business model itself carries benefits and will further Commission policy. *Id.* at 5-6.

94. EPSA requests that the Commission reaffirm its policy that there is no adverse effect on rates and that no hold harmless commitment is required where an applicant's cost-based rates do not allow for automatic pass-through of transaction-related costs because applicants can only recover transaction-related costs through a filing under FPA section 205 in such circumstances.¹⁸⁴ EPSA also asks that the Commission recognize that particular types of rate schedules, including schedules and agreements for reliability must run, reactive power/voltage control, and restoration services, do not allow for automatic pass-through of costs.¹⁸⁵

3. Commission Determination

95. We clarify that the Commission does not intend to exempt classes of transactions that require authorization under FPA section 203 from the requirement to make a showing of no adverse effect on rates. Our intention is to make it clear that, under the Merger Policy Statement, a hold harmless commitment is just one of several ratepayer protection mechanisms that may be appropriate in a given case, but that a hold harmless commitment (or other ratepayer protection) may be unnecessary for some categories of

¹⁸⁴ EPSA Comments at 3 (citing *NRG Energy Holdings*, 146 FERC ¶ 61,196 at P 87).

¹⁸⁵ *Id.* at 3-4.

transactions.¹⁸⁶ In addition, we reaffirm that a hold harmless commitment is not a requirement for an FPA section 203 application; in cases in which some form of ratepayer protection may be appropriate, applicants may offer other forms of ratepayer protection to demonstrate that the transaction has no adverse effect on rates.¹⁸⁷ This observation does not relieve applicants of their obligation to demonstrate that the proposed transaction does not have an adverse effect on rates based on the circumstances of their transaction or to offer ratepayer protection mechanisms where appropriate.¹⁸⁸ Further, the burden of demonstrating that any given transaction presents no adverse effect on rates continues to lie with the applicants.¹⁸⁹

¹⁸⁶ See, e.g., *Pub. Serv. Co. of New Mexico*, 153 FERC ¶ 61,377 at P 39 (finding that there was no adverse effect on wholesale requirements customers because those customers receive service under long-term, Commission-approved contracts with stated rates whose terms would not change a result of the proposed transaction and cannot change absent a filing under FPA section 205 with the Commission to change those rates); *NRG Energy Holdings*, 146 FERC ¶ 61,196 at P 87 (finding that there was no adverse effect on wholesale rate because applicants would continue to make wholesale sales at market-based rates or at cost-based rates, under which applicants had no ability to pass through any increased costs resulting from the proposed transaction).

¹⁸⁷ Merger Policy Statement, FERC Stats. & Regs. ¶ 31,044 at 30,123-24.

¹⁸⁸ See *id.*

¹⁸⁹ *Id.* at 30,123.

96. For example, certain rate schedules do not contain a mechanism that would allow an applicant to pass on transaction-related costs.¹⁹⁰ Although it would be unnecessary to make any hold harmless commitment in connection with such a transaction, the applicant would nonetheless have to demonstrate how the rate schedule precludes passing on transaction-related costs to customers. Furthermore, if applicants believe the transaction for which they seek approval provides needed benefits to customers, they may choose to make such a showing.

97. The transactions we identified in the Proposed Policy Statement (i.e., documented utility needs such as the purchase of an existing generating plant or transmission facility that is needed to serve the acquiring company's customers or forecasted load within a public utility's existing footprint, in compliance with a resource planning process, or to meet specified NERC standards), were only illustrative, and not intended to be an all-inclusive list. As a result, we do not adopt the suggestion by some commenters that the Commission identify other types of transactions that may not require a hold harmless commitment. We emphasize that, in all cases, applicants have the burden of demonstrating that a proposed transaction will have no adverse effect on rates. A hold

¹⁹⁰ See, e.g., *Pub. Serv. Co. of New Mexico*, 153 FERC ¶ 61,377 at P 39 (finding that there was no adverse effect on wholesale requirements customers because those customers receive service under long-term, Commission-approved contracts with stated rates whose terms would not change a result of the proposed transaction and cannot change absent a filing under FPA section 205 with the Commission to change those rates).

harmless commitment or other form of ratepayer protection is only called for in those instances where an applicant cannot otherwise meet this burden.

98. Finally, we note that the Transmission Dependent Utilities misapprehend the statement in the Proposed Policy Statement regarding transactions involving acquisitions of existing facilities to fulfill a NERC reliability standard. Nothing in this Policy Statement requires an entity to acquire or invest in facilities. Instead, this Policy Statement states that if an entity acquires a facility to fulfill a requirement of a NERC reliability standard and it seeks approval under FPA section 203 for that transaction, the entity may present evidence that the transaction's effect on rates is not an adverse effect on rates instead of offering a hold harmless commitment.

E. Other Issues Raised

1. Comments

99. EEI states that the Commission's FPA section 203 analysis already protects customers well.¹⁹¹ EEI asserts that the Commission's current regulations and guidance already ensure that the proper information to examine and address potential effects on customers and markets is required to be provided to the Commission.¹⁹² EEI states that it appreciates the Commission's goal of providing clarity, but it encourages modification of the proposal so that any policy the Commission adopts "puts use of the commitments

¹⁹¹ EEI Comments at 3

¹⁹² *Id.* at 5.

in perspective within the [FPA] section 203 process and is fair and workable.”¹⁹³ EEI asserts that the structure of the Proposed Policy Statement does not clearly identify what the text of the proposed policy is, which it asserts is essential for readers to understand and comment on the proposal.¹⁹⁴ EEI further asserts that given the fundamental changes it suggested to the Proposed Policy Statement, the Commission should respond to those suggestions, re-notice the statement and provide a chance for entities to provide additional feedback.¹⁹⁵

100. EEI and EPSA ask the Commission to clarify that it will not apply any new requirements set out in this Policy Statement to pending or previously-approved section 203 transactions, even if there is a subsequent related FPA section 205 filing.¹⁹⁶ EEI states that parties have structured pending or previous transactions based on the then-applicable review process and it would be “manifestly unfair” to apply new conditions on parties after they have submitted their applications.¹⁹⁷ EPSA states that its members and other market participants seek clarity that any such filings would not be evaluated against

¹⁹³ *Id.* at 6.

¹⁹⁴ *Id.* at 20.

¹⁹⁵ *Id.*

¹⁹⁶ *Id.*; EPSA Comments at 6.

¹⁹⁷ EEI Comments at 20.

any new requirements or policies implemented in a final Policy Statement, but under the policies in existence at the time the relevant transaction was approved.¹⁹⁸

2. Commission Determination

101. We will apply all changes contained in this Policy Statement on a prospective basis, effective 90 days after publication of this Policy Statement in the Federal Register, for applications submitted on and after that effective date. The guidance herein does not alter existing hold harmless commitments accepted by the Commission nor does it modify hold harmless commitments in applications pending at the time of issuance of this Policy Statement. Finally, we decline EEI's request that the Commission refine and reissue the Proposed Policy Statement to allow for additional feedback. The Policy Statement has incorporated and addressed suggestions by commenters, clarifies the scope and definition of the costs that should be subject to hold harmless commitments, and provides general guidance to be implemented on a case-by-case basis.

III. Information Collection Statement

102. The Paperwork Reduction Act (PRA)¹⁹⁹ requires each federal agency to seek and obtain Office of Management and Budget (OMB) approval before undertaking a collection of information directed to ten or more persons or contained in a rule of general applicability. OMB regulations require approval of certain information collection

¹⁹⁸ EPSA Comments at 6-7.

¹⁹⁹ 44 U.S.C. 3501-3520.

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requirements imposed by agency rules.²⁰⁰ Upon approval of a collection(s) of information, OMB will assign an OMB control number and an expiration date.

Respondents subject to the filing requirements of an agency rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control numbers. The following table shows the Commission's estimates for the additional burden and cost,²⁰¹ as contained in the Policy Statement:

Revisions, in the Policy Statement in Docket No. PL15-3					
Requirements	Number and Type of Respondents (1)	Number of Responses per Respondent (2)	Total Number of Responses (1)*(2)=(3)	Average Burden Hours & Cost Per Response (4)	Total Burden Hours & Total Cost (3)*(4)
FERC-519 (FPA Section 203 Filings) ²⁰²	18	1	18	20 hrs.; \$1,440	360 hrs.; \$25,920
FERC-516 (FPA Section 205, Rate and Tariff Filings)	1	1	1 ²⁰³	103.26 hrs.; \$7,434.72	103.26 hrs.; \$7,434.72

²⁰⁰ See 5 CFR 1320.

²⁰¹ The hourly cost figures are based on data for salary plus benefits. The Commission staff thinks that industry is similarly situated to FERC in terms of the average cost of a full time employee. Therefore, we are using the 2015 FERC hourly average for salary plus benefits of \$72 per hour.

²⁰² Commission staff estimates that, due to the Policy Statement, 18 of the FPA Section 203 filings will take 20 additional burden hours. The estimated number of filings is not changing.

²⁰³ Commission staff estimates that one FPA section 205 filing may be made annually subject to the Policy Statement.

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FERC-555, Record Retention	18	1	18	4 hrs.; \$288	72 hrs.; \$5,184
TOTAL					535.26 hrs.; \$38,538.72

Title: FERC-519, Application under Federal Power Act Section 203; FERC-516, Electric Rate Schedules and Tariff Filings; and FERC-555, Preservation of Records for Public Utilities and Licensees, Natural Gas and Oil Pipeline Companies.

Action: Revised Collections of Information.

OMB Control No: 1902-0082 (FERC-519), 1902-0096 (FERC-516), and 1902-0098 (FERC-555).

Respondents: Business or other for profit, and not for profit institutions.

Frequency of Responses: As needed and ongoing.

Necessity of the Information: To protect ratepayers and to mitigate possible adverse effects on rates that may result from mergers or certain other transactions that are subject to section 203 of the FPA, we propose clarifications and additional information collection requirements related to hold harmless commitments offered by applicants.

Internal review: The Commission has reviewed the changes included in the Policy Statement and has determined that the additional reporting and recordkeeping requirements are necessary.

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Interested persons may obtain information on the reporting requirements by contacting:

Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426

[Attention: Ellen Brown, Office of the Executive Director, e-mail:

DataClearance@ferc.gov, Phone: (202) 502-8663, fax: (202) 273-0873].

IV. Document Availability

103. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (<http://www.ferc.gov>) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington DC 20426.

104. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

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105. User assistance is available for eLibrary and the FERC's website during normal business hours from FERC Online Support at (202) 502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202)502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Document Accession #: 20160519-3056

Filed Date: 05/19/2016

Document Content(s)

PL15-3-000.DOCX.....1

PPL CORPORATION, PPL RHODE ISLAND HOLDINGS, LLC,
NATIONAL GRID USA, and THE NARRAGANSETT ELECTRIC COMPANY
Docket No. D-21-09
PPL Corporation and PPL Rhode Island Holdings, LLC's
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Issued on June 8, 2021

Division 1-34

Request:

Please provide PPL's current estimate of the date by which it expects to complete the takeover of the provision of services to Narragansett from National Grid. If the completion of the transfer is contingent on the occurrence of an event or events, please identify or describe with specificity the events the completion of which will trigger such transfer.

Response:

PPL and PPL RI currently expect to complete the integration and transition of all services to The Narragansett Electric Company ("Narragansett") within 24 months after closing PPL RI's acquisition of all National Grid USA's common equity interests in Narragansett. The transfer is not contingent on the occurrence of any specific events; rather, it is contingent on PPL and PPL RI confirming (through testing and other confirmatory measures) that the transfer of each service will be smooth and not result in any impact on the continued provision of safe and reliable service to all Narragansett customers.

Division 1-35

Request:

Paragraph 25 of the Petition states that “PPL also expects that it will have significant opportunities to invest in Narragansett’s electric and gas infrastructure to enhance safety, reliability, and customer satisfaction for Rhode Island customers, a core tenet of PPL’s strategy in all of the jurisdictions in which it provides utility service.” Please explain the basis of this conclusion and identify all investment opportunities that PPL has identified with respect to the Narragansett electric and gas systems. In addition, please provide all related reports and analyses.

Response:

At this time, PPL and PPL RI have not specifically identified areas in which to invest in The Narragansett Electric Company’s electric and gas infrastructure to enhance safety, reliability, and customer satisfaction for Rhode Island customers. PPL’s basis for this conclusion is the experience of its existing electric utility subsidiaries.

PPL Electric Utilities Corporation (“PPL Electric”) has extensive experience working to innovate and modernize the electric grid to cost-effectively improve system reliability and resiliency. In the past ten years, PPL Electric achieved a 30 percent improvement in reliability and improved JD Power customer satisfaction scores by 20 percent, while at the same keeping operations and maintenance costs flat.

PPL Electric’s grid modernization focused on developing telemetered systems leveraged by centralized operations systems to provide industry-leading safety, reliability, power quality, and customer satisfaction for its employees and customers. The key milestones in PPL Electric’s grid modernization effort include the following:

- 2002 – PPL Electric successfully deployed one of North America’s first automated metering infrastructure (“AMI”) systems through power line carrier (“PLC”) communication that enabled remote data transactions and meter reads.
- 2006 – PPL Electric deployed its meter data management system, which supported the processing of meter data. PPL Electric was one of the first utilities in the country to present hourly usage data to all customers.
- 2009 – PPL Electric deployed centralized supervisory control and data acquisition (“SCADA”) for the distribution system.

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- 2011 – PPL Electric began a multi-year distribution telemetered device program for its backbone protective and switchable devices in order to provide improvement to customer reliability.
- 2014 – PPL Electric completed its deployment of its Distribution Management System (“DMS”) that integrated its existing telemetered distribution protective devices and AMI meters.
- 2015 – PPL Electric initiated a pilot program to have its DMS system autonomously react to power outages via its fault location isolation and service restoration (“FLISR”) software.
- 2016 – PPL Electric initiated a multi-year roll out to upgrade its distribution substation circuit breaker relays that increases the amount of data to its DMS.
- 2016 – PPL Electric fully deployed one of the United States’ first fully autonomous FLISR systems to its entire territory. When paired with the distribution automation of its switchable, protective telemetered devices led to significant improvements in customer reliability.
- 2019 – PPL Electric, through a grant with the U.S. Department of Energy, led the development of a distributed energy resource (“DER”) enhanced DMS systems with its vendor General Electric. PPL created this system to integrate DER behavior into its operational system to better integrate DER assets into the distribution grid safely and reliably.
- 2019 – PPL Electric received awards from EPRI and SEL for its development of a high impedance fault detection (downed wire) device programming, which it has deployed on many of its telemetered distribution devices.
- 2020 – PPL Electric completed the upgrade of its entire remote AMI PLC system with a newer and more advanced Radio Frequency (“RF”) Mesh AMI system. The upgrade allowed PPL Electric to leverage the new smart meter capabilities and data to streamline business processes and improve decision making abilities, and providing value to customers.
- 2020 – PPL Electric began the process of implementing Synchrophasor technology, which provides high resolution states of the system (up to 60 messages a second), with initial Synchrophasor architecture laboratory tests completed in Walbert Lab (Proof of Concept) in January 2021.
- 2020 – PPL Electric’s partner vendor Schweitzer Engineering Laboratories (“SEL”) released the new traveling wave relay – SEL T401L – for commercial availability in September 2020. PPL, in partnership with SEL, was able to implement the first relay on the PPL transmission grid about two months after its manufacturing release.

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- 2020 – PPL Electric has installed the Traveling Wave technology on five lines in 2020 including the first installation on 69kV radial line in the world including line monitoring function.

- 2021 – PPL Electric has installed the Traveling Wave technology on an additional (7) lines in 2021 to date and expects to have it implemented on over 30 lines by the end of 2021.

- 2021 – PPL Electric is partnering with SEL and utilizing new relay updates related to the Synchrophasor technology. PPL Electric has also updated Synchrophasor architecture, partnering with falling conductor detection and additional algorithms and data capabilities. The target design completion is currently August 2021.

- 2021 – The first synchrophasor pilot will be deployed at Hosensack 230-69kV substation with a completion date of August 2021. PPL Electric's goal is to verify physical infrastructure in the field and obtain real time data from operation events as well as continuous data samples to advance PPL Electric's algorithms for future system-wide implementation.

- 2021 – As party of the synchrophasor pilot program, PPL Electric is adding downed/falling conductor to the transmission line protection schemes by December 2021.

-2021 – PPL Electric is also deploying IoT (data streaming initiative) retrofit pilot at Hosensack substation. This will deploy Axion units at Hosensack to enable high speed (3kHz) data streaming, incorporating Traveling Wave and Synchrophasor technologies. The IoT architecture is being tested at Walbert Lab and the pilot is scheduled to be in place by end of 2021.

- 2021 – PPL Electric will be completing a multi-year program to add telemetry to all its multi-phase switchable distribution capacitors. There are currently more than 2,300 devices programmed through this program. Each of these devices are currently managed out of PPL Electric's Advanced DMS ("ADMS") system for system volt-var support.

- 2021 – PPL Electric initiated a multi-year program to add telemetry to its underground Low Tension Network ("LTN") devices, including network protectors that will allow for management out of PPL Electric's ADMS system for system volt-var support.

- 2021 – PPL Electric initiated a multi-year program to add telemetry to its distribution voltage regulators that will allow for their management through PPL Electric's ADMS system for system volt-var support.

- 2021 – PPL Electric completed an upgrade of its existing DMS systems to its vendor's ADMS system that provides additional functionality for DER and non-DER systems.

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- 2021 – PPL Electric began implementing a 3-year, Pennsylvania Public Utilities Commission-approved, DER Management pilot program. The pilot enables PPL Electric to test and evaluate the costs and benefits of monitoring and actively managing smart inverters that meet the latest IEEE (Institute of Electrical and Electronics Engineers) standards. The pilot is intended to improve the safety, reliability, power quality, and stability of PPL Electric's grid operations and increase adoption of DER across PPL Electric's service area at a lower cost to customers.

- 2021 – PPL Electric began implementing Dynamic Line Ratings sensors on its transmission system that enable operators to see how much of a circuit's available capacity is being utilized in real-time. With this information, operators can extend a circuit's loading beyond traditional thermal limits without compromising performance or longevity. In a partnership with PJM, PPL Electric piloted this technology this past winter on two lines. The pilot enabled PJM to resolve congestion on the lines without the need for millions of dollars in new or rebuilt lines.

The next steps in the grid modernization plan focus on developing improvements to PPL Electric's ADMS and DER Management systems in preparation for the grid of the future, including regulatory initiatives such as FERC Order 2222. In addition, PPL Electric is expanding reliability and grid stability functionality through new dynamic protective settings on its distribution telemetered protective and switchable devices in order more effectively react to the dynamically changing grid.

Based on these numerous initiatives over the past decade and PPL's extensive experience, PPL and PPL RI expect that, upon the closing of the transaction, they will identify numerous opportunities along the lines of those described above in which to invest in The Narragansett Electric Company's electric and gas infrastructure to enhance safety, reliability, and customer satisfaction for Rhode Island customers

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Division 1-36

Request:

Please provide all Documents, including all reports, assessments, and analyses, in the possession of or prepared by or for PPL or PPL RI (including those provided by National Grid) related to the condition of the Narragansett gas and electric systems.

Response:

Counsel for PPL, PPL RI, National Grid USA ("National Grid"), The Narragansett Electric Company ("Narragansett"), and The Rhode Island Division of Public Utilities and Carriers Advocacy Section (the "Division Advocacy Section") met and conferred regarding the breadth and scope of certain data requests. After that meet and confer, the Division Advocacy Section sent a letter, dated June 22, 2021, advising that PPL, PPL RI, National Grid, and Narragansett can "use sound judgment and the rule of reason in crafting responses and providing responsive documents." The Division Advocacy Section also advised in the June 22, 2021 letter PPL, PPL RI, National Grid, and Narragansett to "consider the Advocacy Section's goal of protecting ratepayers when determining scope and relevancy." Based on the scope and breadth of this request, PPL and PPL RI have applied the rule of reason and used sound judgment in limiting the breadth and scope of documents produced in response to this request, and have considered the Division Advocacy Section's goal of protecting ratepayers in determining which documents it will produce.

Please see National Grid and Narragansett Attachments NG-DIV 1-36-1 through NG-DIV 1-36-22.

Please also see Attachment PPL-DIV 1-36-1, Rover Due Diligence (CONFIDENTIAL).

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Attachment PPL-DIV 1-36-1

Confidential Attachment PPL-DIV 1-36-1 contains confidential commercial or financial information. PPL and PPL RI have requested protective treatment of this confidential attachment in its entirety.

Division 1-37

Request:

Presently the Narragansett-owned transmission assets are, for operational purposes, integrated into the New England Power Company (NEP) d/b/a National Grid transmission system pursuant to Schedule III-B of NEP's FERC Electric Tariff. Please:

- a. Explain whether the Narragansett-owned transmission assets will continue to be integrated with National Grid's transmission system for operational purposes post-acquisition; and
- b. If Narragansett's transmission assets will no longer be integrated with National Grid's transmission system post-Transaction, please identify who will operate Narragansett's transmission assets that are subject to local control; and
- c. Provide any Documents related to the operation of Narragansett's transmission assets post-Transaction.

Response:

- a. PPL and National Grid are still working on the final arrangement, but expect that Narragansett-owned transmission assets will continue to be integrated with the National Grid transmission system for an interim period after closing. PPL expects this interim period to last until approximately mid-2022, after which PPL will operate the Narragansett-owned transmission assets on its own. PPL expects no change regarding the operation of the ISO-NE operated facilities.
- b. See response to (a). After the interim period, PPL expects to operate the Narragansett-owned transmission assets on its own.
- c. Counsel for PPL Corp. ("PPL"), PPL Rhode Island Holdings, LLC ("PPL RI"), National Grid USA ("National Grid"), The Narragansett Electric Company ("Narragansett"), and The Rhode Island Division of Public Utilities and Carriers Advocacy Section (the "Division Advocacy Section") met and conferred regarding the breadth and scope of certain data requests. After that meet and confer, the Division Advocacy Section sent a letter, dated June 22, 2021, advising that PPL, PPL RI, National Grid, and Narragansett can "use sound judgment and the rule of reason in crafting responses and providing responsive documents." The Division Advocacy Section also advised in the June 22, 2021 letter PPL, PPL RI, National Grid, and Narragansett to "consider the Advocacy Section's goal of protecting ratepayers when determining scope and relevancy." Based on the scope and breadth of this request, PPL and PPL RI have applied the rule of reason and used sound judgment in limiting the breadth and scope of documents produced in response to this

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request, and have considered the Division Advocacy Section's goal of protecting ratepayers in determining which documents it will produce.

PPL and PPL RI refer to Attachment PPL-DIV 1-37-1, NEP Tariff No. 1, Schedule III.B. (IFA); Attachment PPL-DIV 1-37-2, Transmission Operating Agreement, and Attachment PPL-DIV-1-37-3, ISO-NE Tariff. PPL and PPL RI anticipate that there may be additional documents that will be completed to transfer the Management of Transmission to PPL, and, accordingly, PPL and PPL RI will supplement this response as appropriate as new milestones are met.

FERC ELECTRIC TARIFF
SECOND REVISED VOLUME NUMBER 1
OF
NEW ENGLAND POWER COMPANY
Filed with
FEDERAL ENERGY REGULATORY COMMISSION

Communications concerning this
Tariff should be addressed to:

Director of Rates
New England Power Company
40 Sylvan Road
Waltham, Massachusetts 02451

NEW ENGLAND POWER COMPANY

Primary Service for Resale

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NEW ENGLAND POWER COMPANY

Primary Service for Resale
and
Transmission Service for Partial Requirements Customers
General Terms and Conditions

Schedule I

A. Tariff.

Primary Service for resale and transmission service for Partial Requirements Customers are available only upon execution of a Service Agreement with the Company in the form set forth hereinafter.

Each such Service Agreement will incorporate these general terms and conditions (Schedule I), the Company's currently effective rate for primary service for resale (Schedule II), the terms and conditions applicable to the type of service to be rendered at said rate (Schedule III) and the specific interconnection arrangements with the Customer.

The Company will file each such Service Agreement with the Federal Energy Regulatory Commission (and such other regulatory agency as may have jurisdiction in the premises) in accordance with the provisions of applicable laws and any rules and regulations thereunder.

B. Amendments.

It is agreed that the Company shall have the right at any time to amend the General Terms and Conditions set forth in this Schedule I to the tariff, the Rate Provisions set forth in Schedule II to the tariff, the Terms and Conditions governing specified types of service set forth in Schedule III to the tariff, and the form of Service Agreement set forth in Schedule IV to the tariff, by serving an appropriate statement of such amendment upon the Customer and filing the same with the Federal Energy Regulatory Commission (and such other regulatory agency as may have jurisdiction in the premises) in accordance with the provisions of applicable laws and any rules and regulations thereunder, and the amendment shall thereupon become effective on the date specified therein, subject to any suspension order duly issued by such agency.

C. Regulation.

This tariff, any Service Agreement executed pursuant thereto, and all the rights, obligations and performance of the parties to such service agreement, are subject to the Federal Power Act and to all other applicable state and federal laws and to all duly promulgated rules, regulations and orders of the Federal Power Commission and any other regulatory agency having

jurisdiction in the premises.

The obligations of the parties are further subject to and conditioned upon their securing and retaining all rights-of-way, franchises, locations, permits and other rights and approvals necessary in order to permit service to be rendered as set forth in the Service Agreement, and each party agrees to use its best efforts to secure and retain all such rights-of-way, franchises, and other rights and approvals.

D. Availability of primary service for resale.

Primary service for resale is available only to electric utilities (including municipalities) engaged in the distribution of electricity to the public, whose electric requirements are supplied in whole or in part by the Company, either directly or over facilities for the use of which the Company has contractual arrangements.

Electricity so supplied is available for the Customer's own use and for resale to ultimate customers in the Customer's service area as it may exist from time to time, which area shall consist of one or more Districts to be specified in the Service Agreement. If the Customer's service area consists of two or more Districts, all provisions of the tariff shall apply to each District separately.

Primary service for resale is also available for sales for resale by the Customer (1) to electric utilities served by the Customer as of the date of and as specified in the Service Agreement; (2) to additional electric utilities which shall then be specified in the Service Agreement; and (3) under convenience contracts for the supply of electricity to borderline customers. With reference to sales under (2) above, the Customer shall give to the Company seven years' notice of intention to serve such utilities; the Customer shall furnish such information as the Company may reasonably request; and the parties shall establish mutually agreeable reasonable terms in connection therewith.

Service for Resale to Interruptible Customers under Schedule III-C is available only to utilities who are also taking service under Schedule III-A or III-B.

The Customer's sources of supply other than the Company shall be specified in the Service Agreement; and seven years' notice shall be given by the Customer to the Company of a change in Customer's source or sources, and such change shall be implemented pursuant to mutually agreed upon reasonable terms.

E. Availability of transmission service.

The types of transmission service available to the Partial Requirements Customer are specified in Schedule III to the tariff, and the Company will consider requests for additional types of transmission service; in each case to the extent that the Company deems its existing and planned transmission capacity can accommodate such additional service without additional new construction. In cases where new construction may be required to accommodate additional types of transmission service, the Company reserves the right in its discretion either to refuse to undertake such further service, or to request financial assurance that any additional transmission investments and costs will be adequately provided for.

F. Character of primary electric service.

Electricity will be supplied in the form of three-phase, sixty-hertz alternating current at the nominal voltage or voltages specified in the Service Agreement.

The Company will maintain and operate its interconnected generating and transmission system, together with any delivery facilities required for service to the Customer, in accordance with good utility practice. The Company will use due diligence in maintaining an aggregate capacity of such facilities sufficiently in excess of current Demand to allow for the Customer's expected load growth, and the Customer will keep the Company informed as to expected trends of its load growth.

The Company shall not be liable in damages to the Customer for any failure to supply electricity nor to provide transmission service in accordance with the preceding paragraphs if prevented from doing so by reason of storm, flood, earthquake, fire, explosion, civil disturbance, labor dispute, act of God or the public enemy, restraint by a court or other public authority, or any cause beyond its reasonable control; and shall not be liable in damages to the Customer for any reduction in voltage or interruption of service resulting from the operation in accordance with good utility practice of an emergency load-reduction program; but in any such case the Company will exercise due diligence to remove the cause of any disability at the earliest practicable time. The Company and the Customer shall have the obligation to operate in accordance with good utility practice, including an emergency load reduction program, and upon request, to consult with each other in regards thereto.

G. Delivery and ownership of facilities.

1. All deliveries will be made a single delivery point in each District (which may also be used to serve other customers of the Company or affiliated companies of the New England Electric System), except where District load can be more feasibly served by multiple delivery points. The Service Agreement shall set forth with respect to each District of the

Customer's system the point or points of delivery, the delivery voltage or voltages and the ownership of transformation and metering equipment.

2. Deliveries at each delivery point will be made at a single voltage except as otherwise provided in the Service Agreement.

3. All lines, apparatus and other equipment up to the point of delivery shall be supplied, maintained and operated by the Company or affiliated companies of the New England Electric System, and all such equipment beyond such point of delivery shall be supplied, maintained and operated by the Customer. The Customer shall, however, supply free of cost a suitable place for the installation of the Company's metering equipment and any of the Company's lines, or other equipment which it is proper to locate on the Customer's property, and the Company shall have access to the Customer's property for all reasonable purposes in connection therewith.

4. All the Customer's lines, apparatus and equipment (and the maintenance, operation and adjustment of the same) which are connected to the facilities of the Company, and the maintenance, operation and adjustment of which may adversely affect the operation of the Company's facilities, shall be subject to the reasonable inspection and approval of the Company.

5. The Customer assumes all responsibility for electricity beyond the point of delivery, and the Company shall not be liable for damage to the person or property of the Customer or of its employees or of any other persons resulting from the use of electricity beyond the point of delivery.

Variations from the provisions of paragraphs 1 through 5 above will be permitted, in the discretion of the Company, if and to the extent that equitable adjustments are provided for and set forth in the Service Agreement.

H. Metering.

The Company reserves the right to determine the metering installations and will supply the metering equipment for determining the quantity and conditions of supply of electricity delivered hereunder. Any exceptions to this provision shall be reflected in the Service Agreement.

If at any time such equipment shall be found to be inaccurate by more than 2% up or down, the owner shall make it accurate and the charges and meter readings for the period of inaccuracy, so far as the same can reasonably be ascertained, shall be adjusted. However, no adjustment prior to the beginning of the next preceding month shall be made except by mutual agreement.

In addition to regular routine tests, the owner shall have any such meter tested at any time upon written request of the other party, and if such meter prove accurate within 2% up or down the expense of the test shall be borne by the party requesting the test.

I. Transmission losses.

Unless otherwise specified in the tariff, all losses incurred in providing transmission service hereunder shall be for the account of the Customer, and delivery of the aggregate quantity of electricity received for transmission, less such losses, shall constitute full performance by the Company. When segregation of energy flows is required to determine such losses, the Company will calculate the same in accordance with good engineering practice.

J. Billing and payment.

Bills for each month shall be rendered during the first part of the next succeeding month and shall be due when rendered.

As used herein the term “month” shall refer to the period between two meter readings each of which shall have been taken within two days of the end of successive calendar months.

When all or part of any bill shall remain unpaid for more than thirty (30) days after the rendering thereof by the Company, interest at the rate of 1 ½% per month shall accrue to the Company from and after the rendering of said bill and be payable to the Company on either: (1) such unpaid amount or (2) in the event the amount of the bill is disputed, the amount finally determined to be due and payable.

Notwithstanding the foregoing, no late payment penalty shall be imposed upon any customer where payment is made within forty-five (45) days of the rendering of the bill by the Company provided that each of the following conditions are met: 1) the average prior calendar year’s monthly billing to such customer was less than \$45,000; and 2) payment of such bill within thirty (30) days by such customer would cause undue hardship because of the fact that one or more part-time employees or officials are essential to the processing of payment by such customer. A letter from an appropriate official of a customer certifying that one or more part-time employees are essential to the processing of payment shall constitute satisfactory evidence that condition 2 herein has been met.

In addition, no late payment penalty shall be imposed upon any customer electing to make installment payments with respect to any bill so long as the weighted average payment date, based on the amount of each payment, is no later than 30 days after the date of the rendering of the bill.

K. Remedies.

If any bill remains unpaid for more than sixty days, except amounts in dispute, the Company may apply to the regulatory agency having jurisdiction to suspend delivery of electricity until full payment has been made of all amounts due.

If either party shall have defaulted in any of its obligations and such default shall have continued for and not been remedied within sixty days after receipt of a written notice from the other party specifying the nature of such default in reasonable detail, the other party may by written notice terminate the Service Agreement at the end of the next succeeding calendar month. No delay by either party in enforcing any of its rights hereunder shall be deemed a waiver of such rights, nor shall a waiver of one default be deemed a waiver of any other or subsequent default.

The enumeration of the foregoing remedies shall not be deemed to be a waiver of any other remedies to which other party is legally entitled.

L. Hours of Labor.

The Company agrees to comply with the provisions of the General Laws of Massachusetts, Chapter 149, Section 34, as amended, with reference to the hours of laborers, workmen or mechanics in its employ, so far as the same may be applicable to work under this tariff.

M. Notices.

Notices by the Company or the Customer shall be in writing, mailed or delivered to the respective addresses set forth in the Service Agreement. Either party may change its address by written notice to the other.

N. Term.

Once initiated, service under this tariff shall continue until terminated by either party giving to the other at least seven years' written notice of termination directed to the end of a calendar month.

A Customer that seeks to terminate service without providing the notice required under this tariff and its service agreement and that has not otherwise agreed to a settlement of its early termination costs may exercise an option to terminate service under this tariff early by giving the

Company thirty days' written notice directed to the end of a calendar month and paying the Contract Termination Charge applicable under Schedule II-C of this tariff. The Contract Termination Charge shall be payable in equal monthly installments of principal and interest, the first payment to be made within 30 days after the date of termination of service ("Early Termination Date"), over the remaining term of the Customer's notice period (or such shorter term, or in a single payment, as agreed by the Company and the Customer). The Customer's payments shall include carrying charges on the unpaid amount of the Contract Termination Charge at the interest rate determined pursuant to section 35.19a of the Commission's regulations (18 C.F.R. 35.19a) effective on the Early Termination Date and compounded monthly. The Company reserves the right to require the Customer to provide security in a form appropriate to the Company and consistent with commercial practices to protect the Company against the risk of non-payment. This paragraph shall not apply to Customers that have entered into settlement agreements with the Company allowing early termination of service under this tariff and establishing the recovery of contract termination charges. The Company at its discretion may waive the thirty days' notice provision under this paragraph.

O. Successors and assigns.

The executed service agreement shall be binding upon, shall inure to the benefit of, and may be performed by, the successors and assigns of the parties.

NEW ENGLAND POWER COMPANY

Schedule II-A

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NEW ENGLAND POWER COMPANY

Schedule II-B

NEW ENGLAND POWER COMPANY

Primary Service for Resale

Rate W-95(N)

Demand Charge:	\$17.17 per month for each kilowatt of Demand.
Energy Charge:	21.83 mills (\$0.02183) for each kilowatt-hour of electricity delivered, except for kilowatt-hours of electricity delivered under Service for Resale to Interruptible Customers, Schedule III-C.
Interruptible Service: Charge	For each kilowatt-hour delivered in any hour pursuant to Schedule III-C, the amount specified for that hour by the Company pursuant to Paragraph C of Schedule III-C
Fuel and Purchased Economic Power Adjustment Clause:	For any month for which the Cost of Fuel is greater or less than 14.0000 mills per kilowatt-hour, the Energy Charge shall be increased or decreased respectively by the applicable fuel adjustment rate per kilowatt-hour delivered, which rate shall be equal to the difference of:

$$\frac{F_m - F_b}{S_m - S_b}$$

Where F is the expense of fossil and nuclear fuel and purchased economic power in the base (b) and current (m) periods; and "S" is the kilowatt-hour sales in the base and current periods, all as defined in Section 35.14 of the Regulations under the Federal Power Act as provided in Order No. 352 issued December 7, 1983 in Docket No. RM83-62-000. F shall also include expenses associated with purchases of electricity from alternate energy suppliers, provided however that payments from such suppliers due to their failure to perform or pursuant to contractual security provisions shall be credited to F above. F shall be credited with the revenues from sales for resale to interruptible customers pursuant to Schedule III-C and such sales shall be excluded from S.

As a signatory to the NEPOOL Agreement, dated as of September 1, 1971, as amended, the Company's reserve capacity criteria is

determined as a part of the NEPOOL reserve requirement. This type of interconnected pool operation avoids the need for member companies to individually determine reserve capacity criteria, while preserving individual company integrity through the basic NEPOOL Agreement. Each member utility's commitment to the Pool's requirements is assured by a monthly assessment of each members "Capability Responsibility", as defined in the NEPOOL Agreement. See also the NEPOOL Agreement, FERC Rate Schedule No. 210. In determining whether a purchase is a reliability purchase, the Company will use its then-applicable NEPOOL reserve requirement, regardless of whether the selling utility is a member of NEPOOL. In the event that a short term operating reserve purchase is made by NEPOOL and an assessable share is billed to NEP, NEP will include in this clause only the cost of fuel associated with such purchase. Part of the costs in evaluating the interchange with NEPEX (the NEPOOL dispatching agency) may initially be estimated. All energy savings shares that are created in the NEPEX dispatch are reflected in fuel costs. The value of the estimated costs will be combined with the value of the actual costs for the billing month to determine the monthly fuel clause factor. Any difference between the actual and estimated data for a billing month will be reflected in cost data utilized in the calculation for the succeeding month.

Notwithstanding the above, whenever the foregoing determination would be affected by energy produced from generating units under construction as they undergo operational tests prior to their in service dates, the components of F shall be adjusted so that its value is the same as it would have been if such test energy were not available. Such adjustment to F in the formula shall also recognize that current wholesale customers have paid a part of the cost of generating units under construction through demand charges reflecting CWIP in rate base; therefore, a credit to F shall be applied equal to the differential between the cost of test energy and the displaced cost of fuel in the ratio that demand contributions for such units bear to the carrying cost of such units.

In addition to the foregoing, F shall also include fifty percent (50%) of all natural gas transportation demand charges incurred for the period beginning November 1, 1991 and ending on the sooner to occur of January 1, 1996 or the conclusion of the construction period for the Manchester Street Station repowering project, provided, however, that revenues received from third parties related to their use of NEP's pipeline capacity during the foregoing period shall be credited to F above. Thereafter, all natural gas

transportation demand charges incurred shall be included in F above.

Once each calendar year, NEP shall reconcile the total incremental fuel costs of all short-term unit sales transactions, and sales pursuant to Schedule III-C, to fuel revenue from these transactions. If the total incremental fuel cost exceeds the fuel revenue, F shall be credited with the differential. The reconciliations shall be done in accordance with the procedures set forth in Dockets 92-372-000 et al. (unit power contracts) and Docket No. 94-1056-000 (Schedule III-C sales).

In accordance with a Surcharge Compliance Filing Settlement Agreement filed in Docket Nos. ER88-630-000, et al., a monthly charge for fuel expense underrecovery will be assessed all Customers except Massachusetts Electric Company, as shown at Appendix C to that Settlement Agreement. The foregoing charge will become effective as approved by the Commission and will continue thereafter for a period of ten (10) years, provided that if any of these Customers terminates service from NEP prior to the conclusion of the amortization period, that Customer shall pay its remaining unamortized fuel expense upon the date it terminates service. The monthly charge will be: Narragansett Electric - \$48,889, Granite State - \$6,499, Groveland - \$225, Merrimac - \$196, Littleton - \$535, Norwood - \$3,128, N.H. Elec. Coop - \$66, GMP - \$52, and Ft. Devens - \$540.

In accordance with the settlement of Docket No. FA91-53-000, F shall also include the 1.5% NEPEX differential billed to NEP by Central Maine Power for the use of low sulphur oil in the Wyman Units 1, 2, and 3 when Wyman 4 is operating.

Standard Delivery Point: For purposes of this Tariff, the “Standard Delivery Point” shall be considered to be that point on the integrated generating and transmission system of the Company that first follows one transformation from the power supply system or, by agreement of the parties, a point in close proximity thereto.

Metering Adjustments: Where delivery is metered at the Company’s supply line voltage, in no case less than 69,000 volts, thereby saving the Company transformer losses then, before determining the number of kilowatts and kilowatt-hours to be billed under the preceding provisions, there shall be deducted from the meter registrations of kilowatts and

kilowatt-hours for the month in question an amount respectively of one percent (1.0%) of such registrations. Where delivery is metered at the sub-transmission voltage, or at the low side terminals of the transformation from the sub-transmission to the distribution of the customer, and not at the low side terminals of the transformation from the Company's supply line, there shall be added to the meter registrations of kilowatts and kilowatt-hours for the month in question an amount respectively of one and one half percent (1.5%) of such registrations.

Transformer Ownership
Credit:

If delivery is made at the Company's supply line voltage, not less than 69,000 volts, and the Company is saved the cost of installing any transformer and associated equipment there will be allowed a credit of thirty cents (\$0.30) per kilowatt of the demand component at the point of delivery which enters into the computation of the Customer's Demand for the month in question. In accordance with a Settlement Agreement in Docket Nos. ER91-565-000, et al., the credit applicable to the Town of Norwood will be twenty-one cents (\$0.21) per kilowatt of the demand component at the point of delivery which enters into the computation of the Customer's Demand for the month in question. The foregoing credits, as applicable, shall be computed after the applicable Metering Adjustments.

Credit for EPRI
Contributions:

A credit of six cents (\$0.06) per kilowatt of the demand component will be allowed to all customers served under this schedule with the exception of the Company's affiliated customers (Massachusetts Electric Company, Narragansett Electric Company and Granite State Electric Company) in order to reflect the Company's commitment to research support of the Electric Power Research Institute (EPRI) unless a customer notifies the Company in writing that it desires to contribute through the Company's commitment, in which event this credit shall not apply to such Customer. In accordance with a Settlement Agreement in Docket Nos. ER91-565, et al., the credit applicable to the Town of Norwood will be nine cents (\$0.09) per kilowatt of the demand component at the point of delivery which enters into the computation of the Customer's Demand for the month in question. These credits shall be computed after the application of any applicable Metering Adjustments and at the point of delivery which enters into the computation of the Customer's Demand for the month in question.

Norwood Yankee:
Surcharge: In accordance with the terms of the W-12 Settlement Amendment dated December 17, 1992 in Docket No. ER90-525 et al., NEP shall apply a monthly surcharge to the Town of Norwood, equal to the amounts calculated in accordance with that settlement.

Norwood Seabrook 1
Amortization Surcharge: In accordance with the terms of the W-95(N) Settlement dated June 30, 1995 in Docket No. ER95-267 et al., NEP shall apply a monthly surcharge to the Town of Norwood, equal to the amounts calculated in accordance with section 2.2(b) of that settlement.

The Company reserves the right to amend the foregoing rate in the manner set forth in its General Terms and Conditions governing primary service for resale in Schedule I.

Effective Date: July 12, 1995

NEW ENGLAND POWER COMPANY

Primary Service for Resale

DETERMINATION OF CONTRACT TERMINATION CHARGE
UNDER EARLY TERMINATION PROVISION

A. Applicability

The terms and conditions of this Schedule II-C are applicable to any eligible all-requirements wholesale customer (“Customer”) of New England Power Company (“Company”) under this tariff which elects the early termination option under Schedule I, Section N of this tariff.

B. Determination of Contract Termination Charge

If a Customer exercises the early termination option under Schedule I, Section N, paragraph 2, of this tariff, the Customer shall pay the Company a Contract Termination Charge (“CTC”) as determined under this schedule. The CTC shall be determined as follows:

$$CTC = (R - M) \times L$$

where:

R = the Customer’s Annual Average Revenue, as determined in Section 1 below;

M = the Estimated Market Value of the Customer’s released capacity and associated energy, as determined under Section 2 below;

L = the Length of Obligation in years, as determined under Section 3 below;

Payment of the CTC by the Customer shall be in accordance with Schedule I, Section N, paragraph 2, of this tariff.

The CRC shall be determined on a net present value basis, with the difference between R

and M discounted to the Early Termination Date as defined in Section 3 below. The discount rate used shall equal the rate determined pursuant to section 35.19a of the Commission's regulations (18 C.F.R. § 35.19a) effective on the Early Termination Date.

In no event shall the CTC exceed the amount determined under section 4 below.

1. R – Average Annual Revenue

The Customer's Annual Average Revenue shall equal the Total Revenue minus the Transmission Revenue.

- a. Total Revenue shall equal the annual average of revenues received by the Company from the Customer over three years under the presently effective rates as shown on Schedule II-A and Schedule II-B of this tariff. The three-year period shall be the 36 months immediately prior to the Early Termination Date as specified by the Customer under the second paragraph of Schedule I, Section N of this tariff. In the event that the rates paid by the Customer under Schedule II-A or Schedule II-B of this tariff have changed during the three-year period, Total Revenue shall be determined using the Customer's revenue for the 12 months immediately prior to the Early Termination Date. The Company at its discretion may use estimates of the Customer's billing units for determining Total Revenue, such estimates to be reconciled to actual billing units within six months after the Early Termination Date. The calculation of Total Revenue shall include credits pursuant to Schedule III-D of this tariff as well as all credits and surcharges applicable to the Customer under the Customer's Service Agreement with the Company under this tariff, with the exception of credits associated with Integrated Facilities arrangements under Schedule III-B of this tariff and any credits associated with the Company's reimbursement of the Customer's payments to third parties for transmission service.
- b. Transmission Revenue shall equal the sum of: (i) the annual average of revenues the Company credited to the Customer with respect to payments made by the Customer to third parties for transmission service pursuant to any applicable provision of the service agreement between the Company and the Customer; or (ii) if the service agreement

does not provide for such credits, the annual average of revenues the Company would have received from the Customer using the presently effective rates under the Company’s Open Access Transmission Tariff, FERC Electric Tariff Original Volume No. 9 (“Tariff No. 9”); and (iii) the annual average of payments made by the Company to the New England Power Pool (“NEPOOL”) for transmission service on the Customer’s behalf under NEPOOL’s Open Access Transmission Tariff, all as determined during the period over which the Total Revenue is determined. The Company at its discretion may use estimates of the Customer’s billing units for determining Transmission Revenue, such estimates to be reconciled to actual billing units within six months after the Early Termination Date.

2. M – Estimated Market Value

The Estimated Market Value shall equal the annual average of the Market Price Estimate for each year of the Length of Obligation (as determined pursuant to Section 3 below) multiplied by the Customer’s Released Load.

- a. *Market Price Estimate* shall equal the per kilowatt-hour amount set forth in the Table below, as in effect on the Early Termination Date, as applicable to each year during the Length of Obligation. The Market Price Estimate shall include both a capacity-related and energy-related component.

<u>Year</u>	<u>Capacity (¢/kWh)</u>	<u>Energy (¢/kWh)</u>	<u>Total (¢/kWh)</u>
1998	1.10	2.71	3.81
1999	1.22	2.64	3.86
2000	1.22	2.66	3.88
2001	1.25	2.61	3.86
2002	1.31	2.63	3.94
2003	1.34	2.71	4.05
2004	1.40	2.72	4.12
2005	1.44	2.77	4.21
2006	1.47	2.86	4.33
2007	1.53	2.95	4.48
2008 forward		prices for 2007 escalated at 2% annually	

- b. *Released Load* shall equal the annual average of the Customer's kilowatt-hour purchases from the Company for the period over which Total Revenue is determined. The Company at its discretion may use estimates of the Customer's kilowatt-hour purchases for determining Released Load, such estimates to be reconciled to actual purchases within six months after the Early Termination Date.

3. L – Length of Obligation

The Length of Obligation shall equal the time period between the Early Termination Date and the Regular Termination Date.

- a. *Early Termination Date* shall be as determined under Schedule I, Section N, paragraph 2 of this tariff
- b. *Regular Termination Date* shall be the date at which the Company or the Customer could have unilaterally terminated service under Schedule I, Section N, paragraph 1 of this tariff and any applicable provisions of the Customer's Service Agreement with the Company under this tariff.

4. Maximum Contract Termination Charge

In no event shall the difference between R and M (as determined in Sections 1 and 2 above) exceed the Customer's annual contribution to the Company's fixed power supply costs under this tariff. The Customer's annual contribution to the company's fixed power supply costs shall equal its Total Revenue minus Transmission Revenue minus the Company's Average Fuel Costs. Average Fuel Costs shall equal the annual average of revenues the Company recovered for its Cost of Fuel as defined in Schedule II-A of this tariff multiplied by the Customer's monthly kilowatt-hour purchases during the period over which Total Revenue is determined in Section 1 above.

NEW ENGLAND POWER COMPANY

Schedule III-A

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NEW ENGLAND POWER COMPANY

Primary Service for Resale

TERMS AND CONDITIONS

governing

ALL-REQUIREMENTS SERVICE - INTEGRATED FACILITIES

Schedule III-B

A. Applicability

The terms and conditions set forth herein shall apply when the Service Agreement is between the Company and a Customer which is affiliated with the New England Power Company, and specifies All-Requirements Service - Integrated Facilities.

B. Integrated facilities: Obligations of the parties.

Recognizing that the generation and transmission facilities owned by the Company and the Customer are physically interconnected and can be operated to achieve maximum economy through integrated operation, the Customer and the Company agree as follows:

1. The Customer will operate and maintain its generating and transmission facilities in accordance with standards fixed from time to time by the Company, and will make available to the Company the full capacity of such facilities to meet the load of the integrated generating and transmission system (consisting of the generating and transmission facilities owned by the Company and affiliated companies of the New England Power Company). The Company and the Customer may agree to exclude from the facilities made available as aforesaid any facilities deemed not to be necessary or feasible for integration, and such excluded facilities shall not be considered part of the integrated generating and transmission system as defined above.
2. The generating and transmission facilities of the Customer made available to the Company under paragraph 1 shall be subject to dispatch by the Company to meet the load of the integrated generating and transmission system, and the output of the Customer's generating units so dispatched shall be deemed to be for the account of the Company. The Customer will conform to maintenance schedules fixed by the Company to ensure maximum availability of capacity.
3. The Company and the customers whose facilities constitute a part of the integrated generating and transmission system will plan jointly for the future requirements of such system. The Customer agrees to make additions to and retirements of its generating and transmission facilities in accordance with

schedules fixed from time to time by the Company.

4. In consideration of the foregoing, the Company assumes responsibility for the supply of the electrical requirements of the Customer from the integrated generating and transmission system, including transmission losses over such system, and agrees to credit the Customer for the use of its generating and transmission facilities, in accordance with the following provisions:
 - a. The Company agrees to sell and the Customer agrees to buy, at the Company's effective rate for primary service for resale, the Customer's entire requirements of electricity for its own use and for resale within the Districts described in the Service Agreement, with the following exceptions: (1) electricity purchased by the Customer from commercial and industrial establishments located within any District of the Customer's service area and specified in the Service Agreement, (2) electricity purchased by the Customer under convenience contracts for the supply of electricity to borderline customers, and (3) such other exceptions as may be mutually agreed upon between the parties and set forth in the Service Agreement.
 - b. For Customer-owned Transmission Plant, the Company will credit each monthly bill rendered to the Customer using the calculation shown below based on the previous month's cost data from Customer's official books and records. Capitalized terms used in this calculation will have the following definitions:
 1. Gross Transmission Plant Allocation Factor shall equal the ratio of Customer's Total Investment in Transmission Plant to Total Plant in Service, excluding General Plant.
 2. PTF Allocation Factor shall equal the ratio of PTF Transmission Plant to Transmission Plant.
 3. PTF-RSP Allocation Factor shall equal the ratio of PTF-RSP Transmission Plant to Transmission Plant.
 4. Transmission Wages and Salaries Allocation Factor shall equal the ratio of Transmission-related direct electric wages and salaries from Customer to Customer's total electric direct wages and salaries and excluding electric administrative and general wages and salaries.
 5. Administrative and General Expense shall equal Customer's electric expenses as recorded in FERC Account Nos. 920-935, less Post Employment Benefits Other than Pensions ("PBOP") included in FERC Account 926, plus the FERC-accepted Post Employment

Benefit Other than Pensions identified in each Customer's Service Agreement or any other amount subsequently approved by FERC under Section 205 of the Federal Power Act.

6. Amortization of Investment Tax Credits shall equal Customer's electric credits as recorded in FERC Account No. 411.4.
7. Amortization of Loss on Reacquired Debt shall equal Customer's electric expenses as recorded in FERC Account No. 428.1.
8. Depreciation Expense for Transmission Plant shall equal Customer's electric transmission plant related depreciation expenses as recorded in FERC Account No. 403 calculated using the depreciation rates set forth in each Customer's Service Agreement.
9. General Plant shall equal Customer's electric gross general plant balance as recorded in FERC Account Nos. 389-399.
10. General Plant Depreciation Expense shall equal Customer's electric general plant related depreciation expenses as recorded in FERC Account No. 403.
11. General Plant Depreciation Reserve shall equal Customer's electric general plant depreciation reserve balance as recorded in FERC Account No. 108.
12. Municipal Tax Expenses shall equal Customer's electric transmission-related municipal tax expense as recorded in FERC Account No. 408.1.
13. Payroll Taxes shall equal those electric payroll tax expenses as recorded in Customer's FERC Account Nos. 408.1.
14. Land Held for Future Use shall equal the Customer's electric transmission-related balance for Land in FERC Account No. 105.
15. Prepayments shall equal Customer's electric prepayment balance as recorded in FERC Account No. 165.
16. PTF-RSP Transmission Plant shall equal any PTF Transmission Plant as defined below and approved as part of the ISO-NE Regional System Plan.
17. PTF Transmission Plant shall equal electric transmission plant as defined in Section II.49 of the ISO-NE OATT and determined in

accordance with Appendix A of Attachment F Implementation Rule, which is entitled "Rules for Determining Investment To Be Included in PTF."

18. Total Accumulated Deferred Income Taxes shall equal the net of Customer's electric deferred tax balance as recorded in FERC Account Nos. 281-283 and Customer's electric deferred tax balance as recorded in FERC Account No. 190, all excluding associated FAS 109 Accumulated Deferred Income Taxes and any Accumulated Deferred Income Taxes associated with pension-related regulatory assets or liabilities.
19. Total Loss on Reacquired Debt shall equal Customer's electric expenses as recorded in FERC Account 189.
20. Total Plant in Service shall equal Customer's total electric gross plant balance as recorded in FERC Account Nos. 301-399.
21. Total Transmission Depreciation Reserve shall equal Customer's electric transmission plant related depreciation reserve balance as recorded in FERC Account 108.
22. Transmission Operation and Maintenance Expense shall equal Customer's electric expenses as recorded in FERC Account Nos. 560-564 and 566-573 less any expenses recorded in FERC Accounts 561.4 and 561.8.
23. Transmission Plant shall equal Customer's electric gross plant balance as recorded in FERC Account Nos. 350-359.
24. Transmission Plant Materials and Supplies shall equal Customer's electric materials and supplies balance as recorded in FERC Account No. 154.
25. Transmission Related Taxes and Fees Charge shall include any fee or assessment imposed by any governmental authority on service provided which is not specifically identified under any other section contained herein.

In the event that the above-referenced FERC accounts are renumbered, renamed, or otherwise modified, the above sections shall be deemed amended to incorporate such renumbered, renamed, modified or additional accounts.

Calculation of Transmission Revenue Requirements

The monthly Transmission Revenue Requirement shall equal the sum of Customer's (A) Return

and Associated Income Taxes (including the Incremental Returns for PTF-RSP and PTF Investment), (B) Transmission Depreciation Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and General Expenses, (I) Direct Assignment Facilities Credit, (J) Transmission Related Taxes and Fees Charge, (K) Billing Adjustments, and (L) Annual True-Up Adjustment. The Incremental Return and Associated Income Taxes for PTF-RSP and PTF Investments shall be calculated using the investment base components specifically identified in Section A.(1) of the formula below.

- A. Return and Associated Income Taxes shall equal the product of each of the Transmission Investment Base (PTF-RSP, PTF and Non-PTF, respectively) and the Cost of Capital Rates applicable to each.
 1. Transmission Investment Base
 - (a) Total Transmission Investment Base shall be defined as a) Transmission Plant, plus (b) Transmission Related General Plant, plus (c) Transmission Land Held for Future Use, plus (d) Transmission Related Construction Work In Progress, less (e) Transmission Related Depreciation Reserve, less (f) Transmission Related Accumulated Deferred Taxes, plus (g) Transmission Related Loss on Reacquired Debt, plus (h) Transmission Prepayments, plus (i) Transmission Materials and Supplies, plus (j) Transmission Related Cash Working Capital.
 - (i) PTF-RSP Investment Base will be the monthly balances of PTF-RSP Transmission Plant, less the sum of (d) Transmission Related Depreciation Reserve and (e) Transmission Related Accumulated Deferred Income Taxes, multiplied by the PTF-RSP Allocation Factor.
 - (ii) PTF Transmission Investment Base will be the monthly balances of PTF Transmission Plant, less PTF-RSP Investment Base, plus the product of: PTF Allocation Factor multiplied by the sum of the [(b) Transmission Related General Plant, plus (c) Transmission Land Held for Future Use, less (d) Transmission Related Depreciation Reserve, less (e) Transmission Related Accumulated Deferred Income Taxes, plus (f) Transmission Related Loss on Reacquired Debt, plus (g) Transmission Prepayments, plus (h) Transmission Materials and Supplies, plus (i) Transmission Related Cash Working Capital].
 - (iii) Non-PTF Transmission Investment Base shall equal Total

Transmission Investment Base less PTF-RSP Investment
Base less PTF Investment Base.

- (b) Transmission Related General Plant shall equal Customer's balance of investment in electric General Plant multiplied by the Transmission Wages and Salaries Allocation Factor.
- (c) Transmission Land Held for Future Use shall equal Customer's balance of electric Transmission-related Land Held for Future Use.
- (d) Transmission Related Construction Work In Progress shall equal the portion of Customer's investment in Transmission-related projects as recorded in FERC Account 107 consistent with Commission orders.
- (e) Transmission Related Depreciation Reserve shall equal Customer's balance of Total Transmission Depreciation Reserve, plus the balance of Transmission Related General Plant Depreciation Reserve. Transmission Related General Plant Depreciation Reserve shall equal the product of General Plant Depreciation Reserve and the Transmission Wages and Salaries Allocation Factor.
- (f) Transmission Related Accumulated Deferred Income Taxes shall equal Customer's electric balance of Total Accumulated Deferred Income Taxes, multiplied by the Gross Transmission Plant Allocation Factor.
- (g) Transmission Related Loss on Reacquired Debt shall equal Customer's electric balance of Total Loss on Reacquired Debt multiplied by the Gross Transmission Plant Allocation Factor.
- (h) Transmission Prepayments shall equal Customer's electric balance of prepayments multiplied by the Gross Transmission Plant Allocation Factor.
- (i) Transmission Materials and Supplies shall equal Customer's electric balance of Transmission Plant Materials and Supplies, multiplied by the Gross Transmission Plant Allocation Factor.
- (j) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Customer's Transmission Operation and Maintenance Expense and Transmission-Related Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will incorporate Customer's imputed capital structure, Customer's actual cost of long-term debt and preferred equity, and approved ROEs for Transmission Investment Bases (PTF-RSP, PTF and Non-PTF, respectively), plus Federal Income Tax and State Income Tax, as applicable.

- a) The Weighted Costs of Capital will be calculated for each of the Transmission Investment Bases (PTF-RSP, PTF and Non-PTF, respectively) based upon the imputed capital structure for Customer in place in accordance with Rhode Island Docket Nos. 2930 and 3617 and will equal the sum of (i), (ii), and each ROE applied in item (iii) below.
 - (i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of Customer's long-term debt then outstanding and the imputed long-term debt capitalization ratio of 45%.
 - (ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of Customer's preferred stock then outstanding and the imputed preferred stock capitalization ratio of 5%.
 - (iii) the return on equity component (ROE), shall be the product of the allowed ROEs applicable to the corresponding investments below and the Customer's imputed common equity capitalization ratio of 50% consistent with FERC's Order on Rehearing issued on March 24, 2008 in FERC Docket Nos. ER04-157-004 and ER04-714-001 and FERC Opinion Nos. 531-A and 531-B issued in Docket No. EL11-66-000 et al., plus any additional incentive ROE adders as may be applied to specific investment approved by the FERC in response to requests for such adders filed by NEP pursuant to Order No. 679, provided that the total ROE for any project, including any such ROE incentives, shall be capped by the top of the applicable zone of reasonableness of 11.74% effective as of October 16, 2014, consistent with FERC Opinion Nos. 531-A and 531-B. To the extent FERC modifies ROEs as applicable to transmission services under the ISO New England Open Access Transmission Tariff, those Returns on Equity shall be applied to this calculation of the Transmission Revenue Requirement pursuant to a filing with FERC under Section 205 of the Federal Power Act.

11.74% - Post-2003 to pre-2009 PTF transmission plant investment included in the Regional System Plan approved by ISO-NE.

11.07% - The remaining PTF transmission plan investment.

10.57% - The remaining transmission plant investment.

(b) Federal Income Tax applied shall equal

$$\frac{(PS + ROE) \times \text{Federal Income Tax Rate}}{(1 - \text{Federal Income Tax Rate})}$$

where PS is the Preferred Stock Component and ROE is the return on equity component, each as determined in Sections 2.(a)(ii) and for the applied ROEs set forth in 2.(a)(iii) above.

(c) State Income Tax shall equal

$$\frac{((PS+ROE) + \text{Federal Income Tax}) \times \text{State Income Tax Rate}}{1 - \text{State Income Tax Rate}}$$

where PS is the Preferred Stock Component and ROE is the return on equity component in Section 2.(a)(ii) and Section 2.(a)(iii) above, Federal Income Tax is Federal Income Tax as determined in Section 2.(b) above.

- B. Transmission Depreciation Expense shall equal Customer's electric Depreciation Expense for Transmission Plant, plus an allocation of electric General Plant Depreciation Expense calculated by multiplying electric General Plant Depreciation Expense by the Transmission Wages and Salaries Allocation Factor.
- C. Transmission Related Amortization of Loss on Reacquired Debt shall equal Customer's electric Amortization of Loss on Reacquired Debt multiplied by the Gross Transmission Plant Allocation Factor.
- D. Transmission Related Amortization of Investment Tax Credits shall equal Customer's electric Amortization of Investment Tax Credits multiplied by the Gross Transmission Plant Allocation Factor.
- E. Transmission Related Municipal Tax Expense shall equal Customer's transmission-related electric municipal tax expense.

- F. Transmission Related Payroll Tax Expense shall equal Customer's total electric payroll tax expense, multiplied by the Transmission Wages and Salaries Allocation Factor.
- G. Transmission Operation and Maintenance Expense shall equal Customer's total electric Transmission Operation and Maintenance Expenses.
- H. Transmission Related Administrative and General Expenses shall equal the sum of Customer's electric Administrative and General Expenses multiplied by the Transmission Wages and Salaries Allocation Factor.
- I. Direct Assignment Facilities Credit shall equal the monthly revenue received by NEP for service provided to any of NEP's wholesale customers that utilize directly assigned transmission, distribution and/or generator interconnection facilities owned by Customer. Such NEP revenue is defined as any revenue NEP receives for Direct Assignment Facilities under the ISO-NE OATT or any interconnection-related charges for Customer-owned and/or maintained facilities under FERC jurisdictional agreements where NEP is the party to the agreement.
- J. Transmission Related Taxes and Fees Charge shall include any fee or assessment imposed by any governmental authority on service provided under this section, including, but not limited to, expenses incurred by the Customer related to third party independent audits conducted at the request of any governmental authority, and any other fee or assessment which is not specifically identified under any other section contained herein. Such costs will be separately identified and included in item H - Administrative and General Expense, above.
- K. Billing Adjustments shall be plus or minus any billing adjustments from the prior transmission billing periods. Billing adjustments shall include, but not be limited to, adjustments due to corrections to any value included in this formula, including, but not limited to, corrections to the FERC Form 1.
- L. Annual True-Up Adjustment
 - 1. NEP shall submit an annual informational filing with the FERC with copies to state commissions and attorneys general in the state of any affected Customer reconciling monthly billings to Customer under this formula to data supplied from Customer's Quarterly FERC Form 1 (the "Annual True-up"). The Annual True-up will be completed no later than (3) months after Customer issues its final 4th Quarter FERC Form 1 for the calendar year which the Annual True-up relates (the "Service Year"). The Annual True-up will reconcile any differences between a recalculation of the costs for the Service Year based on actual data reported in Customer's Quarterly FERC Form 1's as compared to the monthly actual costs invoiced. The recalculation of the costs for the Service Year will be done using the average quarterly balances for all

balance sheet items used in the formula (i.e. Plant, Depreciation Reserve, Deferred Taxes). Expenses will be those Service Year expenses reported in Customer's 4th Quarter FERC Form 1.

2. The difference, if any, between the monthly actual costs invoiced to Customer during the Service Year and the annual revenue requirement based on actual FERC Form 1 data shall be reflected as an adjustment to the monthly revenue requirement calculation for the month following the month in which the Annual True-Up report is issued (the "Annual True-up Adjustment").
3. If the recalculation of costs for the Service Year using FERC Form 1 data exceeds the monthly billed amounts for the Service Year, the Annual True-up Adjustment will be an additional credit to Customer. If the monthly billed amounts for the Service Year exceed the recalculation of costs using FERC Form 1, the Annual True-up Adjustment will be a reduction to the credit to Customer. The Annual True-up Adjustment will be adjusted for interest, whether positive or negative, accrued monthly from December 31 of the Service Year to the end of the calendar month in which the Annual True-up Adjustment will be applied to a monthly billing. Interest shall accrue pursuant to the rate specified in the Commission's regulations 18 C.F.R §35.19a.
4. Any changes to the data inputs, including but not limited to revisions to Customer's FERC Form No. 1, or as the result of any FERC proceeding to consider the Annual True-up, or as a result of the procedures set forth herein not otherwise captured as part of ongoing Billing Adjustments, shall be incorporated into the formula rate and the charges produced by the formula rate (with interest determined in accordance with 18 C.F.R. § 35.19a) in the Annual True-up for the next effective rate period.
5. In any proceeding before the FERC concerning the Annual True-up, the Company shall bear the burden, consistent with Section 205 of the Federal Power Act, of proving that it has correctly applied the terms of the formula rate. Nothing herein is intended to alter the burdens applied by the Commission with respect to prudence challenges.

M. Five-Year Forecast

The Company's annual informational filing will also provide a report containing a five year forecast of anticipated transmission capital expenditures by the Company and its Customers taking service under this Tariff that will, upon completion of projects, be included in transmission rates. The forecast will also include the estimated retail rate impacts for each of the Company's respective Customers under this Schedule III-B.

N. Audit Provisions

1. There will be an “Audit Period” that will extend from the date the informational filing is filed with FERC through December 31 of the year following the Service Year. At any time during the Audit Period, a Customer shall have the right to request an audit or conduct an inspection of the actual data used in the Annual True-Up and any and all transmission charges or credits billed by Company during the Service Year. Subject to the limitation that the Attorneys General of Massachusetts and Rhode Island do not make or receive transmission payments or refunds, they shall have the same procedural rights under this Section as a Customer. Company shall not withhold information, including PBOP information, on grounds of confidentiality, but is entitled to make such information available pursuant to a confidentiality agreement and to restrict access to non-competitive duty personnel and to other personnel as prescribed by FERC. Company is not obligated to disclose privileged information or information protected by the attorney work product doctrine. Company shall exercise all commercially reasonable efforts to provide Customer, within 10 business days, such additional information as Customer may reasonably request. To the extent requested, Company shall meet with any Customer to provide such additional information, explanation, and/or clarification regarding the Annual True-Up or any other information related to Customer billing under this Tariff during the Service Year. During the Audit Period any Customer may request that Company adjust the Annual True-up Adjustment and/or Customer bills rendered during the Service Year. Any adjustment that Company agrees to make may be reflected in the next month following such adjustment. Upon request of any Customer during the Audit Period, Company shall engage a third party independent auditor (the “Auditing Entity”) through the process described in Paragraph 4, below. The Auditing Entity shall certify that the development, accuracy and application of data, is in accordance with the provisions of this Tariff. The Auditing Entity shall provide a Certified Public Accountant’s attestation setting forth such certification (“CPA Attestation”).
2. In addition to the CPA Attestation, the Auditing Entity will provide an audit report that will specify the audit process and procedures; identify the individual auditors and their functions; and include all copies of all written communications with Company personnel, summaries of all other communications related to the audit, descriptions of all data analysis techniques used, findings and recommendations. Also, the Auditing Entity shall make available all workpapers and other documentation and materials that support the CPA Attestation.
3. Company shall engage the Auditing Entity to perform the CPA Attestation duties through a competitive bidding process, evaluating each bidder

according to cost, experience, competency and familiarity with the industry and the regulatory environment. The requesting Customer(s) shall have the right to approve the content of the Request for Proposal and Company's selection of the auditing entity, which approval shall not be unreasonably withheld. If necessary, and after good faith efforts have not resulted in the Company's obtaining an Auditing Entity to provide the CPA Attestation pursuant to this Paragraph 4, the requesting Customer(s) and the Company agree to negotiate in good faith the scope of work that may be needed to provide a CPA Attestation and to accommodate the American Institute of Certified Public Accountants Code of Professional Conduct.

4. In the event an independent audit is performed with respect to a Service Year and the Company determines that the Annual True-Up is incorrect, the Annual True-Up required by Paragraph L of this Tariff may be subsequently adjusted pursuant to the provisions of this Tariff.
5. The reasonable and prudent cost of the Auditing Entity's services and Company's reasonable and prudent costs of engaging the Auditing Entity and providing information to the Auditing Entity and the Customer shall be included as part of the transmission costs charged to the Customers under this Tariff.

Formula rate inputs for rate of return on common equity, depreciation rates and Post-Employment Benefits Other than Pensions (PBOP) shall be stated values until changed pursuant to an FPA Section 205 or 206 filing made effective by the Commission. Application under Section 205 or 206 to modify stated values for depreciation rates or PBOP expense under the formula rate shall not open review of other components of the formula rate.

Calculation of Primary Distribution Revenue Requirements

For Customer-owned distribution facilities utilized by the Company for purposes of providing wholesale transmission service, effective as of the June billing month of each year, the Company will credit each monthly bill rendered to the Customer with one-twelfth of the annual costs determined by multiplying the sum of the applicable Customer's: (i) Distribution Plant Assets; (ii) Shared Substation Assets, and; (iii) Buildings and Facilities, each as set forth in the Customer's Service Agreement, by the Primary Distribution Carrying Charge based upon previous calendar year data. The Primary Distribution Carrying Charge shall be calculated as follows for the applicable Customer:

I. The Primary Distribution System Carrying Charge shall be calculated annually based on actual calendar year data as reported in the FERC Form 1 and shall equal the sum of (A) Return and Associated Income Taxes, (B) Primary Depreciation Expense, (C) Primary Related Amortization of Loss on Reacquired Debt, (D) Primary Related Amortization of Investment Tax Credits, (E) Primary Related Municipal Tax Expense, (F) Primary Operation and Maintenance Expense, (G) Primary Related Administrative and General Expense, and (H) Primary Revenue Credit, divided by Total Primary Distribution Plant.

A. Return and Associated Income Taxes shall equal the product of the Primary Investment Base and the Cost of Capital Rate.

1. Primary Investment Base

Primary Investment Base will be (a) Primary Distribution Plant, plus (b) Primary Related General Plant, plus (c) Primary Plant Held for Future Use, less (d) Primary Depreciation Reserve, less (e) Primary Related Accumulated Deferred Income Taxes, plus (f) Primary Related Loss on Reacquired Debt, plus (g) Primary Materials and Supplies, plus (h) Primary Related Prepayments, plus (i) Primary Related Cash Working Capital.

a) Primary Distribution Plant shall equal the Customer's Plant Accounts 360 to 373 multiplied by allocation factors from the Distribution Allocation Study.

b) Primary Related General Plant shall equal the Customer's Investment in General Plant excluding investment in specific buildings and facilities allocated to Company, multiplied by the Primary Wages & Salaries Allocation Factor. The Primary Wages & Salaries Allocation Factor shall equal the ratio of Total Distribution Wages & Salaries to the Total Customer's Wages & Salaries excluding A&G, multiplied by the ratio of Primary Distribution related O&M to Total Distribution O&M (Primary O&M Allocation Factor).

c) Primary Plant Held for Future Use shall equal the

Customer's Account 105, multiplied by the Primary Land Allocation Factor from the Distribution Allocation Study.

d) Primary Depreciation Reserve shall equal the Customer's Depreciation Reserve multiplied by the ratio of Primary Depreciable Distribution Plant to Total Depreciable Distribution Plant (Primary Depreciable Plant Allocation Factor), plus an allocation of average General Plant Depreciation Reserve calculated by multiplying beginning and end of year General Plant Depreciation Reserve by the Primary Wages and Salaries Allocation Factor described in Section (I)(A)(1)(b) above,

e) Primary Related Accumulated Deferred Income Taxes shall equal the Total Accumulated Deferred Income Taxes, multiplied by the ratio of average Primary Plant in Service to average Total Plant in Service excluding General Plant (Primary Plant Allocation Factor).

f) Primary Related Loss on Reacquired Debt shall equal the Total Loss on Reacquired Debt, multiplied by the Primary Plant Allocation Factor described in Section (I)(A)(1)(e) above.

g) Primary Materials and Supplies shall equal the Customer's Distribution Plant Materials and Supplies, multiplied by the Primary O&M Allocation Factor as described in Section (I)(A)(1)(b) above.

h) Primary Related Prepayments shall equal the Customer's Prepayments, multiplied by the Primary Wages and Salaries Allocator described in Section (I)(A)(1)(b) above.

i) Primary Related Cash Working Capital shall be a 45 day allowance or 12.5% of Primary Operation and Maintenance Expense and Primary Related Administrative and General Expense.

2. Cost of Capital Rate

Cost of Capital Rate will equal (a) the Customer's Weighted Cost of Capital, plus (b) Federal Income Tax, plus (e) State Income Tax.

a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of:

(i) the long-term debt component, which equals the product of the actual dollar weighted average embedded cost to maturity of the Customer's long-term debt then outstanding and the imputed long-term debt capitalization

ratio of 45 percent.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of the Customer's preferred stock then outstanding and the Imputed preferred stock capitalization ratio of 5 percent.

(iii) the return on equity component (ROE), shall be the product of the allowed ROEs of 10.57% as per FERC's Order on Rehearing Issued on March 24, 2008 in FERC Docket Nos. ER04-157-004 and ER04-714-001 and FERC Opinion Nos. 531-A and 531-B issued in Docket No. EL11-66-000 et al. and Customer's imputed common equity capitalization ratio of 50%, plus any additional incentive ROE adders as may be applied to specific investment approved by the FERC in response to requests for such adders filed by NEP pursuant to Order No. 679, provided that the total ROE for any project, including any such ROE incentives, shall be capped by the top of the applicable zone of reasonableness of 11.74% effective as of October 16, 2014, consistent with FERC Opinion Nos. 531-A and 531-B. To the extent FERC modifies ROEs as applicable to transmission services under the ISO New England Open Access Transmission Tariff, those Returns on Equity shall be applied to this calculation of the Transmission Revenue Requirement pursuant to a filing with FERC under Section 205 of the Federal Power Act.

b) Federal Income Tax shall equal

$$\frac{A \times \text{Federal Income Tax Rate}}{1 - \text{Federal Income Tax Rate}}$$

where A is the sum of the preferred stock component and the return on equity component determined in Section (I)(A)(2)(a)(ii) and Section (I)(A)(2)(a)(iii) above.

c) State Income Tax shall equal

$$\frac{(A + \text{Federal Income Tax}) \times \text{State Income Tax Rate}}{1 - \text{State Income Tax Rate}}$$

where A is the sum of the preferred stock component and the return on equity component determined in Section (I)(A)(2)(a)(ii) and Section (I)(A)(2)(a)(iii) above, and Federal Income Tax is the Federal Income Tax as determined in Section (I)(A)(2)(b) above.

- B. Primary Depreciation Expense shall equal Customer's electric distribution-related depreciation expense as recorded in FERC Account No. 403 calculated using the depreciation rates set forth in each Customer's Service Agreement, multiplied by the Primary Depreciable Plant Allocation Factor as described in Section (I)(A)(1)(d) above, plus an allocation of General Plant Depreciation Expense calculated by multiplying General Plant Depreciation Expense by the Primary Wages and Salaries Allocation Factor described in Section (I)(A)(1)(b) above.
- C. Primary Related Amortization of Loss on Reacquired Debt shall equal the Customer's Amortization of Loss on Reacquired Debt, multiplied by the Primary Plant Allocation Factor described in Section (I)(A)(1)(e) above.
- D. Primary Related Amortization of Investment Tax Credits shall equal the Customer's Amortization of Investment Tax Credits, multiplied by the Primary Plant Allocation Factor described in Section (I)(A)(1)(e) above.
- E. Primary Related Municipal Tax Expense shall equal a pro-rata share of the Customer's total municipal taxes allocated by the Primary Plant Allocation Factor described in Section (I)(A)(1)(e) above.
- F. Primary Operation and Maintenance Expense shall be the sum of all expenses charged to FERC Account Numbers 580 through 598, allocated to Primary as indicated by the Distribution Allocation Study.
- G. Primary Related Administrative and General Expenses shall equal the Customer's Administrative and General Expenses, plus Payroll Taxes, multiplied by the Primary Wages & Salaries Allocation Factor described in Section (I)(A)(1)(b) above.
- H. Primary Related Revenue Credit shall equal Customer's Other Operating Revenues excluding any revenues from network distribution transactions, multiplied by the Primary O&M Allocation Factor as defined in (I)(A)(1)(b).

For Company-owned facilities utilized by the Customer for purposes of providing retail distribution service, effective as of the June billing month of each year, the Company will net from the Primary Distribution Revenue Requirement credit applied to each monthly bill rendered to the Customer one-twelfth of Company's annual costs determined by multiplying the sum of the Company's: (i) Transmission Assets (ii) Distribution Plant Assets; (iii) Shared Substation Assets, and; (iv) Buildings and Facilities, each as set forth in the Customer's Service Agreement, by the Annual Facilities Carrying Charge for Transmission Facilities - based upon previous calendar year data. In addition, the Company will net from the Primary Distribution Revenue Requirement credit applied to each monthly bill rendered to the Customer one-twelfth of

Company's annual cost for pole and tower attachments. The Annual Facilities Charge for Transmission Facilities shall be calculated as follows:

1. The Annual Facilities Carrying Charge for Transmission Facilities shall be calculated annually based on actual calendar year data as reported in the FERC Form 1 and shall equal the sum of (A) Return and Associated Income Taxes, (B) Transmission Related Depreciation Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Operation and Maintenance Expense, and (G) Transmission Related Administrative and General Expenses, divided by Total Transmission Plant.

A. Return and Associated Income Taxes shall equal the product of the Transmission Investment Base and the Cost of Capital Rate.

1. Transmission Investment Base

Transmission Investment Base will be (a) Transmission Plant, plus (b) Transmission Related General Plant, plus (c) Transmission Plant Held for Future Use, plus (d) Transmission-related Construction Work in Progress, less (e) Transmission Related Depreciation Reserve, less (f) Transmission Related Accumulated Deferred Income Taxes, plus (g) Transmission Related Loss on Reacquired Debt, plus (h) Transmission Related Materials and Supplies, less (i) Allowance for Funds Used During Construction (AFUDC) Regulatory Liability, plus (j) Transmission Related Prepayments, plus (k) Transmission Related Cash Working Capital.

a) Transmission Plant shall equal NEP's balance of Total Investment in Transmission Plant in FERC Accounts 350 - 359, plus NEP's Total Investment in Distribution Plant in FERC Accounts 360-369 excluding NEP's capital leases in the Hydro-Quebec DC facilities (HQ leases).

b) Transmission Related General Plant shall equal NEP's balance of investment in General Plant in FERC Accounts 389 to 399 excluding General Plant related to NEP's generation facilities.

c) Transmission Plant Held for Future Use shall equal the balance of investment in FERC account 105 excluding generation-related plant held for future use.

d) Transmission Related Construction Work in Progress shall equal the portion of NEP's investment in Transmission related projects as recorded in FERC Account 107 consistent with Commission Orders.

- e) Transmission Related Depreciation Reserve shall equal the balance of Total Depreciation Reserve in FERC Account 108, excluding any generation-related depreciation reserve.
- f) Transmission Related Accumulated Deferred Income Taxes shall equal the net of NEP's Total Accumulated Deferred Income Taxes in FERC Accounts 281-283 and FERC Account 190, all excluding associated FAS 109 Accumulated Deferred Income Taxes and any Accumulated Deferred Income Taxes associated with pension-related regulatory assets or liabilities and any Accumulated Deferred Taxes associated with non-utility assets or generation facilities.
- g) Transmission Related Loss on Reacquired Debt shall equal NEP's balance of Total Loss on Reacquired Debt in FERC Account 189.
- h) Transmission Related Materials and Supplies shall equal NEP's balance of Materials and Supplies in FERC Account 154.
- i) AFUDC Regulatory Liability shall equal the unamortized balance of the capitalized AFUDC booked on NEP's Transmission-related projects as recorded in FERC Account 254 consistent with Commission Orders.
- j) Transmission Related Prepayments shall equal NEP's balance of prepayments in FERC Account 165 excluding any prepayments related to NEP's ongoing generation-related activities.
- k) Transmission Related Cash Working Capital shall be 12.5% allowance (45 days/360) of Transmission Operation and Maintenance Expense and Transmission Related Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate shall equal (a) NEP's Weighted Cost of Capital, plus (b) Federal Income Tax, plus (c) State Income Tax.

- a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of:
 - (i) the long-term debt component, which equals the

product of the actual dollar weighted average embedded cost to maturity of NEP's long-term debt then outstanding and the imputed long-term debt capitalization ratio of 45 percent.

(ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of NEP's preferred stock then outstanding and the imputed preferred stock capitalization ratio of 5 percent.

(iii) the return on equity component (ROE) shall be the product of 10.57% as per FERC's Order on Rehearing issued on March 24, 2008 in FERC Docket Nos. ER04-157-004 and ER04-714-001 and FERC Opinion Nos. 531-A and 531-B issued in Docket No. EL11-66-000 et al., and NEP's imputed common equity capitalization ratio of 50%. To the extent FERC modifies ROEs as applicable to transmission services under the ISO New England Open Access Transmission Tariff, those Returns on Equity shall be applied to this calculation of the Transmission Revenue Requirement pursuant to the filing with FERC under Section 205 of the Federal Power Act.

b) Federal Income Tax shall equal

$$\frac{A \times \text{Federal Income Tax Rate}}{1 - \text{Federal Income Tax Rate}}$$

Where A is the sum of the preferred stock component and the return on equity component determined in Section (1)(A)(2)(a)(ii) and Section (1)(A)(2)(a)(iii) above.

c) State Income Tax shall equal

$$\frac{(A + \text{Federal Income Tax}) \times \text{State Income Tax Rate}}{1 - \text{State Income Tax Rate}}$$

Where A is the sum of the preferred stock component and the return on equity component determined in Section (1)(A)(2)(a)(ii) and Section (1)(A)(2)(a)(iii) above, and the Federal Income Tax is Federal Income Tax as determined in Section (1)(A)(2)(b) above.

B. Transmission Related Depreciation Expense shall equal the Depreciation Expense in FERC Account 403 associated with Transmission Plant, Transmission Related General Plant and Transmission Plant Held for Future Use as described in Sections (1)(A)(1)(a),(b) and (c), less the amortization of AFUDC Regulatory

Liability as recorded in FERC Account 407.3.

- C. Transmission Related Amortization of Loss on Reacquired Debt shall equal NEP's amortization of the balance on Loss on Reacquired Debt recorded in FERC Account 428.1.
- D. Transmission Related Amortization of Investment Tax Credits shall equal the amortization of Investment Tax Credits recorded in FERC Account 411.4, excluding any ITC credits specifically identified as generation-related.
- E. Transmission Related Municipal Tax Expense shall equal NEP's total municipal tax expense recorded in FERC Account 408.1 excluding specifically identified generation-related municipal taxes or payments in lieu of such generation-related municipal taxes.
- F. Transmission Operation and Maintenance Expense shall equal all expenses charged to FERC Account Numbers 560 through 598. Account Number 565, Transmission by Others, shall only include those expenses in support of facilities that are integrated with NEP's Transmission System or other transmission systems.
- G. Transmission Related Administrative and General Expenses shall equal NEP's Administrative and General Expenses recorded in FERC Accounts 920-935, less production-related Administrative and General Expenses associated with joint-owned production units, plus Payroll Taxes.

The Company's rate for tower attachments is \$49.28 per tower. The Company's rate for pole attachments is \$253.27 per pole. The annual cost for the Customer to attach to the Company's towers and poles will be the product of the respective rate multiplied by the number of respective attachments as specified in the Customer's Service Agreement.

The Customer shall afford to the Company the opportunity at any time to make such reasonable examination of the Customer's books and records as the Company may request for the purpose of verifying the basis for calculation of the foregoing monthly credits.

The foregoing credits shall be reviewed annually and upon substantial addition, modification or retirement of the Customer's generating and transmission facilities or other substantial change in circumstances, any changes therein shall be reflected in a revised Service Agreement.

C. Service Agreement Amendments.

If the Service Agreement is amended by mutual consent of the parties, the terms of the agreement as so amended shall be applicable to the Customer's service on and after the effective

date specified therein. If no such amendment has been executed prior to the date specified in the Customer's notice, the Customer may at its election terminate the Service Agreement forthwith or upon such date within the following twelve months as it may specify to the Company in writing.

D. Tariff Amendments.

The Company reserves the right to amend the foregoing terms and conditions in the manner set forth in its General Terms and Conditions governing primary service for resale.

NEW ENGLAND POWER COMPANY

Schedule III-C

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NEW ENGLAND POWER COMPANY

Primary Service for Resale
and Transmission Service
for Partial Requirements Customers

FORM OF SERVICE AGREEMENT

Dated:

Parties: NEW ENGLAND POWER COMPANY
A Massachusetts corporation (the “Company”)

20 Turnpike Road
Westborough, Massachusetts 01581

and

(the “Customer”)

1. Scope of Service Agreement. The Company agrees to sell and transmit and the Customer agrees to buy Primary Service for Resale on the terms set forth in the following Schedules as in effect from time to time:

Schedule I	- General Terms and Conditions
Schedule II	- Rate Provisions
Schedule III	- Terms and Conditions Governing Service

These Schedules and Appendix A to this Service Agreement are expressly included as part of this Agreement.

2. Prior agreements. As of the date of commencement of service hereunder, this Service Agreement shall supersede and cancel all prior contracts between the parties for the type(s) of service specified herein with the following exceptions:

WITNESS the corporate names of the parties, by their proper officers thereunto duly authorized, as of the date first above written.

Executed in duplicate.

NEW ENGLAND POWER COMPANY

By _____
Vice-President

APPENDIX A

NEW ENGLAND POWER COMPANY

Primary Service for Resale
and
Transmission Service for Partial Requirements Customers

1. Name of Customer:
2. Name of District:
3. Service Under:
4. Electric Utilities Served by the Customer
as of the date of the Service Agreement:
(Schedule I - Paragraph D)
5. Electricity Purchased from Commercial
and Industrial Establishments by the
Customer as of the date of the Service
Agreement:
(Schedule I - Paragraph D)
6. Variations from Standard Delivery and
Metering:
(Schedule I - Paragraph G, 5)
7. Entitlements:
 - A. On Customer System
(Schedule III-C - Paragraph C.2.(a))
 - B. Off Customer System
(Schedule III-C - Paragraph C.2.(b))
8. Customer Generation excluded from

Firm Capacity Calculation:

(Schedule III-C - Paragraph C.3.c)

9. Firm Capacity:

(Schedule III-C - Paragraph C.3.c)

10. Integrated Generating, Transmission
 and Facilities Credits Payable by

Company:

(Schedule III-B - Paragraph B.4.b)

11. Primary Service for Resale:

<u>Delivery Points</u>	<u>Delivery Pressure KV (Nominal)</u>	<u>Metering Points</u>	<u>Metering Pressure KV (Nominal)</u>	<u>Metering Adjustments</u>	<u>Delivery Adjustments</u>
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12. Minimum Demand KW: None

13. Minimum Term: None

14. Transmission Service for Partial Requirements Customers:

<u>Transmission Delivery Point(s)</u>	<u>KV (Nominal)</u>	<u>Subtransmission Delivery Point(s)</u>	<u>KV (Nominal)</u>
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TRANSMISSION OPERATING AGREEMENT

TRANSMISSION OPERATING AGREEMENT

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Schedule 11.19(c). Additional Conditions Precedent

TRANSMISSION OPERATING AGREEMENT

This Transmission Operating Agreement (this “TOA” or this “Agreement”), dated as of February 1, 2005, is made and entered into by and among Bangor Hydro-Electric Company; Town of Braintree Electric Light Department; Boston Edison Company, Cambridge Electric Light Company, Canal Electric Company, and Commonwealth Electric Company; Central Maine Power Company; Central Vermont Public Service Corporation; Connecticut Municipal Electric Energy Cooperative; The City of Holyoke Gas and Electric Department; Florida Power & Light Company; Green Mountain Power Corporation; Massachusetts Municipal Wholesale Electric Company; New England Power Company; New Hampshire Electric Cooperative, Inc.; Northeast Utilities Service Company as agent for: The Connecticut Light and Power Company, Western Massachusetts Electric Company, Holyoke Power and Electric Company; Holyoke Water Power Company; and Public Service Company of New Hampshire; Norwood Municipal Light Department; Town of Reading Municipal Light Department; Taunton Municipal Lighting Plant; The United Illuminating Company; Unitil Energy Systems, Inc. and Fitchburg Gas and Electric Light Company; Vermont Electric Cooperative, Inc; and Vermont Electric Power Company, Inc. (herein collectively referred to as the “Initial Participating Transmission Owners”), and the Initial Participating Transmission Owners along with the Vermont Public Power Supply Authority, Vermont Transco LLC and any other Additional Participating Transmission Owners (as defined in Section 11.05 of this Agreement), are collectively referred to herein as the “PTOs” and individually each is referred to as a “PTO”, and ISO New England Inc. (“ISO”), a Delaware corporation (all PTOs and the ISO are collectively referred to herein as the “Parties”).

WHEREAS, each of the PTOs owns and/or operates certain transmission facilities that are interconnected with the transmission facilities of certain other PTOs within the New England Transmission System or otherwise provides transmission service within the New England Transmission System;

WHEREAS, the ISO is a regional transmission organization (“RTO”) authorized by the Federal Energy Regulatory Commission (“FERC”) to exercise the functions required of RTOs pursuant to FERC’s Order No. 2000 (“Order 2000”) and FERC’s RTO regulations;

WHEREAS, in accordance with the requirements of Order 2000, the ISO will be the transmission provider under the ISO Open Access Transmission Tariff (the “ISO OATT”) of non-discriminatory, open access transmission services over the transmission facilities of the PTOs (“Transmission Service”);

WHEREAS, the ISO OATT will be designed to provide for the payment by transmission customers for Transmission Service at rates designed to recover the revenue requirements of the PTOs in supporting the provision of such transmission service by the ISO under the ISO OATT;

WHEREAS, the ISO will be responsible for system planning within the ISO region subject to certain rights and obligations of the PTOs, all as set forth in this Agreement;

WHEREAS, the functions to be performed by the ISO and Order 2000 require that the ISO have the requisite operational authority over the PTOs' transmission facilities;

WHEREAS, in accordance with the terms set forth herein, the PTOs desire for the ISO to exercise, and the ISO desires to exercise, Operating Authority (as defined in Section 3.02 of this Agreement) over the PTOs' Transmission Facilities (as defined in this Agreement) consistent with the requirements of Order 2000;

WHEREAS, the PTOs will, among other things, continue to own, physically operate, and maintain their Transmission Facilities and Local Control Centers; and

WHEREAS, each PTO reserves the right to transfer certain rights and obligations to an Independent Transmission Company in accordance with Attachment M to the ISO OATT.

NOW, THEREFORE, in consideration of the promises, and the mutual representations, warranties, covenants and agreements hereinafter set forth, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, and intending to be legally bound, each of the PTOs and the ISO agree as follows:

ARTICLE I

DEFINITIONS; INTERPRETATIONS

1.01 **Definitions; Interpretations.** Each of the capitalized terms and phrases used in this Agreement (including the foregoing recitals) and not otherwise defined herein shall have the meaning specified in Schedule 1.01. In this Agreement, unless otherwise provided herein:

- (a) words denoting the singular include the plural and vice versa;
- (b) words denoting a gender include all genders;
- (c) references to a particular part, clause, section, paragraph, article, exhibit, schedule, appendix or other attachment shall be a reference to a part, clause, section, paragraph, or article of, or an exhibit, schedule, appendix or other attachment to, this Agreement;
- (d) the exhibits, schedules and appendices attached hereto are incorporated herein by reference and shall be construed with and as an integral part of this Agreement to the same extent as if they were set forth verbatim herein;
- (e) a reference to any statute, regulation, proclamation, ordinance or law includes all statutes, regulations, proclamations, amendments, ordinances or laws varying, consolidating or replacing the same from time to time, and a reference to a statute includes all regulations, policies, protocols, codes, proclamations and ordinances issued or otherwise applicable under that statute unless, in any such case, otherwise expressly provided in any such statute or in this Agreement;

(f) a reference to a particular section, paragraph or other part of a particular statute shall be deemed to be a reference to any other section, paragraph or other part substituted therefor from time to time;

(g) a definition of or reference to any document, instrument or agreement includes any amendment or supplement to, or restatement, replacement, modification or novation of, any such document, instrument or agreement unless otherwise specified in such definition or in the context in which such reference is used;

(h) a reference to any Person (as hereinafter defined) includes such Person's successors and permitted assigns in that designated capacity;

(i) any reference to "days" shall mean calendar days unless "Business Days" (as hereinafter defined) are expressly specified;

(j) if the date as of which any right, option or election is exercisable, or the date upon which any amount is due and payable, is stated to be on a date or day that is not a Business Day, such right, option or election may be exercised, and such amount shall be deemed due and payable, on the next succeeding Business Day with the same effect as if the same was exercised or made on such date or day (without, in the case of any such payment, the payment or accrual of any interest or other late payment or charge, provided such payment is made on such next succeeding Business Day);

(k) words such as "hereunder", "hereto", "hereof" and "herein" and other words of similar import shall, unless the context requires otherwise, refer to this Agreement as a whole and not to any particular article, section, subsection, paragraph or clause hereof;

(l) a reference to "include" or "including" means including without limiting the generality of any description preceding such term, and for purposes hereof the rule of ejusdem generis shall not be applicable to limit a general statement, followed by or referable to an enumeration of specific matters, to matters similar to those specifically mentioned; and

(m) neither this Agreement nor any other agreement, document or instrument referred to herein or executed and delivered in connection herewith shall be construed against any Person as the principal draftsman hereof or thereof.

ARTICLE II

TRANSMISSION FACILITIES

2.01 **Transmission Facilities**. As to any PTO, the transmission facilities over which the ISO shall exercise Operating Authority in accordance with the terms set forth herein shall be:

(a) those facilities of such PTO listed in Schedule 2.01(a) (hereinafter “Category A Facilities”), as such list of facilities may be added to or deleted from in accordance with Sections 2.01(d) and 2.02 below;

(b) those facilities of such PTO listed in Schedule 2.01(b) (hereinafter “Category B Facilities”), as such list of facilities may be added to or deleted from, in accordance with Sections 2.01(d) and 2.02 below; and

(c) those transmission facilities of such PTO within the New England Transmission System with a voltage level of less than 69 kV and all transformers that have no Category A Facilities or Category B Facilities connected to the lower voltage side of the transformer that are not listed on Schedule 2.01(a) and Schedule 2.01(b) (hereinafter “Local Area Facilities”), provided that any excluded facilities of such PTO listed on Schedule 4.01(d) shall not be Local Area Facilities.

(d) As to each PTO, the transmission facilities included on any of the lists of the Category A Facilities or the Category B Facilities contained in Schedule 2.01(a) and Schedule 2.01(b), respectively, as of the Operations Date may be redesignated on another of these two lists, deleted from such list, or redesignated as a Local Area Facility without the necessity of an amendment to this Agreement, but only in the following manner:

(i) at the direction of a Governmental Authority with jurisdiction over the Transmission Facilities in question, provided that the ISO and all PTOs shall be provided prior written notice of such changes;

(ii) as agreed between the ISO and the PTO or PTOs owning the transmission facilities; or

(iii) where the operational characteristics of a transmission facility have been materially modified after the Operations Date (including a change from a radial transmission facility to a looped transmission facility that contributes to the parallel carrying capability of the New England Transmission System) in accordance with Section 2.01(e); provided that any such changes shall also be subject to ISO review consistent with Section 2.06.

(e) All transmission facilities to be redesignated as Category A Facilities, Category B Facilities, or Local Area Facilities or deleted from the lists in Schedule 2.01(a) and Schedule 2.01(b) in accordance with Section 2.01(d)(iii), and all transmission facilities to be

added to the lists in Schedule 2.01(a) and Schedule 2.01(b) in accordance with Section 2.02 shall be classified in accordance with the following standards:

(i) Category A Facilities shall consist of: all transmission lines with a voltage level of 115 kV and above, except for those 115 kV transmission facilities specifically designated as Category B Facilities in accordance with Section 2.01(e)(ii); all transmission interties between Control Areas; all transformers that have Category A Facilities connected to the lower voltage side of the transformer; all transformers that require a Category A Facility to be taken out of service when the transformer is taken out of service; and all breakers and disconnects connected to, and all shunts, relays, reclosing and associated equipment, dynamic reactive resources, FACTS controllers, special protection systems, PARS, and other equipment specifically installed to support the operation of such transmission lines, interties, and transformers.

(ii) Category B Facilities shall consist of: all 115 kV radial transmission lines and all 69 kV transmission lines that are not interties between Control Areas; all transformers that have any Category B Facilities and no Category A Facilities connected to the lower voltage side of the transformer except to the extent such transformers are designated as Category A Facilities in accordance with Section 2.01(e)(i); and all breakers and disconnects connected to, and all shunts, relays, reclosing and associated equipment, dynamic reactive resources, FACTS controllers, special protection systems, PARS, and other equipment specifically installed to support the operation of such Category B Facilities.

(iii) Local Area Facilities shall consist of all transmission facilities with a voltage level of less than 69 kV and all transformers that have no Category A Facilities or Category B Facilities connected to the lower voltage side of the transformer.

(iv) To the extent there is any dispute between the ISO and a PTO or PTOs owning a transmission facility concerning classification of such transmission facility under these standards, such disagreement shall be subject to the dispute resolution provisions of this Agreement, provided that the ISO's classification of a transmission facility under the standards shall govern pending resolution of the dispute.

(f) Collectively, all Category A Facilities, Category B Facilities, and Local Area Facilities shall hereinafter be referred to as the "Transmission Facilities," provided that "Transmission Facilities" shall not include Excluded Assets as defined in Section 2.04 of this Agreement or Merchant Facilities. The ISO shall maintain on its OASIS a posting of the current versions of Schedule 2.01(a) and Schedule 2.01(b), in each instance, reflecting each such change promptly after such change is made.

(g) The classifications set forth in this Section 2.01 are for operational purposes. Rate treatment of Transmission Facilities shall be governed by the ISO OATT, provided that filings for rate treatment under the ISO OATT shall be subject to Section 3.04 of this Agreement.

(h) Though the Chester SVC Facility is not owned by MEPCO, it is recognized as a Category A Facility under this Agreement. The inclusion of the Chester SVC Facility in Schedule 2.01(a) of this agreement by MEPCO, as agent for the Chester SVC Partnership, is for the sole purpose of granting Operating Authority (as defined in Section 3.02) to the ISO, specifically excluding those responsibilities under Section 3.03 of this Agreement and shall not change the established cost recovery arrangements or rate treatment. The Chester SVC Facility costs are recovered under a bilateral contract with New England Hydro Corporation (“NE Hydro”). NE Hydro pays the Chester SVC Partnership a monthly support fee that covers the construction cost and ongoing operation and maintenance costs of the Chester SVC Facility. NE Hydro bills the Phase II HVDC Interconnection Participants to recover its payments. Most Phase II HVDC Interconnection Participants recover their Chester SVC-related support payments through regional rates as originally allowed by the Restated NEPOOL Agreement and now by the ISO OATT Section II.49.

Notwithstanding any other provision of this Agreement, the inclusion of the Chester SVC Facility for the sole purpose of granting Operating Authority as so limited above, is not meant to subject, in any way, the Chester SVC Partnership to regulation as a public utility under the Federal Power Act.

2.02 **New and Acquired Transmission Facilities and Transmission Upgrades.**

(a) Any New Transmission Facility, any Transmission Upgrade, and any Acquired Transmission Facility shall be considered a “Transmission Facility” under this Agreement once it is placed into commercial operation by the applicable PTO(s); shall be designated as a Category A Facility, Category B Facility, or Local Area Facility in accordance with Section 2.01(e) unless otherwise agreed by the ISO and the PTO(s) owning the Transmission Facility; and shall be subject to the Operating Authority of the ISO in accordance with the terms of this Agreement.

(b) The designation of an Acquired Transmission Facility as a Category A, Category B or Local Area Facility shall not require the abrogation or modification of existing contractual arrangements for such Acquired Transmission Facility.

(c) Any Merchant Facility interconnected to or within the New England Transmission System shall not be the subject of this Agreement. Any Merchant Facility interconnected to or within the New England Transmission System constructed and placed in commercial operation after the Operations Date shall be subject to the authority of the ISO under a separate agreement in accordance with Section 2.03 and any applicable provisions of the ISO OATT.

2.03 **Merchant Facilities.** The terms and conditions under which a PTO, an Affiliate of a PTO, or any other entity grants authority over any Merchant Facilities to the ISO shall not be governed by this Agreement, it being understood that such entities shall enter into operating agreements relating to their Merchant Facilities directly with the ISO in accordance with applicable provisions of the ISO OATT. Nothing in this Agreement is intended to limit or expand the right of a PTO, the Affiliate of a PTO, or any other entity to propose, construct, or own Merchant Facilities interconnected to the New England Transmission System.

2.04 **Excluded Assets.** The “Excluded Assets” of a PTO shall consist of those assets and/or facilities of a PTO set forth in Section 2.04(a) and (b). These Excluded Assets are expressly excluded from the definition of Transmission Facilities under this Agreement, and the ISO shall not have Operating Authority over a PTO’s Excluded Assets. Nothing in this Section 2.04 is intended to address the rate treatment of a PTO’s Transmission Facilities or any other asset of a PTO. Rate treatment of Transmission Facilities shall be governed by the ISO OATT, provided that filings for rate treatment under the ISO OATT shall be subject to Section 3.04 of this Agreement:

(a) Any assets, facilities, and/or portions of facilities owned by such PTO that are connected with or associated with those facilities defined as Category A Facilities, Category B Facilities or Local Area Facilities to the extent specifically excluded pursuant to the following items (i) through (vii) of this Section 2.04(a):

(i) proceeds from the use or disposition of Transmission Facilities;

(ii) any payment, refund or credit (1) relating to Taxes in respect of the Transmission Facilities of such PTO, (2) arising under any contracts or tariffs of such PTO and relating to services provided prior to the beginning of the Term, (3) arising under any contract or tariff that provides for rates that are subject to regulation by an agency other than FERC, or (4) relating to a Grandfathered Transmission Agreement;

(iii) any rights, ownership, title or interest any PTO may have with respect to telecommunications assets and equipment, provided that the ISO shall continue to have the right to use such telecommunication assets and equipment attached to or associated with Transmission Facilities solely to the extent needed for the exercise of the ISO’s Operating Authority in accordance with practice prior to the Operations Date and further provided that such use right shall not be assignable by the ISO;

(iv) any existing contracts or contract rights of the PTOs related in any manner to Transmission Facilities unless such PTO agrees to assign or transfer such contracts to the ISO, provided that the PTOs shall exercise their rights and responsibilities under Grandfathered Transmission Agreements in accordance with Section 3.11 and the applicable provisions of this Agreement;

(v) any assets, property rights, licenses, permits or facilities that are used for or in (1) the distribution, generation, trading or marketing of electricity (except for facilities specifically defined as Category A Facilities, Category B Facilities or Local Area Facilities that are used for such activities), (2) gas transportation, gas, water, petroleum, chemical, real estate development, or cable business, or (3) any other activity unrelated to the transmission of electricity located on, or making use of, the Transmission Facilities;

(vi) any causes of action or claims related to Transmission Facilities, provided, that, upon the written agreement of the PTO and the ISO to the assumption by the ISO of the management of such claims under mutually agreed terms and conditions, the ISO may manage a PTO's causes of action or claims against a third party relating to such Transmission Facilities, and provided further that the ISO shall have the right to pursue causes of action or claims against third parties to the extent necessary for the ISO to fulfill its responsibilities for invoicing, collection and disbursement of customer payments in accordance with Section 3.10; and

(vii) any asset or facility for which Operating Authority may not be lawfully transferred or assigned.

(b) Any assets or facilities of such PTO that are not specifically defined as Category A Facilities, Category B Facilities or Local Area Facilities, including without limitation the facilities or portions of facilities described in items (i) through (xii) of this Section 2.04(b):

(i) all cash, cash equivalents, bank deposits, accounts receivable, and any income, sales, payroll, property or other Tax receivables;

(ii) proceeds from the use or disposition of any facilities or assets owned by the PTO;

(iii) certificates of deposit, shares of stock, securities, bonds, debentures, and evidences of indebtedness;

(iv) any rights or interest in trade names, trademarks, service marks, patents, copyrights, domain names or logos;

(v) any payment, refund or credit (1) relating to Taxes, (2) arising under any contracts or tariffs of such PTO and relating to services provided prior to the beginning of the Term, or (3) arising under any contract or tariff that provides for rates that are subject to regulation by an agency other than FERC;

(vi) any facilities, including transmission facilities, located outside the New England Transmission System;

(vii) any rights, ownership, title or interest any PTO may have with respect to telecommunications assets and equipment;

(viii) any existing contracts or contract rights of the PTOs unless such PTO agrees to assign or transfer such contracts to the ISO;

(ix) any assets, property rights, licenses, permits or facilities that are used for or in (1) the distribution, generation, trading or marketing of electricity or (2) gas transportation, gas, water, petroleum, chemical, real estate development, or cable business, or (3) any other activity unrelated to the transmission of electricity whether or not located on, or making use of, the Transmission Facilities;

(x) any causes of action or claims;

(xi) any asset or facility for which Operating Authority may not be lawfully transferred or assigned; and

(xii) any interests of any kind in each PTO's real property, provided that nothing in this Section 2.04 shall: (a) supersede the rights and obligations of the Parties as set forth in the Control Center Lease or Back-up Control Center Lease or (b) restrict the PTOs from conveying interests in real property in any future written agreement into which the ISO and any PTO or group of PTOs may, in their sole discretion, enter.

2.05 Connection with Non-Parties.

On or after the Operations Date, each PTO shall connect its Transmission Facilities with the facilities of any entity that is not a Party, including the facilities of a current or proposed Transmission Customer, and shall install (or cause to be installed) and construct (or cause to be constructed) any transmission facilities required to connect the facilities of a non-Party to a PTO's Transmission Facilities to the extent such connection or construction is required by applicable law, including the Federal Power Act and any applicable regulations issued by FERC and provided that the construction of any such transmission facilities shall be subject to the conditions associated with the PTOs' obligation to build set forth in Schedule 3.09(a). Any such connection shall be subject further to: (1) the receipt of any necessary regulatory approvals, (2) compliance with the procedures set forth in the ISO OATT for review of the reliability and operational impacts of a proposed interconnection (including the procedures for interconnection of a Generating Unit or Elective Transmission Upgrade under the Interconnection Standard or as otherwise provided under the ISO OATT); and (3) execution of an Interconnection Agreement with such entity containing provisions for the safe and reliable operation of each interconnection with respect to such entity's facilities in accordance with Good Utility Practice, applicable NERC/NPCC Requirements, and applicable Law (including the Federal Power Act); provided that

(i) Except as provided in 2.05(ii) below, each PTO shall engage in good faith negotiations as to the terms and conditions of such Interconnection Agreement with any such non-Party, but, except as may be required pursuant to regulations issued by FERC, a PTO shall not be required to enter into any Interconnection Agreement containing terms and conditions unacceptable to such PTO and shall reserve the right to resolve any disputes, and/or make any filings with FERC, with respect thereto.

(ii) With respect to the interconnection of a Large Generating Facility, a Small Generating Facility, or an Elective Transmission Upgrade to any Transmission Facility or OATT Interconnection Distribution Facility of a PTO the Interconnection Agreement shall be a three-party agreement among the PTO, the ISO, and the interconnecting non-Party based on the Schedule 22 Large Generator Interconnection Agreement, Schedule 23 Small Generator Interconnection Agreement, or Schedule 25 Elective Transmission Upgrade Interconnection Agreement, respectively, in the ISO OATT. With respect to the interconnection of other Generating Units to any Transmission Facility of a PTO, the ISO shall be a party to Interconnection Agreements if and to the extent that FERC regulations require the ISO to be a party. Either the ISO or the PTOs, acting jointly in accordance with the Disbursement Agreement among them, may initiate a filing to amend the Schedule 22 Large Generator Interconnection Agreement, Schedule 23 Small Generator Interconnection Agreement, or Schedule 25 Elective Transmission Upgrade Interconnection Agreement under Section 205 of the Federal Power Act and shall include in such filing the views of the ISO and the

PTOs, as applicable, provided that the standard applicable under Section 205 of the Federal Power Act shall apply only to the PTOs' position on any financial obligations of the PTOs or the interconnecting non-Party, and any provisions related to physical impacts of the interconnection on the PTOs' Transmission Facilities or other assets. If the PTO, the ISO and the interconnecting non-Party agree to the terms and conditions of a specific Large Generator Interconnection Agreement, Small Generator Interconnection Agreement, or Elective Transmission Upgrade Interconnection Agreement, as applicable, or any amendments to such an Interconnection Agreement, then the PTO and the ISO shall jointly file the executed Interconnection Agreement, or amendment thereto, with FERC under Section 205 of the Federal Power Act. To the extent the PTO, the ISO and such interconnecting non-Party cannot agree to proposed variations from the Schedule 22, 23, or 25 Interconnection Agreement applicable to a Large Generating Facility, Small Generating Facility, or Elective Transmission Upgrade, respectively, or cannot otherwise agree to the terms and conditions of the Interconnection Agreement, or any amendments to such an Interconnection Agreement, then the PTO and the ISO shall jointly file an unexecuted Interconnection Agreement, or amendment thereto, with FERC under Section 205 of the Federal Power Act and shall identify the areas of disagreement in such filing, provided that, in the event of disagreement on terms and conditions of the Interconnection Agreement related to the costs of upgrades to such PTO's Transmission Facilities, the anticipated schedule for the construction of such upgrades, any financial obligations of the PTO, and any provisions related to physical impacts of the interconnection on the PTO's Transmission Facilities or other assets, then the standard applicable under Section 205 of the Federal Power Act shall apply only to the PTO's position on such terms and conditions.

The costs of interconnection facilities, including additions to or modifications of the Transmission Facilities that are required to accommodate the Large Generating Facility, Small Generating Facility, or Elective Transmission Upgrade, shall be allocated in the manner specified in the ISO OATT.

(iii) The entity requesting the interconnection of an Elective Transmission Upgrade (the "Elective Transmission Upgrade Applicant") shall be responsible for 100% of all of the costs of said upgrade and of any additions to or modifications of the Transmission Facilities that are required to accommodate the Elective Transmission Upgrade. A request for rate treatment of an Elective Transmission Upgrade, if any, shall be determined by FERC in the appropriate proceeding.

2.06 **Review of Transmission Plans.** Each PTO shall submit to the ISO in such form, manner and detail as the ISO may reasonably prescribe: (i) any new or materially changed plans for retirements of or changes in the capacity of such PTO's Transmission

Facilities rated 69 kV or above or plans for construction of New Transmission Facilities or Transmission Upgrades rated 69 kV or above; and (ii) any new or materially changed plan for any other action to be taken by the PTO which may have a significant effect on the stability, reliability or operating characteristics of the PTO's Transmission Facilities, the facilities of any Transmission Owner, or the system of a Participant. The ISO shall provide notification of any such PTO submissions to the appropriate Technical Committee(s). Unless prior to the expiration of ninety (90) days, the ISO notifies the PTO in writing that it has determined that implementation of the plan will have a significant adverse effect upon the reliability or operating characteristics of the PTO's Transmission Facilities, the facilities of any Transmission Owner, or the system of a Participant, the PTO shall be free to proceed. If the ISO notifies the PTO that implementation of such plan has been determined to have a significant adverse effect upon the reliability or operating characteristics of the PTO's Transmission Facilities, the facilities of any Transmission Owner, or the system of a Participant, the PTO shall not proceed to implement such plan unless the PTO takes such action or constructs such facilities as the ISO determines to be reasonably necessary to avoid such adverse effect.

2.07 **Condemnation.** If, at any time, any Governmental Authority commences any process to acquire any Transmission Facilities or any other interest in Transmission Facilities then held by a PTO through condemnation or otherwise through the power of eminent domain, (i) such PTO shall provide the ISO with written notice of such process, (ii) such PTO shall, at its cost, direct any litigation or proceeding regarding such condemnation or eminent domain matter, (iii) such PTO shall have the right to settle any such proceeding without the consent of the ISO, and (iv) any award in condemnation or eminent domain shall be paid to such PTO without any claim to such award by the ISO.

ARTICLE III **OPERATING AUTHORITY**

3.01 **Grant of Operating Authority.**(a) Subject to the terms set forth in this Agreement, including Article III and Article X hereof, effective as of the Operations Date, and with respect to Publicly-Owned PTOs, to the extent permitted by, or in a manner consistent with the laws of any State governing the organization or operation of such Publicly-Owned PTOs, each PTO hereby authorizes the ISO, through its officers, employees, consultants, independent contractors and other personnel, to exercise Operating Authority over the Transmission Facilities, including provision of Transmission Service over the Transmission Facilities under the ISO OATT, and the ISO hereby agrees to assume and exercise Operating Authority over such PTOs' Transmission Facilities in accordance with this Agreement.

(b) The grant by the PTOs to the ISO and the assumption by the ISO of Operating Authority over the Transmission Facilities are solely for the purposes of allowing the ISO to fulfill the functions of an RTO as specified herein (including provision of Transmission Service under the ISO OATT) and do not constitute an assumption by the ISO of any liabilities

with respect to the Transmission Facilities except as otherwise specifically provided herein (including as provided in Article IX of the Agreement).

(c) Nothing herein or elsewhere contained shall be construed as requiring or effecting a transfer of any PTO's responsibility (or the assumption thereof by the ISO) for the physical control of the Transmission Facilities, including the physical operation, repair, maintenance and replacement of such Transmission Facilities, or as conveying to the ISO: (x) any right, ownership, title or interest in or to a PTO's Transmission Facilities; (y) any right of access to any PTO's real property, except as specified in Section 3.02(i); or (z) any rights or authority with respect to a PTO's Excluded Assets, except as specifically provided herein.

3.02 **Definition of ISO Operating Authority.** Consistent with the provisions of this Agreement, including Section 3.02(a) below, "Operating Authority" shall mean those functions set forth in Sections 3.02, 3.03, and 3.08 and those responsibilities set forth in Section 3.05, and shall not include those rights, responsibilities and functions set forth in Sections 3.06 and 3.07. Subject to the first sentence of this Section 3.02, the ISO shall exercise such Operating Authority in accordance with applicable Operating Procedures as specified in Section 3.02(d) below.

(a) The ISO shall perform the following functions with respect to each PTO's Transmission Facilities, consistent with applicable NERC/NPCC Requirements and other applicable regulatory standards, including (as needed) issuing instructions to, or coordinating with, each PTO's Local Control Center(s):

(i) centrally dispatch generation (and dispatchable and interruptible load) and implement real-time balancing, including meeting NERC control performance criteria;

(ii) determine Operating Limits based on forecasted or real-time system conditions and in accordance with the facility ratings established by the PTOs in collaboration with the ISO pursuant to Section 3.06;

(iii) take such actions as may be necessary to plan and maintain short-term (including real-time) reliability and system security (including curtailment of external transactions in accordance with FERC-accepted or -approved Market Rules and the applicable transmission tariff or transmission agreement);

(iv) consistent with the ISO Information Policy, exchange security information with applicable PTOs, non-PTO transmission operators and other neighboring systems and regional entities; and

(v) provide for an ISO Control Center and an independent Back-up Control Center, as the ISO deems necessary to comply with applicable NERC/NPCC Requirements and any applicable regulatory requirement.

(b) The ISO shall receive, confirm and schedule External Transactions for the New England Transmission System; enter into Coordination Agreements and operating arrangements with the operators of neighboring Control Areas; coordinate system operation and emergency procedures with neighboring Control Areas; and administer each PTO's Interconnection Agreements with neighboring Control Areas and scheduling provisions of the tariff(s) applicable to External Transactions, in accordance with the terms of those agreements and tariffs; provided that as of the Operations Date, the applicable agreements and tariffs shall be set forth in Schedule 3.02(b).

(c) The ISO shall act as the Reliability Authority for the New England Transmission System. The ISO may intercede and direct appropriate near-term operational actions in order to protect reliability, provided that nothing in this Section 3.02(c) shall require any PTO to undertake an action contrary to applicable Law or shall limit the right of each PTO pursuant to Section 3.07 to take any action(s) that it deems necessary to prevent loss of human life, injury to persons and/or damage to property.

(d) The ISO shall utilize the Operating Procedures relating to the exercise of Operating Authority over the Transmission Facilities. The Operating Procedures shall initially consist of the Operating Procedures in existence on the Operations Date (hereinafter "Existing Operating Procedures"). Such Existing Operating Procedures shall consist of those Operating Procedures listed in Schedule 3.02(d). The ISO shall develop any modifications to Operating Procedures (including Existing Operating Procedures) and any new Operating Procedures that it may deem necessary or appropriate: (i) in coordination with those PTOs (or their Local Control Centers, as applicable) whose Transmission Facilities will be operated in accordance with such Operating Procedures so as to ensure that that the PTO's (or Local Control Center's) knowledge of their Transmission Facilities is given due consideration in the development or modification of the transmission-related portions of such Operating Procedures and (ii) in consultation with other stakeholders. The ISO shall have the authority to modify Operating Procedures or develop new Operating Procedures without such coordination or consultation when the ISO does not have sufficient time to undertake such coordination or consultation due to emergent and unanticipated circumstances. In the event that the ISO and the applicable PTO(s) disagree about modifications to the transmission-related portions of Operating Procedures or any new Operating Procedures related to the operation of such PTOs' Transmission Facilities, the affected PTO(s) will have the opportunity to submit the dispute for resolution in accordance with the dispute resolution provisions set forth in Section 11.14 herein. Pending such resolution, the ISO shall have the authority, as the system operator with ultimate authority for the real-time operation of the New England Transmission System, to implement any such new Operating Procedures or modified Operating Procedures. Notwithstanding anything in the foregoing, Operating Procedures related to the establishment of ratings for a PTO's New Transmission Facilities and Acquired Transmission Facilities or related to changes to existing ratings of a PTO's Transmission Facilities (collectively "Rating Procedures") shall be developed and placed into effect pursuant to Section 3.06(a)(v).

To the extent the PTOs will be required to physically operate their Transmission Facilities in accordance with any operational documents in effect as of the Operations Date or as subsequently developed or amended by the ISO (other than the Operating Procedures), the ISO shall develop such operational documents and amendments thereto in coordination with those PTOs (or their Local Control Centers, as applicable) whose Transmission Facilities will be operated in accordance with such documents, provided that stakeholders shall have the right to consult in the development of such documents, subject to any limitations associated with the confidential nature of such documents consistent with confidentiality, that the ISO will have the right to place such operating documents into effect in the event of a dispute concerning such documents, and that the affected PTO(s) shall have the right to submit any such dispute for resolution in accordance with the dispute resolution provisions set forth in Section 11.14 herein. Any such coordination between any PTO and the ISO pursuant to this Section 3.04(d) shall be subject to applicable standards of conduct consistent with FERC Order No. 889.

(e) The ISO shall seek agreement with the PTOs, where time limitations do not make it impracticable to do so, on real-time operational decisions affecting the Transmission Facilities not otherwise specified in the Operating Procedures developed in accordance with Section 3.02(d). In the absence of such agreement, or if time limitations do not permit reaching agreement, the ISO shall implement its operational decision. If such ISO decision is disputed, the ISO's position shall control pending resolution of the dispute.

(f) The ISO shall develop, maintain, and, if needed, implement the System Restoration Plan for the New England Transmission System, which shall include the existing PTO Local Restoration Plans. The ISO shall develop any modifications to the System Restoration Plan in consultation with the PTOs and shall incorporate into the System Restoration Plan any modifications developed by each PTO to their PTO Local Restoration Plans, provided that any modifications to the PTO Local Restoration Plans are subject to the ISO's approval in order to coordinate and promote the reliability of the Restoration Plans.

(g) The ISO shall coordinate voltage and reactive dispatch of facilities to the extent normal schedules are unable to be maintained by Local Control Centers.

(h) The ISO shall direct the implementation of emergency procedures, including Load Shedding and voltage reduction, in coordination with the PTO Local Control Centers.

(i) The ISO shall have the authority to perform the following tasks in relation to compliance with current or future PTO responsibilities:

(i) perform all compliance and monitoring responsibilities of the ISO, including the issuance of sanction letters, with respect to existing or successor NERC or NPCC compliance programs associated with standards, criteria and measurements for which the PTOs are responsible and accountable to the ISO. To the extent that the ISO receives a sanction

letter from NERC or NPCC that is substantially related to the actions of a PTO, the ISO may issue a sanction letter to such PTO;

(ii) perform all compliance and monitoring responsibilities of the ISO associated with Operating Procedures relating to standards, criteria and measurements that the PTOs are responsible for and accountable to the ISO. Such responsibilities shall include audits of PTOs for compliance with Operating Procedures to the extent the ISO determines such audits are necessary, and the issuance of sanction letters;

(iii) perform periodic audits of each Local Control Center's and PTO's performance of the functions listed in Sections 3.06 (a)(i), (ii), (iv), (vi), (vii), (viii), (ix) and (x) in accordance with applicable Operating Procedures and applicable reliability standards, including audits to monitor compliance of the Local Control Center (and PTO employees interacting with the Local Control Centers) with the ISO Information Policy and applicable standards of conduct consistent with FERC Order No. 889 in performing these functions. Such Local Control Center audits shall generally be conducted no more frequently than once every three years, provided that the ISO shall have the authority to conduct an audit more frequently if it determines that circumstances so require.

All audits conducted pursuant to this Section 3.02(i) shall be conducted by the ISO or by an independent third party, with expenses of the ISO (or the third-party auditor) borne by the ISO and recovered through its administrative tariff. The PTO shall bear its own expenses in complying with the audit. Such audits shall be conducted during normal business or operational hours and with reasonable notice. The general scope of each audit and the general process for conducting the audit will be discussed with the affected PTO in advance. Nothing in this Section 3.02(i) shall imply that a sanction letter shall include any financial or other penalties. Nothing in this Section 3.02(i) shall limit the right of the ISO to separately file proposals at FERC to assess financial or other penalties against any entity or shall limit the right of the PTOs to comment on or protest any such proposals.

(j) In addition to the functions set forth in Sections 3.02(a) - (i), Operating Authority shall also consist of the following functions that the ISO shall perform with respect to each PTO's Category A Facilities; provided, however, that the ISO (in the absence of the PTO's consent) is not authorized to perform such functions with respect to any PTO's Category B Facilities or Local Area Facilities, unless the outages of such facilities reasonably could be expected to result in a violation of reliability criteria:

(i) monitor and control, in accordance with the facility ratings established by the PTOs in collaboration with the ISO pursuant to Section 3.06, on a real-time basis, power flows on the system, voltage and system frequency; and

(ii) coordinate with the Local Control Centers on the settings for dynamic reactive resources, FACTS controllers, special protection systems, PARS, and other similar dynamic equipment that affects power flows, and approve or direct changes to such settings.

(k) If at any time, any Party provides notice to all of the other Parties that it believes NERC and NPCC documents that are not NERC/NPCC Requirements have been modified so as to expand the scope of the functions to be performed by the ISO or the PTOs, the Parties shall consider in good faith changes to this Agreement that will allow the Parties to follow such guidelines; provided, however, that, the Parties shall have no obligation to agree to such changes. If the Parties cannot agree to such changes, the dispute resolution procedures of Section 11.14 shall be utilized. Nothing in this Section 3.02(k) shall be construed to excuse any Party from complying with applicable NERC/NPCC Requirements.

3.03 **Transmission Services and OATT Administration.**

(a) The ISO shall administer the ISO OATT in the manner specified in this Section 3.03. The ISO's OATT administration responsibilities shall include those enumerated below:

(i) The ISO shall receive, post on OASIS as required by Commission regulations, and respond to requests by Large Generating Facilities and Small Generating Facilities to be interconnected under the ISO OATT, all Transmission Service requests and requests under the Local Service Schedules. Except as provided in Section 3.03(a)(ii), the ISO shall perform the system impact studies and facilities studies (and execute and administer agreements for such studies) in connection with such requests to the Administered Transmission System. Notwithstanding the foregoing, (A) the ISO shall consult with a PTO prior to completion of system impact studies and facilities studies in connection with requests that affect such PTO's Transmission Facilities and distribution facilities and shall include in any such studies the PTO's reasonable estimates of the costs of upgrades to such PTO's Transmission Facilities and distribution facilities needed to implement the conclusions of such studies and the PTO's reasonable anticipated schedule for the construction of such upgrades (provided that the PTO will determine whether the request has an impact on its distribution facilities); (B) nothing in this Agreement shall preclude the ISO from entering into a separate agreement(s) with a PTO for such studies, pursuant to the ISO's supervision and the ISO's authority to require modifications to such studies, to perform system impact studies and facilities studies; (C) except as provided in Section 3.03(a)(ii) with respect to interconnection of Generating Units that would not have an impact on facilities used for the provision of regional transmission service, nothing in this Agreement shall preclude the performance of studies related to the interconnection of Generating Units by a third party consultant to the extent permitted by applicable procedures in the ISO OATT (including procedures

governing the treatment of confidential information) and provided that such studies performed by any third party consultant must include the PTO's reasonable estimates of the costs of upgrades to such PTO's Transmission Facilities and distribution facilities needed to implement the conclusions of such studies and the PTO's reasonable anticipated schedule for the construction of such upgrades; and (D) each PTO shall, upon request by the ISO, conduct any necessary studies related to such PTO's Transmission Facilities and distribution facilities, including system impact studies and facilities studies, and shall assist in the performance of any such studies, including the provision of information and data in accordance with Section 11.09 of this Agreement.

(ii) The ISO shall forward to the appropriate PTO(s) applications for Local Service. The ISO shall review applications for Local Service or requests for the interconnection of Large Generating Facilities and Small Generating Facilities to be interconnected to a Transmission Facility or to an OATT Interconnection Distribution Facility of a PTO to determine whether the service or interconnection would have an impact on facilities used for the provision of regional transmission service. If so, and the interconnection is to a Transmission Facility or an OATT Interconnection Distribution Facility, the ISO will perform a system impact study and facilities study, as necessary to address the impacts on facilities used for the provision of regional transmission service. The PTO shall be responsible for reviewing and responding to requests for Local Service not having an impact on facilities used for the provision of regional transmission service and for interconnections not having an impact on facilities used for the provision of regional transmission service, and shall perform all system impact studies and facilities studies regarding such requests and all studies associated with the distribution facilities of the PTO or its distribution Affiliate; provided, however, that the PTO shall consult with the ISO prior to completion of such system impact studies and facilities studies and further provided that the ISO will use reasonable efforts to assist the PTO and interconnecting party in resolving disputes arising regarding the performance of such studies. The PTOs shall provide the ISO with information necessary to evaluate any such dispute in accordance with Section 11.09 of this Agreement, and shall include provisions in each of their study agreements providing for reimbursement of the ISO's costs incurred in these efforts.

(iv) The ISO shall calculate the TTC and ATC for all inerties on the New England Transmission System and determine the TTC and ATC calculation methodologies for inerties on the New England Transmission System (consistent with applicable NERC/NPCC Requirements and applicable regulatory standards), provided that modifications to calculation methodologies as they exist on the Operations Date shall be developed by the ISO in consultation with the PTOs and other interested stakeholders. To the extent that TTC and ATC on a PTO's Local

Network must be calculated in connection with the provision of Local Service, then the PTO shall calculate such TTC and ATC.

(v) The ISO shall operate and maintain the OASIS (or a successor system) as required by FERC, including posting of TTC/ATC for interties on the New England Transmission System; provided, however, that such system shall conform to the requirements for such systems as specified by FERC. The PTOs shall provide updates to PTO-specific Local Service pages on the OASIS site, subject to the ISO's review of such updates. The ISO shall have the authority to direct any changes to such PTO-specific Local Service pages that it deems appropriate to conform to FERC requirements and the terms and conditions of the ISO OATT.

(vi) The ISO shall procure and act as supplier of last resort of Ancillary Services (including arranging for the sale and purchase of emergency capacity and energy with neighboring Control Areas), in accordance with the ISO OATT and FERC-accepted or -approved Market Rules.

(vii) The ISO shall provide regional Transmission Service to Transmission Customers over the Transmission Facilities in accordance with the rates, terms and conditions of the ISO OATT, subject to Section 3.03(c) with respect to Local Service.

(viii) The ISO shall track inadvertent energy and administer inadvertent energy payback/accounting with neighboring Control Areas in accordance with the terms and conditions of the Interconnection Agreements or Coordination Agreements with neighboring Control Areas and applicable tariff provisions.

(ix) The ISO shall make informational filings with the Commission that are required of an RTO, provided that the relevant PTOs shall provide the ISO with all necessary information to make such filings, in such manner as the ISO shall reasonably prescribe and in accordance with Section 11.09 of this Agreement.

(b) Notwithstanding Section 3.03(a), generators requesting to interconnect with the distribution facilities of a PTO or a PTO's distribution company Affiliate that are not OATT Interconnection Distribution Facilities shall submit service requests to the distribution company or the PTO, as applicable. Retail load customers requesting to interconnect with the Transmission Facilities of a PTO or the distribution facilities of a PTO or a distribution company Affiliate shall submit service requests to the distribution company or the PTO, as applicable. Service requests submitted to the ISO shall be forwarded to the distribution company or, where applicable, the PTO. The distribution company or, where applicable, the PTO shall execute and administer the agreements, and shall be responsible for billing, collections, dispute resolution and the performance of system impact studies and facilities studies, in coordination with the ISO as necessary, in connection with such requests. The PTO or its distribution company Affiliate, as

applicable, shall notify the ISO of situations where the interconnection of multiple generators to distribution facilities that are not OATT Interconnection Distribution Facilities may have cumulative impacts affecting the facilities used for the provision of regional transmission service and shall, in such situations, consult with the ISO in its performance of such studies. The ISO will determine whether such interconnections will have a cumulative impact on facilities used for the provision of regional transmission service.

(c) Local Service. Each PTO authorizes the ISO to act as its agent in the performance of its Transmission Service and OATT administration duties with regard to Local Service, including all ISO responsibilities with respect to Local Service and Local Area Facilities as set forth in Section 3.03(a) above. Each PTO agrees to perform all tasks and undertake all responsibilities necessary and appropriate to facilitate the provision of Local Service in accordance with its Local Service Schedule. Each PTO shall, in accordance with Section 11.09 of this Agreement, provide the ISO with information and data requested by the ISO to perform its Transmission Service and OATT administration duties with regard to Local Service. Each PTO shall maintain its Local Service Schedules in accordance with FERC regulations governing filed rate schedules, shall provide the ISO with copies of proposed changes to its Local Service Schedules when filed with the FERC, and shall notify the ISO when FERC approves or accepts changes to such Local Service Schedules. Each PTO shall be responsible for sending all invoices for Local Service to Transmission Customers and pursuing collections for outstanding payments due for Local Service. The ISO, by the execution of this Agreement, shall not assume any liability in connection with the provision of Local Service other than the liability which may result from an act or omission of the ISO related to the ISO's rights and responsibilities under this Agreement, including an ISO directive and/or instruction to a Party. Nothing in this Section 3.03(c) shall affect the relative rights and responsibilities of the Parties pursuant to Article IX of this Agreement.

(d) Transmission Service Agreements. The ISO and the applicable PTOs shall enter into all agreements for Transmission Service over the Transmission Facilities that commence on or after the Operations Date; provided that:

- (i) A pro forma service agreement (or service agreements) shall be attached to the ISO OATT and such pro forma service agreement(s) shall set forth the respective rights and responsibilities of the Transmission Customer, the ISO, and the PTOs. After the Operations Date, the ISO shall have the authority, pursuant to Section 205 of the Federal Power Act, to amend the pro forma service agreement(s) or the Market Participant Service Agreement ("MPSA") or executed service agreements related to the terms and conditions of regional Transmission Service. After the Operations Date, the PTOs, acting jointly in accordance with the Disbursement Agreement among them, shall have the authority, pursuant to Section 205 of the Federal Power Act, to amend the pro forma service agreement(s) related to the terms and

conditions of Local Service. and each PTO shall have the authority, pursuant to Section 205 of the Federal Power Act, to amend executed service agreements related to the terms and conditions of Local Service.

- (ii) On or after the Operations Date, the ISO shall be responsible for filing with the FERC, or electronically reporting to the FERC as applicable, all new agreements for Transmission Service over the Transmission Facilities. Such filings with respect to Local Service will be made by the ISO as agent for the applicable PTO. In the event of any dispute between the ISO or a PTO and a Transmission Customer concerning the terms and conditions of such service agreements, the ISO shall file an unexecuted copy of the pro forma service agreement set forth in the ISO OATT and shall include in such filing any statement provided by the affected PTO(s) and the Transmission Customers concerning their respective positions on any proposed changes or additions to the pro forma service agreement.
- (iii) Notwithstanding the foregoing, the PTOs (or their affiliated distribution companies) shall be solely authorized to enter into service agreements for retail service and service to generators connected at the distribution facility level.

Nothing in this Section 3.03(d) shall limit the ISO's obligations with respect to Grandfathered Transmission Agreements in accordance with Section 3.11 of this Agreement. The PTOs shall submit all required electronic reports with respect to such Grandfathered Transmission Agreements. If and to the extent that FERC regulations require the ISO to submit such electronic reports for the Grandfathered Transmission Agreements, the PTOs shall provide the ISO with assistance in developing and submitting such required reports.

(e) Local Networks. A "Local Network" shall consist of those networks of Transmission Facilities identified on Attachment E of the ISO OATT as of the Operations Date. The Local Networks shall only be changed to reflect the effectuation of a merger, acquisition, or consolidation and reorganization, to add a new PTO from outside of the New England Control Area, or to reflect the withdrawal from the ISO of a PTO.

3.04 **Application Authority**.

(a) Each PTO other than a Publicly-Owned PTO shall have the authority to submit filings under Section 205 of the Federal Power Act, and each Publicly-Owned PTO shall have the authority to the extent permitted by, or in a manner consistent with state law applicable to Publicly-Owned PTOs, to establish and to revise:

(i) the revenue requirements for all Transmission Facilities of such PTO used for the provision of Transmission Service (including Transmission Facilities leased to the PTO or to which the PTO has contractual entitlements);

(ii) any rates or charges for transmission services that are based solely on the revenue requirements of the Transmission Facilities of a single PTO (including Transmission Facilities leased to the PTO or to which the PTO has contractual entitlements) under such PTO's FERC-accepted or -approved Local Service Schedule to the ISO OATT;

(iii) any terms and conditions for Local Network Service or Local Point-to-Point Transmission Service under such PTO's Local Service Schedule to the ISO OATT;

(iv) any rates or charges for the recovery of such PTO's investment in a New Transmission Facility or Transmission Upgrade that enters commercial service after the effective date of the ISO OATT and the construction of which was not required by, or approved in, an ISO System Plan; provided, however, that if the ISO OATT utilizes a formula-type transmission rate, the revenue requirement for such Transmission Facility shall not be rolled into such rate without a FERC order expressly permitting such roll-in;

(v) any terms and conditions for such PTO's or such PTO's affiliated distribution company's retail access plans, whether such terms and conditions are included in the ISO OATT or in any other tariff applicable to that PTO filed with FERC, and including any such terms and conditions in the ISO OATT or in any other tariff applicable to that PTO that protect against bypass of any provision of that PTO's retail access plan;

(vi) any rates or charges for the recovery of such PTO's wholesale or retail stranded costs and any terms and conditions in the ISO OATT or in any other tariff applicable to that PTO filed with FERC that protect against bypass of rates or charges for the recovery of that PTO's wholesale or retail stranded costs;

(vii) any rates or charges, and terms and conditions related thereto, that implement an incentive or performance-based rate proposal made by one or more (but fewer than all) PTOs, applicable only to service provided by such PTO(s) under their Local Service Schedules; and

(viii) subject to the provisions of Section 2.05, any terms and conditions of Interconnection Agreements with any entities connecting with such PTO's Transmission Facilities, provided that such Interconnection Agreements shall not include any operating arrangements and Coordination Agreements that the ISO may enter into with operators of neighboring Control Areas in accordance with Section 3.02(b).

A PTO shall not have the authority to revise such rates, terms and conditions in a manner that would abridge the rights granted to the ISO in Section 3.04(c). The PTO shall provide written notification to the ISO and stakeholders of any filing described in sub-paragraph (ii) through (viii), above, which notification shall include a detailed description of the filing, at least 30 days in advance of a filing. The PTO shall consult with interested stakeholders upon request. The PTO shall retain the right to modify aspects of any filing authorized by this Section 3.04(a) after it provides written notification to the ISO and stakeholders, and shall provide notification to the ISO and stakeholders of any material modification to such filings.

With respect to any filing described in sub-paragraph (ii) through (viii), above, the PTO shall include in any filing a statement that, in the good faith judgment of the PTO, the proposal will not be inconsistent with the design of the New England Markets, as accepted or approved by FERC. In the event the ISO believes that a proposed filing described in sub-paragraph (ii) through (viii), above, would have such an inconsistency, it shall so advise the PTO and such PTO and the ISO shall consult in good faith to resolve any ISO concerns, but, if such disagreement cannot be resolved, the PTO may submit a filing under Section 205, provided that the PTO's filing (including the transmittal letter for such filing) to FERC shall include any written statement provided by the ISO setting forth the basis for the ISO's concerns. With respect to any PTO whose transmission rates and revenue requirements are not subject to FERC jurisdiction under Section 205 or otherwise, such PTO shall have the right to establish its revenue requirements, and, where applicable, its rates and charges, in accordance with applicable law and submit such revenue requirements, rates and charges to FERC for a determination that inclusion of such revenue requirements, rates and charges in the ISO OATT will yield rates and charges for Transmission Service that satisfy the applicable standard under Section 205.

A PTO shall consult with the ISO to determine whether the ISO will need to make any software modifications in order to implement any filing authorized by this Section 3.04(a) and when any needed software modifications could reasonably be expected to be implemented. The PTO's filing to FERC (and the transmittal letter for such a filing) shall include any written statement provided by the ISO setting forth the basis for any software-related implementation concerns raised by the ISO. The ISO shall make Commercially Reasonable Efforts to implement any needed software modifications by the effective date accepted by the FERC for a filing authorized by this Section 3.04(a), provided that, if the ISO has exercised such Commercially Reasonable Efforts, a failure to implement needed software modifications by the FERC-accepted effective date shall not constitute an event of default by the ISO under this Agreement or subject the ISO to financial damages, and further provided that the ISO shall run retroactive settlements consistent with the FERC-accepted effective date for a filing authorized by this Section 3.04(a) once such software modifications have been implemented.

(b) The PTOs, acting jointly in accordance with the Disbursement Agreement among them, shall have the authority to submit filings under Section 205 of the Federal Power Act to establish and to revise:

(i) the rates and charges for Transmission Service pursuant to which the revenue requirements for all Transmission Facilities of the PTOs used for the provision of Transmission Service are recovered; including the design of any rates or charges for: (A) regional Transmission Service on the New England Transmission System involving the use of more than one PTO's Transmission Facilities; (B) Transmission Service between the New England Transmission System and any other transmission system; (C) Transmission Service through the New England Transmission System between other transmission systems; (D) the recovery of any portion of the revenue requirements of the PTOs attributable to the elimination of any rates or charges (e.g., border charges) for any such Transmission Service; (E) the methodology by which the costs of Transmission Upgrades related to generator interconnections are allocated under the ISO OATT and (F) the methodology by which the costs of New Transmission Facilities and Transmission Upgrades are allocated under the ISO OATT.

(ii) the methodology for the recovery and allocation of the line losses on the New England Transmission System, if and to the extent that the calculation of locational marginal prices for energy is not designed to recover such losses; and

(iii) any rates or charges, and terms and conditions related thereto, that implement an incentive or performance-based rate proposal, applicable to the entire New England Transmission System.

The PTOs shall not have the authority to revise such rates, terms and conditions in a manner that would abridge the rights granted to the ISO in Section 3.04(c). The PTOs shall provide written notification of any proposed filing under this Section 3.04(b) to the ISO and stakeholders, which notification shall include a detailed description of the proposed filing, at least 30 days prior to the filing. The PTOs shall retain the right to modify aspects of any filing authorized by this Section 3.04(b) after they provide written notification to the ISO and stakeholders, and shall provide notification to the ISO and stakeholders of any material modification to such filings. If less than all of the PTOs support the filing, the PTOs will advise the ISO and stakeholders of that fact and the dissenting PTOs shall advise the ISO and stakeholders of their concerns.

The PTOs and the ISO shall make every reasonable effort to agree upon the PTOs' proposed filing under this Section. In the event the PTOs and the ISO are unable to agree on the PTOs' filing under this Section, and the ISO in its good faith judgment concludes that the PTOs' filing will:

(A) be inconsistent with the design of the New England Markets, including the congestion pricing methodology for the ISO region, as accepted or approved by FERC;

(B) have a material adverse effect on the efficiency or competitiveness of the New England Markets, or on the ability of the ISO

to provide transmission access on a not unduly discriminatory or preferential basis; or

(C) have a material adverse effect on the reliability of the ISO bulk power system;

then, except as provided in the next sentence, the PTOs' filing will not become effective until such time as FERC issues an order determining the proposal set forth in the filing to be consistent with the standard applicable under Section 205 of the Federal Power Act, and such a filing (including the transmittal letter for such a filing) shall include any written statement provided by the ISO setting forth the basis for the ISO's concerns. In the case of a filing described in sub-paragraph (iii), above, the PTOs may request that FERC permit the filing to go into effect on an interim basis, notwithstanding the conclusion of the ISO. If FERC grants the PTOs' request to permit the filing to go into effect on an interim basis, the filing will become effective, subject to refund, on the date specified in FERC's order.

The PTOs shall consult with the ISO to determine whether the ISO will need to make any software modifications in order to implement any filing authorized by this Section 3.04(b) and when any needed software modifications could reasonably be expected to be implemented. The PTOs' filing to FERC (and the transmittal letter for such a filing) shall include any written statement provided by the ISO setting forth the basis for any software-related implementation concerns raised by the ISO. The ISO shall make Commercially Reasonable Efforts to implement any needed software modifications by the effective date accepted by the FERC for a filing authorized by this Section 3.04(b), provided that, if the ISO has exercised such Commercially Reasonable Efforts, a failure to implement needed software modifications by the FERC-accepted effective date shall not constitute an event of default by the ISO under this Agreement or subject the ISO to financial damages, and further provided that the ISO shall run retroactive settlements consistent with the FERC-accepted effective date for a filing authorized by this Section 3.04(b) once such software modifications have been implemented.

(c) The ISO shall have the authority to submit filings under Section 205 of the Federal Power Act to establish and to revise:

(i) any terms and conditions of the ISO Tariff, and any separate ISO tariffs, relating to Transmission Service and/or the New England Markets, provided that: (A) the ISO shall not have the authority to revise such terms and conditions in a manner that would abridge the rights granted to the PTOs in Section 3.04(a) or Section 3.04(b); (B) the ISO shall not have the authority to eliminate Local Network Service or Local Point-to-Point Transmission Service provided under the Local Service Schedules; (C) the ISO shall not file to change the state or federally-accepted or -approved terms and conditions of any PTO's retail access plan or the terms and conditions of any retail access plans of a PTO's affiliated distribution company's (including any such terms and conditions that protect against bypass of any provision of a PTO's retail access plan) or the state or federally-accepted or -approved rates and other mechanisms for the recovery of

a PTO's wholesale or retail stranded costs in effect as of the Operations Date; and (D) the ISO shall not have the authority to transfer to any third party the ISO's Section 205 rights to revise the terms and conditions of Transmission Service or the authority to enter into agreements with any group of stakeholders to submit filings under Section 205 of the Federal Power Act to change the terms and conditions of Transmission Service where such proposed changes are not supported by the ISO but are approved by a vote of the stakeholder group.

The ISO shall provide written notification of any proposed filing under this Section 3.04(c) to the PTOs and stakeholders, which notification shall include a detailed description of the proposed filing, at least 30 days prior to the filing. The ISO shall consult with the PTOs and stakeholders and will consider any comments any PTO or stakeholder provides in developing its filing. The ISO shall retain the right to modify aspects of any filing authorized by this Section 3.04(c) after it provides written notification to the PTOs and stakeholders and shall provide notification to the PTOs and stakeholders of any material modification to such filings. In addition, the ISO shall consult with the PTOs to determine whether the filing will have any adverse impact on any PTO's revenue requirements, or on the ability of any PTO to recover its revenue requirements, or have a material adverse impact on the ability of any PTO to implement an incentive rate plan then in effect. If the affected PTOs conclude in their good faith judgment that the filing will have any of such effects, the ISO and the affected PTOs will make every reasonable effort to resolve the concerns of the affected PTOs. In the event that the affected PTOs' concerns cannot be resolved, the ISO may, nevertheless, make a filing under Section 205 provided that, except as provided in the next sentence, such a filing will not become effective until such time as the Commission issues an order determining the proposal set forth in the filing to be consistent with the standard applicable under Section 205 of the Federal Power Act. The ISO may request that FERC permit a filing authorized by this Section 3.04(c) to go into effect on an interim basis, notwithstanding the conclusion of the affected PTOs, provided that the ISO shall include in such a filing (and the transmittal letter for such a filing) any written statement provided by the affected PTOs setting forth the basis for the affected PTOs' concerns. If FERC grants the ISO's request to permit the filing to go into effect on an interim basis, the filing will become effective, subject to refund, on the date specified in FERC's order. Notwithstanding the foregoing, in Exigent Circumstances, the ISO shall have the unilateral authority, upon written notice to the PTOs, the Participants Committee, and the individual Participants, to submit any filing under Section 205 of the Federal Power Act to modify any provision of the ISO Tariff as authorized in this Section 3.04(c), provided that such filing shall be subject to all conditions set forth in this Section 3.04(c) except for those conditions that would limit the ISO from submitting or implementing such an ISO unilateral filing on an expedited basis or that would require the consultation otherwise specified herein.

(d) Except as explicitly set forth in Section 3.04(e), with respect to certain items listed in Sections 3.04(a) and 3.04(b), the ISO shall have no authority to submit a filing under Section 205 of the Federal Power Act to modify any provision of the ISO OATT that implements any of the items listed in Section 3.04(a) or Section 3.04(b). The PTOs shall have no authority to submit a filing under Section 205 of the Federal Power Act to modify any provision

of the ISO OATT that implements any of the items listed in Section 3.04(c). The ISO reserves its rights to intervene in, comment on or protest any filing made by the PTOs, and to submit proposals for the consideration of the PTOs and the PTOs reserve their rights to intervene in, comment on or protest any filing made by the ISO, and to submit proposals for the consideration of the ISO.

(e) In the event the ISO determines that a change in the design of any provision of the ISO OATT described in Section 3.04(a)(ii), (iii), (iv) or (vii) or 3.04(b) is required because the existing design of any rates or charges for Transmission Service is inconsistent with the design of the New England Markets, and such inconsistency will, if not remedied before relief would be available in a proceeding under Section 206 of the Federal Power Act, either: (i) substantially and adversely affect the efficiency or competitiveness of the New England Markets, or (ii) substantially and adversely affect the reliability of the ISO bulk power system, a senior officer of the ISO shall notify the affected PTO(s) of its determination. Upon receipt of such notification, the affected PTO(s) and the ISO shall diligently work together to arrive at appropriate changes in the rates to alleviate the conditions that led to this notification being given, while protecting the rights of the affected PTO(s) to fully recover their revenue requirements and the amount of incentive payments associated with FERC-accepted or -approved incentive arrangements for the PTO(s). If the affected PTO(s) and the ISO agree on a solution to this issue, the affected PTO(s) shall make a filing at FERC under Section 205 consistent with such agreement.

If the affected PTO(s) and the ISO cannot agree on a mutually acceptable Section 205 filing to address this issue within a period of thirty (30) days, and the affected PTO(s) do not make a Section 205 filing within the thirty (30) day period, then the ISO shall have the authority to submit a filing under Section 205 of the Federal Power Act as permitted herein, provided that such a Section 205 filing shall not be submitted until the PTOs have an opportunity to meet with representatives of the ISO Board of Directors if requested by any PTO with reasonable notice, and the ISO may, with the approval of FERC, place a replacement for such rate design into effect, while the proceeding on the ISO's filing is pending before FERC, for a period no longer than fifteen (15) months, provided that such filing shall not propose a modification that adversely affects the rights of the affected PTO(s) to fully recover their FERC-allowed revenue requirements and the amount of incentive payments associated with FERC-allowed incentive arrangements for the PTO(s) or that would result in any costs previously approved or accepted for recovery under either a federal or state-jurisdictional rate thereafter becoming unrecoverable under either a federal or state-jurisdictional rate, and the replacement rate design proposal of the ISO is subject to refund and surcharge, as necessary to restore the status quo ante if FERC does not ultimately approve that proposal. To place its replacement rate design proposal into effect, the ISO shall bear the burden of persuading FERC that: (i) the ISO's replacement proposal is consistent with the standard applicable under Section 205 of the Federal Power Act; (ii) the ISO's determination regarding the inconsistency of the existing rate design with the design of the New England Markets and the impact of that inconsistency, as set forth in the first sentence of this subsection, is correct; and (iii) the ISO's proposal will not adversely affect the rights of the affected PTO(s) to fully recover their FERC-allowed revenue requirements or the amount of

incentive payments associated with FERC-allowed incentive arrangements for the PTO(s) or to fully recover costs previously approved or accepted for recovery under either a federal or state-jurisdictional rate. Notwithstanding the foregoing, in Exigent Circumstances, the ISO shall have the unilateral authority, upon written notice to the PTOs, the Participants Committee and the individual Participants, to submit a filing under Section 205 of the Federal Power Act to modify any provision of the ISO Tariff described in this Section 3.04(e), provided that such filing shall be subject to all conditions set forth in this Section 3.04(e) except for those conditions that would limit the ISO from submitting or implementing such an ISO unilateral filing on an expedited basis or that would require the consultation otherwise specified herein.

(f) In the event the ISO concludes that a filing to establish or to revise the terms and conditions listed in Section 3.04(c) is required and that providing the notification or consultation required under Section 3.04(c) for such filing would result in an unanticipated material adverse effect on the efficiency or competitiveness of the New England Markets or the reliability of the ISO bulk power system in the circumstances, the ISO: (i) shall provide such notification to the PTOs and stakeholders or undertake such consultation with the PTOs and stakeholders as is possible under the circumstances; and (ii) may submit a filing under Section 205 to establish or to revise the terms and conditions listed in Section 3.04(c) upon issuance of a written statement setting forth the circumstances that do not permit such notification or consultation.

(g) In the event the PTO(s) conclude that a filing to establish or to revise the rates, terms and conditions listed in Section 3.04(a) or 3.04(b) is required and that providing the notification or consultation required under Section 3.04(a) or Section 3.04(b) for such filing would result in an unanticipated material under-recovery of the PTO(s)' revenue requirements or other material adverse financial effect on the PTO(s), the PTO(s): (i) shall provide such notification to the ISO and stakeholders or undertake such consultation with the ISO as is possible under the circumstances; and (ii) may make a Section 205 filing to establish or to revise the rates, terms and conditions listed in Section 3.04(a) or 3.04(b) upon issuance of a written statement setting forth the circumstances that do not permit such notification or consultation.

(h) Cost Allocation Moratorium

(i) During the five (5) year period commencing on the Operations Date (the "Moratorium Period"), neither the PTOs, pursuant to Section 3.04(b), nor the ISO, pursuant to Section 3.04(e), shall submit filings under Section 205 of the Federal Power Act to modify:

(A) the provisions and schedules of the ISO OATT governing the split between PTF and Non-PTF transmission facilities in effect prior to the Operations Date for purposes of allocating costs to Transmission Customers;

(B) the provisions and schedules of the ISO OATT establishing the methodology by which the costs of Transmission Upgrades and New

Transmission Facilities related to generator interconnections are allocated under the ISO OATT; and

(C) the provisions and schedules of the ISO OATT establishing the methodology by which the costs of New Transmission Facilities and Transmission Upgrades are allocated under the ISO OATT;

(ii) The Parties' agreement to forego submission of Section 205 filings during the Moratorium Period with respect to the items listed in Section 3.04(h)(i) (A) through (C) above shall not restrict in any way the rights of the PTOs, pursuant to and in accordance with Sections 3.04(b) or 3.04(a), to submit Section 205 filings to modify any elements of the rates applicable to Transmission Service other than those items listed in Section 3.04(h)(i) (A) through (C). Nothing in this Section 3.04(h) shall restrict in any way the rights of the PTOs to submit Section 205 filings to establish incentive or performance-based rates in accordance with Section 3.04(b)(iii) or to submit Section 205 filings to establish formula or stated rates in accordance with Section 3.04(b)(i), provided that such filings do not propose to modify the items listed in Section 3.04(h)(i) (A) through (C). Nothing in this Section 3.04(h) shall restrict in any way the rights of the ISO, pursuant to and in accordance with Section 3.04(e), to submit Section 205 filings to modify any elements of the rates applicable to Transmission Service other than, provided that such filings do not propose to modify the items listed in Section 3.04(h)(i) (A) through (C).

(iii) Notwithstanding Section 3.04(h)(i)(B) above, to the extent that the requirements for any New Transmission Facilities or Transmission Upgrades associated with new or existing generation set forth in the ISO OATT are modified during the Moratorium Period in a manner that creates a new or modified category of generator-related transmission costs, the PTOs shall have the authority, in accordance with Section 3.04(b), to submit Section 205 filings during the Moratorium Period to establish the methodology by which such new or modified generator-related transmission costs are allocated.

(iv) Nothing in this Section 3.04(h) shall supersede or alter the effect of any FERC orders concerning the allocation of costs for specific transmission facilities in the New England region.

(v) Nothing in this Section 3.04(h) shall restrict in any way the rights of the ISO or of any PTO during the Moratorium Period to submit a filing under Section 206 of the Federal Power Act to modify the provisions and schedules described in Section 3.04(h)(i) (A) through (C).

(vi) After the end of the Moratorium Period, the PTOs may exercise their rights in accordance with Section 3.04(b) to submit Section 205 filings to

modify the provisions and schedules described in Section 3.04(h)(i) (A) through (C); provided that:

(A) The PTOs must provide the ISO, the Regional State Committee established by the states in the ISO region (the “Regional State Committee”), and stakeholders no less than 90 days advance notification of the proposed filing, including a detailed description of any proposed change to the cost allocation provisions set forth in Schedules 11 or 12 of the ISO OATT as of the Operations Date (or the successors thereto). The PTOs, the ISO and the Regional State Committee shall engage in a process of consultation and negotiation in order to attempt to reach consensus on such filing.

(B) At least 30 days prior to the proposed filing date the Regional State Committee may inform the PTOs that the Committee opposes the PTOs’ proposal to change the cost allocation provisions set forth in Schedules 11 or 12 of the ISO OATT as of the Operations Date (or the successors thereto).

(C) If the Regional State Committee opposes the PTOs’ proposal to change the cost allocation provisions set forth in Schedules 11 or 12 of the ISO OATT as of the Operations Date (or the successors thereto), the PTOs may make the Section 205 filing to modify the cost allocation provisions set forth in Schedules 11 or 12 of the ISO OATT as of the Operations Date (or the successors thereto); provided that: (1) such filing may not go into effect until FERC has approved the filing; (2) the Regional State Committee will have the right to provide the PTOs with an alternative proposal to change the cost allocation provisions set forth in Schedules 11 or 12 of the ISO OATT as of the Operations Date (or the successors thereto) which the PTOs will include in their Section 205 filing and which will be considered on an equal footing with the PTOs’ proposal in the FERC proceeding, and (3) such alternative proposal shall not adversely affect the rights of the affected PTO(s) to fully recover their FERC-allowed revenue requirements and the amount of incentive payments associated with FERC-allowed incentive arrangements for the PTO(s) or result in any costs previously approved or accepted for recovery under either a federal or state-jurisdictional rate thereafter becoming unrecoverable under either a federal or state-jurisdictional rate.

(D) If, notwithstanding the requirements of Section 3.04(h)(vi)(C), the Regional State Committee submits an alternative proposal to change the cost allocation provisions set forth in Schedules 11 or 12 of the ISO OATT as of the Operations Date (or the successors thereto) that any PTO believes causes an under-recovery of costs when

used in conjunction with the other elements of the rate design for transmission rates filed by the PTOs (or the one already in effect if the PTOs' filing does not propose to change the rate design), the PTO(s) will have the right: (1) to include in such filing an explanation of why the PTO or PTOs believe the Regional State Committee proposal causes an under-recovery of costs contrary to the requirements of Section 3.04(h)(vi)(C); and (2) to file a modified rate design that eliminates such under-recovery (or a rate mechanism filed by one or more PTOs individually for that purpose, when the under-recovery affects them uniquely) in the event that the alternative proposal to change the cost allocation provisions set forth in Schedules 11 or 12 of the ISO OATT as of the Operations Date (or the successors thereto) is approved by the FERC placed into effect coincident with the effective date of such proposal.

(E) Any requirements established by this Section 3.04(h)(vi) with respect to the Regional State Committee shall not subject any PTO or ISO-NE to the jurisdiction or authority of any agent or agency of any state participating in the Regional State Committee.

(vii) After the end of the Moratorium Period, the ISO may exercise its rights in accordance with Section 3.04(e) to submit Section 205 filings to modify the provisions and schedules described in Section 3.04(h)(i) (A) through (C) if the PTOs fail to alleviate the conditions specified in Section 3.04(e).

(i) The ISO shall have sole authority to submit Section 205 filings to recover its administrative, capital and other costs (including the collection of funds from Transmission Customers to support payment of FERC annual charges with respect to transmission service for which the ISO is the Transmission Provider as defined in FERC rules and orders) including the design of any charges therefore (the "ISO Administrative Charge").

(j) Nothing in this Agreement shall restrict in any way the rights of the ISO or of any PTO to submit an application under Section 206 of the Federal Power Act for revisions to the rates, terms and conditions of service under the ISO OATT. Nothing in this Agreement shall subject any Publicly-Owned PTO to regulation of rates and charges applicable to its transmission facilities under Sections 205 or 206 of the Federal Power Act; provided, however, that the justness and reasonableness of regional transmission rates or charges may be evaluated in light of the levels of, and manner in which, the costs of Publicly-Owned PTOs' transmission facilities are recovered under regional transmission rates.

(k) Nothing in this Agreement shall restrict in any way the rights of any PTO to submit a proposal under Section 205 of the Federal Power Act to participate in, join, or become an ITC pursuant to Attachment M to the ISO OATT and, upon approval of such proposal, to withdraw from this Agreement in accordance with Section 10.01 of this Agreement.

(l) Stakeholder Process for Regional Rate Filings.

(i) Absent unanticipated circumstances, every PTO proposal to modify regional rates in accordance with Section 3.04(b) shall be presented by the PTOs to the appropriate stakeholder Technical Committee(s) for consideration and an advisory vote. The Technical Committee, at its next meeting following the one at which the initial presentation is made (which shall be no later than 30 days after any proposal is made), shall: (i) vote on the merits of the proposal as presented or with changes accepted by the PTOs; or (ii) by motion and vote of 66-2/3%, defer action on any proposal presented if it reasonably determines that additional information should and could be provided to more adequately inform the members of such Technical Committee before a vote on the merits is taken. Any deferral shall be for no more than 30 days, after which the PTOs may move for an advisory vote upon their proposal at the next meeting of the Technical Committee (which shall be held within 30 days of the start of the deferral). At that time, the Technical Committee may vote on the merits of the proposal as presented or with changes approved by the Committee, or may vote to oppose the proposal on the grounds that sufficient information has still not been provided, but may not defer consideration of the proposal for any further period without the consent of the PTOs. Failure of the Technical Committee to vote within the time frames set forth in this paragraph shall advance the process to the next step, and in no event shall a period of longer than 60 days be required for the PTOs to submit a proposal to modify regional rate design in accordance with Section 3.04(b) to the Participants Committee.

(ii) Absent unanticipated circumstances and after the fulfillment of the procedures outlined in Section 3.04(l)(i), every PTO proposal to modify regional rates in accordance with Section 3.04(b) shall be presented by the PTOs to the stakeholder Participants Committee for an advisory vote, along with a report of any action, failure to act or advisory vote taken by any Technical Committee(s). Such report shall be considered by the Participants Committee no later than the first regularly scheduled meeting following notification of that presentation. The Participants Committee shall: (i) vote on the merits of the proposal as presented or with changes accepted by the PTOs; or (ii) by motion and vote defer action on any proposal if it reasonably determines that the proposal presented is materially different from the proposal presented to the Technical Committee, and was not voted on by the Technical Committee. Any deferral shall result in a repeat of the processes outlined above. Notwithstanding the foregoing, the Participants Committee may, at its discretion, consider and vote upon any proposal submitted to it and such a vote shall have the same effect as if the proposal had first been voted upon by a Technical Committee. The Participants Committee may not defer action on any item that has been voted on by a Technical Committee and presented to the Participants Committee for an advisory vote unless the PTOs consent to such deferral. If the Participant Committee has not scheduled a meeting to vote on the merits of a PTO proposal to modify regional rates in accordance with Section 3.04(b) prior to date that the PTOs intend to submit such

a proposal to the FERC, then the PTOs shall request that the Participants Committee schedule a special meeting to conduct an advisory vote on the merits of such proposal. In no event shall the PTOs be required to wait for a Participant Committee advisory vote for a period of longer than 90 days after initial notification of such proposal to stakeholders prior to submitting a proposal to modify regional rate design in accordance with Section 3.04(b) to the FERC.

(iii) An advisory vote by the Participants Committee on the merits of any proposal, whether in favor of or in opposition, terminates the stakeholder proceedings absent voluntary resubmission of the same or a modified proposal by the PTOs, at a future time. The PTOs shall report the results of such advisory vote in any relevant filing made by the PTOs with the FERC. A failure by the Participants Committee to vote within the time frames outlined above terminates the Participant proceedings absent voluntary resubmission of the same or a modified proposal by the PTOs at a future time.

(iv) Nothing in this Section 3.04(l) shall limit the ability of the PTOs to submit a filing pursuant to Section 3.04(g) to modify regional rates in the event the PTOs conclude that a filing to modify regional rates is required due to unanticipated circumstances, provided that the PTOs shall provide such notification to the stakeholder Participant Committee or undertake such consultation with the stakeholder Technical Committee(s) and Participant Committee as is possible under the circumstances and shall provide the Participants Committee with a written statement setting forth the circumstances that do not permit the notification or consultation otherwise required by this Section 3.04(l).

(v) The process set forth in this Section 3.04(l) shall not apply to filings related to regional rates submitted to the FERC on an informational basis. The applicable process for review of such informational filings shall be set forth in the ISO OATT.

(m) Highgate Transmission Facilities (HTF).

(i) The costs of the HTF shall be included in the transmission rates for Regional Network Service on a phased-in basis, in accordance with Appendix B to the Attachment F Implementation Rule of the ISO OATT, provided that:

(A) the costs of the HTF shall be fully phased into the transmission rates for Regional Network Service in year 5 as defined in Appendix B to the Attachment F Implementation Rule of the ISO OATT;

(B) the HTF shall not be classified as PTF for rate purposes under the ISO OATT; and

(C) the rate treatment of the HTF shall establish no precedent or presumption concerning rate treatment of any other HVDC transmission facilities.

(ii) the HTF shall be classified as Category A Facilities, provided, however, that the classification of the HTF as Category A facilities under this Agreement shall establish no binding precedent or presumption concerning the operational and other terms and conditions for other HVDC facilities over which the ISO may obtain operational and other authority under this TOA or other ISO operating agreements in the future.

3.05 **The ISO's Responsibilities.**

(a) In addition to its other obligations under this Agreement, in performing its obligations and responsibilities hereunder, and in accordance with Good Utility Practice, the ISO shall:

(i) maintain system reliability;

(ii) in all material respects, act in accordance with applicable Laws and conform to, and implement, all applicable reliability criteria, policies, standards, rules, regulations, orders, license requirements and all other applicable NERC/NPCC Requirements, and other applicable reliability organizations' reliability rules, and all applicable requirements of federal or state laws or regulatory authorities; and

(iii) act without undue preference to any Party.

(b) The ISO shall obtain and retain all necessary authorizations of FERC and other regulatory authorities to function as the New England RTO and shall possess the characteristics and perform the functions required for that purpose.

3.06 **Each PTO's Responsibilities.**

(a) From and after the Operations Date, each PTO shall, in accordance with Good Utility Practice:

(i) direct, physically operate, repair, and maintain its Transmission Facilities and Local Control Centers in accordance with this Agreement, applicable Law, and applicable Operating Procedures;

(ii) operate and maintain, or arrange for a third party, approved by such PTO, in its sole discretion, to operate and maintain, one or more suitable Local Control Centers (including any Local Control Centers maintained as back-up for a PTO's primary Local Control Centers). Each PTO shall provide the ISO

with reasonable notice of any change to its Local Control Center(s) and shall coordinate with the ISO to ensure that such a change will not adversely affect the reliable operation of the New England Transmission System. Each PTO shall have the responsibility to ensure that its Local Control Center(s) will: operate PTO Transmission Facilities on a 24 hour basis, implement the instructions, orders and directions received from the ISO in the exercise of its Operating Authority in accordance with Section 3.02, and perform the following functions in accordance with applicable Operating Procedures:

- (A) switching and tagging;
- (B) on-line monitoring;
- (C) security analysis;
- (D) dispatch voltage and reactive power, provided that the ISO shall dispatch voltage and reactive power to the extent the Local Control Centers are unable to maintain normal voltage schedules;
- (E) coordinate the development of settings for dynamic reactive resources, FACTS controllers, special protection systems, PARS, and other similar dynamic equipment that affects power flows;
- (F) implementation of the PTO Local Restoration Plan and development of modifications to such PTO Local Restoration Plans, subject to the approval of the ISO in order to coordinate and promote the reliability of the Restoration Plans;
- (G) operation and maintenance of communication systems and software;
- (H) implementation of voltage reduction measures;
- (I) implementation of Load Shedding;
- (J) coordinate with the ISO and the other PTOs with respect to congestion management efforts and, to the extent applicable, demand-side management and distributed generation efforts, provided that a PTO employee who is engaged in such coordination and who is not a Local Control Center employee shall be subject to the same standards of conduct and applicable provisions of the ISO

Information Policy as a Local Control Center employee;
and

(K) coordinate with other entities interconnected with the New England Transmission System.

(iii) cooperate with the ISO's performance of the monitoring and audits in connection with all monitoring and compliance provisions detailed in Section 3.02(i) of this Agreement;

(iv) consistent with practice prior to the Operations Date, designate its Local Control Centers to serve as back up to the ISO reliability functions until the ISO re-establishes operational control at its own Back-up Control Center; provided that, in such situations, necessary information will be made available to such Local Control Centers to facilitate the continued operation of the New England Transmission System and that each PTO will comply with Section 11.09 and the ISO Information Policy on file with FERC to prevent such information from reaching any unauthorized person or entity;

(v) collaborate with the ISO with respect to:

(A) the development of Rating Procedures,

(B) the establishment of ratings for each PTO's New Transmission Facilities;

(C) the establishment of ratings for each PTO's Acquired Transmission Facilities that do not have an existing rating as of the Operations Date, and

(D) the establishment of any changes to existing ratings for Transmission Facilities in effect as of the Operations Date.

To the extent there is any disagreement between the ISO and any PTO or PTOs concerning Rating Procedures or the rating of a Transmission Facility owned by such PTO or PTOs, such disagreement shall be the subject of good faith negotiations between the applicable PTO or PTOs and the ISO, provided that; (x) the applicable PTOs' position concerning such Rating Procedures or Transmission Facility ratings shall govern until the applicable PTOs and the ISO agree on a resolution to such disagreement; and (y) nothing in this Section 3.06(a)(v) shall limit the rights of the ISO or of any PTO to submit a filing under Section 206 of the Federal Power Act with respect to Transmission Facility ratings or Rating Procedures. During any collaboration or discussions concerning Transmission Facility ratings, the PTOs shall continue to provide the ISO with

up-to-date ratings information in accordance with the applicable Rating Procedures.

(vi) undertake operating actions in accordance with any tariffs or rate schedules approved or accepted by FERC;

(vii) provide the ISO with the right to use a level of communications capacity (and maintain the equipment associated with this capacity in accordance with Good Utility Practice) on its telecommunication assets and equipment attached to or associated with Transmission Facilities consistent with practice prior to the Operations Date in order to supply reliability-related data including meter, voice and data communications; continue to receive and send (for Regulation purposes) telemetry to and from existing generators and transmission substations; provide for the receipt of such information from generators and substations, and provide metering data and/or telemetry to the ISO (including providing the infrastructure for Regulation and Frequency Response Service), as reasonably necessary for the ISO to perform its obligations under this Agreement and the ISO OATT; provided that a PTO shall have the unfettered right to use communications capacity on its telecommunication assets and equipment attached to or associated with Transmission Facilities for other business purposes to the extent such capacity is not being used by the ISO as of the Operations Date; and provided further that: (1) as required by the Schedule 22 Large Generator Interconnection Agreement and Schedule 23 Small Generator Interconnection Agreement in the ISO OATT, each PTO shall include provisions in its Interconnection Agreements with generators after the Operations Date providing for the installation and maintenance of sufficient communications capability to allow the ISO to exercise its Operating Authority with respect to such generators, and (2) the ISO may include the installation of additional communications capacity as an identified need in the regional transmission expansion plan, in which case such installation may be included within the PTO obligation to build set forth in, and subject to the terms and conditions in, Section 7 of Schedule 3.09(a).

(viii) notify the ISO prior to making changes to the operational status of such PTO's Category B Facilities and provide information on the operational status of Category B Facilities consistent with practice prior to the Operations Date;

(ix) operate or cause to be operated its Local Area Facilities in a manner that does not result in the violation of reliability standards applicable to the New England Transmission System;

(x) provide the ISO with revenue metering data or cause the ISO to be provided with such revenue metering data;

(xi) in all material respects, comply with all applicable laws, regulations, orders and license requirements, and with all applicable requirements, and with all applicable NERC/NPCC Requirements, other applicable reliability organizations' local reliability rules, and all applicable requirements of federal or state laws or regulatory authorities.

(b) Operation of Transmission Facilities During A System Failure. Existing Operating Procedures for use during a System Failure shall be utilized by the ISO and the PTOs. Any modifications to the Existing Operating Procedures for use during a System Failure or new Operating Procedures for use during a System Failure shall be developed by the ISO in the manner specified in Section 3.02(d). The procedures for use during a System Failure shall provide that, in situations where immediate action is required, each PTO's Local Control Center(s) shall have the authority to take the following reliability actions at a minimum, provided that each PTO shall coordinate with the ISO as soon as practicable upon taking such action::

- (i) Undertake those operational functions with respect to Transmission Facilities undertaken by the ISO under non-System Failure conditions;
- (ii) Re-energize transmission facilities following breaker trips;
- (iii) Implement emergency Load Shedding and voltage reduction measures and subsequent restoration;
- (iv) Implement Voltage/VAR control;
- (v) Adjust PARS settings;
- (vi) Dispatch generation as necessary to preserve system reliability; in accordance with applicable NERC/NPCC Requirements and ISO directives; and
- (vii) Take such other measures necessary, consistent with Good Utility Practice, to respond to a System Failure.

Nothing in this Section 3.06(b) shall limit the right of each PTO pursuant to Section 3.07 to take any action(s) that it deems necessary to prevent loss of human life, injury to persons and/or damage to property.

3.07 Reserved Rights of the PTOs.

(a) Notwithstanding any other provision of this Agreement to the contrary, each PTO shall retain all of the rights set forth in this Section 3.07; provided, however, that such rights shall be exercised in a manner consistent with applicable NERC/NPCC Requirements and applicable regulatory standards. This Section 3.07 is not intended to reduce or limit any other rights of a PTO as a signatory to this Agreement or under the ISO OATT.

(i) Nothing in this Agreement shall restrict any rights: (A) of each PTO that is a party to a merger, acquisition or other restructuring transaction to make filings under Section 205 of the Federal Power Act with respect to such PTO's reallocation or redistribution of revenues or the assignment of such PTO's rights or obligations, to the extent the Federal Power Act requires such filings; or (B) of any PTO to terminate its participation in this Agreement pursuant to Article X of this Agreement, notwithstanding any effect its termination from the ISO may have on the distribution of transmission revenues among other PTOs.

(ii) Except as expressly provided in the grant of Operating Authority to the ISO, each PTO retains all rights that it otherwise has incident to its ownership of, and legal and equitable title to, its assets, including its Transmission Facilities and all land and land rights, including the right to build, acquire, sell, lease, merge, dispose of, retire, use as security, or otherwise transfer or convey all or any part of its assets, subject to the PTO's compliance with Section 2.06 of this Agreement. Subject to Article X, a PTO may, directly or indirectly, by merger, sale, conveyance, consolidation, recapitalization, operation of law, or otherwise, transfer all or any portion of such PTO's Transmission Facilities subject to this Agreement but only if such transferee or successors shall agree in writing to be bound by terms of this Agreement.

(iii) Any expansion or modification by a PTO of its Transmission Facilities, any facilities constructed by a PTO to connect the facilities of a current or proposed Transmission Customer to such Transmission Facilities, and/or any new transmission facilities constructed by a PTO pursuant to the ISO Planning Process shall be subject to such PTO's right to recover, pursuant to appropriate financial arrangements and tariffs or contracts, all costs prudently incurred or prudently committed to be incurred, plus a return on invested equity and other capital, associated with constructing and owning or financing such facilities, expansions or modifications to its Transmission Facilities, in accordance with Schedule 3.09(a) hereof.

(iv) The responsibilities granted to the ISO under this Agreement shall not affect the rights of a PTO to modify or expand its Transmission Facilities, nor confer upon the ISO any authority to direct a PTO to modify or expand its Transmission Facilities except as provided in Schedule 3.09(a), and each PTO shall retain all rights and responsibilities specifically assigned to PTOs pursuant to Schedule 3.09(a).

(v) Each PTO shall have the right to adopt and implement, consistent with Good Utility Practice, procedures and to take such actions it deems necessary to protect its facilities from physical damage or to prevent injury or damage to persons or property.

(vi) Each PTO retains the right to take whatever actions, consistent with Good Utility Practice, it deems necessary to fulfill its obligations under applicable Law.

(vii) Nothing in this Agreement shall be construed as limiting in any way the rights of a PTO to make any filing with any applicable state or local regulatory authority.

(viii) Each PTO may request that the ISO commit additional generators (including specific output levels), or each PTO may take other actions permitted under the ISO OATT and Market Rules (including self-scheduling), if the PTO determines that additional generation is needed to ensure local area reliability, provided that the ISO shall make the final determination whether to commit additional generation in accordance with applicable provisions of the ISO OATT and Market Rules

(ix) Subject to Section 2.05, each PTO shall retain the right to enter into Interconnection Agreements with transmission owners, generators and other entities connecting with such PTO's transmission facilities (including Transmission Facilities) and to file such agreements for approval or acceptance by FERC.

(x) Each PTO shall have the right to retain one or more subcontractors to perform any or all of its obligations under this Agreement. The retention of a subcontractor pursuant to the terms of this Section 3.07 shall not relieve the PTO of its primary liability for the performance of any of its obligations under this Agreement.

(b) Any and all other rights and responsibilities of a PTO related to the ownership or operation of its Transmission Facilities not expressly assigned to the ISO under this Agreement will remain with such PTO.

(c) Nothing in this Agreement shall be deemed to impair or infringe on any rights or obligations of the PTOs under the Federal Power Act and FERC's rules and regulations thereunder, provided that any such rights are not inconsistent with the express terms of this Agreement. Nothing contained in this Agreement shall be construed to limit in any way the right of any PTO to take any position, including opposing positions, in any administrative or judicial proceeding or filing by other PTOs or the ISO, notwithstanding that such proceeding or filing may be undertaken or made, explicitly or implicitly, pursuant to this Agreement.

(d) Nothing in this Agreement shall be deemed to impair or infringe on the exemption of Publicly-Owned PTOs, under Section 201(f) of the Federal Power Act, from the obligations and requirements of the Federal Power Act. Notwithstanding anything to the contrary in this Agreement, nothing contained herein shall subject any Publicly-Owned PTO to

any requirement or obligation imposed by the Federal Power Act that would not apply to such Publicly-Owned PTO in the absence of this Agreement.

3.08 **Repair and Maintenance of Transmission Facilities.**

(a) **Planning, Scheduling, and Approval of Transmission Facility Outages.**

(i) Each PTO shall submit to the ISO long-term plans for Transmission Facility outages, shall submit to the ISO schedules for Transmission Facility outages, and shall obtain ISO approval for Transmission Facility outages in accordance with, and to the extent required by, Market Rule 1.

(ii) Notwithstanding any of the foregoing, nothing in this Section 3.08 shall be construed to require a PTO to reschedule an outage of a Transmission Facility or to require a PTO to refrain from initiating switching and tagging procedures to take a Transmission Facility out of service or place it back into service to the extent a PTO determines that such outage or actions are necessary to prevent injury or damage to persons or property or to protect its facilities from physical damage, in accordance with Section 3.07(a)(v) of this Agreement.

(b) **Recovery of Transmission Outage Rescheduling Costs.** The PTO(s) shall have the right, either collectively pursuant to and in accordance with Section 3.04(b), or individually pursuant to and in accordance with Section 3.04(a), to file a schedule to the ISO OATT that will provide for reimbursement to the affected PTO(s) for any direct costs incurred by the PTO(s) due to the ISO's rescheduling or revocation of a previously scheduled or approved Transmission Facility outage to the extent the ISO reschedules or revokes a previously scheduled or approved Transmission Facility outage in accordance with Market Rule 1.

(c) **Annual Assessment of Outage Coordination Efforts.** The ISO shall prepare and issue annual public reports on the scheduling and coordination of transmission outages. Each such annual report shall: (i) assess the accuracy of the ISO's estimation of congestion and RMR cost impacts and the accuracy of PTO and other inputs used in such estimation; (ii) assess any long term impacts of the ISO's exercise of its authority to require the rescheduling of transmission maintenance outages and. (iii) include analyses and data which could allow a PTO to identify potential opportunities for incentives based on efficient coordination of outages and other operational measures that will reduce congestion costs or increase operational flexibility. The ISO shall provide a draft of each such annual report to the PTOs and interested stakeholders prior to issuing a final report and shall consider the input of the PTOs and interested stakeholders in preparing such reports, subject to any applicable restrictions set forth in the ISO Information Policy on file with FERC.

(d) Development of Incentive Proposals. Notwithstanding any other provision in this Agreement, the ISO will apply reasonable efforts to work actively with any interested PTO(s) to analyze alternatives including incentives adopted in other markets and to provide input for use by the interested PTO(s) in developing the design of incentive rates or mechanisms for regional congestion cost reduction. The ISO will work with other stakeholders in a similar fashion if so requested. Any such incentive proposal shall be filed by a PTO or PTOs with FERC in accordance with Section 3.04(a) or Section 3.04(b) as applicable. Such incentive mechanisms shall be designed to further improve coordination of outages or operational measures in a manner that will reduce overall congestion or RMR costs. Any PTO incentive must be approved or accepted by FERC. Each PTO developing an incentive proposal shall attempt to reach agreement with the ISO before filing an incentive proposal with FERC. The ISO may submit filings to the FERC (including a protest or a complaint under Section 206 of the Federal Power Act) raising any questions or concerns that it may have concerning a specific incentive proposal, provided that the ISO shall not contend that an incentive proposal is inappropriate or oppose the proposal on the ground that the PTOs have agreed to the provisions of Section 3.08 of this Agreement.

(e) Market Monitoring of Outage Scheduling. The Market Monitoring Unit of the ISO shall monitor the outage scheduling activities of the PTOs. The Market Monitoring Unit of the ISO shall have the right to request that each PTO provide information to the Market Monitoring Unit concerning the PTO's scheduling of Transmission Facility outages, including the rescheduling or cancellation of any Planned, Scheduled or Approved Outage, and the PTO shall provide such information to the Market Monitoring Unit in accordance with Section 11.09(c) of this Agreement.

(f) Damage or Destruction of Transmission Facilities.

(i) If, at any time during the Term, any of a PTO's Transmission Facilities are damaged or destroyed, then, such PTO shall determine, in its sole discretion, consistent with Good Utility Practice and applicable Law, whether or not (and if so, in what manner) to restore or cause the restoration of such damaged or destroyed Transmission Facilities to substantially the same condition, character or use as existed before the damage or destruction, if at all, provided that such PTO shall consult with the ISO prior to making such determination and shall comply with the requirements specified in Section 2.06.

(ii) Nothing in this Section 3.08(f) shall limit the authority of the ISO to direct a PTO to modify or expand its Transmission Facilities in accordance with the ISO Planning Process, subject to the terms and conditions of Schedule 3.09(a) hereof.

3.09 **Planning and Expansion.**

(a) Each PTO shall perform all of its responsibilities, and exercise each of its rights, with respect to the planning and expansion of the New England Transmission System in accordance with the ISO OATT and Schedule 3.09(a) hereto. The ISO shall perform all of its responsibilities pursuant to the ISO Planning Process set forth in the ISO OATT. Each PTO shall engage in planning for its Local Area Facilities in a manner that is consistent with applicable NERC/NPCC Requirements, Good Utility Practice and the ISO OATT. The ISO and each PTO shall perform all such responsibilities in accordance with applicable Laws and Good Utility Practice. Nothing in this Agreement shall be construed to impose on any PTO an obligation to build transmission facilities except as provided in Schedule 3.09(a) hereto.

(b) The ISO shall utilize the Planning Procedures relating to the planning and expansion of the New England Transmission System. The Planning Procedures shall initially consist of the Planning Procedures in existence on the Operations Date (hereinafter “Existing Planning Procedures”). Such Existing Planning Procedures shall consist of those Planning Procedures listed in Schedule 3.09(b). The ISO shall develop any modifications to Planning Procedures (including Existing Planning Procedures) and any new Planning Procedures that it may deem necessary or appropriate in coordination with the PTOs and other stakeholders. In the event that the ISO and the applicable PTO(s) disagree about modifications to the portions of the Planning Procedures related to the planning and expansion of Transmission Facilities or any new Planning Procedures related to the planning and expansion of Transmission Facilities, the affected PTO(s) will have the opportunity to submit the dispute for resolution in accordance with the dispute resolution provisions set forth in Section 11.14 herein. Pending such resolution, the ISO shall have the authority to implement any such new Planning Procedures or modified Planning Procedures.

3.10 **Invoicing, Collection and Disbursement of Customer Payments.**

(a) Invoicing as of Operations Date. Except as provided in Section 3.10(a)(ii) and beginning on the Operations Date, the ISO will administer its current net settlement system, including invoicing of charges to Transmission Customers for Transmission Services on the Transmission Facilities as follows:

(i) The charges invoiced by the ISO shall include the following (each, an “Invoiced Amount”):

(A) any and all revenue requirements, rates, charges, fees and/or penalties for Transmission Service under the ISO OATT and related service agreements which the PTOs have filed with FERC pursuant to Section 3.04(b) and which have been accepted by FERC, including without limitation recovery of wholesale or retail stranded costs, other than amounts billed directly by PTOs pursuant to Section 3.10(a)(ii) below; and

(B) any and all rates, charges, fees and/or penalties under interconnection agreements which have been filed with and accepted by FERC, other than amounts billed directly by PTOs pursuant to Section 3.10(a)(ii) below.

(ii) Payments relating to Grandfathered Transmission Agreements, all services provided by a PTO pursuant to its Local Service Schedule on or after the Operations Date, interconnection agreements that provide for payment to PTOs, and any other payments made directly to the PTOs prior to the Operations Date shall continue to be invoiced by the PTOs and shall not be invoiced by the ISO; provided that, notwithstanding the foregoing, each PTO and the ISO may enter into separate agreements such that the ISO provides invoicing services for such payments

(iii) The ISO shall remit or credit to the PTOs, consistent with the ISO Tariff and the net settlement system, any and all payments received or collected from Transmission Customers for Invoiced Amounts in accordance with this Agreement and directions provided to the ISO by the PTO Administrative Committee. The PTO Administrative Committee shall provide such directions to the ISO in accordance with the Disbursement Agreement among the PTOs. The PTO Administrative Committee (or such subcommittee as the PTO Administrative Committee shall designate for such purpose) shall also respond to any ISO questions or requests for clarification concerning such directions; provided that the ISO shall be able to rely upon the decision of the PTO Administrative Committee unless and until it receives notification from the PTO Administrative Committee or from a Governmental Authority of reversal of such direction by any Governmental Authority with jurisdiction over this Agreement.

(b) The ISO's Collection Obligations and Application of Financial Assurances

Policies.

(i) If a Transmission Customer defaults on any payment of any PTO Invoiced Amount (the "Owed Amounts"), the ISO shall take all necessary actions to execute or call upon any Financial Assurances held by the ISO attributable to such Transmission Customer.

(ii) In connection with a default on payment of an Invoiced Amount by a Transmission Customer, the ISO shall, upon the request of the PTO AC, take those actions necessary to suspend Transmission Services to such defaulting Transmission Customer, including making a filing under Section 205 of the Federal Power Act to seek consent to suspend such Transmission Services; provided that the ISO need not suspend Transmission Services until FERC approval is first obtained. This provision shall not preclude the ISO from suspending service or making a filing under Section 205 of the FPA to seek to

suspend Transmission Services or other services under the Tariff in any other circumstances.

(c) No Pledge of Invoiced Amounts. The ISO shall not create, incur, assume or suffer to exist any lien, pledge, security interest or other charge or encumbrance, or any other type of preferential arrangement (including a banker's right of set off) against any Invoiced Amounts, any accounts receivables representing Invoiced Amounts, the settlement account maintained by the ISO into which payments on Invoiced Amounts are made and from which remittances are made to the PTOs or any Financial Assurances.

3.11 Grandfathered Transmission Agreements.

(a) Notwithstanding any other provision of this Agreement, Excepted Transactions will remain in effect for the terms of such agreements. Consistent with practice prior to the Operations Date, the ISO shall exercise its Operating Authority and otherwise fulfill its responsibilities under this Agreement in a manner that is consistent with and does not modify or abrogate the terms and conditions of such Excepted Transactions.

(b) Notwithstanding any other provision of this Agreement, Grandfathered Intertie Agreements, as set forth in Schedule 3.11(b), will remain in effect for the terms of such agreements. Consistent with practice prior to the Operations Date, the ISO shall exercise its Operating Authority and otherwise fulfill its responsibilities under this Agreement in a manner that is consistent with and that does not modify or abrogate the terms and conditions of such Grandfathered Intertie Agreements.

(c) Nothing in this Agreement shall require the modification or abrogation of Grandfathered Interconnection Agreements, as set forth in Schedule 3.11(c). Consistent with practice prior to the Operations Date, the PTOs agree to exercise their rights under Grandfathered Interconnection Agreements with generators to direct or request that generators take certain actions as needed to facilitate the exercise of Operating Authority by the ISO and the reliable operation of the New England Transmission System.

(d) All payments due to the PTOs under Grandfathered Transmission Agreements shall continue to be invoiced and collected by the PTOs in accordance with the terms of those agreements and shall not be invoiced or collected by the ISO. Notwithstanding the foregoing, each PTO and the ISO may enter into separate agreements such that the ISO provides invoicing services for such payments.

(e) Nothing in this Agreement shall alter the standards, procedures or requirements applicable to the modification of any Grandfathered Transmission Agreement.

(f) Notwithstanding any other provision of this Agreement, MEPCO Operating Documents, as set forth in Schedule 3.11(f), will remain in effect for the terms of such agreements. The ISO shall exercise its Operating Authority and otherwise fulfill its

responsibilities under this Agreement in a manner that is consistent with and that does not modify or abrogate the terms and conditions of such MEPCO Operating Documents.

(g) Notwithstanding any other provision of this Agreement, MEPCO Grandfathered Transmission Service Agreements will remain in effect for the terms of such agreements or on such earlier date mutually agreed upon by the parties. Any decrease in the rates or charges under these agreements or any increase in the term of these agreements will be subject to the approval of the PTOs. The ISO shall exercise its Operating Authority and otherwise fulfill its responsibilities under this Agreement in a manner that is consistent with and that does not modify or abrogate the terms and conditions of such MEPCO Grandfathered Transmission Service Agreements.

3.12 **Subcontractors.** Each PTO acknowledges and agrees that, subject to the terms set forth herein, including Section 6.07, the ISO has the right to retain one or more subcontractors to perform any or all of its obligations under this Agreement. The retention of a subcontractor pursuant to the terms of this Section 3.12 shall not relieve the ISO of its primary liability for the performance of any of its obligations under this Agreement.

3.13 **Municipal/Tax-Exempt Utilities.**

(a) The Parties to this Agreement hereby recognize the tax-exempt status of any tax-exempt bonds or other evidence of indebtedness of Publicly-Owned PTOs used to finance any Publicly-Owned PTO's Transmission Facilities. Nothing in this Agreement is intended to, and nothing in this Agreement should be construed in a manner that would, jeopardize the tax-exempt status of any tax-exempt bonds or other debt used to finance any Publicly Owned PTO's Transmission Facilities. The Parties to this Agreement contemplate that, as to Publicly-Owned PTOs, this Agreement will be deemed to be a "contract for the operation of an electric transmission facility by an independent entity" which "does not constitute private business use" of their Transmission Facilities under regulations of the Internal Revenue Service appearing, *inter alia*, in 26 C.F.R. § 1.141-7(g)(1)(ii) and subsequently adopted regulations of similar intent and coverage.

(b) In the event of a change in the nature of this Agreement that would jeopardize the tax-exempt status of any tax-exempt bonds or other debt used to finance Publicly-Owned PTO's Transmission Facilities, or a change in the state or federal income tax treatment of the arrangements contemplated by this Agreement, or any other set of circumstances, the effect of which would be to render the participation of Publicly-Owned PTOs in the arrangements established by this Agreement inconsistent with the maintenance of the tax-exempt status of bonds or other debt used to finance any Publicly-Owned PTO's Transmission Facilities, the Parties agree, if so requested, to undertake Commercially Reasonable Efforts to develop revised or replacement arrangements that will enable the Publicly-Owned PTOs to authorize the ISO to exercise Operating Authority over the Publicly-Owned PTOs' Transmission Facilities without incurring adverse state or federal income tax treatment of their outstanding bonds or other debt used to finance any Publicly-Owned PTO's Transmission Facilities, and will otherwise maintain the tax-exempt status of Publicly-Owned PTOs' outstanding bonds or other debt used to finance

any Publicly-Owned PTO's Transmission Facilities. If, and to the extent that, the Parties to this Agreement are not able to accommodate the changes described in this subparagraph (b), the Parties will undertake Commercially Reasonable Efforts to develop an alternative means for Publicly-Owned PTOs to (i) transfer Operating Authority as to its Transmission Facilities to ISO-NE, and (ii) recover the costs of its PTF facilities in the same manner and by the same means as PTOs under this Agreement.

(c) In the event that an electric cooperative or membership corporation that owns PTF and has debt financed or guaranteed by the Rural Utilities Service ("RUS") of the United States Department of Agriculture (a "Cooperative TO") becomes a signatory to this Agreement, this Agreement shall become effective as to that Cooperative TO only upon approval of such participation by the RUS, to the extent required by RUS regulations, including those regulations currently codified at 7 C.F.R. § 1717.608 and subsequently adopted regulations of similar intent and coverage. Should such approval be denied or conditioned by the RUS in a manner unacceptable to the Cooperative TO, the other PTOs or the ISO, the other PTOs and the ISO will consult with the affected Cooperative TO and, if so requested, will undertake Commercially Reasonable Efforts to resolve to the extent practicable the objections articulated (and/or conditions imposed) by the RUS to the participation of the Cooperative TO in the arrangements contemplated by this Agreement. If, and to the extent that, the Parties to this Agreement are not able to accommodate the concerns expressed by the RUS as to the participation of such Cooperative TO, the Parties will undertake Commercially Reasonable Efforts to develop an alternative means for such Cooperative TO to (i) transfer Operating Authority as to its Transmission Facilities to ISO-NE, and (ii) recover the costs of its PTF facilities in the same manner and by the same means as PTOs under this Agreement.

(d) Nothing in this TOA or any other ISO agreement shall require any PTO on whose behalf Tax-Exempt Debt has been or will be issued, or which will issue Tax-Exempt Debt, to refund prior Tax-Exempt Debt or to violate restrictions applicable to facilities financed with Tax-Exempt Debt including contractual restrictions and covenants regarding use of such facilities.

(e) Nothing contained in this Agreement shall be construed to require any Publicly-Owned PTO: (i) to act in contravention of, or (ii) to refrain from acting where failure to act would be in contravention of, or (iii) to constitute consent or acquiescence by any Publicly-Owned PTO to any action or failure to act of any other Party in contravention of the laws of any State governing the organization or operation of the Publicly-Owned PTO.

3.14 **No Impairment of the ISO's Other Legal Rights and Obligations.**

Nothing in this Agreement shall be deemed to impair or infringe on any rights or obligations of the ISO under the Federal Power Act and FERC's rules and regulations thereunder, including the ISO's rights and obligations to submit filings to recover its administrative, capital, and other costs, provided that any such rights are not inconsistent with the express terms of this Agreement. During the Term of this Agreement, the ISO shall:

- (a) have the rights and obligations to design, develop, operate, maintain and administer the New England Markets and congestion pricing mechanisms (including the exclusive right to make Section 205 filings relating to the Market Rules in accordance with Section 3.04),
- (b) have the rights to undertake actions relating to congestion pricing and management in accordance with this Agreement, ISO Market Rules, and applicable FERC orders.

Nothing in this Agreement shall be deemed to impair or infringe on such rights and obligations.

ARTICLE IV

REPRESENTATIONS AND WARRANTIES OF THE PARTIES

4.01 **Representations and Warranties of Each PTO.** As of the time of execution of this Agreement, each PTO, severally, represents and warrants to the ISO and each other PTO as follows:

- (a) **Organization.** It is duly organized, validly existing and in good standing under the laws of the state of its organization.
- (b) **Authorization.** It has all requisite power and authority to execute, deliver and perform this Agreement; the execution, delivery and performance by such PTO of this Agreement have been duly authorized by all necessary and appropriate action on the part of such PTO; and this Agreement has been duly and validly executed and delivered by such PTO and constitutes the legal, valid and binding obligations of such PTO, enforceable against such PTO in accordance with its terms; provided, however, that as to Massachusetts Publicly-Owned PTOs, this representation and warranty shall not be binding unless and until they shall have first obtained a finally adjudicated declaratory ruling from the Massachusetts courts that the transfer of Operating Authority over their Transmission Facilities is lawful and permissible under the Massachusetts General Laws.
- (c) **No Breach.** The execution, delivery and performance by such PTO of this Agreement will not result in a breach of any terms, provisions or conditions of any agreement to which such PTO is a party which breach has a reasonable likelihood of materially and adversely affecting such PTO's performance under this Agreement.
- (d) **Transmission Facilities.** Except as set forth on Schedule 4.01(d), such PTO has listed on one of Schedule 2.01(a) or Schedule 2.01(b), all of the transmission facilities with a voltage level of 69 kV or greater that it owns in the New England Control Area as of the Operations Date and all of the transmission facilities leased to it with a voltage level of 69 kV or greater in the New England Control Area as of the Operations Date.

(e) **NO WARRANTY REGARDING EACH PTO'S TRANSMISSION FACILITIES.** IN CONNECTION WITH EACH PTO'S GRANT OF OPERATING AUTHORITY TO THE ISO OVER SUCH PTO'S TRANSMISSION FACILITIES PURSUANT TO THE TERMS OF THIS AGREEMENT, SUCH PTO'S TRANSMISSION FACILITIES ARE BEING MADE AVAILABLE PURSUANT TO THIS AGREEMENT TO THE ISO "AS IS, WHERE IS," AND SUCH PTO IS NOT MAKING ANY REPRESENTATIONS OR WARRANTIES, WRITTEN OR ORAL, STATUTORY, EXPRESS OR IMPLIED, CONCERNING SUCH TRANSMISSION FACILITIES, INCLUDING, IN PARTICULAR, ANY WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE, ALL OF WHICH ARE HEREBY EXPRESSLY EXCLUDED AND DISCLAIMED. THE FOREGOING PROVISION IS NOT INTENDED TO LIMIT OR CONDITION ANY OBLIGATIONS OF THE PTOS EXPRESSLY PROVIDED FOR ELSEWHERE IN THIS AGREEMENT.

4.02 **Representations and Warranties of the ISO.** As of the time of execution of this Agreement, the ISO represents and warrants to each PTO as follows:

(a) **Organization.** It is duly organized, validly existing and in good standing under the laws of the state of its organization.

(b) **Authorization.** It has all requisite power and authority to execute, deliver and perform this Agreement; the execution, delivery and performance by the ISO of this Agreement have been duly authorized by all necessary and appropriate action on the part of the ISO; and this Agreement has been duly and validly executed and delivered by the ISO and constitutes the legal, valid and binding obligation of the ISO, enforceable against the ISO in accordance with its terms.

(c) **No Breach.** The execution, delivery and performance by the ISO of this Agreement will not result in a breach of any of the terms, provisions or conditions of any agreement to which the ISO is a party which breach has a reasonable likelihood of materially and adversely affecting the ISO's performance under this Agreement.

ARTICLE V

COVENANTS OF THE PTOS

5.01 **Covenants of Each PTO.** Each PTO covenants and agrees that during (i) the Term, or (ii) the period expressly specified herein, as applicable, such PTO shall comply with all covenants and provisions of this Article V, except to the extent the ISO and the number of PTOS necessary to amend this Agreement pursuant to Section 11.04(a) consent in writing to waive such covenants or performance is excused pursuant to Section 11.13(b).

5.02 **Financial Statements and Filings.** If a PTO's financial statements, permit applications or any other filing with any Governmental Authority are publicly available, such PTO shall, upon request by the ISO, provide the ISO information sufficient to allow the ISO to

locate such financial statements, permit applications or other filings, including the date and place of the filing of the relevant documents.

5.03 **Expenses.** Except to the extent specifically provided herein, all costs and expenses incurred by a PTO in connection with the negotiation of this Agreement shall be borne by such PTO; provided that nothing herein shall prevent such PTO from recovering such expenses in accordance with applicable law.

5.04 **Consents and Approvals.**

(a) Each PTO shall exercise Commercially Reasonable Efforts to promptly prepare and file all necessary documentation to effect all necessary applications, notices, petitions, filings and other documents, and shall exercise Commercially Reasonable Efforts to obtain (and will cooperate with each other in obtaining) any consent, acquiescence, authorization, order or approval of, or any exemption or nonopposition by, any Governmental Authority required to be obtained or made by such PTO in connection with this Agreement or the taking of any action contemplated by this Agreement.

(b) Each PTO shall exercise Commercially Reasonable Efforts to obtain consents of all other third parties necessary to the performance of this Agreement by such PTO. Each PTO shall promptly notify the ISO of any failure to obtain any such consents and, if requested by the ISO, shall provide copies of all such consents obtained by such PTO.

(c) Nothing in this Section 5.04 shall require any PTO to pay any sums to a third party, including any Governmental Authority, excluding filing fees paid to any Governmental Authority in connection with a filing necessary or appropriate to further action.

5.05 **Notice and Cure.** Each PTO shall notify the ISO and each other PTO in writing of, and contemporaneously provide the ISO and each other PTO with true and complete copies of any and all information or documents relating to, any event, transaction or circumstance, as soon as practicable after it becomes Known to such PTO, that causes or shall cause any covenant or agreement of such PTO under this Agreement to be breached or that renders or shall render untrue any representation or warranty of such PTO contained in this Agreement as if the same were made on or as of the date of such event, transaction or circumstance. The PTO shall use all Commercially Reasonable Efforts to cure such event, transaction or circumstance as soon as practicable after it becomes Known to such PTO. No notice given pursuant to this Section 5.05 shall have any effect on the representations, warranties, covenants or agreements contained in this Agreement for purposes of determining satisfaction of any condition contained herein or shall in any way limit the ISO's or any other PTO's right to seek indemnity under Article IX.

ARTICLE VI

COVENANTS OF THE ISO

6.01 **Covenants of the ISO.** The ISO covenants and agrees that during (i) the Term, or (ii) the period expressly specified herein, as applicable, the ISO shall comply with all covenants and provisions of this Article VI, except to the extent the Parties consent in writing to a waiver of such covenants or performance is excused pursuant to Section 11.13(b).

6.02 **Financial Statements and Filings.**

(a) To the extent not provided to stakeholders generally or made publicly available by the ISO, the ISO shall make available to each PTO: (i) quarterly unaudited financial statements within sixty (60) days after each quarter end and (ii) annual audited financial statements within one hundred twenty (120) days after each fiscal year end. In each instance, the financial statements made available by the ISO pursuant to (i) and (ii) above shall be prepared in accordance with Generally Accepted Accounting Principles and shall be true and correct in all material respects.

(b) If financial statements, permit applications or any other filing with any Governmental Authority are publicly available, the ISO shall, upon request by a PTO, provide such PTO information sufficient to allow such PTO to locate such financial statements, permit applications or other filings including the date and place of the filing of the relevant documents.

6.03 **Expenses.** Except to the extent specifically provided herein, all costs and expenses incurred by the ISO in connection with the negotiation of this Agreement shall be borne by the ISO; provided that nothing herein shall prevent the ISO from recovering such expenses in accordance with applicable law.

6.04 **Consents and Approvals.**

(a) The ISO shall exercise Commercially Reasonable Efforts to promptly prepare and file all necessary documentation to effect all necessary applications, notices, petitions, filings and other documents, and shall exercise Commercially Reasonable Efforts to obtain (and will cooperate with each PTO in obtaining) any consent, acquiescence, authorization, order or approval of, or any exemption or nonopposition by, any Governmental Authority required to be obtained or made by the ISO in connection with this Agreement or the taking of any action contemplated by this Agreement.

(b) The ISO shall exercise Commercially Reasonable Efforts to obtain consents of all other third parties necessary to performance of this Agreement by the ISO. The ISO shall promptly notify each PTO of any failure or anticipated failure to obtain any such consents and, if requested by such PTO, shall provide copies of all such consents obtained by the ISO.

(c) Nothing in this Section 6.04 shall require the ISO to pay any sums to a third party, including any Governmental Authority, excluding filing fees paid to any Governmental Authority in connection with a filing necessary or appropriate to discharge its obligations hereunder.

6.05 **Notice and Cure.** The ISO shall notify each PTO in writing of, and contemporaneously shall provide each PTO with true and complete copies of any and all information or documents relating to, any event, transaction or circumstance, as soon as practicable after it becomes Known to the ISO, that causes or shall cause any covenant or agreement of the ISO under this Agreement to be breached or that renders or shall render untrue any representation or warranty of the ISO contained in this Agreement as if the same were made on or as of the date of such event, transaction or circumstance. The ISO shall use all Commercially Reasonable Efforts to cure such event, transaction or circumstance as soon as practicable after it becomes Known to the ISO. No notice given pursuant to this Section 6.05 shall have any effect on the representations, warranties, covenants or agreements contained in this Agreement for purposes of determining satisfaction of any condition contained herein or shall in any way limit any right of a PTO to seek indemnity under Article IX.

6.06 **Other PTOs.**

(a) The ISO shall not perform, or enter into an agreement to perform, any Operating Authority or other RTO functions set forth in Section 3.02 or any other portion of this Agreement for any transmission utility in the New England Control Area subject to the jurisdiction of FERC unless such transmission utility enters into and becomes a Party to this

Agreement pursuant to Section 11.05; provided, however, that this Section 6.06 shall not apply to agreements with owners of ties to other Control Areas, agreements with owners of Merchant Facilities, agreements with generators (to the extent the ISO obtains operating authority over transmission tie lines owned by generators through such agreements), or agreements with Independent Transmission Companies.

(b) The ISO may enter into agreements to perform Operating Authority or other RTO functions for one or more transmission utilities in a Control Area outside of New England. If the ISO enters into an agreement to perform Operating Authority or other RTO functions for one or more transmission utilities in an area contiguous to the New England Control Area, such agreement shall not: (i) materially and adversely affect the ISO's ability to perform Operating Authority for any PTO, or (ii) be unduly preferential to any transmission utility similarly situated to any PTO; provided that, if a PTO believes that a proposed agreement to perform Operating Authority or other RTO functions for one or more transmission utilities in a Control Area contiguous to the New England Control Area violates the immediately foregoing proviso, such PTO may notify the ISO, within thirty (30) days after the receipt of the proposed agreement, of its desire to negotiate the additional or modified terms and conditions of this Agreement necessary to relieve said adverse effect or undue preference and if such negotiation is not concluded within thirty (30) days after said notice, either Party may seek to resolve the dispute in accordance with Section 11.14 of this Agreement and may file the additional or modified terms and conditions of this Agreement necessary to relieve said adverse effect or undue preference for approval by the FERC. Notwithstanding anything else in this agreement, including Section 11.04, the PTO proposing any additional or modified terms and conditions of this Agreement shall not be required to demonstrate that the existing terms and conditions of this Agreement are unjust and unreasonable if the ISO has agreed to or the FERC approves the proposed additional or modified terms and conditions in an agreement with transmission utilities in a Control Area contiguous to the New England Control Area. The limitations and procedures in this Section 6.06(b) shall not apply to the ISO's execution and performance of Coordination Agreements (or amendments thereto) with the operators of neighboring Control Areas, to the administration of Interconnection Agreements with neighboring Control Areas, or to the ISO's provision of reliability services to New Brunswick Power Corporation.

(c) Nothing in this Agreement shall be construed as granting any FERC-jurisdictional Initial PTO or Additional PTO the right to recover the costs of its Transmission Facilities pursuant to the ISO OATT or any other regulated tariff absent approval or acceptance by the FERC for such cost recovery. The Parties hereto expressly reserve their rights to oppose a request for such cost recovery for any potential PTO that is not recovering its transmission costs pursuant to FERC regulated transmission tariffs prior to the Operations Date.

6.07 **Management Agreements.** The ISO shall not enter into any management agreement relating to the provision of transmission services with any Person, including a transmission-owning utility, unless such agreement: (a) has been approved by FERC; (b) does not violate the ISO's Code of Conduct and is on an arms-length basis; or (c) if for an aggregate amount of \$1,000,000 or more for a contract with any Participant in the New England Markets,

including PTOs, is the result of a competitive solicitation process, the outcome of which is based on factors that include, among others, skill, qualifications, costs, reputation, and associated risks.

6.08 **ISO Line of Business; Non-Profit-Status.** The ISO shall not be operated on a for-profit basis. This provision is not intended to require the ISO to maintain its status as an entity not subject to federal or state taxes, to require the ISO to remain a Delaware not-for-profit corporation or to assure that in any particular year that the ISO's revenues do not exceed its expenses. The ISO shall not pay dividends or use its net earnings other than to offset ISO operating and capital expenses and maintain reasonable reserves.

ARTICLE VII

TAX MATTERS

7.01 **Responsibility for PTO Taxes.** Each PTO shall prepare and file all Tax Returns and other filings related to its Transmission Business and Transmission Facilities and pay any Tax liabilities related to its Transmission Business and Transmission Facilities. The ISO shall not be responsible for, or required to file, any Tax Returns or other reports for any PTO and shall have no liability for any Taxes related to any PTO's Transmission Business or Transmission Facilities. No PTO shall be responsible for, or required to file, any Tax Returns or other reports for any other PTO and shall have no liability for any Taxes related to any other PTO's Transmission Business or Transmission Facilities. The ISO and each PTO hereby agree that, for tax purposes, a PTO's Transmission Facilities shall be deemed to be owned by such PTO.

7.02 **Responsibility for ISO Taxes.** The ISO shall prepare and file all Tax Returns and other filings related to its operations and pay any Tax liabilities related to its operations. No PTO shall be responsible for, or required to, file any Tax Returns or other reports for the ISO and shall have no liability for any Taxes related to the ISO's operations.

ARTICLE VIII

RELIANCE; SURVIVAL OF AGREEMENTS

8.01 **Reliance; Survival of Agreements.** Notwithstanding any right of any Party (whether or not exercised) to investigate the accuracy of any of the matters subject to indemnification by any other Party contained in this Agreement, each of the Parties has the right to rely fully upon the representations, warranties, covenants and agreements of each other Party contained in this Agreement. The provisions of Sections 11.01, 11.09, 11.13 and 11.17 and Articles VII and IX shall survive the termination of this Agreement. With respect to Section 3.10 of this Agreement, the ISO will perform final billing consistent with Section 3.10 of this Agreement for all services provided until the Termination Date.

ARTICLE IX

INDEMNIFICATION; INSURANCE; LIMITATION OF LIABILITIES

9.01 **Indemnification.**

(a) Subject to Section 9.06(b) through 9.06(e), (i) each PTO shall severally release, indemnify, and hold harmless the ISO from and against any and all damages, losses, liabilities, obligations, claims, demands, suits, proceedings, recoveries, judgments, settlements, costs and expenses, court costs, attorney fees, and all other obligations (each, an “Indemnifiable Loss”) asserted against the ISO by a Person that is not a Party to this Agreement (a “Third Party”) including but not limited to any action by a PTO employee, to the extent alleged to result from, arise out of or be related to such PTO’s acts or omissions that give rise to such Indemnifiable Loss; and (ii) the ISO shall release, indemnify, and hold harmless each PTO from and against any Indemnifiable Loss asserted against such PTO by a Third Party, including but not limited to any action by an ISO employee, to the extent alleged to result from, arise out of or be related to the ISO’s acts or omissions that give rise to such Indemnifiable Loss, including an ISO directive and/or instructions to a Party.

(b) The indemnification by the ISO set forth in Section 9.01(a)(ii) above shall be limited to the extent that the liability of a PTO seeking indemnification would be limited by any applicable Law and arises from a claim by (i) such PTO in such PTO’s role as a Transmission Customer or (ii) a customer of such PTO.

(c) Each PTO shall severally release, indemnify, and hold harmless the ISO from and against any Environmental Damages that the ISO becomes subject to as a result of its exercise of Operational Authority over such PTO’s Transmission Facilities, to the extent such Environmental Damages arose prior to the Operations Date or did not result from the ISO’s acts or omissions.

(d) Each PTO and/or the ISO each hereby (i) waives any defense or immunity it might otherwise have under applicable workers’ compensation laws or any other statute, or judicial decision, disallowing or limiting such indemnification and (ii) consents to a cause of action for indemnity and/or contribution in connection with such indemnification.

9.02 **Notice of Proceedings.** Each party entitled to receive indemnification under this Agreement (each, an “Indemnitee”) shall promptly notify the party who holds an indemnification obligation hereunder (in each case, the “Indemnifying Party”) of any Indemnifiable Loss in respect of which such Indemnitee is or may be entitled to indemnification pursuant to Section 9.01. Such notice shall be given as soon as reasonably practicable after the Indemnitee becomes aware of the Indemnifiable Loss and that any such claim or proceeding may give rise to an indemnification obligation hereunder. Such notice shall describe the nature of the loss or proceeding in reasonable detail and shall indicate, if practicable, the estimated amount of the Indemnifiable Loss that has been or may be sustained by the Indemnitee. The delay or failure of such Indemnitee to provide the notice required pursuant to this Section 9.02 shall not release the

Indemnifying Party from any indemnification obligation which it may have to such Indemnitee except (a) to the extent that such failure or delay materially and adversely affects the Indemnifying Party's ability to defend such action or increases the amount of the Indemnifiable Loss, and (b) that the Indemnifying Party shall not be liable for any costs or expenses of the Indemnitee in the defense of the claim, suit, action or proceeding during such period of failure or delay.

9.03 **Defense of Claims.**

(a) Unless and until the Indemnifying Party (i) acknowledges in writing its obligation within ten (10) calendar days of the Indemnitee's notice of a claim, suit, action or proceeding, and (ii) assumes control of the defense of such claim, suit, action or proceeding in accordance with Section 9.03(b), the Indemnitee shall have the right, but not the obligation, to contest, defend and litigate, with counsel of its own selection, any claim, action, suit or proceeding by any third party alleged or asserted against such Indemnitee in respect of, resulting from, related to or arising out of any matter for which it is entitled to be indemnified hereunder, and the reasonable costs and expenses thereof shall be subject to the indemnification obligations of the Indemnifying Party hereunder.

(b) Upon acknowledging in writing its obligation to indemnify an Indemnitee to the extent required pursuant to this Article IX and paying all reasonable costs incurred by such Indemnitee in its defense, including reasonable attorney's fees, the Indemnifying Party shall be entitled, at its option (subject to Section 9.03(d)), to assume and control the defense of such claim, action, suit or proceeding at its expense with counsel of its selection, subject to the prior reasonable approval of the Indemnitee.

(c) Neither the Indemnifying Party nor the Indemnitee shall be entitled to settle or compromise any such claim, action, suit or proceeding without the prior written consent of the other; provided, however, that such consent shall not be unreasonably withheld.

(d) Following the acknowledgment of the indemnification and the assumption of the defense by the Indemnifying Party pursuant to Section 9.03(b), the Indemnitee shall have the right to employ its own counsel and such counsel may participate in such action, but the fees and expenses of such counsel shall be at the expense of such Indemnitee, when and as incurred, unless: (i) the employment of counsel by such Indemnitee has been authorized in writing by the Indemnifying Party; (ii) the Indemnitee shall have reasonably concluded and specifically notified the Indemnifying Party that there may be a conflict of interest between the Indemnifying Party and the Indemnitee in the conduct of the defense of such action; (iii) the Indemnifying Party shall not in fact have employed independent counsel reasonably satisfactory to the Indemnitee to assume the defense of such action and shall have been so notified by the Indemnitee; (iv) the Indemnitee shall have reasonably concluded and specifically notified the Indemnifying Party that there may be specific defenses available to it which are different from or additional to those available to the Indemnifying Party or that such claim, action, suit or proceeding involves or could have a material adverse effect upon the Indemnitee beyond the scope of this Agreement; or (v) the Indemnifying Party shall not have taken reasonable steps necessary to defend diligently

such action within twenty (20) calendar days after receiving notice from the Indemnitee that the Indemnitee believes the Indemnifying Party has failed to take such steps. If clause (ii), (iii), (iv) or (v) of the preceding sentence shall be applicable, then counsel for the Indemnitee shall have the right to direct the defense of such claim, action, suit or proceeding on behalf of the Indemnitee and the reasonable fees and disbursements of such counsel shall constitute indemnifiable legal or other expenses hereunder.

(e) If the amount of any Indemnifiable Loss incurred by an Indemnitee, at any time subsequent to the making of an indemnity payment by an Indemnifying Party in respect thereof, is reduced by recovery, settlement or otherwise under or pursuant to any insurance coverage, or pursuant to any claim, recovery, settlement or payment by or against any other entity, the amount of such reduction, less any costs, expenses or premiums incurred in connection therewith (together with interest thereon from the date of payment thereof at the Prime Rate) shall promptly be repaid by the Indemnitee to the Indemnifying Party. In the event that the claim, demand or suit giving rise to an Indemnifiable Loss is ultimately adjudicated, if a Final Order confirms that the Indemnitee was not entitled to indemnification hereunder, then the amount advanced by the Indemnifying Party in respect of such Indemnifiable Loss (together with interest thereon from the date of payment thereof at the Prime Rate) shall promptly be paid by the Indemnitee to the Indemnifying Party.

9.04 **Subrogation.** Upon payment of any indemnification by a party pursuant to this Article IX, the Indemnifying Party, without any further action, shall be subrogated to any and all claims that the Indemnitee may have relating thereto, and such Indemnitee shall at the request and expense of the Indemnifying Party cooperate with the Indemnifying Party and give at the request and expense of the Indemnifying Party such further assurances as are necessary or advisable to enable the Indemnifying Party vigorously to pursue such claims.

9.05 **Insurance.**

(a) The ISO shall at all times, at its own cost and expense, carry and maintain or cause to be carried and maintained throughout the Term: (i) liability and errors and omissions insurance (including blanket coverage for contractual liability), insuring the ISO against liability for injury or death to persons, damage to property and environmental restoration, (ii) worker's compensation insurance, (iii) property insurance and (iv) directors' and officers' insurance. The amount of the insurance coverages and deductibles shall generally be comparable to other independent system operators or RTOs, taking into consideration the relative size of the ISO and its contractual and tariff liabilities as compared to the other system operators or RTOs administering similar market structures. In assessing the comparable coverages and deductibles, the ISO may rely on the advice of its insurance consultants.

(b) Each PTO will maintain property insurance on its Transmission Facilities and liability insurance in accordance with good utility practice. Each PTO may self insure such amount to the extent it currently self insures similar policies and amounts.

(c) All insurance required under this Section 9.05 by outside insurers shall be maintained with insurers qualified to insure the obligations or liabilities under this Agreement and having a Best's rating of at least B+ VIII (or an equivalent Best's rating from time to time of B+ VIII), or in the event that from time to time Best's ratings are no longer issued with respect to insurers, a comparable rating by a nationally recognized rating service or such other insurers as may be agreed upon by the PTOs and the ISO.

(d) The PTOs shall be listed as additional insured parties on the liability and errors and omissions insurance required to be maintained by the ISO and the ISO shall be listed as an additional insured party on the liability insurance maintained by each PTO. Upon execution of this Agreement, and when requested thereafter, each Party shall furnish each other Party with certificates of all such insurance policies setting forth the amounts of coverage, policy numbers, and date of expiration for such insurance in conformity with the requirements of this Agreement.

(e) The insurance policies maintained by the ISO hereunder shall not be canceled, terminated or the terms thereof modified or amended without at least thirty (30) days' prior notice to the PTOs.

(f) If any insurance policy required to be maintained by the ISO hereunder shall not be available to the ISO on a commercially reasonable basis (taking into account both terms and premiums), the ISO shall obtain a written report of an independent insurance advisor of recognized national standing, chosen by the PTOs and reasonably acceptable to the ISO, confirming in reasonable detail that such insurance policy, in respect of amount or scope of coverage, is not available on a commercially reasonable basis from insurers of recognized standing. During any period with respect to which any insurance policy required by this Agreement is not commercially available, the ISO shall nevertheless maintain insurance that approximates such required insurance policy as closely as commercially practical, to the extent it is available on a commercially reasonable basis from insurers of recognized standing. If any insurance policy which was previously not held or discontinued because of its commercial unavailability later becomes available on a commercially reasonable basis, the ISO shall obtain or reinstate such insurance.

9.06 **Assumption of Liability.**

(a) (i) Each PTO shall be severally liable to the ISO, and the ISO shall be liable to each PTO, for losses, liabilities, damages, diminution in value, obligations, claims, proceedings, fines, deficiencies and expenses (collectively, "Losses") caused by such Party's grossly negligent acts or omissions or willful misconduct (including the grossly negligent acts or omissions or willful misconduct of such Party's directors, Affiliates, members, officers, employees, agents, and contractors) in connection with the performance of such Party of its obligations under this Agreement; and (ii) no Party shall be liable to another Party for any incidental, indirect, special, exemplary, punitive or consequential damages, including lost revenues or profits, even if such damages are foreseeable or the damaged Party has advised such Party of the possibility of such damages and regardless of whether any such damages are deemed

to result from the failure or inadequacy of any exclusive or other remedy. The foregoing limitations shall not apply to the right of the Parties to seek indemnification under this Agreement in accordance with Section 9.01.

(b) Nothing in this Agreement shall be deemed to affect the right of the ISO to recover its costs due to liability under this Article IX through the ISO Participants Agreement or the ISO Administrative Tariff.

(c) The ISO shall not be liable to any PTO with respect to any damages incurred by such PTO that are directly attributable to the ISO's reliance on facility ratings established by such PTO.

(d) No PTO shall be liable to any other PTO and/or the ISO by reason of this Agreement (whether based on contract, indemnification, warranty, tort, strict liability or otherwise) for: (i) any acts or omissions taken or done in compliance with, or good faith attempts to comply with, the directives and/or instructions of the ISO, except in cases of the gross negligence or willful misconduct of such PTO; and/or (ii) any costs and expenses relating to the operation, repair, maintenance or improvement of any Transmission Facility of the ISO or any other PTO.

(e) Notwithstanding any of the foregoing, the ISO shall be liable in actual damages for failure to make payments or transfer sums under Section 3.10 of this Agreement if the ISO fails to discharge its obligation to prepare and send bills or to perform its obligations pursuant to Section 3.10 of this Agreement.

(f) When VELCO is acting in its capacity as the system operator of Vermont Transco's transmission facilities, VELCO and Vermont Transco shall be jointly and severally liable to ISO-NE pursuant to the terms of the TOA only for actions or failures to act that would give rise to liability to ISO-NE pursuant to the terms of the TOA for a PTO operating its own transmission facilities. Such joint and several liability (a) does not extend to any action or failure to act of VELCO or Vermont Transco with regard to any other activity in which VELCO or Vermont Transco may engage, and (b) expires when VELCO is no longer acting as the managing member of Vermont Transco.

ARTICLE X

TERM; DEFAULT AND TERMINATION

10.01 Term; Termination Date.

(a) Term and Operations Date.

(i) Term. Subject to the terms set forth in this Section 10.01, the initial term of this Agreement (the “Initial Term”) shall commence on the Operations Date and shall continue for a period of five years. Subject to the terms set forth in this Section 10.01, the Initial Term shall be extended automatically for additional two-year periods (each, an “Additional Term”). Any one or more PTOs may withdraw from this Agreement effective at the end of the Initial Term or the end of any Additional Term by providing no less than 180 days’ prior notice of such withdrawal to the other Parties. Together, the Initial Term and the Additional Term(s), if any, shall constitute the term (the “Term”) of this Agreement.

(ii) Operations Date. The “Operations Date” shall be the date on which the ISO and the Initial Participating Transmission Owners unanimously agree to place this Agreement, the ISO OATT, and related agreements and documents into effect. The ISO and the Initial Participating Transmission Owners shall jointly issue a written notice (the “Notice of Operations Date”) at least thirty (30) calendar days in advance of the Operations Date. The Notice of Operations Date shall be posted on the ISO website and filed with FERC on an informational basis.

(b) PTO Withdrawal During The Term. Subject to Section 10.01(e), any one or more PTOs may withdraw from this Agreement at any time during the Term if any of the following shall have occurred:

(i) upon an ISO event of default in accordance with Section 10.03(a), provided that the PTOs shall exercise this right in accordance with Section 10.03(b)(i).

(ii) if a Final Order of FERC, a Final Order of a Federal court or a Federal law sets forth a change in policy stating that: (A) the federal government no longer encourages the participation of transmission owners in RTOs and such Final Order or law affirmatively states that transmission owners participating in an RTO may withdraw therefrom, or (B) that the recovery of costs for existing Transmission Facilities will be subject to any change in policy which would prevent a PTO from recovering the costs of existing Transmission Facilities on a regulated cost-of-service basis; provided that withdrawal pursuant to (A) or (B) of

this provision shall require notice to the other Parties not less than 180 days prior to the Termination Date established pursuant to Section 10.01(e).

(iii) FERC issues an order putting into effect changes to the relative rights and responsibilities of the PTOs and the ISO under this Agreement, including changing the scope and definition of Operating Authority, so as to materially adversely affect the interests of one or more PTOs, unless the PTOs have agreed to such changes in accordance with Section 11.04; provided that: (A) only the PTO(s) affected by such FERC order shall have the right to withdraw pursuant to this provision; (B) withdrawal pursuant to this provision shall require notice to the other Parties not less than 180 days prior to the Termination Date established pursuant to Section 10.01(e); and (C) a PTO providing a notice of withdrawal pursuant to this provision shall be required to rescind such notice if FERC issues a subsequent order prior to the Termination Date so as to eliminate the changes to the relative rights and responsibilities of the PTOs and the ISO under this Agreement.

(iv) the withdrawing PTO has entered into an agreement to form an ITC in accordance with Attachment M to the ISO OATT which has been accepted for filing by the FERC, provided that withdrawal pursuant to this provision shall be effective concurrent with the effective date of such agreement.

(v) the withdrawing PTO has obtained authorization from the FERC to join another RTO or other similar organization (such as an Independent System Operator) in connection with a merger with or acquisition by another entity other than another PTO.

(c) Remaining PTOs. In the event that one or more, but less than all, PTOs withdraw from this Agreement in accordance with Section 10.01(a) or (b), this Agreement shall remain in full force and effect with respect to all other PTOs; provided that in the event of a withdrawal under Section 10.01(a), the remaining PTOs shall have a period of twenty days from the date of the notice provided in accordance with Section 10.01(a) to notify the other Parties that it intends to withdraw from this Agreement at the end of the Initial Term or any Additional Term, as applicable. The “Termination Date” shall mean the date of termination established in accordance with Section 10.01(e).

(d) Termination By the ISO. The ISO may terminate its obligations under this Agreement and surrender its Operating Authority over the Transmission Facilities if any of the following shall have occurred:

(i) the withdrawal of one or more PTOs from this Agreement and as a result of such withdrawal the ISO cannot maintain system reliability or administer efficient and competitive markets.

(ii) FERC issues an order putting into effect material changes in the liability and indemnification protections afforded to the ISO under this Agreement or the ISO OATT, provided that: (A) withdrawal pursuant to this provision shall require notice to the other Parties not less than 180 days prior to the Termination Date established pursuant to Section 10.01(e); and (B) the ISO shall be required to rescind such notice if FERC issues a subsequent order prior to the Termination Date so as to eliminate the material changes to such liability and indemnification protections.

(iii) FERC issues an order putting into effect an amendment or modification of this Agreement that materially adversely affects the ISO’s ability to carry out its responsibilities under this Agreement, unless the ISO has agreed to such changes in accordance with Section 11.04, provided that: (A) withdrawal pursuant to this provision shall require notice to the other Parties not less than 180 days prior to the Termination Date established pursuant to Section 10.01(e); and (B) the ISO shall be required to rescind such notice if FERC issues a subsequent order prior to the Termination Date so as to eliminate the material adverse effect to the ISO’s ability to carry out its responsibilities under this Agreement.

(iv) upon a PTO event of default in accordance with Section 10.04(a), provided that the ISO shall exercise this right in accordance with Section 10.04(b)(i).

(e) Actions Prior To Withdrawal or Termination. Upon submission of a written notice of termination or withdrawal by a Party or Parties, the Party or Parties submitting such notice shall commence the development of a plan under which Operating Authority shall be transferred from the ISO to another entity. The Termination Date with respect to any PTO or the ISO shall not occur until both: (a) the ISO and all affected PTOs have agreed upon a plan addressing the technical, operational and market issues associated with the transfer of Operating Authority in connection with such termination or withdrawal and such plan has been implemented, provided that: (i) if the Parties are unable to reach agreement on such plan, any affected Party shall have the right to submit the matter to FERC for resolution without additional negotiation under Section 11.14; (ii) with respect to a withdrawal pursuant to Section 10.01(a), no PTO shall be required to remain a Party to this Agreement for longer than one year after providing notice of withdrawal; and (iii) in the event of a default by the ISO, the affected PTOs may require that the ISO immediately make arrangements for the orderly transfer of the ISO's invoicing and collection functions with respect to such PTOs prior to the Termination Date in accordance with Section 10.03(b); and (b) all required regulatory approvals, if any, have been obtained for such withdrawal or termination, including any approvals required pursuant to Section 10.01(f).

(f) Approvals. Notwithstanding any other provision contained herein or in any other document to the contrary, any termination or withdrawal requested under this Section 10.01 shall be effective: (1) unless a party to this Agreement seeking to challenge the request demonstrates that the requested termination or withdrawal is contrary to the public interest under the Mobile-Sierra Doctrine and (ii) subject to the FERC's determination under Section 205 of the Federal Power Act that the termination or withdrawal is just, reasonable and not unduly discriminatory or preferential. Each PTO exercising its right to withdraw or terminate in accordance with this Section 10.01 shall file with the FERC, pursuant to Section 205 of the FPA, the tariffs and rate schedules applicable to transmission service over such PTO's Transmission Facilities to become effective upon such termination or withdrawal.

(g) Continuing Obligations. Each withdrawing or terminating Party shall have the following continuing obligations following withdrawal from this Agreement

(i) All financial obligations incurred and payments applicable to the time period prior to the Termination Date shall be honored by the terminating or withdrawing Party and each other Party in accordance with the terms of this Agreement, and each Party shall remain liable for all obligations arising hereunder prior to the Termination Date.

(ii) Any withdrawing PTO that is not a Publicly-Owned PTO shall file a replacement transmission tariff to replace the ISO OATT, unless FERC rules no longer require the filing of such a tariff. Any withdrawing Publicly-Owned PTO shall adopt the Order No. 888 pro forma tariff.

10.02 **Release of Operating Authority.**

(a) Upon the Termination Date, the ISO's right and obligation to exercise Operating Authority over the Transmission Facilities of a PTO with whom this Agreement has terminated shall promptly cease, and, in accordance with Section 10.01, the ISO shall be deemed to have released and returned, and such PTO (or its designee) shall have assumed, Operating Authority over such Transmission Facilities on the Termination Date.

(b) After the Termination Date, the ISO shall take Commercially Reasonable Efforts to assist the terminating PTO or such PTO's designee in resuming performance of the functions comprising Operating Authority.

(c) The expenses associated with any termination under Section 10.01 shall be at the PTO's expense unless (1) the termination is by the ISO pursuant to Section 10.01(d)(ii) or (iii), or (2) pursuant to Section 10.03 in the event of an ISO default.

10.03 **Events of Default of the ISO.**

(a) Events of Default of the ISO. Subject to the terms and conditions of this Section 10.03, the occurrence of any of the following events shall constitute an event of default of the ISO under this Agreement:

(i) Failure by the ISO to perform any material obligation set forth in this Agreement and continuation of such failure for longer than thirty (30) days after the receipt by the ISO of written notice of such failure from a PTO; provided, however, that if the ISO is diligently pursuing a remedy during such thirty (30) day period, said cure period shall be extended for an additional thirty (30) days or as otherwise agreed by all affected Parties

(ii) If there is a dispute between the ISO and a PTO as to whether the ISO has failed to perform a material obligation, the cure period(s) provided in Section 10.03(a)(i) above shall run from the point at which a finding of failure to perform has been made by a Governmental Authority;

(iii) Any attempt (not including consideration of strategic options or entering into exploratory discussions) by the ISO to transfer an interest in, or assign its obligations under, this Agreement, except as otherwise permitted hereunder;

(iv) Failure of the ISO (if it has received the necessary corresponding funds from ISO customers) to pay when due any and all amounts payable to any PTO by the ISO as part of the settlement process pursuant to Section 3.10 within three (3) Business Days;

(v) Failure of the ISO to pay when due any other amounts payable to any PTO by the ISO pursuant to this Agreement within thirty (30) days of the due date;

(vi) The exercise of Operating Authority or other responsibilities under this Agreement in a manner that results in a material amount of damage to or the destruction of a PTO's Transmission Facilities due to the willful misconduct or gross negligence of the ISO or the repeated and persistent exercise by the ISO of its Operating Authority in a manner that subjects Transmission Facilities to the significant risk of a material amount of damage, provided that exercise by the ISO of its Operating Authority over any Transmission Facility both in accordance with the Operating Procedures and within the ratings established by a PTO for such Transmission Facility shall not be considered to subject such Transmission Facility to risk of damage and further provided that nothing in this Section 10.03(a)(v) shall be deemed to excuse the ISO from complying with its obligations under this Agreement or to limit the other events of default specified in this Section 10.03(a).

(vii) With respect to the ISO, (A) the filing of any petition in bankruptcy or insolvency, or for reorganization or arrangement under any bankruptcy or insolvency laws, or voluntarily taking advantage of any such laws by answer or otherwise or the commencement of involuntary proceedings under any such laws, (B) assignment by the ISO for the benefit of creditors; or (C) allowance by the ISO of the appointment of a receiver or trustee of all or a material part of its property if such receiver or trustee is not discharged within thirty (30) days after such appointment.

(b) Remedies for Default. If an event of default by the ISO occurs, each affected PTO shall have the right to avail itself of any or all of the following remedies, all of which shall be cumulative and not exclusive:

(i) To terminate its participation in this Agreement with respect to such PTO in accordance with Section 10.01(e); provided that if the ISO contests such allegation of an ISO event of default, this Agreement shall remain in effect pending resolution of the dispute, but any applicable notice period shall run during the pendency of the dispute;

(ii) To demand that the ISO shall immediately make arrangements for the orderly transfer of Operating Authority over such PTO's Transmission Facilities and assist such PTO or such PTO's designee in resuming performance

of the functions comprising Operating Authority, provided that: (A) such PTO shall not be liable for the reimbursement of the ISO for any costs and expenses incurred by the ISO in connection therewith; (B) the ISO and all affected PTOs shall agree upon a plan addressing the technical and operational issues associated with such transfer of Operating Authority, and such plan has been implemented; and (C) if the Parties are unable to reach agreement on such plan, any affected Party shall have the right to submit the matter to FERC for resolution without additional negotiation under Section 11.14;

(iii) To demand that the ISO shall terminate any right of the ISO, immediately make arrangements for the orderly transfer of the ISO's invoicing and collection functions with respect to such PTO and assist such PTO or such PTO's designee in resuming performance of the functions the later of 20 days from the date of making such demand or the start of the next billing cycle. Without limiting the generality of the foregoing, the ISO agrees to deliver all information and files necessary to perform billing for regional transmission service (the "Regional Billing"), including but not limited to transferring all files then used by the ISO to prepare rate calculations and billing to a billing representative designated by the PTOs. The PTOs will provide the ISO, within 30 days of the Operations Date, with a list of the specific information and files necessary if the PTOs were to perform the Regional Billing;

(iv) To make any payment or perform or comply with any agreement that the ISO shall be obligated to pay, perform or comply with under this Agreement and the amount of reasonable expenses (including attorneys' fees and any other reasonable professionals' fees and expenses) of such PTO incurred in connection with such payment or the performance of or compliance with any such agreement shall be payable by the ISO upon demand;

(v) To obtain such specific performance and/or an injunction to prevent breaches of this Agreement and to enforce specifically the terms and conditions hereof; and/or

(vi) To obtain damages pursuant to the indemnity provisions of Sections 9.01 and 9.06 and for non-performance of invoicing/payment obligations under Section 3.10 of this Agreement.

10.04 **Events of Default of a PTO.**

(a) Events of Default of a PTO. Subject to the terms and conditions of this Section 10.04, the occurrence of any of the events listed below shall constitute an event of default of such PTO under this Agreement (in each instance, a "PTO Default"):

(i) Failure by such PTO to perform any material obligation set forth in this Agreement and continuation of such failure for longer than thirty (30) days

after the receipt by such PTO of written notice of such failure from the ISO, provided, however, that if such PTO is diligently pursuing a remedy during such thirty (30) day period, said cure period shall be extended for an additional thirty (30) days or as otherwise agreed by all affected Parties;

(ii) If there is a dispute between a PTO and the ISO as to whether the PTO has failed to perform a material obligation, the cure period(s) provided in Section 10.04(a)(i) above shall run from the point at which a finding of failure to perform has been made by a Governmental Authority;

(iii) With respect to such PTO, (A) the filing of any petition in bankruptcy or insolvency, or for reorganization or arrangement under any bankruptcy or insolvency laws, or voluntarily taking advantage of any such laws by answer or otherwise or the commencement of involuntary proceedings under any such laws, (B) assignment by such PTO for the benefit of creditors; or (C) allowance by such PTO of the appointment of a receiver or trustee of all or a material part of its property if such receiver or trustee is not discharged within thirty (30) days after such appointment; or

(iv) Failure of the PTO to pay when due any amounts payable to the ISO by such PTO pursuant to this Agreement within thirty (30) days of the due date.

(b) Remedies for Default. If an event of default by a PTO occurs, the ISO shall have the following remedies, all of which shall be cumulative and not exclusive:

(i) terminate this Agreement with respect to such PTO in accordance with Section 10.01(e); provided that if such PTO contests such allegation of a PTO event of default, this Agreement shall remain in effect pending resolution of the dispute, but any applicable notice period shall run during the pendency of the dispute;

(ii) such specific performance and/or an injunction to prevent breaches of this Agreement and to enforce specifically the terms and conditions hereof; or

(iii) obtain damages pursuant to the indemnity provisions of Sections 9.01 and 9.06.

(c) Notwithstanding anything to the contrary herein, nothing in this Section 10.04 shall be deemed to give the ISO or any ISO agent or designee the right to exercise any functions other than those enumerated as Operating Authority in Section 3.02 or the right to take physical control of any PTO facilities.

ARTICLE XI

MISCELLANEOUS

11.01 **Notices.** Unless otherwise expressly specified or permitted by the terms hereof, all communications and notices provided for herein shall be in writing and any such communication or notice shall become effective (a) upon personal delivery thereof, including by overnight mail or courier service, (b) in the case of notice by United States mail, certified or registered, postage prepaid, return receipt requested, upon receipt thereof, or (c) in the case of notice by facsimile, upon receipt thereof; provided that such transmission is promptly confirmed by either of the methods set forth in clauses (a) or (b) above, in each case addressed to each party and copy party hereto at its address set forth in Schedule 11.01 or, in the case of any such party or copy party hereto, at such other address as such party or copy party may from time to time designate by written notice to the other parties hereto; further provided that a notice given in connection with this Section 11.01 but received on a day other than a Business Day, or after business hours in the situs of receipt, will be deemed to be received on the next Business Day.

11.02 **Supersession of Prior Agreements.** With respect to the subject matter hereof, this Agreement (together with all schedules and exhibits attached hereto) constitutes the entire agreement and understanding among the Parties with respect to all subjects covered by this Agreement and supersedes all prior discussions, agreements and understandings among the Parties with respect to such matters, including those agreements set forth on Schedule 11.02 attached hereto. To the extent that such other agreements address subjects addressed in this Agreement, this Agreement shall govern.

11.03 **Waiver.** Any term or condition of this Agreement may be waived at any time by the Party that is entitled to the benefit thereof, but no such waiver shall be effective unless set forth in a written instrument duly executed by or on behalf of the Party waiving such term or condition. No waiver by any Party of any term or condition of this Agreement, in any one or more instances, shall be deemed to be or construed as a waiver of the same or any other term or condition of this Agreement on any future occasion. All remedies, either under this Agreement or by Law or otherwise afforded, shall be cumulative and not alternative.

11.04 **Amendment; Limitations on Modifications of Agreement.**

(a) Except as otherwise specifically provided herein, this Agreement shall only be subject to modification or amendment as follows:

(i) Establishment of Committee. The PTOs shall form a PTO Administrative Committee (“PTO AC”) which shall meet periodically (1) to consider recommendations to the ISO regarding actions, policies and rules of the ISO affecting the PTOs’ Transmission Facilities; (2) to consider and vote upon proposed amendments to this Agreement; (3) to consult with the ISO as may be provided for under this Agreement; and (4) to consider any other matters relating

to the administration of this Agreement by the PTOs. The PTO AC shall be organized in the manner described in Schedule 11.04.

(ii) Amendments to Section 11.04(a)(iii) and Schedule 11.04.

Notwithstanding anything in this Agreement which may be construed to the contrary, the PTOs may unilaterally amend or revise Sections 11.04(a)(iii)(B) and 11.04(a)(iii)(C) of this Agreement and Schedule 11.04 to this Agreement through a vote of the PTO AC as set forth in Section 12 of Schedule 11.04, without the consent of the ISO, and may submit such amended Agreement under Section 205 of the Federal Power Act. Notwithstanding anything in this Agreement which may be construed to the contrary, the ISO may unilaterally amend or revise section 11.04(a)(iii)(A) of this Agreement through the process set forth in that subsection, without the consent of the PTOs, and may submit such amended Agreement under Section 205 of the Federal Power Act.

(iii) Amendments to this Agreement. Except as set forth in section 11.04(a)(ii), this Agreement may be amended by mutual agreement of the PTOs and the ISO and the acceptance of any such amendment by FERC.

- (A) ISO Agreement to Amendments. The ISO shall be deemed to have agreed to such amendment upon execution of the amendment.
- (B) PTO Agreement to General Amendments. Except as otherwise provided in sections 11.04(a)(iii)(C) and 11.04(a)(iii)(D), the PTOs will be deemed to have agreed to such amendment upon a vote of the PTOs meeting all of the following criteria:
 - (1) Weighted Voting. A vote to approve an amendment to this Agreement under this Section 11.04(a)(iii)(B) shall be cast by a number of the Individual Votes of the PTOs equal to or greater than sixty-five (65) percent of the aggregate Individual Votes of all the PTOs;
 - (2) Support of Non-Affiliated PTOs. In addition to the Individual Votes satisfying Section 11.04(a)(iii)(B)(i), a vote of the PTOs to approve an amendment to this Agreement under this Section 11.04(a)(iii)(B) shall be cast by a number of Non-Affiliated PTOs that have Supporting Votes-that are equal to or greater than (x) fifty (50) percent of such Non-Affiliated PTOs or (y) four (4), whichever is less; and;

- (3) Limits on a Single PTO Veto. The negative vote of a single PTO with Individual Votes equal to thirty-five (35) but not more than fifty (50) percent of the aggregate Individual Votes of the PTOs shall not cause the amendment to fail if the combined Individual Votes of the PTOs voting in favor of the amendment are equal to or greater than ninety-five (95) percent of the Individual Votes of all the remaining PTOs. The negative vote of a single PTO with Individual Votes greater than fifty (50) percent of the aggregate Individual Votes of the PTOs voting shall cause the amendment to fail.
- (C) PTO Agreement Requiring a Super Majority Vote. The PTOs will be deemed to have agreed to an amendment to Section 3.04(b) of this Agreement upon a vote of the PTOs meeting both of the following criteria:
- (1) Weighted Voting. A vote to approve an amendment to section 3.04(b) of this Agreement shall be cast by a number of the Individual Votes of the PTOs equal to or greater than ninety-five (95) percent of the aggregate Individual Votes of all the PTOs; and
- (2) Support of Non-Affiliated PTOs. In addition to the Individual Votes satisfying Section 11.04(a)(iii)(C)(i), a vote of the PTOs to approve an amendment to section 3.04(b) of this Agreement shall be cast by a number of Non-Affiliated PTOs that have Supporting Votes that are equal to or greater than (x) seventy (70) percent of such Non-Affiliated PTOs or (y) five (5), whichever is less.
- (D) PTO Agreement Requiring Consent of Affected Party. Notwithstanding anything in this Agreement which may be construed to the contrary, the PTO rights and privileges contained in sections 2.01, 3.04(a), 3.04(j), 3.04(k), 3.07, 3.13, 10.01(a), 10.01(b), and 11.04 of this Agreement and sections 12 and 13 of Schedule 11.04 to this Agreement shall not be modified or diminished by amendment to this Agreement or in any other way without the prior written consent of each PTO that may be affected thereby.
- (E) Amendments to PTO Voting Provisions to Reflect Additional Participating Transmission Owners. If an

unaffiliated transmission utility from outside the New England Control Area becomes or is about to become an Additional Participating Transmission Owner pursuant to Section 11.05 of this Agreement, and if any initial PTO's Individual Vote will change by more than 20 percent as a result, the PTOs shall enter into good faith negotiations to consider appropriate modifications to Sections 11.04(a)(iii)(B) and 11.04(a)(iii)(C) of this Agreement and Schedule 11.04 to this Agreement. The PTOs may unilaterally amend or revise Sections 11.04(a)(iii)(B) and 11.04(a)(iii)(C) of this Agreement and Schedule 11.04 to this Agreement through a vote of the PTO AC as set forth in Section 11.04(a)(iii)(D), without the consent of the ISO, and may submit such amended Agreement to the FERC under Section 205 of the Federal Power Act.

- (F) Supporting Votes. Each PTO that has a minimum of one (1) percent of the aggregate Individual Votes of all the PTOs at the time of the applicable PTO AC meeting shall have a single "Supporting Vote." The Individual Votes of any group of two or more PTOs that each have an Individual Vote of less than one (1) percent may be combined and voted so that if the combined Individual Votes of such PTOs are equal to or greater than one (1) percent of the aggregate Individual Votes of all the PTOs at the time of the applicable PTO AC meeting, such combined Individual Votes shall be counted as a single Supporting Vote. Subject to a sufficient number of Publicly-Owned PTOs executing this Agreement, as of the Operations Date the combined Individual Votes of all of the Publicly-Owned PTOs is expected to be greater than one (1) percent of the aggregate Individual Votes of all the PTOs. In the event that the combined Individual Votes of all of the Publicly-Owned PTOs as of the Operations Date is greater than one (1) percent of the aggregate Individual Votes of all the PTOs, if at any time after the Operations Date, all of the Publicly-Owned PTOs have Individual Votes of less than one (1) percent of the aggregate Individual Votes of all of the PTOs due to the addition of new transmission assets and the depreciation of existing transmission assets, then the combined Individual Votes of all of the Publicly Owned PTOs shall nonetheless be counted as a single Supporting Vote.

(b) In light of the foregoing, the Parties agree that they shall not rely to their detriment on any purported amendment, waiver or other modification of any rights under this Agreement unless the requirements of this Section 11.04 are satisfied and further agree not to assert equitable estoppel or any other equitable theory to prevent enforcement of this provision in any court of law or equity, arbitration or other proceeding.

(c) Absent the agreement of the Parties to any proposed change hereof or an amendment hereof pursuant to Section 11.04(a), the standard of review for changes to the following sections of this Agreement (or changes to any schedules associated with such sections) proposed by a Party, a non-party or the Federal Energy Regulatory Commission acting sua sponte shall be the "public interest" standard of review under the Mobile-Sierra Doctrine: 2.01, 2.04, 3.01, 3.02, 3.03, 3.04, 3.05, 3.06, 3.07, 3.09, 3.10, 3.11, 3.13, 3.14, 4.01(e), 6.06, 6.07, 6.08, 9.01, 9.06, 10.02, 10.03, 10.04, 11.04(a) - (d), 11.05, 11.06, 11.08, 11.17, 11.19(d), and Article I, as it applies to the foregoing sections. Absent the agreement of the Parties to any proposed change hereof or an amendment hereof pursuant to Section 11.04(a), with respect to changes to the remaining provisions of this Agreement proposed by a Party, a non-party or the Federal Energy Regulatory Commission acting sua sponte, the standard of review shall be that provided under Section 206 of the Federal Power Act.

(d) Notwithstanding the Parties' rights under Section 3.04 hereof, neither the ISO nor any PTO shall propose to modify or amend the ISO OATT nor any other tariff, rate schedule, procedure, protocol, or agreement applicable to the ISO or the PTOs in any manner that would limit, alter, or adversely affect the rights and responsibilities of the non-proposing Parties under this Agreement or that would otherwise be inconsistent with the provisions of this Agreement unless: (i) the PTOs and the ISO have entered into a prior written agreement to make corresponding modifications to this Agreement in accordance with this Section 11.04, or (ii) if corresponding modifications to the provisions of this Agreement enumerated in Section 11.04(c) above are required, the proposing Party also requests FERC to find (or FERC has already so found) that the corresponding modifications are required under the "public interest" standard of review under the Mobile-Sierra Doctrine or (iii) if corresponding modifications to the remainder of the Agreement are required, the proposing Party also requests FERC to find (or FERC has already so found) that the corresponding modifications are required under the standard of review under Section 206 of the Federal Power Act.

(e) The Parties shall notify stakeholders of proposed amendments to this Agreement by posting such amendments on the ISO website prior to the filing of such amendments with FERC and shall consider stakeholder input concerning such proposed amendments.

11.05 Additional Participating Transmission Owners. After the Operations Date, subject to the terms set forth herein, including Section 6.06, any owner of transmission facilities may become a PTO under this Agreement and a Party to this Agreement by executing and delivering a counterpart to this Agreement with the consent or approval of the ISO, such consent or approval not to be unreasonably withheld. Owners of transmission facilities that become

PTOs pursuant to the terms of this Section 11.05 shall be referred to herein as “Additional Participating Transmission Owners”; provided, however, that, notwithstanding any other provision contained herein to the contrary, Independent Transmission Companies shall not be deemed to be Additional Participating Transmission Owners hereunder. Notwithstanding Section 11.04 or any other provision contained herein to the contrary, Additional Participating Transmission Owners may become parties to this Agreement without any consent or approval of the other PTOs and without any amendment to this Agreement, except that this Agreement may be amended pursuant to Section 11.04(a)(iii)(E) if an unaffiliated transmission utility from outside the Control Area becomes or is about to become an Additional Participating Transmission Owner.

11.06 **Integration Charges.** Each Additional Participating Transmission Owner that enters into this Agreement after the Operations Date shall pay upon joining or shall promptly reimburse the ISO and each affected PTO for (a) all incremental costs, expenses and charges (including those incurred by the ISO or other PTOs) that, as determined by the ISO, result from the integration of such PTO’s transmission system into the Transmission Facilities over which the ISO exercises Operating Authority and produce an increase in ISO Administrative Charges assessed against users of the New England Transmission System; and (b) such PTO’s Pro Rata Share of the aggregate start-up costs recovered up to that date by the ISO. The ISO shall not implement any integration until it has received from the Additional Participating Transmission Owner payment in full for all such payments or secured a binding agreement that obligates the Additional Participating Transmission Owner to pay all such costs, expenses and other charges as they come due.

11.07 **No Third Party Beneficiaries.** Except as provided in Article IX, it is not the intention of this Agreement or of the Parties to confer a third party beneficiary status or rights of action upon any Person or entity whatsoever other than the Parties and nothing contained herein, either express or implied, shall be construed to confer upon any Person or entity other than the Parties any rights of action or remedies either under this Agreement or in any manner whatsoever.

11.08 **No Assignment; Binding Effect.** Neither this Agreement nor any right, interest or obligation hereunder may be assigned by a Party (including by operation of law) without the prior written consent of each other Party in its sole discretion and any attempt at assignment in contravention of this Section 11.08 shall be void. Any PTO may assign or transfer any or all of its rights, interests and obligations hereunder upon the transfer of its assets through sale, reorganization, or other transfer, provided that:

(a) the PTO’s successors and assigns shall agree to be bound by the terms of this Agreement except that PTO’s successors and assigns shall not be required to be bound by any obligations hereunder to the extent that the PTO has agreed to retain such obligations; and

(b) notwithstanding (a), the PTO shall assign or transfer to any new owner of Transmission Facilities subject to this Agreement all of the rights, responsibilities and obligations associated with the physical operation of such Transmission Facilities as well as all

of the rights, responsibilities and obligations associated with the ISO's Operating Authority with respect to such Transmission Facilities, further provided that the new owner shall have the right to retain one or more subcontractors to perform any or all of its responsibilities or obligations under this Agreement.

Subject to the foregoing, this Agreement is binding upon, inures to the benefit of and is enforceable by the Parties and their respective permitted successors and assigns. No assignment shall be effective until the PTO receives all required regulatory approvals for such assignment.

11.09 Further Assurances; Information Policy; Access to Records.

(a) Each Party agrees, upon another Party's request, to make Commercially Reasonable Efforts to execute and deliver such additional documents and instruments, provide information, and to perform such additional acts as may be necessary or appropriate to effectuate, carry out and perform all of the terms, provisions, and conditions of this Agreement and of the transactions contemplated hereby.

(b) The ISO shall, upon a PTO's request, make available to such PTO any and all information within the ISO's custody or control that is necessary for such PTO to perform its responsibilities and obligations or enforce its rights under this Agreement, provided that such information shall be made available to such PTO only to the extent permitted under the ISO Information Policy and subject to any applicable restrictions in the ISO Information Policy, including provisions of the ISO Information Policy governing the confidential treatment of non-public information, and provided further that any PTO employee or employee of a PTO's Local Control Center shall comply with such ISO Information Policy and any applicable standards of conduct to prevent the disclosure of such information to any unauthorized Person. Any dispute concerning what information is necessary for a PTO to perform its responsibilities and obligations or enforce its right under this Agreement shall be subject to dispute resolution under Section 11.14 of this Agreement.

(c) Each PTO shall, upon the ISO's request, make available to the ISO any and all information within the PTO's custody or control that is necessary for the ISO to perform its responsibilities and obligations or enforce its rights under this Agreement, provided that such information shall be made available to the ISO only to the extent permitted under the ISO Information Policy and subject to any applicable restrictions in the ISO Information Policy, including provisions of the ISO Information Policy governing the confidential treatment of non-public information, and provided further that any ISO employee shall comply with such ISO Information Policy and any applicable standards of conduct to prevent the disclosure of such information to any unauthorized Person. Any dispute concerning what information is necessary for the ISO to perform its responsibilities and obligations or enforce its right under this Agreement shall be subject to dispute resolution under Section 11.14 of this Agreement.

(d) If, in order to properly prepare its Tax Returns, other documents or reports required to be filed with Governmental Authorities or its financial statements or to fulfill its obligations hereunder, it is necessary that the ISO or any PTO be furnished with additional

information, documents or records not referred to specifically in this Agreement, and such information, documents or records are in the possession or control of the ISO or a PTO, the ISO or such PTO shall use its best efforts to furnish or make available such information, documents or records (or copies thereof) at the ISO's or such PTO's request, cost and expense. Any information obtained by the ISO or a PTO in accordance with this paragraph shall be subject to any applicable provisions of the ISO Information Policy

(e) Notwithstanding anything to the contrary contained in this Section 11.09:

(i) no Party shall be obligated by this Section 11.09 to undertake studies or analyses that such Party would not otherwise be required to undertake or to incur costs outside the normal course of business to obtain information that is not in such Party's custody or control at the time a request for information is made pursuant to this Section 11.09;

(ii) if any PTO and the ISO are in an adversarial relationship in litigation or arbitration (other than with respect to litigation or arbitration to enforce this Section 11.09), the furnishing of information, documents or records by the ISO or such PTO in accordance with this Section 11.09 shall be subject to applicable rules relating to discovery;

(iii) no Party shall be compelled to provide any privileged and/or confidential documents or information that are attorney work product or subject to the attorney/client privilege; and

(iv) no Party shall be required to take any action that impairs or diminishes its rights under this Agreement, diminishes any other Party's obligations under this Agreement or otherwise lessens the value of this Agreement to such Party.

11.10 **Business Day.** Notwithstanding anything herein to the contrary, if the date on which any payment is to be made pursuant to this Agreement is not a Business Day, the payment otherwise payable on such date shall be payable on the next succeeding Business Day with the same force and effect as if made on such scheduled date and, provided such payment is made on such succeeding Business Day, no interest shall accrue on the amount of such payment from and after such scheduled date to the time of such payment on such next succeeding Business Day.

11.11 **Governing Law.** This Agreement shall be governed by and construed in accordance with the laws of the State of Delaware including all matters of construction, validity and performance without regard to the conflicts-of-laws provisions thereof.

11.12 **Consent to Service of Process.** Each of the Parties hereby consents to service of process by registered mail, Federal Express or similar courier at the address to which notices to it are to be given, it being agreed that service in such manner shall constitute valid service upon such party or its respective successors or assigns in connection with any such action or

proceeding; provided, however, that nothing in this Section 11.12 shall affect the right of any such Parties or their respective successors and permitted assigns to serve legal process in any other manner permitted by applicable Law or affect the right of any such Parties or their respective successors and assigns to bring any action or proceeding against any other one of such Parties or its respective property in the courts of other jurisdictions.

11.13 **Specific Performance; Force Majeure.**(a) **Specific Performance.** The Parties specifically acknowledge that a breach of this Agreement, whether or not an Event of Default, and notwithstanding any cure period in Section 10.03(b), would cause each of the non-breaching Parties to suffer immediate and irreparable harm due to the unique relationship among the Parties. The Parties hereto shall be entitled to seek specific performance and/or an injunction or injunctions to prevent breaches of the provisions of this Agreement and to enforce specifically the terms and conditions hereof in any court of competent jurisdiction, such remedy being in addition to any other remedy to which any Party may be entitled at law or in equity.

(b) **Force Majeure.** A Party shall not be considered to be in default or breach under this Agreement, and shall be excused from performance or liability for damages to any other party, if and to the extent it shall be delayed in or prevented from performing or carrying out any of the provisions of this Agreement, except the obligation to pay any amount when due, in consequence of any act of God, labor disturbance, failure of contractors or suppliers of materials (not including as a result of non-payment), act of the public enemy or terrorists, war, invasion, insurrection, riot, fire, storm, flood, ice, explosion, breakage or accident to machinery or equipment or by any other cause or causes (not including a lack of funds or other financial causes) beyond such Party's reasonable control, including any order, regulation, or restriction imposed by governmental, military or lawfully established civilian authorities. Any Party claiming a force majeure event shall use reasonable diligence to remove the condition that prevents performance, except that the settlement of any labor disturbance shall be in the sole judgement of the affected Party.

11.14 **Dispute Resolution.** The Parties agree that any dispute arising under this Agreement shall be the subject of good-faith negotiations among the affected Parties and affected market participants, if any. Each affected Party and each affected market participant shall designate one or more representatives with the authority to negotiate the matter in dispute to participate in such negotiations. The affected Parties and affected market participants shall engage in such good-faith negotiations for a period of not less than 60 calendar days, unless: (a) a Party or market participant identifies exigent circumstances reasonably requiring expedited resolution of the dispute by FERC or a court or agency with jurisdiction over the dispute; or (b) the provisions of this Agreement otherwise provide a Party the right to submit a dispute directly to FERC for resolution. Any other dispute that is not resolved through good-faith negotiations may, by any Party or any market participant, be submitted for resolution by FERC or a court or agency with jurisdiction over the dispute upon the conclusion of such negotiations. Any Party or market participant may request that any dispute submitted to FERC for resolution be subject to FERC settlement procedures. Notwithstanding the foregoing, any dispute arising under this Agreement may be submitted to arbitration or any other form of alternative dispute resolution

upon the agreement of all affected Parties and all affected market participants to participate in such an alternative dispute resolution process.

11.15 **Invalid Provisions.** If any provision of this Agreement is held to be illegal, invalid or unenforceable under any present or future Law, and if the rights or obligations of any Party under this Agreement shall not be materially and adversely affected thereby, (a) such provision shall be fully severable, (b) this Agreement shall be construed and enforced as if such illegal, invalid or unenforceable provision had never comprised a part hereof, (c) the remaining provisions of this Agreement shall remain in full force and effect and shall not be affected by the illegal, invalid or unenforceable provision or by its severance herefrom, and (d) the court holding such provision to be illegal, invalid or unenforceable may in lieu of such provision add as a part of this Agreement a legal, valid and enforceable provision as similar in terms to such illegal, invalid or unenforceable provision as it deems appropriate; provided that nothing in this Section 11.15 shall limit a Party's right to appeal conditions to regulatory approval in accordance with Section 11.20(d).

11.16 **Headings and Table of Contents.** The headings of the sections of this Agreement and the Table of Contents are inserted for purposes of convenience only and shall not be construed to affect the meaning or construction of any of the provisions hereof.

11.17 **Liabilities; No Joint Venture.**

(a) The obligations and liabilities of the ISO and each PTO arising out of or in connection with this Agreement shall be several, and not joint, and each Party shall be responsible for its own debts, including Taxes. No Party shall have the right or power to bind any other Party to any agreement without the prior written consent of such other Party. The Parties do not intend by this Agreement to create nor does this Agreement constitute a joint venture, association, partnership, corporation or an entity taxable as a corporation or otherwise. No express or implied term, provision or condition of this Agreement shall be deemed to constitute the parties as partners or joint venturers.

(b) To the extent any Party has claims against any other Party, such Party may only look to the assets of the other Party for the enforcement of such claims and may not seek to enforce any claims against the directors, members, officers, employees, affiliates, or agents of such other Party who, each Party acknowledges and agrees, have no liability, personal or otherwise, by reason of their status as directors, members, officers, employees, affiliates, or agents of that Party, with the exception of fraud or willful misconduct.

11.18 **Counterparts.** This Agreement may be executed in any number of counterparts, each of which shall be deemed an original, but all of which together shall constitute but one and the same instrument. The parties hereto agree that any document or signature delivered by facsimile transmission shall be deemed an original executed document for all purposes hereof.

11.19 **Conditions Precedent.** Notwithstanding anything to the contrary in this Agreement, this Agreement shall not be effective with respect to any Party unless all of the conditions precedent set forth in this Section 11.19 shall have been satisfied or waived.

(a) **Required Regulatory Approvals.** All final required regulatory approvals shall have been obtained and be in full force and effect and shall not be subject to the satisfaction of any condition or conditions that, if accepted, would: (i) in the case of a PTO, in the reasonable judgment of such PTO, in the aggregate have a material adverse effect on the value of the PTO's Transmission Facilities, its expected level of transmission revenues, or its electric utility business, revenues, or financial condition, unless such PTO waives said condition, provided however, that with respect to any required regulatory approval obtained from a Governmental Authority of a State, the condition set forth in this clause shall apply only if such PTO operates its Transmission Business within such State; and (ii) in the case of the ISO, in its reasonable judgment, have a material adverse effect on the ISO's ability to perform its obligations under this or any other agreement to which it is subject, unless the ISO waives such condition.

(b) **Board Consent.** The board of directors of each Party, in its sole discretion, shall have authorized and approved such Party's executing, delivering and performing this Agreement.

(c) **Additional Conditions Precedent.** Additional conditions precedent are listed on Schedule 11.19(c).

(d) **PTOs That Own Facilities Financed by Local Furnishing Bonds or Other Tax-Exempt Debt.** As indicated in Section 3.13, each PTO that owns Transmission Facilities financed through Local Furnishing Bond(s) or other Tax-Exempt Debt shall have adequate assurance, in the opinion of each such PTO, that execution and performance of its obligations under this Agreement will not jeopardize the tax-exempt status of their respective Tax-Exempt Debt or the ability of such PTOs to secure future tax-exempt financing.

(e) **Right to Appeal Conditions to Regulatory Approval.** In the event that a Governmental Authority conditions its regulatory approval of this Agreement on acceptance of a contractual provision, contractual modification, or any other condition or ruling related to formation of the New England RTO that is not acceptable to any Party, such Party shall have the option of agreeing to permit this Agreement to become effective with the condition or ruling to which it objects and appeal the propriety of the condition or ruling to courts of competent jurisdiction; provided that, in the event a Final Order requires a vacation or modification of such objectionable condition or ruling, this Agreement shall thereupon be modified consistent with that Final Order; provided, however, that other Parties may exercise their rights to withdraw

from or terminate this Agreement pursuant to Section 10.01(b) or Section 10.01(d), as applicable.

11.20 **Preserved Rights.** No Party, by executing this Agreement, shall waive any rights to seek rehearing of a Commission order or to appeal a Commission order, including Commission orders concerning the terms and conditions of the NEPOOL tariff and market rules in effect prior to the Operations Date to the extent such terms and conditions have been incorporated into the ISO Tariff. The Parties expressly reserve the rights to pursue all pending requests for rehearing or appeals of such orders, and to file pleadings relating to such requests for rehearing or appeals, to the same extent as if the NEPOOL tariff were still in effect. Changes to the ISO Tariff shall be made to the extent necessary to comply with the results of a Commission rehearing order or judicial appeal concerning the terms and conditions of the NEPOOL tariff and market rules in effect prior to the Operations Date to the extent such terms and conditions have been incorporated into the ISO Tariff. The foregoing sentence shall not be deemed to prevent a Party from expressing its views to the Commission or a court regarding the foregoing compliance filing.

IN WITNESS WHEREOF, this Agreement has been duly executed and delivered by the duly authorized officer of each party as of the date first above written.

Signature

Party

Title of Signatory

Schedule 1.01

Schedule of Definitions

Acquired Transmission Facilities. Any transmission facility acquired within the New England Control Area by one or more PTOs after the Operations Date that meets the classification standards set forth in Section 2.01(e).

Additional Participating Transmission Owners. “Additional Participating Transmission Owners” shall have the meaning ascribed thereto in Section 11.05 of this Agreement.

Additional Term. “Additional Term” shall have the meaning ascribed thereto in Section 10.01(a) of this Agreement.

Affiliate. Any person or entity which controls, is controlled by, or is under common control by another person or entity. For purposes of this definition, "control" shall mean the possession, directly or indirectly and whether acting alone or in conjunction with others, of the authority to direct the management or policies of a person or entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

Agreement. This Transmission Operating Agreement, as it may be amended from time to time.

Ancillary Service. Those services that are necessary to support the transmission of electric capacity and energy from resources to loads while maintaining reliable operation of the transmission system in accordance with Good Utility Practice.

Approved Outages. “Approved Outages” shall have the meaning ascribed thereto in Section 3.08(a)(iv) of this Agreement.

ATC. Available Transfer Capability.

Backstop Transmission Solution. A solution proposed: (i) to address a reliability or market efficiency need identified by the ISO in a Needs Assessment reported by the ISO pursuant to Section 4.1(i) of Attachment K to the ISO OATT, (ii) by the PTO or PTOs with an obligation under Schedule 3.09(a) of the TOA to address the identified need; and (iii) in circumstances in which the competitive solution process specified in Section 4.3 of Attachment K to the ISO OATT will be utilized.

Back-up Control Center. The control center established by the ISO as a back-up to the ISO Control Center.

Back-up Control Center Lease. The lease for premises in Newington, Connecticut entered into by ISO New England Inc. and Rocky River Realty Company for an initial term ending July 31, 2005, and subject to the right of the tenant to four three-year extensions.

Best's. The A.M. Best Company.

Business Day. Any day other than a Saturday or Sunday or an ISO holiday, as posted by the ISO on its website.

Category A Facilities. Those transmission facilities listed in Schedule 2.01(a) of the Agreement, as that list may be modified from time to time in accordance with the terms of this Agreement.

Category B Facilities. Those transmission facilities listed in Schedule 2.01(b) of the Agreement, as that list may be modified from time to time in accordance with the terms of this Agreement.

CBM. Capacity Benefit Margin.

Chester SVC Facility. The Chester Static VAR Compensator ("SVC") Facility is a generator/sink of VARs that is connected to the Orrington-Keswick 345 kV line ("396 line") via a tap at Chester, Maine. The Chester SVC Facility is owned by the Chester SVC Partnership. The Chester SVC Facility's MVar capability is provided by three thyristor switched capacitors, two groups of fixed harmonic filters, and one thyristor controlled reactor. The total operating range is +442 MVar capacitive to -125 MVar inductive. The Chester SVC Facility is one of the reinforcements required with the installation of the Phase II HVDC interconnection between Hydro-Quebec and New England. The Chester SVC Facility was designed to maximize imports from eastern Canada by allowing the simultaneous operation of the Phase II import and New Brunswick to New England transfer at their full capabilities (2000 MW and 700 MW, respectively) while avoiding the need for New Brunswick generation rejection and/or the tripping of the New Brunswick-New England tie, the 396 line, for loss of Phase II imports.

Commercially Reasonable Efforts: A level of effort which in the exercise of prudent judgment in the light of facts or circumstances known, or which should reasonably be known, at the time a decision is made, can be expected by a reasonable person to accomplish the desired result in a manner consistent with Good Utility Practice and which takes the performing party's interests into consideration. "Commercially Reasonable Efforts" will not be deemed to require a Person to undertake unreasonable measures or measures that have a significant adverse economic affect on such Person, including the payment of sums in excess of amounts that would be expended in the ordinary course of business for the accomplishment of the stated purpose.

Commission. The Federal Energy Regulatory Commission.

Control Area. An electric power system or combination of electric power systems, bounded by metering, to which a common automatic generation control scheme is applied in order to:

(a) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and applicable NERC/NPCC Requirements; and

(d) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Control Center Lease. The Master Leasing Agreement, dated as of May 31, 1990, by and between Bankers Leasing corporation, as lessor, and State Street Bank and Trust Company of Connecticut, N.A., not in its individual capacity, but solely as Successor Nominee Trust under a Declaration of Trust, dated as of June 14, 1990, for beneficiaries listed in schedule 1 thereto, and as agent for the NEPOOL participants, as lessee.

Cooperative PTO. A PTO that has loans financed or guaranteed by the Rural Utilities Service.

Cooperative TO. A transmission owner has loans financed or guaranteed by the Rural Utilities Service.

Coordination Agreement. An agreement between the ISO and the operator(s) of one or more neighboring Control Areas addressing issues including interchange scheduling, operational arrangements, emergency procedures, energy for emergency and reliability needs, the exchange of information among Control Areas, and other aspects of the coordinated operation of the Control Areas.

Disbursement Agreement The Rate Design and Funds Disbursement Agreement among the PTOs, as amended and restated from time to time.

Elective Transmission Upgrade. A transmission facility constructed by any Person which is not required to be constructed pursuant to any applicable requirement of this Agreement, but which may be subject to applicable requirements set forth in the ISO OATT and this Agreement.

Elective Transmission Upgrade Applicant. “Elective Transmission Upgrade Applicant” shall have the meaning ascribed thereto in Section 2.05 of this Agreement.

Emergent and Unanticipated Event. For purposes of Section 3.08, “Emergent and Unanticipated Event” shall have the meaning ascribed thereto in Section 3.08(b)(ii)(B) of this Agreement.

Environment. Soil, land surface or subsurface strata, surface waters (including navigable waters, ocean waters, streams, ponds, drainage basins, and wetlands), groundwaters, drinking water supply, stream sediments, ambient air (including indoor air), plant and animal life, and any other environmental medium or natural resource.

Environmental Damages. “Environmental Damages” shall mean any cost, damages, expense, liability, obligation or other responsibility arising from or under Environmental Law consisting of or relating to:

(a) any environmental matters or conditions (including on-site or off-site contamination, occupational safety and health, and regulation of chemical substances or products);

(b) fines, penalties, judgments, awards, settlements, legal or administrative proceedings, damages, losses, claims, demands and response, investigative, remedial or inspection costs and expenses arising under Environmental Law;

(c) financial responsibility under Environmental Law for cleanup costs or corrective action, including any investigation, cleanup, removal, containment or other remediation or response actions (“Cleanup”) required by applicable Environmental Law (whether or not such Cleanup has been required or requested by any Governmental Authority or any other Person) and for any natural resource damages; or

(d) any other compliance, corrective, investigative, or remedial measures required under Environmental Law.

Environmental Laws. Any Law now or hereafter in effect and as amended, and any judicial or administrative interpretation thereof, including any judicial or administrative order, consent decree or judgment, relating to pollution or protection of the Environment, health or safety or to the use, handling, transportation, treatment, storage, disposal, release or discharge of Hazardous Materials.

Excepted Transactions. “Excepted Transactions” shall have the meaning ascribed thereto in the ISO OATT.

Excluded Assets. “Excluded Assets” shall have the meaning ascribed thereto in Section 2.04 of this Agreement.

Exigent Circumstances. “Exigent Circumstances” shall mean circumstances such that the ISO determines in good faith that (i) failure to immediately implement a proposed Tariff filing authorized under Sections 3.04(c) and 3.04(e) of this Agreement would substantially and adversely affect (A) System reliability or security, or (B) the competitiveness or efficiency of the New England Markets, and (ii) invoking the procedures set forth in Sections 3.04(c) and 3.04(e) of this Agreement would not allow for timely redress of the ISO’s concerns.

Existing Operating Procedures. “Existing Operating Procedures” shall have the meaning ascribed thereto in Section 3.02(d) of this Agreement.

External Transactions. Interchange transactions between the New England Transmission System and neighboring Control Areas.

FACTS. Flexible AC Transmission Systems.

FERC. The Federal Energy Regulatory Commission.

Final Order. An order issued by a Governmental Authority in a proceeding after all opportunities for rehearing are exhausted (whether or not any appeal thereof is pending) that has not been revised, stayed, enjoined, set aside, annulled or suspended, with respect to which any required waiting period has expired, and as to which all conditions to effectiveness prescribed therein or otherwise by law, regulation or order have been satisfied.

Financial Assurances. “Financial Assurances” shall have the meaning ascribed thereto in Section 3.10(b) of this Agreement.

FPA. The Federal Power Act.

FTR. A Financial Transmission Right, as defined in the ISO OATT.

Generally Accepted Accounting Principles. The widely accepted set of rules, conventions, standards, and procedures for reporting financial information, as established by the Financial Accounting Standards Board.

Generating Unit. A device for the production of electricity.

Good Utility Practice. Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather includes all acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority. The government of any nation, state or other political subdivision thereof, including any entity exercising executive, military, legislative, judicial, regulatory, or administrative functions of or pertaining to a government, not including any PTO or the ISO.

Grandfathered Interconnection Agreement. An agreement or agreements for the interconnection of any entity to the Transmission Facilities of a PTO that has been executed or approved by an applicable Governmental Authority prior to the Operations Date and that is set forth in Schedule 3.11(c) to this Agreement.

Grandfathered Intertie Agreement. An agreement or agreements for the provision of transmission service over a Control Area intertie or for the interconnection of the Transmission Facilities of a PTO with facilities outside the New England Control Area that has been executed or approved by an

applicable Governmental Authority prior to the Operations Date and that is set forth in Schedule 3.11(b) of this Agreement.

Grandfathered Transmission Agreements. “Grandfathered Transmission Agreements” shall consist of all Excepted Transactions, Grandfathered Interconnection Agreements Grandfathered Intertie Agreements, MEPCO Grandfathered Transmission Service Agreements and MEPCO Operating Documents.

Hazardous Materials. Any waste or other substance that is listed, defined, designated, or classified as, or otherwise determined to be, hazardous, radioactive, or toxic or a pollutant or a contaminant under or pursuant to any Environmental Law, including any admixture or solution thereof, and specifically including petroleum and all derivatives thereof or synthetic substitutes therefor and asbestos or asbestos-containing materials.

Highgate Transmission Facility (HTF). “Highgate Transmission Facility (HTF) shall consist of existing U.S.-based transmission facilities covered under the Agreement for Joint Ownership, Construction and Operation of the Highgate Transmission Interconnection dated as of August 1, 1984 including (1) the whole of a 200 megawatt high-voltage, back-to-back, direct-current converter facility located in Highgate, Vermont and (2) a 345 kilovolt transmission line within Highgate and Franklin, Vermont (which connects the converter facility at the U.S.-Canadian border to a Hydro-Quebec 120 kilovolt line in Bedford, Quebec). The HTF include any upgrades associated with increasing the capacity or changing the physical characteristics of these facilities as defined in the above stated agreement dated August 1, 1984 until the Operations Date, as defined in this Agreement. The current HTF rating is a nominal 225 MW. The HTF are not defined as PTF. Coincident with the Operations Date and except as stipulated in Schedules 9, 12, and Attachment F to the ISO OATT, HTF shall be treated in the same manner as PTF for purposes of the ISO OATT and all references to PTF in the ISO OATT shall be deemed to apply to HTF as well. The treatment of the HTF is not intended to establish any binding precedent or presumption with regard to the treatment for other transmission facilities within the New England Transmission System (including HVDC, MTF, or Control Area Interties) for purposes of the ISO OATT.

Indemnifiable Loss. “Indemnifiable Loss” shall have the meaning ascribed thereto in Section 9.01(a)(i) of this Agreement.

Indemnified Person. “Indemnified Person” shall have the meaning ascribed thereto in Section 9.01(b) of this Agreement.

Indemnified PTO. “Indemnified PTO” shall have the meaning ascribed thereto in Section 9.01(a)(i) of this Agreement.

Indemnifying Party. “Indemnifying Party” shall have the meaning ascribed thereto in Section 9.02 of this Agreement.

Indemnifying PTO. “Indemnifying PTO” shall have the meaning ascribed thereto in Section 9.01(b) of this Agreement.

Indemnitee. “Indemnitee” shall have the meaning ascribed thereto in Section 9.02 of this Agreement.

Independent Transmission Company or ITC. A transmission entity that assumes certain responsibilities in accordance with Attachment M to the ISO OATT, subject to the acceptance or approval of the FERC and a finding of the FERC that the transmission entity satisfies applicable independence requirements.

Individual Votes. “Individual Votes” shall have the meaning ascribed thereto in Section 13 of Schedule 11.04 to this Agreement.

Initial Participating Transmission Owners. The transmission owners listed in the opening paragraph of the Agreement that are signatories to this Agreement as of the Operations Date.

Initial Term. “Initial Term” shall have the meaning ascribed thereto in Section 10.01(a) of this Agreement.

Interconnection Agreement. An agreement or agreements for the interconnection of any entity to the Transmission Facilities of a PTO.

Interconnection Standard. The applicable interconnection standards set forth in the ISO OATT.

Invoiced Amount. “Invoiced Amount” shall have the meaning ascribed thereto in Section 3.10(a)(i) of the Agreement.

ISO. ISO New England Inc., the RTO for New England authorized by the Federal Energy Regulatory Commission to exercise the functions required pursuant to FERC’s Order No. 2000 and FERC’s corresponding regulations.

ISO Administrative Charge. “ISO Administrative Charge” shall have the meaning ascribed thereto in Section 3.04(h) of this Agreement.

ISO Control Center. The primary control center established by the ISO for the exercise of its Operating Authority and the performance of functions as an RTO.

ISO Customers. “ISO Customers” shall have the meaning ascribed thereto in Section 3.10(b) of this Agreement.

ISO Default. “ISO Default” shall have the meaning ascribed thereto in Section 10.03(a) of this Agreement.

ISO Information Policy. The information policy set forth in the ISO OATT.

ISO-NE. ISO New England, Inc.

ISO OATT. The ISO Open Access Transmission Tariff, as in effect from time to time.

ISO Participants Agreement. The agreement among the ISO and stakeholder participants addressing, inter alia, the stakeholder process for the ISO.

ISO Planning Process. The process set forth in the ISO OATT, for the coordinated planning and expansion of the New England Transmission System with provision for the participation of all state regulatory authorities with jurisdiction over retail rates in the ISO region acceptable to those authorities, which process shall be subject to certain terms and conditions set forth in Schedule 3.09(a).

ISO System Plan. The regional system expansion plan for the New England Transmission System.

ISO Tariff. The ISO Transmission, Markets and Services Tariff, as amended from time to time, on file with FERC.

Knowledge. With respect to a Party, the collective actual knowledge of the directors and members of management of such Party, after reasonable inquiry by them of selected employees of such Party whom they believe, in good faith, to be the persons generally responsible for the subject matters to which the knowledge is pertinent. “Known” shall have the meaning correlative to “Knowledge.”

Large Generating Facility. “Large Generating Facility” shall have the meaning ascribed thereto in the ISO OATT.

Law. Any federal, state, local or foreign statute, law, ordinance, regulation, rule, code, order, other requirement or rule of law.

Load Shedding. The systematic reduction of system demand by temporarily decreasing load.

Local Area Facilities. “Local Area Facilities” shall have the meaning ascribed thereto in Section 2.01 of this Agreement.

Local Control Center. Those control centers now in existence (including the CONVEX, REMVEC, Maine and New Hampshire control centers) or established by the PTOs in accordance with Section 3.06(a) of this Agreement that are separate from the ISO Control Center and perform certain functions in accordance with this Agreement.

Local Furnishing Bonds. Tax-exempt bonds utilized to finance facilities for the local furnishing of electric Energy, as described in section 142(f) of the Internal Revenue Code, 26 U.S.C. §142(f). Local Furnishing Bonds do not include Municipal Tax-Exempt Debt.

Local Networks. “Local Networks” shall have the meaning ascribed thereto in Section 3.03(e) of this Agreement.

Local Network Service. Network Transmission Service over the facilities of a single PTO (including facilities leased to the PTO or to which the PTO has contractual entitlements) provided under a FERC-accepted or -approved Local Service Schedule.

Local Point-to-Point Transmission Service. Point-to-point Transmission Service over the facilities of a single PTO (including facilities leased to the PTO or to which the PTO has contractual entitlements) provided under a FERC-accepted or -approved Local Service Schedule.

Local Service. Transmission Service over the facilities of a single PTO (including facilities leased to the PTO or to which the PTO has contractual entitlements) provided under a FERC-accepted or -approved Local Service Schedule.

Local Service Schedule. A PTO-specific rate schedule to the ISO OATT setting forth rates, charges, terms and conditions applicable only to service provided over the Transmission Facilities of such PTO.

Long-Term Transmission Outage Plan. “Long-Term Transmission Outage Plan” shall have the meaning ascribed thereto in Section 3.08(a)(i) of this Agreement.

Major Transmission Outage. “Major Transmission Outage” shall have the meaning ascribed thereto in Section 3.08(a)(ii) of this Agreement.

Market Monitoring Unit. Any market monitoring unit established by the ISO, including any internal market monitoring unit of the ISO and any independent market monitoring unit of the ISO.

Market Participant Service Agreement. The agreement among the ISO and market participants addressing, *inter alia*, the requirements for participating in the New England Markets.

Market Rules. The rules describing how the New England Markets are administered.

MEPCO Grandfathered Transmission Service Agreements (“MGTSAs”). “MEPCO Grandfathered Transmission Service Agreements” shall have the meaning ascribed thereto in the ISO OATT.

MEPCO Operating Documents. Those agreements set forth in Schedule 3.11(f) of this Agreement.

MEPCO Transmission Facility. The 345 kV transmission line, which is owned and operated by MEPCO, connected to Central Maine Power Company at the Maine Yankee Substation in Wiscasset, Maine, and at the Maxcy’s Substation in Windsor, Maine to Bangor Hydro Electric

Company at Orrington, Maine and at its northern end, at the Canadian border to a similar 345 kV transmission line owned by New Brunswick Power.

Merchant Facility. A transmission facility constructed by an entity that assumes all market risks associated with the recovery of costs for the facility and whose costs are not recovered through traditional cost-of-service based rates, but instead are recovered either through negotiated agreements with customers or through market revenues.

Mobile-Sierra Doctrine. The “Mobile-Sierra Doctrine” shall mean the public interest standard of review set forth in United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. 348 (1956).

Moratorium Period. “Moratorium Period” shall have the meaning ascribed thereto in Section 3.04(h)(i) of this Agreement.

NERC. The North American Electric Reliability Council.

Municipal Tax-Exempt Debt. An obligation the interest on which is excluded from gross income for federal tax purposes pursuant to Section 103(a) of the Internal Revenue Code of 1986 or the corresponding provisions of prior law without regard to the identity of the holder thereof. Municipal Tax-Exempt Debt does not include Local Furnishing Bonds.

Municipal Tax-Exempt PTO. A PTP that has issued Municipal Tax-Exempt Debt with respect to any facilities, or rights associated therewith.

Municipal Tax-Exempt TO. A transmission owner that has issued Municipal Tax-Exempt Debt with respect to any facilities, or rights associated therewith.

NERC/NPCC Requirements. NPCC criteria, guides, and procedures, NERC reliability standards, and NERC operating policies and planning standards (until such time as they are replaced by NERC reliability standards) and any successor documents.

NESCOE. The New England State Committee on Electricity, recognized by the Commission as the Regional State Committee for the New England Control Area.

New England Control Area. The Control Area consisting of the interconnected electric power system or combination of electric power systems in the geographic region consisting of Vermont, New Hampshire, Maine, Massachusetts, Connecticut and Rhode Island.

New England Markets. Markets or programs (including congestion pricing and design and implementation of FTRs) for the purchase of energy, capacity, ancillary services, demand response services or other related products or services that are offered in the New England Control Area and that are administered by the ISO pursuant to rules, rates, or agreements on file from time to time with the Commission.

New England Transmission System. The system comprised of the transmission facilities over which the ISO has operational jurisdiction, including the Transmission Facilities of the PTOs and the transmission system of any ITC formed pursuant to Attachment M to the ISO OATT.

New Transmission Facility. Any new transmission facility constructed within the New England Transmission System that goes into commercial operation after the Operations Date.

Non-Affiliated PTOs. Two or more PTOs that are not Affiliates.

Non-Incumbent Transmission Developer Operating Agreement. “Non-Incumbent Transmission Developer Operating Agreement” shall have the meaning ascribed thereto in Section I.2.2 to the ISO Tariff.

Non-PTF. “Non-PTF” shall have the meaning ascribed thereto in the ISO OATT.

Notice of Operations Date. “Notice of Operations Date” shall have the meaning ascribed thereto in Section 10.01(a)(ii) of this Agreement.

NPCC. The Northeast Power Coordinating Council.

OASIS. The Open Access Same-Time Information System of the ISO.

OATT Interconnection Distribution Facility. A distribution facility that is subject to the generator interconnection procedures of the ISO OATT. An OATT Interconnection Distribution Facility is not a Transmission Facility subject to the Operating Authority of the ISO pursuant to this Agreement.

Operating Authority. “Operating Authority” shall have the meaning ascribed thereto in Section 3.02 of this Agreement and shall include the responsibilities set forth in Section 3.05.

Operating Limits. The transfer limits for a transmission interface or generation facility.

Operating Procedures. The operating manuals, procedures, and protocols relating to the exercise of Operating Authority over the Transmission Facilities, as such manuals, procedures, and protocols may be modified from time to time in accordance with this Agreement.

Operations Date. “Operations Date” shall have the meaning ascribed thereto in Section 10.01(a)(ii) of this Agreement.

Order 2000. FERC’s Order No. 2000, *i.e.*, *Regional Transmission Organizations*, Order No. 2000, 65 Fed. Reg. 809 (January 6, 2000), FERC Stats. & Regs. ¶31,089 (1999), *order on reh'g*, Order No. 2000-A, 65 Fed. Reg. 12,088 (March 8, 2000), FERC Stats. & Regs. ¶31,092 (2000), *petitions for review pending sub nom.*, Public Utility District No. 1 of Snohomish County, Washington v. FERC, Nos. 00-1174, *et al.* (D.C. Cir).

Owed Amounts. “Owed Amounts” shall have the meaning ascribed thereto in Section 3.10(c) of this Agreement.

PARS. Phase angle regulators.

Participant. A participant in the New England Markets, Transmission Customer, or other entity that has entered into the ISO Participants Agreement.

Participants Committee. “Participants Committee” shall mean the stakeholder participants committee established pursuant to the ISO Participants Agreement.

Party or Parties. A “Party” shall mean the ISO or any PTO, as the context requires. “Parties” shall mean all PTOs and the ISO.

Person. An individual, partnership, joint venture, corporation, business trust, limited liability company, trust, unincorporated organization, government or any department or agency thereof, or any other entity.

Planned Outages. “Planned Outages” shall have the meaning ascribed thereto in Section 3.08(a)(i) of this Agreement.

Planning Procedures. The manuals, procedures and protocols for planning and expansion of the New England Transmission System, as such manuals, procedures, and protocols may be modified from time to time in accordance with this Agreement.

Prime Rate. The interest rate that commercial banks charge their most creditworthy borrowers, as published in the most recent Wall Street Journal in its “Monday Rates” column.

Pro Rata Share. A PTO’s proportional share of the ISO’s Administrative Charges during such PTO’s first year as a PTO under this Agreement.

PTF. “PTF” shall have the meaning ascribed thereto in the ISO OATT.

PTO or Participating Transmission Owner. “PTO” shall have the meaning ascribed thereto in the opening paragraph of the Agreement. “Participating Transmission Owner” shall have the same meaning as “PTO.”

PTO AC or PTO Administrative Committee. “PTO AC” or “PTO Administrative Committee” shall have the meaning ascribed thereto in Section 11.04(a)(i) of this Agreement.

PTO Default. “PTO Default” shall have the meaning ascribed thereto in Section 10.04(a) of this Agreement.

PTO Joint Account. The joint account established in the name, and for the benefit, of the PTOs, in which each PTO shall own an undivided interest in a proportion equal to the proportion of that PTO’s right of distribution from the deposited Invoiced Amounts.

PTO Local Restoration Plan. The restoration plan developed by each PTO with respect to such PTO's Transmission Facilities.

Public Policy Project. Any New Transmission Facility or Transmission Upgrade that is included in the ISO System Plan as a Public Policy Transmission Upgrade in accordance with Attachment K to the ISO OATT.

Publicly-Owned PTO. A "Publicly-Owned PTO" shall mean a PTO that is exempt, under Section 201(f) of the Federal Power Act, from the obligations and requirements of the Federal Power Act.

Qualified Transmission Project Sponsor. "Qualified Transmission Project Sponsor" shall have the meaning ascribed thereto in Section I.2.2 of the ISO Tariff.

Rating Procedures. "Rating Procedures" shall have the meaning ascribed thereto in Section 3.02(d) of this Agreement.

Regulation and Frequency Response Service. An Ancillary Service as defined in the ISO OATT.

Reliability Authority. "Reliability Authority" shall have the meaning established by NERC, as such definition may change from time to time, provided such definition of Reliability Authority shall not be inconsistent with the specific rights and responsibilities of the ISO and the PTOs under this Agreement.

Restoration Plans. The System Restoration Plan and all PTO Local Restoration Plans.

RFAP. "RFAP" shall have the meaning ascribed thereto in Section 6 of Schedule 3.09(a) to this Agreement.

RMR. Reliability must run resources.

RTO. An independent entity that complies with Order No. 2000 and FERC's corresponding regulations (or an entity that complies with all such requirements except for the scope and regional configuration requirements), as determined by the FERC.

Schedule 22 Large Generator Interconnection Agreement. The interconnection agreement included in Schedule 22 of the ISO OATT.

Schedule 23 Small Generator Interconnection Agreement. The interconnection agreement included in Schedule 23 of the ISO OATT.

Scheduled Outages. "Scheduled Outages" shall have the meaning ascribed thereto in Sections 3.08(a)(ii) and 3.08(a)(iii) of this Agreement.

Small Generating Facility. "Small Generating Facility" shall have the meaning ascribed thereto in the ISO OATT.

Supporting Votes. “Supporting Votes” shall have the meaning ascribed thereto in Section 11.04(a)(iii)(F) of this Agreement.

System Failure. Widespread telecommunication, hardware or software failure or systemic the ISO hardware or software failures that makes it impossible to receive or process bid information, dispatch resources, or exercise Operating Authority over the Transmission Facilities.

Tax or Taxes. All taxes, charges, fees, levies, penalties or other assessments imposed by any United States federal, state or local or foreign taxing authority, including, but not limited to, income, excise, property, sales, transfer, franchise, payroll, withholding, social security or other taxes, including any interest, penalties or additions attributable thereto.

Tax-Exempt Debt. Municipal Tax-Exempt Debt or Local Furnishing Bonds.

Tax Return. Any return, report, information return, or other document (including any related or supporting information) required to be supplied to any authority with respect to Taxes.

Technical Committees. “Technical Committee” shall mean the stakeholder technical committees established pursuant to the ISO Participants Agreement.

Term. “Term” shall have the meaning ascribed thereto in Section 10.01(a)(i) of this Agreement.

Termination Date. “Termination Date” shall have the meaning ascribed thereto in Section 10.01(c) of this Agreement.

TOA. This Transmission Operating Agreement, as it may be amended from time to time.

Transmission Business. The business activities of each PTO related to the ownership, operation and maintenance of its Transmission Facilities.

Transmission Customer. Any entity taking Transmission Service under the ISO OATT.

Transmission Facilities. “Transmission Facilities” shall have the meaning ascribed thereto in Section 2.01 of this Agreement.

Transmission Owner. “Transmission Owner” shall have the meaning ascribed thereto in the ISO OATT.

Transmission Provider. The ISO, in its capacity as the provider of transmission services over the Transmission Facilities of the PTOs in accordance with FERC’s Order No. 2000 and FERC’s RTO regulations.

Transmission Service. The non-discriminatory, open access, wholesale transmission services provided to customers by the ISO in accordance with the ISO OATT.

Transmission Upgrade. Any upgrade to an existing Transmission Facility owned by any PTO that goes into commercial operation after the Operations Date

TRM. Transmission Reliability Margin.

TTC. Total Transfer Capability.

VAR. Volt-Amps Reactive.

Workers Compensation. Any financial award or settlement provided to employees or their dependents under state or federal law due to the occurrence of an employment-related accident, disease or injury.

Workers Compensation Insurance. The insurance, procured by the ISO in accordance with Section 9.05(a), covering losses that the ISO is subject to as an employer under state or federal worker's compensation laws.

Schedule 2.01(a)

Category A Facilities shall consist of all transmission lines listed as "Category A" in this Schedule and all transmission interties between Control Areas, all transformers that have listed Category A lines connected to the lower voltage side of the transformer; all transformers that require a listed line to be taken out of service when the transformer is taken out of service; and all breakers and disconnects connected to, and all shunts, relays, reclosing and associated equipment, dynamic reactive resources, FACTS controllers, special protection systems, PARS, and other equipment specifically installed to support the operation of such transmission lines, interties, and transformers.

The list of Category A Facilities can be found at:

<http://www.oatioasis.com/ISNE/index.html>

Schedule 2.01(b)

Category B Facilities shall consist of transmission lines listed as "Category B" in this schedule, all transformers that have any Category B Facilities and no Category A Facilities connected to the lower voltage side of the transformer except to the extent such transformers are designated as Category A Facilities in accordance with Section 2.01(e)(i); and all breakers and disconnects connected to, and all shunts, relays, reclosing and associated equipment, dynamic reactive resources, FACTS controllers, special protection systems, PARS, and other equipment specifically installed to support the operation of such Category B Facilities.

The list of Category B Facilities can be found at:

<http://www.oatioasis.com/ISNE/index.html>

Schedule 3.02(b)
NORTHEAST UTILITIES SERVICE COMPANY ON BEHALF OF ITS
OPERATING COMPANIES

List of Interconnection Agreements with neighboring Control Areas and
Tariff(s) Applicable to External Transactions

- Long Island Power Authority 10/31/67 Agreement between The Connecticut Light and Power Company and (formally Long Island Lighting Company) Long Island Lighting Company, as amended or superseded

Schedule 3.02(b)
VERMONT ELECTRIC POWER COMPANY
List of Interconnection Agreements with neighboring Control Areas and
Tariff(s) Applicable to External Transactions

- Interconnection Agreement of 2/23/87, between the Highgate Joint Owners and Hydro- Quebec

Schedule 3.02(d)

LIST OF EXISTING OPERATING PROCEDURES

1. ISO New England Manual No. 6 -- Financial Transmission Rights
2. ISO New England Manual 11 – Market Operations
3. ISO New England Manual 20 – Installed Capacity
4. ISO New England Manual 27 – Tariff Accounting
5. ISO New England Manual 28 – Market Rule 1 Accounting
6. ISO New England Manual 29 – Billing
7. ISO New England Manual 35 – Definitions and Abbreviations
8. ISO New England Manual 37- Forward Reserve
9. ISO New England Manual – ISO-NE Load Response Program
10. ISO New England Operating Procedure No. 1 “Central Dispatch Operating Responsibility and Authority of ISO New England, the Local Control Centers and Market Participants”
11. ISO New England Operating Procedure No. 2 “Maintenance Of Communications, Computers, Metering, and Computer Support Equipment”
12. ISO New England Operating Procedure No. 3 “Transmission Outage Scheduling”
13. ISO New England Operating Procedure No. 4 “Action During a Capacity Deficiency”
14. ISO New England Operating Procedure No. 5 “Generation Maintenance and Outage Scheduling”
15. ISO New England Operating Procedure No. 6 “System Restoration”
16. ISO New England Operating Procedure No. 7 “Action In An Emergency”
17. ISO New England Operating Procedure No. 8 “Operating Reserve and Regulation”
18. ISO New England Operating Procedure No. 9 “Scheduling and Dispatch of External Transactions”
19. ISO New England Operating Procedure No. 10 “Analysis and Reporting of Power System Emergencies”
20. ISO New England Operating Procedure No. 11 “Black Start Capability Testing Requirements”
21. ISO New England Operating Procedure No. 12 “Voltage and Reactive Control”
22. ISO New England Operating Procedure No. 13 “Standards For Voltage Reduction and Load Shedding Capability”
23. ISO-NE Operating Procedure No. 14 “Technical Requirements for Generation, Dispatchable and Interruptible Loads”
24. ISO New England Operating Procedure No. 16 “Transmission System Data”
25. ISO New England Operating Procedure No. 17 “Load Power Factor Correction”

26. **ISO New England Operating Procedure No. 18 “Metering and Telemetry Criteria”**
27. **ISO New England Operating Procedure No. 19 “Transmission Operations”**
28. **ISO New England Operating Procedure No. 20 “Cold Weather Event Operations”**
29. **ISO New England Compliance Procedure**
30. **ISO New England Compliance and Enforcement Process For Enhanced NPCC Reliability and NERC Standards**
31. **Master/Local Control Center Procedure #1 “Nuclear Plant Transmission Operations”**
32. **Master/Local Control Center Procedure #2 “Abnormal Conditions Alert”**
33. **Master/Local Control Center Procedure No. 3 “Test Procedure For Local Control Center Satellite Phone Communications”**
34. **Master/Local Control Center Procedure #4 “Rules for Generator Unit Control Modes, Limits and Dispatch Terminology”**
35. **Master/Local Control Center Procedure #5 “Procedure for Millstone Point Station Generation Reduction”**
36. **Master/Local Control Center Procedure #6 “Procedure for Evacuation of ISO New England Control Room”**
37. **Master/Local Control Center Procedure #7 “Processing Transmission Outage Applications”**
38. **Master/Local Control Center Procedure #8 “Coordination of Generation Voltage Regulator Outages”**
39. **Master/Local Control Center Procedure #9 “Operation of the Chester Static VAR Compensator (SVC)”**
40. **Master/Local Control Center Procedure #10 “Generator Governor Control and Operation”**
41. **Common Operating Instructions for Hydro-Québec TransÉnergie and the New England Asset Owners for the ± 450Kv DC Lines Radisson - Nicolet - Sandy Pond (Phase II) and ± 450Kv DC Lines Des Cantons - Monroe (Phase I)**
42. **Common System Dispatch Instructions for Hydro-Québec TransÉnergie and ISO New England Inc. for the ± 450Kv DC Lines Radisson - Nicolet - Sandy Pond (Phase II) and ± 450 kV DC Lines Des Cantons - Monroe (Phase I)**

Schedule 3.09(a)

Planning and Expansion – Participating Transmission Owner Rights and Obligations

1. PTOs’ Rights and Obligations to Build and Associated Conditions Including Cost Recovery:

1.1 The following provisions shall apply to any New Transmission Facility or Transmission Upgrade designated in the ISO System Plan other than a Merchant Transmission Facility except as provided in Section 1.3 of this Schedule:

(a) (i) Subject to the requirements of applicable law, government regulations and approvals, including requirements to obtain any necessary federal, state or local siting, construction and operating permits; the availability of required financing; the ability to acquire necessary rights-of-way; and satisfaction of the other conditions set forth in this Section 1.1, each PTO shall have the obligation to develop, own and construct (or cause to be constructed) any New Transmission Facility or Transmission Upgrade that is designated in the ISO System Plan as necessary and appropriate for system reliability or economic efficiency unless a Qualified Transmission Project Sponsor other than the applicable PTO has been designated by the ISO to construct a New Transmission Facility in accordance with Attachment K to the ISO OATT and consistent with this Schedule 3.09(a); provided that each PTO will retain an obligation to provide a Backstop Transmission Solution in the event that a Qualified Transmission Project Sponsor is unable to complete a system reliability or economic efficiency project on a timely basis.

(ii) If requested by NESCOE or by any State(s) that have expressed an interest in considering transmission options to address public policy requirements in accordance with Attachment K to the OATT, a PTO shall provide a written notice setting forth: (A) a proposed scope for developing a stage one proposal for a Public Policy Project; and (B) a good faith estimate of the costs of preparing such a stage one proposal. The PTO shall prepare such a stage one proposal if directed to proceed by NESCOE or the requesting State(s). The PTO shall also modify the scope for developing a stage one proposal for a Public Policy Project if requested by NESCOE or the requesting State(s). If a PTO is directed to prepare a stage one proposal in accordance with this Section 1.1(a)(ii), and the PTO determines that the costs for developing the requested proposal are reasonably likely to exceed the good faith cost estimate in the PTO’s scoping notice by more than 25 percent, the PTO shall provide NESCOE or the requesting State(s) with a revised good faith estimate of the costs of preparing such a proposal. PTOs that are requested by NESCOE or by the States to submit a stage one proposal shall be entitled to recover, pursuant to rates and appropriate financial arrangements set forth in the ISO OATT and this Agreement, their prudently incurred costs associated therewith. PTOs whose proposed Public Policy Projects advance to stage two in accordance with the ISO OATT shall be entitled to recover, pursuant to rates and appropriate financial arrangements set forth in the OATT and this Agreement all prudently incurred costs associated with developing a stage two solution.

(iii) The PTO may enter into appropriate contracts to fulfill any obligations associated with the ownership and construction of such New Transmission Facilities or Transmission Upgrades.

(b) Each PTO subject to the obligation to build New Transmission Facilities and Transmission Upgrades under Section 1.1(a), shall have the right to own and construct (or cause to be constructed) any New Transmission Facility or Transmission Upgrade located within or connected to its existing electric system that includes one or more of the following characteristics:

- (i) the costs of such New Transmission Facility or Transmission Upgrade will be allocated only to the local customers of the PTO;
- (ii) such New Transmission Facility or Transmission Upgrade involves upgrades to existing transmission or distribution facilities of a PTO. For purposes of this subpart (ii), an upgrade to an existing transmission or distribution facility of a PTO shall include any improvement to, addition to, or replacement of a part of, an existing transmission or distribution facility of a PTO; provided that a Qualified Transmission Project Sponsor may construct and own a New Transmission Facility or Transmission Upgrade where the only upgrades to existing transmission or distribution facilities of a PTO consist of required upgrades to existing substations of a PTO to which such Qualified Transmission Project Sponsor's proposed project will interconnect or other upgrades to a PTO's transmission or distribution facilities to address reliability impacts identified pursuant to the ISO Tariff; and provided further that any such upgrades to existing substations or facilities shall be constructed and owned by the PTO or PTOs that own the affected substation(s) or facilities;
- (iii) with respect to any New Transmission Facility or Transmission Upgrade that is to meet reliability requirements, the forecast date of need identified by ISO-NE in the needs assessment made under Attachment K to the ISO OATT is three years or less from the date that the ISO identifies such need in the needs assessment process, provided that ISO-NE: (A) has separately identified and posted on its website an explanation of the reliability criteria violations and system conditions that the region has a time-sensitive need to solve within three years of the completion of the relevant needs assessment; (B) has followed the process set forth in the ISO-NE OATT for assigning to a PTO responsibility for a project to meet a need within three years of the completion of the relevant needs assessment; (C) has posted on its website a full and supported written description explaining the decision to designate a PTO as the entity responsible for construction and ownership of the reliability project, including an explanation of other transmission or non-transmission options

that the region considered but concluded would not sufficiently address the immediate reliability need, and the circumstances that generated the reliability need and an explanation of why that reliability need was not identified earlier; (D) has provided stakeholders with the opportunity to provide comments on the posted description; and (E) maintains and posts on its website a list of prior year designations of all projects in the limited category of transmission projects for which the PTO(s) was designated as the entity responsible for construction and ownership of the project in accordance with this Section 1.1(b)(iii).

This right shall not affect any rights that an entity may have to construct a Merchant Transmission Facility in response to a need identified by the ISO in the ISO Planning Process

(c) (i) Each PTO's assumption of an obligation to develop proposals for New Transmission Facilities or Transmission Upgrades or to build New Transmission Facilities and Transmission Upgrades under Section 1.1(a) shall be subject to the right of such PTO to recover, pursuant to appropriate financial arrangements and tariffs or contracts, all prudently incurred costs associated with the development of such proposals or the construction and ownership of a New Transmission Facility or Transmission Upgrade that has been included in the ISO System Plan, plus a return on invested equity and other capital.

(ii) If a PTO incurs costs associated with a New Transmission Facility or Transmission Upgrade that has been included in the ISO System Plan, such PTO shall have the right, by filing in accordance with Section 3.04 of this Agreement, to recover all of its costs associated with such New Transmission Facility or Transmission Upgrade that are prudently incurred or prudently committed to be incurred, including costs prudently incurred or prudently committed to be incurred by such PTO in connection with the planning, design, engineering, permitting, procuring and other preparation for construction, and/or construction of the New Transmission Facility or Transmission Upgrade, plus a return on invested equity and other capital.

(d) If a New Transmission Facility or Transmission Upgrade is included in an approved ISO System Plan and the ISO has indicated that the PTO is to commence planning, designing or constructing such New Transmission Facility or Transmission Upgrade, then a PTO that incurs costs in order to implement the ISO System Plan (and satisfy its obligation to build hereunder) by commencing to plan, design or construct such New Transmission Facility or Transmission Upgrade shall be permitted to recover all of its prudently incurred costs as set forth in Section 1.1(c) even if the ISO subsequently determines that the New Transmission Facility or Transmission Upgrade is no longer required and removes it from the ISO System Plan, notwithstanding any contrary FERC policy or rule relating generally to the recovery of the costs of abandoned plant.

(e) If a New Transmission Facility or Transmission Upgrade included in an approved ISO System Plan is not constructed because any of the conditions set forth in this Section 1.1 have not been satisfied or for any other reason, the ISO shall submit a report to the FERC addressing such non-construction, which report shall include a report from the PTO responsible for the planning, design or construction of such New Transmission Facility or Transmission Upgrade.

(f) The regional system planning provisions of the ISO OATT shall include statements that: (i) the submission of a project by a Qualified Transmission Project Sponsor or selection of projects for inclusion in the RSP Project List shall not alter a PTO's use and control of an existing right of way, the retention, modification, or transfer of which remain subject to the relevant state or federal law or regulation, including property or contractual rights, that granted the right-of-way; and (ii) no PTO shall be required pursuant to this Agreement or the ISO OATT to relinquish any of its rights-of-way in order to permit a Qualified Transmission Project Sponsor to develop, construct or own a project.

(g) The PTO(s) shall not have an obligation to construct any specific project proposed by a Qualified Transmission Project Sponsor and selected in the ISO System Plan if that Qualified Transmission Project Sponsor abandons the proposed project. To the extent a Qualified Transmission Project Sponsor abandons a proposed project selected in the ISO System Plan to address current or projected reliability needs on the existing electric system of one of more PTO(s), the affected PTOs shall work with the ISO in accordance with the terms of this Agreement, to develop a Backstop Transmission Solution to the current or projected reliability needs and, to the extent required by Applicable Law, shall submit a mitigation plan to NERC. The pro forma Non-Incumbent Transmission Developer Operating Agreement in the ISO OATT shall include a provision indemnifying the holding all affected PTOs harmless from any and all liability (except for that stemming from an affected PTO's negligence, gross negligence or willful misconduct) resulting from a Qualified Transmission Project Sponsor's failure to timely complete (based on the milestone provisions contained in the ISO OATT) a Reliability Transmission Upgrade (as defined in the ISO OATT) in response to a reliability need identified in the Regional System Plan that the Qualified Transmission Project Sponsor was chosen in the Regional System Plan to construct. As used herein, an "affected PTO" is one that would be subject to penalties assessed by NERC or FERC or adverse regulatory orders or monetary claims or damages due to the Qualified Transmission Project Sponsor's failure to timely complete the Reliability Transmission Upgrade.

(h) A PTO that is proposing to develop a New Transmission Facility that is not located within or connected to the PTO's existing facilities (a "PTO Non-transmission Developer" or "PTO NTD") will indemnify and hold harmless all affected PTOs from any and all liability (except for that stemming from an affected PTO's negligence, gross negligence or willful misconduct) resulting from the PTO NTD's failure to timely complete (based on the milestone provisions contained in the ISO OATT) a Reliability Transmission Upgrade (as defined in the ISO OATT) that the PTO NTD was chosen in the ISO System Plan to construct. As used herein, an "affected PTO" is one that would be subject to penalties assessed by NERC or

FERC or adverse regulatory orders or monetary claims or damages due to the PTO NTD's failure to timely complete the Reliability Transmission Upgrade.

1.2 The PTO shall promptly seek siting and any other required regulatory approvals for which such PTO is designated as the appropriate entity to construct and own or finance facilities included in the ISO System Plan. If requested by the PTO, the ISO shall undertake reasonable efforts (consistent with its technical judgment) to assist the PTO in obtaining required regulatory approvals for New Transmission Facilities or Transmission Upgrades included in the ISO System Plan and approved by the ISO. The assistance may include the provision of testimony, witnesses, and similar assistance. The ISO shall not, in any manner, be precluded from similarly assisting, at its discretion, other projects that address a need identified by the ISO in the ISO System Plan.

1.3 The ISO shall ensure that the ISO Planning Process includes opportunities for state regulatory authorities, including the agency with authority over the retail electricity rates of a PTO with the obligation under Section 1.1(a) to build a New Transmission Facility or Transmission Upgrade, to provide their views to the ISO with respect to need for the New Transmission Facility or Transmission Upgrade.

2. PTO Obligations:

2.1 Each PTO shall support the planning process as described in the ISO OATT and any interregional planning coordination. As requested by the ISO, such support may include conducting any necessary studies, including system impact studies and facilities studies for the PTO's Transmission Facilities, assisting in the performance of such studies or any additional studies, and supplying any information and data reasonably required to prepare an ISO System Plan or to perform transmission enhancement and expansion studies. Notwithstanding the above, the PTOs shall have no obligation to provide support to any Qualified Transmission Project sponsor to facilitate the development of any transmission project proposal of such Qualified Transmission Project Sponsor, provided that this Section 2.1 shall not excuse the PTOs from complying with any other applicable provision of the ISO OATT or this Agreement, including any requirement to provide planning support to the ISO (which support shall include providing to the ISO information necessary to perform system impact studies and feasibility studies for projects of Qualified Transmission Project Sponsors that may be proposed to interconnect with the PTO's facilities), NESCOE, or any state.

2.2 Each PTO shall make reasonable efforts to provide information and support in response to the ISO's requests within the ISO's requested time frames and shall comply with all deadlines set forth in the ISO Planning Process, as specified in the ISO OATT.

2.3 Each PTO shall comply with the ISO's Planning Procedures (which are supplemental to the ISO Planning Process, as specified in the ISO OATT), provided that any modifications to existing Planning Procedures and any new Planning Procedures shall be developed in accordance

with the process set forth for the development of new or modified Planning Procedures in Section 3.09(b) to the TOA.

Schedule 3.09(b)
LIST OF EXISTING PLANNING PROCEDURES

ISO New England Planning Procedure No. 3

Reliability Standards for the New England Area Bulk Power Supply System

ISO New England Planning Procedure No. 4

Procedure for Pool-Supported PTF Cost Review

ISO New England Planning Procedure No. 4-1

Cost Responsibility For Transmission Upgrades With Multiple Needs

ISO New England Planning Procedure No. 5

Procedure for Reporting Notice of Intent to Construct, Retire or Change Facilities in Accordance with Section I.3.9 of the ISO New England Tariff (Proposed Plan Application Procedure)

ISO New England Planning Procedure No. 5-1

Procedure For Review Of Governance Participant's Proposed Plans
(Section I.3.9 Applications: Requirements, Procedures And Forms)

ISO New England Planning Procedure No. 5-3

Guidelines for Conducting and Evaluating Proposed Plan Application Analyses

ISO New England Planning Procedure No. 5-4

Subordinate Proposed Plan Application Policy

ISO New England Planning Procedure No. 5-5

Special Protection Systems Application Guidelines

ISO New England Planning Procedure No. 5-6

Scope Of Study For System Impact Studies Under The Minimum Interconnection Standard

ISO New England Planning Procedure No. 6

Procedures for the Establishment and Study of New England Interconnection

ISO New England Planning Procedure No. 8

Construction Sequencing

Schedule 3.11(b)
NORTHEAST UTILITIES SERVICE COMPANY ON BEHALF OF ITS
OPERATING COMPANIES
List of Grandfathered Intertie Agreements

- Long Island Power Authority 10/31/67 Agreement between The Connecticut Light and Power Company and (formally Long Island Lighting Company) Long Island Lighting Company, as amended or superseded

Schedule 3.11(b)
VERMONT ELECTRIC POWER COMPANY
List of Grandfathered Intertie Agreements

- Interconnection Agreement of 2/23/87, between the Highgate Joint Owners and Hydro-Quebec

Schedule 3.11(b)
VERMONT PUBLIC POWER SUPPLY AUTHORITY
List of Grandfathered Intertie Agreements

- Trans Energie/VPPSA OATT Service Agreement dated 18 August 1997
- Master Agreement between HQ Energy Services and Vermont Public Power Supply Authority dated February 29, 2000

Schedule 3.11(c)
BANGOR HYDRO-ELECTRIC COMPANY
List of Grandfathered Interconnection Agreements

- I/A between Great Northern Paper/Great Lakes Hydro America and BHE (dated 5/23/03)
- I/A between Penobscot Hydro, LLC (PPL) and BHE (dated 5/27/99)
- Special Facilities Agreement between Babcock-Ultrapower West Enfield (BUWE) and BHE (dated 6/30/95)
- Construction and Procurement Agreement between BHE and CASCO Bay Energy Co, LLC dated 11/5/99
- I/C Agreement between BHE and CASCO Bay Energy Co, LLC dated 9/4/98 (revised I/C agreement filed with Commission on 1/22/99)
- Construction Agreement between Brascan Energy Marketing Inc. and BHE (dated 5/23/03)
- I/C Agreement between Katahdin Paper Co, LLC and BHE dated 5/16/03
- West Enfield Purchased Power Agreement, June 9, 1986
- Hydro Associates Penobscot Energy Purchased Power Agreement, as amended through June 26, 1998
- Recovery Company Pumpkin Hill Power – Purchased Power Agreement, as amended through December 4, 1984
- Green Lake Hydro Purchased Power Agreement, as amended through April 18, 2000
- Sebec Hydro Purchased Power Agreement, as amended through March 19, 1984
- Milo Hydro Purchased Power Agreement, as amended through June 1, 1985

Schedule 3.11(c)
BRAINTREE ELECTRIC LIGHT DEPARTMENT
Grandfathered Interconnection Agreements

- Interconnection Agreement between Town of Braintree and Boston Edison Company, dated March 25, 1969
- Interconnection Agreement between Town of Braintree and Boston Edison Company, dated January 25, 1974
- Amendment No. 1 to the January 25, 1974 Interconnection Agreement between Town of Braintree and Boston Edison Company, 1994
Interconnection Agreement between Town of Braintree and Boston Edison Company dated January 25, 1974. Interconnection Agreement between Town of Braintree and Boston Edison Company dated January 25, 1974. Interconnection Agreement between Town of Braintree and Boston Edison Company dated January 25, 1974.

Schedule 3.11(c)
CENTRAL MAINE POWER COMPANY
List of Grandfathered Interconnection Agreements

- I/C Agreement between Abbotts Mill Hydro and CMP (5/22/02)
- I/C Agreement between Androscoggin Energy, LLC (AELLC) and CMP (10/21/98)
- I/C Agreement between Androscoggin Reservoir Company (ARCO) and CMP
- I/C between Boralex Livermore Falls and CMP (4/1/01)
- I/C Agreement between Boralex Stratton Associates and CMP (4/1/98)
- I/C Agreement between Bucksport Energy LLC and CMP (6/13/00)
- I/C Agreement between Calpine Construction Finance Company, LP and CMP (dated 4/12/01-amended 12/12/01)
- I/C Agreement between Casco Bay Energy Company LLC and CMP (construction, procurement and continuing obligations agreement 5/1/00)
- I/C Agreement between city of Lewiston and CMP (3/1/00)

- Continuing Site/Interconnection Agreement between FPL Energy Maine, Inc. and CMP (dated 1/6/98-amended 6/16/98 and 7/24/02)
- I/C Agreement between Gardner Brook Hydro and CMP (2/1/02)
- I/C Agreement Amendment to Gardner Brook Hydro (3/20/02)
- I/C Agreement between Greenville Steam Company and CMP (1/1/01)
- I/C Agreement between International Paper Company and CMP (3/1/00)
- I/C Agreement between J & L Electric and CMP (6/23/03)
- I/C Agreement between Ledgemere Hydro LLC and CMP (12/23/03)
- I/C Agreement between Moosehead Energy, Inc. and CMP (3/1/00)
- I/C Agreement between Kennebec Water District and CMP (3/1/00)
- I/C Agreement between Kezar Falls Hydro and CMP (12/23/03)
- I/C Agreement between Marsh Power L.P. and CMP (3/1/00)
- I/C Agreement between Messalonskee Stream Hydro and CMP (12/23/00)
- I/C Agreement between Regional Waste System Inc. and CMP (1/1/01)
- I/C Agreement between Robbins Lumber, Inc. and CMP (2/15/01)
- I/C Agreement between Rocky Gorge Corporation and CMP (1/1/01)
- I/C Agreement between Rumford Power Associates L.P. and CMP (10/21/98)
- I/C Agreement between S. D. Warren Company and CMP (3/1/00)
- I/C Agreement between Sparhawk Mill Company and CMP (3/1/00)
- I/C Agreement between Stony Brook Hydro and CMP (2/1/02)
- I/C Agreement between Wight Brook Hydro and CMP (2/1/02)

Schedule 3.11(c)
FLORIDA POWER & LIGHT COMPANY-NEW ENGLAND DIVISION
List of Grandfathered Interconnection Agreements

- Interconnection and Operating Agreement by and between Florida Power & Light Company and FPL Energy Seabrook, LLC (6/25/03)

Schedule 3.11(c)
THE CITY OF HOLYOKE GAS AND ELECTRIC DEPARTMENT
Grandfathered Interconnection Agreements

- Fairmont-Holyoke 115 kV Interconnection Agreement between Western Massachusetts Electric Company, Holyoke Water Power Company, and City of Holyoke Gas & Electric Department (dated May 15, 1980) as amended by Schedule 5.3.10 WMECO Matters from Settlement Agreement between Holyoke Water Power Company, Holyoke Power and Electric Company and City of Holyoke Gas & Electric Department (dated June 7, 2001)

- Southhampton-Holyoke 115 kV Interconnection Agreement between Western Massachusetts Electric Company and City of Holyoke Gas & Electric Department (dated May 15, 1980)

Schedule 3.11(c)
NEW ENGLAND POWER COMPANY
Grandfathered Interconnection Agreements

- Direct Assignment Facilities Charge/MAHY and Multiple (dated 6/1/85)
- Direct Assignment Facilities Charge/NECO and ANP Blackstone Energy Company, LLC (dated 5/5/99)
- Direct Assignment Facilities Charge/NECO and Pawtucket Power Associates (dated 12/15/01)
- Direct Assignment Facilities Charge/NEET and Multiple (dated 10/1/86)
- Direct Assignment Facilities Charge/NEP and AES Londonderry, LLC (dated 6/22/01)
- Direct Assignment Facilities Charge/NEP and ANP Bellingham Energy Company, LLC (dated 2/23/99)
- Direct Assignment Facilities Charge/NEP and ANP Blackstone Energy Company, LLC (dated 4/30/99)
- Direct Assignment Facilities Charge/NEP and Ashburnham Municipal Light Plant (dated 12/18/96)
- Direct Assignment Facilities Charge/NEP and Boott Mills Hydropower (dated 6/22/86)
- Direct Assignment Facilities Charge/NEP and Boston Edison Company (dated 12/15/85)
- Direct Assignment Facilities Charge/NEP and Boston Edison Company (dated 6/1/76)
- Direct Assignment Facilities Charge/NEP and Boston Edison Company (dated 1/18/73)
- Direct Assignment Facilities Charge/NEP and Boston Edison Company (dated 5/25/88)
- Direct Assignment Facilities Charge/NEP and Boston Edison Company (dated

10/1/086)

- Direct Assignment Facilities Charge/NEP and Centennial Island Hydroelectric Company (12/29/89)
- Direct Assignment Facilities Charge/NEP and Central Vermont Public Service (dated 9/7/66)
- I/A between NEP/Montaup & Dighton Power Associates, LP (dated 4/10/97)
- Direct Assignment Facilities Charge/NEP and Fitchburg (dated 3/1/02)
- Direct Assignment Facilities Charge/NEP and FPLE Rhode Island State Energy Partners (dated 12/22/00)
- Direct Assignment Facilities Charge/NEP and Gas Recovery Systems (BFI) Randolph (dated 11/23/98)
- Direct Assignment Facilities Charge/NEP and Georgetown Municipal Electric Department (dated 12/6/90)
- Direct Assignment Facilities Charge/NEP and Hingham Municipal Light Plant (dated 7/1/96)
- Direct Assignment Facilities Charge/NEP and HQ AC-Multiple (dated 6/16/87)
- I/A between NEP and Hudson Tap Transmission (dated 6/22/86)
- Direct Assignment Facilities Charge/NEP and Hull Municipal Lighting Plant (dated 7/9/96)
- Direct Assignment Facilities Charge/NEP and Indeck Energy Services of Turner Falls, Inc. (dated 7/7/88)
- Related Facilities Agreement between NEP/Blackstone Valley Electric Company and Lake Road Generating, LLP (dated 8/31/90)
- Direct Assignment Facilities Charge/NEP and Littleton Electric Light Department (MA) (dated 10/31/92)
- Direct Assignment Facilities Charge/NEP and Littleville Power Company (dated 9/27/95)

- Direct Assignment Facilities Charge/NEP and Marblehead Municipal Light Department (dated 12/7/94)
- Direct Assignment Facilities Charge/NEP and Massachusetts Water Resource Authority (dated 9/21/95)
- Direct Assignment Facilities Charge/NEP and MBTA (dated 11/1/96)
- Direct Assignment Facilities Charge/NEP and MBTA (dated 10/1/97)
- Direct Assignment Facilities Charge/NEP and Middleton Municipal Electric Department (dated 12/1/92)
- Direct Assignment Facilities Charge/NEP and Milford Power (dated 3/20/92)
- Direct Assignment Facilities Charge/NEP and Millennium Power Partners (dated 12/29/97)
- Direct Assignment Facilities Charge/NEP and Nantucket (dated 5/5/03)
- Direct Assignment Facilities Charge/NEP and Narragansett Electric Company (dated 4/6/72)
- Direct Assignment Facilities Charge/NECO Boston Edison and New Bedford Gas Edison Light Company (dated 8/31/71)
- Network Integrated Transmission Service between NEP and North Attleborough Electric (dated 7/9/96)
- Direct Assignment Facilities Charge/NEP and NRG Energy, Inc. (Somerset Power, LLC) (First Amendment of I/C Agreement dated 10/13/98) dated 4/26/99
- Direct Assignment Facilities Charge/NEP and Paxton Municipal Light Department (dated 2/27/02)
- Direct Assignment Facilities Charge/NEP and Peabody Municipal Light Department (dated 11/16/90)
- Direct Assignment Facilities Charge/NEP and Pioneer Hydro Inc. (dated 10/18/83)
- Direct Assignment Facilities Charge/NEP and Public Service Company of New Hampshire (dated 2/16/37)

- Direct Assignment Facilities Charge/NEP and Refuse Energy System's Company (dated 6/12/80)
- Direct Assignment Facilities Charge/NEP and River Mill Hydro (10/12/89)
- Direct Assignment Facilities Charge/NEP and Rowley Municipal Lighting Plant (dated 4/10/90)
- Support Agreement /NEP and Seabrook Transmission-Multiple (dated 12/15/87)
- Direct Assignment Facilities Charge/NEP and Sithe Fore River Development (dated 5/25/01)
- Direct Assignment Facilities Charge/NEP and Sterling Municipal Light Department (dated 1/11/86)
- Direct Assignment Facilities Charge/NEP and Taunton Municipal Lighting Plant (dated 9/1/95)
- Direct Assignment Facilities Charge/NEP and Templeton Municipal Light Plant (dated 10/30/81)
- Interconnection Related Facilities Agreement /NEP and Tiverton Power Associates (dated 8/19/98)
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- I/A between NEP and Tiverton Power Associates (dated 6/1/92)
- Direct Assignment Facilities Charge/NEP and UAE Lowell Cogen (dated 5/25/88)
- Direct Assignment Facilities Charge/NEP and UAE Lowell Power (dated 5/9/90)
- Direct Assignment Facilities Charge/NEP and US Gen New England Inc. (PG&E National Energy Group) (dated 9/1/98)
- Support Agreement /NEP and Vermont Electric Power Company, Inc. Bellows Falls (dated 8/1/98)
- Support Agreement/NEP and Vermont Electric Power Company, Inc. W-149 Reconductoring (dated 3/1/95)
- Support Agreement/NEP and Vermont Electric Power Company, Inc. (dated 4/5/74)

- Direct Assignment Facilities Charge/NEP and Wakefield Municipal Light Department (dated 6/16/87)
- Direct Assignment Facilities Charge/NEP and Wheelabrator North Andover, Inc. (dated 1/1/02)
- Direct Assignment Facilities Charge/NHHY and Multiple (dated 6/16/87)
- I/A between MECO and Gas Recovery Systems (BFI) East Bridgewater (dated 5/31/95)
- I/A between MECO and Gas Recovery Systems (BFI) Fall River (dated 5/5/99)
- I/A between MECO and Gas Recovery Systems (BFI) Halifax (dated 5/31/95)
- I/A between MECO and Littleville Power (dated 7/24/79)
- I/A between MECO and Methuen Hydro (dated 12/1/87)
- I/A between MECO and Mini Watt Electric Company (O'Connell Energy) (dated 3/24/82)
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- I/A between MECO and Mini Watt Electric Company (O'Connell Energy) (dated 10/9/91)
- I/A between MECO and Rowley Municipal Lighting Plant (dated 4/10/90)
- I/A between MECO and South Barre Hydroelectric Company (dated 11/13/89)
- I/A between MECO and South Barre Hydroelectric Company (dated 6/1/92)
- I/A between MECO and South Barre Landfill (Zapco) (dated 2/10/87)
- I/A between MECO and Swift River Company (Collins Dam) (dated 8/30/84)
- I/A between MECO and Webster Hydro (dated 7/22/81)
- I/A between MECO and West Dudley Hydroelectric Company (dated 8/1/83)
- I/A between MECO and Northeast Energy Associates (dated 6/20/92)
- I/A between MECO and Ocean State Power (dated 8/16/89)

- I/A between NECO and ANP Milford Power (dated 1/1/02)
- I/A between NEP and Black Hills Energy Capital (dated 1/1/02)
- I/A between NEP and Danvers Electric Department (dated 12/29/92)
- I/A between NEP and Green Mountain Power (dated 8/16/96)
- I/A between NEP and Hingham Municipal Light Plant (dated 10/7/87)
- I/A between NEP and Indeck Pepperell Power Associates, Inc. (dated 1/31/89)
- I/A between NEP and Indeck Pepperell Power Associates, Inc. (dated 5/24/89)
- I/A between NEP and Indeck Pepperell Power Associates, Inc. (dated 10/20/95)
- I/A between NEP and Lowell Cogen (dated 1/1/02)
- Integrated Facilities Agreements/NEP and Massachusetts Electric Company, Granite State Electric, Narragansett Electric Company (dated 1967)
- Network/NECO and Pascoag Utility District (dated 10/24/97)
- Network/NEP and ANP Bellingham Energy Company, LLC (dated 5/30/01)
- Network/NEP and Ashburnham Municipal Light Plant (dated 7/9/96)
- Network/NEP and Boston Edison Company (dated 7/24/98)
- Network/NEP and Boylston Municipal Light (dated 7/9/96)
- Network/NEP and Central Vermont Public Service (dated 10/30/96)
- Network/NEP and Danvers Electric Department (dated 5/31/01)
- Network/NEP and Fitchburg Gas & Electric (dated 3/1/02)
- Network/NEP and Georgetown Municipal Light Department (dated 7/9/96)
- Network/NEP and Granite State Electric Company (dated 10/3/01)
- Network/NEP and Groton Electric Light Department (dated 7/9/96)

- Network/NEP and Groveland Electric Department (dated 6/29/98)
- Network/NEP and Holden Municipal Light Department (dated 7/9/96)
- Network/NEP and Hudson Light & Power Department (dated 7/9/96)
- Network/NEP and Ipswich Utilities Department (dated 7/9/96)
- Network/NEP and Littleton Electric Department (dated 7/9/96)
- Network/NEP and Littleton, NH Water and Light Department (dated 1/1/98)
- Network/NEP and MA Development Devens (dated 11/1/96)
- Network/NEP and Mansfield Municipal Lighting Plant (dated 7/9/96)
- Network/NEP and Marblehead Municipal Light Department (dated 7/9/96)
- Network/NEP and Massachusetts Electric Company (dated 5/27/97)
- Network/NEP and MBTA (dated 8/13/98)
- Network/NEP and Merrimac Municipal Light Department (dated 7/1/98)
- Network/NEP and Middleborough Gas and Electric (dated 3/1/02)
- Network/NEP and Middleton Municipal Electric Department (dated 7/9/96)
- Network/NEP and Millennium Power Partners (dated 2/1/02)
- Network/NEP and New Hampshire Electric Co-Op (dated 10/23/01)
- Network/NEP and Pascoag Utility District (dated 1/1/98)
- Network/NEP and Paxton Municipal Light Department (dated 7/9/96)
- Network/NEP and Peabody Municipal Light Department (dated 7/9/01)
- Network/NEP and PG&E National Energy Group (US GEN) (dated 9/1/98)
- Network/NEP and Princeton Municipal Light Department (dated 7/9/96)

- Network/NEP and Public Service Company of New Hampshire (dated 11/1/01)
- Network/NEP and Reading Municipal Light Department (dated 12/1/99)
- Network/NEP and Rowley Municipal Lighting Plant (dated 7/9/96)
- Network/NEP and Shrewsbury Electric Light Department (dated 7/9/96)
- Network/NEP and Sterling Municipal Light Department (dated 7/9/96)
- Network/NEP and Taunton Municipal Lighting Plant (dated 4/25/03)
- Network/NEP and The Narragansett Electric Company (dated 2/1/02)
- Network/NEP and West Boylston Municipal Lighting Department (dated 7/9/96)
- Network/NEP and Western Mass. Electric Company (dated 4/1/99)
- Other/MECO and MBTA (dated 8/18/97)
- Other/MECO and Milford Power (dated 6/6/91)
- Other/NECO and Blackstone Valley Electric Company/Montaup Electric Company (dated 5/1/00)
- Other/NECO and Boston Edison Company Commonwealth Electric Company (dated 8/31/71)
- Other/NECO and Montaup Electric Company (dated 5/1/00)
- Other/NECO and Montaup Electric Company (dated 5/1/00)
- Other/NECO and The Narragansett Electric Company (dated 12/1/01)
- Other/NECO and The Narragansett Electric Company (dated 5/1/00)
- Other/NEP and Boston Edison Company/Middleborough Gas & Electric Department (dated 1/1/02)
- Other/NEP and MBTA (dated 3/20/98)
- Other/NEP and REMVEC-Multiple (dated 7/1/94)

- Transmission Owners Agreement/MECO and Ashburnham Municipal Light Plant (dated 12/18/96)
- Transmission Owners Agreement/MECO and MBTA (dated 4/18/94)
- I/A between NEP and American Paper Mills of Vermont, Inc. (dated 11/30/00)
- Transmission Owners Agreement/NEP and Gas Recovery Services (formerly Browning Ferris Gas Services-East Bridgewater & Halifax) (dated 5/1/97)
- Transmission Owners Agreement/NEP and Indeck Pepperell Power Associates, Inc. (dated 10/20/95)
- Transmission Owners Agreement/NEP and Pawtucket Power Associates, LP (dated 11/2/01)
- Transmission Owners Agreement/NEP and Templeton Municipal Light Plant (dated 8/4/87)
- Network/NEP and Wakefield Municipal Light Department (dated 7/9/01)
- Agreement for Reinforcement and Improvements of NEP's Transmission System (dated 4/1/83)
- Upper Development-Lower Development Transmission Line Support Agreement: NEET and NEPCo. (dated 1982)
- Service Agreement for Firm Local Generation Delivery Service under NEP's Open Access Transmission Tarriff (dated 9/21/01)
- Network Integration Transmission Service NEP/ Hull Municipal Lighting Plant (dated 7/9/96)
- Network Integration Transmission Service NEP/Templeton Municipal Lighting Plant (dated 7/9/96)
- Network Integration Transmission Service NEP/North Attleborough Templeton & Wakefield (dated 7/9/96)
- Amendment No. 1 Support Improvement Agreement NEP/Boston Edison
- I/A between Eastern Edison/MBTA

- I/A between NEP/MECO Shrewsbury St. (dated 10/23/96)
- Transmission Facilities Support Agreement/NEP /Boston Edison/Mystic Golden Hills (5/25/88)
- Transmission Support Agreement/Boston Edison/Woburn Sandy Pond Tewksbury (dated 7/18/73)
- Support Agreement NEP Seabrook/Tewksbury (12/15/87)
- Support Agreement NEP Seabrook/Tewksbury/Woburn M-139 Line (dated 11/12/85)
- Support Agreement NEP Seabrook/Tewksbury/Woburn M-140 Line (dated 11/12/85)
- I/A Montaup Electric/Somerset Power dated 10/13/98
- Service Agreement NEP/Granite State (dated 10/3/01)
- Ispwich Network Operating Agreement (dated 7/7/97)
- Restated Distribution Agreement MECO/MBTA-Amtrak 2nd Amendment (4/18/94)
- Service Agreement Boston Edison/NEP/Blackstone Valley Electric
- VELCO Letter Agreement/Support reconductoring of W-149 Line (dated 3/11/85)
- Support Agreement Public Service Co. of New Hampshire and Seabrook (dated 5/1/73)
- Support Agreement Public Service Co. of NH and NEP/Seabrook/Tewksbury (dated 12/15/87)
- Facilities Support Agreement NEP and VELCO (dated 4/5/74)
- Amendment to Service Agreement for Firm Local Generation Delivery Service/ANP Bellingham (dated 11/6/00)

- I/A between Eastern Edison Company/Browning Ferris Gas Services, Inc./Bridgewater (dated 4/30/99)
- I/A between MECO/NEP/Granite State/Narragansett-Boott Mills Hydro (dated 12/3/92)
- Agreement for Installation of Surge Arrestors between NEP and ANP Blackstone Energy Company (dated 3/30/00)
- First Amendment to the I/A between NEP/Pepperell Power Associates (dated 5/24/89)
- Service Agreement for Firm Local Generation Delivery Service NEP/ANP Bellingham Energy Company (dated 6/1/01)
- SES Millbury Inc. 12/17/85 Purchase Agreement by and between SES Millbury Company L.P. ("Seller") and New England Power Company ("NEP"), a Massachusetts Corporation
- Undated Amendment to Brayton Point 12/1/04 Large Generator Interconnection Agreement Units 1, 2, 3, & 4 Interconnection Facilities and Associated Equipment Description
- Brayton Point 12/1/04 Large Generator Interconnection Agreement by and between New England Power Company ("Interconnecting Transmission Owner"), ISO New England Inc., and Dominion Energy Brayton Point, LLC, ("Interconnection Customer" with a Large Generating Facility)
- Manchester Street 12/1/04 Standard Large Generator Interconnection Agreement by and between New England Power Company ("NEP"), ISO New England, Inc., and Dominion Energy Manchester Street, Inc., (Interconnection Customer" with a Large Generating Facility)
- Undated Amendment to Manchester Street 12/1/04 Standard Large Generator Interconnection Agreement Units 9, 10, & 11 Interconnection Facilities and Associated Equipment Description
- Undated Amendment to Salem Harbor 12/1/04 Large Generator Interconnection Agreement Units 1, 2, 3, & 4 Interconnection Facilities and Associated Equipment Description
- Salem Harbor 12/1/04 Large Generator Interconnection Agreement by and

between New England Power Company ("NEP"), ISO New England Inc., and Dominion Energy Salem Harbor, LLC, ("Interconnection Customer" with a Large Generating Facility)

- Interconnection Agreement between Blackstone Valley Electric Co. and Pawtucket Generating Co., L.L.C. (11/1/98)
- Agreement between NEP and General Electric Co. (Lynn Plant) (dated as of 7/27/84 and First Amendment thereto (dated as of 7/1/87)

Schedule 3.11(c)
NEW HAMPSHIRE ELECTRIC COOPERATIVE, INC.
Grandfathered Interconnection Agreements

- Agreement Between Public Service of New Hampshire and the New Hampshire Electric Cooperative, Inc. for Interconnection and Delivery Services, dated September 30, 1999
- Letter Amendment to Agreement Between Public Service of New Hampshire and the New Hampshire Electric Cooperative, Inc. for Interconnection and Delivery Services, dated October 30, 2002
- Agreement Between Public Service of New Hampshire and the New Hampshire Electric Cooperative, Inc. for Delivery Services and Interconnection with Vermont, dated November 10, 2003

Schedule 3.11(c)
NORTHEAST UTILITIES ON BEHALF OF ITS OPERATING COMPANIES
List of Grandfathered Interconnection Agreements

- Interconnection and Operations Agreement between Public Service of New Hampshire and AES Londonderry, LLC (dated 2/26/03)
- I/A between The Connecticut Light and Power Company and AES Thames (dated 7/19/99)
- Interconnection, Operations and Maintenance Agreement between Western Massachusetts Electric Company and Altresco Pittsfield, L.P. (dated 7/19/90)
- I/A between The Connecticut Light and Power Company and Capitol District Energy Center Cogeneration Associates (dated 9/15/01)
- Interconnection and Operations Agreement between Western Massachusetts Electric Company and Berkshire Power Company, LLC (dated 12/03)
- Millstone Transmission Support Agreement between The Connecticut Light and Power Company and Central Vermont Public Service Corp. (8/9/74)
- I/A between The Connecticut Light and Power Company and CRRA (12/20/00)
- Interconnection and Operations Agreement between Western Massachusetts Electric Company and Consolidated Edison Energy Massachusetts, Inc. (dated 12/10/01)
- I/A between The Connecticut Light and Power Company and Dominion Nuclear Connecticut, Inc. (dated 3/31/01)
- I/A between Errol Hydroelectric Limited Partnership and Public Service of New Hampshire (dated 4/7/86)
- I/A between The Connecticut and Power Company and Exeter Energy, LP (dated 3/24/03)
- I/A between Public Service of New Hampshire and FPL Energy Seabrook, LLP (dated 11/1/02)
- Seabrook Transmission Support Agreement between PSNH, New England Power Company and FPL Energy Seabrook (dated 6/1/88)
- I/A between The Connecticut Light and Power Company and Hartford Steam Company (dated 8/29/03)
- I/A between Public Service of New Hampshire and Hawkeye Funding, L.P. (Newington Energy) (dated 9/30/02)
- Seabrook Transmission Support Agreement between Public Service of New Hampshire, New England Power Company and Hudson Light & Power (dated 6/1/88)
- I/A between The Connecticut Light and Power Company and Lake Road Trust (dated 12/31/03)
- Interconnection, Operation and Maintenance Agreement between The Western Massachusetts Electric Company and Littleville Power Company, Inc. (dated 12/31/92)
- Millstone 3 Transmission Support Agreement between The Connecticut Light and Power Company and Mass. Municipal Wholesale Electric Company (dated 1/17/74)

- Seabrook Transmission Agreement between The Public Service Company of New Hampshire, New England Power Company and Mass. Municipal Wholesale Electric Company (dated 6/1/88)
- Stony Brook-Ludlow Agreement between Western Massachusetts Electric Company and Mass. Municipal Wholesale Electric Company (dated 8/1/79) (O&M agreement)
- Interconnection, Operation and Maintenance Agreement between Western Massachusetts Electric Company and MASSPOWER (dated 7/1/93)
- I/A between The Connecticut Light and Power Company and Milford Power Company, LLC (dated 7/21/03)
- I/A between The Connecticut Light and Power Company and National Railroad Passenger Corporation (Amtrak) (dated 7/2/99)
- I/A between The Connecticut Light and Power Company and Northeast Generation Company as Amended (dated 3/00)
- I/A between Western Massachusetts Electric Company and Northeast Generation Company as Amended (dated 7/2/99)
- I/A between The Connecticut Light and Power Company and NRG Energy, Inc. (dated 11/15/99)
- I/A between The Public Service Company of New Hampshire and Pontook Hydro, LP (dated 7/25/85)
- I/A between The Public Service Company of New Hampshire and Pinetree Power-Tamworth, Inc. (dated 12/11/87)
- Interconnection Agreement attached to Electricity Purchase Agreement between The Connecticut Light and Power Company and Riley Energy Systems of Lisbon Corporation for The Lisbon Resources Recovery Project (dated 6/3/91)
- Electrical Interconnection, Licensing and Construction of Transmission Facilities Agreement between The Connecticut Light and Power Company and Southern Connecticut Regional Resource Recovery Authority (SCRRA) (dated 1/30/90)
- Seabrook Transmission Support Agreement with PSNH, New England Power Company and Taunton Municipal Light Department (dated 6/1/88)
- I/A with Respect to The Connecticut Light and Power Company and the United Illuminating Company (dated 6/15/74)
- I/A between The Public Service Company of New Hampshire and Vermont Electric Power Company, Inc. (dated 7/13/72)
- Interconnection Authorization Agreement Letter between The Connecticut Light and Power Company and Wallingford Resource Recovery Plant (dated 4/10/87)
- I/A between The Connecticut Light and Power Company and Waterside Power, LLC (dated 5/20/03)
- I/A between The Connecticut Light and Power Company and Waterside Power, LLC (dated 1/15/04)
- I/A between The Public Service Company of New Hampshire and Town of Wolfeboro (dated 9/26/03)
- Letter Agreement between Public Service of New Hampshire and Central Maine Power Company (Section 214 & Saco Valley Substation) (dated 11/18/86)

- Amended and Restated Electricity Purchase Agreement between The Connecticut Light and Power Company and The Dexter Corporation (Windsor Locks Cogeneration Facility) (dated 12/1/87)
- Long Island Power Authority 10/31/67 Agreement between The Connecticut Light and Power Company and (formally Long Island Lighting Company) Long Island Lighting Company, as amended or superseded

Schedule 3.11(c)
NSTAR ELECTRIC & GAS CORP.
ON BEHALF OF ITS OPERATING AFFILIATES
List of Grandfathered Interconnection Agreements

- Related Facilities Agreement between Entergy Nuclear Generation Company and BECo (1/21/03)
- Phase II Boston Edison with “New England Utilities” AC Facilities Support Agreement (6/1/85)
- Concord Municipal Light Plant and Boston Edison I/C Agreement (4/13/93)
- BECo and AES Londonderry, L.L.C. Related Facilities Agreement (RFA) (11/20/01)
- RFA between BECo and ANP Bellingham Energy Company
- I/C Agreement between Boston Edison and ANP Blackstone Energy Company (3/19/99)
- Mirant Kendall and BECo RFA (3/26/02)
- I/C Agreement between Mirant Kendall LLC and Cambridge Electric Light Company (12/24/01)

- Related Facilities Agreement between BECo and PG&E (2002)

- Related Facilities Agreement between Tiverton Power Associates Limited Partnership and Commonwealth Electric Company (9/21/98)

- Radial Line Service Agreement between Town of Reading and BECo (11/10/79)

- Related Facilities Agreement between Canal Electric Company (Unit 2) and the planned Pilgrim Unit 2 of BECo (9/21/72)

- Joint Ownership Agreement between BECo and New Bedford Gas and Light Company (Card St. Line) (1/2/68)
- Ownership Agreement among BECo, New Bedford Gas and Blackstone Valley Electric Company (8/31/71)

- Related Facilities Agreement between Entergy Nuclear Generation Company and Commonwealth Electric Company (8/11/03)

- Facilities Support Agreement between NSTAR and Entergy Nuclear (no date)

- I/C Agreement between Commonwealth Electric Company (NSTAR) and MBTA dated 2/99 (actual date is 5/1/99)

- I/C Agreement between BECo and Northeast Energy Associates (9/23/93)

- I/C Agreement between Commonwealth Electric Company (NSTAR) and Southern Energy New England, LLC (concerning the “Oak Bluffs Diesels”) (5/15/98)
- Support Agreement for Lines 255-2337 and 255-2338 between NEP and BECo (2/22/80)
- Support Agreement for 115kv Line 201-502 between NEP and BECo (5/11/79)
- Support Agreement for a “stabilizing” line (342) between Pilgrim and Canal stationthe agreement is between Commonwealth Electric Company (NSTAR-formerly New Bedford Gas and Edison Light Company) and NEP (two letters dated 3/29/68 and 11/4/74)
- I/C Agreement between BECo (NSTAR) and Sithe Fore River Development LLC (12/31/2000)

- I/C Agreement between Sithe Mystic Development LLC and BECo (3/6/2001)

- I/C Agreement for West Tisbury Diesels between Commonwealth Electric Company (NSTAR) and Southern Energy New England, LLC (5/15/1998)
- Facilities Support Agreement between BECo and Montaup Electric Company regarding 345 kv Tap Line (Whitman Tap) (April 1975)
- Canal Pilgrim Transmission Agreement for construction and support of Line #342
- Agreement for the Purchase and Sale of High Voltage Electric Service By and Between Boston Edison Company and the National Railroad Passenger Corporation (AMTRAK) (7/8/2002)
- Interconnection Agreement between Town of Norwood Municipal Light Department and Boston Edison Company (5/27/2002)
- Interconnection Agreement between Commonwealth Electric Company and Nantucket Electric Company (6/3/1996)
- Interconnection and Operation Agreement between Boston Edison Company and Sithe Energies, Inc. (12/10/1997)
- I/C Agreement for Canal Units between Commonwealth Electric Company and Southern Energy New England, LLC (5/15/1998)
- Transmission Service Agreement between Wellesley Municipal Light Plant and Boston Edison Company (Substitute Third Revised Rate Schedule FERC No. 167)

Schedule 3.11(c)
READING MUNICIPAL LIGHT DEPARTMENT
Grandfathered Interconnection Agreements

- Boston Edison Company Radial Line Transmission Service Over Lines 211-503 and 211-504, FERC Electric Rate Schedule No. 125
- Agreement between Edison Electric Illuminating Company and Town of Reading, dated April 29, 1926

Schedule 3.11(c)
TAUNTON MUNICIPAL LIGHT DEPARTMENT
Grandfathered Interconnection Agreements

- Interconnection Agreement between City of Taunton and Montaup Electric Company, dated July 31, 1970

- Amendments to July 31, 1970 Interconnection Agreement between City of Taunton and Montaup Electric Company, dated May 25, 1971, September 1, 1978, November 1, 1987, and November 1, 1988

Schedule 3.11(c)
UNITED ILLUMINATING COMPANY
List of Grandfathered Interconnection Agreements

- *Exhibit B only* to Service Agreement between United Illuminating and Bridgeport Energy LLC (6/9/98)
- I/C Agreement between United Illuminating and Cross Sound Cable (7/9/02)
- I/C Agreement between United Illuminating and McCallum Enterprises (10/19/87)
- I/C Agreement between United Illuminating and Quinnipiac Energy LLC (8/8/00)
- I/C Agreement between United Illuminating and Wisvest-Connecticut LLC (4/16/99)
- *Appendix D only* to Power Purchase Agreement between United Illuminating and Connecticut Resources Recovery Authority (12/1/85)

Schedule 3.11(c)
UNITIL ENERGY SYSTEMS, INC. AND
FITCHBURG GAS AND ELECTRIC LIGHT COMPANY
List of Grandfathered Interconnection Agreements

- *The attached Interconnection Agreement of Wheeling Agreement between Unitil Energy Systems and Briar Hydro Associates (Effective Date – December 2, 2002)*
- *The attached Interconnection Agreement of Wheeling Agreement between Unitil Energy Systems and New Hampshire Hydro Associates (Effective Date – July 2, 1983)*
- *The attached Interconnection Agreement of Wheeling Agreement between Unitil Energy Systems and Penacook Hydro Associates (Effective Date –April 15, 1985)*
- *I/C Agreement between Fitchburg Gas & Elec. And KES Fitchburg (Interconnector) (1/29/91)*
- *Revised Service Agreement for Network Integration Transmission Service effective January 26, 2005, between Fitchburg Gas and Electric Light Company and Massachusetts Bay Transportation Authority*
- *Service Agreement for Network Integration Transmission Service dated March 1, 1997 between New England Power Company and Fitchburg Gas and Electric Light Company*
- *Service Agreement for Network Integration Transmission Service dated March 1, 2002 between New England Power Company and Fitchburg Gas and Electric Light Company*
- *Service Agreement No. 1 dated March 1, 1994 under Unitil Energy Systems, Inc. Tariff for Firm Transmission Service and Related Interconnection between Concord Electric Company and SES Concord Company, LP*

Schedule 3.11(c)
VERMONT ELECTRIC POWER COMPANY
List of Grandfathered Interconnection Agreements

- I/A for Hydro-Quebec Derby Line Tie (1/88)

Schedule 3.11(c)
VERMONT TRANSCO LLC
List of Grandfathered Interconnection Agreements

- I/A between Vermont Electric Power and Entergy Nuclear Vermont Yankee (dated 7/27/02)

Schedule 3.11(c)
VERMONT PUBLIC POWER SUPPLY AUTHORITY
List of Grandfathered Interconnection Agreements

- Interconnection Agreement between Hydro-Quebec and Vermont Public Power Supply Authority dated September 1, 1995

Schedule 3.11(f)
List of MEPCO Operating Documents

1. Permit Authorizing Maine Electric Power Company, Inc. to Construct, Operate, Maintain and Connect Electric Transmission Facilities at the International Border between the United States and Canada. July 25, 1969 (FPC Docket No. E-7486).
2. Order Authorizing Transmission of Electricity to Canada, July 21, 1970 (FPC Docket No. E-7534).
3. Order Amending Prior Order Authorizing Exportation of Electric Energy to a Foreign Country, February 25, 1977, Effective date November 1, 1976 (FPC Docket No. 7534).
4. Chester SVC Partnership Agreement, dated as of July 1, 1990.
5. The Chester SVC Partnership Basic Operating Agreement, originally dated as of July 1, 1990 and recently extended through July 1, 2010. (FERC ER05-1278-000).
6. The Phase II Maine Electric Power SVC Facilities Support Agreement, dated as of October 1, 1988.
7. The Assignment and Purchase and Sale Agreement (between MEPCO and Chester SVC Partnership), dated as of July 1, 1990.
8. The Ground Lease Agreement (between MEPCO and Chester SVC Partnership), dated as of July 1, 1990.
9. The Chester SVC Partnership, Limited Recourse Senior Notes, Note Agreement, Dated as of December 20, 1990.

Schedule 4.01(d)
New England Transmission
Facilities Not Subject to this Agreement

<u>Circuit #</u>	<u>Stations</u>	<u>Voltage (kV)</u>
3512	Sandy Pond-Phase II Converter Pole 1	345
3521	Sandy Pond-Phase II Converter Pole 2	345
G207	Comerford-Phase I Converter Pole 1	230
H208	Comerford-Phase I Converter Pole 2	230
451/452	Sandy Pond-Comerford-Des Cantons	+/- 450 DC
387	Halvarsson Tap-Converter	345
481	Halvarsson-Tomson	+/- 150 DC
388	Orrington-Maxy's	345
392	Maxy's-Maine Yankee	345
396	Keswick-Chester-Orrington	345
T1	Orrington Transformer	345/115

Schedule 11.01

NOTICES

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Schedule 11.02
Superseded Agreements

The Interim Independent System Operator Agreement

The Maine Electric Power Company (MEPCO) Transmission Operating Agreement

Schedule 11.04

PTO Administrative Committee

1. The PTO AC established pursuant to Section 11.04 shall function as described in this Schedule 11.04.
2. Representatives. Each PTO shall appoint a representative and an alternate representative to serve as a member of the PTO AC with authority to act for that PTO with respect to actions taken or decisions made by the PTO AC.
 - a. Initial Representatives. Within thirty (30) days of the Operations Date, each PTO shall appoint its representative and alternate and provide written notice thereof to the other PTOs and to the ISO. Subsequent to the Operations Date, an entity that becomes a PTO pursuant to Section 11.05 of this Agreement shall appoint its representative and alternate and provide written notice to the other PTOs within thirty (30) days after becoming a PTO.
 - b. Change of or Substitution for a Representative or Alternate. A PTO may at any time, upon providing written notice to the other PTOs and to the ISO, designate a replacement representative or alternate. Any designated member of the PTO AC, by providing written notice to the Chair of the PTO AC, may also designate a substitute to act for him or her with respect to any matter specified in such written notice.
3. Officers. At the initial meeting of the PTO AC, a Chair and Vice Chair from different companies shall be elected among the PTOs' representatives on the PTO AC. The term of office for the Chair and Vice Chair shall be one year, or until succession to each office occurs as provided herein. Except as provided in Section 4, at each annual meeting, the Vice Chair shall succeed to the office of the Chair, and a new Vice Chair from a different company as the new and outgoing Chairs shall be elected.
4. Vacancies. If the office of the Chair becomes vacant for any reason, the Vice Chair shall succeed to the office of the Chair and a new Vice Chair from a different company shall be elected at the next regular or special meeting to serve the remainder of the term; provided that if the remaining term is less than six months, the new Chair and Vice Chair shall serve for the remaining term plus an additional term of one year. If the office of the Vice Chair becomes vacant for any reason, a new Vice Chair from a different company as the Chair shall be elected at the next regular or special meeting and shall serve out the term of the Vice Chair whose office became vacant.
5. Duties of the Officers. The Chair shall (1) call and preside at meetings of the PTO AC; (2) cause minutes of each meeting to be taken and maintained; (3) cause notices and agendas of all meetings and minutes of the prior meeting to be distributed as set forth below; and (4) carry out such other responsibilities as the PTO AC shall assign or as may be specified in this Agreement. The Vice Chair shall preside at meetings of the PTO AC

if the Chair is absent for any reason, and shall otherwise act for the Chair at the Chair's request.

6. Meetings. The PTO AC shall hold meetings no less frequently than once each calendar quarter as scheduled by the Chair. At the initial meeting, one of such regular meetings shall be designated as the annual meeting, at which officers shall be elected. The matters to be addressed at all meeting shall be specified in a written agenda provided in the notice distributed pursuant to Section 7 hereof.

7. Notice of Meetings. Written notice and agendas for a meeting shall be distributed by the Chair by facsimile or email to the PTOs' representatives and any designated alternates and to the ISO not later than ten (10) days prior to the meeting; provided, however, that meetings may be called on shorter notice as the Chair deems necessary to deal with an emergency or to meet a deadline for action; provided further that no vote shall be taken on any matter at any meeting or special meeting without at least three days prior written notice to the PTOs' representatives of the matter to be voted upon unless the representatives of the PTOs agree unanimously to waive this minimum notice requirement. The Chair shall include in the agenda for the meeting any matters that one or more PTOs request to be included.

8. Special Meetings. A special meeting of the PTO AC may be called at any time by two or more unaffiliated PTOs having combined Individual Votes exceeding twenty five percent of the aggregate Individual Votes of the PTOs at the time of the proposed special meeting; provided that the Chair shall schedule such special meeting at a time and location convenient to the representatives (but no more than ten days after the request for the meeting) and shall issue an agenda setting forth the issue or issues to be considered at the behest of the PTOs requesting the special meeting no less than five days before the scheduled date thereof.

9. Attendance. Regular or special meetings may be conducted in person or by telephone as authorized by the Chair or pursuant to rules adopted by the PTO AC in according with the voting procedures set forth in Section 12 below. Each PTO shall be represented at a meeting by its representative or alternate, or a duly-designated substitute representative. A PTO shall also have the right to designate another PTO to vote on such PTO's behalf at a meeting by proxy provided to the Chair in advance of the meeting. Any PTO choosing not to participate in a meeting pursuant to one of the methods described in this section 9 shall be deemed to have given its proxy to the Chair to vote on the non-participating PTO's behalf.

10. Open Meetings. All meetings of the PTO AC shall be open to all PTOs that are signatories to this Agreement and each such PTO shall receive timely written notice of a meeting.

11. Cost of Meetings. Each PTO shall be solely responsible for all costs incurred for its representative or alternate to attend any meeting. The PTOs shall share the costs incurred by the host of any meeting of the PTO AC in proportion to their Individual Votes.

12. Manner of Acting. Actions taken by the PTO AC with respect to amendments to this Agreement shall require the support of the number of votes specified in Section 11.04(a)(iii)(B), (C), or (D) of the Agreement as applicable.

13. Individual Votes. For all purposes under Section 11.04(a)(iii) and this Schedule 11.04, the “Individual Votes” of Non-Affiliated PTOs shall mean the number of votes accorded to each PTO at the time of the applicable meeting pursuant to the following formula: Each Individual Vote shall be equal to the average of the net book value and the gross book value, as determined in accordance with generally accepted accounting principles for electric utilities, of the Transmission Facilities comprising the New England Transmission System of each PTO: (expressed in dollars and divided by one million (1,000,000)), as determined on April 1 of each year on the basis of the book values of the Transmission Facilities as of the prior December 31, provided that the book value of the following facilities shall not be included in the calculation of such PTO’s Individual Votes:

- a. The Merchant Facilities of a PTO or a PTO’s affiliate; and
- b. The transmission facilities comprising Phase I and Phase II of the Hydro-Quebec interconnection, the Highgate interconnection, and the MEPCO interconnection until such time as a PTO includes the capital investment for its ownership of these transmission facilities in the ISO OATT in a manner such that the allowed return on equity for the PTO’s ownership in these facilities is treated the same as the return on equity of the PTO’s Transmission Facilities.

For those PTOs that are public utilities under the Federal Power Act, the values used to calculate Individual Votes shall be those used in such PTO’s Form 1 filing with the FERC. For any PTOs that are not required to make FERC Form 1 filings, the values used shall be consistent with generally accepted accounting practices for public utilities with the objective that the Individual Votes of such non-FERC jurisdictional PTOs shall be calculated on a consistent basis with those of the FERC-jurisdictional PTOs.

14. Text of Amendments. The text of any amendment to be voted upon at a meeting of the PTO AC shall be distributed to the representatives no less than fourteen (14) days before the meeting at which the amendment is to be considered; provided that the representatives may agree to make changes to such amendment at such meeting.

15. Record of Voting. The Chair shall cause each PTO that is a signatory to this Agreement to be provided with a written record of all votes (with the exception of straw votes or other informal votes) undertaken at a meeting of the PTO AC, including votes with respect to amendments to this Agreement pursuant to Section 11.04(a) of this Agreement and votes with respect to joint PTO Section 205 filings pursuant to the Disbursement Agreement.

Schedule 11.19(c)
Additional Conditions Precedent

SECTION I – GENERAL TERMS AND CONDITIONS

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I.1 Purpose and Components of this Tariff; ISO Objectives

I.1.1 Purpose of this Tariff:

This Tariff provides the rates, terms and conditions for transmission, market and other services provided by the ISO within the New England Control Area.

I.1.2 Components of this Tariff:

This Tariff includes the following components:

- (a) these general terms and conditions (Section I) and the ISO New England Financial Assurance Policy (Exhibit IA) and the ISO New England Billing Policy (Exhibit ID);
- (b) the ISO Open Access Transmission Tariff (the “OATT”) (Section II);
- (c) the ISO Market Rule 1 (Section III);
- (d) provisions for the recovery of the ISO’s administrative expenses and the ISO's capital funding arrangements (Section IV); and
- (e) other attachments, including a *pro forma* Market Participant Service Agreement (Attachment A)

I.1.3 Mission of ISO:

The mission of ISO is (through means including, but not limited to, planning, central dispatching, coordinated maintenance of electric supply and demand-side resources and transmission facilities, obtaining emergency power for Market Participants from other Control Areas, system restoration (where required), the development of market rules, the provision of an open access regional transmission tariff and the provision of a means for effective coordination with other control areas and utilities situated in the United States and Canada):

- (a) to assure the bulk power supply of the New England Control Area conforms to proper standards of reliability;
- (b) to create and sustain open, non-discriminatory, competitive, unbundled markets for energy, capacity, and ancillary services (including Operating Reserves) that are (i) economically efficient and balanced between buyers and sellers, and (ii) provide an opportunity for a participant to receive compensation through the market for a service it provides in a manner consistent with proper standards of reliability and the long-term sustainability of competitive markets;
- (c) to provide market rules that (i) promote a market based on voluntary participation, (ii) allow market participants to manage the risks involved in offering and purchasing services, and (iii)

compensate at fair value (considering both benefits and risks) any required service, subject to Commission's jurisdiction and review;

- (d) to allow informed participation and encourage ongoing market improvements;
- (e) to provide transparency with respect to the operation of and the pricing in markets and purchase programs;
- (f) to provide access to competitive markets within the New England Control Area and to neighboring regions; and
- (g) to provide for an equitable allocation of costs, benefits and responsibilities among market participants.

In fulfilling this mission and consistent with the preceding principles, the ISO shall strive to perform all its functions and services in a cost-effective manner, for the benefit of all those served by the ISO. To assist stakeholders in evaluating any major ISO initiative that affects market design, system planning or operation of the New England bulk power system, the ISO will provide quantitative and qualitative information on the need for and the impacts, including costs, of the initiative.

I.2 Rules of Construction; Definitions

I.2.1 Rules of Construction:

In this Tariff, unless otherwise provided herein:

- (a) words denoting the singular include the plural and vice versa;
- (b) words denoting a gender include all genders;
- (c) references to a particular part, clause, section, paragraph, article, exhibit, schedule, appendix or other attachment shall be a reference to a part, clause, section, paragraph, or article of, or an exhibit, schedule, appendix or other attachment to, this Tariff;
- (d) the exhibits, schedules and appendices attached hereto are incorporated herein by reference and shall be construed with an as an integral part of this Tariff to the same extent as if they were set forth verbatim herein;
- (e) a reference to any statute, regulation, proclamation, ordinance or law includes all statutes, regulations, proclamations, amendments, ordinances or laws varying, consolidating or replacing the same from time to time, and a reference to a statute includes all regulations, policies, protocols, codes, proclamations and ordinances issued or otherwise applicable under that statute unless, in any such case, otherwise expressly provided in any such statute or in this Tariff;
- (f) a reference to a particular section, paragraph or other part of a particular statute shall be deemed to be a reference to any other section, paragraph or other part substituted therefor from time to time;
- (g) a definition of or reference to any document, instrument or agreement includes any amendment or supplement to, or restatement, replacement, modification or novation of, any such document, instrument or agreement unless otherwise specified in such definition or in the context in which such reference is used;
- (h) a reference to any person (as hereinafter defined) includes such person's successors and permitted assigns in that designated capacity;
- (i) any reference to "days" shall mean calendar days unless "Business Days" (as hereinafter defined) are expressly specified;
- (j) if the date as of which any right, option or election is exercisable, or the date upon which any amount is due and payable, is stated to be on a date or day that is not a Business Day, such right, option or election may be exercised, and such amount shall be deemed due and payable, on the next succeeding Business Day with the same effect as if the same was exercised or made on such date or day (without, in the case of any such payment, the payment or accrual of any interest or

other late payment or charge, provided such payment is made on such next succeeding Business Day);

- (k) words such as “hereunder,” “hereto,” “hereof” and “herein” and other words of similar import shall, unless the context requires otherwise, refer to this Tariff as a whole and not to any particular article, section, subsection, paragraph or clause hereof; and a reference to “include” or “including” means including without limiting the generality of any description preceding such term, and for purposes hereof the rule of *ejusdem generis* shall not be applicable to limit a general statement, followed by or referable to an enumeration of specific matters, to matters similar to those specifically mentioned.

I.2.2. Definitions:

In this Tariff, the terms listed in this section shall be defined as described below:

Active Demand Capacity Resource is one or more Demand Response Resources located within the same Dispatch Zone, that is registered with the ISO, assigned a unique resource identification number by the ISO, and participates in the Forward Capacity Market to fulfill a Market Participant’s Capacity Supply Obligation pursuant to Section III.13 of Market Rule 1.

Actual Capacity Provided is the measure of capacity provided during a Capacity Scarcity Condition, as described in Section III.13.7.2.2 of Market Rule 1.

Actual Load is the consumption at the Retail Delivery Point for the hour.

Additional Resource Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Additional Resource Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Administrative Costs are those costs incurred in connection with the review of Applications for transmission service and the carrying out of System Impact Studies and Facilities Studies.

Administrative Export De-List Bid is a bid that may be submitted in a Forward Capacity Auction by certain Existing Generating Capacity Resources subject to a multi-year contract to sell capacity outside of the New England Control Area during the associated Capacity Commitment Period, as described in Section III.13.1.2.3.1.4 of Market Rule 1.

Administrative Sanctions are defined in Section III.B.4.1.2 of Appendix B of Market Rule 1.

ADR Neutrals are one or more firms or individuals identified by the ISO with the advice and consent of the Participants Committee that are prepared to act as neutrals in ADR proceedings under Appendix D to Market Rule 1.

Advance is defined in Section IV.A.3.2 of the Tariff.

Affected Party, for purposes of the ISO New England Billing Policy, is defined in Section 6.3.5 of the ISO New England Billing Policy.

Affiliate is any person or entity that controls, is controlled by, or is under common control by another person or entity. For purposes of this definition, "control" means the possession, directly or indirectly, of the authority to direct the management or policies of an entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

AGC is automatic generation control.

AGC SetPoint is the desired output signal for a Resource providing Regulation that is produced by the AGC system as frequently as every four seconds.

AGC SetPoint Deadband is a deadband expressed in megawatts that is applied to changing values of the AGC SetPoint for generating units.

Allocated Assessment is a Covered Entity's right to seek and obtain payment and recovery of its share in any shortfall payments under Section 3.3 or Section 3.4 of the ISO New England Billing Policy.

Alternative Dispute Resolution (ADR) is the procedure set forth in Appendix D to Market Rule 1.

Alternative Technology Regulation Resource (ATRR) is one or more facilities capable of providing Regulation that have been registered in accordance with the Asset Registration Process. An Alternative Technology Regulation Resource is eligible to participate in the Regulation Market.

Ancillary Services are those services that are necessary to support the transmission of electric capacity and energy from resources to loads while maintaining reliable operation of the New England Transmission System in accordance with Good Utility Practice.

Announced Schedule 1 EA Amount, Announced Schedule 2 EA Amount, Announced Schedule 3 EA Amount are defined in Section IV.B.2.2 of the Tariff.

Annual Transmission Revenue Requirements are the annual revenue requirements of a PTO's PTF or of all PTOs' PTF for purposes of the OATT shall be the amount determined in accordance with Attachment F to the OATT.

Annual Reconfiguration Transaction is a bilateral transaction that may be used in accordance with Section III.13.5.4 of Market Rule 1 to specify a price when a Capacity Supply Obligation is transferred using supply offers and demand bids in Annual Reconfiguration Auctions.

Applicants, for the purposes of the ISO New England Financial Assurance Policy, are entities applying for Market Participant status or for transmission service from the ISO.

Application is a written request by an Eligible Customer for transmission service pursuant to the provisions of the OATT.

Asset is a Generator Asset, a Demand Response Asset, a component of an On-Peak Demand Resource or Seasonal Peak Demand Resource, a Load Asset (including an Asset Related Demand), an Alternative Technology Regulation Resource, or a Tie-Line Asset.

Asset Registration Process is the ISO business process for registering an Asset.

Asset Related Demand is a Load Asset that has been discretely modeled within the ISO's dispatch and settlement systems, settles at a Node, has been registered in accordance with the Asset Registration

Process, and is made up of either: (1) one or more individual end-use metered customers receiving service from the same point or points of electrical supply with an aggregate average hourly load of 1 MW or greater during the 12 months preceding its registration or (2) one or more storage facilities with an aggregate consumption capability of at least 1 MW.

Asset Related Demand Bid Block-Hours are Block-Hours assigned to the Lead Market Participant for each Asset Related Demand bid. Blocks of the bid in effect for each hour will be totaled to determine the daily quantity of Asset Related Demand Bid Block-Hours. In the case that a Resource has a Real-Time unit status of “unavailable” for an entire day, that day will not contribute to the quantity of Asset Related Demand Bid Block-Hours. However, if the Resource has at least one hour of the day with a unit status of “available,” the entire day will contribute to the quantity of Asset Related Demand Bid Block-Hours.

Asset-Specific Going Forward Costs are the net costs of an asset that is part of an Existing Generating Capacity Resource, calculated for the asset in the same manner as the net costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.1.1 (for an asset with a Static De-List Bid or an Export Bid) or Section III.13.1.2.3.2.1.1.2 (for an asset with a Permanent De-List Bid or Retirement De-List Bid).

Assigned Meter Reader reports to the ISO the hourly and monthly MWh associated with the Asset. These MWh are used for settlement. The Assigned Meter Reader may designate an agent to help fulfill its Assigned Meter Reader responsibilities; however, the Assigned Meter Reader remains functionally responsible to the ISO.

Auction Revenue Right (ARR) is a right to receive FTR Auction Revenues in accordance with Appendix C of Market Rule 1.

Auction Revenue Right Allocation (ARR Allocation) is defined in Section 1 of Appendix C of Market Rule 1.

Auction Revenue Right Holder (ARR Holder) is an entity which is the record holder of an Auction Revenue Right (excluding an Incremental ARR) in the register maintained by the ISO.

Authorized Commission is defined in Section 3.3 of the ISO New England Information Policy.

Authorized Person is defined in Section 3.3 of the ISO New England Information Policy.

Automatic Response Rate is the response rate, in MW/Minute, at which a Market Participant is willing to have a Regulation Resource change its output or consumption while providing Regulation between the Regulation High Limit and Regulation Low Limit.

Average Hourly Load Reduction is either: (i) the sum of the On-Peak Demand Resource's electrical energy reduction during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; or (ii) the sum of the Seasonal Peak Demand Resource's electrical energy reduction during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month. The On-Peak Demand Resource's or Seasonal Peak Demand Resource's electrical energy reduction and Average Hourly Load Reduction shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Hourly Output is either: (i) the sum of the On-Peak Demand Resource's electrical energy output during Demand Resource On-Peak Hours in the month divided by the number of Demand Resource On-Peak Hours in the month; or (ii) the sum of the Seasonal Peak Demand Resource's electrical energy output during Demand Resource Seasonal Peak Hours in the month divided by the number of Demand Resource Seasonal Peak Hours in the month. Electrical energy output and Average Hourly Output shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements, as described in Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Average Monthly PER is calculated in accordance with Section III.13.7.1.2.2 of Market Rule 1.

Backstop Transmission Solution is a solution proposed: (i) to address a reliability or market efficiency need identified by the ISO in a Needs Assessment reported by the ISO pursuant to Section 4.1(i) of Attachment K to the ISO OATT, (ii) by the PTO or PTOs with an obligation under Schedule 3.09(a) of the TOA to address the identified need; and (iii) in circumstances in which the competitive solution process specified in Section 4.3 of Attachment K to the ISO OATT will be utilized.

Bankruptcy Code is the United States Bankruptcy Code.

Bankruptcy Event occurs when a Covered Entity files a voluntary or involuntary petition in bankruptcy or commences a proceeding under the United States Bankruptcy Code or any other applicable law concerning insolvency, reorganization or bankruptcy by or against such Covered Entity as debtor.

Bilateral Contract (BC) is any of the following types of contracts: Internal Bilateral for Load, Internal Bilateral for Market for Energy, and External Transactions.

Bilateral Contract Block-Hours are Block-Hours assigned to the seller and purchaser of an Internal Bilateral for Load, Internal Bilateral for Market for Energy and External Transactions; provided, however, that only those contracts which apply to the Real-Time Energy Market will accrue Block-Hours.

Binary Storage DARD is a DARD that participates in the New England Markets as part of a Binary Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Binary Storage Facility is a type of Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Blackstart Capability Test is the test, required by ISO New England Operating Documents, of a resource's capability to provide Blackstart Service.

Blackstart Capital Payment is the annual compensation, as calculated pursuant to Section 5.1, or as referred to in Section 5.2, of Schedule 16 to the OATT, for a Designated Blackstart Resource's Blackstart Equipment capital costs associated with the provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Blackstart Equipment is any equipment that is solely necessary to enable the Designated Blackstart Resource to provide Blackstart Service and is not required to provide other products or services under the Tariff.

Blackstart O&M Payment is the annual Blackstart O&M compensation calculated under either Section 5.1 or 5.2 of Schedule 16 of the OATT, as applicable.

Blackstart Owner is the Market Participant who is authorized on behalf of the Generator Owner(s) to offer or operate the resource as a Designated Blackstart Resource and is authorized to commit the resource to provide Blackstart Service.

Blackstart Service is the Ancillary Service described in Section II.47 of the Tariff and Schedule 16 of the OATT.

Blackstart Service Commitment is the commitment by a Blackstart Owner for its resource to provide Blackstart Service and the acceptance of that commitment by the ISO, in the manner detailed in ISO New England Operating Procedure No. 11 – Designated Blackstart Resource Administration (OP 11), and which includes a commitment to provide Blackstart Service established under Operating Procedure 11 – Designated Blackstart Resource Administration (OP11).

Blackstart Service Minimum Criteria are the minimum criteria that a Blackstart Owner and its resource must meet in order to establish and maintain a resource as a Designated Blackstart Resource.

Blackstart Standard Rate Payment is the formulaic rate of monthly compensation, as calculated pursuant to Section 5 of Schedule 16 to the OATT, paid to a Blackstart Owner for the provision of Blackstart Service from a Designated Blackstart Resource.

Blackstart Station is comprised of (i) a single Designated Blackstart Resource or (ii) two or more Designated Blackstart Resources that share Blackstart Equipment.

Blackstart Station-specific Rate Payment is the Commission-approved compensation, as calculated pursuant to Section 5.2 of Schedule 16 to the OATT, paid to a Blackstart Owner on a monthly basis for the provision of Blackstart Service by Designated Blackstart Resources located at a specific Blackstart Station.

Blackstart Station-specific Rate Capital Payment is a component of the Blackstart Station-specific Rate Payment that reflects a Blackstart Station's capital Blackstart Equipment costs associated with the provision of Blackstart Service (excluding the capital costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Block is defined as follows: (1) With respect to Bilateral Contracts, a Bilateral Contract administered by the ISO for an hour; (2) with respect to Supply Offers administered by the ISO, a quantity with a related price for Energy (Supply Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (3) with respect to Demand Bids administered by the ISO, a quantity with a related price for Energy (Demand Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (4) with respect to Increment Offers administered by the ISO, a quantity with a related price for Energy (Increment Offers for Energy may contain multiple sets of quantity and price pairs for each hour); (5) with respect to Decrement Bids administered by the ISO, a quantity with a related price for Energy (Decrement Bids for Energy may contain multiple sets of quantity and price pairs for each hour); (6) with respect to Asset Related Demand bids administered by the ISO, a quantity with a related price for Energy (Asset Related Demand bids may contain multiple sets of quantity and price pairs for each hour); and (7) with respect to Demand Reduction Offers administered by the ISO, a quantity of reduced demand with a related price (Demand Reduction Offers may contain multiple sets of quantity and price pairs for the day).

Block-Hours are the number of Blocks administered for a particular hour.

Budget and Finance Subcommittee is a subcommittee of the Participants Committee, the responsibilities of which are specified in Section 8.4 of the Participants Agreement.

Business Day is any day other than a Saturday or Sunday or ISO holidays as posted by the ISO on its website.

Cancelled Start NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Capability Demonstration Year is the one year period from September 1 through August 31.

Capacity Acquiring Resource is a resource that is seeking to acquire a Capacity Supply Obligation through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1, or; (2) an annual or monthly reconfiguration auction, as described in Section III.13.4.

Capacity Balancing Ratio is a ratio used in calculating the Capacity Performance Payment in the Forward Capacity Market, as described in Section III.13.7.2.3 of Market Rule 1.

Capacity Base Payment is the portion of revenue received in the Forward Capacity Market as described in Section III.13.7.1 of Market Rule 1.

Capacity Capability Interconnection Standard has the meaning specified in Schedule 22, Schedule 23, and Schedule 25 of the OATT.

Capacity Clearing Price is the clearing price for a Capacity Zone for a Capacity Commitment Period resulting from the Forward Capacity Auction conducted for that Capacity Commitment Period, as determined in accordance with Section III.13.2.7 of Market Rule 1.

Capacity Commitment Period is the one-year period from June 1 through May 31 for which obligations are assumed and payments are made in the Forward Capacity Market.

Capacity Cost (CC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Capacity Export Through Import Constrained Zone Transaction is defined in Section III.1.10.7(f)(i) of Market Rule 1.

Capacity Load Obligation is the quantity of capacity for which a Market Participant is financially responsible as described in Section III.13.7.5.2 of Market Rule 1.

Capacity Load Obligation Acquiring Participant is a load serving entity or any other Market Participant seeking to acquire a Capacity Load Obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 of Market Rule 1.

Capacity Network Import Capability (CNI Capability) is as defined in Section I of Schedule 25 of the OATT.

Capacity Network Import Interconnection Service (CNI Interconnection Service) is as defined in Section I of Schedule 25 of the OATT.

Capacity Load Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a portion of its Capacity Load Obligation to another entity, as described in Section III.13.5 of Market Rule 1.

Capacity Load Obligation Transferring Participant is an entity that has a Capacity Load Obligation and is seeking to shed such obligation through a Capacity Load Obligation Bilateral, as described in Section III.13.5.2 of Market Rule 1.

Capacity Network Resource (CNR) is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Network Resource Interconnection Service (CNR Interconnection Service) is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Performance Bilateral is a transaction for transferring Capacity Performance Score, as described in Section III.13.5.3 of Market Rule 1.

Capacity Performance Payment is the performance-dependent portion of revenue received in the Forward Capacity Market, as described in Section III.13.7.2 of Market Rule 1.

Capacity Performance Payment Rate is a rate used in calculating Capacity Performance Payments, as described in Section III.13.7.2.5 of Market Rule 1.

Capacity Performance Score is a figure used in determining Capacity Performance Payments, as described in Section III.13.7.2.4 of Market Rule 1.

Capacity Rationing Rule addresses whether offers and bids in a Forward Capacity Auction may be rationed, as described in Section III.13.2.6 of Market Rule 1.

Capacity Scarcity Condition is a period during which performance is measured in the Forward Capacity Market, as described in Section III.13.7.2.1 of Market Rule 1.

Capacity Scarcity Condition is a period during which performance is measured in the Forward Capacity Market, as described in Section III.13.7.2.1 of Market Rule 1.

Capacity Supply Obligation is an obligation to provide capacity from a resource, or a portion thereof, to satisfy a portion of the Installed Capacity Requirement that is acquired through a Forward Capacity Auction in accordance with Section III.13.2, a reconfiguration auction in accordance with Section III.13.4, or a Capacity Supply Obligation Bilateral in accordance with Section III.13.5.1 of Market Rule 1.

Capacity Supply Obligation Bilateral is a bilateral contract through which a Market Participant may transfer all or a part of its Capacity Supply Obligation to another entity, as described in Section III.13.5.1 of Market Rule 1.

Capacity Transfer Rights (CTRs) are calculated in accordance with Section III.13.7.5.4.

Capacity Transferring Resource is a resource that has a Capacity Supply Obligation and is seeking to shed such obligation, or a portion thereof, through: (1) a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1, or; (2) an annual or monthly reconfiguration auction, as described in Section III.13.4.

Capacity Zone is a geographic sub-region of the New England Control Area as determined in accordance with Section III.12.4 of Market Rule 1.

Capacity Zone Demand Curves are the demand curves used in the Forward Capacity Market for a Capacity Zone as specified in Sections III.13.2.2.2 and III.13.2.2.3.

Capital Funding Charge (CFC) is defined in Section IV.B.2 of the Tariff.

CARL Data is Control Area reliability data submitted to the ISO to permit an assessment of the ability of an external Control Area to provide energy to the New England Control Area in support of capacity offered to the New England Control Area by that external Control Area.

Category B Designated Blackstart Resource has the same meaning as Designated Blackstart Resource.

Charge is a sum of money due from a Covered Entity to the ISO, either in its individual capacity or as billing and collection agent for NEPOOL pursuant to the Participants Agreement.

CLAIM10 is the value, expressed in megawatts, calculated pursuant to Section III.9.5.3 of the Tariff.

CLAIM30 is the value, expressed in megawatts, calculated pursuant to Section III.9.5.3 of the Tariff.

Claimed Capability Audit is performed to determine the real power output capability of a Generator Asset or the demand reduction capability of a Demand Response Resource.

Cluster Enabling Transmission Upgrade (CETU) has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Enabling Transmission Upgrade Regional Planning Study (CRPS) has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Entry Deadline has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Cluster Interconnection System Impact Study (CSIS) has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Clustering has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

CNR Capability is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Coincident Peak Contribution is a Market Participant's share of the New England Control Area coincident peak demand for the prior calendar year as determined prior to the start of each Capacity Commitment Period, which reflects the sum of the prior year's annual coincident peak contributions of the customers served by the Market Participant at each Load Asset. Daily Coincident Peak Contribution values shall be submitted by the Assigned Meter Reader or Host Participant by the meter reading deadline to the ISO.

Commercial Capacity is capacity that has achieved FCM Commercial Operation.

Commission is the Federal Energy Regulatory Commission.

Commitment Period is (i) for a Day-Ahead Energy Market commitment, a period of one or more contiguous hours for which a Resource is cleared in the Day-Ahead Energy Market, and (ii) for a Real-Time Energy Market commitment, the period of time for which the ISO indicates the Resource is being committed when it issues the Dispatch Instruction. If the ISO does not indicate the period of time for which the Resource is being committed in the Real-Time Energy Market, then the Commitment Period is the Minimum Run Time for an offline Resource and one hour for an online Resource.

Common Costs are those costs associated with a Station that are avoided only by the clearing of the Static De-List Bids, the Permanent De-List Bids, or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

Completed Application is an Application that satisfies all of the information and other requirements of the OATT, including any required deposit.

Compliance Effective Date is the date upon which the changes in the predecessor NEPOOL Open Access Transmission Tariff which have been reflected herein to comply with the Commission's Order of April 20, 1998 became effective.

Composite FCM Transaction is a transaction for separate resources seeking to participate as a single composite resource in a Forward Capacity Auction in which multiple Designated FCM Participants provide capacity, as described in Section III.13.1.5 of Market Rule 1.

Conditional Qualified New Resource is defined in Section III.13.1.1.2.3(f) of Market Rule 1.

Confidential Information is defined in Section 2.1 of the ISO New England Information Policy, which is Attachment D to the Tariff.

Confidentiality Agreement is Attachment 1 to the ISO New England Billing Policy.

Congestion is a condition of the New England Transmission System in which transmission limitations prevent unconstrained regional economic dispatch of the power system. Congestion is the condition that results in the Congestion Component of the Locational Marginal Price at one Location being different

from the Congestion Component of the Locational Marginal Price at another Location during any given hour of the dispatch day in the Day-Ahead Energy Market or Real-Time Energy Market.

Congestion Component is the component of the nodal price that reflects the marginal cost of congestion at a given Node or External Node relative to the reference point. When used in connection with Zonal Price and Hub Price, the term Congestion Component refers to the Congestion Components of the nodal prices that comprise the Zonal Price and Hub Price weighted and averaged in the same way that nodal prices are weighted to determine Zonal Price and averaged to determine the Hub Price.

Congestion Cost is the cost of congestion as measured by the difference between the Congestion Components of the Locational Marginal Prices at different Locations and/or Reliability Regions on the New England Transmission System.

Congestion Paying LSE is, for the purpose of the allocation of FTR Auction Revenues to ARR Holders as provided for in Appendix C of Market Rule 1, a Market Participant or Non-Market Participant Transmission Customer that is responsible for paying for Congestion Costs as a Transmission Customer paying for Regional Network Service under the Transmission, Markets and Services Tariff, unless such Transmission Customer has transferred its obligation to supply load in accordance with ISO New England System Rules, in which case the Congestion Paying LSE shall be the Market Participant supplying the transferred load obligation. The term Congestion Paying LSE shall be deemed to include, but not be limited to, the seller of internal bilateral transactions that transfer Real-Time Load Obligations under the ISO New England System Rules.

Congestion Revenue Fund is the amount available for payment of target allocations to FTR Holders from the collection of Congestion Cost.

Congestion Shortfall means congestion payments exceed congestion charges during the billing process in any billing period.

Continuous Storage ATRR is an ATRR that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage DARD is a DARD that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage Generator Asset is a Generator Asset that participates in the New England Markets as part of a Continuous Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Continuous Storage Facility is a type of Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Control Agreement is the document posted on the ISO website that is required if a Market Participant's cash collateral is to be invested in BlackRock funds.

Control Area is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

- (1) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);
- (2) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;
- (3) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and the criteria of the applicable regional reliability council or the North American Electric Reliability Corporation; and
- (4) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Controllable Behind-the-Meter Generation means generation whose output can be controlled located at the same facility as a DARD or a Demand Response Asset, excluding: (1) generators whose output is separately metered and reported and (2) generators that cannot operate electrically synchronized to, and that are operated only when the facility loses its supply of power from, the New England Transmission System, or when undergoing related testing.

Coordinated External Transaction is an External Transaction at an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented. A transaction to wheel energy into, out of or through the New England Control Area is not a Coordinated External Transaction.

Coordinated Transaction Scheduling means the enhanced scheduling procedures set forth in Section III.1.10.7.A.

Correction Limit means the date that is one hundred and one (101) calendar days from the last Operating Day of the month to which the data applied. As described in Section III.3.6.1 of Market Rule 1, this will be the period during which meter data corrections must be submitted unless they qualify for submission as a Requested Billing Adjustment under Section III.3.7 of Market Rule 1.

Cost of Energy Consumed (CEC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Cost of Energy Produced (CEP) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Cost of New Entry (CONE) is the estimated cost of new entry (\$/kW-month) for a capacity resource that is determined by the ISO for each Forward Capacity Auction pursuant to Section III.13.2.4.

Counterparty means the status in which the ISO acts as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Customer (including assignments involving Customers) involving sale to the ISO, and/or purchase from the ISO, of Regional Transmission Service and market and other products and services, and other transactions and assignments involving Customers, all as described in the Tariff.

Covered Entity is defined in the ISO New England Billing Policy.

Credit Coverage is third-party credit protection obtained by the ISO in the form of credit insurance coverage.

Credit Qualifying means a Rated Market Participant that has an Investment Grade Rating and an Unrated Market Participant that satisfies the Credit Threshold.

Credit Threshold consists of the conditions for Unrated Market Participants outlined in Section II.B.2 of the ISO New England Financial Assurance Policy.

Critical Energy Infrastructure Information (CEII) is defined in Section 3.0(j) of the ISO New England Information Policy, which is Attachment D to the Tariff.

Current Ratio is, on any date, all of a Market Participant's or Non-Market Participant Transmission Customer's current assets divided by all of its current liabilities, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Curtailement is a reduction in the dispatch of a transaction that was scheduled, using transmission service, in response to a transfer capability shortage as a result of system reliability conditions.

Customer is a Market Participant, a Transmission Customer or another customer of the ISO.

Data Reconciliation Process means the process by which meter reconciliation and data corrections that are discovered by Governance Participants after the Invoice has been issued for a particular month or that are discovered prior to the issuance of the Invoice for the relevant month but not included in that Invoice or in the other Invoices for that month and are reconciled by the ISO on an hourly basis based on data submitted to the ISO by the Host Participant Assigned Meter Reader or Assigned Meter Reader.

Day-Ahead is the calendar day immediately preceding the Operating Day.

Day-Ahead Adjusted Load Obligation is defined in Section III.3.2.1(a) of Market Rule 1.

Day-Ahead Congestion Revenue is defined in Section III.3.2.1(i) of Market Rule 1.

Day-Ahead Demand Reduction Obligation is defined in Section III.3.2.1(a) of Market Rule 1.

Day-Ahead Energy Market means the schedule of commitments for the purchase or sale of energy, purchase of demand reductions, payment of Congestion Costs, payment for losses developed by the ISO as a result of the offers and specifications submitted in accordance with Section III.1.10 of Market Rule 1.

Day-Ahead Energy Market Congestion Charge/Credit is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Energy Market Energy Charge/Credit is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Energy Market Loss Charge/Credit is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Energy Market NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Export and Decrement Bid NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead External Transaction Import and Increment Offer NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Day-Ahead Generation Obligation is defined in Section III.3.2.1(a) of Market Rule 1.

Day-Ahead Load Obligation is defined in Section III.3.2.1(a) of Market Rule 1.

Day-Ahead Locational Adjusted Net Interchange is defined in Section III.3.2.1(a) of Market Rule 1.

Day-Ahead Loss Charges or Credits is defined in Section III.3.2.1(k) of Market Rule 1.

Day-Ahead Loss Revenue is defined in Section III.3.2.1(j) of Market Rule 1.

Day-Ahead Prices means the Locational Marginal Prices resulting from the Day-Ahead Energy Market.

DDP Dispatchable Resource is any Dispatchable Resource that the ISO dispatches using Desired Dispatch Points in the Resource's Dispatch Instructions.

Debt-to-Total Capitalization Ratio is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's total debt (including all current borrowings) divided by its total shareholders' equity plus total debt, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Decrement Bid means a bid to purchase energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical load. An accepted Decrement Bid results in scheduled load at the specified Location in the Day-Ahead Energy Market.

Default Amount is all or any part of any amount due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due (other than in the case of a payment dispute for any amount due for transmission service under the OATT).

Default Period is defined in Section 3.3.h(i) of the ISO New England Billing Policy.

Delivering Party is the entity supplying capacity and/or energy to be transmitted at Point(s) of Receipt under the OATT.

Demand Bid means a request to purchase an amount of energy, at a specified Location, or an amount of energy at a specified price, that is associated with a physical load. A cleared Demand Bid in the Day-Ahead Energy Market results in scheduled load at the specified Location. Demand Bids submitted for use in the Real-Time Energy Market are specific to Dispatchable Asset Related Demands only.

Demand Bid Block-Hours are the Block-Hours assigned to the submitting Customer for each Demand Bid.

Demand Bid Cap is \$2,000/MWh.

Demand Capacity Resource means an Existing Demand Capacity Resource or a New Demand Capacity Resource. There are three Demand Capacity Resource types: Active Demand Capacity Resources, On-Peak Demand Resources, and Seasonal Peak Demand Resources.

Demand Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for Demand Response Resources in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

Demand Reduction Offer is an offer by a Market Participant with a Demand Response Resource to reduce demand.

Demand Reduction Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Demand Reduction Offer. Blocks of the Demand Reduction Offer in effect for each hour will be totaled to determine the quantity of Demand Reduction Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of “unavailable” for the entire day, that day will not contribute to the quantity of Demand Reduction Offer Block-Hours. However, if the Resource has at least one hour of the day with a unit status of “available,” the entire day will contribute to the quantity of Demand Reduction Offer Block-Hours.

Demand Reduction Threshold Price is a minimum offer price calculated pursuant to Section III.1.10.1A(f).

Demand Resource On-Peak Hours are hours ending 1400 through 1700, Monday through Friday on non-Demand Response Holidays during the months of June, July, and August and hours ending 1800 through 1900, Monday through Friday on non-Demand Response Holidays during the months of December and January.

Demand Resource Seasonal Peak Hours are those hours in which the actual, real-time hourly load, as measured using real-time telemetry (adjusted for transmission and distribution losses, and excluding load associated with Exports and Storage DARDs) for Monday through Friday on non-Demand Response Holidays, during the months of June, July, August, December, and January, as determined by the ISO, is equal to or greater than 90% of the most recent 50/50 system peak load forecast, as determined by the ISO, for the applicable summer or winter season.

Demand Response Asset is an asset comprising the demand reduction capability of an individual end-use customer at a Retail Delivery Point or the aggregated demand reduction capability of multiple end-use customers from multiple delivery points (as described in Section III.8.1.1(f)) that has been registered in accordance with III.8.1.1.

Demand Response Available is the capability of the Demand Response Resource, in whole or in part, at any given time, to reduce demand in response to a Dispatch Instruction.

Demand Response Baseline is the expected baseline demand of an individual end-use metered customer or group of end-use metered customers as determined pursuant to Section III.8.2.

Demand Response Holiday is New Year's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day, and Christmas Day. If the holiday falls on a Saturday, the holiday will be observed on the preceding Friday; if the holiday falls on a Sunday, the holiday will be observed on the following Monday.

Demand Response Resource is an individual Demand Response Asset or aggregation of Demand Response Assets within a DRR Aggregation Zone that has been registered in accordance with Section III.8.1.2.

Demand Response Resource Notification Time is the period of time between the receipt of a startup Dispatch Instruction and the time the Demand Response Resource starts reducing demand.

Demand Response Resource Ramp Rate is the average rate, expressed in MW per minute, at which the Demand Response Resource can reduce demand.

Demand Response Resource Start-Up Time is the period of time between the time a Demand Response Resource starts reducing demand at the conclusion of the Demand Response Resource Notification Time and the time the resource can reach its Minimum Reduction and be ready for further dispatch by the ISO.

Designated Agent is any entity that performs actions or functions required under the OATT on behalf of the ISO, a Transmission Owner, a Schedule 20A Service Provider, an Eligible Customer, or a Transmission Customer.

Designated Blackstart Resource is a resource that meets the eligibility requirements specified in Schedule 16 of the OATT, which includes any resource referred to previously as a Category B Designated Blackstart Resource.

Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for a Generator Asset and/or Dispatchable Asset Related Demand in accordance with the provisions set forth in ISO New England Operating Procedure No. 14.

Designated FCM Participant is any Lead Market Participant, including any Provisional Member that is a Lead Market Participant, transacting in any Forward Capacity Auction, reconfiguration auctions or

Capacity Supply Obligation Bilateral for capacity that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

Designated FTR Participant is a Market Participant, including FTR-Only Customers, transacting in the FTR Auction that is otherwise required to provide additional financial assurance under the ISO New England Financial Assurance Policy.

Desired Dispatch Point (DDP) means the control signal, expressed in megawatts, transmitted to direct the output, consumption, or demand reduction level of each Generator Asset, Dispatchable Asset Related Demand, or Demand Response Resource dispatched by the ISO in accordance with the asset's Offer Data.

Direct Assignment Facilities are facilities or portions of facilities that are constructed for the sole use/benefit of a particular Transmission Customer requesting service under the OATT or a Generator Owner requesting an interconnection. Direct Assignment Facilities shall be specified in a separate agreement among the ISO, Interconnection Customer and Transmission Customer, as applicable, and the Transmission Owner whose transmission system is to be modified to include and/or interconnect with the Direct Assignment Facilities, shall be subject to applicable Commission requirements, and shall be paid for by the Customer in accordance with the applicable agreement and the Tariff.

Directly Metered Assets are specifically measured by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP-18. Directly Metered Assets include all Tie-Line Assets, all Generator Assets, as well as some Load Assets. Load Assets for which the Host Participant is not the Assigned Meter Reader are considered Directly Metered Assets. In addition, the Host Participant Assigned Meter Reader determines which additional Load Assets are considered Directly Metered Assets and which ones are considered Profiled Load Assets based upon the Host Participant Assigned Meter Reader reporting systems and process by which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Disbursement Agreement is the Rate Design and Funds Disbursement Agreement among the PTOs, as amended and restated from time to time.

Dispatch Instruction means directions given by the ISO to Market Participants, which may include instructions to start up, shut down, raise or lower generation, curtail or restore loads from Demand Response Resources, change External Transactions, or change the status or consumption of a

Dispatchable Asset Related Demand in accordance with the Supply Offer, Demand Bid, or Demand Reduction Offer parameters. Such instructions may also require a change to the operation of a Pool Transmission Facility. Such instructions are given through either electronic or verbal means.

Dispatch Zone means a subset of Nodes located within a Load Zone established by the ISO for each Capacity Commitment Period pursuant to Section III.12.4A.

Dispatchable Asset Related Demand (DARD) is an Asset Related Demand that is capable of having its energy consumption modified in Real-Time in response to Dispatch Instructions. A DARD must be capable of receiving and responding to electronic Dispatch Instructions, must be able to increase or decrease energy consumption between its Minimum Consumption Limit and Maximum Consumption Limit in accordance with Dispatch Instructions, and must meet the technical requirements specified in the ISO New England Operating Procedures and Manuals.

Dispatchable Resource is any Generator Asset, Dispatchable Asset Related Demand, Demand Response Resource, or, with respect to the Regulation Market only, Alternative Technology Regulation Resource, that, during the course of normal operation, is capable of receiving and responding to electronic Dispatch Instructions in accordance with the parameters contained in the Resource's Supply Offer, Demand Bid, Demand Reduction Offer or Regulation Service Offer. A Resource that is normally classified as a Dispatchable Resource remains a Dispatchable Resource when it is temporarily not capable of receiving and responding to electronic Dispatch Instructions.

Dispute Representatives are defined in 6.5.c of the ISO New England Billing Policy.

Disputed Amount is a Covered Entity's disputed amount due on any fully paid monthly Invoice and/or any amount believed to be due or owed on a Remittance Advice, as defined in Section 6 of the ISO New England Billing Policy.

Disputing Party, for the purposes of the ISO New England Billing Policy, is any Covered Entity seeking to recover a Disputed Amount.

Distributed Generation means generation directly connected to end-use customer load and located behind the end-use customer's Retail Delivery Point that reduces the amount of energy that would otherwise have been produced on the electricity network in the New England Control Area, provided that

the facility's Net Supply Capability is (i) less than 5 MW or (ii) less than or equal to the Maximum Facility Load, whichever is greater.

DRR Aggregation Zone is a Dispatch Zone entirely within a single Reserve Zone or Rest of System or, where a Dispatch Zone is not entirely within a single Reserve Zone or Rest of System, each portion of the Dispatch Zone demarcated by the Reserve Zone boundary.

Do Not Exceed (DNE) Dispatchable Generator is any Generator Asset that is dispatched using Do Not Exceed Dispatch Points in its Dispatch Instructions and meets the criteria specified in Section III.1.11.3(e). Do Not Exceed Dispatchable Generators are Dispatchable Resources.

Do Not Exceed Dispatch Point is a Dispatch Instruction indicating a maximum output level that a DNE Dispatchable Generator must not exceed.

Dynamic De-List Bid is a bid that may be submitted by Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Capacity Resources in the Forward Capacity Auction below the Dynamic De-List Bid Threshold, as described in Section III.13.2.3.2(d) of Market Rule 1.

Dynamic De-List Bid Threshold is the price specified in Section III.13.1.2.3.1.A of Market Rule 1 associated with the submission of Dynamic De-List Bids in the Forward Capacity Auction.

EA Amount is defined in Section IV.B.2.2 of the Tariff.

Early Amortization Charge (EAC) is defined in Section IV.B.2 of the Tariff.

Early Amortization Working Capital Charge (EAWCC) is defined in Section IV.B.2 of the Tariff.

Early Payment Shortfall Funding Amount (EPSF Amount) is defined in Section IV.B.2.4 of the Tariff.

Early Payment Shortfall Funding Charge (EPSFC) is defined in Section IV.B.2 of the Tariff.

EAWW Amount is defined in Section IV.B.2.3 of the Tariff.

EBITDA-to-Interest Expense Ratio is, on any date, a Market Participant's or Non-Market Participant Transmission Customer's earnings before interest, taxes, depreciation and amortization in the most recent fiscal quarter divided by that Market Participant's or Non-Market Participant Transmission Customer's expense for interest in that fiscal quarter, in each case as shown on the most recent financial statements provided by such Market Participant or Non-Market Participant Transmission Customer to the ISO.

Economic Dispatch Point is the output, reduction, or consumption level to which a Resource would have been dispatched, based on the Resource's Supply Offer, Demand Reduction Offer, or Demand Bid and the Real-Time Price, and taking account of any operating limits, had the ISO not dispatched the Resource to another Desired Dispatch Point.

Economic Maximum Limit or Economic Max is the maximum available output, in MW, of a Generator Asset that a Market Participant offers to supply in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Generator Asset's Offer Data. This represents the highest MW output a Market Participant has offered for a Generator Asset for economic dispatch. A Market Participant must maintain an up-to-date Economic Maximum Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an updated Economic Maximum Limit) for all hours in which a Generator Asset has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Economic Minimum Limit or Economic Min is (a) for a Generator Asset with an incremental heat rate, the maximum of: (i) the lowest sustainable output level as specified by physical design characteristics, environmental regulations or licensing limits; and (ii) the lowest sustainable output level at which a one MW increment increase in the output level would not decrease the incremental cost, calculated based on the incremental heat rate, of providing an additional MW of output, and (b) for a Generator Asset without an incremental heat rate, the lowest sustainable output level that is consistent with the physical design characteristics of the Generator Asset and with meeting all environmental regulations and licensing limits, and (c) for a Generator Asset undergoing Facility and Equipment Testing or auditing, the level to which the Generator Asset requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing, and (d) for Non-Dispatchable Resources the output level at which a Market Participant anticipates its Non-Dispatchable Resource will be available to operate based on fuel limitations, physical design characteristics, environmental regulations or licensing limits.

Economic Study is defined in Section 4.1(b) of Attachment K to the OATT.

Effective Offer is the Supply Offer, Demand Reduction Offer, or Demand Bid that is used for NCPC calculation purposes as specified in Section III.F.1(a).

EFT is electronic funds transfer.

Elective Transmission Upgrade is defined in Section I of Schedule 25 of the OATT.

Elective Transmission Upgrade Interconnection Customer is defined in Schedule 25 of the OATT.

Electric Reliability Organization (ERO) is defined in 18 C.F.R. § 39.1.

Electric Storage Facility is a storage facility that participates in the New England Markets as described in Section III.1.10.6 of Market Rule 1.

Eligible Customer is: (i) Any entity that is engaged, or proposes to engage, in the wholesale or retail electric power business is an Eligible Customer under the OATT. (ii) Any electric utility (including any power marketer), Federal power marketing agency, or any other entity generating electric energy for sale or for resale is an Eligible Customer under the OATT. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico. However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the unbundled transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that entity is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer). (iii) Any end user taking or eligible to take unbundled transmission service or Local Delivery Service pursuant to a state requirement that the Transmission Owner with which that end user is directly interconnected or the distribution company having the service territory in which that entity is located (if that entity is a retail customer) offer the transmission service or Local Delivery Service, or pursuant to a voluntary offer of such service by the Transmission Owner with which that end user is directly interconnected, or the

distribution company having the service territory in which that entity is located (if that entity is a retail customer) is an Eligible Customer under the OATT.

Eligible FTR Bidder is an entity that has satisfied applicable financial assurance criteria, and shall not include the auctioneer, its Affiliates, and their officers, directors, employees, consultants and other representatives.

Emergency is an abnormal system condition on the bulk power systems of New England or neighboring Control Areas requiring manual or automatic action to maintain system frequency, or to prevent the involuntary loss of load, equipment damage, or tripping of system elements that could adversely affect the reliability of an electric system or the safety of persons or property; or a fuel shortage requiring departure from normal operating procedures in order to minimize the use of such scarce fuel; or a condition that requires implementation of Emergency procedures as defined in the ISO New England Manuals.

Emergency Condition means an Emergency has been declared by the ISO in accordance with the procedures set forth in the ISO New England Manuals and ISO New England Administrative Procedures.

Emergency Energy is energy transferred from one control area operator to another in an Emergency.

Emergency Minimum Limit or Emergency Min means the minimum output, in MWs, that a Generator Asset can deliver for a limited period of time without exceeding specified limits of equipment stability and operating permits.

EMS is energy management system.

End-of-Round Price is the lowest price associated with a round of a Forward Capacity Auction, as described in Section III.13.2.3.1 of Market Rule 1.

End User Participant is defined in Section 1 of the Participants Agreement.

Energy is power produced in the form of electricity, measured in kilowatthours or megawatthours.

Energy Administration Service (EAS) is the service provided by the ISO, as described in Schedule 2 of Section IV.A of the Tariff.

Energy Component means the Locational Marginal Price at the reference point.

Energy Efficiency is installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy needed, while delivering a comparable or improved level of end-use service. Such measures include, but are not limited to, the installation of more energy efficient lighting, motors, refrigeration, HVAC equipment and control systems, envelope measures, operations and maintenance procedures, and industrial process equipment.

Energy Imbalance Service is the form of Ancillary Service described in Schedule 4 of the OATT.

Energy Market is, collectively, the Day-Ahead Energy Market and the Real-Time Energy Market.

Energy Non-Zero Spot Market Settlement Hours are the sum of the hours for which the Customer has a positive or negative Real-Time System Adjusted Net Interchange or for which the Customer has a positive or negative Real-Time Demand Reduction Obligation as determined by the ISO settlement process for the Energy Market.

Energy Offer Floor is negative \$150/MWh.

Energy Transaction Units (Energy TUs) are the sum for the month for a Customer of Bilateral Contract Block-Hours, Demand Bid Block-Hours, Asset Related Demand Bid Block-Hours, Supply Offer Block-Hours, Demand Reduction Offer Block-Hours, and Energy Non-Zero Spot Market Settlement Hours.

Equipment Damage Reimbursement is the compensation paid to the owner of a Designated Blackstart Resource as specified in Section 5.5 of Schedule 16 to the OATT.

Equivalent Demand Forced Outage Rate (EFORD) means the portion of time a unit is in demand, but is unavailable due to forced outages.

Estimated Capacity Load Obligation is, for the purposes of the ISO New England Financial Assurance Policy, a Market Participant's share of Zonal Capacity Obligation from the latest available month, adjusted as appropriate to account for any relevant Capacity Load Obligation Bilaterals, HQICCs, and Self-Supplied FCA Resource designations for the applicable month.

Establish Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.2.

Excepted Transaction is a transaction specified in Section II.40 of the Tariff for the applicable period specified in that Section.

Existing Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

Existing Capacity Qualification Package is information submitted for certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

Existing Capacity Resource is any resource that does not meet any of the eligibility criteria to participate in the Forward Capacity Auction as a New Capacity Resource.

Existing Capacity Retirement Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

Existing Capacity Retirement Package is information submitted for certain existing resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

Existing Demand Capacity Resource is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.2 of Market Rule 1.

Existing Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.2.1 of Market Rule 1.

Existing Import Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.1 of Market Rule 1.

Expedited Study Request is defined in Section II.34.7 of the OATT.

Export-Adjusted LSR is as defined in Section III.12.4(b)(ii).

Export Bid is a bid that may be submitted by certain resources in the Forward Capacity Auction to export capacity to an external Control Area, as described in Section III.13.1.2.3.1.3 of Market Rule 1.

Exports are Real-Time External Transactions, which are limited to sales from the New England Control Area, for exporting energy out of the New England Control Area.

External Elective Transmission Upgrade (External ETU) is defined in Section I of Schedule 25 of the OATT.

External Market Monitor means the person or entity appointed by the ISO Board of Directors pursuant to Section III.A.1.2 of Appendix A of Market Rule 1 to carry out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

External Node is a proxy bus or buses used for establishing a Locational Marginal Price for energy received by Market Participants from, or delivered by Market Participants to, a neighboring Control Area or for establishing Locational Marginal Prices associated with energy delivered through the New England Control Area by Non-Market Participants for use in calculating Non-Market Participant Congestion Costs and loss costs.

External Resource means a generation resource located outside the metered boundaries of the New England Control Area.

External Transaction is the import of external energy into the New England Control Area by a Market Participant or the export of internal energy out of the New England Control Area by a Market Participant in the Day-Ahead Energy Market and/or Real-Time Energy Market, or the wheeling of external energy through the New England Control Area by a Market Participant or a Non-Market Participant in the Real-Time Energy Market.

External Transaction Cap is \$2,000/MWh for External Transactions other than Coordinated External Transactions and \$1,000/MWh for Coordinated External Transactions.

External Transaction Floor is the Energy Offer Floor for External Transactions other than Coordinated External Transactions and negative \$1,000/MWh for Coordinated External Transactions.

External Transmission Project is a transmission project comprising facilities located wholly outside the New England Control Area and regarding which an agreement has been reached whereby New England ratepayers will support all or a portion of the cost of the facilities.

Facilities Study is an engineering study conducted pursuant to the OATT by the ISO (or, in the case of Local Service or interconnections to Local Area Facilities as defined in the TOA, by one or more affected PTOs) or some other entity designated by the ISO in consultation with any affected Transmission Owner(s), to determine the required modifications to the PTF and Non-PTF, including the cost and scheduled completion date for such modifications, that will be required to provide a requested transmission service or interconnection on the PTF and Non-PTF.

Facility and Equipment Testing means operation of a Resource to evaluate the functionality of the facility or equipment utilized in the operation of the facility.

Failure to Maintain Blackstart Capability is a failure of a Blackstart Owner or Designated Blackstart Resource to meet the Blackstart Service Minimum Criteria or Blackstart Service obligations, but does not include a Failure to Perform During a System Restoration event.

Failure to Perform During a System Restoration is a failure of a Blackstart Owner or Designated Blackstart Resource to follow ISO or Local Control Center dispatch instructions or perform in accordance with the dispatch instructions or the Blackstart Service Minimum Criteria and Blackstart Service obligations, described within the ISO New England Operating Documents, during a restoration of the New England Transmission System.

Fast Start Demand Response Resource is a Demand Response Resource that meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; (ii) Minimum Time Between Reductions does not exceed one hour; (iii) Demand Response Resource Start-Up Time plus Demand Response Resource Notification Time does not exceed 30 minutes; (iv) has personnel available to respond to Dispatch Instructions or has automatic remote response capability; and (v) is capable of receiving and acknowledging a Dispatch Instruction electronically.

Fast Start Generator means a Generator Asset that the ISO can dispatch to an on-line or off-line state through electronic dispatch and that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes; (iv) available for dispatch (when it is either in an on-line or off-line state) and manned or has automatic remote dispatch capability; and (v) capable of receiving and acknowledging a start-up or shut-down Dispatch Instruction electronically.

FCA Cleared Export Transaction is defined in Section III.1.10.7(f)(ii) of Market Rule 1.

FCA Qualified Capacity is the Qualified Capacity that is used in a Forward Capacity Auction.

FCM Capacity Charge Requirements are calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

FCM Charge Rate is calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

FCM Commercial Operation is defined in Section III.13.3.8 of Market Rule 1.

FCM Deposit is calculated in accordance with Section VII.B.1 of the ISO New England Financial Assurance Policy.

FCM Financial Assurance Requirements are described in Section VII of the ISO New England Financial Assurance Policy.

Final Forward Reserve Obligation is calculated in accordance with Section III.9.8(a) of Market Rule 1.

Financial Assurance Default results from a Market Participant or Non-Market Participant Transmission Customer's failure to comply with the ISO New England Financial Assurance Policy.

Financial Assurance Obligations relative to the ISO New England Financial Assurance Policy are determined in accordance with Section III.A(v) of the ISO New England Financial Assurance Policy.

Financial Transmission Right (FTR) is a financial instrument that evidences the rights and obligations specified in Sections III.5.2.2 and III.7 of the Tariff.

Firm Point-To-Point Service is service which is arranged for and administered between specified Points of Receipt and Delivery in accordance with Part II.C of the OATT.

Firm Transmission Service is Regional Network Service, Through or Out Service, service for Excepted Transactions, firm MTF Service, firm OTF Service, and firm Local Service.

Flexible DNE Dispatchable Generator is any DNE Dispatchable Generator that meets the following criteria: (i) Minimum Run Time does not exceed one hour; (ii) Minimum Down Time does not exceed one hour; and (iii) cold Notification Time plus cold Start-Up Time does not exceed 30 minutes.

Force Majeure - An event of Force Majeure means any act of God, labor disturbance, act of the public enemy or terrorists, war, invasion, insurrection, riot, fire, storm or flood, ice, explosion, breakage or accident to machinery or equipment, any curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond the control of the ISO, a Transmission Owner, a Schedule 20A Service Provider, or a Customer, including without limitation, in the case of the ISO, any action or inaction by a Customer, a Schedule 20A Service Provider, or a Transmission Owner, in the case of a Transmission Owner, any action or inaction by the ISO, any Customer, a Schedule 20A Service Provider, or any other Transmission Owner, in the case of a Schedule 20A Service Provider, any action or inaction by the ISO, any Customer, a Transmission Owner, or any other Schedule 20A Service Provider, and, in the case of a Transmission Customer, any action or inaction by the ISO, a Schedule 20A Service Provider, or any Transmission Owner.

Formal Warning is defined in Section III.B.4.1.1 of Appendix B of Market Rule 1.

Formula-Based Sanctions are defined in Section III.B.4.1.3 of Appendix B of Market Rule 1.

Forward Capacity Auction (FCA) is the annual Forward Capacity Market auction process described in Section III.13.2 of Market Rule 1.

Forward Capacity Auction Starting Price is calculated in accordance with Section III.13.2.4 of Market Rule 1.

Forward Capacity Market (FCM) is the forward market for procuring capacity in the New England Control Area, as described in Section III.13 of Market Rule 1.

Forward Energy Inventory Election is the total MWh value for which a Market Participant elects to be compensated at the forward rate in the inventoried energy program as described in Section III.K.1(d) of Market Rule 1.

Forward LNG Inventory Election is the portion of a Market Participant's Forward Energy Inventory Election attributed to liquefied natural gas in the inventoried energy program as described in Section III.K.1(d) of Market Rule 1.

Forward Reserve means TMNSR and TMOR purchased by the ISO on a forward basis on behalf of Market Participants as provided for in Section III.9 of Market Rule 1.

Forward Reserve Assigned Megawatts is the amount of Forward Reserve, in megawatts, that a Market Participant assigns to eligible Forward Reserve Resources to meet its Forward Reserve Obligation as defined in Section III.9.4.1 of Market Rule 1.

Forward Reserve Auction is the periodic auction conducted by the ISO in accordance with Section III.9 of Market Rule 1 to procure Forward Reserve.

Forward Reserve Auction Offers are offers to provide Forward Reserve to meet system and Reserve Zone requirements as submitted by a Market Participant in accordance with Section III.9.3 of Market Rule 1.

Forward Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Forward Reserve costs attributable to meeting the Forward Reserve requirement as calculated in accordance with Section III.9.9 of Market Rule 1.

Forward Reserve Clearing Price is the clearing price for TMNSR or TMOR, as applicable, for the system and each Reserve Zone resulting from the Forward Reserve Auction as defined in Section III.9.4 of Market Rule 1.

Forward Reserve Credit is the credit received by a Market Participant that is associated with that Market Participant's Final Forward Reserve Obligation as calculated in accordance with Section III.9.8 of Market Rule 1.

Forward Reserve Delivered Megawatts are calculated in accordance with Section III.9.6.5 of Market Rule 1.

Forward Reserve Delivery Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Failure-to-Activate Megawatts are calculated in accordance with Section III.9.7.2(a) of Market Rule 1.

Forward Reserve Failure-to-Activate Penalty is the penalty associated with a Market Participant's failure to activate Forward Reserve when requested to do so by the ISO and is defined in Section III.9.7.2 of Market Rule 1.

Forward Reserve Failure-to-Activate Penalty Rate is specified in Section III.9.7.2 of Market Rule 1.

Forward Reserve Failure-to-Reserve, as specified in Section III.9.7.1 of Market Rule 1, occurs when a Market Participant's Forward Reserve Delivered Megawatts for a Reserve Zone in an hour is less than that Market Participant's Forward Reserve Obligation for that Reserve Zone in that hour. Under these circumstances the Market Participant pays a penalty based upon the Forward Reserve Failure-to-Reserve Penalty Rate and that Market Participant's Forward Reserve Failure-to-Reserve Megawatts.

Forward Reserve Failure-to-Reserve Megawatts are calculated in accordance with Section III.9.7.1(a) of Market Rule 1.

Forward Reserve Failure-to-Reserve Penalty is the penalty associated with a Market Participant's failure to reserve Forward Reserve and is defined in Section III.9.7.1 of Market Rule 1.

Forward Reserve Failure-to-Reserve Penalty Rate is specified in Section III.9.7.1(b)(ii) of Market Rule 1.

Forward Reserve Fuel Index is the index or set of indices used to calculate the Forward Reserve Threshold Price as defined in Section III.9.6.2 of Market Rule 1.

Forward Reserve Heat Rate is the heat rate as defined in Section III.9.6.2 of Market Rule 1 that is used to calculate the Forward Reserve Threshold Price.

Forward Reserve Market is a market for forward procurement of two reserve products, Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

Forward Reserve MWs are those megawatts assigned to specific eligible Forward Reserve Resources which convert a Forward Reserve Obligation into a Resource-specific obligation.

Forward Reserve Obligation is a Market Participant's amount, in megawatts, of Forward Reserve that cleared in the Forward Reserve Auction and adjusted, as applicable, to account for bilateral transactions that transfer Forward Reserve Obligations.

Forward Reserve Obligation Charge is defined in Section III.10.4 of Market Rule 1.

Forward Reserve Offer Cap is \$9,000/megawatt-month.

Forward Reserve Payment Rate is defined in Section III.9.8 of Market Rule 1.

Forward Reserve Procurement Period is defined in Section III.9.1 of Market Rule 1.

Forward Reserve Qualifying Megawatts refer to all or a portion of a Forward Reserve Resource's capability offered into the Real-Time Energy Market at energy offer prices above the applicable Forward Reserve Threshold Price that are calculated in accordance with Section III.9.6.4 of Market Rule 1.

Forward Reserve Resource is a Resource that meets the eligibility requirements defined in Section III.9.5.2 of Market Rule 1 that has been assigned Forward Reserve Obligation by a Market Participant.

Forward Reserve Threshold Price is the minimum price at which assigned Forward Reserve Megawatts are required to be offered into the Real-Time Energy Market as calculated in Section III.9.6.2 of Market Rule 1.

FTR Auction is the periodic auction of FTRs conducted by the ISO in accordance with Section III.7 of Market Rule 1.

FTR Auction Revenue is the revenue collected from the sale of FTRs in FTR Auctions. FTR Auction Revenue is payable to FTR Holders who submit their FTRs for sale in the FTR Auction in accordance with Section III.7 of Market Rule 1 and to ARR Holders and Incremental ARR Holders in accordance with Appendix C of Market Rule 1.

FTR Credit Test Percentage is calculated in accordance with Section III.B.1(b) of the ISO New England Financial Assurance Policy.

FTR Financial Assurance Requirements are described in Section VI of the ISO New England Financial Assurance Policy.

FTR Holder is an entity that acquires an FTR through the FTR Auction to Section III.7 of Market Rule 1 and registers with the ISO as the holder of the FTR in accordance with Section III.7 of Market Rule 1 and applicable ISO New England Manuals.

FTR-Only Customer is a Market Participant that transacts in the FTR Auction and that does not participate in other markets or programs of the New England Markets. References in this Tariff to a “Non-Market Participant FTR Customers” and similar phrases shall be deemed references to an FTR-Only Customer.

FTR Settlement Risk Financial Assurance is an amount of financial assurance required by a Designated FTR Participant for each bid submission into an FTR Auction and for each bid awarded to the individual participant in an FTR Auction. This amount is calculated pursuant to Section VI.A of the ISO New England Financial Assurance Policy.

GADS Data means data submitted to the NERC for collection into the NERC’s Generating Availability Data System (GADS).

Gap Request for Proposals (Gap RFP) is defined in Section III.11 of Market Rule 1.

Gas Day means a period of 24 consecutive hours beginning at 0900 hrs Central Time.

Generating Capacity Resource means a New Generating Capacity Resource or an Existing Generating Capacity Resource.

Generator Asset is a device (or a collection of devices) that is capable of injecting real power onto the grid that has been registered as a Generator Asset in accordance with the Asset Registration Process.

Generator Imbalance Service is the form of Ancillary Service described in Schedule 10 of the OATT.

Generator Interconnection Related Upgrade is an addition to or modification of the New England Transmission System (pursuant to Section II.47.1, Schedule 22 or Schedule 23 of the OATT) to effect the interconnection of a new generating unit or an existing generating unit whose energy capability or capacity capability is being materially changed and increased whether or not the interconnection is being effected to meet the Capacity Capability Interconnection Standard or the Network Capability Interconnection Standard. As to Category A Projects (as defined in Schedule 11 of the OATT), a Generator Interconnection Related Upgrade also includes an upgrade beyond that required to satisfy the Network Capability Interconnection Standard (or its predecessor) for which the Generator Owner has committed to pay prior to October 29, 1998.

Generator Owner is the owner, in whole or part, of a generating unit whether located within or outside the New England Control Area.

Good Utility Practice means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather includes all acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act Section 215(a)(4).

Governance Only Member is defined in Section 1 of the Participants Agreement.

Governance Participant is defined in the Participants Agreement.

Governing Documents, for the purposes of the ISO New England Billing Policy, are the Transmission, Markets and Services Tariff and ISO Participants Agreement.

Governing Rating is the lowest corporate rating from any Rating Agency for that Market Participant, or, if the Market Participant has no corporate rating, then the lowest rating from any Rating Agency for that Market Participant's senior unsecured debt.

Grandfathered Agreements (GAs) is a transaction specified in Section II.45 for the applicable period specified in that Section.

Grandfathered Intertie Agreement (GIA) is defined pursuant to the TOA.

Handy-Whitman Index of Public Utility Construction Costs is the Total Other Production Plant index shown in the Cost Trends of Electric Utility Construction for the North Atlantic Region as published in the Handy-Whitman Index of Public Utility Construction Costs.

Highgate Transmission Facilities (HTF) are existing U. S.-based transmission facilities covered under the Agreement for Joint Ownership, Construction and Operation of the Highgate Transmission Interconnection dated as of August 1, 1984 including (1) the whole of a 200 megawatt high-voltage, back-to-back, direct-current converter facility located in Highgate, Vermont and (2) a 345 kilovolt transmission line within Highgate and Franklin, Vermont (which connects the converter facility at the U.S.-Canadian border to a Hydro-Quebec 120 kilovolt line in Bedford, Quebec). The HTF include any upgrades associated with increasing the capacity or changing the physical characteristics of these facilities as defined in the above stated agreement dated August 1, 1984 until the Operations Date, as defined in the TOA. The current HTF rating is a nominal 225 MW. The HTF are not defined as PTF. Coincident with the Operations Date and except as stipulated in Schedules, 9, 12, and Attachment F to the OATT, HTF shall be treated in the same manner as PTF for purposes of the OATT and all references to PTF in the OATT shall be deemed to apply to HTF as well. The treatment of the HTF is not intended to establish any binding precedent or presumption with regard to the treatment for other transmission facilities within the New England Transmission System (including HVDC, MTF, or Control Area Interties) for purposes of the OATT.

Host Participant or Host Utility is a Market Participant or a Governance Participant transmission or distribution provider that reconciles the loads within the metering domain with OP-18 compliant metering.

Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Hourly PER is calculated in accordance with Section III.13.7.1.2.1 of Market Rule 1.

Hourly Requirements are determined in accordance with Section III.A(i) of the ISO New England Financial Assurance Policy.

Hourly Shortfall NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Hub is a specific set of pre-defined Nodes for which a Locational Marginal Price will be calculated for the Day-Ahead Energy Market and Real-Time Energy Market and which can be used to establish a reference price for energy purchases and the transfer of Day-Ahead Adjusted Load Obligations and Real-Time Adjusted Load Obligations and for the designation of FTRs.

Hub Price is calculated in accordance with Section III.2.8 of Market Rule 1.

HQ Interconnection Capability Credit (HQICC) is a monthly value reflective of the annual installed capacity benefits of the Phase I/II HVDC-TF, as determined by the ISO, using a standard methodology on file with the Commission, in conjunction with the setting of the Installed Capacity Requirement. An appropriate share of the HQICC shall be assigned to an IRH if the Phase I/II HVDC-TF support costs are paid by that IRH and such costs are not included in the calculation of the Regional Network Service rate. The share of HQICC allocated to such an eligible IRH for a month is the sum in kilowatts of (1)(a) the IRH's percentage share, if any, of the Phase I Transfer Capability times (b) the Phase I Transfer Credit, plus (2)(a) the IRH's percentage share, if any, of the Phase II Transfer Capability, times (b) the Phase II Transfer Credit. The ISO shall establish appropriate HQICCs to apply for an IRH which has such a percentage share.

Import Capacity Resource means an Existing Import Capacity Resource or a New Import Capacity Resource offered to provide capacity in the New England Control Area from an external Control Area.

Inadvertent Energy Revenue is defined in Section III.3.2.1(o) of Market Rule 1.

Inadvertent Energy Revenue Charges or Credits is defined in Section III.3.2.1(p) of Market Rule 1.

Inadvertent Interchange means the difference between net actual energy flow and net scheduled energy flow into or out of the New England Control Area.

Increment Offer means an offer to sell energy at a specified Location in the Day-Ahead Energy Market which is not associated with a physical supply. An accepted Increment Offer results in scheduled supply at the specified Location in the Day-Ahead Energy Market.

Incremental ARR is an ARR provided in recognition of a participant-funded transmission system upgrade pursuant to Appendix C of this Market Rule.

Incremental ARR Holder is an entity which is the record holder of an Incremental Auction Revenue Right in the register maintained by the ISO.

Incremental Cost of Reliability Service is described in Section III.13.2.5.2.5.2 of Market Rule 1.

Independent Transmission Company (ITC) is a transmission entity that assumes certain responsibilities in accordance with Section 10.05 of the Transmission Operating Agreement and Attachment M to the OATT, subject to the acceptance or approval of the Commission and a finding of the Commission that the transmission entity satisfies applicable independence requirements.

Information Request is a request from a potential Disputing Party submitted in writing to the ISO for access to Confidential Information.

Initial Market Participant Financial Assurance Requirement is calculated for new Market Participants and Returning Market Participants, other than an FTR-Only Customer or a Governance Only Member, according to Section IV of the ISO New England Financial Assurance Policy.

Installed Capacity Requirement means the level of capacity required to meet the reliability requirements defined for the New England Control Area, as described in Section III.12 of Market Rule 1.

Interchange Transactions are transactions deemed to be effected under Market Rule 1.

Interconnecting Transmission Owner has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Agreement is the “Large Generator Interconnection Agreement”, the “Small Generator Interconnection Agreement”, or the “Elective Transmission Upgrade Interconnection Agreement” pursuant to Schedules 22, 23 or 25 of the ISO OATT or an interconnection agreement approved by the Commission prior to the adoption of the Interconnection Procedures.

Interconnection Customer has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Interconnection Feasibility Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Interconnection Procedure is the “Large Generator Interconnection Procedures”, the “Small Generator Interconnection Procedures”, or the “Elective Transmission Upgrade Interconnection Procedures” pursuant to Schedules 22, 23, and 25 of the ISO OATT.

Interconnection Reliability Operating Limit (IROL) has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

Interconnection Request has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, or Section I of Schedule 25 of the OATT.

Interconnection Rights Holder(s) (IRH) has the meaning given to it in Schedule 20A to Section II of this Tariff.

Interconnection System Impact Study Agreement has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23 and Section I of Schedule 25 of the OATT.

Interest is interest calculated in the manner specified in Section II.8.3.

Interface Bid is a unified real-time bid to simultaneously purchase and sell energy on each side of an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented.

Intermittent Power Resource is a wind, solar, run of river hydro or other renewable resource that does not have control over its net power output.

Internal Bilateral for Load is an internal bilateral transaction under which the buyer receives a reduction in Real-Time Load Obligation and the seller receives a corresponding increase in Real-Time Load Obligation in the amount of the sale, in MWs. An Internal Bilateral for Load transaction is only applicable in the Real-Time Energy Market.

Internal Bilateral for Market for Energy is an internal bilateral transaction for Energy which applies in the Day-Ahead Energy Market and Real-Time Energy Market or just the Real-Time Energy Market under which the buyer receives a reduction in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation and the seller receives a corresponding increase in Day-Ahead Adjusted Load Obligation and Real-Time Adjusted Load Obligation in the amount of the sale, in MWs.

Internal Elective Transmission Upgrade (Internal ETU) is defined in Section I of Schedule 25 of the OATT.

Internal Market Monitor means the department of the ISO responsible for carrying out the market monitoring and mitigation functions specified in Appendix A and elsewhere in Market Rule 1.

Interregional Planning Stakeholder Advisory Committee (IPSAC) is the committee described as such in the Northeast Planning Protocol.

Interregional Transmission Project is a transmission project located within the New England Control Area and one or more of the neighboring transmission planning regions.

Interruption Cost is the amount, in dollars, that must be paid to a Market Participant each time the Market Participant's Demand Response Resource is scheduled or dispatched in the New England Markets to reduce demand.

Inventoried Energy Day is an Operating Day that occurs in the months of December, January, or February during the winters of 2023-2024 and 2024-2025 (inventoried energy program) and for which the average of the high temperature and the low temperature on that Operating Day, as measured and reported by the National Weather Service at Bradley International Airport in Windsor Locks, Connecticut, is less than or equal to 17 degrees Fahrenheit, as described in Section III.K.3.1 of Market Rule 1.

Investment Grade Rating, for a Market (other than an FTR-Only Customer) or Non-Market Participant Transmission Customer, is either (a) a corporate investment grade rating from one or more of the Rating Agencies, or (b) if the Market Participant or Non-Market Participant Transmission Customer does not have a corporate rating from one of the Rating Agencies, then an investment grade rating for the Market Participant's or Non-Market Participant Transmission Customer's senior unsecured debt from one or more of the Rating Agencies.

Invoice is a statement issued by the ISO for the net Charge owed by a Covered Entity pursuant to the ISO New England Billing Policy.

Invoice Date is the day on which the ISO issues an Invoice.

ISO means ISO New England Inc.

ISO Charges, for the purposes of the ISO New England Billing Policy, are both Non-Hourly Charges and Hourly Charges.

ISO Control Center is the primary control center established by the ISO for the exercise of its Operating Authority and the performance of functions as an RTO.

ISO-Initiated Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.4.

ISO New England Administrative Procedures means procedures adopted by the ISO to fulfill its responsibilities to apply and implement ISO New England System Rules.

ISO New England Billing Policy is Exhibit ID to Section I of the Transmission, Markets and Services Tariff.

ISO New England Filed Documents means the Transmission, Markets and Services Tariff, including but not limited to Market Rule 1, the Participants Agreement, the Transmission Operating Agreement or other documents that affect the rates, terms and conditions of service.

ISO New England Financial Assurance Policy is Exhibit IA to Section I of the Transmission, Markets and Services Tariff.

ISO New England Information Policy is the policy establishing guidelines regarding the information received, created and distributed by Market Participants and the ISO in connection with the settlement, operation and planning of the System, as the same may be amended from time to time in accordance with the provisions of this Tariff. The ISO New England Information Policy is Attachment D to the Transmission, Markets and Services Tariff.

ISO New England Manuals are the manuals implementing Market Rule 1, as amended from time to time in accordance with the Participants Agreement. Any elements of the ISO New England Manuals that substantially affect rates, terms, and/or conditions of service shall be filed with the Commission under Section 205 of the Federal Power Act.

ISO New England Operating Documents are the Tariff and the ISO New England Operating Procedures.

ISO New England Operating Procedures (OPs) are the ISO New England Planning Procedures and the operating guides, manuals, procedures and protocols developed and utilized by the ISO for operating the ISO bulk power system and the New England Markets.

ISO New England Planning Procedures are the procedures developed and utilized by the ISO for planning the ISO bulk power system.

ISO New England System Rules are Market Rule 1, the ISO New England Information Policy, the ISO New England Administrative Procedures, the ISO New England Manuals and any other system rules, procedures or criteria for the operation of the New England Transmission System and administration of the New England Markets and the Transmission, Markets and Services Tariff.

ITC Agreement is defined in Attachment M to the OATT.

ITC Rate Schedule is defined in Section 3.1 of Attachment M to the OATT.

ITC System is defined in Section 2.2 of Attachment M to the OATT.

ITC System Planning Procedures is defined in Section 15.4 of Attachment M to the OATT.

Joint ISO/RTO Planning Committee (JIPC) is the committee described as such in the Northeastern Planning Protocol.

Late Payment Account is a segregated interest-bearing account into which the ISO deposits Late Payment Charges due from ISO Charges and interest owed from participants for late payments that are collected and not distributed to the Covered Entities, until the Late Payment Account Limit is reached, under the ISO New England Billing Policy and penalties collected under the ISO New England Financial Assurance Policy.

Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Lead Market Participant, for purposes other than the Forward Capacity Market, is the entity authorized to submit Supply Offers, Demand Bids or Demand Reduction Offers for a Resource and to whom certain Energy TUs are assessed under Schedule 2 of Section IV.A of the Tariff. For purposes of the Forward Capacity Market, the Lead Market Participant is the entity designated to participate in that market on behalf of an Existing Capacity Resource or a New Capacity Resource.

Limited Energy Resource means a Generator Asset that, due to design considerations, environmental restriction on operations, cyclical requirements, such as the need to recharge or refill or manage water flow, or fuel limitations, are unable to operate continuously at full output on a daily basis.

Load Asset means a physical load that has been registered in accordance with the Asset Registration Process. A Load Asset can be an Asset Related Demand, including a Dispatchable Asset Related Demand.

Load Management means measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that curtail electrical usage or shift electrical usage while delivering a comparable or acceptable level of end-use service. Such measures include, but are not limited to, energy management systems, load control end-use cycling, load curtailment strategies, and energy storage that curtails or shifts electrical usage by means other than generating electricity.

Load Shedding is the systematic reduction of system demand by temporarily decreasing load.

Load Zone is a Reliability Region, except as otherwise provided for in Section III.2.7 of Market Rule 1.

Local Area Facilities are defined in the TOA.

Local Benefit Upgrade(s) (LBU) is an upgrade, modification or addition to the transmission system that is: (i) rated below 115kV or (ii) rated 115kV or above and does not meet all of the non-voltage criteria for PTF classification specified in the OATT.

Local Control Centers are those control centers in existence as of the effective date of the OATT (including the CONVEX, REMVEC, Maine and New Hampshire control centers) or established by the PTOs in accordance with the TOA that are separate from the ISO Control Center and perform certain functions in accordance with the OATT and the TOA.

Local Delivery Service is the service of delivering electric energy to end users. This service is subject to state jurisdiction regardless of whether such service is provided over local distribution or transmission facilities. An entity that is an Eligible Customer under the OATT is not excused from any requirements of state law, or any order or regulation issued pursuant to state law, to arrange for Local Delivery Service with the Participating Transmission Owner and/or distribution company providing such service and to pay all applicable charges associated with such service, including charges for stranded costs and benefits.

Local Network is defined as the transmission facilities constituting a local network as identified in Attachment E, as such Attachment may be modified from time to time in accordance with the Transmission Operating Agreement.

Local Network Load is the load that a Network Customer designates for Local Network Service under Schedule 21 to the OATT.

Local Network RNS Rate is the rate applicable to Regional Network Service to effect a delivery to load in a particular Local Network, as determined in accordance with Schedule 9 to the OATT.

Local Network Service (LNS) is the network service provided under Schedule 21 and the Local Service Schedules to permit the Transmission Customer to efficiently and economically utilize its resources to serve its load.

Local Point-To-Point Service (LPTP) is Point-to-Point Service provided under Schedule 21 of the OATT and the Local Service Schedules to permit deliveries to or from an interconnection point on the PTF.

Local Public Policy Transmission Upgrade is any addition and/or upgrade to the New England Transmission System with a voltage level below 115kV that is required in connection with the construction of a Public Policy Transmission Upgrade approved for inclusion in the Regional System Plan pursuant to Attachment K to the ISO OATT or included in a Local System Plan in accordance with Appendix 1 to Attachment K.

Local Resource Adequacy Requirement is calculated pursuant to Section III.12.2.1.1.

Local Second Contingency Protection Resources are those Resources identified by the ISO on a daily basis as necessary for the provision of Operating Reserve requirements and adherence to NERC, NPCC and ISO reliability criteria over and above those Resources required to meet first contingency reliability criteria within a Reliability Region.

Local Service is transmission service provided under Schedule 21 and the Local Service Schedules thereto.

Local Service Schedule is a PTO-specific schedule to the OATT setting forth the rates, charges, terms and conditions applicable to Local Service.

Local Sourcing Requirement (LSR) is a value calculated as described in Section III.12.2.1 of Market Rule 1.

Local System Planning (LSP) is the process defined in Appendix 1 of Attachment K to the OATT.

Localized Costs are costs that the ISO, with advisory input from the Reliability Committee, determines in accordance with Schedule 12C of the OATT shall not be included in the Pool-Supported PTF costs recoverable under this OATT, or in costs allocated to Regional Network Load according to Section 6 of Schedule 12. If there are any Localized Costs, the ISO shall identify them in the Regional System Plan.

Location is a Node, External Node, Load Zone, DRR Aggregation Zone, or Hub.

Locational Marginal Price (LMP) is defined in Section III.2 of Market Rule 1. The Locational Marginal Price for a Node is the nodal price at that Node; the Locational Marginal Price for an External Node is the nodal price at that External Node; the Locational Marginal Price for a Load Zone, DRR Aggregation Zone or Reliability Region is the Zonal Price for that Load Zone, DRR Aggregation Zone or Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub.

Long Lead Time Facility (Long Lead Facility) has the meaning specified in Section I of Schedule 22 and Schedule 25 of the OATT.

Long-Term is a term of one year or more.

Long-Term Transmission Outage is a long-term transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Loss Component is the component of the nodal LMP at a given Node or External Node on the PTF that reflects the cost of losses at that Node or External Node relative to the reference point. The Loss Component of the nodal LMP at a given Node on the non-PTF system reflects the relative cost of losses at that Node adjusted as required to account for losses on the non-PTF system already accounted for through tariffs associated with the non-PTF. When used in connection with Hub Price or Zonal Price, the term Loss Component refers to the Loss Components of the nodal LMPs that comprise the Hub Price or Zonal Price, which Loss Components are averaged or weighted in the same way that nodal LMPs are averaged to determine Hub Price or weighted to determine Zonal Price.

Loss of Load Expectation (LOLE) is the probability of disconnecting non-interruptible customers due to a resource deficiency.

Lost Opportunity Cost (LOC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

LSE means load serving entity.

Lump Sum Blackstart Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Lump Sum Blackstart Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Manual Response Rate is the rate, in MW/Minute, at which the output of a Generator Asset, or the consumption of a Dispatchable Asset Related Demand, is capable of changing.

Marginal Loss Revenue Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Marginal Reliability Impact is the change, with respect to an increment of capacity supply, in expected unserved energy due to resource deficiency, as measured in hours per year.

Market Credit Limit is a credit limit for a Market Participant's Financial Assurance Obligations (except FTR Financial Assurance Requirements) established for each Market Participant in accordance with Section II.C of the ISO New England Financial Assurance Policy.

Market Credit Test Percentage is calculated in accordance with Section III.B.1(a) of the ISO New England Financial Assurance Policy.

Market Efficiency Transmission Upgrade is defined as those additions and upgrades that are not related to the interconnection of a generator, and, in the ISO's determination, are designed to reduce bulk power system costs to load system-wide, where the net present value of the reduction in bulk power system costs to load system-wide exceeds the net present value of the cost of the transmission addition or upgrade. For purposes of this definition, the term "bulk power system costs to load system-wide"

includes, but is not limited to, the costs of energy, capacity, reserves, losses and impacts on bilateral prices for electricity.

Market Participant is a participant in the New England Markets (including a FTR-Only Customer) that has executed a Market Participant Service Agreement, or on whose behalf an unexecuted Market Participant Service Agreement has been filed with the Commission.

Market Participant Financial Assurance Requirement is defined in Section III of the ISO New England Financial Assurance Policy.

Market Participant Obligations is defined in Section III.B.1.1 of Appendix B of Market Rule 1.

Market Participant Service Agreement (MPSA) is an agreement between the ISO and a Market Participant, in the form specified in Attachment A or Attachment A-1 to the Tariff, as applicable.

Market Rule 1 is ISO Market Rule 1 and appendices set forth in Section III of this ISO New England Inc. Transmission, Markets and Services Tariff, as it may be amended from time to time.

Market Violation is a tariff violation, violation of a Commission-approved order, rule or regulation, market manipulation, or inappropriate dispatch that creates substantial concerns regarding unnecessary market inefficiencies.

Material Adverse Change is any change in financial status including, but not limited to a downgrade to below an Investment Grade Rating by any Rating Agency, being placed on credit watch with negative implication by any Rating Agency if the Market Participant or Non-Market Participant Transmission Customer does not have an Investment Grade Rating, a bankruptcy filing or other insolvency, a report of a significant quarterly loss or decline of earnings, the resignation of key officer(s), the sanctioning of the Market Participant or Non-Market Participant Transmission Customer or any of its Principles imposed by the Federal Energy Regulatory Commission, the Securities Exchange Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; the filing of a material lawsuit that could materially adversely impact current or future financial results; a significant change in the Market Participant's or Non-Market Participant Transmission Customer's credit default spreads; or a significant change in market capitalization.

Material Adverse Impact is defined, for purposes of review of ITC-proposed plans, as a proposed facility or project will be deemed to cause a “material adverse impact” on facilities outside of the ITC System if: (i) the proposed facility or project causes non-ITC facilities to exceed their capabilities or exceed their thermal, voltage or stability limits, consistent with all applicable reliability criteria, or (ii) the proposed facility or project would not satisfy the standards set forth in Section I.3.9 of the Transmission, Markets and Services Tariff. This standard is intended to assure the continued service of all non-ITC firm load customers and the ability of the non-ITC systems to meet outstanding transmission service obligations.

Maximum Capacity Limit is a value calculated as described in Section III.12.2.2 of Market Rule 1.

Maximum Consumption Limit is the maximum amount, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD’s Offer Data. A Market Participant must maintain an up-to-date Maximum Consumption Limit (and where applicable, must provide the ISO with any telemetry required by ISO New England Operating Procedure No. 18 to allow the ISO to maintain an updated Maximum Consumption Limit) for all hours in which a DARD has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Maximum Daily Consumption Limit is the maximum amount of megawatt-hours that a Storage DARD expects to be able to consume in the next Operating Day.

Maximum Facility Load is the highest demand of an end-use customer facility since the start of the prior calendar year (or, if unavailable, an estimate thereof), where the demand evaluated is established by adding metered demand measured at the Retail Delivery Point and the output of all generators located behind the Retail Delivery Point in the same time intervals.

Maximum Interruptible Capacity is an estimate of the maximum demand reduction and Net Supply that a Demand Response Asset can deliver, as measured at the Retail Delivery Point.

Maximum Load is the highest demand since the start of the prior calendar year (or, if unavailable, an estimate thereof), as measured at the Retail Delivery Point.

Maximum Number of Daily Starts is the maximum number of times that a Binary Storage DARD or a Generator Asset can be started or that a Demand Response Resource can be interrupted in the next Operating Day under normal operating conditions.

Maximum Reduction is the maximum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Measure Life is the estimated time an On-Peak Demand Resource or Seasonal Peak Demand Resource measure will remain in place, or the estimated time period over which the facility, structure, equipment or system in which a measure is installed continues to exist, whichever is shorter. Suppliers of On-Peak Demand Resources or Seasonal Peak Demand Resources comprised of an aggregation of measures with varied Measures Lives shall determine and document the Measure Life either: (i) for each type of measure with a different Measure Life and adjust the aggregate performance based on the individual measure life calculation in the portfolio; or (ii) as the average Measure Life for the aggregated measures as long as the demand reduction capability of the resource is greater than or equal to the amount that cleared in the Forward Capacity Auction or reconfiguration auction for the entire Capacity Commitment Period, and the demand reduction capability for an Existing On-Peak Demand Resource or Existing Seasonal Peak Demand Resource is not over-stated in a subsequent Capacity Commitment Period. Measure Life shall be determined consistent with the resource's Measurement and Verification Plan, which shall be reviewed by the ISO to ensure consistency with the measurement and verification requirements of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Documents mean the measurement and verification documents described in Section 13.1.4.3.1 of Market Rule 1 that are submitted by On-Peak Demand Resources and Seasonal Peak Demand Resources, which include Measurement and Verification Plans, Updated Measurement and Verification Plans, Measurement and Verification Summary Reports, and Measurement and Verification Reference Reports.

Measurement and Verification Plan means the measurement and verification plan submitted by an On-Peak Demand Resource or Seasonal Peak Demand Resource as part of the qualification process for the Forward Capacity Auction pursuant to the requirements of Section III.13.1.4.3 of Market Rule 1 and the ISO New England Manuals.

Measurement and Verification Reference Reports are optional reports submitted by On-Peak Demand Resources or Seasonal Peak Demand Resources during the Capacity Commitment Period subject to the schedule in the Measurement and Verification Plan and consistent with the schedule and reporting standards set forth in the ISO New England Manuals. Measurement and Verification Reference Reports update the prospective demand reduction capability of the On-Peak Demand Resource or Seasonal Peak Demand Resource project based on measurement and verification studies performed during the Capacity Commitment Period.

Measurement and Verification Summary Report is the monthly report submitted by an On-Peak Demand Resource or Seasonal Peak Demand Resource with the monthly settlement report for the Forward Capacity Market, which documents the total demand reduction capability for all On-Peak Demand Resources and Seasonal Peak Demand Resources in operation as of the end of the previous month.

MEPCO Grandfathered Transmission Service Agreement (MG TSA) is a MEPCO long-term firm point-to-point transmission service agreement with a POR or POD at the New Brunswick border and a start date prior to June 1, 2007 where the holder has elected, by written notice delivered to MEPCO within five (5) days following the filing of the settlement agreement in Docket Nos. ER07-1289 and EL08-56 or by September 1, 2008 (whichever is later), MG TSA treatment as further described in Section II.45.1.

Merchant Transmission Facilities (MTF) are the transmission facilities owned by MTOs, defined and classified as MTF pursuant to Schedule 18 of the OATT, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in a MTOA or Attachment K to the OATT, rated 69 kV or above and required to allow energy from significant power sources to move freely on the New England Transmission System.

Merchant Transmission Facilities Provider (MTF Provider) is an entity as defined in Schedule 18 of the OATT.

Merchant Transmission Facilities Service (MTF Service) is transmission service over MTF as provided for in Schedule 18 of the OATT.

Merchant Transmission Operating Agreement (MTOA) is an agreement between the ISO and an MTO with respect to its MTF.

Merchant Transmission Owner (MTO) is an owner of MTF.

Meter Data Error means an error in meter data, including an error in Coincident Peak Contribution values, on an Invoice issued by the ISO after the completion of the Data Reconciliation Process as described in the ISO New England Manuals and in Section III.3.8 of Market Rule 1.

Meter Data Error RBA Submission Limit means the date thirty 30 calendar days after the issuance of the Invoice containing the results of the Data Reconciliation Process as described in the ISO New England Manuals and in Section III.3.6 of Market Rule 1.

Metered Quantity For Settlement is defined in Section III.3.2.1.1 of Market Rule 1.

Minimum Consumption Limit is (a) the lowest consumption level, in MW, available for economic dispatch from a DARD and is based on the physical characteristics as submitted as part of the DARD's Offer Data, and (b) for a DARD undergoing Facility and Equipment Testing or auditing, the level to which the DARD requests and is approved to operate or is directed to operate for purposes of completing the Facility and Equipment Testing or auditing.

Minimum Down Time is the number of hours that must elapse after a Generator Asset or Storage DARD has been released for shutdown at or below its Economic Minimum Limit or Minimum Consumption Limit before the Generator Asset or Storage DARD can be brought online and be released for dispatch at its Economic Minimum Limit or Minimum Consumption Limit.

Minimum Generation Emergency means an Emergency declared by the ISO in which the ISO anticipates requesting one or more Generator Assets to operate at or below Economic Minimum Limit in order to manage, alleviate, or end the Emergency.

Minimum Generation Emergency Credits are those Real-Time Dispatch NCPC Credits calculated pursuant to Appendix F of Market Rule 1 for resources within a reliability region that are dispatched during a period for which a Minimum Generation Emergency has been declared.

Minimum Reduction is the minimum available demand reduction, in MW, of a Demand Response Resource that a Market Participant offers to deliver in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the Demand Response Resource's Demand Reduction Offer.

Minimum Reduction Time is the minimum number of hours of demand reduction at or above the Minimum Reduction for which the ISO must dispatch a Demand Response Resource to reduce demand.

Minimum Run Time is the number of hours that a Generator Asset must remain online after it has been scheduled to reach its Economic Minimum Limit before it can be released for shutdown from its Economic Minimum Limit or the number of hours that must elapse after a Storage DARD has been scheduled to consume at its Minimum Consumption Limit before it can be released for shutdown.

Minimum Time Between Reductions is the number of hours that must elapse after a Demand Response Resource has received a Dispatch Instruction to stop reducing demand before the Demand Response Resource can achieve its Minimum Reduction after receiving a Dispatch Instruction to start reducing demand.

Minimum Total Reserve Requirement, which does not include Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Monthly Blackstart Service Charge is the charge made to Transmission Customers pursuant to Section 6 of Schedule 16 to the OATT.

Monthly Capacity Payment is the Forward Capacity Market payment described in Section III.13.7.3 of Market Rule 1.

Monthly Peak is defined in Section II.21.2 of the OATT.

Monthly PER is calculated in accordance with Section III.13.7.1.2.2 of Market Rule 1.

Monthly Real-Time Demand Reduction Obligation is the absolute value of a Customer's hourly Real-Time Demand Reduction Obligation summed for all hours in a month, in MWhs.

Monthly Real-Time Generation Obligation is the sum, for all hours in a month, at all Locations, of a Customer's Real-Time Generation Obligation, in MWhs.

Monthly Real-Time Load Obligation is the absolute value of a Customer's hourly Real-Time Load Obligation summed for all hours in a month, in MWhs.

Monthly Regional Network Load is defined in Section II.21.2 of the OATT.

Monthly Statement is the first weekly Statement issued on a Monday after the tenth of a calendar month that includes both the Hourly Charges for the relevant billing period and Non-Hourly Charges for the immediately preceding calendar month.

MRI Transition Period is the period specified in Section III.13.2.2.1.

MUI is the market user interface.

Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

MW is megawatt.

MWh is megawatt-hour.

Native Load Customers are the wholesale and retail power customers of a Transmission Owner on whose behalf the Transmission Owner, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate its system to meet the reliable electric needs of such customers.

NCPC Charge means the charges to Market Participants calculated pursuant to Appendix F to Market Rule 1.

NCPC Credit means the credits to Market Participants calculated pursuant to Appendix F to Market Rule 1.

Needs Assessment is defined in Section 4.1 of Attachment K to the OATT.

NEMA, for purposes of Section III of the Tariff, is the Northeast Massachusetts Reliability Region.

NEMA Contract is a contract described in Appendix C of Market Rule 1 and listed in Exhibit 1 of Appendix C of Market Rule 1.

NEMA Load Serving Entity (NEMA LSE) is a Transmission Customer or Congestion Paying LSE Entity that serves load within NEMA.

NEMA or Northeast Massachusetts Upgrade, for purposes of Section II of the Tariff, is an addition to or modification of the PTF into or within the Northeast Massachusetts Reliability Region that was not, as of December 31, 1999, the subject of a System Impact Study or application filed pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff; that is not related to generation interconnections; and that will be completed and placed in service by June 30, 2004. Such upgrades include, but are not limited to, new transmission facilities and related equipment and/or modifications to existing transmission facilities and related equipment. The list of NEMA Upgrades is contained in Schedule 12A of the OATT.

NEPOOL is the New England Power Pool, and the entities that collectively participated in the New England Power Pool.

NEPOOL Agreement is the agreement among the participants in NEPOOL.

NEPOOL GIS is the generation information system.

NEPOOL GIS Administrator is the entity or entities that develop, administer, operate and maintain the NEPOOL GIS.

NEPOOL GIS API Fees are the one-time on-boarding fees and annual maintenance fees charged to NEPOOL by the NEPOOL GIS Administrator for each NEPOOL Participant or Market Participant that accesses the NEPOOL GIS through an application programming interface pursuant to Rule 3.9(b) of the operating rules of the NEPOOL GIS.

NEPOOL Participant is a party to the NEPOOL Agreement.

NERC is the North American Electric Reliability Corporation or its successor organization.

NESCOE is the New England States Committee on Electricity, recognized by the Commission as the regional state committee for the New England Control Area.

Net Commitment Period Compensation (NCPC) is the compensation methodology for Resources that is described in Appendix F to Market Rule 1.

Net CONE is an estimate of the Cost of New Entry, net of non-capacity market revenues, for a reference technology resource type and is intended to equal the amount of capacity revenue the reference technology resource would require to be economically viable given reasonable expectations of the energy and ancillary services revenues under long-term equilibrium conditions.

Net Regional Clearing Price is described in Section III.13.7.5 of Market Rule 1.

Net Supply is energy injected into the transmission or distribution system at a Retail Delivery Point.

Net Supply Capability is the maximum Net Supply a facility is physically and contractually able to inject into the transmission or distribution system at its Retail Delivery Point.

Network Capability Interconnection Standard has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Network Customer is a Transmission Customer receiving RNS or LNS.

Network Import Capability (NI Capability) is defined in Section I of Schedule 25 of the OATT.

Network Import Interconnection Service (NI Interconnection Service) is defined in Section I of Schedule 25 of the OATT.

Network Resource is defined as follows: (1) With respect to Market Participants, (a) any generating resource located in the New England Control Area which has been placed in service prior to the Compliance Effective Date (including a unit that has lost its capacity value when its capacity value is

restored and a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) until retired; (b) any generating resource located in the New England Control Area which is placed in service after the Compliance Effective Date until retired, provided that (i) the Generator Owner has complied with the requirements of Sections II.46 and II.47 and Schedules 22 and 23 of the OATT, and (ii) the output of the unit shall be limited in accordance with Sections II.46 and II.47 and Schedules 22 and 23, if required; and (c) any generating resource or combination of resources (including bilateral purchases) located outside the New England Control Area for so long as any Market Participant has an Ownership Share in the resource or resources which is being delivered to it in the New England Control Area to serve Regional Network Load located in the New England Control Area or other designated Regional Network Loads contemplated by Section II.18.3 of the OATT taking Regional Network Service. (2) With respect to Non-Market Participant Transmission Customers, any generating resource owned, purchased or leased by the Non-Market Participant Transmission Customer which it designates to serve Regional Network Load.

New Brunswick Security Energy is defined in Section III.3.2.6A of Market Rule 1.

New Capacity Offer is an offer in the Forward Capacity Auction to provide capacity from a New Generating Capacity Resource, New Import Capacity Resource or New Demand Capacity Resource.

New Capacity Qualification Deadline is a deadline, specified in Section III.13.1.10 of Market Rule 1, for submission of certain qualification materials for the Forward Capacity Auction, as discussed in Section III.13.1 of Market Rule 1.

New Capacity Qualification Package is information submitted by certain new resources prior to participation in the Forward Capacity Auction, as described in Section III.13.1 of Market Rule 1.

New Capacity Resource is a resource (i) that never previously received any payment as a capacity resource including any capacity payment pursuant to the market rules in effect prior to June 1, 2010 and that has not cleared in any previous Forward Capacity Auction; or (ii) that is otherwise eligible to participate in the Forward Capacity Auction as a New Capacity Resource.

New Capacity Show of Interest Form is described in Section III.13.1.1.2.1 of Market Rule 1.

New Capacity Show of Interest Submission Window is the period of time during which a Project Sponsor may submit a New Capacity Show of Interest Form or a New Demand Capacity Resource Show of Interest Form, as described in Section III.13.1.10 of Market Rule 1.

New Demand Capacity Resource is a type of Demand Capacity Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1 of Market Rule 1.

New Demand Capacity Resource Qualification Package is the information that a Project Sponsor must submit, in accordance with Section III.13.1.4.1.1.2 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Demand Capacity Resource.

New Demand Capacity Resource Show of Interest Form is described in Section III.13.1.4.1.1.1 of Market Rule 1.

New England Control Area is the Control Area for New England, which includes PTF, Non-PTF, MTF and OTF. The New England Control Area covers Connecticut, Rhode Island, Massachusetts, New Hampshire, Vermont, and part of Maine (i.e., excluding the portions of Northern Maine and the northern portion of Eastern Maine which are in the Maritimes Control Area).

New England Markets are markets or programs for the purchase of energy, capacity, ancillary services, demand response services or other related products or services (including Financial Transmission Rights) that are delivered through or useful to the operation of the New England Transmission System and that are administered by the ISO pursuant to rules, rates, or agreements on file from time to time with the Federal Energy Regulatory Commission.

New England System Restoration Plan is the plan that is developed by ISO, in accordance with NERC Reliability Standards, NPCC regional criteria and standards, ISO New England Operating Documents and ISO operating agreements, to facilitate the restoration of the New England Transmission System following a partial or complete shutdown of the New England Transmission System.

New England Transmission System is the system of transmission facilities, including PTF, Non-PTF, OTF and MTF, within the New England Control Area under the ISO's operational jurisdiction.

New Generating Capacity Resource is a type of resource participating in the Forward Capacity Market, as described in Section III.13.1.1.1 of Market Rule 1.

New Import Capacity Resource is a type of resource participating in the Forward Capacity Market, as defined in Section III.13.1.3.4 of Market Rule 1.

New Resource Offer Floor Price is defined in Section III.A.21.2.

NMPTC means Non-Market Participant Transmission Customer.

NMPTC Credit Threshold is described in Section V.A.2 of the ISO New England Financial Assurance Policy.

NMPTC Financial Assurance Requirement is an amount of additional financial assurance for Non-Market Participant Transmission Customers described in Section V.D of the ISO New England Financial Assurance Policy.

Node is a point on the New England Transmission System at which LMPs are calculated.

No-Load Fee is the amount, in dollars per hour, for a Generator Asset that must be paid to Market Participants with an Ownership Share in the Generator Asset for being scheduled in the New England Markets, in addition to the Start-Up Fee and price offered to supply energy, for each hour that the Generator Asset is scheduled in the New England Markets.

Nominated Consumption Limit is the consumption level specified by the Market Participant for a Dispatchable Asset Related Demand as adjusted in accordance with the provisions of Section III.13.7.5.1.3.

Non-Commercial Capacity is the capacity of a New Capacity Resource or an Existing Capacity Resource, or portion thereof, that has not achieved FCM Commercial Operation.

Non-Commercial Capacity Cure Period is the time period described in Section VII.D of the ISO New England Financial Assurance Policy.

Non-Commercial Capacity Financial Assurance Amount (Non-Commercial Capacity FA Amount)

is the financial assurance amount held on Non-Commercial Capacity cleared in a Forward Capacity Auction as calculated in accordance with Section VII.B.2 of the ISO New England Financial Assurance Policy.

Non-Designated Blackstart Resource Study Cost Payments are the study costs reimbursed under Section 5.3 of Schedule 16 of the OATT.

Non-Dispatchable Resource is any Resource that does not meet the requirements to be a Dispatchable Resource.

Non-Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Non-Hourly Requirements are determined in accordance with Section III.A(ii) of the ISO New England Financial Assurance Policy, which is Exhibit 1A of Section I of the Tariff.

Non-Incumbent Transmission Developer is a Qualified Transmission Project Sponsor that: (i) is not currently a PTO; (ii) has a transmission project listed in the RSP Project List; and (iii) has executed a Non-Incumbent Transmission Developer Operating Agreement. “Non-Incumbent Transmission Developer” also includes a PTO that proposes the development of a transmission facility not located within or connected to its existing electric system; however, because such a PTO is a party to the TOA, it is not required to enter into a Non-Incumbent Transmission Developer Operating Agreement.

Non-Incumbent Transmission Developer Operating Agreement (or NTDOA) is an agreement between the ISO and a Non-Incumbent Transmission Developer in the form specified in Attachment O to the OATT that sets forth their respective rights and responsibilities to each other with regard to proposals for and construction of certain transmission facilities.

Non-Market Participant is any entity that is not a Market Participant.

Non-Market Participant Transmission Customer is any entity which is not a Market Participant but is a Transmission Customer.

Non-Municipal Market Participant is defined in Section II of the ISO New England Financial Assurance Policy.

Non-PTF Transmission Facilities (Non-PTF) are the transmission facilities owned by the PTOs that do not constitute PTF, OTF or MTF.

Non-Qualifying means a Market Participant that is not a Credit Qualifying Market Participant.

Notice of RBA is defined in Section 6.3.2 of the ISO New England Billing Policy.

Notification Time is the time required for a Generator Asset to synchronize to the system from the time a startup Dispatch Instruction is received from the ISO.

Northeastern Planning Protocol is the Amended and Restated Northeastern ISO/RTO Planning Coordination Protocol on file with the Commission and posted on the ISO website at the following URL: www.iso-ne.com/static-assets/documents/2015/07/northeastern_protocol_dmeast.doc.

NPCC is the Northeast Power Coordinating Council.

Obligation Month means a time period of one calendar month for which capacity payments are issued and the costs associated with capacity payments are allocated.

Offer Data means the scheduling, operations planning, dispatch, new Resource, and other data, including Generator Asset, Dispatchable Asset Related Demand, and Demand Response Resource operating limits based on physical characteristics, and information necessary to schedule and dispatch Generator Assets, Dispatchable Asset Related Demands, and Demand Response Resources for the provision or consumption of energy, the provision of other services, and the maintenance of the reliability and security of the transmission system in the New England Control Area, and specified for submission to the New England Markets for such purposes by the ISO.

Offer Review Trigger Prices are the prices specified in Section III.A.21.1 of Market Rule 1 associated with the submission of New Capacity Offers in the Forward Capacity Auction.

Offered CLAIM10 is a Supply Offer value or a Demand Reduction Offer value between 0 and the CLAIM10 of the resource that represents the amount of TMNSR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

Offered CLAIM30 is a Supply Offer value or a Demand Reduction Offer value between 0 and the CLAIM30 of the resource that represents the amount of TMOR available either from an off-line Fast Start Generator or from a Fast Start Demand Response Resource that has not been dispatched.

On-Peak Demand Resource is a type of Demand Capacity Resource and means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource On-Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Open Access Same-Time Information System (OASIS) is the ISO information system and standards of conduct responding to requirements of 18 C.F.R. §37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

Open Access Transmission Tariff (OATT) is Section II of the ISO New England Inc. Transmission, Markets and Services Tariff.

Operating Authority is defined pursuant to a MTOA, an OTOA, the TOA or the OATT, as applicable.

Operating Data means GADS Data, data equivalent to GADS Data, CARL Data, metered load data, or actual system failure occurrences data, all as described in the ISO New England Operating Procedures.

Operating Day means the calendar day period beginning at midnight for which transactions on the New England Markets are scheduled.

Operating Reserve means Ten-Minute Spinning Reserve (TMSR), Ten-Minute Non-Spinning Reserve (TMNSR) and Thirty-Minute Operating Reserve (TMOR).

Operations Date is February 1, 2005.

OTF Service is transmission service over OTF as provided for in Schedule 20.

Other Transmission Facility (OTF) are the transmission facilities owned by Transmission Owners, defined and classified as OTF pursuant to Schedule 20, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in the OTOA, rated 69 kV or above, and required to allow energy from significant power sources to move freely on the New England Transmission System. OTF classification shall be limited to the Phase I/II HVDC-TF.

Other Transmission Operating Agreements (OTOA) is the agreement(s) between the ISO, an OTO and/or the associated service provider(s) with respect to an OTF, which includes the HVDC Transmission Operating Agreement and the Phase I/II HVDC-TF Transmission Service Administration Agreement. With respect to the Phase I/II HVDC-TF, the HVDC Transmission Operating Agreement covers the rights and responsibilities for the operation of the facility and the Phase I/II HVDC-TF Transmission Service Administration Agreement covers the rights and responsibilities for the administration of transmission service.

Other Transmission Owner (OTO) is an owner of OTF.

Ownership Share is a right or obligation, for purposes of settlement, to a percentage share of all credits or charges associated with a Generator Asset or a Load Asset, where such facility is interconnected to the New England Transmission System.

Participant Expenses are defined in Section 1 of the Participants Agreement.

Participant Required Balance is defined in Section 5.3 of the ISO New England Billing Policy.

Participant Vote is defined in Section 1 of the Participants Agreement.

Participants Agreement is the agreement among the ISO, the New England Power Pool and Individual Participants, as amended from time to time, on file with the Commission.

Participants Committee is the principal committee referred to in the Participants Agreement.

Participating Transmission Owner (PTO) is a transmission owner that is a party to the TOA.

Passive DR Audit is the audit performed pursuant to Section III.13.6.1.5.4.

Passive DR Auditing Period is the summer Passive DR Auditing Period (June 1 to August 31) or winter Passive DR Auditing Period (December 1 to January 31) applicable to On-Peak Demand Resources and Seasonal Peak Demand Resources.

Payment is a sum of money due to a Covered Entity from the ISO.

Payment Default Shortfall Fund is defined in Section 5.1 of the ISO New England Billing Policy.

Peak Energy Rent (PER) is described in Section III.13.7.1.2 of Market Rule 1.

PER Proxy Unit is described in Section III.13.7.1.2.1 of Market Rule 1.

Permanent De-list Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.5 of Market Rule 1.

Phase I Transfer Credit is 40% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Phase I/II HVDC-TF is defined in Schedule 20A to Section II of this Tariff.

Phase I/II HVDC-TF Transfer Capability is the transfer capacity of the Phase I/II HVDC-TF under normal operating conditions, as determined in accordance with Good Utility Practice. The “Phase I Transfer Capability” is the transfer capacity under normal operating conditions, as determined in accordance with Good Utility Practice, of the Phase I terminal facilities as determined initially as of the time immediately prior to Phase II of the Phase I/II HVDC-TF first being placed in service, and as adjusted thereafter only to take into account changes in the transfer capacity which are independent of any effect of Phase II on the operation of Phase I. The “Phase II Transfer Capability” is the difference between the Phase I/II HVDC-TF Transfer Capability and the Phase I Transfer Capability.

Determinations of, and any adjustment in, Phase I/II HVDC-TF Transfer Capability shall be made by the ISO, and the basis for any such adjustment shall be explained in writing and posted on the ISO website.

Phase One Proposal is a first round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade, as applicable, by a Qualified Transmission Project Sponsor.

Phase II Transfer Credit is 60% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

Phase Two Solution is a second round submission, as defined in Section 4.3 of Attachment K of the OATT, of a proposal for a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade by a Qualified Transmission Project Sponsor.

Planning Advisory Committee is the committee described in Attachment K of the OATT.

Planning and Reliability Criteria is defined in Section 3.3 of Attachment K to the OATT.

Planning Authority is an entity defined as such by the North American Electric Reliability Corporation.

Point(s) of Delivery (POD) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available to the Receiving Party under the OATT.

Point of Interconnection shall have the same meaning as that used for purposes of Schedules 22, 23 and 25 of the OATT.

Point(s) of Receipt (POR) is point(s) of interconnection where capacity and/or energy transmitted by a Transmission Customer will be made available by the Delivering Party under the OATT.

Point-To-Point Service is the transmission of capacity and/or energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Local Point-To-Point Service or OTF Service or MTF Service; and the transmission of capacity and/or energy from the Point(s) of Receipt to the Point(s) of Delivery under the OATT pursuant to Through or Out Service.

Pool-Planned Unit is one of the following units: New Haven Harbor Unit 1 (Coke Works), Mystic Unit 7, Canal Unit 2, Potter Unit 2, Wyman Unit 4, Stony Brook Units 1, 1A, 1B, 1C, 2A and 2B, Millstone Unit 3, Seabrook Unit 1 and Waters River Unit 2 (to the extent of 7 megawatts of its Summer capability and 12 megawatts of its Winter capability).

Pool PTF Rate is the transmission rate determined in accordance with Schedule 8 to the OATT.

Pool RNS Rate is the transmission rate determined in accordance with paragraph (2) of Schedule 9 of Section II of the Tariff.

Pool-Scheduled Resources are described in Section III.1.10.2 of Market Rule 1.

Pool Supported PTF is defined as: (i) PTF first placed in service prior to January 1, 2000; (ii) Generator Interconnection Related Upgrades with respect to Category A and B projects (as defined in Schedule 11), but only to the extent not paid for by the interconnecting Generator Owner; and (iii) other PTF upgrades, but only to the extent the costs therefore are determined to be Pool Supported PTF in accordance with Schedule 12.

Pool Transmission Facility (PTF) means the transmission facilities owned by PTOs which meet the criteria specified in Section II.49 of the OATT.

Posting Entity is any Market Participant or Non-Market Participant Transmission Customer providing financial security under the provisions of the ISO New England Financial Assurance Policy.

Posture means an action of the ISO to deviate from the jointly optimized security constrained economic dispatch for Energy and Operating Reserves solution for a Resource produced by the ISO's technical software for the purpose of maintaining sufficient Operating Reserve (both online and off-line) or for the provision of voltage or VAR support.

Posturing Credits are the Real-Time Posturing NCPC Credits for Generators (Other Than Limited Energy Resources) Postured for Reliability and the Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability.

Power Purchaser is the entity that is purchasing the capacity and/or energy to be transmitted under the OATT.

Principal is (i) the sole proprietor of a sole proprietorship; (ii) a general partner of a partnership; (iii) a president, chief executive officer, chief operating officer or chief financial officer (or equivalent position) of an organization; (iv) a manager, managing member or a member vested with the management authority for a limited liability company or limited liability partnership; (v) any person or entity that has the power to exercise a controlling influence over an organization's activities that are subject to regulation by the Federal Energy Regulatory Commission, the Securities and Exchange Commission, the Commodity Futures Trading Commission, any exchange monitored by the National Futures Association, or any state entity responsible for regulating activity in energy markets; or (vi) any person or entity that: (a) is the direct owner of 10% or more of any class of an organization's equity securities; or (b) has directly contributed 10% or more of an organization's capital.

Profiled Load Assets include all Load Assets that are not directly metered by OP-18 compliant metering as currently described in Section IV (Metering and Recording for Settlements) of OP18, and some Load Assets that are measured by OP-18 compliant metering (as currently described in Section IV of OP-18) to which the Host Participant Assigned Meter Reader allocates non-PTF losses.

Project Sponsor is an entity seeking to have a New Generating Capacity Resource, New Import Capacity Resource or New Demand Capacity Resource participate in the Forward Capacity Market, as described in Section III.13.

Proxy De-List Bid is a type of bid used in the Forward Capacity Market.

Provisional Member is defined in Section I.68A of the Restated NEPOOL Agreement.

PTO Administrative Committee is the committee referred to in Section 11.04 of the TOA.

Public Policy Requirement is a requirement reflected in a statute enacted by, or a regulation promulgated by, the federal government or a state or local (e.g., municipal or county) government.

Public Policy Transmission Study is a study conducted by the ISO pursuant to the process set out in Section 4A.3 of Attachment K of the OATT, and consists of two phases: (i) an initial phase to produce a

rough estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Local Transmission Study is a study conducted by a PTO pursuant to the process set out in Section 1.6 of Attachment K Appendix 1 of the OATT, and consists of two phases: (i) an initial phase to produce an estimate of the costs and benefits of concepts that could meet transmission needs driven by public policy requirements; and (ii) a follow-on phase designed to produce more detailed analysis and engineering work on transmission concepts identified in the first phase.

Public Policy Transmission Upgrade is an addition and/or upgrade to the New England Transmission System that meets the voltage and non-voltage criteria for Public Policy Transmission Upgrade PTF classification specified in the OATT, and has been included in the Regional System Plan and RSP Project List as a Public Policy Transmission Upgrade pursuant to the procedures described in Section 4A of Attachment K of the OATT.

Publicly Owned Entity is defined in Section I of the Restated NEPOOL Agreement.

Qualification Process Cost Reimbursement Deposit is described in Section III.13.1.9.3 of Market Rule 1.

Qualified Capacity is the amount of capacity a resource may provide in the summer or winter in a Capacity Commitment Period, as determined in the Forward Capacity Market qualification processes.

Qualified Generator Reactive Resource(s) is any generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Non-Generator Reactive Resource(s) is any non-generator source of dynamic reactive power that meets the criteria specified in Schedule 2 of the OATT.

Qualified Reactive Resource(s) is any Qualified Generator Reactive Resource and/or Qualified Non-Generator Reactive Resource that meets the criteria specified in Schedule 2 of the OATT.

Qualified Transmission Project Sponsor is defined in Sections 4B.2 and 4B.3 of Attachment K of the OATT.

Queue Position has the meaning specified in Section I of Schedule 22, Attachment 1 to Schedule 23, and Section I of Schedule 25 of the OATT.

Rapid Response Pricing Asset is: (i) a Fast Start Generator; (ii) a Flexible DNE Dispatchable Generator; or (iii) a Binary Storage DARD with Offer Data specifying a Minimum Run Time and a Minimum Down Time not exceeding one hour each. A Rapid Response Pricing Asset shall also include a Fast Start Demand Response Resource for which the Market Participant's Offer Data meets the following criteria: (i) Minimum Reduction Time does not exceed one hour; and (ii) Demand Response Resource Notification Time plus Demand Response Resource Start-Up Time does not exceed 30 minutes.

Rapid Response Pricing Opportunity Cost is the NCPC Credit described in Section III.F.2.3.10.

Rated means a Market Participant that receives a credit rating from one or more of the Rating Agencies, or, if such Market Participant is not rated by one of the Rating Agencies, then a Market Participant that has outstanding unsecured debt rated by one or more of the Rating Agencies.

Rating Agencies are Standard and Poor's (S&P), Moody's, and Fitch.

Rationing Minimum Limit is the MW quantity for a New Generating Capacity Resource or Existing Generating Capacity Resource below which an offer or bid may not be rationed in the Forward Capacity Auction, but shall not apply to supply offers or demand bids in a substitution auction as specified in Section III.13.2.8.2 and Section III.13.2.8.3.

RBA Decision is a written decision provided by the ISO to a Disputing Party and to the Chair of the NEPOOL Budget and Finance Subcommittee accepting or denying a Requested Billing Adjustment within twenty Business Days of the date the ISO distributes a Notice of RBA, unless some later date is agreed upon by the Disputing Party and the ISO.

Reactive Capability Audit is an audit that measures the ability of a Reactive Resource to provide or absorb reactive power to or from the transmission system at a specified real power output or consumption.

Reactive Resource is a device that dynamically adjusts reactive power output automatically in Real-Time over a continuous range, taking into account control system response bandwidth, within a specified voltage bandwidth in response to grid voltage changes. These resources operate to maintain a set-point voltage and include, but are not limited to, Generator Assets, Dispatchable Asset Related Demands that are part of an Electric Storage Facility, and dynamic transmission devices.

Reactive Supply and Voltage Control Service is the form of Ancillary Service described in Schedule 2 of the OATT.

Real-Time is a period in the current Operating Day for which the ISO dispatches Resources for energy and Regulation, designates Resources for Regulation and Operating Reserve and, if necessary, commits additional Resources.

Real-Time Adjusted Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Adjusted Load Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Commitment NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Congestion Revenue is defined in Section III.3.2.1(i) of Market Rule 1.

Real-Time Demand Reduction Obligation is defined in Section III.3.2.1(c) of Market Rule 1.

Real-Time Demand Reduction Obligation Deviation is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Dispatch NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Energy Inventory is a component of the spot payment that a Market Participant may receive through the inventoried energy program, as described in Section III.K.3.2.1 of Market Rule 1.

Real-Time Energy Market means the purchase or sale of energy, purchase of demand reductions, payment of Congestion Costs, and payment for losses for quantity deviations from the Day-Ahead Energy Market in the Operating Day and designation of and payment for provision of Operating Reserve in Real-Time.

Real-Time Energy Market Deviation Congestion Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market Deviation Energy Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market Deviation Loss Charge/Credit is defined in Section III.3.2.1(g) of Market Rule 1.

Real-Time Energy Market NCPC Credits are the Real-Time Commitment NCPC Credit and the Real-Time Dispatch NCPC Credit.

Real-Time External Transaction NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Generation Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Generation Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time High Operating Limit is the maximum output, in MW, of a Generator Asset that could be achieved, consistent with Good Utility Practice, in response to an ISO request for Energy (including pursuant to Section III.13.6.4 of Market Rule 1), for each hour of the Operating Day, as reflected in the Generator Asset's Offer Data. This value is based on real-time operating conditions and the physical operating characteristics and operating permits of the facility and must be submitted for all Generator Assets (other than Settlement Only Resources).

Real-Time Load Obligation is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Load Obligation Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange is defined in Section III.3.2.1(b) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange Deviation is defined in Section III.3.2.1(d) of Market Rule 1.

Real-Time Loss Revenue is defined in Section III.3.2.1(l) of Market Rule 1.

Real-Time Loss Revenue Charges or Credits are defined in Section III.3.2.1(m) of Market Rule 1.

Real-Time NCP Load Obligation is the maximum hourly value, during a month, of a Market Participant's Real-Time Load Obligation summed over all Locations, excluding exports, in kilowatts.

Real-Time Offer Change is a modification to a Supply Offer pursuant to Section III.1.10.9(b).

Real-Time Posturing NCPC Credit for Generators (Other Than Limited Energy Resources)

Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Posturing NCPC Credit for Limited Energy Resources Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Prices means the Locational Marginal Prices resulting from the ISO's dispatch of the New England Markets in the Operating Day.

Real-Time Reserve Charge is a Market Participant's share of applicable system and Reserve Zone Real-Time Operating Reserve costs attributable to meeting the Real-Time Operating Reserve requirement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Clearing Price is the Real-Time TMSR, TMNSR or TMOR clearing price, as applicable, for the system and each Reserve Zone that is calculated in accordance with Section III.2.7A of Market Rule 1.

Real-Time Reserve Credit is a Market Participant's compensation associated with that Market Participant's Resources' Reserve Quantity For Settlement as calculated in accordance with Section III.10 of Market Rule 1.

Real-Time Reserve Designation is the amount, in MW, of Operating Reserve designated to a Resource in Real-Time by the ISO as described in Section III.1.7.19 of Market Rule 1.

Real-Time Reserve Opportunity Cost is defined in Section III.2.7A(b) of Market Rule 1.

Real-Time Synchronous Condensing NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time System Adjusted Net Interchange means, for each hour, the sum of Real-Time Locational Adjusted Net Interchange for a Market Participant over all Locations, in kilowatts.

Receiving Party is the entity receiving the capacity and/or energy transmitted to Point(s) of Delivery under the OATT.

Reference Level is defined in Section III.A.5.7 of Appendix A of Market Rule 1.

Regional Benefit Upgrade(s) (RBU) means a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in the OATT; and (iii) is included in the Regional System Plan as either a Reliability Transmission Upgrade or a Market Efficiency Transmission Upgrade identified as needed pursuant to Attachment K of the OATT. The category of RBU shall not include any Transmission Upgrade that has been categorized under any of the other categories specified in Schedule 12 of the OATT (e.g., an Elective Transmission Upgrade shall not also be categorized as an RBU). Any upgrades to transmission facilities rated below 115kV that were PTF prior to January 1, 2004 shall remain classified as PTF and be categorized as an RBU if, and for so long as, such upgrades meet the criteria for PTF specified in the OATT.

Regional Network Load is the load that a Network Customer designates for Regional Network Service under Part II.B of the OATT. The Network Customer's Regional Network Load shall include all load designated by the Network Customer (including losses) and shall not be credited or reduced for any behind-the-meter generation. A Network Customer may elect to designate less than its total load as

Regional Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Transmission Customer has elected not to designate a particular load at discrete Points of Delivery as Regional Network Load, the Transmission Customer is responsible for making separate arrangements under Part II.C of the OATT for any Point-To-Point Service that may be necessary for such non-designated load.

Regional Network Service (RNS) is the transmission service over the PTF described in Part II.B of the OATT, including such service which is used with respect to Network Resources or Regional Network Load that is not physically interconnected with the PTF.

Regional Planning Dispute Resolution Process is described in Section 12 of Attachment K to the OATT.

Regional System Plan (RSP) is the plan developed under the process specified in Attachment K of the OATT.

Regional Transmission Service (RTS) is Regional Network Service and Through or Out Service as provided over the PTF in accordance with Section II.B, Section II.C, Schedule 8 and Schedule 9 of the OATT.

Regulation is the capability of a specific Resource with appropriate telecommunications, control and response capability to respond to an AGC SetPoint.

Regulation and Frequency Response Service is the form of Ancillary Service described in Schedule 3 of the OATT. The capability of performing Regulation and Frequency Response Service is referred to as automatic generation control (AGC).

Regulation Capacity is the lesser of five times the Automatic Response Rate and one-half of the difference between the Regulation High Limit and the Regulation Low Limit of a Resource capable of providing Regulation.

Regulation Capacity Requirement is the amount of Regulation Capacity required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Capacity Offer is an offer by a Market Participant to provide Regulation Capacity.

Regulation High Limit is an offer parameter that establishes the upper bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Low Limit is an offer parameter that establishes the lower bound for AGC SetPoints and is used in the determination of a Resource's Regulation Capacity.

Regulation Market is the market described in Section III.14 of Market Rule 1.

Regulation Resources are those Alternative Technology Regulation Resources, Generator Assets, and Dispatchable Asset Related Demands that satisfy the requirements of Section III.14.2. Regulation Resources are eligible to participate in the Regulation Market.

Regulation Service is the change in output or consumption made in response to changing AGC SetPoints.

Regulation Service Requirement is the estimated amount of Regulation Service required to maintain system control and reliability in the New England Control Area as calculated and posted on the ISO website.

Regulation Service Offer is an offer by a Market Participant to provide Regulation Service.

Related Person is defined pursuant to Section 1.1 of the Participants Agreement.

Related Transaction is defined in Section III.1.4.3 of Market Rule 1.

Reliability Administration Service (RAS) is the service provided by the ISO, as described in Schedule 3 of Section IV.A of the Tariff, in order to administer the Reliability Markets and provide other reliability-related and informational functions.

Reliability Committee is the committee whose responsibilities are specified in Section 8.2.3 of the Participants Agreement.

Reliability Markets are, collectively, the ISO's administration of Regulation, the Forward Capacity Market, and Operating Reserve.

Reliability Region means any one of the regions identified on the ISO's website. Reliability Regions are intended to reflect the operating characteristics of, and the major transmission constraints on, the New England Transmission System.

Reliability Transmission Upgrade means those additions and upgrades not required by the interconnection of a generator that are nonetheless necessary to ensure the continued reliability of the New England Transmission System, taking into account load growth and known resource changes, and include those upgrades necessary to provide acceptable stability response, short circuit capability and system voltage levels, and those facilities required to provide adequate thermal capability and local voltage levels that cannot otherwise be achieved with reasonable assumptions for certain amounts of generation being unavailable (due to maintenance or forced outages) for purposes of long-term planning studies. Good Utility Practice, applicable reliability principles, guidelines, criteria, rules, procedures and standards of ERO and NPCC and any of their successors, applicable publicly available local reliability criteria, and the ISO System Rules, as they may be amended from time to time, will be used to define the system facilities required to maintain reliability in evaluating proposed Reliability Transmission Upgrades. A Reliability Transmission Upgrade may provide market efficiency benefits as well as reliability benefits to the New England Transmission System.

Remittance Advice is an issuance from the ISO for the net Payment owed to a Covered Entity where a Covered Entity's total Payments exceed its total Charges in a billing period.

Remittance Advice Date is the day on which the ISO issues a Remittance Advice.

Renewable Technology Resource is a Generating Capacity Resource or an On-Peak Demand Resource that satisfies the requirements specified in Section III.13.1.1.1.7.

Re-Offer Period is the period that normally occurs between the posting of the of the Day-Ahead Energy Market results and 2:00 p.m. on the day before the Operating Day during which a Market Participant may submit revised Supply Offers, revised External Transactions, or revised Demand Bids associated with Dispatchable Asset Related Demands or, revised Demand Reduction Offers associated with Demand Response Resources.

Replacement Reserve is described in Part III, Section VII of ISO New England Operating Procedure No. 8.

Request for Alternative Proposals (RFAP) is the request described in Attachment K of the OATT.

Requested Billing Adjustment (RBA) is defined in Section 6.1 of the ISO New England Billing Policy.

Required Balance is an amount as defined in Section 5.3 of the Billing Policy.

Reseller is a MGTSA holder that sells, assigns or transfers its rights under its MGTSA, as described in Section II.45.1(a) of the OATT.

Reserve Adequacy Analysis is the analysis performed by the ISO to determine if adequate Resources are committed to meet forecasted load, Operating Reserve, and security constraint requirements for the current and next Operating Day.

Reserve Constraint Penalty Factors (RCPFs) are rates, in \$/MWh, that are used within the Real-Time dispatch and pricing algorithm to reflect the value of Operating Reserve shortages and are defined in Section III.2.7A(c) of Market Rule 1.

Reserve Quantity For Settlement is defined in Section III.10.1 of Market Rule 1.

Reserve Zone is defined in Section III.2.7 of Market Rule 1.

Reserved Capacity is the maximum amount of capacity and energy that is committed to the Transmission Customer for transmission over the New England Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II.C or Schedule 18, 20 or 21 of the OATT, as applicable. Reserved Capacity shall be expressed in terms of whole kilowatts on a sixty-minute interval (commencing on the clock hour) basis, or, in the case of Reserved Capacity for Local Point-to-Point Service, in terms of whole megawatts on a sixty-minute interval basis.

Resource means a Generator Asset, a Dispatchable Asset Related Demand, an External Resource, an External Transaction, or a Demand Response Resource.

Restated New England Power Pool Agreement (RNA) is the Second Restated New England Power Pool Agreement, which restated for a second time by an amendment dated as of August 16, 2004 the New England Power Pool Agreement dated September 1, 1971, as the same may be amended and restated from time to time, governing the relationship among the NEPOOL members.

Rest-of-Pool Capacity Zone is a single Capacity Zone made up of the adjacent Load Zones that are neither export-constrained nor import-constrained.

Rest of System is an area established under Section III.2.7(d) of Market Rule 1.

Retail Delivery Point is the point on the transmission or distribution system at which the load of an end-use facility, which is metered and assigned a unique account number by the Host Participant, is measured to determine the amount of energy delivered to the facility from the transmission and distribution system. If an end-use facility is connected to the transmission or distribution system at more than one location, the Retail Delivery Point shall consist of the metered load at each connection point, summed to measure the net energy delivered to the facility in each interval.

Retirement De-List Bid is a bid to retire an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource from all New England Markets, as described in Section III.13.1.2.3.1.5.

Returning Market Participant is a Market Participant, other than an FTR-Only Customer or a Governance Only Member, whose previous membership as a Market Participant was involuntarily terminated due to a Financial Assurance Default or a payment default and, since returning, has been a Market Participant for less than six consecutive months.

Revenue Requirement is defined in Section IV.A.2.1 of the Tariff.

Reviewable Action is defined in Section III.D.1.1 of Appendix D of Market Rule 1.

Reviewable Determination is defined in Section 12.4(a) of Attachment K to the OATT.

RSP Project List is defined in Section 1 of Attachment K to the OATT.

RTEP02 Upgrade(s) means a Transmission Upgrade that was included in the annual NEPOOL Transmission Plan (also known as the “Regional Transmission Expansion Plan” or “RTEP”) for the year 2002, as approved by ISO New England Inc.’s Board of Directors, or the functional equivalent of such Transmission Upgrade, as determined by ISO New England Inc. The RTEP02 Upgrades are listed in Schedule 12B of the OATT.

RTO is a regional transmission organization or comparable independent transmission organization that complies with Order No. 2000 and the Commission’s corresponding regulation.

Same Reserve Zone Export Transaction is defined in Section III.1.10.7(f)(iii) of Market Rule 1.

Sanctionable Behavior is defined in Section III.B.3 of Appendix B of Market Rule 1.

Schedule, Schedules, Schedule 1, 2, 3, 4 and 5 are references to the individual or collective schedules to Section IV.A. of the Tariff.

Schedule 20A Service Provider (SSP) is defined in Schedule 20A to Section II of this Tariff.

Scheduling Service, for purposes of Section IV.A and Section IV.B of the Tariff, is the service described in Schedule 1 to Section IV.A of the Tariff.

Scheduling, System Control and Dispatch Service, for purposes of Section II of the Tariff, is the form of Ancillary Service described in Schedule 1 of the OATT.

Seasonal Claimed Capability is the summer or winter claimed capability of a Generator Asset or Generating Capacity Resource, and represents the maximum dependable load carrying ability of the asset or resource, excluding capacity required for station use.

Seasonal Claimed Capability Audit is the Generator Asset audit performed pursuant to Section III.1.5.1.3.

Seasonal DR Audit is the Demand Response Resource audit performed pursuant to Section III.1.5.1.3.1.

Seasonal Peak Demand Resource is a type of Demand Capacity Resource and shall mean installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that reduce the total amount of electrical energy consumed during Demand Resource Seasonal Peak Hours, while delivering a comparable or acceptable level of end-use service. Such measures include Energy Efficiency, Load Management, and Distributed Generation.

Section III.1.4 Transactions are defined in Section III.1.4.2 of Market Rule 1.

Section III.1.4 Conforming Transactions are defined in Section III.1.4.2 of Market Rule 1.

Security Agreement is Attachment 1 to the ISO New England Financial Assurance Policy.

Selected Qualified Transmission Project Sponsor is the Qualified Transmission Project Sponsor that proposed the Phase Two or Stage Two Solution that has been identified by the ISO as the preferred Phase Two or Stage Two Solution.

Selected Qualified Transmission Project Sponsor Agreement is the agreement between the ISO and a Selected Qualified Transmission Project Sponsor. The Selected Qualified Transmission Project Sponsor Agreement is provided in Attachment P to the OATT.

Self-Schedule is the action of a Market Participant in committing its Generator Asset or DARD, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Generator Asset or DARD would have been committed by the ISO to provide the service. For a Generator Asset, Self-Schedule is the action of a Market Participant in committing a Generator Asset to provide Energy in an hour at its Economic Minimum Limit, whether or not in the absence of that action the Generator Asset would have been committed by the ISO to provide the Energy. For a DARD, Self-Schedule is the action of a Market Participant in committing a DARD to consume Energy in an hour at its Minimum Consumption Limit, whether or not in the absence of that action the DARD would have been committed by the ISO to consume Energy. For an External Transaction, a Self-Schedule is a request by a Market Participant for the ISO to select the External Transaction regardless of the LMP. Demand Response Resources are not permitted to Self-Schedule.

Self-Supplied FCA Resource is described in Section III.13.1.6 of Market Rule 1.

Senior Officer means an officer of the subject entity with the title of vice president (or similar office) or higher, or another officer designated in writing to the ISO by that officer.

Service Agreement is a Transmission Service Agreement or an MPSA.

Service Commencement Date is the date service is to begin pursuant to the terms of an executed Service Agreement, or the date service begins in accordance with the sections of the OATT addressing the filing of unexecuted Service Agreements.

Services means, collectively, the Scheduling Service, EAS and RAS; individually, a Service.

Settlement Financial Assurance is an amount of financial assurance required from a Designated FTR Participant awarded a bid in an FTR Auction. This amount is calculated pursuant to Section VI.C of the ISO New England Financial Assurance Policy.

Settlement Only Resources are generators of less than 5 MW of maximum net output when operating at any temperature at or above zero degrees Fahrenheit, that meet the metering, interconnection and other requirements in ISO New England Operating Procedure No. 14 and that have elected Settlement Only Resource treatment as described in the ISO New England Manual for Registration and Performance Auditing.

Shortfall Funding Arrangement, as specified in Section 5.1 of the ISO New England Billing Policy, is a separate financing arrangement that can be used to make up any non-congestion related differences between amounts received on Invoices and amounts due for ISO Charges in any bill issued.

Short-Term is a period of less than one year.

Significantly Reduced Congestion Costs are defined in Section III.G.2.2 of Appendix G to Market Rule 1.

SMD Effective Date is March 1, 2003.

Solar High Limit is the estimated power output (MW) of a solar Generator Asset given the Real-Time solar and weather conditions, taking into account equipment outages, and absent any self-imposed

reductions in power output or any reduction in power output as a result of a Dispatch Instruction, calculated in the manner described in the ISO Operating Documents.

Solar Plant Future Availability is the forecasted Real-Time High Operating Limit of a solar Generator Asset, calculated in the manner described in the ISO Operating Documents.

Solutions Study is described in Section 4.2(b) of Attachment K to the OATT.

Special Constraint Resource (SCR) is a Resource that provides Special Constraint Resource Service under Schedule 19 of the OATT.

Special Constraint Resource Service is the form of Ancillary Service described in Schedule 19 of the OATT.

Specified-Term Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Sponsored Policy Resource is a New Capacity Resource that: receives an out-of-market revenue source supported by a government-regulated rate, charge or other regulated cost recovery mechanism, and; qualifies as a renewable, clean or alternative energy resource under a renewable energy portfolio standard, clean energy standard, alternative energy portfolio standard, renewable energy goal, or clean energy goal enacted (either by statute or regulation) in the New England state from which the resource receives the out-of-market revenue source and that is in effect on January 1, 2018.

Stage One Proposal is a first round submission, as defined in Sections 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Stage Two Solution is a second round submission, as defined in Section 4A.5 of Attachment K of the OATT, of a proposal for a Public Policy Transmission Upgrade by a Qualified Transmission Project Sponsor.

Standard Blackstart Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 of the OATT, for a Designated Blackstart Resource's capital Blackstart Equipment costs associated with the provision of Blackstart Service (except for capital costs associated with adhering to NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

Start-of-Round Price is the highest price associated with a round of a Forward Capacity Auction as described in Section III.13.2.3.1 of Market Rule 1.

Start-Up Fee is the amount, in dollars, that must be paid for a Generator Asset to Market Participants with an Ownership Share in the Generator Asset each time the Generator Asset is scheduled in the New England Markets to start-up.

Start-Up Time is the time it takes the Generator Asset, after synchronizing to the system, to reach its Economic Minimum Limit and, for dispatchable Generator Assets, be ready for further dispatch by the ISO.

State Estimator means the computer model of power flows specified in Section III.2.3 of Market Rule 1.

Statements, for the purpose of the ISO New England Billing Policy, refer to both Invoices and Remittance Advices.

Static De-List Bid is a bid that may be submitted by an Existing Generating Capacity Resource, Existing Import Capacity Resource, or Existing Demand Capacity Resource in the Forward Capacity Auction to remove itself from the capacity market for a one year period, as described in Section III.13.1.2.3.1.1 of Market Rule 1.

Station is one or more Existing Generating Capacity Resources consisting of one or more assets located within a common property boundary.

Station Going Forward Common Costs are the net costs associated with a Station that are avoided only by the clearing of the Static De-List Bids, the Permanent De-List Bids or the Retirement De-List Bids of all the Existing Generating Capacity Resources comprising the Station.

Station-level Blackstart O&M Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Station-level Specified-Term Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Station-level Standard Blackstart Capital Payment is defined and calculated as specified in Section 5.1.2 of Schedule 16 to the OATT.

Storage DARD is a DARD that participates in the New England Markets as part of an Electric Storage Facility, as described in Section III.1.10.6 of Market Rule 1.

Summer ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.1 of Market Rule 1.

Summer Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources pursuant to Section III.9. The time period associated with the Summer Capability Period is the period of June 1 through September 30.

Summer Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.1(c) of Market Rule 1.

Supply Offer is a proposal to furnish energy at a Node or Regulation from a Resource that meets the applicable requirements set forth in the ISO New England Manuals submitted to the ISO by a Market Participant with authority to submit a Supply Offer for the Resource. The Supply Offer will be submitted pursuant to Market Rule 1 and applicable ISO New England Manuals, and include a price and information with respect to the quantity proposed to be furnished, technical parameters for the Resource, timing and other matters. A Supply Offer is a subset of the information required in a Market Participant's Offer Data.

Supply Offer Block-Hours are Block-Hours assigned to the Lead Market Participant for each Supply Offer. Blocks of the Supply Offer in effect for each hour will be totaled to determine the quantity of Supply Offer Block-Hours for a given day. In the case that a Resource has a Real-Time unit status of "unavailable" for the entire day, that day will not contribute to the quantity of Supply Offer Block-Hours.

However, if the Resource has at least one hour of the day with a unit status of “available,” the entire day will contribute to the quantity of Supply Offer Block-Hours.

Synchronous Condenser is a generator that is synchronized to the grid but supplying no energy for the purpose of providing Operating Reserve or VAR or voltage support.

System Condition is a specified condition on the New England Transmission System or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm MTF or OTF Service on the MTF or the OTF using the curtailment priority pursuant to Section II.44 of the Tariff or Curtailment of Local Long-Term Firm Point-to-Point Transmission Service on the non-PTF using the curtailment priority pursuant to Schedule 21 of the Tariff. Such conditions must be identified in the Transmission Customer’s Service Agreement.

System Impact Study is an assessment pursuant to Part II.B, II.C, II.G, Schedule 21, Schedule 22, Schedule 23, or Schedule 25 of the OATT of (i) the adequacy of the PTF or Non-PTF to accommodate a request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or new Local Service or an Elective Transmission Upgrade, and (ii) whether any additional costs may be required to be incurred in order to provide the interconnection or transmission service.

System Operator shall mean ISO New England Inc. or a successor organization.

System Operating Limit (SOL) has the meaning specified in the Glossary of Terms Used in NERC Reliability Standards.

System-Wide Capacity Demand Curve is the demand curve used in the Forward Capacity Market as specified in Section III.13.2.2.

TADO is the total amount due and owing (not including any amounts due under Section 14.1 of the RNA) at such time to the ISO, NEPOOL, the PTOs, the Market Participants and the Non-Market Participant Transmission Customers, by all PTOs, Market Participants and Non-Market Participant Transmission Customers.

Tangible Net Worth is the value, determined in accordance with international accounting standards or generally accepted accounting principles in the United States, of all of that entity's assets less the following: (i) assets the ISO reasonably believes to be restricted or potentially unavailable to settle a claim in the event of a default (e.g., regulatory assets, restricted assets, and Affiliate assets), net of any matching liabilities, to the extent that the result of that netting is a positive value; (ii) derivative assets, net of any matching liabilities, to the extent that the result of that netting is a positive value; (iii) the amount at which the liabilities of the entity would be shown on a balance sheet in accordance with international accounting standards or generally accepted accounting principles in the United States; (iv) preferred stock; (v) non-controlling interest; and (vi) all of that entity's intangible assets (e.g., patents, trademarks, franchises, intellectual property, goodwill and any other assets not having a physical existence), in each case as shown on the most recent financial statements provided by such entity to the ISO.

Technical Committee is defined in Section 8.2 of the Participants Agreement.

Ten-Minute Non-Spinning Reserve (TMNSR) is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Ten-Minute Non-Spinning Reserve Service is the form of Ancillary Service described in Schedule 6 of the OATT.

Ten-Minute Reserve Requirement is the combined amount of TMSR and TMNSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Ten-Minute Spinning Reserve (TMSR) is a form of ten-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Ten-Minute Spinning Reserve Requirement is the amount of TMSR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Ten-Minute Spinning Reserve Service is the form of Ancillary Service described in Schedule 5 of the OATT.

Third-Party Sale is any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Regional Network Load or Local Network Load under the Regional Network Service or Local Network Service, as applicable.

Thirty-Minute Operating Reserve (TMOR) is a form of thirty-minute reserve capability, determined pursuant to Section III.1.7.19.2.

Thirty-Minute Operating Reserve Service is the form of Ancillary Service described in Schedule 7 of the OATT.

Through or Out Rate (TOUT Rate) is the rate per hour for Through or Out Service, as defined in Section II.25.2 of the OATT.

Through or Out Service (TOUT Service) means Point-To-Point Service over the PTF provided by the ISO with respect to a transaction that goes through the New England Control Area, as, for example, a single transaction where energy or capacity is transmitted into the New England Control Area from New Brunswick and subsequently out of the New England Control Area to New York, or a single transaction where energy or capacity is transmitted into the New England Control Area from New York through one point on the PTF and subsequently flows over the PTF prior to passing out of the New England Control Area to New York, or with respect to a transaction which originates at a point on the PTF and flows over the PTF prior to passing out of the New England Control Area, as, for example, from Boston to New York.

Tie-Line Asset is a physical transmission tie-line, or an inter-state or intra-state border arrangement created according to the ISO New England Manuals and registered in accordance with the Asset Registration Process.

Total Available Amount is the sum of the available amount of the Shortfall Funding Arrangement and the balance in the Payment Default Shortfall Fund.

Total Blackstart Capital Payment is the annual compensation calculated under either Section 5.1 or Section 5.2 of Schedule 16 of the OATT, as applicable.

Total Blackstart Service Payments is monthly compensation to Blackstart Owners or Market Participants, as applicable, and as calculated pursuant to Section 5.6 of Schedule 16 to the OATT.

Total Reserve Requirement, which includes Replacement Reserve, is the combined amount of TMSR, TMNSR, and TMOR required system-wide as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

Total System Capacity is the aggregate capacity supply curve for the New England Control Area as determined in accordance with Section III.13.2.3.3 of Market Rule 1.

Transaction Unit (TU) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers.

Transition Period: The six-year period commencing on March 1, 1997.

Transmission Charges, for the purposes of the ISO New England Financial Assurance Policy and the ISO New England Billing Policy, are all charges and payments under Schedules 1, 8 and 9 of the OATT.

Transmission Congestion Credit means the allocated share of total Transmission Congestion Revenue credited to each holder of Financial Transmission Rights, calculated and allocated as specified in Section III.5.2 of Market Rule 1.

Transmission Congestion Revenue is defined in Section III.5.2.5(a) of Market Rule 1.

Transmission Constraint Penalty Factors are described in Section III.1.7.5 of Market Rule 1.

Transmission Credit Limit is a credit limit, not to be used to meet FTR Requirements, established for each Market Participant in accordance with Section II.D and each Non-Market Participant Transmission Customer in accordance with Section V.B.2 of the ISO New England Financial Assurance Policy.

Transmission Credit Test Percentage is calculated in accordance with Section III.B.1(c) of the ISO New England Financial Assurance Policy.

Transmission Customer is any Eligible Customer that (i) executes, on its own behalf or through its Designated Agent, an MPSA or TSA, or (ii) requests in writing, on its own behalf or through its Designated Agent, that the ISO, the Transmission Owner, or the Schedule 20A Service Provider, as applicable, file with the Commission, a proposed unexecuted MPSA or TSA containing terms and conditions deemed appropriate by the ISO (in consultation with the applicable PTO, OTO or Schedule 20A Service Provider) in order that the Eligible Customer may receive transmission service under Section II of this Tariff. A Transmission Customer under Section II of this Tariff includes a Market Participant or a Non-Market Participant taking Regional Network Service, Through or Out Service, MTF Service, OTF Service, Ancillary Services, or Local Service.

Transmission Default Amount is all or any part of any amount of Transmission Charges due to be paid by any Covered Entity that the ISO, in its reasonable opinion, believes will not or has not been paid when due.

Transmission Default Period is defined in Section 3.4.f of the ISO New England Billing Policy.

Transmission Late Payment Account is defined in Section 4.2 of the ISO New England Billing Policy.

Transmission Late Payment Account Limit is defined in Section 4.2 of the ISO New England Billing Policy.

Transmission Late Payment Charge is defined in Section 4.1 of the ISO New England Billing Policy.

Transmission, Markets and Services Tariff (Tariff) is the ISO New England Inc. Transmission, Markets and Services Tariff, as amended from time to time.

Transmission Obligations are determined in accordance with Section III.A(vi) of the ISO New England Financial Assurance Policy.

Transmission Operating Agreement (TOA) is the Transmission Operating Agreement between and among the ISO and the PTOs, as amended and restated from time to time.

Transmission Owner means a PTO, MTO or OTO.

Transmission Provider is the ISO for Regional Network Service and Through or Out Service as provided under Section II.B and II.C of the OATT; Cross-Sound Cable, LLC for Merchant Transmission Service as provided under Schedule 18 of the OATT; the Schedule 20A Service Providers for Phase I/II HVDC-TF Service as provided under Schedule 20A of the OATT; and the Participating Transmission Owners for Local Service as provided under Schedule 21 of the OATT.

Transmission Requirements are determined in accordance with Section III.A(iii) of the ISO New England Financial Assurance Policy.

Transmission Security Analysis Requirement shall be determined pursuant to Section III.12.2.1.2.

Transmission Service Agreement (TSA) is the initial agreement and any amendments or supplements thereto: (A) in the form specified in either Attachment A or B to the OATT, entered into by the Transmission Customer and the ISO for Regional Network Service or Through or Out Service; (B) entered into by the Transmission Customer with the ISO and PTO in the form specified in Attachment A to Schedule 21 of the OATT; (C) entered into by the Transmission Customer with an OTO or Schedule 20A Service Provider in the appropriate form specified under Schedule 20 of the OATT; or (D) entered into by the Transmission Customer with a MTO in the appropriate form specified under Schedule 18 of the OATT. A Transmission Service Agreement shall be required for Local Service, MTF Service and OTF Service, and shall be required for Regional Network Service and Through or Out Service if the Transmission Customer has not executed a MPSA.

Transmission Upgrade(s) means an upgrade, modification or addition to the PTF that becomes subject to the terms and conditions of the OATT governing rates and service on the PTF on or after January 1, 2004. This categorization and cost allocation of Transmission Upgrades shall be as provided for in Schedule 12 of the OATT.

UDS is unit dispatch system software.

Unconstrained Export Transaction is defined in Section III.1.10.7(f)(iv) of Market Rule 1.

Uncovered Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Uncovered Transmission Default Amounts are defined in Section 3.4.f of the ISO New England Billing Policy.

Unrated means a Market Participant that is not a Rated Market Participant.

Unsecured Covered Entity is, collectively, an Unsecured Municipal Market Participant and an Unsecured Non-Municipal Covered Entity.

Unsecured Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Municipal Market Participant is defined in Section 3.3(h) of the ISO New England Billing Policy.

Unsecured Municipal Transmission Default Amount is defined in Section 3.4.f of the ISO New England Billing Policy.

Unsecured Non-Municipal Covered Entity is a Covered Entity that is not a Municipal Market Participant or a Non-Market Participant Transmission Customer and has a Market Credit Limit or Transmission Credit Limit of greater than \$0 under the ISO New England Financial Assurance Policy.

Unsecured Non-Municipal Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Non-Municipal Transmission Default Amount is defined in Section 3.3(i) of the ISO New England Billing Policy.

Unsecured Transmission Default Amounts are, collectively, the Unsecured Municipal Transmission Default Amount and the Unsecured Non-Municipal Transmission Default Amount.

Unsettled FTR Financial Assurance is an amount of financial assurance required from a Designated FTR Participant as calculated pursuant to Section VI.B of the ISO New England Financial Assurance Policy.

Updated Measurement and Verification Plan is an optional Measurement and Verification Plan that may be submitted as part of a subsequent qualification process for a Forward Capacity Auction prior to the beginning of the Capacity Commitment Period of the On-Peak Demand Resource or Seasonal Peak Demand Response project. The Updated Measurement and Verification Plan may include updated project specifications, measurement and verification protocols, and performance data as described in Section III.13.1.4.3.1.2 of Market Rule 1 and the ISO New England Manuals.

VAR CC Rate is the CC rate paid to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Payment is the payment made to Qualified Reactive Resources for VAR Service capability under Section IV.A of Schedule 2 of the OATT.

VAR Service is the provision of reactive power voltage support to the New England Transmission System by a Qualified Reactive Resource or by other generators that are dispatched by the ISO to provide dynamic reactive power as described in Schedule 2 of the OATT.

Virtual Cap is \$2,000/MWh.

Virtual Requirements are determined in accordance with Section III.A(iv) of the ISO New England Financial Assurance Policy.

Volt Ampere Reactive (VAR) is a measurement of reactive power.

Volumetric Measure (VM) is a type of billing determinant under Schedule 2 of Section IV.A of the Tariff used to assess charges to Customers under Section IV.A of the Tariff.

Wind High Limit is the estimated power output (MW) of a wind Generator Asset given the Real-Time weather conditions, taking into account equipment outages, and absent any self-imposed reductions in power output or any reduction in power output as a result of a Dispatch Instruction, calculated in the manner described in the ISO Operating Documents.

Wind Plant Future Availability is the forecasted Real-Time High Operating Limit of a wind Generator Asset, calculated in the manner described in the ISO Operating Documents.

Winter ARA Qualified Capacity is described in Section III.13.4.2.1.2.1.1.2 of Market Rule 1.

Winter Capability Period means one of two time periods defined by the ISO for the purposes of rating and auditing resources pursuant to Section III.9. The time period associated with the Winter Capability Period is the period October 1 through May 31.

Winter Intermittent Reliability Hours are defined in Section III.13.1.2.2.2.2(c) of Market Rule 1.

Year means a period of 365 or 366 days, whichever is appropriate, commencing on, or on the anniversary of March 1, 1997. Year One is the Year commencing on March 1, 1997, and Years Two and higher follow it in sequence.

Zonal Price is calculated in accordance with Section III.2.7 of Market Rule 1.

Zonal Capacity Obligation is calculated in accordance with Section III.13.7.5.2 of Market Rule 1.

Zonal Reserve Requirement is the combined amount of TMSR, TMNSR, and TMOR required for a Reserve Zone as described in Section III.2.7A and ISO New England Operating Procedure No. 8.

I.3 Obligations of Market Participants and Other Customers

The ISO acts as Counterparty for sales to its Customers of Regional Transmission Service, and for agreements and transactions with its Customers, including but not limited to assignments involving Customers, and agreements and transactions with Customers involving sale to the ISO and/or purchase from the ISO of energy, capacity, reserves, regulation, Ancillary Services, FTRs and involving other products, service and transactions, all as specified in Sections II and III of the Tariff (collectively, the “Products”).

To the extent permitted by applicable law, any warranties provided by the sellers or assignors to the ISO of the Products which cover the Products, whether express or implied, are hereby passed to the Customers on a “pass through basis” and to the extent not passed through, any such warranties are hereby assigned by ISO to Customers. Sellers and assignors to the ISO and Customers acknowledge that warranties on such Products are limited to that offered by the seller or assignor to the ISO and will exist, if at all, solely between the seller or assignor to the ISO and the Customer. AS BETWEEN CUSTOMER AND ISO AS COUNTERPARTY, NO EXPRESS OR IMPLIED WARRANTIES ARE MADE BY THE ISO REGARDING THE PRODUCTS SOLD BY THE ISO AS COUNTERPARTY, AND ANY SUCH PRODUCTS ARE PROVIDED ON AN “AS IS” AND “AS AVAILABLE” BASIS. THE ISO MAKES NO WARRANTY OR REPRESENTATION THAT THE PRODUCTS WILL BE UNINTERRUPTED OR ERROR FREE. THE CUSTOMER HEREBY WAIVES, AND THE ISO HEREBY DISCLAIMS, ALL OTHER WARRANTIES, EXPRESSED OR IMPLIED, INCLUDING, WITHOUT LIMITATION, ANY WARRANTY OF MERCHANTABILITY, FITNESS FOR A PARTICULAR PURPOSE, TITLE AND NON-INFRINGEMENT. THE ISO DOES NOT WARRANT THAT THE PRODUCTS OFFERED WILL MEET CUSTOMER’S REQUIREMENTS. NO ORAL OR WRITTEN INFORMATION OR ADVICE GIVEN BY THE ISO OR ANY AUTHORIZED REPRESENTATIVE OF THE ISO SHALL CREATE A WARRANTY OR IN ANY WAY INCREASE THE SCOPE OF ANY PASS THROUGH OR ASSIGNED WARRANTY. SOME JURISDICTIONS DO NOT ALLOW THE EXCLUSION OF IMPLIED WARRANTIES IN CERTAIN CIRCUMSTANCES, SO THE ABOVE EXCLUSION APPLIES ONLY TO THE EXTENT PERMITTED BY APPLICABLE LAW.

I.3.1. Service Agreement:

Receipt of service under this Tariff requires the execution of a Market Participant Service Agreement in the form specified in Attachment A or Attachment A-1, as applicable, to this Tariff unless the Customer seeks transmission service only and does not participate in the New England Markets (in which case the

Customer must execute a Transmission Service Agreement). Receipt of Local Service under Section II of this Tariff requires the execution of a Transmission Service Agreement in the form specified in Attachment A to Schedule 21 of Section II of this Tariff for Local Service and shall be subject to the requirements of Schedule 21. Receipt of OTF Service under Section II of this Tariff requires the execution of a Transmission Service Agreement in the appropriate form specified under Schedule 20 of Section II of this Tariff and shall be subject to the requirements of Schedule 20.

I.3.2. Assets:

Each Market Participant shall, to the fullest extent practicable, cause all of the Assets it owns or operates to be designed, constructed, maintained and operated in accordance with Good Utility Practice and the provisions of this Tariff, the ISO New England Operating Procedures, and the ISO New England Planning Procedures.

I.3.3. Maintenance and Repair:

Each Market Participant shall, to the fullest extent practicable: (a) cause Assets owned or operated by it to be withdrawn from operation for maintenance and repair only in accordance with maintenance schedules reported to, and approved and published by the ISO in accordance with the ISO New England Operating Procedures, (b) restore such Assets to good operating condition with reasonable promptness, and (c) in emergency situations, accelerate maintenance and repair at the reasonable request of the ISO in accordance with the ISO New England Planning Procedures.

I.3.4. Central Dispatch:

Each Market Participant shall, to the fullest extent practicable, subject each of the Assets it owns or operates to central dispatch by the ISO; provided, however, that each Market Participant shall at all times be the sole judge as to whether or not and to what extent safety requires that at any time any of such facilities will be operated at less than their full capacity.

I.3.5. Provision of Information:

The Customers shall provide the ISO with any and all information within their custody or control that the ISO deems necessary to perform its obligations under this Tariff, subject to applicable confidentiality limitations contained in the ISO New England Information Policy. Each Customer shall ensure that the ISO has an accurate list of the Customer's Affiliates. The ISO will compile a list that shall be considered definitive. It will be the Customer's responsibility to regularly review the list and to promptly (and in

advance of Affiliate changes, where possible) provide the ISO with additions and/or corrections to the list and, when requested, relevant supporting documentation.

I.3.6. Records and Information:

Each Customer shall keep such records as may reasonably be required by the ISO, and shall furnish to the ISO such records, reports and information (including forecasts) as it may reasonably require, provided that confidentiality thereof is protected in accordance with the ISO New England Information Policy.

I.3.7. Payment of Invoices; Compliance with Policies:

Each Customer is obligated to pay when due in accordance with this Tariff, the ISO New England Financial Assurance Policy and the ISO New England Billing Policy all amounts invoiced to it pursuant to this Tariff, and to comply with those terms, conditions and policies in all respects. If a Customer fails to meet the requirements specified in the ISO New England Financial Assurance Policy and ISO New England Billing Policy, the ISO may take such actions as are specified in those policies.

I.3.8. Protective Devices for Transmission Facilities:

Each Market Participant shall install, maintain and operate such protective equipment and switching, voltage control, load shedding and emergency facilities as the ISO and the applicable Transmission Owner may determine to be required in order to assure continuity of service and the stability of the New England Transmission System.

I.3.9. Review of Market Participant's Proposed Plans:

I.3.9.1 Submission and Review of Proposed Plan Applications:

Each Market Participant and Transmission Owner shall submit to the ISO at least sixty (60) days prior to the proposed in service date in such form, manner and detail as the ISO may reasonably prescribe, (i) any new or materially changed plan for additions to or changes to any generating and demand resources or transmission facilities rated 69 kV or above subject to control of such Market Participant or Transmission Owner, and (ii) any new or materially changed plan for any other action to be taken by the Market Participant or Transmission Owner, except for retirements of or reductions in the capacity of a generating resource or a demand resource, which may have a significant effect on the stability, reliability or operating characteristics of the Transmission Owner's transmission facilities, the transmission facilities of another Transmission Owner, or the system of a Market Participant. In the case of changes to

transmission facilities-developed through the Solutions Study process or the competitive solution process, no significant action (other than engineering reasonably necessary to support the Solutions Study or competitive solution process) shall be taken.

Unless the ISO notifies the Market Participant or Transmission Owner in writing within sixty (60) days of the submittal (or ninety (90) days if the ISO determines that it requires additional time), that it has determined that implementation of the plan will have a significant adverse effect upon the reliability or operating characteristics of the Transmission Owner's transmission facilities, the transmission facilities of another Transmission Owner, or the system of a Market Participant, the Market Participant or Transmission Owner shall be free to proceed.

The ISO shall maintain on its website a list of such applications that are currently under review and the status of each such application. The ISO shall provide notice of any action taken with respect to any such applications, including an explanation of its reasons for such action, to each Market Participant or Transmission Owner as soon as reasonably practicable after such action is taken. The time limits provided by this section may be changed with respect to any such submission by agreement between the ISO and the Market Participant or Transmission Owner.

I.3.9.2 Additional Review of Additions of or Changes to Generating Resources:

Proposals for new generating resources or modifications to existing generating resources are also subject to the terms set out in Schedule 22, the Large Generator Interconnection Procedures and Agreement, and Schedule 23, the Small Generator Interconnection Procedures and Agreement, to Section II of the Tariff.

I.3.9.3 Reliability Review of Retirements of or Reductions in Capacity of an Existing Demand Capacity Resource or Existing Generating Capacity Resource:

Proposals for the reduction of capacity from an Existing Demand Capacity Resource or an Existing Generating Capacity Resource below its Qualified Capacity amount for the relevant Capacity Commitment Period, including unit retirement, are reviewed for reliability impact pursuant to the terms set out in Section III.13.2.5.2.5 of the Tariff. Once a demand resource or generating resource has a cleared de-list bid pursuant to Section III of the Tariff it may reduce its capacity consistent with the terms of its de-list bid for all or any part of the Capacity Commitment Period of the approved de-list without further reliability review. However, any proposed physical modification to a de-listed generating facility must comply with the requirements, including the reliability review process, set out in Schedules 22 or 23, as applicable.

I.3.10. Market Participant to Avoid Adverse Effect:

If the ISO notifies a Market Participant pursuant to Section I.3.9.1 that implementation of the Market Participant's or Transmission Owner's plan has been determined to have a significant adverse effect upon the reliability or operating characteristics of the Transmission Owner's transmission facilities, the transmission facilities of another Transmission Owner, or the system of one or more Market Participants, the Market Participant or Transmission Owner shall not proceed to implement such plan unless the Market Participant (or the Non-Market Participant on whose behalf the Market Participant has submitted its plan) or Transmission Owner takes such action or constructs at its expense such facilities as the ISO determines to be reasonably necessary to avoid such adverse effect.

I.4 Termination Of Status As A Customer

The ISO shall have the right to terminate a Customer for the reasons stated, and in the manner specified, in the ISO New England Financial Assurance Policy and ISO New England Billing Policy.

I.5 Force Majeure, Liability and Indemnification

I.5.1. Force Majeure:

Neither the ISO, a Transmission Owner, a Schedule 20A Service Provider nor a Customer will be considered in default as to any obligation under this Tariff if prevented from fulfilling the obligation due to an event of Force Majeure; notwithstanding the foregoing, no event of Force Majeure affecting any entity shall excuse that entity from any payment, charge, penalty, financial consequence or settlement responsibility that it is obligated to make under this Tariff. An entity whose performance under this Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Tariff, and shall promptly notify the ISO, the Transmission Owner, a Schedule 20A Service Provider or the Customer, whichever is appropriate, of the commencement and end of each event of Force Majeure.

I.5.2. Liability:

The ISO shall not be liable for money damages or other compensation to the Customer for actions or omissions by the ISO in performing its obligations under this Tariff or any Service Agreement thereunder, except to the extent such act or omission by the ISO is found to result from its gross negligence or willful misconduct. A Transmission Owner shall not be liable for money damages or other compensation to the Customer for acts or omissions by such Transmission Owner in performing its obligations under this Tariff or any Service Agreement thereunder, except to the extent such act or omission by such Transmission Owner is found to result from its gross negligence or willful misconduct. A Schedule 20A Service Provider shall not be liable for money damages or other compensation to the Customer for action or omissions by such Schedule 20A Service Provider in performing its obligations under this Tariff or any Service Agreement thereunder, except to the extent such act or omission by such Schedule 20A Service Provider is found to result from its gross negligence or willful misconduct. To the extent the Customer has claims against the ISO, a Transmission Owner or Schedule 20A Service Provider, the Customer may only look to the assets of the ISO, a Transmission Owner or Schedule 20A Service Provider (as the case may be) for the enforcement of such claims and may not seek to enforce any claims against the directors, members, shareholders, officers, employees or agents of the ISO, a Transmission Owner or Schedule 20A Service Provider or Affiliate who, the Customer acknowledges and agrees, have no personal or other liability for obligations of the ISO, a Transmission Owner or Schedule 20A Service Provider by reason of their status as directors, members, shareholders, officers, employees or agents of the ISO, a Transmission Owner, Schedule 20A Service Provider or Affiliate. In no event shall the ISO, a Transmission Owner, Schedule 20A Service Provider or any Customer be liable for any

incidental, consequential, multiple or punitive damages, loss of revenues or profits, attorneys fees or costs arising out of, or connected in any way with the performance or non-performance under this Tariff or any Service Agreement thereunder. Notwithstanding the foregoing, nothing in this section shall diminish a Customer's obligations under Section I.5.3 of this Tariff or under Schedules 18, 20 and 21 of the OATT.

I.5.3. Indemnification:

Each Customer shall at all times indemnify, defend, and save harmless the ISO, the Transmission Owners and the Schedule 20A Service Providers and their respective directors, officers, members, employees and agents from its properly allocable share of any and all damages, losses, claims and liabilities by or to third parties arising out of or resulting from the performance by the ISO, Transmission Owners or Schedule 20A Service Providers under this Tariff or any Service Agreement thereunder, any bankruptcy filings made by a Customer, or the actions or omissions of the Customer in connection with this Tariff or any Service Agreement thereunder, except in case of the ISO, gross negligence or willful misconduct by the ISO or its directors, officers, members, employees or agents, and, in the case of a Transmission Owner or Schedule 20A Service Provider, the gross negligence or willful misconduct by such Transmission Owner or Schedule 20A Service Provider or its directors, officers, members, employees or agents. Each Customer shall also reimburse the ISO for any indemnity payments made by the ISO pursuant to an operating agreement filed with the Commission. The ISO shall recover the amounts due from each Customer under this Section I.5.3 through Section IV.A of the Tariff in the same manner as the ISO recovers insurance expense (premium) costs, and each Customer shall be responsible for a share of the amounts due from all Customers under this Section I.5.3 that is proportionate to its responsibility for a share of such total insurance expense (premium) costs. The amount of any indemnity payment or reimbursement of indemnity payment hereunder by a Customer shall be reduced (including, without limitation, retroactively) by any insurance proceeds or other amounts actually recovered by the indemnified or reimbursed party in respect of the indemnified action, claim, demand, cost, damage or liability or ISO indemnification payment. The obligations of each Customer to indemnify the ISO, Transmission Owners and Schedule 20A Service Providers shall be several, and not joint or joint and several.

I.6 Dispute Resolution:

Any dispute arising under this Tariff shall be the subject of good-faith negotiations among the ISO, the Transmission Owner, the Schedule 20A Service Provider, and a Customer, as applicable, unless otherwise stated in this Tariff, except that disputes concerning Schedules 18, 20 and 21 shall be resolved directly between the Customer and the MTO, OTO, Schedule 20A Service Provider or PTO, as applicable, using the procedures specified below. Each affected party shall designate one or more representatives with the authority to negotiate the matter in dispute to participate in such negotiations. The affected parties shall engage in such good-faith negotiations for a period of not less than sixty (60) calendar days, unless: (a) a party identifies exigent circumstances reasonably requiring expedited resolution of the dispute by the Commission or a court or agency with jurisdiction over the dispute; or (b) the provisions of this Tariff otherwise provide a party the right to submit a dispute directly to the Commission for resolution. Any other dispute that is not resolved through good-faith negotiations may be submitted by any party for resolution to the Commission, to a court or to an agency with jurisdiction over the dispute upon the conclusion of such negotiations. Any party may request that any dispute submitted to the Commission for resolution be subject to the Commission's settlement procedures. Notwithstanding the foregoing, any dispute arising under this Tariff may be submitted to arbitration or any other form of alternative dispute resolution upon the agreement of all affected parties to participate in such an alternative dispute resolution process.

I.7 Creditworthiness:

Exhibits IA through ID to Section I of the Tariff provide the ISO's credit review procedures and the types of security that are acceptable to the ISO to protect against the risk of non-payment, and shall be binding upon Customers.

I.8 Rights Under The Federal Power Act:

Nothing in this Tariff shall restrict the rights of any party to exercise its rights under relevant provisions of the Federal Power Act.

I.9 Pre-Existing Contracts:

To the extent that Customers are parties to pre-existing wholesale power or transmission service contracts effective as of the Operations Date, and further, to the extent that provisions in such pre-existing wholesale power or transmission service contracts make reference to the Restated New England Power Pool Agreement (“RNA”), then such provisions shall remain in effect but the references to the RNA contained therein shall be deemed instead to make reference to the applicable provisions in the agreements and tariffs filed in connection with the establishment of the ISO, as determined pursuant to Attachment C of the Tariff, i.e., the Mapping Document.

SECTION II
ISO NEW ENGLAND OPENACCESS TRANSMISSION TARIFF

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II.A. COMMON SERVICE PROVISIONS

II.1 Definitions

Whenever used in this OATT, in either the singular or plural number, capitalized terms shall have the meanings specified in Section I of the Tariff. Terms used in this OATT that are not defined in Section I shall have the meanings customarily attributed to such terms by the electric utility industry in New England or as defined elsewhere in the ISO New England Filed Documents.

II.2 Purpose of This OATT

Non-discriminatory open-access transmission service over the New England Transmission System is provided by the ISO under the terms and conditions of this OATT. Ancillary Services will be supplied by the ISO in accordance with Section II.4 of this OATT. The ISO acts as Counterparty for sales to its Customers of Regional Transmission Service and Ancillary Services, and as Counterparty with suppliers of Ancillary Services. The ISO offers Regional Transmission Service, as made available to the ISO under the terms of the TOA for provision to its Customers, at the rates established by the PTOs. Where Ancillary Services are initially supplied to the ISO by Market Participants for provision to the ISO's Customers, the ISO pays to or charges its Market Participants or Customers (as applicable) the amounts produced by the pertinent market clearing process or through the other pricing mechanisms described in the Tariff.

This OATT is intended to provide for comparable, non-discriminatory treatment of all similarly situated Transmission Owners, Qualified Transmission Project Sponsors and all Transmission Customers, and it shall be construed in the manner which best achieves this objective.

This OATT provides for a two-tier transmission arrangement integrating regional service which is provided by the ISO under this OATT, and Local Service which is provided by the PTOs under Schedule 21 of this OATT.

II.3 Market Rule 1

This OATT is intended to provide for transmission service in conjunction with the Standard Market Design as provided for in Market Rule 1. The provisions of Market Rule 1 are incorporated by reference as a part of this OATT, and shall apply to all entities that receive service under this OATT.

II.4 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within the New England Control Area. The Transmission Customer is required to purchase, pursuant to the applicable Schedule, from the ISO: (i) Scheduling, System Control and Dispatch Service, (ii) Reactive Supply and Voltage Control Service, (iii) Blackstart Service, and (iv) Special Constraint Resource Service.

The ISO shall arrange for the following Ancillary Services, but only for a Transmission Customer with a load obligation in the New England Markets pursuant to Market Rule 1: (i) Regulation and Frequency Response Service, (ii) Energy Imbalance Service, (iii) Ten Minute Spinning Reserve Service, (iv) Ten-Minute Non-Spinning Reserve Service (v) Thirty-Minute Operating Reserve Service and (vi) Generator Imbalance Service. A Transmission Customer with a load obligation in the New England Markets pursuant to Market Rule 1 is required to acquire these Ancillary Services, whether from the ISO, from a third party, or by self-supply.

A Transmission Customer may not decline the ISO's offer of these Ancillary Services unless the Transmission Customer demonstrates to the ISO that the Transmission Customer has acquired Ancillary Services of equal quality from another source. The Transmission Customer that is not a Market Participant must list in its Application which Ancillary Services it will purchase from the ISO.

Ancillary Services for (a) MTF shall be charged and paid for in accordance with Schedule 18 of the OATT; (b) OTF shall be charged and paid for in accordance with Schedule 20 of the OATT; and (c) Local Services shall be charged and paid for in accordance with Schedule 21.

The specific Ancillary Services, prices and/or compensation methods are described on the Schedules that are attached to and made a part of this OATT and in Market Rule 1. Sections II.4.1 through II.4.9 below list the Ancillary Services.

II.4.1 Scheduling, System Control and Dispatch Service: The rates and/or methodology are described in Schedules 1, 18, 20 and 21 of this OATT.

II.4.2 Reactive Supply and Voltage Control Service: The rates and/or methodology are described in Schedules 2 and 21 of this OATT as applicable.

II.4.3 Regulation and Frequency Response Service: Where applicable, the rates and/or methodology that shall apply to Transmission Customers for this service are described in Schedule 3 of this OATT and Market Rule 1.

II.4.4 Energy Imbalance Service: Where applicable, the rates and/or methodology that shall apply to Transmission Customers for this service are described in Schedule 4 of this OATT and Market Rule 1.

II.4.5 Ten-Minute Spinning Reserve Service: Where applicable, the rates and/or methodology that shall apply to Transmission Customers for this service are described in Schedule 5 of this OATT and Market Rule 1.

II.4.6 Ten-Minute Non-Spinning Reserve Service: Where applicable, the rates and/or methodology that shall apply to Transmission Customers for this service are described in Schedule 6 of this OATT and Market Rule 1.

II.4.6A Thirty-Minute Operating Reserve Service: Where applicable, the rates and/or methodology that shall apply to Transmission Customers for this service are described in Schedule 7 of this OATT and Market Rule 1.

II.4.7 Blackstart Service: The rates and/or methodology that shall apply to Transmission Customers for this service are described in Schedule 16 of this OATT.

II.4.8 Generator Imbalance Service: Where applicable, the rates and/or methodology that shall apply to Transmission Customers for this service are described in Schedule 10 of this OATT and Market Rule 1.

II.4.9 Special Constraint Resource Service: The rates and/or methodology that shall apply to Transmission Customers for this service are described in Schedule 19 of this OATT and Market Rule 1.

II.5 Open Access Same-Time Information System (OASIS)

Terms and conditions regarding the ISO Open Access Same-Time Information System and standards of conduct are set forth in 18 C.F.R. §37 of the Commission's regulations (Open Access Same-Time Information System and Standards of Conduct for Public Utilities) and 18 C.F.R. §38 of the Commission's regulations (Business Practice Standards and Communications Protocols for Public Utilities). Information concerning

(i) available transfer capability, (ii) transmission rates and (iii) System Conditions that may give rise to interruptions or Curtailments shall be made available to all Transmission Customers through the OASIS on a timely and non-discriminatory basis. Transmission Owners and/or the Schedule 20A Service Providers shall make available to the ISO the information required to permit the maintenance of the OASIS in compliance with Commission Order 889 and any other applicable Commission orders; provided that no Transmission Owner and/or the Schedule 20A Service Providers shall be required to furnish information which is required to be treated as confidential in accordance with the ISO policy without appropriate arrangements to protect the confidentiality of such information. In the event available transfer capability, as posted on OASIS, is insufficient to accommodate a request for the interconnection of a new or materially changed generating unit or a new or materially changed interconnection to another Control Area or new Regional Network Service or new Local Service or an Elective Transmission Upgrade, additional studies may be required as provided by this OATT pursuant to Sections II.19, II.34, and II.47 and Schedule 21. The ISO shall maintain a single OASIS that is applicable to the entire region. Transmission service offered over the New England Transmission System shall be administered under this RTO-wide OASIS node and associated business procedures. Transmission service offered over MTF or OTF shall be administered under this RTO-wide OASIS node (and associated business procedures) in accordance with the associated operating agreement and/or service administration agreement, OATT Schedules and business procedures.

The ISO, Transmission Owners, and Schedule 20A Service Providers shall post on OASIS and their public websites an electronic link to all rules, standards and practices that (i) relate to the terms and conditions of transmission service, (ii) are not subject to a North American Energy Standards Board (NAESB) copyright restriction, and (iii) are not otherwise included in this Tariff. The ISO, Transmission Owners, and Schedule 20A Service Providers shall post on OASIS and on their public website an electronic link to the NAESB website where any rules, standards and practices that are protected by copyright may be obtained. The ISO, Transmission Owners, and Schedule 20A Service Providers shall also post on OASIS and on their public website an electronic link to a statement of the process by which they shall add, delete or otherwise modify

the rules, standards and practices that are not included in this Tariff. Such process shall set forth the means by which the ISO, Transmission Owners, and Schedule 20A Service Providers shall provide reasonable advance notice to Transmission Customers and Eligible Customers of any such additions, deletions or modifications, the associated effective date, and any additional implementation procedures that the ISO, Transmission Owners, and Schedule 20A Service Providers deem appropriate.

II.6 Local Furnishing and Other Tax-Exempt Bonds

II.6.1 Transmission Owners That Own Facilities Financed by Local Furnishing or Other

Tax-Exempt Bonds: This provision is applicable only to Transmission Owners that have financed facilities for the local furnishing of electric energy with tax-exempt bonds, as described in Section 142(f) of the Internal Revenue Code (“local furnishing bonds”) or other tax-exempt bonds, as described in Section 103(b) of the Internal Revenue Code (“other tax-exempt bonds”). Notwithstanding any other provision of this OATT, the ISO shall not be required to provide service to any Eligible Customer pursuant to this OATT if the provision of such transmission service would jeopardize the tax-exempt status of any local furnishing bond(s) or other tax-exempt bonds used to finance the Transmission Owner’s facilities that would be used in providing such transmission service.

II.6.2 Alternative Procedures for Requesting Transmission Service -Local Furnishing Bonds: If a Transmission Owner determines that the provision of transmission service to be provided under this OATT would jeopardize the tax-exempt status of any local furnishing bond(s) used to finance the Transmission Owner’s facilities that would be used in providing such transmission service, the ISO shall be advised within thirty (30) days of receipt of a Completed Application by an Eligible Customer requesting such service, or the date on which this OATT becomes effective, whichever is applicable.

If an Eligible Customer thereafter renews its request for the same transmission service referred to above in this Section II.6.2 by tendering an application under Section 211 of the Federal Power Act, the Transmission Owner, within ten days of receiving a copy of the Section 211 application, will waive its rights to receive a request for service under Section 213(a) of the Federal Power Act and to the issuance of a proposed order under Section 212(c) of the Federal Power Act. The Commission, upon receipt of the Transmission Owner’s waiver of its rights to a request for service under Section 213(a) of the Federal Power Act and to the issuance of a proposed order under Section 212(c) of the Federal Power Act, shall issue an order under Section 211 of the Federal Power Act. Upon issuance of the order under Section 211 of the Federal Power Act, the Transmission Owner shall be required to provide the requested transmission service in accordance with the terms and conditions of this OATT.

II.6.3 Alternative Procedures for Requesting Transmission Service – Other Tax-Exempt Bonds: If a Transmission Owner determines that the provision of transmission service to be provided under the OATT would jeopardize the tax-exempt status of any other tax-exempt bonds used to finance the

Transmission Owner's facilities that would be used in furnishing such transmission service, it shall notify the ISO within thirty (30) days of the date on which this OATT becomes effective, and shall elect in its notice either to comply with the procedure specified in Section II.6.2 or to make its facilities unavailable under the OATT and thereby waive its right to share in the distribution of revenues received under the OATT derived from such facilities. Any such election may be changed at any time.

II.7 Reciprocity

A Transmission Customer receiving transmission service under this OATT, including transmission service under Local Service Schedules, agrees to provide comparable transmission service that it is capable of providing to the Market Participants, Transmission Owners and/or the Schedule 20A Service Providers, and their distribution Affiliates on similar terms and conditions over facilities used for the transmission of electric energy in Canada or used for such transmission in the United States and that are owned, controlled or operated by, or on behalf of the Transmission Customer and over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer's corporate Affiliates. Transmission of power on the Transmission Customer's system to the border of the New England Control Area and transfer of ownership at that point shall not satisfy, or relieve the Transmission Customer of, the obligation to provide reciprocal service. This reciprocity requirement applies not only to the Transmission Customer that obtains transmission service under the OATT, but also to all parties to a transaction that involves the use of transmission service under the OATT, including the power seller, buyer and any intermediary, such as a power marketer. This reciprocity requirement also applies to any Transmission Customer that owns, controls or operates transmission facilities that uses an intermediary, such as a power marketer, to request transmission service under the OATT. If the Transmission Customer does not own, control or operate transmission facilities, the Transmission Customer must include in its Application a sworn statement of one of its duly authorized officers or other representatives that the purpose of its Application is not to assist an Eligible Customer to avoid the requirements of this provision.

II.8 Billing and Invoicing; Accounting

II.8.1 Billing Procedure: Billings to Transmission Customers shall be made in accordance with this Section II.8, Schedules 18, 20 and 21 and the ISO New England Billing Policy, as applicable, and as may be supplemented by other billing procedures established pursuant to the TOA, a MTOA or an OTOA, as applicable.

II.8.2 Invoicing: Invoicing and payments are addressed in Attachments L1, L2, L3 and L4 to Section II of the Transmission, Markets and Services Tariff.

II.8.3 Interest on Unpaid Balances: Interest on any unpaid amounts (including amounts placed in escrow) will be calculated in accordance with the methodology specified for interest on refunds in 18 C.F.R. §35.19a(a)(2)(iii) of the Commission's regulations. Interest on delinquent amounts will be calculated from the due date of the bill to the date of payment. Payments must be made by Electronic Funds Transfer or in immediately available funds.

II.8.4 Customer Default: In the event a Transmission Customer fails to make payment to the ISO for services under this OATT, other than under Schedules 18, 20 and 21 of this OATT, on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after the ISO notifies the Transmission Customer to cure such failure, a default by the Transmission Customer will be deemed to exist under this OATT. Additional default provisions may apply as stated under the ISO New England Billing Policy, Exhibit ID to Section I of the Transmission, Markets and Services Tariff. Upon the occurrence of a default under this OATT, the ISO may initiate a proceeding with the Commission to terminate service but shall not terminate service until the Commission approves such termination. In the event of a billing dispute between the ISO and the Transmission Customer, service will continue to be provided under a Service Agreement, and service termination proceedings will not be initiated as long as the Transmission Customer continues to make all payments invoiced by the ISO, including any disputed amounts, subject to resolution of such dispute in favor of such Transmission Customer. If the Transmission Customer fails to meet this requirement for continuation of service, then the ISO may provide notice to the Transmission Customer of the ISO's intention to suspend service in sixty days, in accordance with applicable Commission rules and regulations, and may proceed with such suspension.

II.8.5 Study Costs and Revenues: Transmission Owners shall (i) include in a separate operating revenue account or sub-account the revenues, if any, it receives from transmission service when making Third-Party Sales under Section II of the Tariff, and (ii) include in a separate transmission operating expense account or sub-account, costs properly chargeable to expense that are incurred to perform any System Impact Studies or Facilities Studies which the Transmission Owner conducts or is subcontracted to conduct to determine if it must construct new transmission facilities or upgrades necessary for its own uses, including Third-Party Sales, if any, under this OATT; and include in a separate operating revenue account or sub-account the revenues received for System Impact Studies or Facilities Studies performed when such amounts are separately stated and identified in a billing under the OATT.

II.8.6 Billing and Invoicing For Other Services and Transactions: Billings and invoicing for MTF Service, OTF Service, Local Service, Excepted Transactions, Grandfathered Intertie Agreements and MEPCO Grandfathered Transmission Service Agreements will be made pursuant to the terms and conditions of Schedules 18, 20 and 21 of this OATT, Excepted Transactions, Grandfathered Intertie Agreements or MEPCO Grandfathered Transmission Service Agreements under which service is provided.

II. 8.7 Study Costs and Revenues of a Non-Incumbent Transmission Developer: Non-Incumbent Transmission Developers that are not otherwise party to the TOA shall include in a separate transmission operating expense account or sub-account, costs properly chargeable to expenses that are incurred to perform studies for Phase One Proposals and Phase Two Solutions, and Stage One Proposals and Stage Two Solutions pursuant to Attachment K of this OATT; and include in a separate operating revenue account or sub-account the revenues received for such studies when such amounts are separately stated and identified in a billing under the OATT.

II.8.8 Refund Obligations and Surcharge Rights Associated With Adjustments to Regional and Local Rates: The ISO, PTOs and Non-Incumbent Transmission Developers shall (consistent with Attachment L4 to this OATT) calculate refunds from the PTOs or Non-Incumbent Transmission Developers to the ISO and/or surcharges by the PTOs or Non-Incumbent Transmission Developers to the ISO, which will be passed through by the ISO to its Customers, attributable to adjustments associated with charges under Attachment F and Schedules 1, 8, 9, 13 and 14 of this OATT resulting from: (i) an audit of the regional rates; (ii) a Commission order, including, without limitation, orders approving settlements and letter orders or (iii) a billing correction. Any recalculations shall be made as though any such adjustments had been in effect as of the effective date of the required change(s), with interest to the extent required by applicable order or contract. The affected PTO(s) or Non-Incumbent Transmission Developer(s) shall

individually calculate any refunds and/or surcharges associated with any changes in the rates under their respective Local Service Schedules or other rate recovery mechanisms, as appropriate. The ISO, PTOs and Non-Incumbent Transmission Developers shall, to the extent necessary, reasonably cooperate with each other in performing such recalculations. The refund obligations to the ISO associated with such adjustments to rates under Schedules 1, 8, 9 and 21 shall be several, and not joint, obligations and rights of the PTOs; the refund obligations to the ISO associated with such adjustments to rates under Schedules 13 and 14 shall be several, and not joint, obligations and rights of the Non-Incumbent Transmission Developers.

II.8.9 Creditworthiness: The creditworthiness procedures are specified in Attachments L1 through L4 to this OATT.

II.9 Regulatory Filings

Nothing contained in this OATT or any Service Agreement shall be construed as affecting in any way the right of the ISO, the Transmission Owners, a Schedule 20A Service Provider, or a Non-Incumbent Transmission Developer to file (as specified in and subject to the terms of the TOA, an MTOA, an OTOA or NTDOA, as applicable) with the Commission under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation.

Nothing contained in this OATT or any Service Agreement shall be construed as affecting in any way the ability of any Transmission Customer receiving service under this OATT, an Excepted Transaction, a Grandfathered Intertie Transaction or a MEPCO Grandfathered Transmission Service Agreement to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

II.10 Stranded Costs

II.10.1 General: This OATT shall not be used to evade or enhance in whole or in part any requirements of state or federal law concerning stranded costs, or any order or regulation issued pursuant to state or federal law concerning stranded costs, or the stranded cost policies or other charges established by law or by the regulatory commission with jurisdiction.

II.10.2 Commission Requirements: A Transmission Owner, a Schedule 20A Service Provider or a distribution company having the service territory in which the Transmission Customer is located which seeks to recover stranded costs from a Transmission Customer may do so in accordance with the terms, conditions and procedures in the Commission's Order No. 888 or other relevant Commission orders. However, the Transmission Owner or Schedule 20A Service Provider must file separately any specific proposed stranded cost charge under Section 205 of the Federal Power Act.

II.10.3 Wholesale Contracts: Nothing in this Section II.10 is intended to affect or alter the rights or obligations of parties under wholesale requirements contracts.

II.10.4 Right to Seek or Contest Recovery Unimpaired: No provision in this OATT shall impair a Transmission Owner's, Schedule 20A Service Provider's or distribution company's right to seek stranded cost relief from the appropriate regulatory body or court or the right of any entity to contest such relief.

II.11 Nature of Regional Network Service

Regional Network Service is the service over the PTF pursuant to Part II.B of this OATT which is provided by the ISO to Network Customers to serve their loads. It includes transmission service over the PTF for the delivery to a Network Customer of its energy and capacity in Network Resources and delivery to or by Network Customers of energy and capacity in Market transactions.

When a Real-Time External Transaction purchase is submitted by the Transmission Customer and is scheduled in the Real-Time Energy Market, the submission shall be deemed a request for Regional Network Service and the ISO shall generate a reservation for the transmission service over the PTF equal to the transaction's maximum scheduled flow during the operating hour. This reservation amount shall be the basis for the Reserved Capacity. Each Transmission Customer which has a Regional Network Load within or outside of the New England Control Area shall pay for Regional Network Service under the terms of Section II.B of this OATT.

II.B. REGIONAL NETWORK SERVICE

Regional Network Service will be provided by the ISO to Transmission Customers pursuant to the applicable terms and conditions of this OATT. Local Network Service will be provided pursuant to the applicable terms and conditions of Schedule 21 of this OATT.

II.12 Availability of Regional Network Service

II.12.1 Provision of Regional Network Service: Regional Network Service shall be available to each Eligible Customer.

II.12.2 Eligibility to Receive Regional Network Service: Regional Network Service shall be taken and paid for by each Eligible Customer which has a load within the New England Control Area unless the Eligible Customer operates its own Control Area. Transmission Customers which take Regional Network Service must also take Local Network Service except as otherwise provided in Section II.40 of this OATT. The Local Network Service shall provide:

- (a) for a pro rata allocation of monthly revenue requirements not otherwise paid for through charges to Eligible Customers for Local Point-to-Point Service among the PTO's Network Customers receiving service under the Local Service Schedule on the basis of their loads during the hour in the month in which the total connected load to the Local Network is at its maximum, without any adjustment for credits for generation;
- (b) for the recovery under the Local Service Schedule from Eligible Customers taking Regional Network Service of that portion of the PTO's annual transmission revenue requirements with respect to PTF which is not recovered through the distribution of revenues from Regional Network Service;
- (c) that where all or a part of the load of Transmission Customers taking service under this OATT is connected directly to PTF, the Transmission Customers receiving the service shall have no obligation to pay charges for service across Non-PTF transmission facilities with respect to that portion of the connected load after the Transition Period, but shall continue to pay its share of any other Local Network Service costs directly associated with the PTF-connected load; provided that in the event of any inconsistency between the foregoing provisions and the terms of any Excepted Transaction which is listed in Attachment G-1 to this OATT, the Excepted Transaction shall control;
- (d) that if the PTO receives a distribution out of revenues paid for Through or Out Service, the amounts received shall reduce its Local Network Service revenue requirements; and

- (e) that if the PTO receives transmission revenues from a Transmission Customer taking Local Network Service from the PTO with respect to an Excepted Transaction, the amounts received shall reduce the amount due from such Transmission Customer connected to the PTO's transmission system for Local Network Service provided thereto by the PTO rather than reducing the PTO's total cost of service.

II.13 [Reserved]

II.14 [Reserved]

II.15 Nature of Regional Network Service

II.15.1 Scope of Service: Regional Network Service is the transmission service described above that allows Network Customers to efficiently and economically utilize their resources and Interchange Transactions to serve their Regional Network Load located in the New England Control Area and any additional load that may be designated pursuant to Section II.18.3 of this OATT. The Network Customer taking Regional Network Service must obtain or provide Ancillary Services pursuant to Section II.4 of this OATT.

II.15.2 ISO and PTO Responsibilities: As provided in the TOA and this OATT, the ISO and the PTOs will plan, construct, operate and maintain the PTF in accordance with Good Utility Practice and their planning obligations in Attachment K in order to allow the ISO to provide the Network Customer with Regional Network Service over the PTF. Each PTO, on behalf of its Native Load Customers, shall be required to designate resources and loads in the same manner as any Network Customer under Part II.B of this OATT. This information must be consistent with the information used by the ISO to calculate available transfer capability. The PTOs and the ISO as applicable and in accordance with the TOA shall include the Network Customer's Regional Network Load in PTF planning and shall, consistent with Good Utility Practice and Attachment K, endeavor to construct and place into service sufficient transfer capability to deliver Network Resources to serve the Network Customer's Regional Network Load on a basis comparable to the PTOs' delivery of their own generating and purchased resources to their Native Load Customers.

II.15.3 Real Power Losses: Real power losses are associated with all transmission service. Neither the ISO nor the Transmission Owners nor the Schedule 20A Service Providers are obligated to provide real power losses. The cost of PTF losses shall be recovered through the Loss Component of the Locational Marginal Prices provided for in ISO New England Operating Documents.

II.15.4 Restrictions on Use of Service: The Network Customer is entitled to use Regional Network Service for any of the uses specified in Part II.B of this OATT.

II.16 Initiating Service

II.16.1 Condition Precedent for Receiving Service: Subject to the terms and conditions of Part II.B of this OATT, the ISO will provide Regional Network Service to any Eligible Customer, provided that (i) the Eligible Customer completes an Application for service as provided under Part II.B of this OATT, (ii) the Eligible Customer and the ISO complete the technical arrangements set forth in Sections II.16.3 and II.16.4 of this OATT, and (iii) unless the Eligible Customer has executed an MPSA or on whose behalf the RTO has filed an unexecuted MPSA, the Eligible Customer executes a Service Agreement in the form of Attachment B to this OATT for service under Part II.B of this OATT or requests in writing that the ISO file a proposed unexecuted Service Agreement with the Commission.

II.16.2 Application Procedures: An Eligible Customer requesting Regional Network Service (which includes a request to recognize a new Regional Network Load) under this OATT must submit an Application for Regional Transmission Service, which can be found on the OASIS, to the ISO as far as possible in advance of the month in which service is to commence. Unless a MPSA has been executed, a deposit approximating the charge for one (1) month of service will also be required. Completed Applications for Regional Network Service will be assigned a priority according to the date and time the Application is received, with the earliest Application receiving the highest priority. A Completed Application shall provide all of the information included in 18 C.F.R. §2.20 including but not limited to the following:

- (a) The identity, address, telephone number and facsimile number of the party requesting service;
- (b) A statement that the party requesting service is, or will be upon commencement of service, an Eligible Customer under this OATT;
- (c) A description of the Regional Network Load at each Point of Delivery. This description should separately identify and provide the Eligible Customer's best estimate of the total loads to be served at each transmission voltage level, and the loads to be served from each Transmission Owner substation at the same transmission voltage level. The description should include a ten-year forecast of summer and winter load resource requirements beginning with the first year after the service is scheduled to commence;

- (d) The amount and location of any interruptible loads included in the Regional Network Load. This shall include the summer and winter capacity requirements for each interruptible load (had such load not been interruptible), that portion of the load subject to interruption, the conditions under which an interruption can be implemented and any limitations on the amount and frequency of interruptions. An Eligible Customer should identify the amount of interruptible customer load (if any) included in the ten-year load forecast provided in response to (iii) above;
- (e) A description of Network Resources (current and ten-year projection). For each on-system Network Resource, if not otherwise available to the ISO, such description shall include:
- Unit size and amount of capacity from that unit to be designated as Network Resource
 - VAR capability (both leading and lagging) of all generators
 - Operating restrictions
 - Any periods of restricted operations throughout the year
 - Maintenance schedules
 - Minimum loading level of unit
 - Normal operating level of unit
 - Any must-run unit designations required for system reliability or contract reasons
 - Approximate variable dispatch price (\$/MWh), consistent with Market Rule 1, for redispatch computations
 - Arrangements governing sale and delivery of power to third parties from generating facilities located in the New England Control Area, where only a portion of unit output is designated as a Network Resource; For each off-system Network Resource, such description shall include:
 - Identification of the Network Resource as an off-system resource
 - Amount of power to which the customer has rights
 - Identification of the control area from which the power will originate
 - Point(s) of Delivery to the New England Transmission System
 - Transmission arrangements on the external transmission system(s)
 - Operating restrictions, if any
 - Any periods of restricted operations throughout the year
 - Maintenance schedules
 - Minimum loading level of unit

- Normal operating level of unit
- Any must-run unit descriptions required for system reliability or contract reasons
- Approximate variable generating cost (\$/MWH) for redispatch computations;

(f) Description of Eligible Customer's transmission system:

- Load flow and stability data, such as real and reactive parts of the load, lines, transformers, reactive devices and load type, including normal and emergency ratings of all transmission equipment in a load flow format compatible with that used by the ISO.
- Operating restrictions needed for reliability
- Operating guides employed by system operators and the ISO
- Contractual restrictions or committed uses of the Eligible Customer's transmission system, other than the Eligible Customer's Regional Network Loads and Resources
- Location of Network Resources described in subsection (v) above
- Ten-year projection of system expansions or upgrades
- Transmission system maps that include any proposed expansions or upgrades
- Thermal ratings of Eligible Customer's Control Area ties with other Control

Areas;

(g) Service Commencement Date and the term of the requested Regional Network Service. The minimum term for Regional Network Service is one (1) year; and

(h) A statement signed by an authorized officer from or agent of the Network Customer attesting that all of the network resources listed pursuant to Section 16.2(e) satisfy the following conditions:

- (1) the Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service under Part II.B of the OATT; and (2)
- the Network Resources do not include any resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Regional Network Load on a non-interruptible basis; and

- (i) Any additional information required of the Transmission Customer as specified in Attachment K.

Unless the Eligible Customer and the ISO agree to a different time frame, the ISO must acknowledge the request within ten (10) days of receipt. The acknowledgment must include a date by which a response, including a Transmission Service Agreement (unless an MPSA has been filed), will be sent to the Eligible Customer. If an Application fails to meet the requirements of this section, the ISO shall notify the Eligible Customer requesting service within fifteen (15) days of receipt and specify the reasons for such failure. Wherever possible, the ISO will attempt to remedy deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the ISO shall return the Application without prejudice to the Eligible Customer, who may thereafter file a new or revised Application that fully complies with the requirements of this section. The Eligible Customer will be assigned a new reservation priority consistent with the date of the new or revised Application. The ISO shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

II.16.3 Technical Arrangements to be Completed Prior to Commencement of Service: Regional Network Service shall not commence until the PTO, the Network Customer, or a third party, have completed installation of all equipment specified by the ISO consistent with Good Utility Practice and any additional requirements reasonably and consistently imposed to ensure the reliable operation of the PTF. The PTO and the ISO shall exercise reasonable efforts, in coordination with the Network Customer, to complete such arrangements as soon as practicable taking into consideration the Service Commencement Date.

II.16.4 Network Customer Facilities: The provision of Regional Network Service shall be conditioned upon the Network Customer's constructing, maintaining and operating the facilities on its side of each Point of Delivery or interconnection necessary to reliably deliver capacity and energy from the PTF to the Network Customer. The Network Customer shall be solely responsible for constructing or installing and operating and maintaining all facilities on the Network Customer's side of each such Point of Delivery or interconnection.

II.16.5 Filing of Transmission Service Agreement: The ISO will file Service Agreements for Regional Network Service with the Commission in compliance with applicable Commission regulations.

II.17 Network Resources

II.17.1 Designation of Network Resources: The designation of generation resources as Network Resources shall be effected automatically in accordance with the definition thereof for Market Participant and as required within the MPSA. Except as provided in the preceding sentence, a Network Customer shall designate to the ISO those Network Resources which are owned, purchased or leased by it. The Network Resources so designated may not include resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Regional Network Load on a non-interruptible basis. Any owned, purchased or leased resources that were serving the Network Customer's loads under firm agreements entered into on or before the Compliance Effective Date shall be deemed to continue to be so owned, purchased or leased by it until the Network Customer informs the ISO of a change.

II.17.2 Designation of New Network Resources: The Network Customer shall identify to the ISO (and the PTO, as applicable) with as much advance notice as practicable any new (or modification to existing) Network Resources which are owned, purchased or leased by the Network Customer. A designation of a Network Resource as owned, purchased or leased by the Transmission Customer must be made by a notice to the ISO and the PTO, as applicable.

II.17.3 Termination of Network Resources: The Network Customer may terminate the designation of all or part of a Network Resource as owned, purchased or leased by it at any time but should provide notification to the ISO and the affected Transmission Owner(s) or the Schedule 20A Service Provider as soon as reasonably practicable.

II.17.4 Network Customer Redispatch Obligation: As a condition to receiving Regional Network Service, the Network Customer agrees to redispatch its Network Resources as requested by the ISO pursuant to Section II.20.2 of this OATT. The ISO will redispatch all Resources subject to its control, pursuant to ISO New England Operating Documents, in order to meet load and to accommodate Real-Time External Transactions. Transmission Customers will be charged for the Congestion Costs and any other costs associated with such redispatch in accordance with ISO New England Operating Documents.

II.17.5 Transmission Arrangements for Network Resources Not Physically Interconnected With The PTF: The Network Customer shall be responsible for any arrangements necessary to deliver capacity and

energy from a Network Resource not physically interconnected with the PTF. The ISO will undertake reasonable efforts to assist the Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

II.17.6 Limitation on Designation of Resources: The Network Customer must demonstrate that it owns, leases or has committed to purchase an Ownership Share in a generation resource pursuant to an executed contract in order to designate the generating resource to serve its Regional Network Load. Alternatively, the Network Customer may establish that execution of a contract is contingent upon the availability of transmission service under Part II.B of this OATT. An Ownership Share in a generating unit within the New England Control Area which is placed in service after the Compliance Effective Date (other than a unit which has lost its capacity value when its capacity value is restored or a deactivated unit which may be reactivated without satisfying the requirements of Section II.46 of the OATT in accordance with the provisions thereof) may not be designated to serve a Network Customer's load unless, and only to the extent that, it has been determined to be integrated into the PTF in accordance with Section II.46 of this OATT.

II.17.7 Use of Interface Capacity by the Network Customer: There is no limitation upon a Network Customer's use of the PTF at any particular interface to integrate the Network Customer's resources (or substitute purchases in Interchange Transactions) with its Regional Network Loads. However, a Network Customer's use of the ISO total interface capacity, between the New England Control Area and a neighboring control area, to serve its Regional Network Load may not exceed the transfer capability of that interface.

II.18 Designation of Regional Network Load

II.18.1 Regional Network Load: The Network Customer must designate the individual Regional Network Loads to which it expects to have served through Regional Network Service.

II.18.2 Regional Network Load Located Within the New England Control Area: The Network Customer shall provide the ISO and the affected Transmission Owner(s) with as much advance notice as reasonably practicable of the designation of Regional Network Load that is located within the New England Control Area and that will be directly or indirectly receiving service over the PTF. A designation of new Regional Network Load must be made through a modification of service pursuant to a new Application. The PTOs will use due diligence to install or cause to be installed any transmission facilities required to interconnect a new Regional Network Load designated by the Network Customer. The costs of new facilities required to interconnect a new Regional Network Load shall be determined in accordance with the procedures provided in Section II.19.4 of this OATT and shall be charged to the Network Customer in accordance with Commission policy and Schedules 11 and 12 to this OATT.

II.18.3 Regional Network Load Located Outside the New England Control Area): This section applies to both initial designation pursuant to Section II.18.1 of this OATT and the subsequent addition of new Regional Network Load not physically interconnected with the PTF. To the extent that the Network Customer desires to obtain transmission service for a load outside the New England Control Area, the Network Customer shall have the option of (1) electing to include the entire load as Regional Network Load for all purposes under Part II.B of this OATT and designating resources to serve such additional Regional Network Load, or (2) excluding that entire load from its Regional Network Load. To the extent that the Network Customer gives notice of its intent to add a new Regional Network Load as part of its Regional Network Load pursuant to this section the request must be made through a modification of service pursuant to a new Application, and shall be available only so long as a scheduling and interconnection agreement acceptable to the ISO shall be required to be in effect with (a) the Control Area in which the load is located and (b) any control areas that are providing transmission service between the control area in which the load is located and the ISO. Charges for such portion of the service shall be the applicable Through or Out Service rate as determined under Section II.25 of this OATT times the amount reserved for the Regional Network Load which is not physically interconnected with the PTF.

II.18.4 New Interconnection Points: To the extent the Network Customer desires to add a new Point of Delivery or interconnection point between the PTF and a Regional Network Load, the Network Customer shall provide the ISO with as much advance notice as reasonably practicable.

II.18.5 Changes in Service Requests: Under no circumstances shall the Network Customer's decision to cancel or delay a requested change in Regional Network Service (the addition of a new Network Resource, if any, or designation of a new Regional Network Load) in any way relieve the Network Customer of its obligation to pay the costs of transmission facilities constructed by the PTOs and charged to the Network Customer as reflected in the applicable Transmission Service Agreement or other appropriate agreement. However, the ISO must treat any requested change in Regional Network Service in a non-discriminatory manner.

II.18.6 Annual Load and Resource Information Updates: The Network Customer shall provide the ISO with annual updates of Regional Network Load and Network Resource forecasts consistent with those included in its Application under Part II.B of this OATT including, but not limited to, any information provided under Section 16.2(i) pursuant to Attachment K. The Network Customer also shall provide the ISO with timely written notice of material changes in any other information provided in its Application relating to the Network Customer's Regional Network Load, Network Resources, its transmission system or other aspects of its facilities or operations affecting the ability of the ISO to provide reliable service.

II.19 Study Procedures For Regional Network Service Requests

II.19.1 Notice of Need for System Impact Study: After receiving a request for service, the ISO shall review the effect of the requested service on the reliability requirements to meet existing and pending obligations of any affected Transmission Owner(s) and on the obligations of the particular PTO(s) whose PTF facilities will be impacted by the proposed service and shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the methodology for completing a System Impact Study is provided in Attachment D to this OATT. If the ISO determines that a System Impact Study is necessary to accommodate the requested service, it shall as soon as practicable so inform the Eligible Customer and any affected Transmission Owner(s), and so inform the PTO(s) if the System Impact Study is to be performed by the PTO(s). If the likely result of the study is that a Direct Assignment Facility will be required, the study shall be performed by the affected PTO(s), subject to review by the ISO. In such cases, the ISO shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study agreement in the form of Attachment I to this OATT, or in any other form that is mutually agreed to, pursuant to which the Eligible Customer shall agree to reimburse the ISO and any affected Transmission Owner(s) for performing or participating in the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute a System Impact Study agreement and return it to the ISO within fifteen (15) days. If the Eligible Customer elects not to execute a System Impact Study agreement, its Application shall be deemed withdrawn and its deposit (less the reasonable administrative costs incurred by the ISO and any affected Transmission Owner(s)) shall be returned with Interest.

II.19.2 System Impact Study Agreement and Cost Reimbursement:

- (a) The System Impact Study agreement, whether in the form detailed in Attachment I or in any other form that is mutually agreed to, will clearly specify the ISO's actual estimate of the actual cost, and time for completion of the System Impact Study. The actual charge shall not exceed the actual cost of the study. The System Impact Study shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the PTF.

- (b) If in response to multiple Eligible Customers requesting the service in relation to the same competitive solicitation, a single System Impact Study to accommodate the service, the costs of that study shall be prorated among the Eligible Customers.
- (c) For System Impact Studies conducted on behalf of a Transmission Owner, the Transmission Owners on whose behalf the System Impact Study is conducted will record the cost of the System Impact Studies pursuant to Section II.8.5 of this OATT.

II.19.3 System Impact Study Procedures: Upon receipt of an executed System Impact Study agreement, the ISO and any affected Transmission Owners and indirectly affected MTOs or OTOs will use due diligence to complete the required System Impact Study within a sixty-day period. The System Impact Study, if required, shall identify any system constraints, or the need for additional Direct Assignment Facilities or other facility additions or upgrades to provide the requested service. In the event that the ISO and the PTO designated to perform the study are unable to complete the required System Impact Study within such time period, the ISO shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies and an estimate of any increase in cost which will result from the delay. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer as soon as the System Impact Study is complete. The ISO will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for the Transmission Owners. The ISO shall notify the Eligible Customer immediately upon completion of the System Impact Study if the New England Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study the Eligible Customer must execute a Transmission Service Agreement(s) or request the filing of an unexecuted Transmission Service Agreement(s), or the Application shall be deemed terminated and withdrawn.

II.19.4 Facilities Study Procedures: If a System Impact Study indicates that additions or upgrades to the PTF are needed to supply the Eligible Customer's service or to mitigate indirect impacts on the MTF or OTF facilities, the ISO, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study agreement in the form of Attachment J to this OATT, or in any other form that is mutually agreed to, which is to be entered into by the Eligible Customer and the ISO and, if deemed necessary by the ISO, by one or more affected PTO(s) and pursuant to which the Eligible

Customer shall agree to reimburse the ISO and any affected PTO(s) for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study agreement and return it to the ISO within fifteen (15) days. If the Eligible Customer elects not to execute a Facilities Study agreement, its Application shall be deemed withdrawn and its deposit, if any (less the reasonable Administrative Costs incurred by the ISO and any affected entities), shall be returned with Interest. Upon receipt of an executed Facilities Study agreement, the ISO and any affected PTO(s), will use due diligence to complete the required Facilities Study within a sixty-day period. If the ISO and any affected PTO(s) are unable to complete the Facilities Study in the allotted time period, the ISO shall notify the Eligible Customer and provide an estimate of the time needed to reach a final determination and any resulting increase in the cost, along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Eligible Customer, (ii) the Eligible Customer's appropriate share of the cost of any required Transmission Upgrades, and (iii) the time required to complete such construction and initiate the requested service. The Eligible Customer shall provide a letter of credit or other reasonable form of security acceptable to the affected PTO(s) or other entities that will be responsible for the construction of the new facilities or upgrades equivalent to the costs of new facilities or upgrades consistent with commercial practices as established by the Uniform Commercial Code. The Eligible Customer shall have thirty (30) days to execute a Transmission Service Agreement(s) or request the filing of an unexecuted Transmission Service Agreement(s) and provide the required letter of credit or other form of security or the request no longer will be a Completed Application and shall be deemed terminated and withdrawn. In addition to the foregoing, each Facilities Study shall, if requested by the Transmission Customer, contain a non-binding estimate from the ISO of the Incremental ARRs, if any, resulting from the construction of the new facilities. After completion of the transmission upgrade or expansion, the ISO shall determine the Incremental ARRs, if any, resulting from the upgrade or expansion. The Transmission Customer shall be responsible for the cost of any study required to determine the Incremental ARRs.

II.19.5 Penalties for Failure to Meet Study Deadlines:

Sections 19.3 and 19.4 require the ISO to use due diligence to meet 60-day study completion deadlines for System Impact Studies and Facilities Studies.

- (i) The ISO is required to file a notice with the Commission in the event that more than twenty (20) percent of System Impact Studies and Facilities Studies completed by the ISO in any two consecutive calendar quarters are not completed within the 60-day study completion

deadlines. Such notice must be filed within thirty (30) days of the end of the calendar quarter triggering the notice requirement.

- (ii) For the purposes of calculating the percent of System Impact Studies and Facilities Studies processed outside of the 60day study completion deadlines, the ISO shall consider all System Impact Studies and Facilities Studies that it completes during the calendar quarter. The percentage should be calculated by dividing the number of those studies which are completed on time by the total number of completed studies. The ISO may provide an explanation in its notification filing to the Commission if it believes there are extenuating circumstances that prevented it from meeting the 60-day study completion deadlines.
- (iii) The ISO is subject to an operational penalty if it completes ten (10) percent or more of System Impact Studies and Facilities Studies outside of the 60-day study completion deadlines for each of the two calendar quarters immediately following the quarter that triggered its notification filing to the Commission. The operational penalty will be assessed for each calendar quarter for which an operational penalty applies, starting with the calendar quarter immediately following the quarter that triggered the ISO's notification filing to the Commission. The operational penalty will continue to be assessed each quarter until the ISO completes at least ninety (90) percent of all System Impact Studies and Facilities Studies within the 60-day deadline.

For penalties assessed in accordance with subsection (iii) above, the penalty amount for each System Impact Study or Facilities Study shall be equal to \$500 for each day the ISO takes to complete that study beyond the 60-day deadline.

II.19.6 Clustering of Regional Network Service Studies:

- (a) Cluster Studies Request: The ISO, on its own initiative, or at the request of a group of Eligible Customers may consider studying specified requests for Regional Network Service in a cluster for the purpose of the System Impact Study and Facilities Study.
- (b) Notice of Study Cluster: At the same time that the ISO informs the Eligible Customers that a System Impact Study or a Facilities Study is necessary to accommodate the requested Regional Network Service in accordance with Sections II.19.1 and II.19.4 of this OATT, the ISO will also notify the Eligible Customers, either in response to their joint request or on its own

initiative that (i) studying specific multiple requests for Regional Network Service in a cluster may result in a more efficient study process or may result in a more efficient and economic construction of the new facilities or upgrades and (ii) it can reasonably accommodate the cluster study, in light of the complexity involved in studying multiple requests for service simultaneously and the time necessary to perform a cluster study, as specified in Sections II.19.3 and II.19.4 of this OATT. If an Eligible Customer chooses not to have its request for Regional Network Service studied as part of the cluster, it shall have ten (10) days from the date that the ISO notifies the Eligible Customer of its intent to study specific multiple requests for Regional Network Service in a cluster to inform the ISO of its determination to have its request studied separately.

(c) Cluster Study Process and Procedures: The ISO shall follow the process and procedures set forth in Sections II.19.1 through II.19.4 of this OATT with respect to the performance of the System Impact Study and the Facilities Study, except that:

(i) For clustered studies, a single study agreement either in the form detailed in Attachment I or Attachment J of this OATT, as applicable, or in any other form that is mutually agreed to, will be tendered by the ISO to all Eligible Customers, which is to be entered into by all the Eligible Customers and the ISO and, if deemed necessary by the ISO, by one or more affected PTO(s), and pursuant to which the Eligible Customers shall agree to reimburse the ISO and affected PTO(s) for performing the required study. The costs of that study will be divided equally among the Eligible Customers, unless otherwise agreed to by the ISO and the Eligible Customers.

(ii) For clustered studies, the 60-day time periods for completion of the System Impact Study and the Facilities Study will commence on the date on which all Eligible Customers in the cluster have executed the applicable study agreement. If the ISO and any affected PTO(s) are unable to complete the applicable study in the allotted time period, the ISO shall notify the Eligible Customers and provide an estimate of the time needed to complete the study and an explanation of the reasons that additional time is required to complete the study.

(iii) In the event that ISO determines that additions or upgrades to the PTF are required to accommodate the requests for Regional Network Service that are studied as part of a cluster, the costs of the Transmission Upgrades will be allocated to each Eligible Customer whose

request was studied as part of the cluster based on each Eligible Customer's share of the total megawatts of service requested, unless otherwise agreed to by the ISO and the Eligible Customers.

(iv) At the request of a Transmission Customer whose Regional Network Service request was studied as part of a cluster, the ISO shall provide a non-binding estimate of the Incremental ARR, if any, resulting from the construction of new facilities based on the Transmission Customer's share of the costs of the new facilities. The Transmission Customer shall be responsible for the cost of any study required to determine the Incremental ARR.

II.20 Load Shedding and Curtailments

II.20.1 Procedures: Prior to the Service Commencement Date, the ISO and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to Section II.22 of this OATT with the objective of responding to contingencies on the PTF. The parties will implement such programs during any period when the ISO determines that a system contingency exists and such procedures are necessary to alleviate such contingency. The ISO will notify all affected Network Customers in a timely manner of any scheduled Curtailment.

II.20.2 Transmission Constraints: During any period when the ISO determines that a transmission constraint exists on the PTF, MTF or OTF, and such constraint may impair the reliability of the New England Transmission System, the ISO will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of the system. To the extent the ISO determines that the reliability of the system can be maintained by redispatching resources, the ISO will initiate procedures pursuant to Section II.22 of this OATT to redispatch the appropriate resources and the Transmission Customers' own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate between the PTO's use of the PTF on behalf of their Native Load Customers and any Network Customer's use of the PTF to serve its designated Regional Network Load.

II.20.3 Cost Responsibility for Relieving Transmission Constraints: Whenever the ISO implements least-cost redispatch procedures in response to a transmission constraint, the Transmission Customers will bear the costs of such redispatch in accordance with ISO New England Operating Documents.

II.20.4 Curtailments of Scheduled Deliveries: If a transmission constraint on the PTF, MTF or OTF cannot be relieved through the implementation of least-cost redispatch procedures and the ISO determines that it is necessary to effect a Curtailment of scheduled deliveries, such schedule shall be curtailed in accordance with Section II.22 of this OATT.

II.20.5 Allocation of Curtailments: The ISO shall on a non-discriminatory basis, effect a Curtailment of the transaction(s) that effectively relieves the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by the customers taking MTF Service, OTF Service and/or Through or Out Service and Network Customers on a nondiscriminatory basis. The ISO

shall not direct the Network Customer to effect a Curtailment of its schedules to an extent greater than the ISO would effect a Curtailment of the Transmission Owner's or Schedule 20A Service Provider's schedules under similar circumstances. Notwithstanding the preceding provisions of this Section, Real-Time External Transactions shall be scheduled and curtailed in accordance with Section II.44 of this OATT.

II.20.6 Load Shedding: To the extent that a system contingency exists on the PTF, OTF and/or MTF and the ISO determines that it is necessary for the customers taking MTF Service, OTF Service and/or Through or Out Service and Network Customers to shed load, the Parties shall shed load in accordance with the ISO New England Operating Documents.

II.20.7 System Reliability: Notwithstanding any other provisions of this OATT, the ISO reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to effect a Curtailment of Regional Network Service without liability on the part of the ISO or the Transmission Owners for the purpose of making necessary adjustments to, changes in, or repairs on the Transmission Owners' lines, substations and facilities, and in cases where the continuance of Regional Network Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on the PTF or on any other system(s) directly or indirectly interconnected with the PTF, the ISO, consistent with Good Utility Practice, also may effect a Curtailment of Regional Network Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. The ISO will give the Transmission Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Regional Network Service will be not unduly discriminatory relative to the Transmission Owners' or Schedule 20A Service Provider's use of the Transmission System on behalf of their Native Load Customers. Section II.22 of this OATT shall specify the rate treatment and all related terms and conditions applicable in the event that the Transmission Customer fails to respond to established Load Shedding and Curtailment procedures.

II.21 Rates and Charges

II.21.1 Regional Network Service: Each Transmission Customer which has a load in the New England Control Area and takes Regional Network Service for a month shall be subject to the applicable provisions of Part II.B. of this OATT and shall pay to the ISO for such month an amount equal to its Monthly Regional Network Load for the month times the applicable Local Network RNS Rate (except as provided for in Section II.21.3), and shall pay in addition any amount which it is required to pay for the service pursuant to Section II.18.3 and Schedules 13 and 14 of this OATT. It shall also be obligated to pay for any Direct Assignment Facilities and its share of any new facilities or upgrades required to provide the requested service including applicable study costs to the extent they are consistent with Commission policy and Schedules 11 and 12, and any ancillary service charges and other charges and/or costs required to be paid pursuant to the Transmission, Markets and Services Tariff. The applicable Local Network RNS Rate shall be the rate, determined in accordance with Schedule 9 to this OATT, which is applicable to (i) a delivery to load in the particular Local Network in which the load served by the Transmission Customer is located, or (ii) to the extent that the ISO, after consultation with the affected PTOs, at the request of a PTO who owns the Local Network where the Regional Network Load is located, recognizes Regional Network Load to be the responsibility of another PTO, the applicable Local Network RNS Rate shall be the Local Network RNS Rate of the PTO responsible for such Regional Network Load. In the event the Transmission Customer serves Regional Network Load located on more than one Local Network, the amount to be paid by it shall be separately computed for the Regional Network Load located on each Local Network.

II.21.2 Determination of Network Customer's Monthly Regional Network Load: Network Customer's "Monthly Regional Network Load" is its hourly load (including its designated Regional Network Load not physically interconnected with the PTF under Section II.18.3 of this OATT) coincident with the coincident aggregate load of all Network Customers served in each Local Network in the hour in which the coincident load is at its maximum for the month ("Monthly Peak"). For Regional Network Load located within the New England Control Area, the Monthly Regional Network Load of all Network Customers within a Local Network shall be calculated by the associated PTO. For Regional Network Load located outside of the New England Control Area, the Monthly Regional Network Load of all Network Customers shall be calculated by the associated PTO (in consultation with the ISO and the associated Balancing Authority).

II.21.3 Exception to Payment for Regional Network Service: Regional Network Service charges associated with an Electric Storage Facility's charging load: The applicable Local Network RNS Rate shall be reduced to zero for monthly Regional Network Load associated with the charging load of an Electric Storage Facility. The reduction to zero of the applicable Local Network RNS Rate shall only apply to the Schedule 9 charges. This discount will only be applied to Electric Storage Facility charging load that (a) is reported under a separately identified Regional Network Load that does not include station service load or any other load and (b) is providing one or more of the following services to the ISO: reactive power voltage support, operating reserves, regulation and frequency response, balancing energy supply and demand, or addressing a reliability concern. Electric Storage Facilities shall be considered to be balancing energy supply and demand when they are responding to ISO dispatch instructions in the Real-Time Energy Market. The applicable Local Network RNS Rate will be applied to Electric Storage Facility charging load unless it is reported as described in (a) above and is providing one or more services as described in (b) above.

II.22 Operating Arrangements

II.22.1 Network Customer Obligation: The Network Customer shall plan, construct, operate and maintain all of its equipment and facilities connected to the New England Transmission System in a safe and efficient manner and in accordance with manufacturers' recommendations, Good Utility Practice, applicable regulations, the ISO New England Operating Documents and requirements of the Electric Reliability Organization (ERO) as defined in 18 C.F.R § 39.1 and NPCC.

II.22.2 General Network Operating Terms and Conditions: The terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Part II.B of the OATT are specified in Section II.22 of this OATT, and in the ISO New England Operating Documents. The ISO, the applicable PTO(s) and the Network Customer shall (i) operate and maintain equipment necessary for integrating the Network Customer within the PTF (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment), (ii) transfer data among the ISO, the PTO(s) and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside the PTF, interchange schedules, unit outputs for redispatch required under Section II.20 of this OATT, voltage schedules, loss factors and other real time data), (iii) use software programs required for data links and constraint dispatching, (iv) exchange data on forecasted loads and resources necessary for long-term planning, and (v) address any other technical and operational considerations required for implementation of Part II.B of this OATT, including scheduling protocols. The Network Customer shall satisfy its Control Area requirements by contracting with the ISO and all the applicable PTOs. In the alternative, the Network Customer may satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, in a manner which satisfies ERO and NPCC requirements and receives any necessary ERO and NPCC approvals, subject to applicable federal and state regulatory approvals and subject to the development and implementation of a reasonable transition plan that, inter alia, satisfies applicable established system reliability criteria.

- (a) **Electrical Supply:** The electrical supply to the Point(s) of Delivery shall be in the form of three-phase sixty-hertz alternating current at a voltage class determined by mutual agreement of the ISO, the applicable PTO(s) and the Network Customer.

- (b) **Maintenance Outage Procedures:** The ISO and the applicable PTO(s) will utilize the ISO New England Operating Procedures with respect to the timing of scheduled maintenance of the New England Transmission System and Network Resources.
- (c) **Reporting Obligations:** The Network Customer shall be responsible for all information required by the ERO, NPCC, the applicable PTO(s) or the ISO. The Network Customer shall respond promptly and completely to the ISO's and the applicable PTO(s)' reasonable requests for information, including but not limited to, data necessary for operations, maintenance, regulatory requirements and analysis. In particular, that information may include:

For Regional Network Loads:

- ten-year coincident, seasonal (summer, winter) annual peak load forecast, aggregated by geographic distribution area
- load power factor performance by geographic distribution area
- Underfrequency load shedding capability aggregated by geographic distribution area
- Block load shedding capability aggregated by geographic distribution area
- Disturbance/interruption reports
- Protection system setting conformance
- Protection system testing and maintenance conformance
- Planned changes to protection systems
- Metering testing and maintenance conformance
- Planned changes in transformation capability
- Conformance to harmonic and voltage fluctuation limits
- Dead station tripping conformance
- Voltage reduction capability conformance

For Network Resources and interconnected generators:

- Ten-year forecast of generation capacity retirements and additions, if applicable
- Generator reactive capability verification
- Generator underfrequency relaying conformance
- Protection system testing and maintenance conformance
- Planned changes to protection system
- Planned changes to generation parameters

- Metering testing and maintenance conformance

Failure by the Network Customer to do so may constitute default and permits the ISO to terminate the TSA, in accordance with Commission requirements. Delinquency in responding by the Network Customer will result in a fine as described in Section II.22.5 below.

The Network Customer shall supply accurate and reliable information to the system operators regarding metered values for MW, MVAR, volt, amp, frequency, breaker status indication, and all other information deemed necessary by the ISO and the applicable PTO(s) for reliable operation. Information shall be gathered for electronic communication using a methodology acceptable to the ISO. All equipment used for metering, SCADA, RTU, RAPR, and communications must be approved by the ISO and the applicable PTO(s).

- (d) **Operational Obligations:** The Network Customer and Transmission Owner shall request permission from the ISO prior to opening and/or closing circuit breakers per applicable ISO New England Operating Procedures. The Network Customer shall carry out all switching orders from the ISO or the applicable PTO(s) in a timely manner.

The Network Customer shall balance the load at the Point(s) of Delivery such that the difference in the individual phase currents are acceptable to the ISO as specified in the ISO New England Operating Procedures.

The Network Customer's equipment shall conform with any harmonic distortion and voltage fluctuation standards specified in ISO New England Operating Procedures. The Network Customer's equipment must comply with all environmental requirements to the extent they impact the operation of the New England Transmission System. The Network Customer shall operate all of its equipment and facilities connected to the New England Transmission System in a safe and efficient manner and in accordance with manufacturers' recommendations, Good Utility Practice, applicable regulations, and requirements of the ISO, the applicable PTO(s) and NPCC.

- (e) **Notice of Transmission Service Interruptions:** If at any time, in the reasonable exercise of the ISO's judgment, operation of the Network Customer's equipment adversely affects the quality of service or interferes with the safe and reliable operation of the New England

Transmission System, the ISO may discontinue transmission service, consistent with Section II.20, until the condition has been corrected.

- (f) **Access and Control:** Properly accredited representatives of the ISO shall at all reasonable times have access to the Network Customer's facilities to make reasonable inspections and obtain information required in connection with this OATT. Such representatives shall make themselves known to the Network Customer's personnel, state the object of their visit, and conduct themselves in a manner that will not interfere with the construction or operation of the Network Customer's facilities.
- (g) **Point(s) of Delivery:** Regional Network Service will be delivered by the ISO at the Point(s) of Delivery specified in the Network Customer's application referred to in Section II.16.2 of this OATT (a blank form of which is posted on the OASIS), as approved and amended from time to time. Each Point of Delivery shall have a unique identifier, meter location, meter number, metered voltage, terms on meter compensation and, the actual, or if not currently in service, the projected in-service year.
- (h) **Maintenance of Equipment:** The ISO may request that the Network Customer test, calibrate, verify or validate the data link, metering, data acquisition, transmission, protective, or other equipment or software consistent with the Network Customer's routine obligation to maintain its equipment and facilities or for the purposes of trouble shooting problems on the network facilities. The Network Customer will be responsible for the cost to test, calibrate, verify or validate the equipment or software. The ISO shall have the right to inspect the tests, calibrations, verifications and validations of the data link, metering, data acquisition, transmission, protective, or other equipment or other software connected to the New England Transmission System. The Network Customer, at the ISO's request, shall supply the ISO with a copy of the installation, test, and calibration records of the data link, metering, data acquisition, transmission, protective or other equipment or software connected to the New England Transmission System. The ISO shall have the right, at the Network Customer's expense, to monitor the factory acceptance test, the field acceptance test, and the installation of any metering, data acquisition, transmission, protective or other equipment or software connected to the ISO's system.

- (i) **Emergency System Operations:** The Network Customer's equipment and facilities, etc. shall be subject to all applicable emergency operation standards required of and by the ISO to operate in an interconnected transmission network. The ISO reserves the right to take whatever actions or inactions it deems necessary during emergency operating conditions to: (i) preserve the integrity of the New England Transmission System, (ii) limit or prevent damage, (iii) expedite restoration of service, or (iv) preserve public safety.
- (j) **Cost Responsibility:** The Network Customer shall be responsible for all costs incurred by the ISO relative to the Network Customer's facilities. Some costs may be allocated to several Network Customers. If the method for allocating costs is not clearly defined, then the method for allocation will be at the ISO's discretion.

II.22.3 Network Resource Obligations: The following obligations of the Network Customer are specific to a generator Network Resource.

- (a) **Voltage or Reactive Control Requirements:** Unless directed otherwise, the Network Customer will operate its existing interconnected generation facility(ies) with an automatic voltage regulator(s). The voltage regulator will control voltage at the Point(s) of Receipt consistent with the range of voltage scheduled by the ISO.

At the discretion of the ISO, the Network Customer may be directed to deactivate the automatic voltage regulator and to supply reactive power in accordance with the requirements specified in the ISO New England Operating Procedures and shall be provided and compensated as specified in Schedule 2 of this OATT.

- (b) If the Network Customer has not installed capacity sufficient to operate its generation facility consistent with recommendations of the ISO resulting from the System Impact and Facilities Studies or fails to operate at such capacity, applicable PTO(s) may install, at the Network Customer's expense, reactive compensation equipment necessary to ensure the proper voltage or reactive supply at the Point(s) of Receipt.
- (c) **Station Service:** When the Network Customer's generation facility is producing electricity, the Network Customer must supply its own station service power. If and when the Network Customer's generation facility is not producing electricity, the Network

Customer must obtain station service capacity and energy from another supplier or another of its resources.

- (d) **Protection Requirements:** The Network Customer must meet protection requirements as defined in the ISO New England Operating Documents, and ERO and NPCC documents, as may be adopted or amended from time to time.
- (e) **Coordination of Operations:** All operations (including start-up, shutdown and determination of hourly generation) will be coordinated by the ISO.

II.22.4 Obligations for Delivery to Load: The following obligations are specific to delivery to load.

- (a) **Power Factor Requirement:** The Transmission Customer agrees to maintain an overall load power factor and reactive power supply within predefined sub-areas as measured at the Point(s) of Delivery within ranges specified by the ISO New England Operating Procedures which identify the power factor levels that must be maintained throughout the applicable sub-area for each anticipated level of total New England load. The Network Customer agrees to maintain load power factor and reactive power requirements within the range specified by the ISO for the sub-area based on total New England load during that hour. The ISO may revise the power factor limits required from time to time. If the Network Customer lacks the capability to maintain the load power factor within the ranges specified, the applicable PTO(s) may:
 - i) install, at the Network Customer's expense, reactive compensation equipment necessary to ensure proper load power factor at the Point(s) of Delivery;
 - ii) charge the Network Customer.
- (b) **Protection Requirements:** The Network Customer's relay and protection systems must comply with all applicable ISO New England Operating Procedures and ERO and NPCC criteria, rules, procedures, guidelines, standards or requirements as may be adopted or amended from time to time.

(c) **Operational Obligations:** The Network Customer shall be responsible for operating and maintaining security of its electric system in a manner that avoids adverse impact to the New England Transmission System or others' interconnected systems and complies with ISO New England Operating Procedures, and ERO and NPCC operating criteria, rules, procedures, guidelines and interconnection standards as may be amended or adopted from time to time. These actions include, but are not limited to:

- voltage reduction load shedding
- underfrequency load shedding
- block load shedding
- dead station tripping
- transferring load between point(s) of delivery
- implementing voluntary load reductions including interruptible customers
- starting stand-by generation
- permitting transmission owner controlled service restoration following supply delivery contingencies on transmission owner facilities.

II.22.5 Default: If the Network Customer's equipment fails to perform consistent with the obligations specified in this OATT , then the Network Customer will be deemed to be in default and service may be suspended immediately and subject to a termination through an ISO filing with the Commission. If the Network Customer fails to provide the information required in Section II.22.2(c) in a timely manner, the ISO shall be permitted to assess a penalty of \$100 per day until such information is provided in its entirety to the ISO.

II.23 Application of Part II.B to Transmission Customers

If the Transmission Customer is a Market Participant, in order to receive Regional Network Service, it must be party to a Market Participant Service Agreement and a service agreement for Local Network Service.

If the Transmission Customer is not a Market Participant, in order to receive Regional Network Service, it must be party to a Transmission Service Agreement (Attachment B to this OATT) and a service agreement for Local Network Service.

II.C. THROUGH OR OUT SERVICE; LOCAL SERVICE; MTF SERVICE; OTF SERVICE

Through or Out Service, Local Service, MTF Service or OTF Service will be provided pursuant to the applicable terms and conditions of Part II.C, Schedule 18, Schedule 20 and Schedule 21 of this OATT.

When a Real-Time External Transaction that exports energy out of or wheels energy through the New England Control Area is submitted by the Transmission Customer and is scheduled in the Real-Time Energy Market, the submission shall be deemed a request for Through or Out Service and the ISO shall generate a reservation for transmission service over the PTF equal to the transaction's maximum scheduled flow during the operating hour. This reservation amount shall be the basis for the Reserved Capacity. The Transmission Customer shall pay for its Reserved Capacity under the terms of Section II.25, Section II.27, Section II.29, and the Local Service Schedule of this OATT, whichever is applicable.

II.24 Through or Out Service

II.24.1 Provision of Through or Out Service: Through or Out Service shall be provided by the ISO, and shall be available to any Transmission Customer.

II.24.2 Use of Through or Out Service: A Transmission Customer shall take Through or Out Service for the transmission of any transaction that requires the use of PTF if either (i) the transaction goes through the New England Control Area and the Point(s) of Receipt are at one point on the New England Control Area boundary and the Point(s) of Delivery are at another point on the New England Control Area boundary, as, for example, from New Brunswick to New York or from one point on the New England Control Area boundary with New York to another point on the Control Area boundary with New York, or (ii) the transaction goes out of the New England Control Area and the Point(s) of Receipt are within the New England Control Area and the Point(s) of Delivery are at a New England Control Area boundary, as, for example, from Boston to New York.

II.25 Payment and Rate for Through or Out Service

II.25.1 Payment for Through or Out Service: Each Transmission Customer that takes Through or Out Service shall pay to the ISO a charge per kilowatt of Reserved Capacity based on an annual rate (the “TOU Rate”) which shall be the Pool PTF Rate, except as provided for in Section II.25.3. The Transmission Customer shall also be obligated to pay any ancillary service charges and any other charges required to be paid pursuant to this Tariff.

II.25.2 Rate for Through or Out Service (“TOU Rate”): The rate per hour for Through or Out Service shall be the annual Pool PTF Rate divided by 8760. The Pool PTF Rate shall be the rate determined annually in accordance with paragraph (2) of Schedule 8.

II.25.3 Exceptions to Payment for Through or Out Service: Through or Out Service Charges to the New York Control Area: The TOU Rate shall be reduced to zero for any Through or Out Service transaction that (a) goes through or out of the New England Control Area and (b) has the New England/New York Control Area boundary as its Point of Delivery, provided that a Commission-approved New York ISO tariff provision is in effect that reduces charges to zero on transactions through or out of the New York Control Area to the New England Control Area boundary. The reduction to zero of the TOU Rate to New York shall only apply to the Schedule 8 charges. The reduction of the TOU Rate to zero pursuant to this Section II.25.3 shall not apply to transmission customers taking service under Section II.18.3 of this Tariff; such transmission customers shall continue to pay charges for such service based on the full TOU Rate as applied to the amount reserved for the Regional Network Load which is not physically interconnected with the PTF.

II.26 Reservation of Capacity for Through or Out Service

Compliance with the applicable requirements of Part II.C of this OATT is required for the initiation of Through or Out Service.

II.27 MTF Service

Schedule 18 to this OATT shall govern MTF Service.

II.28 Local Service

Schedule 21 to this OATT shall govern Local Point-to-Point Service and Local Network Service.

II.29 OTF Service

Schedule 20 to this OATT shall govern OTF Service.

II.30 Nature of Through or Out Service

Advance reservations will not be required for Through or Out Service under this OATT. However, other advance reservations may be required for MTF Service and OTF Service pursuant to Schedule 18 and Schedule 20 to this OATT, as appropriate. When a Real-Time External Transaction that exports energy out of, or wheels energy through, the New England Control Area is submitted by the Transmission Customer and is scheduled in the Real-Time Energy Market, the submission shall be deemed a request for Through or Out Service and the ISO shall generate a reservation for Through or Out Service equal to the transaction's maximum scheduled flow during the operating hour; this reservation amount shall be the basis for the Reserved Capacity. The Transmission Customer shall pay for its Reserved Capacity under the terms of Section II.25 of this OATT.

II.30.1 Term: The term of Through or Out Service shall be one hour increments in conjunction with Real-Time External Transactions scheduled in the Real-Time Energy Market.

II.30.2 Transmission Priority: All Through or Out Service offered under this OATT will be deemed to have the same transmission priority. Through or Out Service will have transmission priority equal to Native Load Customers, Network Customers and customers for Excepted Transactions. In the event the PTF, OTF and MTF are constrained, transmission priorities shall be established separately for the PTF, OTF and MTF, respectively.

II.30.3 Use of Through or Out Service by the Transmission Owners or Schedule 20A Service

Providers: To the extent that a Transmission Owner or Schedule 20A Service Provider conducts business as a Transmission Customer it will be subject to the rates, terms and conditions of this OATT when making Third-Party Sales to be transmitted as Through or Out Service under (i) agreements executed after November 1, 1996 or (ii) agreements executed on or before November 1, 1996 to the extent that the Commission requires them to be unbundled, by the date specified by the Commission. A Transmission Owner or Schedule 20A Service Provider will maintain separate accounting, pursuant to Section II.8 of this OATT, for any use of Through or Out Service to make Third-Party Sales to the extent not paid for under this OATT. To the extent that a Transmission Owner or Schedule 20A Service Provider conducts business as a Transmission Customer it shall be subject to charges associated with its Reserved Capacity across MTF and OTF under the terms of Schedule 18 and Schedule 20 to this OATT, as required.

II.30.4 Service Agreements: Unless an MPSA has been executed, a standard form Transmission Service Agreement (Attachment A to the OATT) will be offered to an Eligible Customer when it submits a

Completed Application for Through or Out Service to be transmitted pursuant to this OATT. Executed Service Agreements that contain the information required under this OATT will be filed with the Commission in compliance with applicable Commission regulations.

II.30.5 Transmission Customer Obligations for Facility Additions or Redispatch Costs: The ISO will redispatch all Resources subject to its control, pursuant to Market Rule 1, in order to meet load and to accommodate Real-Time External Transactions. Transmission Customers will be charged for the Congestion Costs and any other costs associated with such redispatch in accordance with Market Rule 1.

II.30.6 Classification of Through or Out Service: Deliveries will be provided from the Point(s) of Receipt to the Point(s) of Delivery. Each Point of Receipt at which transmission capacity is reserved for Through or Out Service by the Transmission Customer shall be set forth in the schedule submitted in accordance with the ISO System Rules. When a Real-Time External Transaction that exports energy out of or wheels energy through the New England Control Area is submitted by the Transmission Customer and is scheduled in the Real-Time Energy Market, the submission shall be deemed a request for Through or Out Service and the ISO will generate a reservation for Through or Out Service equal to the Real-Time External Transaction's maximum scheduled flow during the operating hour; this reservation amount shall be the basis for the Reserved Capacity. The Transmission Customer will be billed and shall pay for its Reserved Capacity under the terms of Section II.25 of this OATT.

II.31 Service Availability

II.31.1 General Conditions: Through or Out Service on the PTF shall be available to any Transmission Customer that has met the applicable requirements of Section II.32.

II.31.2 Determination of Available Transfer Capability on MTF, non-PTF, OTF, and PTF: A description of the MTO's, OTO's and PTO's specific methodology for assessing available transfer capability over the MTF, OTF and non-PTF that are posted on the OASIS (Section II.5 of this OATT) are contained in the Schedule-specific Attachment C to Schedules 18, 20 and 21, respectively, of this OATT. A description of the ISO's specific methodology for assessing available transfer capability over the PTF interfaces that is posted on the OASIS (Section II.5 of this OATT) is contained in Attachment C to this OATT.

II.31.3 Initiating Service in the Absence of an Executed Transmission Service Agreement: If the ISO and the Transmission Customer requesting Through or Out Service, who has not executed an MPSA or on whose behalf the ISO has not filed an unexecuted MPSA with the Commission, cannot agree on all the terms and conditions of the applicable Transmission Service Agreement, the ISO will file with the Commission, within thirty (30) days after the date the Transmission Customer provides written notification directing the ISO to file, an unexecuted Transmission Service Agreement containing terms and conditions deemed appropriate by the ISO (in consultation with the applicable PTO) for such requested transmission service. The service will be commenced subject to the Transmission Customer agreeing to (i) pay whatever rate the Commission ultimately determines to be just and reasonable, and (ii) comply with the terms and conditions of this OATT including providing appropriate security deposits in accordance with the terms of Section II.34.3.

II.31.4 Obligation to Provide Transmission Service that Requires Expansion or Modification of the New England Transmission System: If a Transmission Customer requests that the PTF be expanded or modified, one or more PTOs or other entities will be designated to use due diligence to expand or modify the PTF to increase transfer capability, provided that the Transmission Customer agrees to compensate the PTO(s) or other entities that will be responsible for the construction of any new facilities or upgrades for the costs of such new facilities or upgrades pursuant to the terms of Section II.38. The ISO and the designated PTOs or other entities will conform to Good Utility Practice and the planning obligations in Attachment K in determining the need for new transmission facilities or upgrades and in coordinating the design and

construction of such facilities. This obligation applies only to those facilities that the designated PTO(s) or other entities have the right to expand or modify.

II.31.5 Deferral of Service: Any Incremental ARR associated with new transmission facilities or upgrades shall be subject to completion of construction of those transmission facilities and upgrades and to such upgrades being placed in service.

II.31.6 Real Power Losses: Real power losses are associated with all transmission service. The ISO, Transmission Owners and Schedule 20A Service Providers are not obligated to provide real power losses. The cost of PTF losses shall be recovered through the Loss Component of the Locational Marginal Prices pursuant to Market Rule 1. Real power losses across MTF shall be allocated in accordance with Schedule 18 of this OATT and real power losses across OTF shall be allocated in accordance with Schedule 20 of this OATT.

II.31.7 Load Shedding: To the extent that a system contingency exists on the PTF, MTF or OTF and the ISO determines that it is necessary for the Transmission Owners and the Transmission Customers to shed load, the Parties shall shed load in accordance with the ISO System Rules or in accordance with other mutually agreed-to provisions.

II.32 Transmission Customer Responsibilities

II.32.1 Conditions Required of Transmission Customers: Through or Out Service will be provided only if the following conditions are satisfied by the Transmission Customer that is not a Market Participant. A Transmission Customer that is a Market Participant has already satisfied these conditions under the MPSA

- a. The Transmission Customer has pending a Completed Application for service;
- b. The Transmission Customer meets the creditworthiness criteria set forth in Attachment L2 of this OATT;
- c. The Transmission Customer will have arrangements in place for any other transmission service necessary to effect the delivery from the generating source to the Point of Receipt prior to the time service under the OATT commences;
- d. The Transmission Customer has executed a Transmission Service Agreement or has agreed to receive service pursuant to Section II.31.3 of this OATT;
- e. The Transmission Customer must submit Real-Time External Transactions in accordance with the applicable ISO System Rules and will receive transmission service in conjunction with the scheduled energy in the Real-Time Energy Market in accordance with Market Rule 1;
- f. The Transmission Customer agrees to pay for all applicable transmission service and market charges chargeable to such Transmission Customer under the Transmission, Markets and Services Tariff; and
- g. The Transmission Customer provides the information required by the planning process in Attachment K.

II.32.2 Transmission Customer Responsibility for Third-Party Arrangements: Any arrangements for transmission service and the scheduling of capacity and energy that may be required by neighboring electric systems shall be the responsibility of the Transmission Customer requesting service. The Transmission Customer shall provide, unless waived by the ISO, notification to the ISO identifying such neighboring

electric systems and authorizing them to schedule the capacity and energy to be transmitted pursuant to this OATT on behalf of the Receiving Party at the Point of Delivery or the Delivering Party at the Point of Receipt. The Transmission Customer shall arrange for transmission service, as necessary, in accordance with Schedule 18 for MTF and Schedule 20 for OTF. The ISO will undertake reasonable efforts to assist the Transmission Customer in making such arrangements, including without limitation, providing any information or data required by such neighboring electric system pursuant to Good Utility Practice.

II.33 Procedures for Arranging Through or Out Service

Through or Out Service shall be provided in conjunction with hourly offered Real-Time External Transactions submitted to the Real-Time Energy Market and scheduled during an operating hour in accordance with Section II.44 of the OATT and the applicable ISO System Rules. It will not be necessary for Transmission Customers that are Market Participants to complete the requirements in this Section II.33 of the OATT. Transmission Customers that are not Market Participants intending to request transmission service through the submittal of a Real-Time External Transaction shall first complete the requirements in this Section II.33 of the OATT.

II.33.1 Application: A request for Through or Out Service for a Transmission Customer that is not a Market Participant shall be made in an Application, delivered to ISO New England, One Sullivan Road, Holyoke, MA 01040-2841 or such other address as may be specified from time to time. The request should be delivered at least sixty (60) days in advance of the calendar month in which service is requested to commence. The ISO will consider requests for such service on shorter notice when practicable. Transmission service requests should be submitted by transmitting the Completed Application to the ISO by mail or telefax. Each of these methods will provide a time-stamped record for establishing the reservation priority of the Application.

II.33.2 Completed Application: A Completed Application for Through or Out Service for a Transmission Customer that is not a Market Participant shall provide all of the information included in 18 C.F.R. §2.20 including but not limited to the following:

- (i) The identity, address, telephone number and facsimile number of the entity requesting service;
- (ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under this OATT;
- (iii) The location of the Point(s) of Receipt and Point(s) of Delivery and the identities of the Delivering Parties and the Receiving Parties;
- (iv) The location of the generating facility(ies) supplying the capacity and energy, and the location of the load ultimately served by the capacity and energy transmitted. The ISO will treat this information as confidential in accordance with the ISO New England Information

Policy except to the extent that disclosure of this information is required by this OATT, by regulatory or judicial order, or for reliability purposes pursuant to Good Utility Practice. The ISO will treat this information consistent with the standards of conduct contained in 18 C.F.R. Part 37 of the Commission's regulations;

- (v) A description of the supply characteristics of the capacity and energy to be delivered;
- (vi) An estimate of the capacity and energy expected to be delivered to the Receiving Party;
- (vii) The Service Commencement Date and the term of the requested transmission service;
- (viii) The transmission capacity requested for each Point of Receipt and each Point of Delivery on the PTF and/or MTF or OTF; customers may combine their requests for service in order to satisfy the minimum transmission capacity requirement; and
- (ix) Any additional information required by the planning process in Attachment K.

The ISO will treat this information consistent with the standards of conduct contained in 18 C.F.R. Part 37 of the Commission's regulations.

II.33.3 Deposit: A Completed Application for Through or Out Service by a Transmission Customer that is not a Market Participant shall also include a deposit of one month's charge based on the estimate of the capacity and energy expected to be delivered to the Receiving Party. If the Application is rejected by the ISO because it does not meet the conditions for service as set forth herein, or in the case of requests for service arising in connection with losing bidders in a request for proposals ("RFP"), the deposit will be returned with Interest, less any reasonable administrative costs incurred by the ISO or any affected Transmission Owners in connection with the review of the Application. The deposit also will be returned with Interest less any reasonable administrative costs incurred by the ISO or any affected Transmission Owner if the new facilities or upgrades needed to provide the service cannot be completed. If an Application is withdrawn or the Eligible Customer decides not to enter into a Transmission Service Agreement for the service, the deposit will be refunded in full, with Interest, less reasonable administrative costs incurred by the ISO or any affected Transmission Owners to the extent such costs have not already been recovered from the Eligible Customer. The ISO will provide to the Eligible Customer a complete accounting of all costs deducted from the refunded deposit, which the Eligible Customer may contest if

there is a dispute concerning the deducted costs. Deposits associated with construction of new facilities or upgrades are subject to the provisions of Section II.34 of this OATT. If a Transmission Service Agreement for Through or Out Service is executed, the deposit, with interest, will be returned to the Transmission Customer upon expiration or termination of the Transmission Service Agreement. Applicable Interest will be calculated from the day the deposit is credited to the ISO's account.

II.33.4 Notice of Deficient Application: If an Application fails to meet the requirements of this OATT, the ISO will notify the entity requesting service within fifteen (15) days of the ISO's receipt of the Application of the reasons for such failure. The ISO will attempt to remedy minor deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the ISO will return the Application, along with any deposit (less the reasonable administrative costs incurred by the ISO or any affected Transmission Owner in connection with the Application), with Interest. Upon receipt of a new or revised Application that fully complies with the requirements of this OATT, the Eligible Customer will be assigned a new reservation priority based upon the date of receipt by the ISO of the new or revised Application.

II.33.5 Execution of Transmission Service Agreement: The ISO will notify the Eligible Customer as soon as practicable but no later than thirty (30) days after receipt of the Completed Application, and will tender a Transmission Service Agreement to the Eligible Customer. The service agreement will allow the Transmission Customer that is not a Market Participant to submit External Transactions in accordance with Market Rule 1 and the applicable ISO System Rules. Failure of an Eligible Customer to execute and return the Transmission Service Agreement or request the filing of an unexecuted Transmission Service Agreement pursuant to Section II.31.3, within fifteen (15) days after it is tendered by the ISO shall be deemed a withdrawal and termination of the Application and any deposit (less the reasonable administrative costs incurred by the ISO and any affected Transmission Owner in connection with the Application) submitted will be refunded with Interest. Nothing herein limits the right of an Eligible Customer to file another Application after such withdrawal and termination.

II.34 Study Procedures For Through or Out Service Requests

II.34.1 Notice of Need for System Impact Study: After receiving a request for Through or Out Service (a “Study Request”), the ISO will review the effect of the proposed service on the reliability requirements to meet existing and pending obligations of the Transmission Customers, and the obligations of any affected Transmission Owner(s) whose facilities will be impacted by the proposed service and determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the methodology for completing a System Impact Study is provided in Attachment D. After receiving a Request, the ISO will within thirty (30) days of receipt of a Study Request, tender a System Impact Study agreement in the form of Attachment I to this OATT, or in any other form that is mutually agreed to, pursuant to which the Eligible Customer shall agree to reimburse the ISO and any affected Transmission Owners for performing or participating in the required System Impact Study. Before a Study Request is evaluated, the Eligible Customer shall execute the System Impact Study agreement and return it to the ISO within fifteen (15) days. If the Eligible Customer elects not to execute a System Impact Study agreement, its request shall be deemed withdrawn and its deposit (less the reasonable administrative costs incurred by the ISO and any affected Transmission Owner(s) in connection with the Application), will be returned with Interest.

II.34.2 System Impact Study Agreement and Cost Reimbursement:

- (i) The System Impact Study agreement shall clearly specify the ISO’s estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. The System Impact Study will rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer shall not be assessed a charge for such existing studies; however, the Eligible Customer shall be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer’s request for service on the PTF and indirectly affected MTF or OTF.
- (ii) If in response to multiple Eligible Customers requesting a similar study in relation to the same competitive solicitation, a single System Impact Study is sufficient to accommodate the requests, the costs of that study will be equitably prorated among the Eligible Customers.

- (iii) For System Impact Studies conducted on behalf of a Transmission Owner, the Transmission Owner will record the cost of the System Impact Studies pursuant to Section II.8.5 to this OATT.

II.34.3 System Impact Study Procedures: Upon receipt of an executed System Impact Study agreement, the ISO and any affected Transmission Owners will use due diligence to complete the required System Impact Study within a sixty-day period. The System Impact Study shall identify the need for additional Direct Assignment Facilities or facility additions or upgrades required to comply with the Eligible Customer's request. In the event that the required System Impact Study cannot be completed within such time period, the ISO will so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required study and an estimate of any increase in cost which will result from the delay. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer as soon as the System Impact Study is complete. The ISO will use the same due diligence in completing the System Impact Study for an Eligible Customer that is not a Market Participant as it uses when completing studies for an Eligible Customer that is a Market Participant. The ISO will notify the Eligible Customer immediately upon completion of the System Impact Study.

II.34.4 Facilities Study Procedures: After a System Impact Study indicates that additions or upgrades to the PTF or indirectly affected MTF or OTF are needed to accommodate the Eligible Customer's Request, the ISO, within thirty (30) days of the completion of the System Impact Study, will tender to the Eligible Customer a Facilities Study agreement in the form of Attachment J to this OATT, or in any other form that is mutually agreed to, which is to be entered into by the Eligible Customer and the ISO and, if deemed necessary by the ISO, by one or more PTO(s) and pursuant to which the Eligible Customer shall agree to reimburse the ISO and any affected PTO(s) or other entity designated by the ISO for performing any required Facilities Study. If the Eligible Customer wants the ISO to undertake the Facilities Study, the Eligible Customer shall execute the Facilities Study agreement and return it to the ISO within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study agreement, its Study Request shall be deemed withdrawn and its deposit, if any (less the reasonable administrative costs incurred by the ISO and any affected entity in connection with the Application), will be returned with Interest. Upon receipt of an executed Facilities Study agreement, the ISO and any affected PTO(s) or other designated entity will use due diligence to cause the required Facilities Study to be completed within a sixty-day period. If a Facilities Study cannot be completed in the allotted time period, the ISO will notify the Eligible Customer and provide an estimate of the time needed to reach a final determination and any resulting increase in the cost,

along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study shall include a good faith estimate of (i) the cost of Direct Assignment Facilities to be charged to the Eligible Customer, or (ii) the Eligible Customer's appropriate share of the cost of any required upgrades, modifications or additions to the PTF, and (iii) the time required to complete such construction. The Eligible Customer shall provide a letter of credit or other reasonable form of security acceptable to the affected Transmission Owner(s) or other entities that will be responsible for the construction of the new facilities or upgrades equivalent to the costs of the new facilities or upgrades and consistent with relevant commercial practices, as established by the Uniform Commercial Code.

In addition to the foregoing, each Facilities Study shall, if requested by the Transmission Customer, contain a non-binding estimate from the ISO of the Incremental ARR, if any, resulting from the construction of the new facilities. After completion of the transmission upgrade or expansion, the ISO shall determine the Incremental ARR, if any, resulting from the upgrade or expansion. The Transmission Customer shall be responsible for the cost of any study required to determine the Incremental ARR.

II.34.5 Facilities Study Modifications: Any change in design arising from inability to site or construct proposed facilities will require development of a revised good faith estimate. New good faith estimates also will be required in the event of new statutory or regulatory requirements that are effective before the completion of construction or other circumstances beyond the control of the affected Transmission Owners or other entities that are responsible for the construction of the new facilities or upgrades and that significantly affect the final cost of the new facilities or upgrades to be charged to the Eligible Customer pursuant to the provisions of this OATT.

II.34.6 Due Diligence in Completing New Facilities: The ISO will use due diligence to designate PTOs or other entities to add necessary facilities or upgrade the PTF, MTF or OTF within a reasonable time. A PTO or other entity will have no obligation to upgrade its existing or planned transmission system if doing so would impair system reliability or otherwise impair or degrade existing firm service. Nothing in this OATT shall be deemed to create an obligation to build upgrades that an entity does not otherwise have by contract, law or regulation.

II.34.7 Expedited Procedures for New Facilities: In lieu of the procedures set forth above, the Eligible Customer shall have the option to expedite the process by requesting the ISO to tender at one time, together with the results of required studies, an "Expedited Study Request" pursuant to which the Eligible Customer would agree to pay for all costs incurred pursuant to the terms of this OATT. In order to exercise this option,

the Eligible Customer shall request in writing an Expedited Study Request covering all of the above-specified items within thirty (30) days of receiving the results of the System Impact Study identifying the need for facility additions or upgrades and costs to be incurred in providing the requested service. While the ISO, on behalf of the PTO(s) or other entities that will be responsible for constructing the new facilities or upgrades, agrees to provide the Eligible Customer with its best estimate of the new facility costs and other charges that may be incurred, such estimate shall not be binding and the Eligible Customer shall agree in writing to pay for all costs incurred pursuant to the provisions of this OATT. The Eligible Customer shall execute and return such an Expedited Study Request within fifteen (15) days of its receipt or the Eligible Customer's request for service will cease to be a Completed Application and will be deemed terminated and withdrawn.

II.34.8 Penalties for Failure to Meet Study Deadlines: Sections 34.3 and 34.4 require the ISO to use due diligence to meet 60-day study completion deadlines for System Impact Studies and Facilities Studies.

- (i) The ISO is required to file a notice with the Commission in the event that more than twenty (20) percent of System Impact Studies and Facilities Studies completed by the ISO in any two consecutive calendar quarters are not completed within the 60-day study completion deadlines. Such notice must be filed within thirty (30) days of the end of the calendar quarter triggering the notice requirement.
- (ii) For the purposes of calculating the percent of System Impact Studies and Facilities Studies processed outside of the 60-day study completion deadlines, the ISO shall consider all System Impact Studies and Facilities Studies that it completes during the calendar quarter. The percentage should be calculated by dividing the number of those studies which are completed on time by the total number of completed studies. The ISO may provide an explanation in its notification filing to the Commission if it believes there are extenuating circumstances that prevented it from meeting the 60-day study completion deadlines.
- (iii) The ISO is subject to an operational penalty if it completes ten (10) percent or more of System Impact Studies and Facilities Studies outside of the 60-day study completion deadlines for each of the two calendar quarters immediately following the quarter that triggered its notification filing to the Commission. The operational penalty will be assessed for each calendar quarter for which an operational penalty applies, starting with the calendar quarter immediately following the quarter that triggered the ISO's notification filing to the Commission. The operational penalty will continue to be assessed each quarter

until the ISO completes at least ninety (90) percent of all System Impact Studies and Facilities Studies within the 60-day deadline.

- (iv) For penalties assessed in accordance with subsection (iii) above, the penalty amount for each System Impact Study or Facilities Study shall be equal to \$500 for each day the ISO takes to complete that study beyond the 60-day deadline.

II.35 New Transmission Facilities for Through or Out Service

II.35.1 Delays in Construction of New Facilities: If any event occurs that will materially affect the time for completion of new facilities, or the ability to complete such facilities, the ISO will promptly notify the Transmission Customer. In such circumstances, the ISO will within thirty (30) days of notifying the Transmission Customer of such delays, convene a technical meeting with the Transmission Customer and any affected Transmission Owners or other entities responsible for construction to evaluate the alternatives available to the Transmission Customer. The ISO and the affected Transmission Owners or other entities will make available to the Transmission Customer studies and work papers related to the delay, including all information that is in the possession of the ISO or the Transmission Owners or other entities that are responsible for the construction of the new facilities or upgrades that is reasonably needed by the Transmission Customer to evaluate any alternatives.

II.35.2 Alternatives to the Original Facility Additions: When the review process of Section II.35.1 to this OATT determines that one or more alternatives exist to the originally planned construction project, the ISO will present such alternatives for consideration by the Transmission Customer. If, upon review of any alternatives, the Transmission Customer desires to proceed subject to construction of the alternative facilities, it may request the ISO to submit a revised Transmission Service Agreement. In the event the ISO and the affected PTO(s) or other entities responsible for construction conclude that no reasonable alternative exists and the Transmission Customer disagrees, the Transmission Customer may seek relief under the dispute resolution procedures pursuant to the Transmission, Markets and Services Tariff or it may refer the dispute to the Commission for resolution.

II.35.3 Refund Obligation for Unfinished Facility Additions: If the ISO, the affected PTOs or other entities responsible for construction and the Transmission Customer mutually agree that no other reasonable alternatives exist, the obligation to provide the requested construction of additional facilities shall terminate and any deposit made by the Transmission Customer shall be returned, with Interest. The Transmission Customer shall be responsible for all costs prudently incurred by the ISO and by the affected PTO(s) or other entities that have been responsible for the construction of the new facilities or upgrades through the date that any required regulatory approval is denied or construction is suspended and for cost of removal, if necessary, of facilities constructed prior to suspension.

II.36 Provisions Relating to the Systems of Other Utilities

II.36.1 Responsibility for Third-Party System Additions: Neither the ISO nor any other entity which is not the Transmission Customer will be responsible for making arrangements for any necessary engineering, permitting, and construction of transmission or distribution facilities on the system(s) of any other entity or for obtaining any regulatory approval for such facilities. The ISO will undertake reasonable efforts to assist the Transmission Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

II.36.2 Coordination of Third-Party System Additions: In circumstances where the need for transmission facilities or upgrades is identified pursuant to the provisions of this OATT, and if such upgrades further require the addition of transmission facilities on third-party systems, the ISO and the Transmission Owners or other entities that are responsible for the construction of any new facilities or upgrades on the PTF, MTF or OTF will have the right to coordinate construction on the PTF, MTF or OTF with the construction required by the third parties. The ISO and the Transmission Owners or other entities that are responsible for the construction of any new facilities or upgrades on the PTF, MTF or OTF may, after consultation with the Transmission Customer and representatives of such other systems, defer construction of new transmission facilities or upgrades on the PTF, MTF or OTF if the new transmission facilities on another system cannot be completed in a timely manner. The ISO will notify the Transmission Customer in writing of the basis for any decision to defer construction and the specific problems that must be resolved before the construction of new facilities will be initiated or resumed. Within sixty (60) days of receiving written notification by the ISO of a decision to defer construction pursuant to this section, the Transmission Customer may challenge the decision in accordance with the dispute resolution procedures contained in the OATT or it may refer the dispute to the Commission for resolution.

II.37 Metering and Power Factor at Points of Receipt and Delivery

II.37.1 Transmission Customer Obligations: Unless the ISO otherwise agrees, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under this OATT and to communicate the information to the ISO. Unless otherwise agreed, such equipment shall remain the property of the Transmission Owner or Transmission Customer, as applicable.

II.37.2 ISO Access to Metering Data: The ISO will have access to such metering data as may reasonably be required to facilitate measurements and billing under the applicable Service Agreement and ISO New England Operating Documents.

II.37.3 Power Factor: Unless otherwise agreed, the Transmission Customer is required to maintain a power factor within the same range as other Transmission Customers and Transmission Owners maintain pursuant to Good Utility Practice and applicable ISO requirements. The power factor requirements are specified in the applicable Service Agreement and the ISO Operating Document, where applicable.

II.38 Compensation for New Facilities and Redispatch Costs

Whenever a System Impact Study performed in connection with a Study Request identifies the need for new facilities or upgrades, the Transmission Customer shall be responsible for such costs to the extent they are consistent with Commission policy and Schedules 11, 12 and 21 to this OATT, as applicable. The ISO will redispatch all Resources subject to its control, pursuant to Market Rule 1, in order to meet load and to accommodate Real-Time External Transactions. Transmission Customers will be charged for the Congestion Costs and any other costs associated with such redispatch in accordance with ISO New England Operating Documents. The Transmission Customer shall be responsible for costs of new facilities or upgrades required to provide the requested service to the extent they are consistent with Commission policy and Schedules 11, 12 and 21 to this OATT, as applicable.

II.D. TRANSITION PERIOD SERVICE; EXCEPTED TRANSACTIONS

The Transition Period, and additional arrangements to be in effect during the succeeding five-year period, will permit the phase-in on a negotiated basis of the OATT rates.

II.39 Transition Arrangements:

The transition arrangements include (i) the treatment provided for certain Excepted Transactions in Section II.40 of this OATT, (ii) the provisions in Schedule 9 to this OATT for the phase-in of the rates for Regional Network Service, and (iii) the Transition Period and succeeding five-year period.

II.40 Excepted Transactions:

Notwithstanding any other section of the OATT, the power transfers and other uses of the PTF effected under the transmission agreements in effect on November 1, 1996 specified below (“Excepted Transactions”) will continue to be effected under such agreements for the respective periods specified below rather than under this OATT, but not thereafter, and such transfers and other uses will continue to be effected after such period, if still occurring, under this OATT. Transmission Customers receiving service under the agreements listed in Attachment G-1 to this OATT shall not be required to take Local Network Service for such transfers and other uses. The period for which each Excepted Transaction will continue to be effected under such existing transmission agreements shall be, for the period from the effective date of the OATT until the termination of the transmission agreement:

- (a) transfers and other uses within the New England Control Area, as of November 1, 1996, of the PTF under the support or exchange agreements specified in Attachment G to this OATT;
- (b) transfers and other uses within the New England Control Area, as of November 1, 1996, of the PTF under the comprehensive network service agreements specified in Attachment G-1 to this OATT; and
- (c) transfers and other uses within the New England Control Area, as of November 1, 1996, of the PTF under the other transmission agreements or OATT service agreements specified in Attachment G to this OATT.

The transfers or other uses under any of the transmission agreements covering the transfers referred to above shall be in accordance with the terms of the transmission agreement as in effect on November 1, 1996, or a modification of the terms which is expressly provided for in the agreement as in effect on November 1, 1996 and is accomplished without amendment of the agreement or by an amendment entered into after November 1, 1996 that does not extend the term of the agreement or increase the amount of the service. Further, notwithstanding the foregoing restriction on the amendment after November 1, 1996 of transmission agreements with respect to Excepted Transactions, the transmission arrangements for the MASSPOWER and Altresco facilities may continue as Excepted Transactions in accordance with transmission agreement amendments or memoranda of understanding entered into as of December, 1996 which do not extend the term of the agreements. The PTOs shall review and approve the addition of

agreements (if inadvertently omitted), modifications to existing descriptions of agreements (if incorrectly stated), or the deletion of agreements to Attachments G, G-1, G-2, and G-3 to this OATT, provided that the PTOs shall file such additions, modifications and deletions to Attachment G, G-1, G-2 and G-3 with the Commission pursuant to Section 205 of the FPA.

For the purpose of determining transmission priorities under this OATT,

- (i) internal Excepted Transactions shall have the same transmission priority as Firm Point-To-Point Service transactions for resources in existence on the effective date of this OATT which are effected as Regional Network Service; and
- (ii) Excepted Transactions which are External Transactions listed in Attachment G-3 to this OATT shall have transmission priority in accordance with Section II.44 of this OATT.

When the transfers and other uses effected under the transmission agreements that are Excepted Transactions cease to be Excepted Transactions before the end of their term, the transactions shall be effected under this OATT, to the extent appropriate, but the transactions shall continue to have a transmission priority not less than the priority that they would have had if Regional Network Service had been used for the transactions from the effective date of this OATT. New transactions entered into after November 1, 1996 under umbrella OATT agreements then in effect will not be Excepted Transactions.

Notwithstanding the foregoing or any other section of the OATT, existing agreements which provide for the support of the costs of transmission facilities or for the interconnection of transmission facilities shall continue in effect until the termination of the agreement to provide for such support or for the rights and obligations of the parties with respect to the interconnection arrangements. Attachment G-2 to this OATT lists certain additional agreements covering transactions, the status of which is described in the Attachment.

Section II.44 of this OATT shall apply for the purposes of scheduling and curtailment of Excepted Transactions that are also External Transactions.

II.E. CONGESTION MANAGEMENT ON THE NE TRANSMISSION SYSTEM

II.41 Congestion Costs and Congestion Revenue

When Congestion exists, the Congestion Costs shall be reflected in Locational Marginal Prices calculated in accordance with Market Rule 1. Congestion Cost shall be recovered from Transmission Customers taking service under the OATT pursuant to Market Rule 1. Transmission Congestion Revenue shall be collected and disbursed in accordance with Market Rule 1.

II.42 Financial Transmission Rights

A system of Financial Transmission Rights shall be implemented pursuant to Sections 5 and 7 of Market Rule 1.

II.43 Auction Revenue Rights and Incremental ARRs:

A system of Auction Revenue Rights and Incremental ARRs shall be implemented pursuant to Appendix C of Market Rule 1.

II.F. EXTERNAL TRANSACTIONS

II.44 Scheduling and Curtailment Rules

For purposes of scheduling and Curtailment of Real-Time External Transactions over interconnections between the New England Control Area and neighboring Control Areas, the following rules shall apply:

- (1) For External Interfaces that are not subject to Coordinated Transaction Scheduling
 - (a) Real-Time External Transaction sales and purchases that (i) are supported by those service agreements referenced in Attachment G-3 to this OATT that have not opted for Auction Revenue Rights consideration under applicable ISO System Rules or (ii) are supported by those service agreements referenced in Attachment H to this OATT, and (iii) have been submitted into the Real-Time Energy Market prior to the Day-Ahead Energy Market Scheduling deadline established in Section III.1.10.1A of the Tariff as a Self-Scheduled Real-Time External Transaction (“real-time without price”) at an External Node referenced in Attachment G-3 or Attachment H to this OATT shall be assigned the highest transmission priority when compared to other Real-Time External Transaction purchases or sales at that node having the same offer price or bid price. In the event that the transfer limit for a given external interface does not allow all Excepted Transactions or MEPCO Grandfathered Transactions submitted over that interface to flow, they shall be scheduled or curtailed on a pro-rata basis. For Real-Time External Transactions referenced in Attachment G-3 or Attachment H to this OATT that also require an advance physical reservation associated with a MTF or OTF external interface, the MTF or OTF transmission priority shall take precedence over the above language for the purposes of scheduling and curtailment under Sections II.44(1)(c) and II.44(1)(d) of this OATT, respectively. For Excepted Transactions or MEPCO Grandfathered Transactions that are tied within economic merit, and tied within transmission priority, such transactions cleared in the Day-Ahead Energy Market that have a corresponding Real-Time Energy Market External Transaction will have scheduling and curtailment priority in the Real-Time Energy Market before Excepted Transactions or MEPCO Grandfathered Transactions not cleared in the Day-Ahead Energy Market;
 - (b) For external interfaces where advance physical reservations are not required, in the event that the transfer limit for a given external interface does not allow all such Real-Time External Transactions submitted over that interface to flow, the scheduling and Curtailment of Real-Time External Transactions shall be based on economic merit order in accordance with the ISO System Rules. In the case of a tie within economic merit,

transmission priority will be used as the next tiebreaker. In the case of a tie within economic merit and within transmission priority, those External Transactions that cleared in the Day-Ahead Energy Market that have a corresponding Real-Time Energy Market External Transaction will have scheduling and curtailment priority in the Real-Time Energy Market before those that did not clear in the Day-Ahead Energy Market. In the case of a tie within economic merit, transmission priority, and Day-Ahead Energy Market status, Real-Time External Transactions sales that were submitted pursuant to Section III.1.10.7(f) of the Tariff will have scheduling and curtailment priority over those that were not submitted pursuant to Section III.1.10.7(f). After economic merit, transmission priority, Day-Ahead Energy Market status, and supported in Real-Time status pursuant to Section III.1.10.7(f) of the Tariff have been considered, (i) the Real-Time Energy Market timestamp shall be used as the final tiebreaker for External Transactions not submitted pursuant to Section II.44(a) and (ii) pro-rata scheduling and curtailment shall be used as the final tiebreaker for External Transactions submitted pursuant to Section II.44(a). With the exception of Section II.44(a) of this OATT, all transactions crossing external interfaces not requiring advance physical reservations shall have equal transmission priority;

- (c) For external interfaces where advance physical reservations are required, in the event that the transfer limit for a given external interface does not allow all such Real-Time External Transactions submitted over that interface to flow, the scheduling of Real-Time External Transactions which satisfy the reservation requirements for service shall be based on economic merit order in accordance with the ISO System Rules. In the case of a tie within economic merit, transmission priority shall be used as a tiebreaker. Relative to a given interface, transmission priority is based on the priority rights of the associated MTF or OTF advance physical reservation. In the case of a tie within economic merit and within a category of transmission service, those External Transactions that cleared in the Day-Ahead Energy Market that have a corresponding Real-Time Energy Market External Transaction shall be scheduled in the Real-Time Energy Market before those that did not clear in the Day-Ahead Energy Market. In the case of a tie within economic merit, transmission priority, and Day-Ahead Energy Market status, Real-Time External Transactions sales that were submitted pursuant to Section III.1.10.7(f) of the Tariff will have scheduling and curtailment priority over those that were not submitted pursuant to Section III.1.10.7(f). After economic merit, transmission priority, Day-Ahead Energy

Market status, and supported in Real-Time status pursuant to Section III.1.10.7(f) of the Tariff have been considered, (i) the associated Real-Time Energy Market timestamp shall be used as the final tiebreaker for scheduling within a given subcategory of non-firm transmission service and (ii) pro-rata scheduling shall be used as the final tiebreaker for ties within firm transmission service;

- (d) For external interfaces where advance physical reservations are required, Curtailments resulting from a reduction in total transfer capability shall be based on transmission priority of the associated MTF or OTF advance physical reservation to the extent possible. In the case of a tie within a category of transmission service, those External Transactions that cleared in the Day-Ahead Energy Market that have a corresponding Real-Time Energy Market External Transaction shall be curtailed in the Real-Time Energy Market after those that did not clear in the Day-Ahead Energy Market. In the case of a tie within transmission priority associated with External Transaction sales that cleared in the Day-Ahead Energy Market that have a corresponding Real-Time Energy Market External Transaction, those Real-Time Energy Market External Transactions that were submitted pursuant to Section III.1.10.7(f) of the Tariff will be curtailed after those that were not submitted pursuant to Section III.1.10.7(f). After transmission priority, Day-Ahead Energy Market status, and supported in Real-Time status pursuant to Section III.1.10.7(f) of the Tariff have been considered, (i) the associated Real-Time Energy Market timestamp shall be used as the final tiebreaker for curtailments within a given sub-category of non-firm transmission service and (ii) pro-rata curtailment shall be used as the final tiebreaker for ties within firm transmission service;
- (e) In instances of a Real-Time External Transaction scheduled against multiple advance physical reservations on a MTF or OTF external interface, the lowest transmission priority of the associated advance physical reservations shall apply; and
- (f) Scheduling and Curtailment of Real-Time External Transactions shall be conducted in accordance with the specifications of the ISO New England Operating Documents. Real-Time External Transactions not satisfying Section III.1.10.7(i) criteria shall be scheduled and curtailed under the following protocol as may be necessary to respond to and prevent system-wide Emergencies: (1) initial scheduling and curtailment priority shall be based upon whether the transaction cleared the Day-Ahead Energy Market; in the case of a tie within Day-Ahead Energy Market cleared

transactions, priority will next be given to transactions based on the priority of the transmission service; and a tie within any specific transmission service shall be resolved based on the timestamp of the Real-Time Energy Market submission; and (2) secondary scheduling and curtailment priority shall be provided to External Transactions that were only submitted or scheduled in the Real-Time Energy Market and did not clear the Day-Ahead Energy Market; in the case of an economic tie among Real-Time Energy Market cleared transactions, priority will next be given to transactions based on the priority of the transmission service; and a tie within any specific transmission service shall be resolved based on the timestamp of the Real-Time Energy Market submission. Real-Time External Transactions satisfying Section III.1.10.7(i) criteria shall be treated in accordance with that section.

- (2) For External Interfaces that are subject to Coordinated Transaction Scheduling, the transmission priority for all Real Time External Transactions is equal. As such, the associated Real Time External Transactions shall be scheduled and curtailed on the basis of economic merit order in accordance with Section III.1.10.7A of the Tariff and the Coordination Agreement between ISO-NE and the NYISO. In the event of a tie within economics, all affected Real-Time External Transactions will be reduced on a pro-rata basis.
- (3) Terms and Conditions applied to all External Interfaces
 - (a) The transmission priority for wheel-through transactions will be based on the transmission service utilized at the restricted external interface as indicated by the transmission reservation;
 - (b) Transmission Customers wishing to schedule Real-Time External Transactions shall comply with applicable ISO System Rules;
 - (c) Real-Time External Transactions scheduled in the Real-Time Energy Market shall continue to be scheduled and curtailed according to Section II.44(1) and (2), as applicable, when there are transmission limitations on an external interface, except as may be necessary to respond to emergencies;
 - (d) The ISO will redispatch all Resources subject to its control, pursuant to Market Rule 1, in order to meet load and to accommodate Real-Time External Transactions. Transmission

Customers will be charged for the Congestion Cost and any other costs associated with such redispatch in accordance with Market Rule 1. Pursuant to such redispatch, in the event the ISO exercises its right to effect a Curtailment, in whole or part, of Through or Out Service, MTF Service or OTF Service, no credit or other adjustment shall be provided as a result of the Curtailment with respect to the charge payable by the customer;

- (e) The ISO will furnish to the Delivering Party's system operator schedules from each applicable scheduling interval equal to those furnished by the Receiving Party (unless reduced for losses) and will deliver the capacity and energy provided by such schedules;
- (f) Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the ISO, and the ISO will have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered;
- (g) The ISO shall apply the above-listed rules consistent with maintaining the reliability of the New England Transmission System; and
- (h) The ISO shall develop and post procedures on its Internet website reflecting the above-listed External Transaction rules.

II.45 Grandfathered Agreements

II.45.1

MEPCO Grandfathered Transmission Service Agreements (MGTSAs) over the New

Brunswick/New England Interface: The period for which each MGTTA listed in Attachment H to this OATT will be in effect shall be from the effective date on which the costs of the MEPCO transmission facilities are included in the Pool RNS Rate under the OATT until the associated transmission agreement termination date noted in Attachment H to this OATT, subject to roll over or renewal in accordance with the provisions of subsection II.45.1(b) below. New MEPCO transmission service agreements entered into after June 1, 2007 will not be eligible for MGTTA treatment.

The transfers or other uses under any of the MGTSAs and the associated charges shall be in accordance with the terms of the pertinent transmission agreement listed in Attachment H or otherwise posted on OASIS. This OATT, including in particular this Section II.45 providing for MGTTA service, will supersede and replace Schedule 20B that preexisted this Section II.45, and be deemed its successor. MGTSAs may be assigned, rolled over or terminated in accordance with the following terms.

- (a) Sale or assignment of MGTSAs: An MGTTA holder may sell, assign or transfer all or a portion of its rights under the MGTTA, but only to another Eligible Customer (“Assignee”). The MGTTA holder that sells, assigns or transfers its rights under its MGTTA is hereafter referred to as the Reseller. Compensation to Resellers shall be at rates established by agreement between the Reseller and the Assignee.

The Assignee must execute the pro forma service agreement in Attachment H-1 to this OATT governing reassignments of transmission service prior to the date on which the reassigned service commences. MEPCO shall charge the Reseller, as appropriate, at the rate stated in the MGTTA or the associated OASIS schedule and credit the Reseller with the price reflected in the Assignee’s Service Agreement with MEPCO or the appropriate OASIS schedule; provided that, such credit shall be reversed in the event of non-payment by Assignee. The Assignee will receive the same service as did the Reseller and the priority for the Assignee will be the same as that of the Reseller. The Assignee will be subject to all terms and conditions of this OATT. The Reseller shall remain liable for the performance of all obligations under the MGTTA. All sales or assignments of capacity must be conducted

through or otherwise posted on OASIS on or before the date the reassigned service commences. Resellers may also use the OASIS to post transmission capacity available for resale.

- (b) Reservation Priority for MGTTSA holders: MGTTSA holders with a contract term of five years or more have the right to continue to take transmission service when the MGTTSA expires or rolls over. The MGTTSA holder must provide notice to MEPCO whether it will exercise its right of first refusal no less than one year prior to the expiration date of its MGTTSA. This transmission reservation priority for MGTTSA holders is an ongoing right that may be exercised at the end of all firm contract terms of five years or longer. MGTTSAs will become subject to the five year/one year requirement on the first rollover date after December 1, 2008; provided that, the one-year notice requirement shall apply to MGTTSAs with five years or more left in their terms as of December 1, 2008.
- (c) Terminations: MGTTSAs shall be terminated on the associated Attachment H termination date, subject to Section II.45(b) above, or, subject to Section 3.11(g) of the TOA, on such date mutually agreed upon by the parties.

MEPCO shall periodically review Attachment H and shall file any necessary changes with the Commission.

For purposes of determining transmission priorities under this OATT, MGTTSAs (which are listed in Attachment H) shall have transmission priority in accordance with Section II.44.

Section II.44 of this OATT shall apply for the purposes of scheduling and curtailment of External Transactions, including those associated with MGTTSAs.

Upon termination or expiration of its MGTTSA, the MGTTSA holder will receive transmission service pursuant to either Schedule 8 or 9 under this OATT, as appropriate.

II.46 General

Additions to or modifications of the PTF may be required or permitted under this OATT, and be subject to related rights, obligations and procedures, in any of the following circumstances:

- (a) An addition or modification may be required under Part II.B or Part II.C of the OATT in order to meet a new request for Regional Network Service or Through or Out Service. Where such an addition or modification is to be effected, the rights and obligations of the ISO, the PTOs and Transmission Customers shall be determined in accordance with the applicable provisions of Parts II.B and II.C of this OATT.
- (b) An addition or modification may be required to permit the interconnection of a new or modified generating unit or the interconnection of an Elective Transmission Upgrade. Where such an addition or modification is to be effected, the rights and obligations of the ISO, the PTOs, and the Generator Owner or applicant for an Elective Transmission Upgrade, shall be determined in accordance with Section II.47 of this OATT and Schedules 11, 12, 22, 23, and 25 to this OATT.
- (c) A Reliability Transmission Upgrade, Market Efficiency Transmission Upgrade, NEMA Upgrade or Public Policy Transmission Upgrade may be required or proposed pursuant to a Regional System Plan and Attachment K of this OATT. Where a Reliability Transmission Upgrade, Market Efficiency Transmission Upgrade, NEMA Upgrade or Public Policy Transmission Upgrade is to be effected, the rights and obligations of the ISO, the PTOs, Non-Incumbent Transmission Developers, and Transmission Customers shall be determined in accordance with the TOA, the NTDOA, Schedule 12 and Attachment K, as applicable.
- (d) Consistent with reliability and safety standards, Transmission Owners, and operators of affected Local Control Centers in New England Control Area and the ISO will coordinate scheduled generation and transmission facility outages so as to minimize, to the extent practicable, Congestion Costs and Local Second Contingency Protection Resource NCPC Charges (as calculated pursuant to Market Rule 1) in accordance with the TOA, MTOA and applicable ISO New England Operating Procedures. The ISO shall provide Transmission Owners and the operators of the affected Local Control Centers with such information as is

necessary to enable them to perform this function. Any information provided to Transmission Owners and the operators of the affected Local Control Centers pursuant to this provision will be subject to all the applicable requirements of the Commission's Order 889.

These provisions for PTF additions and modifications are not intended to be exclusive.

Nothing in this OATT is intended to preclude any entity from identifying and constructing Elective Transmission Upgrades on a merchant or other basis, so long as it obtains all required legal rights and approvals and satisfies applicable ISO and affected Transmission Owner requirements relating to such facilities.

An addition or modification under the TOA which constitutes PTF under the OATT shall become part of the PTF and shall be fully subject to this OATT, whether or not all or any part of the costs of the addition or modification are included in Pool Supported PTF costs. The transmission priorities, if any, with respect to the use of the addition or modification as among the owner and supporters of the addition or modification and other Transmission Customers shall be determined under Parts II.A to II.D, inclusive, of this OATT.

To the extent that a Generator Owner is responsible for the costs of a Generator Interconnection Related Upgrade or Elective Transmission Upgrade, or an entity other than a Generator Owner is responsible for costs of any other system upgrade, the Generator Owner or entity which supports part or all of the costs of the addition or modification shall be entitled to a share of any associated Incremental ARR's equivalent to the share of the total costs of such upgrade which it supports, as assigned and allocated in accordance with Appendix C of Market Rule 1. Any incremental FTRs resulting from Generator Interconnection Related Upgrades or other upgrades shall be auctioned along with other FTRs in accordance with Section 7 of Market Rule 1.

If issues of cost allocation arise with respect to the recovery of any of the costs provided for in this Part II.G of this OATT, or in Schedules 9, 11, 12, 13 or 14 to this OATT, such issues shall be subject to determination by the Commission in the appropriate proceeding.

II.G. SYSTEM PLANNING, ADDITIONS AND MODIFICATIONS

II.47 Interconnection Procedures and Requirements

II.47.1 Interconnection of Generating Unit Under the Capacity Capability Interconnection Standard or the Network Capability Interconnection Standard: Any Generator Owner that proposes after the Compliance Effective Date (i) to place in service in the New England Control Area a new generating unit at a site which the Generator Owner owns or controls, or which it has the right to acquire or control, or (ii) to materially change and/or increase the capacity of an existing generating unit located in the New England Control Area shall comply with and be subject to the ISO New England Operating Documents, including, but not limited to, the Interconnection Procedures contained in Schedules 22 and 23 of this OATT and shall enter into an Interconnection Agreement in the form provided in Appendix 6 to Schedule 22 or Exhibit 1 to Schedule 23 of this OATT. The ISO shall have authority to administer the Interconnection Procedures and shall be a party to the Interconnection Agreement along with the Interconnection Customer and the Interconnecting Transmission Owner (as such terms are defined in Schedules 22 and 23 of this OATT).

II.47.2 Generator Interconnection Proposal Review: The Generator Owner shall submit its proposal for review in accordance with Section I.3.9 of the Transmission, Markets and Services Tariff and related ISO New England Operating Documents and thereafter take any action required pursuant to Section I.3.10 of the Transmission, Markets and Services Tariff as a result of such review.

II.47.3 Generator Right to Interconnection: Upon the satisfaction of the obligations described in Sections II.47.1 and II.47.2, and subject to all necessary legal rights and approvals being obtained, the Generator Owner's unit shall have the right to be interconnected with the PTF or Non-PTF.

II.47.4 Compliance with Schedule 11: A Generator Owner proposing the interconnection of a new or materially changed generating unit shall be responsible for the costs of any required Generator Interconnection Related Upgrades that do not constitute costs of Pool Supported PTF in accordance with Schedule 11 of this OATT, and shall comply with the affected PTO's requirements with respect to security, credit assurances and/or deposits in accordance with Schedule 11 of this OATT.

With respect to upgrades required to meet the Capacity Capability Interconnection Standard or the Network Capability Interconnection Standard, and consistent with reliability and safety standards, PTOs (in accordance with the TOA and applicable ISO New England Operating Documents), MTOs (in accordance with a MTOA and applicable ISO New England Operating Documents), OTOs (in accordance with an

OTOA and applicable ISO New England Operation Documents), the interconnecting Generator Owner and the ISO shall jointly use their best reasonable efforts to develop Congestion Cost and Local Second Contingency Protection Resource NCPC Charge estimates and construction schedules designed to minimize, to the extent practicable, the financial impact of the upgrade-related transmission outages on all affected parties. The development of the aforementioned construction schedule shall include consultation with any affected existing Generator Owner. To the extent it is possible to implement a procedure that facilitates the ability of interconnecting Generator Owners and Interconnecting Transmission Owners and any affected PTO(s) to minimize, to the extent reasonably practicable, the associated Local Second Contingency Protection Resource NCPC Charge and Congestion Cost exposure prior to implementation of SMD, the parties agree to continue the use of the procedure after the implementation of SMD to the extent that such procedures are consistent with SMD. There shall be no payment under this OATT of lost opportunity costs to Generator Owners for generating units that are dispatched down or dispatched off. In connection with the consultation required by this paragraph, the affected parties shall, as necessary, enter into nondisclosure agreements protecting commercially sensitive information from unlimited disclosure in order to facilitate the development of construction schedules designed to minimize the financial impact on the affected parties.

Where requests received by the ISO are for interconnection to the MTF or OTF, the responsibilities under Section II.47.1 of the Tariff will be solely within the MTO's or OTO's discretion. If the MTO or OTO acts to interconnect transmission facilities to its MTF or OTF, it will consult and coordinate with the ISO prior to completion of any system impact studies and facilities studies in connection with such interconnection requests. Likewise, the ISO will consult with the MTO or OTO on any proposed interconnection requests that may adversely affect the MTF or OTF. Nothing in this Tariff shall preclude the ISO from entering into an agreement(s) with the MTO or OTO for such MTO or OTO, pursuant to the ISO's supervision, to perform system impact studies and facilities studies in connection with any interconnection requests. All interconnections to MTF or OTF must conform to the pro forma interconnection rules and procedures on file with the Commission for the ISO. Nothing in this Tariff shall preclude the performance of studies related to the interconnection of generating units by a third party consultant to the extent permitted by applicable procedures in this OATT (including procedures governing the treatment of confidential information) and provided that such studies performed by any third party consultant must include the MTO's or OTO's reasonable estimates of the costs of upgrades to such MTO's MTF or OTO's OTF needed to implement the conclusions of such studies and the MTO's or OTO's reasonable anticipated schedule for the construction of such upgrades.

II.47.5 Interconnection of Elective Transmission Upgrades: Any entity may undertake the design, construction and interconnection of an Elective Transmission Upgrade (“Elective Transmission Upgrade Interconnection Customer”). In undertaking the design, construction and interconnection of an Elective Transmission Upgrade, the Elective Transmission Upgrade Interconnection Customer shall comply with and be subject to the ISO New England Operating Documents, including, but not limited to, the Interconnection Procedures contained in Schedule 25 of this OATT and shall enter into an Interconnection Agreement in the form provided in Appendix 6 to Schedule 25 of this OATT. The ISO shall have authority to administer the Interconnection Procedures and shall be a party to the Interconnection Agreement along with the Interconnection Customer and the Interconnecting Transmission Owner (as such terms are defined in Schedule 25 of this OATT).

The Elective Transmission Upgrade Interconnection Customer shall submit its proposal for review in accordance with Section I.3.9 of the Transmission, Markets and Services Tariff and related ISO New England Operating Documents and thereafter take any action required pursuant to Section I.3.10 of the Transmission, Markets and Services Tariff as a result of such review.

Upon satisfaction of the obligations described in this Section II.47.5 and Schedule 25 of this OATT, and subject to all necessary legal rights and approvals being obtained, and upon satisfaction of any conditions placed on the Elective Transmission Upgrade Interconnection Customer pursuant to Sections I.3.9 and I.3.10 of the Transmission, Markets and Services Tariff, the Elective Transmission Upgrade shall have the right to be interconnected with the PTF or Non-PTF.

Any entity that constructs and/or maintains the Elective Transmission Upgrade shall be responsible for 100% of all of the costs of said upgrade and of any additions to or modifications of the PTF and Non-PTF that are required to accommodate the Elective Transmission Upgrade. A request for rate treatment of an Elective Transmission Upgrade, if any, shall be determined by the Commission in the appropriate proceeding.

II.48 Interconnection Service Capabilities

II.48.1 Establishing CNR Capability and CNI Capability

- (a) **CNR Capability shall be established as follows:** Section 5.2.3 of Schedule 22 and Section 1.6.4.3 of Schedule 23 of this OATT describe the establishment of CNR Capability for a Generating Facility that was treated as an Existing Generating Capacity Resource in the fourth Forward Capacity Auction. For a Generating Facility newly obtaining or increasing CNR Interconnection Service in the fourth Forward Capacity Auction or thereafter, summer CNR Capability shall be established as the highest MW quantity of Capacity Supply Obligation obtained by the Generating Capacity Resource for the summer period and winter CNR Capability shall be established as the higher of (1) the highest MW quantity of Capacity Supply Obligation obtained by the associated Generating Capacity Resource for the winter period and (2) the Generating Facility's summer CNR Capability multiplied by the ratio of the Generating Capacity Resource's winter Qualified Capacity to summer Qualified Capacity for the auction in which the entry occurred.

At the time of its establishment pursuant to the preceding paragraph, a Generating Facility's CNR Capability shall not exceed its maximum net MW electrical output at the Point of Interconnection at an ambient temperature at or above 90 degrees F for summer and at or above 20 degrees F for winter.

- (b) **CNI Capability shall be established as follows:** Summer and winter CNI Capability for an External ETU with CNI Interconnection Service pursuant to Schedule 25 of this OATT shall be established as the total MW quantity of Capacity Supply Obligation(s) obtained by its associated New Import Capacity Resource(s) in the summer and winter periods, respectively.

At the time of its establishment pursuant to the preceding paragraph, the CNI Capability shall not exceed the maximum net MW electrical capability at the Point of Interconnection and shall not exceed applicable seasonal equipment ratings determined pursuant to industry standards and consistent with the specifications described in ISO New England Planning and Operating Procedures.

II.48.2 Establishing NR Capability and NI Capability

- (a) **NR Capability shall be established as follows:** Section 5.2.4 of Schedule 22 and Section 1.6.4.4 of Schedule 23 of this OATT describe the establishment of NR Capability for a Generating Facility that was treated as an Existing Generating Capacity Resource in the fourth Forward Capacity Auction. In

all other cases, summer and winter NR Capability for a Generating Facility shall be established as the Generating Facility's maximum net MW electrical output at the Point of Interconnection at an ambient temperature at or above 50 degrees F for summer and at or above 0 degrees F for winter. A Generating Facility's summer and winter NR Capability shall be equal to or greater than its summer and winter CNR Capability, respectively.

(b) NI Capability shall be established as follows: For an External ETU with NI Interconnection Service pursuant to Schedule 25 of this OATT, summer and winter NI Capability shall be established as the maximum net MW electrical capability at the Point of Interconnection and shall not exceed applicable seasonal equipment ratings determined pursuant to industry standards and consistent with the specifications described in ISO New England Planning and Operating Procedures. An External ETU's summer and winter NI Capability shall be equal to or greater than its summer and winter CNI Capability, respectively.

II.48.3 Reductions to CNR Capability and CNI Capability: CNR Capability and CNI Capability shall be reduced as follows upon partial or full exit from the Forward Capacity Market as a result of any of the following actions: (1) a voluntary or mandatory termination pursuant to Section III.13.3.4A of the Tariff results in a reduction to summer and winter CNR Capability (or summer and winter CNI Capability) equal to the respective reduction to summer and winter Qualified Capacity described in III.13.3.4A; (2) the failure of the Import Capacity Resource(s) associated with an External ETU to offer into a Forward Capacity Auction in a MW quantity equal to the CNI Capability of the External ETU, as described in Section III.13.1.3 of the Tariff, results in a reduction to summer and winter CNI Capability equal to the respective reduction to summer and winter Capacity Network Import Interconnection Service described in Section III.13.1.3; (3) a failure to operate commercially for a period of three calendar years resulting in retirement pursuant to Section III.13.2.5.2.5.3(d) of the Tariff results in a reduction of summer and winter CNR Capability (or summer and winter CNI Capability) to zero; (4) a full exit from the Forward Capacity Market as the result of the operation of a Retirement De-List Bid or a Permanent De-List Bid, described in Section III.13.2.5.2.5.3 of the Tariff, and/or a substitution auction demand bid, described in Section III.13.2.8 of the Tariff, results in a reduction of summer and winter CNR Capability (or summer and winter CNI Capability) to zero; and a partial exit from the Forward Capacity Market as the result of the operation of a Retirement De-List Bid or a Permanent De-List Bid and/or a substitution auction demand bid results in a reduction of CNR Capability (or CNI Capability) as described below.

(a) Summer CNR/CNI Capability Following Partial Exit Resulting From De-List Bid and/or

Substitution Auction Demand Bid: Following the partial permanent exit from the Forward Capacity Market of a Generating Capacity Resource (or an Import Capacity Resource associated with an External ETU) as a result of the operation of a de-list bid and/or a substitution auction demand bid, the summer CNR Capability of the associated Generating Facility (or the summer CNI Capability of the associated External ETU) shall be reduced to equal (1) the associated summer Qualified Capacity (or, where there is more than one Import Capacity Resource associated with an External ETU, the sum of the associated summer Qualified Capacities) for the Forward Capacity Auction in which the partial exit occurred minus (2) the MW quantity that exited the Forward Capacity Market.

(b) Winter CNR/CNI Capability Following Partial Exit Resulting From De-List Bid and/or

Substitution Auction Demand Bid: Following the partial permanent exit from the Forward Capacity Market of a Generating Capacity Resource (or an Import Capacity Resource associated with an External ETU) as a result of the operation of a de-list bid and/or a substitution auction demand bid, the winter CNR Capability of the associated Generating Facility (or the winter CNI Capability of the associated External ETU) shall be reduced to equal (1) the Generating Facility's summer CNR Capability (or the External ETU's summer CNI Capability) reduced as described in subsection (a) of this Section II.48.3 multiplied by (2) the ratio of the associated winter Qualified Capacity (or, where there is more than one Import Capacity Resource associated with an External ETU, the sum of the associated winter Qualified Capacities) to the associated summer Qualified Capacity (or, where there is more than one Import Capacity Resource associated with an External ETU, the sum of the associated summer Qualified Capacities) for the Forward Capacity Auction in which the partial exit occurred; provided that a different winter CNR Capability value may be established to account for winter capability remaining after the removal of summer capability if the ISO determines that engineering information submitted no later than 10 calendar days after the conclusion of the Forward Capacity Auction supports the use of the different value.

II.48.4 Reductions to NR Capability and NI Capability: NR Capability and NI Capability shall be reduced as follows for Generating Facilities and External ETUs as a result of any of the following actions:

- (1) a partial or full voluntary retirement results in partial or full reduction of NR Capability or NI Capability;
- (2) a failure to operate commercially for a period of three calendar years (as described in Section III.13.2.5.2.5.3(d) of the Tariff) results in a reduction of NR Capability or NI Capability to zero;
- (3) a full retirement of a Generating Facility or an External ETU as the result of the operation of a Retirement De-List Bid or an unconditional Permanent De-List Bid (as described in Section III.13.1.2.4.1(a) and Section III.13.2.5.2.5.3 of the Tariff) and/or a substitution auction demand bid (as

described in Section III.13.2.8 of the Tariff) results in a reduction of NR Capability or NI Capability to zero; and a partial retirement as the result of the operation of a Retirement De-List Bid or an unconditional Permanent De-List Bid and/or a substitution auction demand bid results in a reduction of NR Capability or NI Capability as described below.

(a) Summer NR/NI Capability Following Partial Retirement Resulting From De-List Bid and/or

Substitution Auction Demand Bid: Following the partial retirement of a Generating Facility (or an External ETU) as a result of the operation of a de-list bid and/or a substitution auction demand bid, the summer NR Capability of the Generating Facility (or summer NI Capability of the External ETU) shall be reduced to equal (1) the Generating Facility's summer CNR Capability (or the External ETU's summer CNI Capability) reduced as described in subsection (a) of Section II.48.3 multiplied by (2) the ratio of the Generating Facility's summer NR Capability (or the External ETU's summer NI Capability) prior to the Forward Capacity Auction to the Generating Facility's summer CNR Capability (or the External ETU's summer CNI Capability) prior to the Forward Capacity Auction.

(b) Winter NR/NI Capability Following Partial Retirement Resulting From De-List Bid and/or

Substitution Auction Demand Bid: Following the partial retirement of a Generating Facility (or an External ETU) as a result of the operation of a de-list bid and/or a substitution auction demand bid, the winter NR Capability of the Generating Facility (or winter NI Capability of the External ETU) shall be reduced to equal (1) the Generating Facility's summer NR Capability (or the External ETU's summer NI Capability) reduced as described in subsection (a) of this Section II.48.4 multiplied by (2) the ratio of the Generating Facility's winter NR Capability (or the External ETU'S winter NI Capability) prior to the Forward Capacity Auction to the Generating Facility's summer NR Capability (or the External ETU'S summer NI Capability) prior to the Forward Capacity Auction; provided that a different winter NR Capability value may be established to account for winter capability remaining after the removal of summer capability if the ISO determines that engineering information submitted no later than 10 calendar days after the conclusion of the Forward Capacity Auction supports the use of the different value.

However, if the resulting winter NR Capability (or winter NI Capability) is less than the Generating Facility's winter CNR Capability (or External ETU's winter CNI Capability), the winter NR Capability (or winter NI Capability) will be set equal to the winter CNR Capability (or winter CNI Capability).

II.H. OTHER TRANSMISSION PROVISIONS

II.49 Definition of PTF

PTF or Pool Transmission Facilities are the transmission facilities owned by PTOs, over which the ISO shall exercise Operating Authority in accordance with the terms set forth in the TOA, rated 69 kV or above required to allow energy from significant power sources to move freely on the New England Transmission System, and include:

1. All transmission lines and associated facilities owned by PTOs rated 69 kV and above, except for lines and associated facilities that (i) were not built as Public Policy Transmission Upgrades and (ii) contribute little or no parallel capability to the PTF. The following do not constitute PTF:
 - (a) Unless they were built as part of a Public Policy Transmission Upgrade,
 - i. Those lines and associated facilities which are required to serve local load only,
 - ii. Generator leads, which are defined as radial transmission from a generation bus to the nearest point on the PTF; or
 - iii. Lines that are normally operated open.
 - (b) Lines and associated facilities that are classified as MTF or OTF.
2. All Public Policy Transmission Upgrades that are comprised of transmission lines rated 115 kV or above, and associated facilities rated 115kV or above, owned by PTOs, and identified pursuant to Attachment K to the OATT shall constitute PTF.
3. Parallel linkages in network stations owned by PTOs (including substation facilities such as transformers, circuit breakers and associated equipment) interconnecting the lines which constitute PTF.
4. If a PTOs with significant generation in its transmission and distribution system (initially 25 MW) is connected to the New England Transmission System and none of the transmission facilities owned by the PTO qualify to be included in PTF as defined in (1), (2) and (3) above, then such PTO's connection to PTF will constitute PTF if both of the following requirements are met for this connection:

- (a) The connection is rated 69 kV or above.
 - (b) The connection is the principal transmission link between the PTO and the remainder of the PTF network.
5. Rights of way and land owned by PTOs required for the installation of facilities that constitute PTF under (1), (2), (3) or (4) above.

The ISO shall review at least annually the status of transmission lines and associated facilities and determine whether such facilities constitute PTF and shall prepare and keep current a schedule or catalogue of PTF facilities.

The following examples indicate the intent of the above definitions:

Unless they were built as part of a Public Policy Transmission Upgrade, radial tap lines to local load are excluded.

Lines which loop, from two geographically separate points on the PTF, the supply to a load bus from the PTF are included.

Lines which loop, from two geographically separate points on the PTF, the connections between a generator bus and the PTF are included

.

Radial connections or connections from a generating station to a single substation or switching station on the PTF are excluded, unless the requirements of paragraph (2) or (4) above are met.

Transmission facilities owned or supported by a Related Person of a PTO which are rated 69 kV or above and are required to allow Energy from significant power sources to move freely on the New England Transmission System shall also constitute PTF provided (i) such Related Person files with the ISO its consent to such treatment; and (ii) the ISO determines that treatment of the facilities as PTF will facilitate accomplishment of the ISO's objectives. If such facilities constitute PTF pursuant to this paragraph, they shall be treated as "owned" or "supported," as applicable, by a PTO for purposes of this OATT and the other provisions of the TOA, including the ability to include the cost associated with such PTF and any

Transmission Support Expenses for support of PTF made by its Related Person in that PTO's Annual Transmission Revenue Requirements, pursuant to Attachment F of the OATT.

Of those transmission facilities that are upgrades, modifications or additions, on and after January 1, 2004, to the transmission system administered by the ISO under the Interim Independent System Operator Agreement, or to the New England Transmission System on or after the Operations Date, only those that: (i) are rated 115kV or above, and (ii) otherwise meet the non-voltage criteria specified in Section II.49 shall be classified as PTF. Those transmission facilities that were PTF pursuant to the Restated NEPOOL Agreement on December 31, 2003, and any upgrades to such facilities that meet the criteria specified in Section II.49, shall remain classified as PTF for all purposes under this Tariff.

II.50 Additions to or Upgrades of PTF

The possible need for an addition to or upgrade of PTF may be identified in connection with the planning process of Attachment K of this OATT, an application or request for service under this OATT, or a request for the installation of or material change to a generation or transmission facility, or may be separately identified by an ISO committee under the Participants Agreement, a Market Participant or the ISO. In such cases, a study, if necessary, to assess available transfer capability and, if necessary, a System Impact Study and a Facility Study, shall be performed by the affected PTO(s) in whose Local Network(s) the addition or upgrade would or might be effected or their designee(s), or the ISO, in the case of a System Impact Study, or the ISO's designee(s), with review of the study by the ISO if it does not perform the study. Studies to assess available transfer capability and System Impact Studies and Facilities Studies shall be conducted, as appropriate, in accordance with any affected PTO's Local Service Schedule of this OATT, or in accordance with the applicable methodology specified in Attachments C and D to this OATT, and the provisions of the Local Service Schedules to this OATT or the applicable provisions of Attachments I and J to this OATT shall apply, as appropriate, with respect to the payment of the costs of the study and the other matters covered thereby.

Responsibility for the costs of new PTF or any modification or other upgrade of PTF shall be determined, to the extent applicable, in accordance with Parts II.B and II.C and Schedules 11 and 12 to this OATT, including without limitation the provisions relating to responsibility for the costs of new PTF or modifications or other upgrades to PTF exceeding regional system, regulatory or other public requirements set forth in Section (3)(b) of Schedule 11 and Schedule 12 to this OATT.

SCHEDULE 1

SCHEDULING, SYSTEM CONTROL AND DISPATCH SERVICE

Scheduling, System Control and Dispatch Service is the service required to schedule at the regional level the movement of power through, out of, within, or into the New England Control Area. Local level service is provided by the PTOs under Schedule 21 to this OATT. For transmission service under this OATT, this Ancillary Service can be provided only by the ISO and the Transmission Customer must purchase this service from the ISO. Charges for Scheduling, System Control and Dispatch Service are to be based on the expenses incurred by the ISO, and by the individual PTOs in the operation of Local Control Center dispatch centers or otherwise, to provide these services. The expenses incurred by the ISO in providing these services recovered under Section IV of the OATT. A surcharge for the expenses incurred by PTOs in the provision of these services for transmission service over the PTF will be added to the Through or Out Service rate and to the Regional Network Service rate. Any Scheduling, System Control and Dispatch Service expenses for the provisions of these services for MTF Service shall be determined separately and assessed to Transmission Customers receiving MTF Service, in accordance with the arrangements between the Transmission Customers receiving MTF Service and the MTF Provider.

The expenses incurred in providing Scheduling, System Control and Dispatch Service for transmission service over the PTF for each PTO will be determined by an annual calculation based on the previous calendar year's data as shown, in the case of PTOs which are subject to the Commission's jurisdiction, in the PTO's FERC Form 1 report for that year, and shall be based on actual data in lieu of allocated data if specifically identified in the Form 1 report. The surcharge shall be redetermined annually as of June 1 in each year and shall be in effect for the succeeding twelve (12) months. The rate surcharge per kilowatt for each month is one-twelfth of the amount derived by dividing the total annual PTO expenses for providing the service by the sum of the average of the coincident Monthly Peaks (as defined in Section II.21.2) of all Local Networks for the prior calendar year.

Each Transmission Customer which is obligated to pay the rate for Regional Network Service for a month shall pay the surcharge on the basis of the number of kilowatts of its Monthly Network Load (as defined in Section II.21.2 of this OATT) for the month. Each Transmission Customer which is obligated to pay the

rate for Through or Out Service for the applicable period shall pay the surcharge on the basis of the highest amount of its Reserved Capacity for each transaction scheduled as Through or Out Service for such period.

The details for implementation of Schedule 1 for transmission service over the PTF shall be established in accordance with the Implementation Rule for Schedule 1 attached to this OATT.

SCHEDULE 1 IMPLEMENTATION RULE

This rule provides detail with respect to the calculation of the rate surcharge each year for Scheduling, System Control and Dispatch Service, which is defined in the OATT as the service required to schedule the movement of power through, out of, within, or into the New England Control Area over Pool Transmission Facilities (“PTF”). This service also includes the dispatch and security analysis of the system. Scheduling, System Control and Dispatch Service for transmission service over transmission facilities other than PTF is provided under Schedule 21 of the OATT. For transmission service under the OATT, this Ancillary Service will be provided by the ISO, and rates collected under Schedule 1 are based on expenses incurred by the Local Control Centers, and the PTOs (as described herein) in providing the necessary elements of this service to the ISO. All of the costs of the ISO for the provision of service under Schedule 1 will be recovered under Section IV of the Transmission, Markets and Services Tariff. Schedule 1 of the OATT is for collection only of the revenue requirements for Local Control Centers and PTOs for System Control and Dispatch Service. Any Transmission Customer taking Regional Network Service or Through or Out Service shall be subject to the rate surcharge calculated under Schedule 1 of the OATT as described in more detail in this rule below.

The PTOs shall make an annual informational filing on or before July 31 of each year showing the Schedule 1 rate surcharge to be utilized by the ISO in the billing of Schedule 1 Ancillary Service that will be in effect for the period beginning June 1 of that year through May 31 of the subsequent year. If there are any corrections made to the information reflected in the informational filing after it has been submitted, the PTOs would file corrections to the informational filing. At least thirty (30) days before the informational filing is made with the Commission, the PTOs shall make available to Transmission Customers and any other interested parties a draft of the proposed filing for review and comment prior to the filing by posting such draft on the RTO NE website. The filing of the informational filing does not reopen the formula rate set forth below for review, but rather is contestable only with respect to the accuracy of the information

contained in the informational filing. The ISO shall have the discretion to conduct audits of such charges, with advisory Stakeholder input on the scope of audit, including on any agreed-upon procedures to be used by the auditor. In this provision, the term “agreed-upon procedures” shall have the meaning afforded to it by the American Institute of Certified Public Accountants.

I. DEFINITIONS

Capitalized terms used in this rule that are not defined in the Tariff have the following definitions:

Scheduling and Dispatch Surcharge Rate shall equal the rate surcharge that is determined for the applicable period beginning on June 1, 1999, in accordance with Section II of this rule below.

PTF Transmission-Related Local Control Center Scheduling and Dispatch Expense shall equal the PTF transmission related expenses incurred by the PTO from REMVEC II, CONVEX/ESCC, and the Maine Local Control Center as recorded in each PTO’s FERC Form 1, Account Nos. 561-561.4, excluding any charges recorded in this account that were incurred under the OATT or Schedule 21 of the OATT. The expenses shall be net of any revenues, as reflected in FERC Account No. 456, received by the PTO for providing scheduling and dispatch services, excluding any revenues recorded in this account that were received as a result of charges under the OATT.

REMVEC II is a Local Control Center of the ISO providing security analysis of PTF.

Local PTF Transmission-Related Scheduling and Dispatch Expense shall equal the sum of (1) each PTO’s expenses as recorded in FERC Account Nos. 561-561.4, excluding any ISO and Local Control Center related expenses and any expenses recorded in these accounts, that were incurred under this OATT or the Schedule 21 of this OATT of each PTO as a Transmission Customer, multiplied by the PTF Transmission Plant Allocator, (2) NSTAR Electric Company (East) SCADA-related expenses as calculated in accordance with Appendix A of this Rule, (3) the Central Maine Power Company Local Control Center revenue requirements as calculated in accordance with Appendix B of this Rule, and (4) the CL&P Dispatch Center Revenue Requirement as calculated in accordance with Appendix C of the Rule.

PTF Transmission Plant Allocation Factor is the factor for allocating transmission costs and expenses between PTF and Non-PTF as determined for the applicable period pursuant to Attachment F of the OATT.

II. CALCULATION OF THE SCHEDULING AND DISPATCH SURCHARGE

A. Surcharge for Regional Network Service Customers

For Network Customers, the scheduling and dispatch surcharge for Regional Network Service shall equal the Network Customer's Regional Monthly Network Load, as defined in Section II.21.2 of the OATT, multiplied by the Monthly Scheduling and Dispatch Surcharge Rate as determined in accordance with Section II.C below.

B. Surcharge for Through or Out Customers

For Through or Out Service Customers, the Scheduling and Dispatch Surcharge shall equal the Transmission Customer's Reserved Capacity for each transaction scheduled for the month multiplied by the applicable Monthly or Hourly Scheduling and Dispatch Surcharge Rate, as determined in accordance with Section II.C below.

C. Scheduling and Dispatch Surcharge Rate

The Scheduling and Dispatch Surcharge Rate will be the surcharge rate in effect from time to time for the applicable period, determined pursuant to the formula described below based on the prior calendar year's data. The Scheduling and Dispatch Surcharge Rate shall be redetermined each year, with the new Surcharge Rate going into effect on June 1 of each year, and be effective for the succeeding twelve months.

In the case of PTOs which are subject to the Commission's jurisdiction, the data used shall be as identified in the PTO's FERC Form 1 report for that year, and shall be based on actual data in lieu of allocated data if specifically identified in the FERC Form 1. When FERC Form 1 data is not the direct source of the data used in the formula, the worksheets used to develop the inputs will reflect Appendix A, Appendix B, and Appendix C of this Rule.

The Scheduling and Dispatch Surcharge Rate shall be equal to the sum of (1) PTF Transmission-Related Local Control Center Scheduling and Dispatch Expense, (2) Local PTF Transmission Related Scheduling and Dispatch Expense, (3) less Schedule 1 revenues from the prior year surcharges for Short-Term Point-To-Point Transactions, and divided by the annual average of the sum of all Regional Network Customers Monthly Peak Load, as defined in Section II.21.2 of the OATT, from the prior calendar year plus the Long-Term Firm Point-To-Point Service Reserved Capacity, from the prior calendar year.

The Monthly Scheduling and Dispatch Surcharge Rate shall equal one-twelfth of the Scheduling and Dispatch Surcharge Rate.

The Hourly Scheduling and Dispatch Surcharge Rate shall be the annual rate divided by 8760.

APPENDIX A TO SCHEDULE 1 IMPLEMENTATION RULE

NSTAR ELECTRIC COMPANY (EAST) SCADA

This service is required to schedule the movement of power through, out of, within, or into the New England Control Area over Pool Transmission Facilities (PTF). Service under this schedule represents the contribution to that service provided by the PTO's own Dispatch Center, commonly referred to as SCADA. These costs are excluded from costs in Attachment F.

The PTF Revenue Requirement for the scheduling, system control and dispatch service that is based on data for the calendar year 2004 or later shall include an allocated PTF-related amount of Incremental Return and Associated Income Taxes on SCADA-related transmission plant investments included in the Regional System Plan and placed in-service on or after January 1, 2004 (such investments referred to herein as "Post-2003 Dispatch Center Investment"). The Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment shall reflect a surcharge of a 100 basis point ROE adder applicable to certain investment base components as specified in the formula below. The data used in determining the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment shall be based on actual data in lieu of allocated data if specifically identified in NSTAR Electric's (East) accounting records.

Definitions: Dispatch Center Wages and Salaries Allocation Factor: Ratio of Dispatch Center Related Direct Wages and Salaries to NSTAR Electric's (East) total Direct Wages and Salaries excluding Administrative and General Wages and Salaries.

Dispatch Center Plant Allocation Factor: Ratio of Total Investment in Dispatch Center Plant plus Dispatch Center Related General Plant, to Total Plant in service.

Dispatch Center Transmission Plant Allocation Factor: Ratio of Total Investment in Dispatch Center Plant plus Dispatch Center Related General Plant, to Total Investment in Transmission Plant.

The PTF Revenue Requirement for the Scheduling System Control and Dispatch Service shall equal the sum of the PTO's: (A) Return and Associated Income Taxes (including the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment), (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Related Amortization of Investment Tax Credits, (D) Dispatch Center Related Municipal Tax Expense, (E) Dispatch Center Related Payroll Tax Expense (F) Dispatch Center Operation and Maintenance Expense, and (G) Dispatch Center Related Administrative and General Expense; multiplied by the PTF Transmission Plant Allocation Factor.

The Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment shall be calculated using the Dispatch Center investment base components specifically identified in Section A.1 of the formula below.

A. Return and Associated Income Taxes shall equal the product of the Dispatch Center Investment Base and the Cost of Capital Rate. To calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, the Dispatch Center Investment Base will only include items (a), (d) and (e) under Section (A)(1), calculated in the manner indicated.

1. **The Dispatch Center Investment Base** will consist of (a) Dispatch Center Plant in FERC accounts 350-359, plus (b) Dispatch Center Related General Plant, plus (c) Dispatch Center Plant Held for Future Use, less (d) Dispatch Center Related Depreciation Reserve, less (e) Dispatch Center Related Accumulated Deferred Taxes, plus (f) Other Regulatory Assets, plus (g) Dispatch Center Prepayments, plus (h) Dispatch Center Materials and Supplies, plus (i) Dispatch Center Related Cash Working Capital.

- a. **Dispatch Center Plant** will equal the year-end balance of the PTO's Investment in Dispatch Center per FERC accounts 350 through 359. Dispatch Center Plant Investment is not included in PTF investment in the Attachment F revenue requirement. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, Post-2003 Dispatch Center Plant shall be separately identified.
- b. **Dispatch Center Related General Plant** shall equal the PTO's year-end balance of Investment in General Plant multiplied by the Dispatch Center Wages and Salaries Allocation Factor described above.

- c. Dispatch Center Plant Held for Future Use shall equal the year-end balance of Transmission related Dispatch Center Investment in FERC account 105.

- d. Dispatch Center Related Depreciation Reserve shall equal the year-end balance of Transmission Dispatch Center Depreciation Reserve, plus the year-end balance of Dispatch Center Related General Depreciation Reserve. Dispatch Center Related General Plant Depreciation Reserve shall equal the product of General Plant Depreciation Reserve and the Dispatch Center Wages and Salaries Allocation Factor described above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, Dispatch Center Depreciation Reserve associated with the Post-2003 Dispatch Center Investment, shall equal the balance of the Dispatch Center Depreciation Reserve multiplied by the ratio of Post-2003 Dispatch Center Plant to total investment in Dispatch Center Plant.

- e. Dispatch Center Related Accumulated Deferred Taxes shall equal the year-end balance of Total Accumulated Deferred Income Taxes, multiplied by the Dispatch Center Plant Allocation Factor described above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, Total Accumulated Deferred Income Taxes associated with the Post-2003 Dispatch Center Investment, shall equal the balance of total property-related accumulated deferred income taxes as recorded in FERC Accounts 281 and 282, multiplied by the Dispatch Center Plant Allocation Factor, further multiplied by the ratio of the Post-2003 Dispatch Center Plant to total investment in Dispatch Center Plant.

- f. Other Regulatory Assets shall equal the year-end balance of FAS 106 multiplied by the Dispatch Center Wages and Salaries Allocation Factor described in Section (A) (2) (b) above and the year-end balance of FAS 109, net of FAS 109 liability, multiplied by the Dispatch Center Plant Allocation Factor described in above.

- g. Dispatch Center Prepayments shall equal the year-end balance of Prepayments multiplied by the Dispatch Center Wages and Salaries Allocation Factor described above.

- h.** Dispatch Center Materials and Supplies shall equal the year-end balance of Transmission Plant Materials and Supplies multiplied times the Dispatch Center Plant Allocation Factor described above.
- i.** Dispatch Center Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Dispatch Center Transmission Related Operation and Maintenance Expense and Dispatch Center Transmission Related Administrative and General Expense.

2. The Cost of Capital Rate shall equal (a) the Weighted Cost of Capital, plus (b) Federal Income Taxes, plus (c) State Income Taxes.

- a.** the Weighted Cost of Capital will be calculated based upon the PTO's capital structure at the end of each year and will equal the sum of (i), (ii) and (iii) below.

The Cost of Capital Rate to be used in calculating the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, shall only reflect item (iii) below and shall apply in the manner indicated below.

- i.** the Long Term Debt Component, which equals the product of the actual weighted average embedded cost to maturity of Long Term Debt then outstanding and the ratio that Long-Term Debt is to Total Capital.
- ii.** the Preferred Stock Component, which equals the product of the actual weighted average embedded cost to maturity of Preferred Stock then outstanding and the ratio that Preferred Stock is to Total Capital.
- iii.** the Return on Equity Component, which equals the product of the PTO's Return on Equity as set in the PTO's RNS open access rate and the ratio that Common Equity is to Total Capital. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, the incremental return on equity shall be the product of 1.00% and the ratio of Common Equity to Total Capital.

b. Federal Income Taxes shall equal

$$\frac{A + [(C+B)/D] \times FT}{1 - FT}$$

Where FT is the Federal Income Tax Rate and A is the sum of the Preferred Stock Component and the Return on Equity Component, as determined in Sections A.2.(a)(ii) and (iii) above, B is Dispatch Center Related Amortization of Investment Tax Credits, as determined in Section II.D. below, C is the Equity AFUDC component of Dispatch Center Depreciation Expense, as defined in Section B., and D is Dispatch Center Investment Base, as determined in A.1., above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, the incremental Federal Income Tax shall equal:

$$(A' * FT) / (1 - FT)$$

Where FT is the Federal Income Tax Rate and A' is the incremental return on equity component, as determined in Section A.2.(a)(iii) above.

c. State Income Taxes shall equal

$$\frac{(A + [(C+B)/D] + \text{Federal Income Tax}) \times ST}{1 - ST}$$

Where ST is the State Income Tax Rate and A is the sum of the Preferred Stock Component and the Return on Equity Component, as determined in Section A.2.(a)(ii), and Section A.2.(a)(iii) above, and Federal Income Tax is the rate determined in Section A.2.(b) above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Dispatch Center Investment, the incremental State Income Tax shall equal:

$$(A' + \text{Federal Income Tax}) * ST / (1 - ST)$$

Where ST is the State Income Tax Rate and A' is the incremental return on equity component, as determined in Section A.2.(a)(iii) above, and Federal Income Tax is the rate determined in Section A.2.(b) above.

B. Dispatch Center Depreciation Expense shall equal the sum of Transmission Depreciation Expense for Dispatch Center Plant, plus an allocation of General Plant Depreciation Expense calculated by multiplying General Plant Depreciation Expense by the Dispatch Center Wages and Salaries Allocation Factor, described in Section (A)(1)(b) above.

C. Dispatch Center Related Amortization of Investment Tax Credits shall equal the PTO's Amortization of Investment Tax Credits multiplied by the Dispatch Center Plant Allocation Factor described above.

D. Dispatch Center Related Municipal Tax Expense shall equal the PTO's total Municipal Tax Expense multiplied by the Dispatch Center Plant Allocation Factor described above.

E. Dispatch Center Related Payroll Tax Expense shall equal the PTO's total electric payroll tax expense, multiplied by the Dispatch Center Wages and Salaries Allocation Factor, described above.

F. Dispatch Center Operation and Maintenance Expense shall equal all expenses related to SCADA operation charged to FERC Account Number 561 through 561.4, excluding any ISO and Local Control Center related expenses and any expenses recorded in this Account that were incurred under this OATT or the Local Service Schedules of this OATT as a Transmission Customer.

G. Dispatch Center Related Administrative and General Expenses shall equal the sum of (1) PTO's Administrative and General Expenses multiplied by the Dispatch Center Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Dispatch Center Plant Allocation Factor, and (3) Expenses included in Account 928 (excluding Merger-Related Costs included in Account 928) related to FERC Assessments multiplied by Dispatch Center Plant Allocation Factor, plus any other Federal and State Dispatch Center related expenses or assessments, plus specific Dispatch Center related expenses included in Account 930.1 plus Transmission Merger-Related Costs multiplied by the Dispatch Center Transmission Plant Allocation Factor.

**APPENDIX B TO SCHEDULE 1 IMPLEMENTATION RULE CENTRAL MAINE POWER
COMPANY LOCAL CONTROL CENTER**

I. DEFINITIONS

Capitalized terms not otherwise defined in the Tariff and as used in this rule have the following definitions:

A. ALLOCATION FACTORS

1. Wages and Salaries Allocation Factor shall equal the ratio of the Local Control Center Direct Wages and Salaries to total direct wages and salaries excluding administrative and general wages and salaries.
2. Local Control Center Wages and Salaries Allocation Factor shall equal the ratio of the Transmission Local Control Center Direct Wages and Salaries to total Local Control Center Direct Wages and Salaries.
3. Local Control Center PTF Allocation Factor shall equal the ratio of the Local Control Center PTF Direct Wages and Salaries to the total Local Control Center Transmission Direct Wages and Salaries.
4. Local Control Center Plant Allocation Factor shall equal the ratio of the Total Investment in Local Control Center Plant to Total Plant in service.

B. TERMS

Administrative and General Expense shall equal the PTO's expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928, and 930.1.

Amortization of Investment Tax Credits shall equal the PTO's credits as recorded in FERC Account No. 411.4

Amortization of Loss on Reacquired Debt shall equal the PTO's expenses as recorded in FERC Account No. 428.1

Other Regulatory Assets/Liabilities -FAS 106 shall equal the net of the PTO's FAS 106 balance as recorded in FERC Account 182.3 and any FAS 106 balance as recorded in the PTO's FERC Account No. 254.

Other Regulatory Assets/Liabilities -FAS 109 shall equal the net of the PTO's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in the PTO's FERC Account No. 254.

Payroll Taxes shall equal those payroll expenses as recorded in the PTO's FERC Account Nos. 408.1 and 409.1.

Plant Held for Future Use shall equal the PTO's balance in FERC Account No. 105.

Prepayments shall equal the PTO's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal the PTO's expenses as recorded in FERC Account No. 924.

PTF Local Control Center Direct Wages and Salaries shall equal the PTO's direct wages and salaries related to providing PTF Local Control Center services as recorded in FERC Account No. 561.

Local Control Center Direct Wages and Salaries shall equal the PTO's direct wages and salaries related to providing Local Control Center services as recorded in FERC Account Nos. 556, 561-561.4, and 581.

Local Control Center Operation and Maintenance Expense shall equal the PTO's expenses recorded in FERC Account Nos. 556, 561-561.4, & 581, less any costs included in FERC Account Nos. 561-561.4 that are otherwise recoverable pursuant to Subpart (1) of the Local PTF

Transmission Related Scheduling and Dispatch Expense of the rule implementing the Schedule 1 rate surcharge of the OATT.

Local Control Center Plant Depreciation Reserve shall equal the PTO's depreciation reserve balance for Local Control Center Related Plant as recorded in FERC Account No. 108.

Materials and Supplies shall equal the PTO's balance as recorded in FERC Account No. 154.

Local Control Center Related Depreciation Expense shall equal the PTO's depreciation expense for Local Control Center Related Plant as recorded in FERC Account No. 403.

Local Control Center Related Plant shall equal the PTO's gross plant balances used for system control and dispatch purposes as recorded in FERC Account Nos. 303-399. To the extent that such plant includes any amounts recorded as transmission investment in FERC Account Nos. 350-359, such amounts will be excluded for purposes of determining annual transmission revenue requirements pursuant to the billing rule which implements Attachment F of the OATT.

Local Control Center Support Revenues shall equal the revenues received from Local Control Center supporters as recorded in FERC Account Nos. 454 and 456, excluding any revenues received under Schedule 1 of the OATT or the PTO's Local Service Schedule.

Total Accumulated Deferred Income Taxes shall equal the net of the deferred tax balances as recorded in FERC Account Nos. 281-283 and 190.

Total Loss on Reacquired Debt shall equal the PTO's balance as recorded in FERC Account No. 189.

Total Municipal Tax Expense shall equal the PTO's municipal tax expenses as recorded in FERC Account Nos. 408.1 and 409.1.

Total Plant in Service shall equal the PTO's total gross plant balance as recorded in FERC Account Nos. 301-399.

Transmission Local Control Center Direct Wages and Salaries shall equal the PTO's direct wages and salaries related to providing Local Control Center services as recorded in FERC Account No. 561-561.4.

II. CALCULATION OF TOTAL LOCAL CONTROL CENTER REVENUE REQUIREMENTS

The Local Control Center Revenue Requirements based on data for calendar year 2004 or later shall include an Incremental Return and Associated Income Taxes on Central Maine's local control center investments included in the Regional System Plan and placed in service on or after January 1, 2004 (such investments referred to herein as "Post-2003 Investment"). The Incremental Return and Associated Income Taxes for Post-2003 Investment shall reflect a surcharge of a 100 basis point ROE adder applicable to certain investment base components as specified in the formula below. The data used in determining the Incremental Return and Associated Income Taxes for Post-2003 Investment shall be based on actual data in lieu of allocated data if specifically identified in Central Maine's accounting records.

The Local Control Center Revenue Requirement shall equal the sum of the Local Control Center related (A) Return and Associated Income Taxes (including the Incremental Return and Associated Income Taxes for Post-2003 Investment), (B) Depreciation Expense, (C) Amortization of Loss on Reacquired Debt, (D) Amortization of Investment Tax Credits, (E) Municipal Tax Expense, (F) Payroll Tax Expense, (G) Operations and Maintenance Expense, (H) Administrative and General, minus (I) Support Revenues.

The Incremental Return and Associated Income Taxes for Post-2003 Investment shall be calculated using the investment base components specifically identified in Section A.1. of the formula below.

A. **Return and Associated Income Taxes** shall equal the product of the Local Control Center Investment Base and the Cost of Capital Rate reflected in the PTO's Attachment F formula of the OATT. To calculate the Incremental Return and Associated Income Taxes for Post 2003 Investment, Local Control Center Investment Base shall only include Sections II.A.1.(a), (b), and (c), in the manner indicated.

1. **Local Control Center Investment Base**

The Local Control Center Investment Base will be the year end balances of Local Control Center related: (a) Plant, plus (b) Plant Held for Future Use, less (c) Depreciation Reserve, less (d) Accumulated Deferred Taxes, plus (e) Loss on Reacquired Debt, plus (f) Other Regulatory Assets/Liabilities, plus (g) prepayments, plus (h) Materials and Supplies, plus (i) Cash Working Capital.

- (a) Local Control Center Related Plant shall equal the balance of the PTO's Investment in Local Control Center Plant. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, Post 2003 Local Control Center Plant shall be separately identified.
- (b) Local Control Center Related Plant Held for Future Use shall equal the balance of Plant Held for Future Use multiplied by the Local Control Center Plant Allocation Factor.
- (c) Local Control Center Related Depreciation Reserve shall equal the Depreciation Reserve for the PTO's investment in Local Control Center plant. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, Local Control Center Depreciation Reserve shall equal the Depreciation Reserve for the PTO's Local Control Center Plant identified in (a) above.
- (d) Local Control Center Related Accumulated Deferred Taxes shall equal the PTO's electric balance of Accumulated Deferred Income Taxes multiplied by the Local Control Center Plant Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, Local Control Center Accumulated Deferred Taxes shall equal the PTO's balance of total property related accumulated deferred income taxes recorded in FERC account 281 and 282 multiplied by the Local Control Center Plant Allocation Factor and further multiplied by the ratio of Post-2003 Investment to Total Local Control Center Related Plant.
- (e) Local Control Center Related Loss on Reacquired Debt shall equal the PTO's electric balance of Total Loss on Reacquired Debt multiplied by the Local Control Center Plant Allocation Factor.

- (f) Local Control Center Related Other Regulatory Assets/Liabilities shall equal the PTO's electric balance of any deferred recovery of FAS 106 expenses multiplied by the Local Control Center Wages and Salaries Allocation Factor, plus the PTO's electric balance of FAS 109 multiplied by the Local Control Center Plant Allocation Factor.
- (g) Local Control Center Related Prepayments shall equal the PTO's electric balance of prepayments multiplied by the Local Control Center Plant Allocation Factor.
- (h) Local Control Center Related Materials and Supplies shall equal the PTO's electric balance of Plant Materials and Supplies, multiplied by the Local Control Center Plant Allocation Factor.
- (i) Local Control Center Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of Local Control Center Operation and Maintenance Expense, Local Control Center Related Administrative and General Expense.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the PTO's Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

- (a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of (i),(ii), and (iii) below. The Cost of Capital Rate to be used in calculating the Incremental Return and Associated Income Taxes for Post-2003 Investment shall only reflect item (iii) below and shall apply in the manner indicated below
- (b) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of the PTO's long-term debt then outstanding and the ratio that long-term debt is to the PTO's total capital.

- (c) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of the PTO's preferred stock then outstanding and the ratio that preferred stock is to the PTO's total capital.
- (d) the return on equity component, which equals the product of the PTO's Return on Equity as set in the PTO's RNS open access rate and the ratio that common equity is to the PTO's total capital. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, the incremental return on equity shall be the product of Central Maine's incremental return on equity of 1.0% and the ratio that common equity is to the PTO's total capital.
- (e) Federal Income Tax shall equal

$$\frac{(A+[(C+B)/D]) \times FT}{1 - FT}$$

Where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of Local Control Center Depreciation Expense, as defined in II.B., and D is Local Control Center Investment Base, as determined in II.A.1., above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, the incremental Federal Income Tax shall equal

$$\frac{(A' * FT)}{(1 - FT)}$$

where FT is the Federal Income Tax Rate and A' is the incremental return on equity component, as determined in Section II.A.2.(a)(iii) above.

- (f) State Income Tax shall equal

$$(A+[(C+B)/D] + \text{Federal Income Tax}) \times ST$$

1 – ST

Where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.D. below, C is the equity AFUDC component of Local Control Center Depreciation Expense, as defined in II.B., D is the Local Control Center Investment Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.1.(b) above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 Investment, the incremental State Income Tax shall equal

$$\frac{(A' + \text{Federal Income Tax})(ST)}{(1 - ST)}$$

where ST is the State Income Tax Rate, A' is the incremental return on equity component determined in Section II.A.2.(a)(iii) above, and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

- B. Local Control Center Depreciation Expense shall equal the Local Control Center Plant Depreciation Expense and Accumulated Amortization.
- C. Local Control Center Related Amortization of Loss on Reacquired Debt shall equal the PTO's electric balance of Loss on Reacquired Debt multiplied by the Local Control Center Plant Allocation Factor.
- D. Local Control Center Related Amortization of Investment Tax Credits shall equal the PTO's electric Amortization of Investment Tax Credits multiplied by the Local Control Center Plant Allocation Factor.
- E. Local Control Center Related Municipal Tax Expense shall equal the PTO's total electric municipal tax expense multiplied by the Local Control Center Plant Allocation Factor.
- F. Local Control Center Related Payroll Tax Expense shall equal the PTO's total electric payroll tax expense, multiplied by the Wages and Salaries Allocation Factor.

- G. Local Control Center Operation and Maintenance Expense shall equal the PTO's Operation and Maintenance Expenses recorded in FERC Account Nos. 556, 561-561.4, and 581, less any costs included in FERC Account Nos. 561-561.4 that are otherwise recoverable pursuant to Subpart (1) of Local PTF Transmission Related Scheduling and Dispatch Expense of the rule implementing the Schedule 1 rate surcharge of the OATT.
- H. Local Control Center Related Administrative and General Expenses shall equal the sum of (1) PTO's Administrative and General Expenses multiplied by the Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Local Control Center Plant Allocation Factor, and (3) Expenses included in Account 928 related to FERC Assessments multiplied by the Local Control Center Plant Allocation Factor, plus any other Federal and State Local Control Center related expenses or assessments, plus specific Local Control Center related expenses included in Account 930.1.
- I. Transmission Support Revenues shall equal the PTO's revenue received for providing system control and dispatch service.

III. CALCULATION OF LOCAL CONTROL CENTER TRANSMISSION REVENUE REQUIREMENTS

The Total Local Control Center Revenue Requirements derived in Section II. above are further multiplied by the Local Control Center Wages and Salaries Allocation Factor defined in Section I. A. 2. above to determine the transmission related revenue requirement, and further multiplied by the Local Control Center PTF Allocation Factor defined in Section I. A. 3. above, to determine the PTF Transmission related revenue requirements to be included in Schedule I of the OATT.

APPENDIX C TO SCHEDULE 1 IMPLEMENTATION RULE

CL&P DISPATCH CENTER REVENUE REQUIREMENT

This appendix calculates the CL&P Dispatch Center Revenue Requirement for use in calculating part (4) of the Local PTF Transmission-Related Scheduling and Dispatch expenses in the Schedule 1 Implementation Rule. The CL&P Dispatch Center Revenue Requirement for use during a calendar year shall be based on CL&P's costs for the immediately preceding calendar year.

I. DEFINITIONS

Capitalized terms not otherwise defined in Section II.1 of the OATT and as used in this appendix have the following definitions:

Dispatch Center means CL&P's CONVEX dispatch center.

Dispatch Center Plant shall equal CL&P's year-end gross plant balances used for CL&P's Dispatch Center as recorded in FERC Account Nos. 303, 350-359, and 389-399.

Dispatch Center Depreciation Reserve shall equal CL&P's year-end depreciation reserve balance for Dispatch Center Plant as recorded in FERC Account No. 108. Dispatch Center Accumulated Deferred Income Taxes shall equal the net of CL&P's year-end deferred tax balances for Dispatch center Plant as recorded in FERC Account Nos. 281-283 and 190.

II. CALCULATION OF TOTAL DISPATCH CENTER REVENUE REQUIREMENT

The Dispatch Center Revenue Requirement shall equal the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C) Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense; provided, that during the period June 1, 2008 through May 31, 2009, the Dispatch Center Revenue Requirement shall equal the product of (i) the number of months (or fractions thereof) remaining in 2007 on and after the date upon which the Convex Agreements are permitted to be made effective by FERC, divided by 12 and (ii) the sum of (A) Dispatch Center Return and Associated Income Taxes, (B) Dispatch Center Depreciation Expense, (C)

Dispatch Center Amortization of Investment Tax Credits, and (D) Dispatch Center Municipal Tax Expense. “CONVEX Agreements” refers to the agreements between The Connecticut Light & Power Company and various entities relating to the operation of the Dispatch Center and filed with FERC contemporaneously with the filing of this Appendix C.

A. Dispatch Center Return and Associated Income Taxes shall equal the product of the Dispatch Center Investment Base and the Cost of Capital Rate.

1. Dispatch Center Investment Base

The Dispatch Center Investment Base will be the year-end balances of:

(a) Dispatch Center Plant, less (b) Dispatch Center Depreciation Reserve, less (c) Dispatch Center Accumulated Deferred Income Taxes.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the Weighted Cost of Capital, plus (b) Federal Income Tax, plus (c) State Income Tax.

(a) The Weighted Cost of Capital will be calculated based upon CL&P’s capital structure at the end of each year and will equal the sum of (i), (ii), and (iii) below.

(i) The long-term debt component, which equals the product of the year-end balance of CL&P’s first mortgage bonds and pollution control notes adjusted for premiums, discounts, debt expense and losses on reacquired debt and the ratio of the long term debt to CL&P’s total capital.

(ii) The preferred stock component, which equals the product of the year-end balance of CL&P’s preferred stock adjusted for premiums, discounts and unamortized issue expense and the ratio of the preferred stock to CL&P’s total capital.

(iii) The common equity component, which equals the product of 10.3% and the ratio of the common equity to CL&P’s total capital.

(b and c) Federal and State Income Taxes shall be computed as follows:

$$A \times B \times C$$

where: A = Dispatch Center Investment Base

B = Cost of equity capital (the sum of the preferred stock component and common equity component)

C = $TC / (1 - TE)$, where TE is the effective combined federal and state statutory income tax rates in effect at the applicable time.

- B. Dispatch Center Depreciation Expense shall equal CL&P's Dispatch Center depreciation expense as recorded in FERC Account No. 403.
- C. Dispatch Center Amortization of Investment Tax Credits shall equal CL&P's Dispatch Center amortization of investment tax credits as recorded in FERC Account No. 411.1.
- D. Dispatch Center Municipal Tax Expense shall equal CL&P's Dispatch Center municipal tax expense as recorded in FERC Account Nos. 408.1 and 409.1.

SCHEDULE 2

REACTIVE SUPPLY AND VOLTAGE CONTROL SERVICE

In order to maintain transmission voltages on the New England Transmission System (for voltage constraints that are reflected in the ISO's systems for operating the New England Transmission System or in the ISO New England Operating Procedures) within acceptable limits, Qualified Reactive Resources are operated to produce (or absorb) reactive power. Thus, VAR Service must be provided to support Regional Network Service and Through or Out Service on the New England Transmission System (both of which services have a direct impact on voltage constraints that are reflected in the ISO's systems for operating the New England Transmission System or in the ISO New England Operating Procedures). The amount of VAR Service that must be supplied with respect to a Transmission Customer's Regional Network Service and Through or Out Service will be determined based on the degree of dynamic reactive power support necessary to maintain transmission voltages within limits that are consistently adhered to in the operation of the New England Transmission System. Additional detailed requirements regarding the processes used to collect data and calculate amounts due or payable under this Schedule 2 are described in the Ancillary Service Schedule 2 Business Procedure posted on the ISO website. Transmission Customers taking Local Service, MTF Service or OTF Service may also need to acquire voltage support services not otherwise provided under this Schedule 2 pursuant to Schedules 18, 20A or 21 to this OATT, as appropriate.

I. DEFINITIONS

Whenever used in this Schedule, in either the singular or plural number, capitalized terms shall have the meanings specified in Section I.2.2. of the Tariff.

II. ELIGIBILITY FOR PAYMENT UNDER SCHEDULE 2

A. Qualified Generator Reactive Resources

Qualified Generator Reactive Resources shall be eligible for VAR Payments under this Schedule 2. A Qualified Generator Reactive Resource shall be offered into the Real-Time Energy Market at a MW level of at least its Economic Min in all hours of the month whenever the resource is physically available, and be eligible for commitment by the ISO for the purpose of providing reactive power voltage support to the

New England Transmission System. Qualified Generator Reactive Resources are subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures for the purpose of providing reactive power voltage support to the New England Transmission System. In addition, any generator that is dispatched by ISO for the purpose of providing voltage support to the New England Transmission System shall be eligible to recover its Lost Opportunity Costs (“LOC”), Cost of Energy Consumed (“CEC”), and Cost of Energy Produced (“CEP”) pursuant to Sections IV.B-D of this Schedule 2.

A generator is eligible to be designated as a Qualified Generator Reactive Resource by the ISO if it meets the criteria listed below, and a Qualified Generator Reactive Resource designation may be retained as long as the criteria listed below continues to be met:

1. the entity owning or controlling the reactive power capability of the generator reactive resource is a Market Participant;
2. the generator is: (a) interconnected to the New England Transmission System or (b) interconnected to the distribution system but participating in the New England Markets and (c) is metered and dispatchable by the ISO or otherwise subject to operational control by the ISO;
3. the generator provides measurable dynamic reactive power voltage support to the New England Transmission System, as determined from time-to-time by the ISO, and has its automatic voltage regulating equipment status telemetered to the ISO and the applicable Local Control Center;
4. the generator meets the reactive power testing requirements applicable to generators, as determined from time-to-time by the ISO and specified in the ISO New England Operating Documents;
5. the installation of the generator shall have been approved in accordance with the requirements of Section I.3.9 of the Tariff or its predecessor or successor provisions under the New England regional transmission arrangements; and

6. the Market Participant provides accurate reactive capability data to the ISO as specified in ISO New England Operating Documents.

B. Qualified Non-Generator Reactive Resources

Qualified Non-Generator Reactive Resources shall be eligible for VAR Payments under this Schedule 2. However, to the extent that cost recovery for the dynamic reactive power capability of a non-generator resource could occur under the PTF cost recovery mechanism, it shall occur only under such cost recovery mechanism and not under this Schedule 2.

A non-generator is eligible to be designated as a Qualified Non-Generator Reactive Resource by the ISO if it meets the criteria listed below, and a Qualified Non-Generator Reactive Resource designation may be retained as long as the criteria listed below continues to be met:

1. the entity owning or controlling the reactive power capability of the non-generator reactive power resource is a Market Participant;
2. the non-generator reactive power equipment provides measurable dynamic reactive power voltage support to the New England Transmission System, as determined from time-to-time by the ISO;
3. the type of dynamic reactive power equipment is within a category of equipment that has been approved by the ISO, with advisory input from the Reliability Committee;
4. the dynamic reactive power equipment is subject to the Operating Authority of the ISO and all necessary operating protocols for provision of reactive power voltage support from such equipment are in place;
5. such equipment is interconnected to the New England Transmission System and metered and dispatchable by the ISO or otherwise subject to operational control by the ISO, and has its automatic voltage regulating equipment status telemetered to the ISO and the applicable Local Control Center;

6. the non-generator reactive resource meets the reactive power testing requirements applicable to such non-generators, as determined from time-to-time by the ISO and specified in the ISO New England Operating Documents;
7. the installation of such equipment shall have been approved in accordance with the requirements of Section I.3.9 of the Tariff or its predecessor provisions under the New England regional transmission arrangements; and
8. the Market Participant provides accurate reactive capability data to the ISO as specified in ISO New England Operating Documents.

C. Non-Dynamic Reactive Resources

Nothing in this Schedule 2 is intended to preclude, or provide support for, the cost recovery under a separate schedule to the Tariff, filed with the Commission pursuant to the requirements of Sections 205 or 206 of the Federal Power Act, for non-generator, non-dynamic reactive resources that are interconnected to and provide VAR Service to the New England Transmission System but do not meet the criteria to be deemed either Qualified Non-Generator Reactive Resources or PTF.

III. DETERMINATION AND ALLOCATION OF VAR SERVICE CHARGES

Transmission Customers must purchase VAR Service from the ISO for the support of transmission voltages on the New England Transmission System. With the exception of VAR Service charges related to high voltage conditions, the hourly charge for VAR Service shall be paid by each Transmission Customer that receives either Regional Network Service or Through or Out Service. In the event that VAR Service charges for an hour are exclusively related to service provided to meet reliability criteria that address high voltage conditions in one or more Reliability Regions, then the VAR Service charges associated with high voltage conditions for that hour are allocated to each Transmission Customer within the affected Reliability Regions that receives Regional Network Service based on its pro rata share of Regional Network Load within the affected Reliability Regions. VAR Service charges are determined pursuant to the following formula:

$$\begin{aligned}
 CH = & (CC + LOC_0 + CEC_0 + CEP_0) \left(\frac{HL_1 + RC_1}{HL + RC} \right) \\
 & + (LOC_{HV} + CEC_{HV} + CEP_{HV}) \left(\frac{HLR_1}{HL + RC} \right)
 \end{aligned}$$

HLR

in which the inputs to the formula have the following meaning:

CH = the amount to be paid by the Transmission Customer for the hour;

CC = the Capacity Costs for the hour shall be the VAR Revenue Requirement determined as set forth herein divided by the number of hours in the month;

LOC_{HV} = the Lost Opportunity Costs for the hour to be paid for a dynamic reactive power resource that supplies VAR Service to meet reliability criteria in the Transmission Customer's Reliability Region, provided the VAR Service is supplied exclusively to address high voltage conditions within one or more Reliability Regions;

LOC_O = the Lost Opportunity Costs for the hour to be paid for a dynamic reactive power resource that provides VAR Service to meet reliability criteria within one or more Reliability Regions excluding the costs for VAR Service that is supplied exclusively to address high voltage conditions;

CEP_{HV} = the Cost of Energy Produced which is the portion of the amount paid for the hour for Energy produced by a dynamic reactive power resource for VAR Service to meet reliability criteria in the Transmission Customer's Reliability Region, provided the VAR Service is supplied exclusively to address high voltage conditions within one or more Reliability Regions;

CEP_O = the Cost of Energy Produced which is the portion of the amount paid for the hour for Energy produced by a dynamic reactive power resource for VAR Service to meet reliability criteria within one or more Reliability Regions excluding the costs for VAR Service supplied exclusively to address high voltage conditions;

CEC_{HV} = the Cost of Energy Consumed which is the cost of energy used in the hour by a dynamic reactive power resource in order to supply VAR Service to meet reliability criteria in the Transmission Customer's Reliability Region, provided the VAR Service is supplied exclusively to address high voltage conditions within one or more Reliability Regions;

CEC_0 = the Cost of Energy Consumed which is the cost of Energy used in the hour by a dynamic reactive power resource in order to provide VAR Service to meet reliability criteria within one or more Reliability Regions excluding the costs for VAR Service supplied exclusively to address high voltage conditions;

HL_I = the Regional Network Load of the Transmission Customer for the hour;

HL = the aggregate of the Regional Network Loads of all Transmission Customer for the hour;

HLR_1 = that portion of the Regional Network Load of the Transmission Customer that is within a Reliability Region where VAR Service charges in the hour were a result of VAR Service provided exclusively to meet reliability criteria that address high voltage conditions;

HLR = the aggregate of all the Regional Network Loads of all Transmission Customers within Reliability Regions where VAR Service charges in the hour were a result of VAR Service provided exclusively to meet reliability criteria that address high voltage conditions;

RC_I = the Reserved Capacity for Through or Out Service of the Transmission Customers for the hour, excluding any Coordinated External Transaction Reserved Capacity for Through or Out Service; and

RC = the aggregate Reserved Capacity for Through or Out Service of all Transmission Customers for the hour, excluding all Coordinated External Transaction Reserved Capacity for Through or Out Service.

IV. DETERMINING A QUALIFIED REACTIVE RESOURCE'S PAYMENT UNDER THIS SCHEDULE

The compensation to be paid to resources providing VAR Service shall be as set forth below.

A. Capacity Cost (CC)

1. A Qualified Reactive Resource shall be eligible to receive VAR Payments under the Capacity Cost component of this Schedule 2 for the capability to provide VAR Service.
2. Payment for VAR Service is intended to compensate a Qualified Generator or Non-Generator Reactive Resource for VAR Service at the resource's Point of Interconnection. For those resources interconnected under an agreement other than the Interconnection Agreement established pursuant to Schedules 22, 23, or 25 and without a defined Point of Interconnection, the resource will be compensated for VAR Service at the point where the resource interconnected to the existing Administered Transmission System.
3. Payment for VAR Service associated with lagging capability is not intended to compensate a Qualified Generator Reactive Resource for reactive power absorbed by the generator step-up transformer. Payment for VAR Service associated with leading capability is intended to compensate a Qualified Generator Reactive Resource for reactive power absorbed by the generator step-up transformer.
4. The "VAR CC Rate" will be established each year as of January 1 on a prospective basis for that calendar year and shall be the Adjusted CC Rate * Min (1, (1.2*Forecast Peak Adjusted Reference Load for the year/(SUM of all Qualified Reactive Resources' Summer Seasonal Claimed Capability))).
5. The "Base CC Rate" shall be \$2.19/kVAR-yr effective January 1, 2012.
6. The Adjusted CC Rate shall be a single rate applied over the full range of leading and lagging capability of a Qualified Reactive Resource and shall be determined as described below. The Base CC Rate shall be converted into an Adjusted CC Rate, expressed in the form of \$/kVARyr, representing the amount to be paid for leading and lagging capability. The Adjusted CC Rate shall be calculated in accordance with the following formula:
Adjusted CC Rate (CCRateadjusted) shall equal: (the Base CC Rate (CCRatebase) * Current Total Aggregate lagging VARs) / (Current Total Aggregate Lagging VARs + Current Total Aggregate Leading VARs). The basis of each such formula element and methodology for calculation is set forth in the Schedule 2 VAR Payment Implementation Rule. The details of the Schedule 2 VAR Payment Implementation Rule may be modified by the ISO without a filing under the Federal Power Act, provided that: (i) the

modifications are consistent with the requirements of this Schedule 2; and (ii) the modifications receive the support of at least two-thirds of the voting percentage of the Transmission Committee members.

7. The “Forecast Peak Adjustment Reference Load” shall be the value published in the then-most recently published Forecast Report of Capacity, Energy, Loads and Transmission (the “CELT Report”) at the time the VAR CC Rate is established for a year.
8. “Seasonal Claimed Capability” for Qualified Reactive Resources shall be determined as follows:
 - a. A “Qualified Generator Reactive Resource’s Seasonal Claimed Capability” shall be the Seasonal Claimed Capability of each Qualified Generator applicable for the season in which the ISO Forecast Peak Adjusted Load is forecast to occur. The Seasonal Claimed Capability (SCC) represents the Summer (SCC-S) and Winter (SCC-W) Claimed Capability of a generating unit (or ISO approved combination of units in accordance with ISO New England Operating Procedures). Claimed Capability Ratings are the maximum dependable load carrying ability, in megawatts to three decimal places, of such unit or units, excluding capacity required for station use. SCC-S and SCC-W are the MW values of the Resource that will be used as billing determinants under this Tariff.
 - b. A “Qualified Non-Generator Reactive Resource’s Seasonal Claimed Capability” shall be 2.5 times the maximum dynamic reactive power capability on a lagging basis demonstrated by the Qualified Non-Generator Reactive Resource during the testing of its VAR Service capability consistent with ISO Procedures for measurement of such capability in megawatts to three decimal places.
9. The “VAR Revenue Requirement” shall be the sum over a month of all Qualified Reactive Resources’ VAR Payments.
10. A Qualified Reactive Resource’s VAR Payment shall equal $(1/12) * (\text{VAR CC Rate} * \text{Qualified VARs})$.

11. Qualified Reactive Resources will be paid their VAR Payment under this Section for each month of a calendar year starting with the month in which the resource is approved as a Qualified Reactive Resource.

 12. “Qualified VARs” shall be determined as follows:
 - (a) In accordance with the ISO New England Operating Procedures, the Qualified VARs of a Qualified Reactive Resource shall:
 - i. be determined through actual testing in accordance with the then-applicable VAR testing procedures set forth in the ISO New England Operating Procedures. At least every five (5) years after that initial test, an ongoing test of the capability of a Qualified Reactive Resource to supply VAR Service in both leading and lagging capability shall be conducted.
 - ii. use the average value of the reactive output or absorption during the lagging or leading test respectively, except that if any recorded value is less than 75% of the average value, the Qualified VARs shall be based upon that minimum value.
 - iii. equal the sum total of the absolute values of the leading and lagging VAR capability of the resource determined pursuant to this section.

 - (b) Qualified VARs of a Qualified Generator Reactive Resource:
 - The Qualified VARs of a Qualified Generator Reactive Resource that i) has not yet performed an initial Reactive Capability Audit; or ii) has been granted a waiver under the Ancillary Service Schedule 2 Business Procedure of the audit-based calculation of Qualified VARs shall be equal to the sum of the absolute values of the:
 - i) lagging VAR capability (adjusted downward for reactive power absorbed between the resource and its Point(s) of Interconnection):
 - a) At 90% of the Summer Network Resource Capability for Intermittent Power Resources, Continuous Storage Facilities, and Qualified Generator Reactive Resources without a Summer Seasonal Claimed Capability, or,
 - b) At the Summer Seasonal Claimed Capability for non-intermittent Generator Reactive Resources;
- and-

- ii) leading VAR capability (adjusted upward for reactive power absorbed between the resource and its Point(s) of Interconnection) at Economic Min with all generating units of the Qualified Generator Reactive Resource online.
- (c) The Qualified VARs of a Qualified Non-Generator Reactive Resource that i) has not yet performed an initial Reactive Capability Audit; or ii) has been granted a waiver under the Ancillary Service Schedule 2 Business Procedure of the audit-based calculation of Qualified VARs shall be equal to the sum of the absolute values of the lagging VAR capability at the corresponding Summer Seasonal Claimed Capability or an equivalent point and the leading VAR capability at the corresponding Economic Min point or an equivalent point as indicated on the Qualified Non-Generator Reactive Resource's reactive capability data, as required in ISO Operating Documents, that is submitted to and approved by the ISO and then in effect adjusted for reactive power absorbed between the resource and its Point(s) of Interconnection.

B. Lost Opportunity Cost (LOC)

- 1. The LOC for generators that are dispatched down by, or at the request of, the ISO, or a Local Control Center for the purpose of providing VAR Service will be calculated pursuant to Market Rule 1.
- 2. Qualified Non-Generator Reactive Resources shall be eligible for payment of the LOC for Qualified Non-Generator Reactive Resources that are dispatched down (pursuant to the authority established within written operating protocols developed under Section II.B.4) at the request of the ISO or a Local Control Center for the purpose of providing VAR Service. The LOC of such Qualified Non-Generator Reactive Resources will be calculated pursuant to procedures established at the time of approval of the equipment type pursuant to Section II.B and filed with the Commission pursuant to the requirements of Section 205 of the Federal Power Act.

C. Cost of Energy Consumed (CEC)

1. The CEC associated with resources that are producing or absorbing reactive power at zero real power output at the request of the ISO or a Local Control Center for the purpose of providing VAR Service will equal the cost of the additional Energy to produce the reactive power and will be calculated in each hour as follows: $CEC = (MWhUnit * (LMP \text{ or actual Energy cost}))$, where the MWh Unit are calculated pursuant to the Ancillary Service Schedule 2 Business Procedure. The actual Energy cost applies only if the Energy is purchased through a bilateral contract.
2. For the Chester SVC, or any other non-generator reactive resource, recovering its costs under another Tariff schedule, the CEC will be set to zero (\$0), and the cost of Energy to supply reactive supply and voltage control from the resource will be treated as losses on the New England Transmission System.

D. Cost of Energy Produced (CEP)

1. The CEP associated with generating units that are brought on-line by the ISO or a Local Control Center for the purpose of providing VAR Service shall equal the portion of the total NCPC (as defined in Market Rule 1) to be paid that resource for a day that is attributed to the hour(s) during which the resource is run to provide VAR Service in accordance with Market Rule 1 and the ISO New England Operating Documents.
2. Qualified Non-Generator Reactive Resources shall be eligible for payment of the CEP incurred by Qualified Non-Generator Reactive Resources for the purpose of providing VAR Service (pursuant to the authority established within written operating protocols developed under Section II.B.4). The CEP of such Qualified Non-Generator Reactive Resources shall be measured pursuant to procedures established at the time of approval of the equipment type pursuant to Section II.B and filed with the Commission pursuant to the requirements of Section 205 of the Federal Power Act.

V. ALTERNATIVE PAYMENT FOR VAR SERVICE

Where a non-generator source of VAR Service (i) responds to identified needs for dynamic reactive power on the New England Transmission System, as identified in the Regional System Plan, and (ii) is confirmed by the ISO as a dynamic reactive power resource that will meet the identified need, and (iii) such non-generator source of VAR Service meets the criteria to be a Qualified Non-Generator Reactive

Resource but cannot recover its costs of providing dynamic reactive power under Schedule 2, such non-generator may submit a separate schedule to the ISO OATT to be filed with the Commission pursuant to the requirements of Section 205 of the Federal Power Act for a rate to be paid to allow such resource to recover its costs related to providing VAR Service. In such case, it shall not be considered a Qualified Non-Generator Reactive Resource under this Schedule 2 and its provision of VAR Service and payment shall be governed solely by such separate schedule filed with the Commission.

SCHEDULE 2 VAR PAYMENT IMPLEMENTATION RULE

This rule describes the steps to be taken to calculate the VAR CC Rate in accordance with Section IV.A. of Schedule 2. On an annual basis, the Base CC Rate shall be converted into a VAR CC Rate, expressed in the form of \$/kVAR-yr, representing the amount to be paid for leading and lagging capability.

The following calculations shall be done in December of each year to calculate the VAR CC Rate for the next year of VAR Payments for leading and lagging reactive power capability in the following year. As described below, the VAR CC Rate shall be updated on an annual basis utilizing the most current leading and lagging test results, and it is expected to take three years to test all of the Qualified Reactive Resources in leading mode.

1. Calculate the “Current Total Aggregate Lagging VARs”, which shall equal the “Current Net Aggregate Tested Lagging VARs” plus the “Current Net Aggregate Non-Tested Lagging VARs”;
Where:
 - a. the Current Net Aggregate Tested Lagging VARs shall equal the total of Lagging Qualified VAR Capability for all Schedule 2 Qualified Reactive Resources that have completed a successful lagging VAR test, as reflected in the VAR Annual Capacity Cost Rate Report that is posted on the ISO website; this value will reflect the lagging kVARs of a Schedule 2 Qualified Reactive Resource as taken from its lagging VAR test results adjusted for losses incurred for such VARs to reach the Point(s) of Interconnection, (i.e., gross lagging VARs test results adjusted down for losses); and
 - b. the Current Net Aggregate Non-Tested lagging VARs shall equal the total of Lagging Qualified VAR Capability for all Schedule 2 Qualified Reactive Resources that have not yet completed a successful lagging VAR test, as reflected in the VAR Annual Capacity Cost Rate Report that is posted on the ISO website; this value will reflect the lagging

kVARs of a Schedule 2 Qualified Reactive Resource as taken from its reactive capability (and line and transformer impedance, where needed to calculate losses) data, submitted to and approved by the ISO, at the points defined in IV.12, adjusted for losses incurred for such VARs to reach the Point(s) of Interconnection (i.e., gross lagging VARs reactive capability data, as required in ISO Operating Documents, at SCC adjusted down for losses).

- c. Increase and decrease limiters shall be applied to potential increases or decreases in the Current Total Aggregate Lagging VARs as follows:
 - i. Current Total Aggregate Lagging VARs Limiters for 2010:
 - The Current Total Aggregate Lagging VARs value shall not be limited for 2010.
 - ii. Current Total Aggregate Lagging VARs Limiters for 2011 and beyond:
 - Current Total Aggregate Lagging VARs Increase Limiter for 2011 and beyond: the calculated Current Total Aggregate Lagging VARs will be limited to no greater than 130% of the Current Total Aggregate Lagging VARs value used in the determination of $CCRate_{adjusted}$ for 2010; and
 - Current Total Aggregate Lagging VARs Decrease Limiter for 2011 and beyond: the calculated Current Total Aggregate Lagging VARs will be limited to no less than 70% of the Current Total Aggregate Lagging VARs value used in the determination of $CCRate_{adjusted}$ for 2010.
2. Calculate the Current Total Aggregate Leading VARs which shall equal the Current Net Aggregate Tested Leading VARs plus the Current Net Aggregate Non-Tested Leading VARs;

Where:

- a. the Current Net Aggregate Tested Leading VARs shall equal the total of Leading Qualified VAR Capability for all Schedule 2 Qualified Reactive Resources that have completed a successful Leading VAR Test, as reflected in the VAR Annual Capacity Cost Rate Report that is posted on the ISO website; this value will reflect the Leading kVARs of Schedule 2 Qualified Reactive Resources as taken from its leading VAR test

results adjusted for losses incurred for such VARs to reach the Point(s) of Interconnection (i.e., gross leading VARs test results adjusted up for losses);

- b.** the Current Net Aggregate Non-Tested Leading VARs: shall equal the total of Leading Qualified VAR Capability for all Schedule 2 Qualified Reactive Resources that have not yet completed a successful Leading VAR Test, as reflected in the VAR Annual Capacity Cost Rate Report that is posted on the ISO website. This value will reflect the Leading kVARs of Schedule 2 Qualified Reactive Resources as taken from its reactive capability data, as required in the ISO Operating Documents, (and line and transformer impedance, where needed to calculate losses) data at the points defined in IV.12, adjusted for losses incurred for such VARs to reach the Point(s) of Interconnection, (i.e., gross leading VARs reactive capability data, as required in the ISO Operating Documents, at Economic Min adjusted up for losses).
- c.** Current Total Aggregate Leading VARs Limiters
- i.** Current Total Aggregate Leading VARs Limiters for 2010:
- The Current Total Aggregate Leading VARs value shall not be limited for 2010.
- ii.** Current Total Aggregate Leading VARs Limiters for 2011 and beyond:
- Current Total Aggregate Leading VARs Increase Limiter for 2011 and beyond: the calculated Current Total Aggregate Leading VARs will be limited to no greater than 130% of the Current Total Aggregate Leading VARs value used in the determination of $CCRate_{adjusted}$ for 2010; and
 - Current Total Aggregate Leading VARs Decrease Limiter for 2011 and beyond: the calculated Current Total Aggregate Leading VARs will be limited to no less than 70% of the Current Total Aggregate Leading VARs value used in the determination of $CCRate_{adjusted}$ for 2010.

3. Calculate the Adjusted CC Rate ($CCRate_{adjusted}$): shall equal (the Base CC Rate_e * Current Total Aggregate Lagging VARs) / (Current Total Aggregate Lagging VARs + Current Total Aggregate Leading VARs).
4. VAR CC Rate (“VARCCRate”): shall equal (the Adjusted CC Rate) * (the lesser of 1 or $(1.2 * \text{“Forecast Peak Adjusted Reference Load” for the year} / \text{the sum of the “Qualified Reactive Resources’ Seasonal Claimed Capability”})$);

Where:

- a. the “Forecast Peak Adjusted Reference Load” for the year shall equal the amount specified as “Adjusted Reference Load” for the applicable year in *Section I.1 -Summaries – Summer* from the most current *Forecast Report of Capability, Energy, Loads and Transmission (CELT Report)*;
- b. The sum of the “Qualified Reactive Resources’ Seasonal Claimed Capability” shall equal the Qualified Generator Reactive Resources’ Seasonal Claimed Capability plus the Qualified Non-Generator Reactive Resources’ Adjusted Seasonal Claimed Capability;

Where:

- i. the Qualified Generator Reactive Resources’ Seasonal Claimed Capability is reflected in the VAR Annual Capacity Cost Rate Report; and
 - ii. the Qualified Non-Generator Reactive Resources’ Adjusted Seasonal Claimed Capability is reflected in the VAR Annual Capacity Cost Rate Report.
5. Monthly VAR Payment for a Qualified Reactive Resource in a particular month shall equal the $(VARCCRate / 12 * (\text{its Monthly Net Lagging VARs for that month} + \text{its Monthly Net Leading VARs for that month}))$, as reflected in the applicable monthly *VAR Status Summary Report* that is posted on the ISO website.
 - a. Monthly Net Lagging VARs: Qualified Reactive Resource’s Monthly Net Lagging VARs value shall equal its VAR value based on (a) its most recent successful Lagging VAR test or (b) if it has not yet completed such a test, its VAR value at SCC, or equivalent point,

based on its submitted and ISO accepted reactive capability data, as required in the ISO Operating Documents, and line and transformer impedance data. The Qualified VAR Resource's Monthly Net Lagging VARs value shall be reflected in the applicable monthly VAR Status Summary Report that is posted on the ISO website.

- b.** Monthly Net Leading VARs: a Qualified Reactive Resource's Monthly Net Leading VARs value shall equal its VAR value based on (a) its most recent successful Leading VAR test or (b) if it has not yet completed such a test, its VAR value at Economic Min, or equivalent point, based on its submitted and ISO accepted reactive capability data, as required in the ISO Operating Documents, and line and transformer impedance data. The Qualified Reactive Resource's Monthly Net Leading VARs value shall be reflected in the applicable monthly VAR Status Summary Report that is posted on the ISO website.

SCHEDULE 3

REGULATION AND FREQUENCY RESPONSE SERVICE

Regulation and Frequency Response Service (automatic generator control or AGC) is necessary to provide for continuous balancing of resources (generation and interchange) with load, and for maintaining scheduled interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the ISO and this service will be available to all Transmission Customers that have a load obligation in the New England Markets pursuant to Market Rule 1. The Transmission Customer must either take this service from the ISO through the New England Markets or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. The ISO will take into account the speed and accuracy of regulation resources in its determination of Regulation and Frequency Response reserve requirements, including as it reviews whether a self-supplying Transmission Customer has made alternative comparable arrangements. Upon request by the self-supplying Transmission Customer, the ISO will share with the Transmission Customer its reasoning and any related data used to make the determination of whether the Transmission Customer has made alternative comparable arrangements.

Charges for this Service shall be determined on the basis of offers submitted by Market Participants in accordance with Market Rule 1. The transmission service required with respect to Regulation and Frequency Response Service will be paid for as part of Regional Network Service or Through or Out Service by all Market Participants and other entities that have a load obligation in the New England Markets Pursuant to Market Rule 1. The charge for Regional Network Service is determined in accordance with Schedule 9 to this OATT. The charge for Through or Out Service is determined in accordance with Schedule 8 to this OATT.

SCHEDULE 4
ENERGY IMBALANCE SERVICE

Energy Imbalance Service is not a service that is required in the New England Control Area. Energy-related charges for the New England Control Area are governed by a multi-settlement, locational-based energy market pursuant to rules specified in Sections III.2 and III.3 of Market Rule 1, ISO Tariff Section III.

SCHEDULE 5

TEN-MINUTE SPINNING RESERVE SERVICE

Ten-Minute Spinning Reserve Service is a service provided for the purpose of serving load. It is provided at the request of the ISO by Resources that are electrically synchronized to the New England Transmission System and that can respond within ten (10) minutes to a system contingency. This ancillary service will be available to all Transmission Customers that have a load obligation in the New England Markets in accordance with Market Rule 1. The Transmission Customer may either supply this service with its own resources or through bilateral arrangements, or obtain the service from the ISO through the New England Markets.

The total of Ten-Minute Spinning Reserve Service requirements for the New England Control Area in each hour is determined by the ISO in accordance with applicable ISO System Rules.

The amount of and charges for Ten-Minute Spinning Reserve Service will be accounted and paid for pursuant to Market Rule 1. The transmission service required with respect to Ten-Minute Spinning Reserve Service will be furnished as part of Regional Network Service and Through or Out Service. The charge for Regional Network Service is determined in accordance with Schedule 9 to this OATT. The charge for Through or Out Service is determined in accordance with Schedule 8 to this OATT.

SCHEDULE 6

TEN-MINUTE NON-SPINNING RESERVE SERVICE

Ten-Minute Non-Spinning Reserve Service is a service provided for the purpose of serving load. It is provided at the request of the ISO by Resources that are electronically synchronized or not electronically synchronized to the New England Transmission System and that can respond within ten (10) minutes to a system contingency. This ancillary service will be available to all Transmission Customers that have a load obligation in the New England Markets in accordance with Market Rule 1. The Transmission Customer may either supply this service with its own resources or through bilateral arrangements, or obtain the service from the ISO through the New England Markets.

The total Ten-Minute Non-Spinning Reserve Service requirements for the New England Control Area in each hour is determined by the ISO in accordance with applicable ISO System Rules.

The amount of and charges for Ten-Minute Non-Spinning Reserve Service will be accounted and paid for pursuant to Market Rule 1.

The transmission service required with respect to Ten-Minute Non-Spinning Reserve Service will be furnished as part of Regional Network Service or Through or Out Service. The charge for Regional Network Service is determined in accordance with Schedule 9 to this OATT. The charge for Through or Out Service is determined in accordance with Schedule 8 to this OATT.

SCHEDULE 7

THIRTY-MINUTE OPERATING RESERVE SERVICE

Thirty-Minute Operating Reserve Service is a service provided for the purpose of serving load. It is provided at the request of the ISO by Resources that are electrically synchronized or not electrically synchronized to the New England Transmission System and that can respond within thirty (30) minutes to a system contingency. This ancillary service will be available to all Transmission Customers that have a load obligation in the New England Markets in accordance with Market Rule 1. The Transmission Customer may either supply this service with its own resources or through bilateral arrangements or obtain the service from the ISO through the New England Markets.

The total Thirty-Minute Operating Reserve Service requirements for the New England Control Area in each hour is determined by the ISO in accordance with applicable ISO System Rules.

The amount of and charges for Thirty-Minute Operating Reserve Service will be accounted and paid for pursuant to Market Rule 1.

The transmission service required with respect to Thirty-Minute Operating Reserve Service will be furnished as part of Regional Network Service or Through or Out Service. The charge for Regional Network Service is determined in accordance with Schedule 9 to this OATT. The charge for Through or Out Service is determined in accordance with Schedule 8 to this OATT.

SCHEDULE 8

THROUGH OR OUT SERVICE; THE POOL PTF RATE

- (1) Except as provided for in accordance with Section II.25.3 of the OATT, a Transmission Customer shall pay to the ISO the Pool PTF Rate for Through or Out Service reserved for it in accordance with Section II.24 of this OATT. The Transmission Customer shall also be obligated to pay any applicable ancillary service charges and any charges required to be paid pursuant to this Tariff.
- (2) The Pool PTF Rate in effect at any time shall be determined annually on the basis of the information for the most recent calendar year contained in Form 1 filings (or similar information on the books of PTOs that are not required to submit a Form 1 filing) and shall be changed annually effective as of June 1 in each year. The Pool PTF rate shall be equal to (i) the sum for all PTOs of Annual Transmission Revenue Requirements plus the Forecasted Transmission Revenue Requirements and Annual True-ups determined in accordance with Attachment F divided by (ii) the sum of the coincident Monthly Peaks (as defined in Section II.21.2 of this OATT) of all Local Networks. The rate per hour for Through or Out Service shall be the annual Pool PTF Rate divided by 8760. Revenues associated with Short-Term Point-To-Point reservations will be credited to the sum of all PTOs' Annual Transmission Revenue Requirements referred to in (i) above.
- (3) Discounts: Three principal requirements apply to discounts for Through or Out Service as follows (1) any offer of a discount made by the PTOs through the ISO must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an Affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from Point(s) of Receipt to Point(s) of Delivery, the PTO must offer through the ISO the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same Point(s) of Delivery on the PTF.

SCHEDULE 9 REGIONAL NETWORK SERVICE

Except as provided for in Section II.21.3, a Transmission Customer which serves a Regional Network Load in the New England Control Area shall pay to the ISO each month for Regional Network Service the amount determined in accordance with the following formula:

$$A = 1/12 (R * L)$$

in which

A = the amount to be paid

R = the Local Network RNS Rate per Kilowatt for the current Year for the PTO which owns the Local Network from which the Transmission Customer's load is served, except that in the case where such Local Network is owned by a PTO that does not have its own specific Local Network RNS Rate pursuant to this Schedule 9, or where it has been recognized by the ISO that such PTO is not responsible for a Regional Network Load within its Local Network, such "R" component shall be the Local Network RNS Rate per Kilowatt for the current Year for the PTO recognized by the ISO to be responsible for such Regional Network Load.

L = the Transmission Customer's Monthly Network Load for the month

It shall also be obligated to pay any ancillary charges and any charges required to be paid pursuant to Market Rule 1.

Each Local Network RNS Rate is to be determined in accordance with the remaining provisions of this Schedule 9. The rate will be determined by looking separately at (a) the costs associated with facilities which are in service at December 31, 1996, (b) the costs associated with new facilities which are placed in service after December 31, 1996, (c) the costs associated with the HTF, in accordance with Attachment F Implementation Rule and (d) the costs determined in accordance with Appendix C to the Attachment F Implementation Rule. Costs of new facilities are to be shared regionally on a per Kilowatt basis in

determining the rates of each of the PTOs with a Local Network and a Local Network RNS Rate, unless otherwise allocated to a particular entity pursuant to this OATT.

Costs of existing facilities are to be determined separately for each PTO and reflected in the rate for service to Transmission Customers serving load in the PTO's Local Network. This is initially subject to a band width which limits the variation of the PTO per Kilowatt cost from the average per Kilowatt cost for all PTOs to not less than 70%, or more than 130%, of the average cost.

- (2) The Pool RNS Rate per Kilowatt \$1 in Year One, \$4 in Year Two, \$7 in Year Three, \$10 in Year Four and \$13 in Years Five and Six and the period from the end of Year Six to the next succeeding June 1, and is equal to the Pool PTF Rate for each Year thereafter.
- (3) For PTOs that have a Local Network RNS Rate, the Local Network RNS Rate for a Year shall be a percentage of the Pool RNS Rate for the year and shall be equal to the Pool RNS Rate after the end of the transitional period described in paragraph (4) of this Schedule. The percentage for each PTO for each Year shall equal the percentage which the sum of (i) the PTO's pre-1997 Local Network RNS Rate and (ii) the post-1996 Pool PTF Rate represents of (iii) the Pool PTF Rate for the Year.
- (4) The pre-1997 Local Network RNS Rate for each PTO having a Local Network RNS Rate, shall be determined by comparing its individual pre-1997 PTF Rate, for the most recent calendar year for which information is available from Form 1 filings or otherwise to the pre-1997 Pool PTF Rate for the same calendar year. If the PTO's individual pre-1997 PTF Rate for a Year is less than the pre-1997 Pool PTF Rate, its pre-1997 Local Network RNS Rate for the Year shall be the rate determined by reducing the pre-1997 Pool PTF Rate by the percentage which the PTO's pre-1997 PTF Rate is less than the pre-1997 Pool PTF Rate; provided that in no event shall its pre-1997 Local Network RNS Rate be less than 70% of the pre-1997 Pool PTF Rate, until the end of Year Five, and thereafter shall be no less than 50% of the pre-1997 Pool PTF Rate for Year Six through Year Eleven, and shall be equal to the pre-1997 Pool PTF Rate for Year Twelve and thereafter. If the PTO's individual pre-1997 PTF Rate is greater than the pre-1997 Pool PTF Rate, its pre-1997 Local Network RNS Rate shall be the rate determined by increasing the pre-1997 Pool PTF Rate by the percentage which its pre-1997 PTF Rate is greater than the pre-1997 Pool

PTF Rate; provided that in no event shall its pre-1997 Local Network RNS Rate be greater than 130% of the pre-1997 Pool PTF Rate until the end of Year Six, and thereafter shall be no greater than 127% of the pre-1997 Pool PTF Rate for Year Seven, 123% of the pre-1997 Pool PTF Rate for Year Eight, 118% of the pre-1997 Pool PTF Rate for Year Nine, 112% of the pre-1997 Pool PTF Rate for Year Ten, 105% of the pre-1997 Pool PTF Rate for Year Eleven, and shall be equal to the pre-1997 Pool PTF Rate for Year Twelve and thereafter. If for any Year the revenues to be received from the payment by Transmission Customers of their respective applicable Local Network RNS Rates will average more or less than the Pool PTF Rate per Kilowatt for the Year, each Local Network RNS Rate will be increased or decreased, as appropriate, so that the revenues to be received per Kilowatt per Year will equal the Pool PTF Rate per Kilowatt for the Year.

- (5) The individual pre-1997 PTF Rate of a PTO which owns a Local Network and has a Local Network RNS Rate for a year is the amount derived annually by dividing the sum of its Annual Transmission Revenue Requirements for the most recent calendar year for which information is available from Form 1 filings (or similar information on the books of PTOs that are not required to submit a Form 1 filing) with respect to PTF placed in service before January 1, 1997, as determined in accordance with Attachment F to this OATT and Annual True-Up, by the average for the twelve months of the calendar year on which the rate is based of the sum of the coincident Monthly Peaks for the Local Network, plus any Regional Network Load located in the Local Network of another PTO, for which the PTO is recognized by the ISO to be responsible, as adjusted each month for losses.

With respect to (a) Publicly Owned Entities, and (b) PTOs not recovering costs pursuant to the NEPOOL open access transmission tariff prior to June 1, 2004 and determined by the ISO not to have its own Local Network RNS Rate, the pre-1997 Annual Transmission Revenue Requirement and pre-1997 Annual True-Up for such PTO shall be recovered by adding such PTO's pre-1997 Annual Transmission Revenue Requirements and pre-1997 Annual True-Up to the initial bandwidth adjusted Annual Transmission Revenue Requirements and Annual True-Ups of those PTOs that have a Local Network RNS Rate in proportion to each such other PTO's total pre-1997 bandwidth adjusted Annual Transmission Revenue Requirement and pre-1997 Annual True-Up.

- (6) The pre-1997 Pool PTF Rate shall be determined in accordance with the following formula:

$$R = (ATTR + ATU) / ARNL$$

and the post-1996 Pool PTF Rate shall be determined in accordance with the following formula:

$$R' = (ATTR' + FTRR + ATU') / ARNL$$

in which

R = the pre-1997 Pool PTF Rate

R' = the post-1996 Pool PTF Rate

ATTR = the aggregate of the Annual Transmission Revenue Requirements of the PTOs with respect to PTF placed in service before January 1, 1997, as determined in accordance with Attachment F to this OATT.

ATTR' = the aggregate of the Annual Transmission Revenue Requirements of the PTOs with respect to (a) PTF placed in service on or after January 1, 1997, including upgrades, modifications or additions to PTF placed in service before January 1, 1997 and (b) HTF, as determined in accordance with Attachment F to this OATT.

FTRR = the aggregate of the Forecasted Transmission Revenue Requirements of the PTOs, as determined in accordance with Appendix C to the Attachment F Implementation Rule to this OATT.

ATU = the aggregate of the Pre-1997 Annual True-ups as determined in accordance with Appendix C to the Attachment F Implementation Rule to this OATT.

ATU' = the aggregate of the Post-1996 Annual True-Ups as determined in accordance with Appendix C to the Attachment F Implementation Rule to this OATT.

ARNL = the average for the twelve months of the calendar year on which the rate is based of the sum of the coincident Monthly Peaks for all Local Networks, as adjusted each month for ISO losses, plus any Long-Term Reserved Capacity amount reserved prior to March 1, 2003 for each Transmission Customer for Firm Through or Out Service.

- (7) As used in this Schedule, “Monthly Peak” and “Monthly Network Load” each has the meaning specified in Section II.21.2 of this OATT.
- (8) With the exception of any provision of this Schedule relating to the determination or application of the post-1996 Pool PTF Rate and technical changes to the last sentence of paragraph (4) of this Schedule 9 to allocate costs as necessary to keep PTOs within the band widths identified in that paragraph, the provisions of this Schedule 9 shall not be amended for service rendered under this OATT through December 31, 2003, except by agreement in writing of the parties executing the Settlement Agreement in FERC Docket Nos. OA97-237-000 et al. and compliance with the applicable requirements of the ISO Agreement.

SCHEDULE 10
GENERATOR IMBALANCE SERVICE

Generator Imbalance Service is not a service that is required in the New England Control Area.

Generator-related energy charges for the New England Control Area are governed by a multi-settlement, locational-based energy market pursuant to rules specified in Sections III.2 and III.3 of Market Rule 1, ISO Tariff Section III.

SCHEDULE 11

GENERATOR INTERCONNECTION RELATED UPGRADE AND ELECTIVE TRANSMISSION INTERCONNECTION RELATED UPGRADE COSTS

(1) Classification of Generating Projects. The treatment for purposes of this OATT of the Generator Interconnection Related Upgrade costs with respect to the facilities needed for the interconnection of a particular new or modified generating unit project in accordance with Section II.47 of this OATT depends on whether the project is a Category A Project, a Category B Project or a Category C Project, as follows:

- (a) A Category A Project is one whose Generator Owner committed to pay for upgrade costs on or after October 1, 1998 and prior to October 29, 1998 and has filed a petition with the Commission requesting that the costs associated with the interconnection of its generation project be determined in accordance with Schedule 11 of this OATT, as evidenced either by the filing of an executed Transmission Service Agreement or by the filing of an unexecuted Transmission Service Agreement.
- (b) A Category B Project is any one whose Generator Owner committed to pay for upgrade costs on or after October 29, 1998 and prior to June 22, 1999, as evidenced either by the filing of an executed Transmission Service Agreement or by the filing of an unexecuted Transmission Service Agreement. To the extent not otherwise covered by the preceding sentence, a Category B Project includes any one (other than a Category A Project) on which the Generator Owner had expended at least \$5,000,000, including amounts due under irrevocable commitments, as of June 22, 1999. Category B Projects are those projects listed as Category A Projects in Section 1(a) of this Schedule 11, but no longer qualify as Category A Projects, that had expended at least \$5,000,000 (including amounts due under irrevocable commitments) as of June 22, 1999, as reasonably determined by the ISO, as well as the following projects:

Sithe, Mystic Station Expansion

Sithe Edgar Station Expansion, Fore River

Sithe, West Medway

PG&E, Generating Lake Road Generating
PDC, Milford Power
PDC, Meriden Power
Reliant Energy, Hope Rhode Island
IDC FPL, Bellingham
Constellation, Merrimack (Nickel Hill) Energy Project
SEI, Canal Re-powering
ANP, Bellingham
ANP, Blackstone
Cabot, Island End
Calpine, Westbrook Power
HQ, Bucksport
AES, Londonderry
ConEd, Newington
Mirant, Kendall Repowering Project

- (c) A Category C Project is any project which is not a Category A Project or a Category B Project.
- (2) Direct Interconnection Transmission Costs. Direct Interconnection Transmission Costs shall mean the cost of facilities constructed for sole use of the Generator Owner that are not PTF. One hundred percent of Direct Interconnection Transmission Costs shall be the responsibility of the Generator Owner whether the Generator Owner's project is a Category A Project, a Category B Project or a Category C Project.
- (3) Treatment of Category A Project Transmission Costs. The allocation of costs of Generator Interconnection Related Upgrades for Category A Projects will be determined as follows:
- (d) One-half of the Shared Amount (as defined below) of the capital cost of the PTF upgrade shall constitute Pool Supported PTF and be included in Annual Transmission Revenue Requirements under Attachment F to this OATT. The Generator Owner shall be obligated to pay, in addition to the Direct Interconnection Transmission Costs, the other half of the Shared Amount of the capital cost of the PTF upgrade and all of the capital costs in excess

of the Shared Amount, and any applicable tax gross-up amounts, and such amounts to be paid by the Generator Owner shall not be included in Annual Transmission Revenue Requirements under Attachment F to this OATT. Following completion of the construction or modification of the Generator Interconnection Related Upgrade, the Generator Owner shall be obligated to pay its pro rata share of all of the annual costs (including cost of capital, federal and state income taxes, O&M and A&G expenses, annual property taxes and other related costs) which are allocable to such upgrade, pursuant to the interconnection agreement with the individual PTO or its designee which is responsible for the construction or modification, and such agreement may be filed with the Commission by the PTO, either signed or unsigned, on its own or at the request of the Generator Owner.

- (e) In determining the cost responsibilities related to a Generator Interconnection Related Upgrade to PTF, the ISO may determine that all or a portion of the proposed facilities exceed regional system, regulatory or other public requirements. In such a case, the ISO shall determine the amount of the excess costs of the Generator Interconnection Related Upgrade which shall be borne by the entity which is responsible for requiring such excess costs, and the excess costs shall not be included in the calculation of the Shared Amount.
- (f) The Shared Amount of the capital cost of the Generator Interconnection Related Upgrade of PTF shall be initially determined as of the time that the System Impact Study agreement is executed by all parties and the Generator Owner has paid the cost of the study (such initial determination to be based on the estimated cost of the Generator Interconnection Related Upgrade, subject to later adjustment as set forth below) subject to truing up the KW element of the following formula upon completion of the Generator Interconnection Upgrade, and shall be the lesser of (1) the full actual capital cost of the Generator Interconnection Related Upgrade of PTF (excluding any costs which are determined to be excess costs in accordance with paragraph (b) above) or (2) the amount determined in accordance with the following formula:

$$P = (KW \times R \times 0.50) / C$$

in which:

P is the maximum amount to be shared;

KW in the case of a generating unit, is the actual demonstrated net capability of the new generating unit or increase in the capacity of an existing generating unit corrected to 50°F in kilowatts. If winter operating conditions are shown in the System Impact Study and/or application under Section 3.9 of Section I of the Transmission, Markets and Services Tariff to require additional transmission reinforcements beyond those reinforcements required for summer operating conditions, the net capability of the unit will be corrected to an ambient air temperature of 0°F;

R is the Pool PTF Rate in effect on the Compliance Effective Date, which is \$15.57 per kilowatt year, adjusted to reflect compliance with the April 5, 1999 Settlement Agreement, approved by the Commission by order dated July 30, 1999 in Docket Nos. OA97-237-000, et al.; and

C is the weighted average carrying charge factor of all of the PTOs which own PTF, determined, as of the Compliance Effective Date, in accordance with Attachment F to the OATT, which is 15.87 percent, adjusted to reflect compliance with the April 5, 1999 Settlement Agreement, approved by the Commission by order dated July 30, 1999 in Docket Nos. OA97-237-000, et al.

(g) All payments required hereunder shall be determined initially on an estimated basis, and then adjusted after the appropriate portion of the construction or modification costs has been reflected in OATT rates in the first adjustment of OATT rates after the upgrade has been placed in commercial operation.

(h) The provisions in this Section (3) with respect to allocation of costs for Generator Interconnection Related Upgrades of PTF for Category A projects are subject to further clarifications and/or modifications to reflect the outcome of proceedings in Commission Docket Nos. ER98-3853 (including any court appeals) and EL00-62-000, et al., and further Commission orders with respect thereto.

- (4) Treatment of Category B Project Transmission Costs. The costs of Generator Interconnection Related Upgrades in connection with a Category B Project shall be allocated in the same way as Generator Interconnection Related Upgrades for Category A projects.
- (5) Treatment of Category C Project Transmission Costs. If a Generator Interconnection Related Upgrade or an Elective Transmission Upgrade Interconnection Related Upgrade (collectively, “Upgrade”) is required in order to satisfy the Capacity Capability Interconnection Standard or the Network Capability Interconnection Standard (or its predecessor standard) in connection with a Category C Project, the Generator Owner or Elective Transmission Upgrade Interconnection Customer (“ETU IC”), as applicable, shall be obligated to pay all of the cost of such Upgrade, including all Direct Interconnection Transmission Costs and any applicable tax gross-up amounts, to the extent such costs would not have been incurred but for the interconnection; provided that, if the ISO determines that a particular Upgrade provides benefits to the system as a whole as well as to particular parties, then the cost of such Upgrade shall be allocated in the same way as Reliability Transmission Upgrades. If the Upgrade consists of Interconnecting Transmission Owner’s Interconnection Facilities, Network Upgrades, or Distribution Upgrades, including a Cluster Enabling Transmission Upgrade, that were identified under Clustering and are not included in Direct Interconnection Transmission Costs, then the costs to be paid by each Generator Owner or ETU IC (that is not the ETU IC for an ETU that is taking the place of a CETU, or portion thereof, pursuant to Section 4.2.3.4 of Schedule 22, Section 1.5.3.3.3.4 of Schedule 23, or Section 4.2.3.4 of Schedule 25, Section II of the Tariff) with an Interconnection Request included in the cluster shall be the total costs of such Upgrade multiplied by the ratio of the Generator Owner or ETU IC’s respective distribution impact divided by the total distribution impact of the entire cluster based on the following distribution factor cost allocation methodology.

Distribution Factor Cost Allocation Methodology: The distribution factor is the measure of responsiveness or change in electrical loading on system facilities due to a change in electric power transfer from one part of the electric system to another, expressed in percent of the change in power transfer. The calculation of the distribution factor for each of the eligible Upgrades shall: (i) use the final CSIS Study Case for summer peak load conditions; (ii) use the pre-contingency condition (i.e., no contingencies will be modeled); and, (iii) be conducted using a transfer from the injection point associated with the respective Generator Owner or ETU IC’s facility to New England Control Area load. The distribution impact of each Generator Owner or ETU IC with an Interconnection

Request included in the cluster shall be determined by multiplying the Generator Owner or ETU IC's respective distribution factor, as calculated above, by the Summer Network Resource Capability in the case of a Generating Facility or the absolute value of the higher of the requested bidirectional capability that results in a positive distribution factor in the case of an Elective Transmission Upgrade. The total distribution impact of the entire cluster shall be the sum of all of the individual distribution impacts for the Generator Owners and ETU ICs with Interconnection Requests included in the cluster.

Where cost allocation for an Upgrade identified under Clustering cannot be determined using the distribution factor cost allocation methodology (e.g., a dynamic reactive device), each Generator Owner or ETU IC with an Interconnection Request included in the cluster shall be obligated to pay the costs of such Upgrade based upon its pro rata megawatt share of the Interconnection Requests included in the cluster study to be determined using the Summer Network Resource Capability in the case of a Generating Facility and the absolute value of the higher of the requested bidirectional capability in the case of an Elective Transmission Upgrade.

Following completion of the construction or modification, the Generator Owner or ETU IC shall be obligated to pay all (or, in the case of an Upgrade identified under Clustering, its share) of the annual costs (including federal and state income taxes, O&M and A&G expenses, annual property taxes and other related costs) which are allocable to the Upgrade, pursuant to the interconnection agreement (or support agreement) with the individual PTO or its designee which is responsible for the construction or modification, and such agreement may be filed with the Commission by the PTO, either signed or unsigned, on its own or at the request of the Generator Owner or ETU IC.

A Generator Owner with a Generating Facility or ETU IC with an Elective Transmission Upgrade that achieves Commercial Operation within ten years of the In-Service Date of a Cluster Enabling Transmission Upgrade (to be referred to as a "Late Comer Project") shall reimburse the entities (i.e., Generator Owner or ETU IC) that have contributed to the costs of the Cluster Enabling Transmission Upgrade by the amount of said entities' corresponding reduction in Cluster Enabling Transmission Upgrade costs based on the comparison of the Cluster Enabling Transmission Upgrade cost allocation with and without the added Late Comer Project, if the Late Comer Project: (i) interconnects directly to the Cluster Enabling Transmission Upgrade, (ii) connects to a

substation where the Cluster Enabling Transmission Upgrade terminates, or (iii) (a) is greater than five megawatt and is greater than one percent of the Cluster Enabling Transmission Upgrade normal rating, and (b) (1) has an impact on the Cluster Enabling Transmission Upgrade that is greater than five percent of the Cluster Enabling Transmission Upgrade normal rating or (2) has a distribution factor on the Cluster Enabling Transmission Upgrade that is greater than or equal to 20 percent using the distribution factor methodology described above. A Generator Owner or ETU IC that has contributed to the costs of the Cluster Enabling Transmission Upgrade shall have the payments associated with the Cluster Enabling Transmission Upgrade adjusted based on the depreciation schedule that is being used for the Cluster Enabling Transmission Upgrade.

- (6) Treatment of Elective Transmission Upgrades for Generating Units. If a Generator Owner has requested an Elective Transmission Upgrade pursuant to Section II.47 of this OATT in connection with a new or materially changed generation unit, the Generator Owner shall be subject to the cost, credit assurance and contract obligations set forth in Section II.47 of this OATT and Schedule 12 to this OATT for Elective Transmission Upgrades.
- (7) Contract and Credit Requirements. If a Generator Interconnection Related Upgrade or an Elective Transmission Upgrade Interconnection Related Upgrade (collectively, "Upgrade") is required, the Generator Owner or Elective Transmission Upgrade Interconnection Customer ("ETU IC") requesting such upgrade, at the request of the PTO or its designee responsible for effecting the construction or modification, shall be obligated to pay to the PTO or its designee responsible for effecting the Upgrade an amount equal to its share of the estimated cost of the construction at one time or in monthly or other periodic installments, including, without limitation, all costs associated with acquiring land, rights of way easements, purchasing equipment and materials, installing, constructing, interconnecting, and testing the facilities; O&M and engineering costs; all related overheads; and any and all associated taxes and government fees. In addition to, or in lieu of said payment, the affected PTO or its designee may require the Generator Owner or ETU IC to provide, as security for its obligation to pay any unfunded balance of the construction costs, a letter of credit or other reasonable form of security acceptable to the PTO or its designee that will be responsible for the construction equivalent to the cost of the upgrade including taxes and consistent with relevant commercial practices, as established by the Uniform Commercial Code. As soon as reasonably practical, but in any event within 180 days after completion of the construction or modifications, or as otherwise mutually agreed, the PTO or its designee responsible for the

construction or modification will determine the difference, if any, between the estimated cost already paid by the Generator Owner or ETU IC to the PTO or its designee responsible for the construction or modification and its share of the actual cost of the construction or modification, and will either receive from the Generator Owner or ETU IC, with Interest (if the sum paid is insufficient) or pay to the Generator Owner or ETU IC, with Interest (if the sum paid is surplus) the difference; provided that if, at the time such determination is made, items of construction that remain to be completed and/or some construction costs have not been invoiced and paid, the PTO or its designee responsible for the construction or modification shall continue to be entitled to recover from the Generator Owner or ETU IC the Generator Owner or ETU IC's share of the costs of such remaining items and may retain a reserve to cover such items. Furthermore, the PTO shall release any letter of credit or other security instrument received by the PTO, up to the amount allowed to be recovered through the PTO's Annual Transmission Revenue Requirement for Category A and B Projects, no later than sixty (60) days after the later of the reflection of such costs in the regional rates and the commercial operation of the Generating Facility or Elective Transmission Upgrade addition or modification. To the extent Upgrades, or any portion thereof, are completed in a calendar year, PTO will use their best efforts to reflect such facilities in their Annual Transmission Revenue Requirements calculated on the basis of that year. That portion of the construction or modification costs or deposit paid by the Generator Owner or ETU IC may, by mutual agreement of the PTO and the Generator Owner or ETU IC, either be retained by the PTO, or be refunded to the Generator Owner or ETU IC upon the Generator Owner or ETU IC executing a contract with the PTO obligating the Generator Owner or ETU IC to pay the PTO the ongoing transmission revenue requirement associated with its share of the Upgrade, including but not limited to cost of capital, federal and state income taxes, O&M and A&G costs, annual property taxes and all other related costs, and providing the PTO with an irrevocable letter of credit or other form of security acceptable to the PTO. In the event the Generator Owner or ETU IC's portion of the construction or modification costs is retained by the PTO or its designee in accordance with the preceding sentence, the Generator Owner or ETU IC will be obligated (i) to pay the federal and state income taxes required to be paid by the PTO with respect to the retained amount, and (ii) to pay annually its percentage of the O&M and A&G costs, annual property taxes and all other related costs, except for those costs required to be paid under (i) or any costs that are retained by the PTO in accordance with the interconnection agreement. If the Generator Owner or ETU IC for whatever reason goes out of business, or otherwise abandons its Generating Facility or Elective Transmission Upgrade project and the Upgrade has already been partially or completely constructed, the

Generator Owner or ETU IC shall be responsible for all of the unrecovered ongoing costs of the upgrade that would not have been incurred but for the proposed generation or ETU project. Nothing contained herein shall prevent the PTO or its designee responsible for the construction or modification and the Generator Owner or ETU IC from negotiating other methods for providing financial security associated with the cost of an upgrade deemed acceptable to the PTO or other entity. Subject to the foregoing, the interconnection and support agreements for an Upgrade may specify the basis for continued support of such upgrade in the event of the cancellation of the project due to a failure to obtain regulatory approvals or permits or required rights of way or other property, or action to terminate the project before its completion for whatever reason and any other matters.

Interest payable hereunder shall be calculated in accordance with Section II.8.3 of the OATT.

SCHEDULE 12

TRANSMISSION COST ALLOCATION ON AND AFTER JANUARY 1, 2004

This Schedule 12 describes the cost allocation treatment of upgrades, modifications or additions to the transmission system in New England on and after January 1, 2004. Nothing in this Schedule 12 shall eliminate the PTF status of transmission facilities that were PTF on December 31, 2003; and any upgrades to such facilities that continue to meet the definition of PTF specified in this OATT shall be classified as PTF for all purposes under this OATT. The costs of all upgrades to the Highgate Transmission Facilities will be treated as HTF and allocated according to this schedule, as may be amended from time to time, provided that such HTF upgrades shall not be limited by Appendix B to Attachment F Implementation Rule under this OATT if classified as Regional Benefit Upgrades.

A. Process for Categorizing Upgrades for Cost Allocation:

Upgrades, modifications or additions to the New England Transmission System shall be categorized by the ISO, with advisory input from the Reliability Committee and the Planning Advisory Committee, as appropriate. A list of categorized Transmission Upgrades shall be made part of each annual and interim RSP, subject to the provisions of Attachment K of this OATT.

B. Transmission Cost Allocation by Category:

1. Generator Interconnection Related Upgrades:

The cost for all Generator Interconnection Related Upgrades shall be allocated pursuant to Schedule 11 of this OATT.

2. Elective Transmission Upgrades:

The cost for all Elective Transmission Upgrades shall not be included in the Pool-Supported PTF costs recoverable under this OATT, but shall be allocated solely to the entity or entities volunteering to make and pay for such Elective Transmission Upgrades.

3. NEMA Upgrades:

The cost for all NEMA Upgrades shall be included in the Pool-Supported PTF costs recoverable under this Tariff for so long as such Transmission Upgrades continue to meet the definition of PTF under this OATT and allocated to Transmission Customers taking service under this OATT.

4. RTEP02 Upgrades:

The costs for all RTEP02 Upgrades placed in service on or before December 20, 2007, shall be included in the Pool-Supported PTF costs recoverable under this OATT for so long as such Transmission Upgrades continue to meet the definition of PTF under this OATT and allocated to Transmission Customers taking service under this OATT.

5. Regional Benefit Upgrades:

The cost for all Regional Benefit Upgrades, as well as all transmission facilities that were PTF as of December 31, 2003 and upgrades to such facilities that meet the definition of PTF under this OATT, shall be included in the Pool-Supported PTF costs recoverable under this OATT for so long as such Transmission Upgrades and such existing PTF continue to meet the definition of PTF under this OATT and allocated to Transmission Customers taking service under this OATT. Market Efficiency Transmission Upgrades that are not RBUs shall not be included in the Pool-Supported PTF Costs recoverable under this OATT.

6. Public Policy Transmission Upgrade Costs:

(a) Seventy percent of the costs of each Public Policy Transmission Upgrade shall be allocated to Transmission Customers taking service under this OATT in the same manner as Regional Benefit Upgrades.

(b) The remaining thirty percent of the costs of each Public Policy Transmission Upgrade shall be allocated to the Regional Network Load of each state in direct proportion to the state's share of the public policy planning need that gives rise to the Public Policy Transmission Upgrade ("Planning Need"). Each state's share of the Planning Need shall be: (i) as shown in a Planning Need identified by NESCOE in a request for a Public Policy Transmission Study pursuant to Section 4A.1 of Attachment K, based on its estimate of the MWhs of electric energy (or MWs of capacity, if applicable) needed over the requested study period to satisfy the state and federal Public Policy Requirements it identified for evaluation and how such needs are allocated among the states, which shall take into account the MWhs (or MWs of capacity, if applicable) associated with contracts and other mechanisms that are available and capable to satisfy the Public Policy Requirements for the year or years of need considered in the requested Public Policy Transmission Study; or (ii) if NESCOE does not provide a Planning Need in such a request, the load-ratio share of the Regional Network Load of each state that has been identified pursuant to the

procedures set forth in Sections 4A.1 and 4A.1.1 of Attachment K as having one or more Public Policy Requirements that will be evaluated in the corresponding Public Policy Transmission Study. Nothing in this Schedule 12 shall prevent the applicable PTOs from filing with the Commission an alternative cost allocation for a Public Policy Transmission Upgrade in accordance with the TOA or a Qualified Transmission Project Sponsor that is not a PTO from filing with the Commission an alternative cost allocation for a Public Policy Transmission Upgrade. The revenue requirements for such Public Policy Transmission Upgrades shall be separately determined in accordance with the provisions of Attachment F to this OATT, subject to separate incentives or other modifications specifically approved by the Commission for such upgrades under Section 205 of the Federal Power Act.

Notwithstanding anything else in this Section 6, the costs of Public Policy Transmission Upgrades to address the Public Policy Requirement of a local government shall not be allocated under Schedule 12 and shall be allocated under a separate local schedule or cost recovery mechanism.

7. Local Benefit Upgrades:

The cost for Local Benefit Upgrades shall not be included in the Pool-Supported PTF costs recoverable under this OATT.

8. Localized Costs:

Localized Costs shall not be included in the Pool-Supported PTF costs recoverable under this OATT, or in costs allocated to Regional Network Load according to Section 6 of this Schedule 12, but instead the responsibility for such Localized Costs shall be the responsibility of the entity or entities causing or subject to such Localized Costs. The System Operator, in accordance with Schedule 12C of this OATT, shall review RTEP02 Upgrades, Regional Benefit Upgrades, reconstructions/replacements of all or part of Pool Transmission Facilities, and Public Policy Transmission Upgrades and identify any Localized Costs associated with them.

9. Merchant Transmission Facilities Cost Allocation

The cost of all Merchant Transmission Facilities, including the cost of Transmission Upgrades required to interconnect the Merchant Transmission Facilities to the PTF, shall be the responsibility of the developer of the Merchant Transmission Facilities, and shall not be included in the Pool-Supported PTF costs recoverable under this OATT.

SCHEDULE 12A

NEMA UPGRADES

A “Northeast Massachusetts Upgrade” is an addition to or modification of the PTF into or within the Northeast Massachusetts Reliability Region that was not, as of December 31, 1999, the subject of a System Impact Study or application filed pursuant to Section 18.4 of the NEPOOL Agreement; that is not related to generation interconnections; and that will be completed and placed in service by June 30, 2004. The aggregate capital costs of the Northeast Massachusetts Upgrades which qualify as Pool-Supported PTF costs shall not exceed \$35,000,000. A general description of the projects which constitute the NEMA Upgrades is provided in the list below.

1. Framingham 230/115kV autotransformer and breaker replacement
2. Upgrade Framingham to West Medway 230 kV line (240-601)
3. Add Mystic 345kV breaker #101S
4. West Walpole 345/115kV autotransformer and breaker replacement
5. Rebuild Speen Street to Sudbury 115kV line (342-507) and replace breakers at both ends
6. Waltham 230/115kV autotransformer and breaker replacement
7. Upgrade Waltham to West Medway 230 kV line (282-602)
8. Upgrade Framingham to Speen Street 115kV line (433-507) and replace breakers at Framingham
9. Add a third Waltham 115kV phase shifting transformer
10. Upgrade Sherborn 115kV station equipment
11. Merrimack (New Hampshire) 230/115kV autotransformer replacement

**SCHEDULE 12B
 RTEP02 UPGRADES**

Following is a general description of projects which constitute the RTEP02 Upgrades.

Project Description
New Brunswick – New England Tie Performance Enhancement <input type="checkbox"/> Series compensation
MEPCO Special Protection Systems Alternative <input type="checkbox"/> Alternative 1: Decommission existing SPS and install new direct logic sensing Transfer Trip SPS. <input type="checkbox"/> Alternative 2: Extend time delay on existing flow based SPS and install new direct logic sensing Transfer Trip SPS. <input type="checkbox"/> Alternative 3: Decommission existing SPS and install new direct logic sensing Transfer Trip SPS with fault discrimination.
Bangor Hydro Electric Down East Transmission Reliability Improvement <input type="checkbox"/> New transmission path between Rebel Hill and the Epping/Washington County area <input type="checkbox"/> Reconfiguration of existing facilities.
CMP Autotransformer-Outage Reliability Improvement <input type="checkbox"/> Review/mitigation of 120°F sag limits. <input type="checkbox"/> Mitigation of line overloading that limits select pockets of generation. <input type="checkbox"/> Mitigation of low voltages that may be improved with implementation of the new Maine Voltage Operating Guide and capacitor bank additions.
Maine and New Hampshire Voltage Enhancements <input type="checkbox"/> Install 24 MVAR capacitors at Sanford 115 kV substation <input type="checkbox"/> Add 50 MVARs of capacitors at Ocean Road and Madbury <input type="checkbox"/> Add 60 MVARs of capacitors at Three Rivers <input type="checkbox"/> Add 170 MVARs of capacitors at Maxcys and western Maine
Maine – New Hampshire Transfer Capability Short Term Enhancements <input type="checkbox"/> Schiller to Bolt Hill 115 kV N133 line upgrade <input type="checkbox"/> Quaker Hill to Three Rivers 115 kV 197 line upgrade <input type="checkbox"/> Maguire to Three Rivers 115 kV 250 line upgrade <input type="checkbox"/> Alternate project: Southern Maine substation re-configuration or series reactor
Requirements for Closing PSNH'S Y138 Line – Saco Valley to White Lake <input type="checkbox"/> Saco Valley 115 kV breaker additions <input type="checkbox"/> 120 MVAR of shunt reactive compensation is needed between the Maine and New Hampshire ends of the transmission system <input type="checkbox"/> Series reactor overload mitigation system is needed on the New Hampshire end of the Beebe to White Lake 115 kV B112 line <input type="checkbox"/> Alternative: Beebe 115kV phase shifter <input type="checkbox"/> Beebe substation terminal equipment upgrades on B112 line to change out circuit breaker, disconnect switches, bus work and secondary equipment <input type="checkbox"/> Re-rate 28 miles of 115 kV Section 214 transmission line from Kimball Road to Harrison and Lovell in Maine <input type="checkbox"/> White Lake 115kV capacitor

<p>Southern New Hampshire Reinforcements</p> <ul style="list-style-type: none"> <input type="checkbox"/> Rebuild Scobie 115 kV substation to breaker and a half arrangement <input type="checkbox"/> Re-conductor Deerfield to Garvins 115 kV G146 line <input type="checkbox"/> Add a second 345/115 kV 400 MVA autotransformer at Scobie substation <input type="checkbox"/> Add a second 345/115 kV 400 MVA autotransformer at Deerfield substation <input type="checkbox"/> Add three 50 MVAR capacitor banks at the Deerfield 115 kV substation <input type="checkbox"/> Deerfield dynamic voltage control <input type="checkbox"/> New 115 kV line from Reeds Ferry – Huse Road <input type="checkbox"/> Upgrade Greggs 115 kV substation <input type="checkbox"/> Upgrade Merrimack 115 kV substation <input type="checkbox"/> Add Amherst 345 kV 4 – breaker ring bus <input type="checkbox"/> Add six 50 MVAR capacitor banks at the Scobie 115 kV substation <input type="checkbox"/> Re-terminate Deerfield autotransformer and/or second breaker <input type="checkbox"/> Re-conductor two 115 kV circuits from Schiller – Scobie (U181/H141 and E194/R193) <input type="checkbox"/> Alternatives considered: <ul style="list-style-type: none"> o Newington 345/115 kV autotransformer o Coburn Road 345/115 kV autotransformer o Rebuilding the 115 kV Deerfield – Laconia D140 line
<p>Northwest Vermont Near-term Voltage Reinforcement</p> <ul style="list-style-type: none"> <input type="checkbox"/> Essex Capacitors, two 24.75 MVAR 115 kV banks
<p>Rutland Reliability Project</p> <ul style="list-style-type: none"> <input type="checkbox"/> Energize existing Coolidge-West Rutland line at 345 kV <input type="checkbox"/> Add two West Rutland 345/115 kV transformers <input type="checkbox"/> Add three 345 kV circuit breakers at Coolidge <input type="checkbox"/> Add three 115 kV circuit breakers at West Rutland <input type="checkbox"/> Add two 24.75 MVAR 115 kV capacitor banks at Coolidge
<p>Northwest Vermont Reliability Project</p> <ul style="list-style-type: none"> <input type="checkbox"/> New Haven-West Rutland 345 kV line and 345/115 kV New Haven substation with 115 kV ring bus <input type="checkbox"/> Granite 230 kV PAR, 25 MVAR capacitor bank and breaker additions <input type="checkbox"/> 150 MVAR STATCOM at Granite <input type="checkbox"/> Blissville 115 kV PAR <input type="checkbox"/> New Haven-Vergennes-Queen City 115 kV line <input type="checkbox"/> Hartford 115 kV breaker – Add an existing 115 kV motorized SCADA controlled disconnect switch with a circuit breaker at Hartford substation on the line toward the Chelsea substation <input type="checkbox"/> Granite to Middlesex 230 kV <input type="checkbox"/> Addition of 230/115 kV and 345/115 kV autotransformers <input type="checkbox"/> Addition of breakers and shunt devices
<p>Vermont Northern Loop Project</p> <ul style="list-style-type: none"> <input type="checkbox"/> New Irasburg – Newport 115 kV line (“northern loop”) (7 miles of new 115/46kV double circuit construction) <input type="checkbox"/> New 115 kV breaker at St. Johnsbury <input type="checkbox"/> Two new 115 kV breakers at Irasburg <input type="checkbox"/> New five breaker 115 kV ring bus at Highgate <input type="checkbox"/> St Albans Line reconfiguration and substation upgrade-Reconfigure St Albans lines and breakers to replace the single 115kV tap line with two “in and out” lines
<p>Monadnock Regional Reinforcement</p> <ul style="list-style-type: none"> <input type="checkbox"/> Addition of switched capacitor banks at Chestnut Hill 115 kV bus <input type="checkbox"/> Potential alternatives: <ul style="list-style-type: none"> o New Fitzwilliam 345/115 kV substation north of Flagg Pond tapped onto the Scobie Pond – Vermont Yankee 345 kV 379 line and separation of the existing lines between Flagg Pond and Pratts Junction. o (Third) Pratts Junction to Flagg Pond 115 kV line
<p>Greater Metro-West Transmission Supply Study</p> <ul style="list-style-type: none"> <input type="checkbox"/> Install tie breaker and second radial Northborough – Hudson 115 kV line <input type="checkbox"/> Re-conductor Woodside-Northborough / Fitch Rd 69 kV W-23 line <input type="checkbox"/> Millbury 115 kV 63 MVAR Capacitor Bank <input type="checkbox"/> Northborough 115 kV 54 MVAR Capacitor Bank <input type="checkbox"/> Fitch Road – Rebuild 69 kV station <input type="checkbox"/> Re-conductor Fitch Rd to Pratts Junction 69 kV N40 line <input type="checkbox"/> Install Woodside 69 kV breaker

<p>Central Massachusetts Reliability Reinforcement</p> <ul style="list-style-type: none"> <input type="checkbox"/> Re-conductor V174 Carpenter Hill to Millbury 115 kV <input type="checkbox"/> Install new 345/115 kV autotransformer in Central Massachusetts (e.g. Pratts Junction, Millbury) <input type="checkbox"/> Install second Wachusett 115/69 kV autotransformer <input type="checkbox"/> Pratts Junction 115/69/13.8 kV transformer replacement
<p>Springfield/Western Massachusetts Reliability Reinforcements</p> <ul style="list-style-type: none"> <input type="checkbox"/> Improve sag clearances on the 115 kV Blandford – Pleasant 1421 line <input type="checkbox"/> Pleasant 115 kV capacitor bank <input type="checkbox"/> As determined by study
<p>NEMA/Boston Short-term Reliability Reinforcements</p> <p>Potential North Shore upgrades include:</p> <ul style="list-style-type: none"> <input type="checkbox"/> B154N/C155N Ward Hill to Salem Harbor 115 kV line upgrades (re-sag/re-conductor) <input type="checkbox"/> Second Ward Hill 345/115 kV transformer <input type="checkbox"/> Completion of the Golden Hills 345 kV ring bus <input type="checkbox"/> Split up switching of Mystic-Golden Hills 345 kV cables (348X+Y) <input type="checkbox"/> F-158N and Q-169 Golden Hills to Everett and to Lynn 115 kV line upgrades <input type="checkbox"/> Other 115 kV line upgrades
<p>NEMA/Boston Long-term Reliability Reinforcements</p> <p>Potential upgrades include:</p> <ul style="list-style-type: none"> <input type="checkbox"/> Mystic-K Street-Kingston 345 kV loop <input type="checkbox"/> Other 345 kV and/or 115 kV line upgrades <input type="checkbox"/> Build 345 kV line from Scobie to Tewksbury
<p>Norwood Municipal Light Department Reliability Reinforcements</p> <ul style="list-style-type: none"> <input type="checkbox"/> Install two new 115 kV underground lines to Norwood’s new Ellis Avenue substation (2.2 miles each) <input type="checkbox"/> Construct new Ellis Avenue substation (4-breaker ring distribution station with two transformers rated 55 MVA each) <input type="checkbox"/> Modify existing Dean Street substation
<p>Auburn Area Reliability Reinforcements</p> <ul style="list-style-type: none"> <input type="checkbox"/> Re-tension (upgrade) E20 115 kV line from Auburn Street to L1 tap <input type="checkbox"/> Re-conductor F19 115 kV line from Bridgewater to S1 tap (4.1 miles) <input type="checkbox"/> Re-conductor G18 115 kV line from Bridgewater to Dupont (7.6 miles) <input type="checkbox"/> Replace bus work, wave trap, and change current transformer ratios at Dupont <input type="checkbox"/> Replace wave trap at Bridgewater <input type="checkbox"/> Re-tension (upgrade) C2 115 kV from Auburn Street to Dupont <input type="checkbox"/> Replace wave traps at both the Auburn Street and Dupont <input type="checkbox"/> Upgrade bus work at Dupont <input type="checkbox"/> Re-tension (upgrade) A94 115 kV line from Auburn Street to Parkview <input type="checkbox"/> Re-tension (upgrade) S1 115 kV line from Belmont Tap to Belmont <input type="checkbox"/> Upgrade bus work at Belmont <input type="checkbox"/> Re-tension E20 115 kV line from Bridgewater to L1 tap <input type="checkbox"/> Install new 115 kV circuit breaker between Auburn Street 345/115 kV autotransformer and the bus tie that connects the north and south 115 kV buses at Auburn Street
<p>Cape Cod Supply Study</p> <ul style="list-style-type: none"> <input type="checkbox"/> Canal to Bourne #120 115 kV line (string a second Canal – Bourne 115 kV line on the existing Canal to Bourne 115 kV double circuit structures) <input type="checkbox"/> Canal to Oak #399 345 kV line (convert existing #120 115 kV line to 345 kV operation) <input type="checkbox"/> Install 345/115 kV autotransformer at Oak Street <input type="checkbox"/> Add one 80 MVAR capacitor bank, STATCOM or SVC at the 115 kV Barnstable station <input type="checkbox"/> Expand the Canal 345 kV substation with a 3rd two-breaker bay
<p>SEMA/RI Short-term Export Enhancement</p> <ul style="list-style-type: none"> <input type="checkbox"/> Upgrade 345 kV circuit breaker 314 Millbury substation to provide IPT capability <input type="checkbox"/> Upgrade 345 kV circuit breaker 142 Sherman Road substation to provide IPT capability <input type="checkbox"/> Replace West Walpole 104, 105, 108, 109 with IPT breakers <input type="checkbox"/> Re-wire West Medway 111, 112 to IPT <input type="checkbox"/> Potential upgrades to or replacements of breakers at <ul style="list-style-type: none"> o Canal o Brayton Point

<p>SEMA/RI Long-term Export Enhancement Potential major 345 kV long-term system enhancements</p> <ul style="list-style-type: none"> <input type="checkbox"/> Card – West Farnum – Sherman – Millbury 345 kV <input type="checkbox"/> Card – West Farnum – Sherman – Millbury 345 kV tapping the Millstone to Manchester 345 kV line at Card <input type="checkbox"/> Montville – Kent – West Farnum – Millbury 345 kV <input type="checkbox"/> Other major 345 kV enhancements that link SEMA/RI to the NEMA/Boston area
<p>Northwest Connecticut Import Capability Enhancements</p> <ul style="list-style-type: none"> <input type="checkbox"/> Upgrade Canton-North Bloomfield terminal equipment (associated with the 1784 line) <input type="checkbox"/> Add 40 MVAR of capacitors at Franklin Drive <input type="checkbox"/> Add 50 MVAR of capacitors at Canton <input type="checkbox"/> Re-conductor Canton-Weingart 115 kV line 1732 (with 1272 conductor)
<p>Norwalk-Stamford Area Glenbrook Static Var Compensator</p> <ul style="list-style-type: none"> <input type="checkbox"/> Add 150 MVAR statcom at the Glenbrook substation <input type="checkbox"/> Add three 50 MVAR 115 kV fixed capacitor banks at the Glenbrook substation <input type="checkbox"/> Re-terminate the 115 kV Darien-South End 1977 line at the Glenbrook substation
<p>Southwest Connecticut Reliability Reinforcement</p> <ul style="list-style-type: none"> <input type="checkbox"/> Build new 345 kV line from Plumtree to Norwalk <input type="checkbox"/> Build new 345 kV line from Devon to Trumbull Junction <input type="checkbox"/> Build new 345 kV line from Trumbull Junction to Norwalk <input type="checkbox"/> Build new 345 kV line from Devon to Beseck <input type="checkbox"/> Build new 345 kV line from Trumbull Junction to Pequonnock <input type="checkbox"/> Build new 345 kV cable from Norwalk to Glenbrook <input type="checkbox"/> Add new 345 kV substations at Plumtree, Norwalk, Pequonnock, Devon and Beseck Junction <input type="checkbox"/> Add 3-150 MVA (or larger) autotransformers at Norwalk (one), Pequonnock (one), Devon (one) and Glenbrook (one) <input type="checkbox"/> Add one 3-200 MVA autotransformers at Pequonnock to shift output from Bridgeport Energy to the 345 kV <input type="checkbox"/> Establish new 115 kV substation adjacent to Devon (East Devon) <input type="checkbox"/> Other 115 kV work all with new 345 kV structures <input type="checkbox"/> Build new 115 kV cable from Glenbrook to Norwalk Harbor <input type="checkbox"/> Add series reactor at Ash Creek
<p>Norwalk Harbor to Northport 138 kV (1385) Replacement</p> <ul style="list-style-type: none"> <input type="checkbox"/> Replace 138 kV Norwalk (CT) – Northport (NY) 1385 cable with three (3-phase) cables insulated with a solid dielectric.
<p>East-West Oscillation Mitigation Alternatives include:</p> <ul style="list-style-type: none"> <input type="checkbox"/> Reduce transfers from New Brunswick to New England <input type="checkbox"/> Control unit dispatch in Maine <input type="checkbox"/> Add power system stabilizers to key units in New England <input type="checkbox"/> Determine interdependence with other concurrent system transfers
<p>Connecticut Light & Power Over-Dutied Circuit Breaker Replacement</p> <ul style="list-style-type: none"> <input type="checkbox"/> Frost Bridge (one): 10K-2 <input type="checkbox"/> Glenbrook (four): 2T, 7T, 1753 line, 1792 line <input type="checkbox"/> Hanover (one): 1355 line <input type="checkbox"/> Manchester (three): 14T, 15T, 10K-2 <input type="checkbox"/> Montville (fourteen): 7T, 8T, 9T, 13T, 14T, 15T, 16T, 18T, 19T, 20T, 21T, 22T, 23T, 24T <input type="checkbox"/> Norwalk (seven): 1T, 2T, 3T, 4T, 6T, 7T, 9T <input type="checkbox"/> Bunker Hill (one): 1T <input type="checkbox"/> Glenbrook (three): 4T, 9T, 1887 line <input type="checkbox"/> Norwalk (two): 5T, 8T
<p>Western Massachusetts Electric Over-dutied Circuit Breaker Replacement</p> <ul style="list-style-type: none"> <input type="checkbox"/> West Springfield (six): 1544 line, 8C-1T-2, 8C-2T-2, 8C-6T-2, 8C-3T-2, 1311 line <input type="checkbox"/> Clinton (two): 1T, 2T <input type="checkbox"/> East Springfield (two): 2T, 3T
<p>Brayton Substation Reliability Modifications</p> <ul style="list-style-type: none"> <input type="checkbox"/> Brayton Point 345 kV and 115 kV protection upgrades; includes construction of new control house
<p>Stamford Area Reliability Reinforcements</p> <ul style="list-style-type: none"> <input type="checkbox"/> Re-conductor 115 kV 1880 line Rowayton Junction – Glenbrook <input type="checkbox"/> Re-conductor 115 kV 1890 line Ely Avenue – Glenbrook
<p>Barbour Hill Area Reliability Reinforcement</p> <ul style="list-style-type: none"> <input type="checkbox"/> Barber Hill re-conductoring and installation of the 3rd line into the area

<p>Connecticut/Swct Reliability Reinforcements</p> <ul style="list-style-type: none"> <input type="checkbox"/> Replace the double circuit tower on the 345 kV Millstone-Southington 348 line and the 345 kV Scovill Rock-East Shore 387 line at Black Pond Junction <input type="checkbox"/> Southington and Frost Bridge 115 kV capacitor bank <input type="checkbox"/> Rebuild Glenbrook 115 kV substation <input type="checkbox"/> Build new 115 kV line from Frost Bridge to Walnut Hill Junction <input type="checkbox"/> Re-conductor 115 kV Farmington – Newington 1783 line <input type="checkbox"/> Re-conductor 115 kV Old Town – Norwalk 1720/1730 lines <input type="checkbox"/> Replace existing transformers at the Ansonia substation with load tap changing (LTC) transformers <input type="checkbox"/> Establish a Metro North 115/27.6 kV substation <input type="checkbox"/> Upgrade 1710/1730 115 kV cables <input type="checkbox"/> Upgrade Baird to Congress 115 kV line <input type="checkbox"/> New Trumbull Junction 115/13.8 kV substation <input type="checkbox"/> New Southport 115/13.8 kV substation <input type="checkbox"/> Grand Avenue – West River 115 kV cable upgrade <input type="checkbox"/> 69kV Falls Village area conversion to 115kV
<p>NSTAR Reliability Reinforcements</p> <ul style="list-style-type: none"> <input type="checkbox"/> Mystic capacitor <input type="checkbox"/> Re-conductor Waltham to Sudbury 115 kV line 282-507 <input type="checkbox"/> Re-conductor 115 kV Auburn Street – Kingston line 191
<p>Second New Brunswick Tie Project</p> <ul style="list-style-type: none"> <input type="checkbox"/> Point Lepreau to Orrington – new 345 kV line
<p>Maine CMP Reliability Reinforcements</p> <ul style="list-style-type: none"> <input type="checkbox"/> Add 115/34.5 kV transformer at Spring Street substation <input type="checkbox"/> Convert Maguire Road to a switching substation by replacing switches with breakers <input type="checkbox"/> Add 115/34.5 kV transformer at Raymond substation on Section 208/209 <input type="checkbox"/> Establish a new Old Orchard Beach 115/34.5 kV substation and 115 kV line <input type="checkbox"/> Highland: Add 115 kV breaker <input type="checkbox"/> Add 115 kV line from Spring Street substation to Sewall substation <input type="checkbox"/> Establish a new Fore River 115/12 kV substation tapping Section 275
<p>Rhode Island Reliability Reinforcements</p> <ul style="list-style-type: none"> <input type="checkbox"/> Install new 345/115 kV autotransformer in SEMA/RI (e.g. Kent County, West Farnum)
<p>Middletown Area Reliability Reinforcements</p> <ul style="list-style-type: none"> <input type="checkbox"/> Haddam 345/115 kV autotransformer <input type="checkbox"/> 40 MVAR capacitor banks at Haddam and Branford <input type="checkbox"/> Rebuild Manchester – Hopewell 1767 line <input type="checkbox"/> Rebuild East Meriden – North Wallingford 1466 line
<p>Eastern Connecticut Reliability Reinforcement</p> <ul style="list-style-type: none"> <input type="checkbox"/> Re-conductor 69 kV Montville – Gails Ferry – Tunnel line (100 – 400) <input type="checkbox"/> Brooklyn 345/115 kV autotransformer <input type="checkbox"/> Card 345kV circuit breaker <input type="checkbox"/> Montville 345kV circuit breaker <input type="checkbox"/> Re-terminate the 345-kV Millstone – Manchester 310 line at Card <input type="checkbox"/> Rebuild 115kV Card – Wawecus 1080 line
<p>Vermont Long Range Study Projects</p> <ul style="list-style-type: none"> <input type="checkbox"/> Chelsea 115kV Breakers - Replace two SCADA controlled motorized disconnect switches with 115kV circuit breakers at the existing Chelsea substation <input type="checkbox"/> Georgia Substation Ring Bus – Rebuild the existing Georgia substation 115kV bus into a ring bus <input type="checkbox"/> Burlington 115kV loop – 5.7 miles of new line between two existing substations <input type="checkbox"/> Middlesex substation relocation and breaker addition <input type="checkbox"/> Bennington to Manchester to Vernon Road 115kV with Manchester 115/46kv substation <input type="checkbox"/> Granite to Middlesex 230kV with necessary substation upgrades <input type="checkbox"/> Add parallel 115/69 kV transformer on Y25 at Bennington to provide backup

The Braintree Electric Light Department (BELD) Transmission Facilities

- 18.4 Applications BELD-02-T01, BELD-02-T02, and BELD-02-X01 for the closing of the 115 kV Braintree loop at the Middle Street Substation #10 in Braintree, Massachusetts to improve the Braintree system reliability, with an in service date of June 2003, as detailed in Mr. H. Joseph Morley's November 22, 2002 transmittal to Mr. Richard Burke. The project consists of:
 - a) Closing the Braintree 115 kV loop at Middle Street Substation #10 in Braintree, Massachusetts by closing circuit breaker #102. (BELD-02-T01)
 - b) At the Potter Station, installation of a 115 kV, three (3) ohm series reactor inserted in the Station ring bus between Breaker #162 and Cable 115-10-16, operation of breaker #164 as normally open and to only be operated closed when the BELD 115 kV loop is open at another station, and installation of a 115 kV circuit switcher to isolate the Potter units GSU when the units are not on-line, to reduce power flows through the Braintree loop and on NSTAR line 478-509 between Grove Street Substation and Holbrook. (BELD-02-T02)
 - c) Installation of a second high-speed protection group, on BELD cable 115-9-4 between Grove Street and Plain Street Substations in Braintree, Massachusetts with the high-speed protection groups at both the Grove Street and Plain Street Substation being independent in accordance with NPCC criteria, to eliminate area stability concerns. (BELD-02-X01)

SCHEDULE 12C

DETERMINATION OF LOCALIZED COSTS ON AND AFTER JANUARY 1, 2004

Introduction

The purpose of this Schedule 12C is to describe procedures that the ISO will use in determining Localized Costs for eligible Transmission Upgrades as specified below on or after January 1, 2004.

Review and Approval

These Schedule 12C review and approval procedures are separate and distinct from any other approval procedures within the Transmission, Markets and Services Tariff and are not a condition for receiving approval under any other section of the Transmission, Markets and Services Tariff. If submission of a proposed plan for a Transmission Upgrade by a Market Participant or Transmission Owner for review pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff is required, then the approval for Transmission Upgrade cost allocations as described under this Schedule 12C of this OATT cannot occur sooner than after that review has been completed and it has been determined, pursuant to Section I.3.9 of the Transmission, Markets and Services Tariff, that the Market Participant or Transmission Owner is free to proceed with implementation of the proposed Transmission Upgrade.

Entities conducting transmission system studies shall review and discuss transmission design and construction alternatives as they are developed under a System Impact Study (“SIS”) or as part of the Regional System Plan with the System Operator, Reliability Committee and the Planning Advisory Committee, as deemed appropriate by the ISO.

1. Review Procedures For Determining Localized Costs

All (1) RTEP02 Upgrades; (2) Regional Benefit Upgrades developed pursuant to Section 4.2 of Attachment K of the OATT; (3) reconstructions/replacements of all or part of Pool Transmission Facilities; and (4) Regional Benefit Upgrades and Public Policy Transmission Upgrades developed pursuant to Sections 4.3 and 4A (respectively) of Attachment K of the OATT shall be reviewed by the ISO with advisory input from the Reliability Committee to determine if any of the costs associated with such upgrades are Localized Costs, except that a proposed Transmission Upgrade which costs less than

\$500,000 may be exempted from this review by the ISO. The ISO, with advisory input from the Reliability Committee, will review and update, as appropriate, the \$500,000 threshold on an annual basis.

The Market Participant or Transmission Owner seeking cost recovery for a proposed Transmission Upgrade, including reconstruction or replacement, shall submit to the ISO and the Reliability Committee the following information as deemed appropriate by the ISO:

- (a) A description of (i) the proposed Transmission Upgrade and any feasible and practical transmission alternatives that were considered, and (ii) the most currently available study grade or better estimates of the construction, including the potential impact on the bulk power system during the construction of such upgrade, and (iii) the operating costs of the proposed Transmission Upgrade and any feasible and practical transmission alternatives that were considered.
- (b) A summary of the technical analysis performed for the Transmission Upgrade and the identified transmission alternatives.
- (c) A review and discussion of the need for the proposed Transmission Upgrade.
- (d) A discussion of why the requested Transmission Upgrade was selected over other transmission alternatives, with a description of the benefits of the proposed Transmission Upgrade over other transmission alternatives from an operational, timing of implementation, cost and reliability perspective.

If in reviewing the application and associated information, the ISO, with advisory input from the Reliability Committee, decides that additional information, review, or study is required prior to acting on the application, the ISO, with advisory input from the Reliability Committee, may elect to defer action and solicit supplementary information, review, or study as required. Sources for such additional information may be, but are not limited to, the entity sponsoring the application, Transmission Owners, or the Reliability Committee.

In making its determination of whether Localized Costs exist for the Transmission Upgrades identified in (1), (2) and (3) above, the ISO will consider the reasonableness of the proposed engineering design and

construction method with respect to (i) Good Utility Practice, (ii) the current engineering design and construction practices in the area in which the Transmission Upgrade is built, (iii) alternate feasible and practical Transmission Upgrades and (iv) the relative costs, operation, timing of implementation, efficiency and reliability of the proposed Transmission Upgrades.

In making its determination of whether Localized Costs exist for the Transmission Upgrades identified in (4) above, the ISO will consider incremental costs resulting from changes to the Transmission Upgrade described in the Transmission Cost Allocation application (or any revisions thereto) for regional rate recovery compared to the description of the Transmission Upgrade in Schedule A to the Selected Qualified Transmission Project Sponsor Agreement. Localized Costs for the Transmission Upgrades identified in (4) above that are located on a PTO's existing transmission system, where the Selected Qualified Transmission Project Sponsor is not the PTO for the existing system element(s), will be determined in a manner consistent with the process described for the Transmission Upgrades identified in (1), (2) and (3) above.

Local siting requirements for transmission facilities shall not be dispositive of whether or not Localized Costs exist with respect to any particular Transmission Upgrade.

The ISO will develop detailed procedures to fulfill the objectives and requirements of this Schedule 12C.

2. Additional Transmission Upgrade Costs or Design Changes Subsequent to the ISO's Determination of Localized Costs

If the costs associated with a Transmission Upgrade exceed the estimated Pool-Supported PTF costs determined in the original Localized Costs review by ten percent, or the design associated with the construction of a Transmission Upgrade is materially changed subsequent to the ISO's determination of Localized Costs, then the applicant for Pool-Supported PTF costs shall be required to submit its Transmission Upgrade again to a review by the ISO to determine if any of the incremental costs or costs associated with the change in design are Localized Costs.

3. Dispute Resolution Regarding Determination of Localized Costs

The ISO's determination of Localized Costs under this OATT shall take effect on the date on which the ISO issues its written findings and determination. The applicant for cost recovery (the "Applicant") whose project is deemed to include Localized Costs may dispute such decision by the ISO by submitting

within 60 days of such decision formal written notice of the dispute to the ISO, describing in detail the basis for its challenge of the ISO's determination. The Applicant and the ISO shall then enter into good faith negotiations for a period not to exceed 60 days from the date of the Applicant's written notice to try to resolve the dispute.

If there is no satisfactory resolution of the dispute at the end of the negotiation period, the Applicant shall then have the right to file a Section 206 complaint with the Commission.

SCHEDULE 13
RECOVERY OF PUBLIC POLICY TRANSMISSION COSTS BY NON-INCUMBENT
TRANSMISSION DEVELOPERS

1. Applicability

1.1 Use by Non-Incumbent Transmission Developers

This schedule is to be utilized by Non-Incumbent Transmission Developers that: (i) are not also Participating Transmission Owners, and (ii) are Qualified Transmission Project Sponsors. This schedule is designed to enable the recovery of all prudently incurred costs, to the extent permitted in Section 4A of Attachment K to this OATT, related to preparation of Stage One Proposals and Stage Two Solutions, and the recovery of “construction work in progress” costs stemming from the PTF transmission facilities associated with a Public Policy Transmission Upgrade.

1.2 Costs Recovered Under Schedule 13 May Not Also Be Recovered Through Another Schedule

Any costs recovered by the Non-Incumbent Transmission Developer under this Schedule 13 cannot also be recovered under another Schedule to this OATT.

1.3 Transfer of Unrecovered Costs Upon Execution of the Transmission Operating Agreement

Following the execution of the Transmission Operating Agreement by the Non-Incumbent Transmission Developer, any costs approved pursuant to Section 4A of Attachment K to this OATT that are not already recovered under this Schedule 13 may be recovered under the appropriate cost recovery mechanism set forth in this OATT.

2. Stage One Proposal and Stage Two Solution Costs

2.1 Section 205 Rate Filing

Prior to recovering any Stage One Proposal or Stage Two Solution costs that are subject to recovery in accordance with Section 4A of Attachment K to this OATT, a Non-Incumbent Transmission Developer shall submit a filing with the Commission pursuant to Section 205 of the Federal Power Act requesting approval of the actual Stage One Proposal or Stage Two Solution costs and the period of time over which the costs are to be recovered. Upon approval by the Commission, such terms of recovery shall be included in discrete schedules to this Schedule 13. The Non-Incumbent Transmission Developer shall notify the ISO of the Commission-approved Stage One Proposal and Stage Two Solution costs and the applicable recovery period recognized in the Commission Order.

2.2 Invoicing and Collection by ISO

The ISO acts as counterparty for the billing and collection agent on behalf of Non-Incumbent Transmission Developers for recovery of their Commission-approved Stage One Proposal and Stage Two Solution costs, in accordance with Section 4A of Attachment K to this OATT and the applicable NESCOE Public Policy Transmittal. Upon notification from a Non-Incumbent Transmission Developer of the Commission Order approving costs for recovery, the ISO shall allocate and invoice such costs as identified in Section 4A of Attachment K.

3. Construction Work in Progress Costs

3.1 Section 205 Rate Filing

In accordance with the terms of the Non-Incumbent Transmission Developer Operating Agreement and the applicable NESCOE Public Policy Transmittal, a Non-Incumbent Transmission Developer may submit filings to the Commission pursuant to Section 205 of the Federal Power Act for recovery of its “construction work in progress” costs of the PTF transmission facilities associated with a Public Policy Transmission Upgrade. Upon approval by the Commission, such terms of recovery shall be included in discrete schedules to this Schedule 13.

SCHEDULE 14
RECOVERY OF REGIONAL BENEFIT UPGRADE COSTS BY NON-INCUMBENT
TRANSMISSION DEVELOPERS

1. Applicability

1.1 Use by Non-Incumbent Transmission Developers

This schedule is to be utilized by Non-Incumbent Transmission Developers that: (i) are not also Participating Transmission Owners, and (ii) are Qualified Transmission Project Sponsors. This schedule is designed to enable the recovery of prudently incurred costs, to the extent permitted in Section 4.3 of Attachment K to this OATT, related to Phase 2 Solutions for Reliability Transmission Upgrades or Market Efficiency Transmission Upgrades (i.e., a Regional Benefit Upgrade), and the recovery of “construction work in progress” costs stemming from a Regional Benefit Upgrade.

1.2 Costs Recovered Under Schedule 14 May Not Also Be Recovered Through Another Schedule

Any cost recovered by the Non-Incumbent Transmission Developer under this Schedule 14 cannot also be recovered under another Schedule to this OATT.

1.3 Transfer of Unrecovered Costs Upon Execution of the Transmission Operating Agreement

Following the execution of the Transmission Operating Agreement by the Non-Incumbent Transmission Developer, any costs that are not already recovered under this Schedule 14 may be recovered under the appropriate cost recovery mechanism set forth to this OATT, as appropriate.

2. Phase Two Solution Costs

2.1 Section 205 Rate Filing

Prior to recovering any Phase Two Solutions costs and in accordance with Section 4.3(g) of Attachment K to this OATT, a Non-Incumbent Transmission Developer shall submit a filing with the Commission pursuant to Section 205 of the Federal Power Act requesting approval of the actual

Phase Two Solution costs and the period of time over which the costs are to be recovered. Upon approval by the Commission, such terms of recovery shall be included in discrete schedules to this Schedule 14. The Non-Incumbent Transmission Developer shall notify the ISO of the Commission-approved Phase Two Solution costs and the applicable recovery period recognized in the Commission Order.

2.2 Invoicing and Collection by ISO

The ISO acts as counterparty for the billing and collection agent for Non-Incumbent Transmission Developers for recovery of their Commission-approved Phase Two Solution costs, in accordance with Section 4.3(h) of Attachment K to this OATT. Upon notification from a Non-Incumbent Transmission Developer of the Commission Order approving costs for recovery, the ISO shall allocate and invoice such costs on a pro rata basis to Monthly Regional Network Load over the period recognized in the Commission Order. The ISO shall disburse the monthly collected amounts to the Non-Incumbent Transmission Developer, as appropriate.

3. Construction Work in Progress Costs

3.1 Section 205 Rate Filing

In accordance with the terms of the Non-Incumbent Transmission Developer Operating Agreement, a Non-Incumbent Transmission Developer may submit filings to the Commission pursuant to Section 205 of the Federal Power Act for recovery of its “construction work in progress” costs associated with a Regional Benefit Upgrade. Upon approval by the Commission, such terms of recovery shall be included in discrete schedules to this Schedule 14.

SCHEDULE 15

NORTHEASTERN INTERREGIONAL COST ALLOCATION METHODOLOGY

I. Cost Allocation

1. Costs of Approved Interregional Transmission Projects

The cost allocation methodology reflected in this Section 1 shall be referred to as the “Northeastern Interregional Cost Allocation Methodology” (or “NICAM”), and shall not be modified without the mutual consent of the Section 205 rights holders in each region.

The costs of approved Interregional Transmission Projects shall be allocated among the PJM, NYISO, and ISO-NE regions in accordance with the cost allocation principles of FERC Order No. 1000, as follows:

(a) To be eligible for interregional cost allocation, an Interregional Transmission Project must be selected in the regional transmission plan for purposes of cost allocation in each of the transmission planning regions in which the transmission project is proposed to be located, pursuant to FERC accepted agreements and tariffs on file with FERC in each region. With respect to Interregional Transmission Projects and other transmission projects involving NYISO and PJM, the cost allocation of such projects shall be in accordance with the Joint Operating Agreement (“JOA”) among and between NYISO and PJM. With respect to Interregional Transmission Projects and other transmission projects involving NYISO and ISO-NE, the cost allocation for such projects shall be in accordance with the respective tariffs of NYISO and ISO-NE.

(b) The share of the costs of an Interregional Transmission Project allocated to a region will be determined by the ratio of the present value of the estimated costs of such region’s displaced regional transmission project to the total of the present values of the estimated costs of the displaced regional transmission projects in all regions that have selected the Interregional Transmission Project in their regional transmission plans.

(i) The present values of the estimated costs of each region’s displaced regional transmission project shall be based on a common base date that will be the beginning of the calendar month

of the cost allocation analysis for the subject Interregional Transmission Project (the “Base Date”).

- (ii) In order to perform the analysis in this Section (b), the estimated cost of the displaced regional transmission projects shall specify the year’s dollars in which those estimates are provided.
- (iii) The present value analysis for all displaced regional transmission projects shall use a common discount rate. The regions having displaced projects will mutually agree, in consultation with their respective transmission owners, on the discount rate to be used for the present value analysis.
- (iv) In the IPSAC review process, the regions having displaced projects will review and determine, in consultation with their respective transmission owners, that reasonably comparable estimating procedures have been used prior to applying this cost allocation.

(c) No cost shall be allocated to a region that has not selected the Interregional Transmission Project in its regional transmission plan.

(d) If a portion of an Interregional Transmission Project evaluated under the Protocol is included by a region (Region 1) in its regional transmission plan, but there is no regional need or displaced regional transmission project in Region 1 and the neighboring region (Region 2) has a regional need or displaced regional project for the Interregional Transmission Project and includes the Interregional Transmission Project in its regional transmission plan, all of the costs of the Interregional Transmission Project shall be allocated to Region 2 in accordance with the NICAM and none of the costs will be allocated to Region 1. However, Region 1 may voluntarily agree, with the mutual consent of the Section 205 rights holders, in the affected regions (including the Long Island Power Authority and the New York Power Authority if in the NYISO region), to use an alternative cost allocation method filed with and accepted by the Commission.

(e) The portion of the costs allocated to a region pursuant to the NICAM shall be further allocated to that region’s transmission customers pursuant to the applicable provisions of the region’s FERC-filed documents and agreements.

(f) The following example illustrates the cost allocation for such an Interregional Transmission Project:

- A cost allocation analysis of the costs of Interregional Transmission Project Z is to be performed during a given month establishing the beginning of that month as the Base Date.
- Region A has identified a reliability need in its region and has selected a transmission project (Project X) as the preferred solution in its regional plan. The estimated cost of Project X is: Cost (X), provided in a given year's dollars. The number of years from the Base Date to the year associated with the cost estimate of Project (X) is: N(X).
- Region B has identified a reliability need in its region and has selected a transmission project (Project Y) as the preferred solution in its Regional Plan. The estimated cost of Project Y is: Cost (Y), provided in a given year's dollars. The number of years from the Base Date to the year associated with the cost estimate of Project (Y) is: N(Y).
- Regions A and B, through the interregional planning process have determined that an Interregional Transmission Project (Project Z) will address the reliability needs in both regions more efficiently and cost-effectively than the separate regional projects. The estimated cost of Project Z is: Cost (Z). Regions A and B have each determined that Interregional Transmission Project Z is the preferred solution to their reliability needs and have adopted that Interregional Transmission Project in their respective regional plans in lieu of Projects X and Y respectively. If Regions A and B have agreed to bear the costs of upgrades in other affected transmission planning regions, these costs will be considered part of Cost (Z).
- The discount rate used for all displaced regional transmission projects is: D
- Based on the foregoing assumptions, the following formulas will be used:
 - Present Value of Cost (X) = PV Cost (X) = $\text{Cost (X)} / (1+D)^{N(X)}$
 - Present Value of Cost (Y) = PV Cost (Y) = $\text{Cost (Y)} / (1+D)^{N(Y)}$
 - Cost Allocation to Region A = $\text{Cost (Z)} \times \text{PV Cost (X)} / [\text{PV Cost (X)} + \text{PV Cost (Y)}]$

- Cost Allocation to Region B = Cost (Z) x PV Cost (Y)/[PV Cost (X) + PV Cost (Y)]
- Applying those formulas, if:
 - Cost (X) = \$60 Million and N(X) = 8.25 years
 - Cost (Y) = \$40 Million and N(Y) = 4.50 years
 - Cost (Z) = \$80 Million
 - D = 7.5% per year
 - Then:
 - PV Cost (X) = $60/(1+0.075)^{8.25} = 33.039$ Million
 - PV Cost (Y) = $40/(1+0.075)^{4.50} = 28.888$ Million
 - Cost Allocation to Region A = $\$80 \times 33.039/(33.039 + 28.888) = \$42,681$ Million
 - Cost Allocation to Region B = $\$80 \times 28.888/(33.039+28.888) = \37.319 Million

2. Other Cost Allocation Arrangements

(a) Except as provided in Section 2.(b), the NICAM is the exclusive means by which any costs of an Interregional Transmission Project may be allocated between or among PJM, NYISO, and ISO-NE.

(b) Nothing in the FERC-filed documents of ISO-NE, NYISO or PJM shall preclude agreement by entities with cost allocation rights under Section 205 of the Federal Power Act for their respective regions (including the Long Island Power Authority and New York Power Authority in the NYISO region) to enter into separate agreements to allocate the cost of Interregional Transmission Projects proposed to be located in their regions as an alternative to the NICAM, or other transmission projects identified pursuant to assessments and studies conducted pursuant to Section 6 of the Northeastern Planning Protocol. Such other cost-allocation methodologies must be approved in each region pursuant to the Commission-approved rules in each region, filed with and accepted by the Commission, and shall apply only to the region's share of the costs of an Interregional Transmission Project or other transmission projects pursuant to Section 6 of the Northeastern Planning Protocol, as applicable.

3. Filing Rights

Nothing in this Schedule 15 will convey, expand, limit or otherwise alter any rights of ISO-NE, NYISO, PJM, each region's transmission owners, market participants, or other

entities to submit filings under Section 205 of the Federal Power Act regarding Interregional Cost Allocation or any other matter.

Where applicable, the regions have been authorized by entities that have cost allocation rights for their respective regions to implement the provisions of this Schedule.

4. Merchant Transmission and Individual Transmission Owner Projects

Nothing in this Agreement shall preclude the development of Interregional Transmission Projects that are funded solely by merchant transmission developers or by individual transmission owners.

5. Consequences to Other Regions from Regional or Interregional Transmission Projects

Except as provided in this Schedule 15 or where cost responsibility is expressly assumed by the ISO-NE region in other documents, agreements or tariffs on file with FERC, the ISO-NE region shall not be responsible for compensating another region for required upgrades or for any other consequences in another planning region associated with regional or interregional transmission facilities, including but not limited to, transmission projects identified pursuant to Section 6 of the Restated Northeastern Planning Coordination Protocol or Interregional Transmission Projects identified pursuant to Section 7 of the Restated Northeastern Planning Coordination Protocol.

SCHEDULE 16

Blackstart Service

Introduction and Description of Service

Blackstart Service is necessary to facilitate a stable and orderly system restoration following a partial or complete shutdown of the New England Transmission System. Resources are offered by Blackstart Owners to provide Blackstart Service and, if selected by the ISO, are modified (if required), maintained, tested and operated by a Market Participant, or its designee, in accordance with this Schedule 16. The ISO shall select those resources whose locations and capabilities support the New England System Restoration Plan. Following agreement between the owner and the ISO, such selected resources (“Designated Blackstart Resources”) shall provide and are eligible to receive compensation for providing Blackstart Service. Blackstart Service is provided by Blackstart Owners via Designated Blackstart Resources, arranged for through the ISO, and utilized by Transmission Customers. Transmission Customers are charged for Blackstart Service based on their pro-rata share of Monthly Regional Network Load.

1. Eligibility Requirements:

A resource must meet the eligibility requirements listed below, as detailed in ISO New England Operating Procedure No. 11 – Designated Blackstart Resource Administration (OP 11), to be considered for compensation as a Designated Blackstart Resource.

- 1.1.** The Blackstart Owner offers the resource to provide Blackstart Service;
- 1.2.** The offered resource must be selected by the ISO to provide Blackstart Service, based on the technical requirements to satisfy NERC, NPCC and ISO restoration criteria;
- 1.3.** The ISO accepts the Blackstart Owner’s offer to provide Blackstart Service;
- 1.4.** The Blackstart Owner and resource meet the following Blackstart Service Minimum Criteria:
 - 1.4.1.** the resource is located within the ISO New England Reliability Coordinator Area;

1.4.2. the resource is metered and dispatchable by the ISO or otherwise subject to operational control by the ISO during the restoration of the New England Transmission System following a partial or complete shutdown of the New England Transmission System;

1.4.3. the resource is capable of starting and remaining energized without support from either offsite power or another Designated Blackstart Resource until such time as additional load is directed to be picked up pursuant to instruction from the ISO or Local Control Center;

1.4.4. the resource is capable of closing its output circuit breaker to a de-energized bus;

1.4.5. the resource is maintained and staffed in a manner that allows it to be brought online and available for loading by the ISO or Local Control Center within a specified time period, with such period being measured from the initiation of the startup instruction from the ISO or Local Control Center;

1.4.6. the resource has the ability to maintain frequency within a prescribed range and is able to operate in a mode with zero governor droop or the equivalent;

1.4.7. the resource has an automatic voltage regulator capable of being placed in automatic voltage control mode;

1.4.8. the resource has the ability to provide lead and lag power factor capability;

1.4.9. the resource has access to a fuel supply during a shutdown of the New England Transmission System that will allow it to, in accordance with ISO or Local Control Center dispatch instruction, run at full capacity for a specified minimum amount of time;

1.4.10. the Blackstart Owner maintains a communication capability from the resource to either the Local Control Center or the ISO, as directed by the ISO, that is independent of a public telephone or cellular phone communication network and is confirmed to be capable of operating during a shutdown of the New England Transmission System; and

1.5. A Blackstart Service Commitment is established between the Blackstart Owner and the ISO.

2. Term of Blackstart Service

2.1. Term of Blackstart Service Commitment:

The Designated Blackstart Resource's term of Blackstart Service Commitment, as established under OP 11, shall start on the effective date of the resource's Blackstart Service Commitment and, for a resource that:

2.1.1. does not establish a Specified-Term Blackstart Capital Payment, the Blackstart Service Commitment shall continue until terminated in accordance with Section 2.3. The Blackstart Owner and the ISO by mutual agreement may establish a minimum period for the open term, which shall not be greater than the number of years of the recovery period, as shown in Table 4a of Appendix A, that corresponds to the age of the Designated Blackstart Resource on the effective date of the Blackstart Service Commitment.

2.1.2. establishes a Specified-Term Blackstart Capital Payment, the term of Blackstart Service Commitment shall equal the number of years of the recovery period, as shown in Table 4a of Appendix A, that corresponds to the age of the Designated Blackstart Resource on the effective date of the Blackstart Service Commitment (i.e., the "specified term"). The age of the resource shall be calculated based on the "In-Service Date", as stated in the ISO's "Forecast Report of Capacity, Energy, Loads, and Transmission (CELT Report)."

At the expiration of the specified term of Blackstart Service Commitment and unless otherwise terminated in accordance with Section 2.3, a Designated Blackstart Resource will commence a new term of Blackstart Service Commitment in accordance with Section 2.1 and OP 11.

2.2 Termination:

2.2.1. Mutual Termination: The Blackstart Service Commitment may be terminated at any time by mutual agreement of the Blackstart Owner and ISO. If the Blackstart Service Commitment is terminated under this provision, then the Designated Blackstart Resource's Blackstart Standard Rate Payments or Blackstart Station-specific Rate Payments, as appropriate, will cease on the first day of the month following the day that the Blackstart Service Commitment is terminated and the Designated Blackstart Resource shall not recover any Lump Sum Blackstart Payments.

2.2.2. Unilateral Termination:

2.2.2.1. Either the Blackstart Owner or the ISO may terminate the Blackstart Service Commitment upon at least two (2) years' written notice to the other party following the effective date of the Blackstart Service Commitment. In the event of a Force Majeure, the two-year written notice requirement shall be waived.

2.2.2.1.1. If the Blackstart Owner terminates the Blackstart Service Commitment under this provision, then the Designated Blackstart Resource's Blackstart Standard Rate Payments or Blackstart Station-specific Rate Payments, as appropriate, will cease on the first day of the month following the day that the Blackstart Service Commitment is terminated and the Designated Blackstart Resource shall not recover any Lump Sum Blackstart Payments, except as provided for in Section 2.3.2.1.2.

2.2.2.1.2. A Blackstart Owner may terminate the Blackstart Service Commitment of a Designated Blackstart Resource that establishes a Specified-Term Blackstart Capital Payment in order to retire the Designated Blackstart Resource if such retirement has been approved or required under the Tariff. The payment of the Blackstart O&M Payment shall cease on the first day of the month following the day, as recognized by ISO, that the Designated Blackstart Resource stopped providing Blackstart Service.

If the Blackstart Resource is retired in compliance with this Section, then it shall receive a single lump-sum payment in the month following the effective date of the retirement that equals the Lump Sum Blackstart Capital Payment as determined in Section 5.4.

2.2.2.1.3. If the ISO terminates a Blackstart Service Commitment under this provision for reasons other than provided in Section 2.3.2.2, then:

2.2.2.1.3.1. the Designated Blackstart Resource's Blackstart O&M Payment will cease on the first day of the month following the day that the Blackstart Service Commitment is terminated; and

2.2.2.1.3.2. the Blackstart Resource shall receive a single lump-sum payment in the month following the effective date of the termination that equals the Lump Sum Blackstart Capital Payment as determined in Section 5.4.

2.2.2.2. Regardless of the term length, the ISO may terminate the Blackstart Service Commitment:

2.2.2.2.1. with ninety (90) days' notice to the Blackstart Owner following the issuance by the ISO to the Blackstart Owner of a Failure to Maintain Blackstart Capability notice. The ISO shall not terminate the Blackstart Service Commitment if the Blackstart Owner corrects the failure within this ninety-day notice period; or

2.2.2.2. with ninety (90) days notice to the Blackstart Owner following the issuance by the ISO to the Blackstart Owner of a Failure to Perform During a System Restoration notice. The ISO shall not terminate the Blackstart Service Commitment if the Failure to Perform During a System Restoration was determined by the ISO to be due to an event of Force Majeure.

2.2.2.3. If the ISO terminates the Blackstart Service Commitment under either Section 2.2.2.2.1 or Section 2.2.2.2.2, then any remaining Designated Blackstart Resource Blackstart Standard Rate Payments or Blackstart Station-specific Rate Payments will cease on the first day of the month following the day that the Blackstart Service Commitment is terminated and the Designated Blackstart Resource shall not recover any Lump Sum Blackstart Payments.

3. Rights and Obligations

3.1. The Blackstart Owner shall follow ISO and Local Control Center operating dispatch instructions during the restoration of the New England Transmission System following a partial or complete shutdown of the New England Transmission System, in accordance with the Designated Blackstart Resource's Blackstart Service obligations, as stated in this Section 3, and Blackstart Service Minimum Criteria.

3.2. The Blackstart Owner shall not subject the Designated Blackstart Resource to any agreement, arrangement or procedure that conflicts with the resource's ability to provide Blackstart Service, including any agreement, arrangement or procedure that would prevent the resource from following ISO or Local Control Center dispatch instructions during the restoration of the New England Transmission System following a partial or complete shutdown of the New England Transmission System.

3.3. The Blackstart Owner shall maintain the ability of the Designated Blackstart Resource to perform in accordance with ISO New England Operating Documents.

3.4. The Blackstart Owner shall, at least once every 12 months, ensure that the Designated Blackstart Resource passes all Blackstart Capability Tests and complies with all reporting requirements, in accordance with OP 11.

3.5. The ISO shall have the right to be present during the performance of a Blackstart Capability Test and to inspect the Designated Blackstart Resource and the Blackstart Owner's procedures and records that pertain to the operation and maintenance of Blackstart Service to confirm the resource's ability to provide Blackstart Service and assess the accuracy of information provided to the ISO and Local Control Centers.

3.6. A Blackstart Owner that desires to submit a request to retire or modify equipment that would diminish the ability of a Designated Blackstart Resource to provide Blackstart Service may submit the request if it simultaneously submits a notice of Blackstart Service Commitment termination to the ISO in accordance with Section 2.3. The notice of Blackstart Service Commitment termination may be conditional on the ISO's approval of the request to retire or modify.

3.7. The terms and conditions of Schedule 16 shall apply to the Designated Blackstart Resource, whether or not it has a Capacity Supply Obligation, while the Designated Blackstart Resource is committed to provide Blackstart Service.

3.8. The Blackstart Owner shall be entitled to take the Designated Blackstart Resource out of operation in accordance with the schedule for planned outages as established by the ISO, provided that the ISO has the right, working with the Blackstart Owner and the Local Control Center, to reposition the outage for reliability reasons with respect to Blackstart Service when establishing the planned outage schedule.

3.9. The Blackstart Owner shall inform the ISO and Local Control Center of any planned outage of equipment under the Blackstart Owner's control that affects the Designated Blackstart Resource's ability to provide Blackstart Service.

3.10. The Blackstart Owner shall maintain documentation of its procedures and training for starting the resource, energizing a de-energized bus and maintaining voltage and frequency during restoration, and provide this documentation to the ISO, upon request.

4. Failure to Meet Blackstart Service Obligations

4.1. A Blackstart Owner shall notify the ISO and Local Control Center as soon as practicable and within 15 minutes of identifying a failure or inability of a Designated Blackstart Resource to meet the Blackstart Service Minimum Criteria and Blackstart Service obligations specified in Schedule 16 and in the ISO New England Operating Documents pertaining to Blackstart Service. Such conditions include any forced outage of equipment under the Blackstart Owner's control that affects the Designated Blackstart Resource's ability to provide Blackstart Service, or that might constitute a Failure to Maintain Blackstart Capability or a Failure to Perform During a System Restoration.

4.2. Upon receipt of the notice described in Section 4.1, the ISO shall assess all available information associated with a Designated Blackstart Resource's inability to meet its Blackstart

Service Minimum Criteria and Blackstart Service obligations, and provide notice to the Blackstart Owner that a Failure to Maintain Blackstart Capability or a Failure to Perform During a System Restoration event has occurred (collectively or individually, a “Failure”) if the ISO determines based on that assessment that a Failure has occurred.

4.3. The Blackstart Owner shall exercise diligence to correct the condition that caused the Failure promptly and provide notice to the ISO when the Failure has been corrected. The ISO shall review and provide prompt acknowledgement of such notice. If the Blackstart Owner determines that the Failure will continue for a period greater than 30 days from the date of the Failure, the Blackstart Owner shall submit a correction plan for approval by the ISO.

4.4. Suspension of Payments as a result of a Failure to Maintain Blackstart Capability.

4.4.1. If a Failure to Maintain Blackstart Capability has not been corrected within 30 days from date of the Failure, regardless of whether an ISO-approved correction plan is in place, then the ISO shall set the Designated Blackstart Resource’s Blackstart O&M Payment to zero effective on the date of the Failure.

4.4.2. If a Failure to Maintain Blackstart Capability has not been corrected within 60 days from the date of the Failure or on a date established by the ISO based on a Blackstart Owner’s submitted correction plan (whichever is later), then the ISO shall set the Designated Blackstart Resource’s Total Blackstart Capital Payment to zero beginning on the day following the date that the correction was to be completed.

4.5. Suspension of Payments as a result of a Failure to Perform During a System Restoration: Following a Failure to Perform During a System Restoration event, the ISO shall set the Designated Blackstart Resource’s Blackstart O&M Payment and Total Blackstart Capital Payment to zero effective on the date of the Failure to Perform During a System Restoration. The ISO shall not suspend a Designated Blackstart Resource’s Blackstart O&M Payment and Total Blackstart Capital Payment, if the Failure to Perform During a System Restoration was determined by the ISO to be due to an event of Force Majeure.

4.6. Resumption of Suspended Payments: Following the suspension of a Blackstart O&M Payment or Total Blackstart Capital Payment, the payment(s) shall resume upon the date, as recognized by the ISO, on which the Failure was corrected, *provided, however*, that the ISO retains its rights to terminate under the circumstances described in Section 2.3.2.2.

4.7. Suspension of Payments or a Resumption of Suspended Payments: A suspension of payments or a resumption of suspended payments under Section 4 shall result in a pro rata adjustment of the resource’s Blackstart Standard Rate Payments or Blackstart Station-specific Rate Payments, as appropriate, for the month(s) in which the suspension is applied or removed.

5. Blackstart Service Payments

A Blackstart Owner is eligible to receive payment for the provision of Blackstart Service from a Designated Blackstart Resource based on either the Blackstart Standard Rate Payment established in accordance with Section 5.1 or a Blackstart Station-specific Rate Payment established in accordance with Section 5.2. Unless stated otherwise, a Designated Blackstart Resource’s Blackstart Standard Rate Payments or Blackstart Station-specific Rate Payments, as appropriate, shall start on the first day of the month following the effective day of the Blackstart Service Commitment, and shall cease on the first day of the month following the day that the Blackstart Service Commitment is terminated.

5.1. Blackstart Standard Rate Payment

5.1.1. General Provisions

The Blackstart Standard Rate Payment utilizes the payment parameters contained within Appendix A to Schedule 16 – Blackstart Standard Rate Components and Capital Recovery Factors (“Appendix A”). The ISO utilizes Appendix A, the ISO’s CELT Report and documentation provided by the Blackstart Owner to determine the Blackstart Standard Rate Payment that a Designated Blackstart Resource is to receive for Blackstart Service.

5.1.1.1. Designated Blackstart Resources that the ISO recognizes as requiring the addition of Blackstart Equipment to meet Blackstart Service Minimum Criteria may elect to establish the Specified-Term Blackstart Capital Payment for a single term determined in accordance with Section 2.1.2.

5.1.1.2. Designated Blackstart Resources may establish one (and only one) of the following: Station-level Standard Blackstart Capital Payment, an individual Additional Resource Standard Blackstart Capital Payment, a Station-level Specified-Term Blackstart Capital Payment or an individual Additional Resource Specified-Term Blackstart Capital Payment.

5.1.1.3. The values in Tables 1, 2, 3, and 7 of Appendix A shall be adjusted on an annual basis in accordance with the most recent “Handy-Whitman Index of Public Utility Construction Costs” and then rounded to the nearest dollar. The annual adjustment calculation shall become

effective on January 1 of the next year. The ISO shall post on its website the updated Appendix A.

The adjustment of the values in Table 1 and Table 7 shall be derived based on the Handy-Whitman index values for the North Atlantic Region for July for “Common Labor” at Table B-1, line 19 (or its successor).

The adjustment of the values in Table 2 and Table 3 shall be derived based on the Handy-Whitman index values for the North Atlantic Region for July for “Total Other Production Plant” at Table E-1, line 28 (or its successor).

5.1.2. A Designated Blackstart Resource at a Blackstart Station shall be entitled to Blackstart Service compensation in a month based on the following formula, Blackstart Owner-submitted data and values from Appendix A.

$$\text{Blackstart Standard Rate Payment}_{\text{individual}} = (\text{Blackstart O\&M Payment}_{\text{station}} + \text{Total Blackstart Capital Payment}_{\text{station}}) / 12 * \text{Designated Blackstart Resource}_{\text{individual}} \text{ nameplate MVA value} / \sum \text{Designated Blackstart Resource}_{\text{individual}} \text{ nameplate MVA values at the Blackstart Station}$$

Where:

$$\text{Total Blackstart Capital Payment}_{\text{station}} = \text{Standard Blackstart Capital Payment}_{\text{station}} + \text{Specified-Term Blackstart Capital Payment}_{\text{station}}$$

5.1.2.1. Blackstart O&M Payment_{station}: The Blackstart O&M Payment provides compensation to Blackstart Stations for the operating and maintenance expenses associated with the provision of Blackstart Service from Designated Blackstart Resources located at the Blackstart Station, and is derived based on the following formula using data from Tables 1 and 5 of Appendix A.

$$\text{Blackstart O\&M Payment}_{\text{station}} = \text{Station-level Blackstart O\&M Payment} + \sum \text{Additional Resource Blackstart O\&M Payment for each additional Designated Blackstart Resource at the Blackstart Station.}$$

Where:

The Station-level Blackstart O&M Payment is determined by selecting from Table 1 of Appendix A (based on the appropriate Designated Blackstart Resource type specified in Table 5 of Appendix A) the largest applicable Station-level Blackstart O&M Payment value for the Designated Blackstart Resource(s) located at the Blackstart Station; and

The Additional Resource Blackstart O&M Payment is determined by selecting from Table 1 of Appendix A (based on the appropriate Designated Blackstart Resource type specified in Table 5 of Appendix A) the applicable payment values associated with each additional Designated Blackstart Resource(s) located at the Blackstart Station and excludes the Designated Blackstart Resource used to determine the Station-level Blackstart O&M Payment.

5.1.2.2. Standard Blackstart Capital Payment_{station} or Specified-Term Blackstart Capital Payment_{station}: The Standard Blackstart Capital Payment_{station} or Specified-Term Blackstart Capital Payment_{station}, but not both, provides compensation to Blackstart Stations for the capital cost associated with the provision of Blackstart Service from Designated Blackstart Resources located at the Blackstart Station.

5.1.2.2.1. The Standard Blackstart Capital Payment_{station} is derived based on the following formula using data from Tables 2 and 5 of Appendix A.

Standard Blackstart Capital Payment_{station} = Station-level Standard Blackstart Capital Payment + Σ Additional Resource Standard Blackstart Capital Payment for each additional Designated Blackstart Resource at the Blackstart Station that is eligible to establish such a payment.

Where:

The Station-level Standard Blackstart Capital Payment is determined by selecting from Table 2 of Appendix A (based on the appropriate Designated Blackstart Resource type specified in Table 5 of Appendix A) the largest applicable Station-level Standard Blackstart Capital Payment value for the Designated Blackstart Resource(s) located at the Blackstart Station that are eligible to receive a Station-level Standard Blackstart Capital Payment. The Station-level Standard Blackstart Capital Payment shall be set to zero if any Designated Blackstart Resource located at the Blackstart Station is recovering a Station-level Specified-Term Blackstart Capital Payment.

The Additional Resource Standard Blackstart Capital Payment is determined by selecting from Table 2 of Appendix A (based on the appropriate Designated Blackstart Resource type specified in Table 5 of Appendix A) the applicable payment value associated with each additional Designated Blackstart Resource (s) located at the Blackstart Station that establishes an Additional Resource Standard Blackstart Capital Payment and excludes (i) the Designated Blackstart Resource located at the Blackstart Station that is used to establish the Station-level Standard Blackstart Capital Payment or Station-level Specified-Term Blackstart Capital Payment and (ii) the Designated Blackstart Resources located at the Blackstart Station that establish an Additional Resource Specified-Term Blackstart Capital Payment.

5.1.2.2.2. The Specified-Term Blackstart Capital Payment_{station} is derived based on the following formula using data from Tables 3, 4a and 5.

Specified-Term Blackstart Capital Payment_{station} = Station-level Specified-Term Blackstart Capital Cost * the appropriate capital recovery factor + Σ Additional Resource Specified-Term Blackstart Capital Cost * the appropriate capital recovery factor for each additional Designated Blackstart Resource at the Blackstart Station that is eligible to establish such a payment.

Where:

The Station-level Specified-Term Blackstart Capital Payment is determined by selecting, based on Tables 3 and 4a of Appendix A, the largest “Station-level Specified-Term Blackstart Capital Cost * the appropriate capital recovery factor” value for the Designated Blackstart Resource(s) located at the Blackstart Station that are eligible to receive a Station-level Specified-Term Blackstart Capital Payment.

The Additional Resource Specified-Term Blackstart Capital Payment is determined by selecting, based on Tables 3 and 4a of Appendix A, the “Additional Resource Specified-Term Blackstart Capital Cost* the appropriate capital recovery factor” associated with each additional Designated Blackstart Resource(s) located at the Blackstart Station that establishes an Additional Resource Specified-Term Blackstart Capital Payment and excludes (i) the Designated Blackstart Resource located at the Blackstart Station that is used to establish the Station-level Standard Blackstart Capital Payment or Station-level Specified-Term Blackstart Capital Payment and (ii) the Designated Blackstart Resources

located at the Blackstart Station that establish an Additional Resource Standard Blackstart Capital Payment.

The capital recovery factor is based on Table 4a of Appendix A and reflects the age of the Designated Blackstart Resource that is recovering a Specified-Term Blackstart Capital Payment, where the age is determined by the resource's "In-Service Date", as stated in the CELT Report.

5.2. Blackstart Station-specific Rate Payment

The Blackstart Station-specific Rate Payment provides compensation to Blackstart Stations for the operation, maintenance and capital expenses associated with the provision of Blackstart Service from Designated Blackstart Resources located at the Blackstart Station, and is established by Commission acceptance of a Blackstart Owner's filing, under Section 205 of the Federal Power Act, to establish or revise Blackstart Station-specific Rate Payment reflecting cost-based Blackstart Service compensation.

5.2.1. The rate schedule shall specify two categories of Blackstart Service payments (Blackstart O&M Payment and Total Blackstart Capital Payment) of a Blackstart Station that are to be recovered annually for the provision of Blackstart Service.

5.2.2. The Blackstart Owner is responsible for making all appropriate filings with the Commission and Blackstart Service compensation shall be governed solely by the Commission-approved rate schedule.

5.2.3. A Designated Blackstart Resource shall be entitled to compensation in a month based on the following formula:

$$\text{Blackstart Station-specific Rate Payment}_{\text{individual}} = (\text{Blackstart O\&M Payment}_{\text{station}} + \text{Total Blackstart Capital Payment}_{\text{station}}) / 12 * \text{Designated Blackstart Resource}_{\text{individual}} \text{ nameplate MVA value} / \sum \text{Designated Blackstart Resource}_{\text{individual}} \text{ nameplate MVA values at the Blackstart Station.}$$

Where:

$\text{Blackstart O\&M Payment}_{\text{station}}$ = the Commission-accepted annual Blackstart O&M Payment for the Blackstart Station, which shall include operations and maintenance

compensation for the provisions of Blackstart Service and for compliance with all associated NERC Critical Infrastructure Protection Reliability Standards.

Total Blackstart Capital Payment_{station} = the Commission-accepted annual Blackstart Capital Payment for the Blackstart Station.

5.3. Non-Designated Blackstart Resource Study Cost Payments

If a Market Participant undertakes, at the direction of the ISO, a study to assess the viability of converting an offered resource to a Designated Blackstart Resource and the ISO issues a final determination not accepting a resource as a Designated Blackstart Resource, then the Market Participant(s) with Ownership Shares in the resource shall be reimbursed for either (i) the Non-Designated Blackstart Resource Study Cost Payment in Table 7 to Appendix A or (ii) Commission-accepted compensation for study costs. This payment provides compensation for study costs that were incurred after the date that the Blackstart Owner and ISO agreed that studies to determine the technical feasibility of the resource to provide Blackstart Service should be undertaken through the date of the final determination, including expenses incurred to fulfill information requests. Such study cost compensation shall be made within a single monthly payment and charged to Transmission Customers based upon their pro-rata Monthly Regional Network Load share in the month in which the compensation is paid.

5.4. Lump Sum Blackstart Payment

A Lump Sum Blackstart Payment provides compensation for Designated Blackstart Resources that are retired or terminated under Section 2.3.2.1.2 or Section 2.3.2.1.3, respectively, and shall be paid to the retired or terminated Designated Blackstart Resource as a single lump-sum payment in the month following the effective date of the retirement or termination. A Lump Sum Blackstart Payment reflects the present value of the remaining Standard Blackstart Capital Payments due the eligible, retiring or terminated Designated Blackstart Resource(s).

5.4.1. The Lump Sum Blackstart Payment_{individual} is derived based on the following formula.

Lump Sum Blackstart Payment_{individual} = (Lump Sum Blackstart Capital Payment_{station}) * Designated Blackstart Resource_{individual} nameplate MVA value of the retiring or terminated Designated Blackstart Resource / Σ all the retiring or

terminated Designated Blackstart Resource ^{individual} nameplate MVA values at the Blackstart Station.

5.4.1.1. For eligible retiring or terminated Designated Blackstart Resource(s) receiving Blackstart Standard Rate Payment under Section 5.1, the Lump Sum Blackstart Payment ^{station} is derived based on the following formula using data from Tables 2, 3, 4a, 4b, and 5 of Appendix A that is in effect on the retirement or termination date.

5.4.1.1.1. At a Blackstart Station where (i) one of the Designated Blackstart Resources being retired or terminated establishes a Station-level Standard Blackstart Capital Payment, (ii) has a minimum period associated with its open-term Blackstart Service Commitment and (iii) the effective date of retirement or termination is within the minimum period, the Lump Sum Blackstart Capital Payment ^{station} shall equal the present value of the monthly Station-level Standard Blackstart Capital Payment, using data from Tables 2, 4a, 4b and 5, for the remaining months of the minimum period associated with the open-term Blackstart Service Commitment.

5.4.1.1.2. At a Blackstart Station comprised of more than one Designated Blackstart Resource, where one of the Designated Blackstart Resources being retired or terminated establishes a Specified-Term Blackstart Capital Payment ^{station}, the Lump Sum Blackstart Capital Payment ^{station} shall equal the present value of the monthly Specified-Term Blackstart Capital Payment, using data from Tables 3, 4a, 4b and 5, for the remaining months of the term of Blackstart Service Commitment.

5.4.1.1.3. The Lump Sum Blackstart Capital Payment ^{station} that is calculated pursuant to Section 5.4.1.1.1 or Section 5.4.1.1.2 shall be adjusted by: (a) adding, if any and as applicable, for any other Designated Blackstart Resources are being retired or terminated and that have a minimum period associated with the open-term Blackstart Service Commitment, the present value of the Additional Resource Standard Blackstart Capital Payment(s), using data from Tables 2, 4a, 4b and 5, for the remaining months of the applicable minimum period of Blackstart Service Commitment; (b) adding, if any and as applicable, for any other Designated Blackstart Resources are being retired or terminated and that have a specified-term associated with their Blackstart Service Commitment, the present value of the Additional Resource Specified-Term Blackstart Capital Cost(s), using data from Tables 3, 4a, 4b and 5, for the remaining months of the applicable specified-term Blackstart Service Commitment; (c) subtracting, if any and as applicable, for any Designated Blackstart Resources are continuing in service and that have a minimum periods associated with their open-term Blackstart Service Commitments, the present

value of the new Station-level Standard Blackstart Capital Payment, using data from Tables 2, 4a, 4b and 5, for the remaining months of the applicable minimum period; and (d) subtracting, if any and as applicable, for any Designated Blackstart Resources are continuing in service and that have a specified-term Blackstart Service Commitment, the present value of the new Station-level Specified-Term Blackstart Capital Cost, using data from Tables 3, 4a, 4b and 5, for the remaining months of the applicable specified-term of Blackstart Service Commitment.

5.4.1.2. For eligible, retiring or terminated Designated Blackstart Resource(s) receiving Blackstart Station-specific Rate Payment under Section 5.2, the Lump Sum Blackstart Payment _{individual}, Lump Sum Blackstart Capital and Payment _{station} is derived in accordance with the Lump Sum Blackstart Payment provisions included in the applicable Blackstart Owner’s Section 205 Blackstart Station-specific Rate Payment filing, as approved by FERC.

5.5. Equipment Damage Reimbursement

Blackstart Owners are eligible for Equipment Damage Reimbursement under Schedule 16 for equipment damage to a Designated Blackstart Resource: (1) that resulted from operating such equipment in response to operating dispatch instructions from the ISO during the restoration of the New England Transmission System, (2) for which reasonably available and customary insurance was sought and not available for the damages incurred and (3) that would not have occurred but for the Blackstart Owner’s provision of Blackstart Service from that Designated Blackstart Resource. The burden of making such showings will be upon the Blackstart Owners and it is the responsibility of the Blackstart Owners to seek Commission approval under Section 205 of the Federal Power Act for any reimbursement under this Section. Equipment Damage Reimbursement _{individual} shall equal the Commission-approved Equipment Damage Reimbursement for a Designated Blackstart Resource.

5.6. Total Blackstart Service Payments

The Total Blackstart Service Payments in a month shall be based on the following formula:

$$\begin{aligned} \text{Total Blackstart Service Payments}_{\text{month}} = & \sum \text{Blackstart Standard Rate Payment}_{\text{individual}} + \sum \\ & \text{Blackstart Station-specific Rate Payment}_{\text{individual}} + \sum \text{Non-Designated Blackstart Resource} \\ & \text{Study Cost Payments for the month} + \sum \text{Lump Sum Blackstart Payments}_{\text{individual}} + \sum \\ & \text{Equipment Damage Reimbursement}_{\text{individual}}. \end{aligned}$$

6. Monthly Blackstart Service Charge

Each Transmission Customer shall pay a charge for Blackstart Service in a month, which is calculated using the following formula:

$$\text{Blackstart Service Charge}_{\text{month}} = \text{Blackstart Service Payments}_{\text{month}} * \text{Transmission Customer's Monthly Regional Network Load for the month} / \text{Sum of all Transmission Customer's Monthly Regional Network Load for the month.}$$

Appendix A to Schedule 16
Blackstart Standard Rate Components and Capital Recovery Factors

Table 1 - Blackstart O&M Payments

Designated Blackstart Resource ("DBR") Type	Station-level Blackstart O&M Payment (\$/year for the first DBR)	Additional Resource Blackstart O&M Payment (\$/year for each additional DBR)
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Fossil Resources:

MVA <= 10	\$71,100	\$11,050
10 < MVA <= 60	\$77,700	\$11,950
60 < MVA <= 90	\$80,200	\$12,750
90 < MVA <= 300, Small Starting Requirement (Simple Cycle)	\$113,900	\$15,450
90 < MVA <= 300, Small Starting Requirement (Combined cycle)	\$416,300	\$25,150
90 < MVA <= 300, Medium Starting Requirement	\$672,400	\$34,050
90 < MVA <= 300, Large Starting Requirement	\$676,400	\$34,150
300 < MVA, Large Starting Requirement	\$819,700	\$50,250

Hydroelectric Resources:

10 < MVA <= 60	\$77,700	\$11,950
60 < MVA <= 90	\$80,200	\$12,750

Table 2 - Standard Blackstart Capital Payments

Designated Blackstart Resource ("DBR") Type	Proxy Unit Type	Configuration	Station-level Blackstart Capital Payment (\$/year for the first DBR)	Additional Resource Blackstart Capital Payment (\$/year for each additional DBR)
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Fossil Resources:

MVA <= 10	Wartsilla 34DF	1 x SCGT	\$239,400	\$32,300
10 < MVA <= 60	LM2500	1 x SCGT	\$253,200	\$32,300
60 < MVA <= 90	LM6000	1 x SCGT	\$253,200	\$32,300
90 < MVA <= 300, Small Starting Requirement (Simple Cycle)	LMS100	1 x SCGT	\$332,000	\$32,300
90 < MVA <= 300, Small Starting Requirement (Combined cycle)	GE 7EA	2 x CCGT	\$1,637,300	\$32,700
90 < MVA <= 300, Medium Starting Requirement	Siemens 501F	2 x CCGT	\$2,488,300	\$32,700
90 < MVA <= 300, Large Starting Requirement	GE 7FA	2 x CCGT	\$2,488,300	\$32,700
300 < MVA, Large Starting Requirement	GE HA.02	2 x CCGT	\$2,997,900	\$32,700

Hydroelectric Resources:

10 < MVA <= 60	LM2500	1 x SCGT	\$253,200	\$32,300
60 < MVA <= 90	LM6000	1 x SCGT	\$253,200	\$32,300

Note: Standard Blackstart Capital Payments are calculated using Specified-Term Blackstart Capital Costs from Table 3 and a 25 Year capital recovery factor from Table 4a., rounded to nearest \$100.

Table 3 - Specified-Term Blackstart Capital Cost

Designated Blackstart Resource ("DBR") Type	Configuration	Station-level Specified-Term Blackstart Capital Cost (\$ for the first DBR)	Additional Resource Specified-Term Blackstart Capital Cost (\$ for each additional DBR)
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Fossil Resources:

MVA <= 10	1 x SCGT	\$2,170,722	\$292,700
10 < MVA <= 60	1 x SCGT	\$2,295,886	\$292,700
60 < MVA <= 90	1 x SCGT	\$2,295,886	\$292,700
90 < MVA <= 300, Small Starting Requirement (Simple Cycle)	1 x SCGT	\$3,010,809	\$292,700
90 < MVA <= 300, Small Starting Requirement (Combined cycle)	2 x CCGT	\$14,847,052	\$296,300
90 < MVA <= 300, Medium Starting Requirement	2 x CCGT	\$22,564,862	\$296,300
90 < MVA <= 300, Large Starting Requirement	2 x CCGT	\$22,564,862	\$296,300
300 < MVA, Large Starting Requirement	2 x CCGT	\$27,186,123	\$296,300

Hydroelectric Resources:

10 < MVA <= 60	Multi-unit Plant	\$2,295,886	\$292,700
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60 < MVA <= 90	Multi-unit Plant	\$2,295,886	\$292,700
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Table 4a - Blackstart Capital Recovery Factors

Designated Blackstart Resource Age	Recovery Period (years)	Capital Recovery Factor
$X \leq 5$ years	25	0.1103
$5 < X \leq 10$ years	20	0.1199
$10 < X \leq 15$ years	15	0.1371
15 years < X	10	0.1626

Table 4b - Weighted Average Cost of Capital

Weighted Average Cost of Capital	10.01%	
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Table 5 - Designated Blackstart Resource Classes

Designated Blackstart Resource Type	Proxy Generating Units
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Fossil Resources:

MVA <= 10	Diesels (Wartsila)
10 < MVA <= 60	LM2500
60 < MVA <= 90	LM6000
90 < MVA <= 300 Small Starting Requirement Simple Cycle	LMS100
90 < MVA <= 300 Small Starting Requirement Combined Cycle	GE 7EA
90 < MVA <= 300 Medium Starting Requirement	Siemens 501F
90 < MVA <= 300 Large Starting Requirement	GE 7FA
300 < MVA Large Starting Requirement	GE HA.02

Hydro Resources:

10 < MVA <= 60	LM2500
60 < MVA <= 90	LM6000

Table 6 - Reserved

**Table 7 - Non-Designated Blackstart Resource
Study Payment**

Non-Designated Blackstart Resource Study Payment (\$)	\$115,560
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SCHEDULE 17
RECOVERY OF CRITICAL INFRASTRUCTURE PROTECTION COSTS
BY FACILITIES CRITICAL TO THE DERIVATION OF INTERCONNECTION RELIABILITY
OPERATING LIMITS

Introduction

NERC Reliability Standard CIP-002-5.1a – Cyber Security – BES Cyber System Categorization (“CIP-002-5.1”) requires the identification, assessment and categorization of facilities that NERC defines as Bulk Electric System (“BES”) Cyber Systems and associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that their loss, compromise, or misuse could have on the reliable operation of the BES. Criterion 2.6 in Attachment 1 – Impact Rating Criteria to CIP-002-5.1 assigns a medium impact rating to generation and transmission facilities that the ISO identifies as critical to the derivation of Interconnection Reliability Operating Limits and their associated contingencies (“IROL-Critical Facilities”). In accordance with CIP-002-5.1, an owner of an IROL-Critical Facility (“IROL-Critical Facility Owner”) must comply with the controls included in the NERC CIP Reliability Standards corresponding to the medium impact category.

This Schedule 17 provides for the recovery of an IROL-Critical Facility Owner’s incremental capital, operation and maintenance, and associated administrative and regulatory costs paid to comply with the NERC CIP Reliability Standards corresponding to the medium impact category (collectively, “IROL-CIP Costs”), as approved by the Commission’s acceptance of the IROL-Critical Facility Owner’s filing pursuant to Section 205 of the Federal Power Act, at one or more IROL-Critical Facilities to the extent cost recovery for the IROL-CIP Costs is not provided for under another provision of the Tariff or a contractual arrangement to which the IROL-Critical Facility Owner is a party. Eligible IROL-CIP Costs are above and beyond the costs paid by the IROL-Critical Facility Owner to comply with NERC CIP Reliability Standards corresponding to low impact requirements. Nothing in this Schedule 17 shall restrict or limit the rights of an IROL-Critical Facility Owner to make a filing with the Commission

pursuant to Section 205 of the Federal Power Act to recover IROL-CIP Costs through a means other than this Schedule 17.

Under this Schedule 17, the ISO will act as the billing and collection agent on behalf of the IROL-Critical Facility Owners for recovery of their Commission-approved IROL-CIP Costs. The ISO will allocate to, invoice, and collect from Transmission Customers that receive Regional Network Service and/or Through or Out Service IROL-CIP Costs approved by the Commission and, upon collection of such costs, will pay equivalent amounts to the pertinent IROL-Critical Facility Owner(s), in the manner specified in this Schedule 17.

1. IROL-Critical Facility Designation and Notification

The ISO shall designate a generation facility or transmission facility as an IROL-Critical Facility in accordance with applicable NERC Reliability Standards. When the ISO identifies a generator or transmission facility as IROL-Critical, the ISO shall provide written notification of the designation to the IROL-Critical Facility Owner or its Lead Market Participant, as applicable. The notice shall specify: (a) the facility by name and asset identification if applicable, and (b) the effective date for the IROL-Critical Facility designation.

The ISO reviews IROL-Critical Facility designations annually or more frequently based on New England Transmission System changes. If, based on this review, the ISO determines that an IROL-Critical Facility no longer meets applicable NERC criteria for designation as an IROL-Critical Facility, the ISO shall provide written notice to the IROL-Critical Facility Owner or its Lead Market Participant, as applicable, of the effective date of such termination.

2. Requirements for Recovery of IROL-CIP Costs

2.1 Pre-Filing Obligations of an IROL-Critical Facility Owner

To recover IROL-CIP Costs under this Schedule 17, in accordance with Section 2.2 below, an IROL-Critical Facility Owner must submit a filing to the Commission pursuant to Section 205 of the Federal Power Act requesting approval of IROL-CIP Costs proposed to be recovered. An IROL-Critical Facility Owner that intends to make a Section 205 filing for the recovery of IROL-CIP Costs pursuant to this Schedule 17 shall comply with the following pre-filing requirements:

(A) Prior to submitting a Section 205 filing for recovery of IROL-CIP Costs, the IROL-Critical Facility Owner shall provide to the ISO a summary description of the proposed filing, including the incremental medium impact IROL-CIP Costs and the supporting data, calculations, and workpapers for those costs, with any confidential or proprietary information redacted, and contact information for the IROL-Critical Facility Owner. The ISO shall post on its website all materials provided to the ISO by the IROL-Critical Facility Owner. To receive automated notification of the ISO's postings of the materials provided by the IROL-Critical Facility Owner, entities may self-subscribe to the ISO's Schedule 17 distribution list. Any entity that wishes to participate as an interested party ("Interested Party") in the pre-filing review process described in Sections 2.1(B) and (C) below shall contact the IROL-Critical Facility Owner to request Interested Party status by no later than the tenth day following the interactive session described in Section 2.1(B) below.

(B) No sooner than fifteen (15) days following the ISO's posting of the materials provided by the IROL-Critical Facility Owner on the ISO website, the IROL-Critical Facility Owner shall host, either in-person or on-line, an interactive briefing session to review the summary materials and examine the IROL-CIP Costs proposed for recovery.

(C) Following the interactive briefing session described in Section 2.1(B) above, the IROL-Critical Facility Owner shall provide an additional sixty (60) days for: (i) Interested Parties to raise issues and/or request further information from the IROL-Critical Facility Owner, and (ii) the IROL-Critical Facility Owner to provide the requested information and seek to address any issues presented by Interested Parties. An IROL-Critical Facility Owner may extend the 60-day period at its discretion. The IROL-Critical Facility Owner shall be free to submit its Section 205 filing for recovery of IROL-CIP Costs under this Schedule 17 no sooner than the earlier of: (i) the conclusion of the 60-day period, (ii) the

eleventh day following the interactive briefing session described in Section 2.1(B) above, if no entity contacted the IROL-Critical Facility Owner seeking to participate in the pre-filing review process as an Interested Party, or (iii) the date by which all Interested Parties, as identified by the tenth day following the interactive session in accordance with Section 2.1(A) above, have informed the IROL-Critical Facility Owner that they no longer desire additional pre-filing time to review the IROL-Critical Facility Owner's IROL-CIP Cost information. The IROL-Critical Facility Owner shall provide notice of its Section 205 filing to Interested Parties.

2.2 IROL-Critical Facility Owner's Section 205 Rate Filing

(A) IROL-CIP Costs, including capital, operation and maintenance, and associated administrative and regulatory costs, are recoverable only to the extent they (i) are incurred by the IROL-Critical Facility Owner during the period in which the subject facility is designated as an IROL-Critical Facility; (ii) are paid by the IROL-Critical Facility Owner during the cost recovery period specified by the IROL-Critical Facility Owner in the Table 1 provided in Attachment to this Schedule 17; (iii) are presented by the IROL-Critical Facility Owner in a Section 205 filing and approved by the Commission; and (iv) satisfy all other conditions for recovery, as set forth in this Schedule 17. It is the responsibility of the IROL-Critical Facility Owner to notify the ISO of the Commission's approval of its filings to recover IROL-CIP Costs under this Schedule 17.

(B) Information supporting IROL-CIP Costs proposed for recovery under this Schedule 17 shall conform to the data requirements set forth in the Table 1 provided in Attachment A to this Schedule 17, including identification of the specific IROL-Critical Facility associated with the claimed IROL-CIP Costs; categorization of costs by function and subject matter; and specification of the cost recovery period in which the costs were paid. The IROL-Critical Facility Owner bears all responsibility for supporting claimed IROL-CIP Costs, for satisfying the requirements of Section 205, and for demonstrating eligibility for recovery under this Schedule 17.

(C) An IROL-Critical Facility Owner may submit a Section 205 filing to recover IROL-CIP Costs under this Schedule 17 no more frequently than once every twelve (12) months. However, the

time-period for which IROL-CIP Costs are claimed (and reflected in such Section 205 filings) is not limited to twelve (12) months.

3. Invoicing and Collection of IROL-CIP Costs by ISO

The ISO acts as the billing and collection agent on behalf of the IROL-Critical Facility Owner for recovery of IROL-CIP Costs approved by the Commission's acceptance of the IROL-Critical Facility Owner's filing pursuant to Section 205 of the Federal Power Act. Upon notification from the IROL-Critical Facility Owner that a Commission Order approving IROL-CIP Costs for recovery under this Schedule 17 has been issued, the ISO shall initiate payment of such costs to the IROL-Critical Facility Owners, and allocation and invoicing of such costs to Transmission Customers in the manner set forth in Sections 3.1 and 3.2 below.

3.1 Monthly Payment to IROL-Critical Facility Owner

The ISO shall remit Commission-approved IROL-CIP Costs collected by the ISO in monthly payments of equal amounts over twelve (12) consecutive months to the applicable Market Participants based on their respective ownership shares in an associated IROL-Critical Facility. The ISO shall commence monthly payment of IROL-CIP Costs in the Monthly Statement issued for the first month immediately following the ISO's receipt of the IROL-Critical Facility Owner's notification of the Commission Order approving IROL-CIP Costs for recovery.

3.2 IROL-CIP Charges

The ISO shall invoice the total of Commission-approved IROL-CIP Cost in a given month to Transmission Customers receiving Regional Network Service or Through or Out Service on a monthly basis. Each Transmission Customer shall pay a charge for IROL-CIP Costs ("IROL-CIP Charge") in each month, which charge shall be calculated using the following formula:

$$IROL-CIP Charge_{month} = CIP_{month} \times \frac{[MRNL_{month,c} + AVETOUT_{month,c}]}{[\sum_{c=1}^{customers} MRNL_{month,c} + \sum_{c=1}^{customers} AVETOUT_{month,c}]}$$

Where:

CIP_{month} = Total IROL-CIP Costs_m payments made to IROL-Critical Facility Owners in month *m*.

$MRNL_{month,c}$ = Regional Network Load in the month for customer *c*

$AVETOUT_{month,c}$ = Average across the hours in the month of Reserved Capacity for Through or Out Service (excluding any Coordinated External Transaction Reserved Capacity for Through or Out Service) for customer *c*

ATTACHMENT A TO SCHEDULE 17

Table 1 - Incremental CIP Compliance Costs for a Facility Designated as IROL-Critical

Required Information

General Information

Facility Name	
Asset ID	
Date of IROL-Critical Designation (mm/yyyy)	
Summer Claimed Capability (MW)	
Winter Claimed Capability (MW)	
Original In-Service Date	
Interconnection Voltage	
Primary Fuel	
Dual Fuel Capable? (y/n)	
Facility includes External Routable Connectivity (y/n)	
Part of a Multi-unit Station? (y/n)	
If yes, number of units at the station	

Cost Recovery Period during which CIP Costs were Paid

Starting Date of Cost Recovery Period	
Ending Date of Cost Recovery Period	

Actual Paid Incremental Costs for the Specified Period

	Total Incremental CIP Compliance Costs for IROL- Critical Facility
Labor	\$ -
Equipment & Hardware	\$ -
Software/Application Licenses, Maintenance and Support, and Upgrade Costs	\$ -
Outside Services and Fees	\$ -
Physical Improvements	\$ -
Production, Printing, and Shipping Costs	\$ -
Other, including Associated Administrative and Regulatory Costs	\$ -
Total Actual Paid Incremental Costs for the Specified Period	\$ -

SCHEDULE 18 - MTF; MTF SERVICE

This Schedule 18 contains the main substantive provisions regarding the treatment of MTF and MTF Service under the OATT.

1. Definitions

Capitalized terms used and defined in this Schedule 18 shall have the meaning given them under this Schedule. Capitalized terms used and not defined in this Schedule 18 but defined in other provisions of the Tariff shall have the meaning given them under those provisions. Capitalized terms used in this Schedule 18 that are not defined in it or elsewhere in the Tariff shall have the meanings customarily attributed to such terms by the electric utility industry in New England.

1.1 MTF: The Cross Sound Cable high voltage, direct current Merchant Transmission Facilities of +/- 150 kV and associated dc/ac converter facilities that are directly interconnected with the 345 kV PTF in Connecticut at the East Shore substation, and the 138kV transmission facilities at the Shoreham substation on Long Island, New York that were subject to the Commission order in TransEnergie U.S., Ltd., 91 FERC 61,230 (2000) (Docket No. ER00-1-000).

1.2 MTF Provider: The owner of MTF, or its Designated Agent, that offers transmission service over the MTF to Eligible Customers through the MTF Transmission Provider Page on the OASIS.

1.3 MTF Service: Point-To-Point Transmission Service over MTF.

1.4 MTF Service Charge: The charge applicable to MTF Service, which shall be determined pursuant to arrangements between the MTF Provider and Eligible Customers that take MTF Service under this Schedule 18. The charge applicable to MTF Service shall be in accordance with the Commission's authorization for the MTF Provider to charge negotiated rates (i.e., rates established pursuant to market mechanisms as recognized for merchant transmission projects and not included in other OATT rates) for the use of transmission service over its MTF.

1.5 MTF Transmission Provider Page: The transmission provider page for the MTF located on the OASIS. Transmission Service over the MTF to Eligible Customers will be offered through the MTF Transmission Provider Page. Some of the information posted on the MTF Transmission Provider Page shall include: values for Available Transfer Capability (ATC); offerings for MTF Service (including

Firm, Non-Firm and secondary transmission rights); the parameters and results of the Commission-mandated open-season process used to initially allocate transmission rights; a description of the Commission-approved rights allocation process; and procedures for the application for and acquisition of MTF Service.

2. Allocation of Available Transfer Capability Over MTF

2.1 Commission-Approved Allocation Process: All available transfer capability over MTF shall be allocated to the owner of the MTF who may assign it under a Commission-approved rights allocation process. The MTF Provider shall post the results of the Commission-approved rights allocation process on the MTF Transmission Provider Page. To the extent that transfer capability over MTF is not fully reserved through the Commission-approved rights allocation process, such excess transfer capability shall be available in accordance with this Schedule 18. In the event that the entire capability of the MTF is reserved under the Commission-approved rights allocation process, secondary rights to use the MTF, to the extent unused by the primary rights holders, shall be offered on the MTF Transmission Provider Page on the OASIS by MTF Providers in accordance with a Commission-approved process for offering such rights.

3. MTF Service

3.1 Nature of MTF Service

(a) Term of MTF Service:

- (i) Firm MTF Service:** The minimum term of Firm MTF Service shall be one day and the maximum term shall be that specified in the MTF Transmission Service Agreement.
- (ii) Non-firm MTF Service:** Non-Firm MTF Service will be available for periods ranging from one hour to one month and shall be that specified in the MTF Transmission Service Agreement. However, a Transmission Customer who purchases Non-Firm MTF Service will be entitled to reserve a sequential term of service (such as a sequential monthly term without having to wait for the initial term to expire before requesting another monthly term) so that the total time period for which the reservation applies may be greater than one month, subject to the requirements of this Schedule 18.

(b) Reservation, Interruption, and Curtailment Priority for MTF Service:

- (i)** The MTF Provider shall post on the MTF Transmission Provider Page, rules setting reservation, interruption and Curtailment priorities for Firm and Non-Firm MTF Service. Such rules shall be non-discriminatory and consistent with the Commission's approval of the rights to charge negotiated rates (i.e., rates established pursuant to market mechanisms as recognized for merchant transmission projects and not included in other OATT rates).
- (ii)** If an MTF Provider fails to post such rules, then reservation, interruption and Curtailment priorities for Firm and Non-Firm MTF Service shall be the same as those established under the OATT for transmission service over the PTF.
- (iii)** MTF reservation priorities shall be established separately from OTF or PTF reservation priorities.
- (iv)** Firm MTF Service: The MTF reservation priority for either Long-Term Firm MTF Service or Short-Term Firm MTF Service (which are based upon an award of rights to transmission service over the MTF pursuant to a Commission-approved rights allocation process) shall be determined by the date of the issuance of such award.
- (v)** Non-Firm MTF Service: Non-Firm MTF Service shall be available from transfer capability in excess of that needed for reliable service to Long-Term and Short-Term Firm MTF Service. A higher reservation priority will be assigned to Non-Firm MTF Service reservations with a longer duration of service than those reservations with a shorter duration. Competing requests of equal duration for Non-Firm MTF Service will be prioritized based on the highest price offered by the Eligible Customer for the transmission service, or in the event the price for all Eligible Customers is the same, will be prioritized on a first-come, first-served basis (i.e., in the chronological sequence in which each Transmission Customer has reserved service). Eligible Customers that have already reserved shorter-term service over MTF have the right of first refusal to match any longer-term request before being preempted, provided that such Eligible Customer's advance reservation is consistent with any modified request for Non-Firm MTF Service.

- (c) **Use of MTF Service By a Transmission Customer:** If a Transmission Customer elects to take MTF Service, it may reserve transmission service to facilitate both the delivery of energy and/or capacity to it over the MTF (to the extent permitted under the Transmission, Markets and Services Tariff) commensurate with the associated MTF transmission reservation designated by it in Completed Applications and the delivery of Energy and/or capacity to or from it over the MTF to the extent permitted under the Transmission, Markets and Services Tariff. In order to fulfill its obligations to serve load or to consummate a transaction, a Transmission Customer that takes MTF Service under this Schedule 18 must also take service under Schedule 8 or 9 of this OATT for use of the PTF and under Schedule 21 of this OATT for use of the Non-PTF, as applicable. Any load-serving entity may use MTF Service to effect transactions in bilateral arrangements.
- (d) **MTF Transmission Service Agreements:** A standard form MTF Transmission Service Agreement (Attachment A) will be offered to an Eligible Customer when it submits a Completed Application for Long-Term Firm, Short-Term Firm or Non-Firm MTF Service pursuant to this Schedule 18. Executed MTF Transmission Service Agreements that contain the information required under this Schedule 18 will be filed with the Commission in compliance with applicable Commission regulations.
- (e) **Classification of MTF Service:**
- (i) Transmission Customers requesting MTF Service for the transmission of capacity and energy do so with the full realization that such service is subject to availability and Curtailment pursuant to Section II.44 of this OATT and that the ISO will redispatch all Resources subject to its control, pursuant to the Transmission, Markets and Services Tariff, in order to meet load and to accommodate External Transactions. Transmission Customers will be charged for the Congestion Costs and any other costs associated with such redispatch in accordance with the Transmission, Markets and Services Tariff.
- (ii) Each Point of Receipt at which firm transmission capacity is reserved for Long-Term Firm MTF Service by the Transmission Customer shall be set forth in the MTF Transmission Service Agreement for such Service along with a corresponding capacity reservation over the MTF associated with each Point of Receipt.

- (iii) Points of Receipt and corresponding capacity reservations shall be as mutually agreed upon by the MTF Provider and the Transmission Customer for Short-Term Firm MTF Service. Each Point of Delivery at which firm transmission capacity is reserved for Short-Term Firm MTF Service by the Transmission Customer shall be set forth in the MTF Transmission Service Agreement for such Service along with a corresponding capacity reservation associated with each Point of Delivery. Points of Delivery and corresponding capacity reservations shall be as mutually agreed upon by the MTF Provider and the Transmission Customer for Short-Term Firm MTF Service.
- (iv) Non-Firm MTF Service shall be offered under applicable terms and conditions contained in this Schedule 18. Non-Firm MTF Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application.
- (v) The greater of either (1) the sum of the capacity reservations at the Point(s) of Receipt, or (2) the sum of the capacity reservations at the Point(s) of Delivery shall be the Transmission Customer's Reserved Capacity over the MTF. The Customer's use may not exceed its capacity reserved over the MTF at each Point of Receipt and each Point of Delivery except as otherwise specified in this Schedule 18.
- (f) **Scheduling Associated with MTF Service:** Market External Transactions submitted into the Real-time Market and associated with MTF Service shall be dispatched pursuant to the Transmission, Markets and Services Tariff. Transmission Customers will be charged for the Congestion Costs and any other costs associated with such dispatch in accordance with the Transmission, Markets and Services Tariff.
- (g) **Curtailment Associated with MTF Service:** When the ISO determines that an electrical emergency exists on the New England Transmission System and implements emergency procedures to effect a Curtailment of MTF Service, the Transmission Customer shall make the required reductions upon the ISO's request. The ISO reserves the right to effect a Curtailment, as necessary, in whole or in part, of any MTF Service provided under this Schedule 18 when, in the ISO's sole discretion, an emergency or other unforeseen

condition impairs or degrades the reliability of the New England Transmission System. The ISO will notify all affected Transmission Customers in a timely manner of any Curtailments. The ISO will redispatch all Resources subject to its control, pursuant to this Tariff, in order to meet load and to accommodate External Transactions. To the extent not otherwise provided for in this Section, External Transactions using MTF Service shall be Curtailed or interrupted in accordance with Section II.44 of this OATT. Transmission Customers will be charged for the Congestion Costs and any other costs associated with such redispatch in accordance with the Transmission, Markets and Services Tariff. Pursuant to such redispatch, in the event that the ISO exercises its right to effect a Curtailment, in whole or part, of Firm MTF Service, no credit or other adjustment shall be provided as a result of the Curtailment with respect to the charge payable by the Transmission Customer, unless provided for by the MTF Provider under arrangements between the MTF Provider and the Transmission Customer.

3.2 Availability of MTF Service: To the extent that transfer capability over MTF has not been fully allocated in accordance with Section 2 of this Schedule 18, a Transmission Customer that is an Eligible Customer (except as provided below) may reserve Firm or Non-Firm MTF Service. Such service shall be provided and administered by the MTF Provider(s) and shall be reserved pursuant to the applicable terms and conditions of this Schedule 18. MTF Service shall be reserved through the MTF Provider pursuant to this Schedule 18. Service on the MTF requires advance reservations.

MTF Service is available to any Eligible Customer unless an MTF Provider has informed the ISO that MTF Service shall not be made available to such Eligible Customer due to that Customer's failure to make necessary payments for previously assessed MTF Service Charges or failure to meet the creditworthiness or operational requirements posted by the MTF Provider on the MTF Transmission Provider Page on the OASIS.

3.3 Reservation of MTF Service: An Eligible Customer requesting Firm or Non-Firm MTF Service shall comply with the applicable provisions of this Schedule 18.

4. Transmission Customer Responsibilities

4.1 Conditions Required of Transmission Customers: MTF Service will be provided by the MTF Provider only if the following conditions are satisfied by the Transmission Customer. Conditions (a) through (e) apply to both Firm or Non-Firm MTF Service while (f) applies to Firm MTF Service only.

- (a) The Transmission Customer has pending a Completed Application for service;
- (b) The Transmission Customer meets the creditworthiness criteria set forth in the information posted by the MTF Provider on the MTF Transmission Provider Page on the OASIS.
- (c) The Transmission Customer and the MTF Provider have executed a MTF Transmission Service Agreement pursuant to this Schedule 18;
- (d) The Transmission Customer agrees to have arrangements in place for any other transmission service necessary to effect the delivery from the generating source to the Point of Receipt prior to the time service under this OATT commences;
- (e) The Transmission Customer agrees to submit External Transactions into the New England Markets in accordance with the applicable ISO System Rules; and
- (f) The Transmission Customer agrees to pay for any facilities or upgrades constructed or any Congestion Costs or other redispatch costs chargeable to such Transmission Customer under this Schedule 18, and the Transmission, Markets and Services Tariff, whether or not the Transmission Customer takes service for the full term of its MTF reservation.

4.2 Transmission Customer Responsibility for Third-Party Arrangements: Any arrangements for transmission service and the scheduling of capacity and energy that may be required by neighboring electric systems shall be the responsibility of the Transmission Customer requesting service. The Transmission Customer shall provide, unless waived by the ISO, notification to the ISO identifying such neighboring electric systems and authorizing them to schedule the capacity and energy to be transmitted pursuant to this OATT on behalf of the Receiving Party at the Point of Delivery or the Delivering Party at the Point of Receipt. The Transmission Customer shall arrange for transmission service, as necessary, in accordance with this OATT, including Schedules 8, 9, 20 and 21. The ISO will undertake reasonable

efforts to assist the Transmission Customer in making such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

5. Procedures for Arranging Firm MTF Service

5.1 Application: Eligible Customers seeking MTF Service must submit a Completed Application for MTF Service to the MTF Provider. MTF Service Applications should be submitted by entering the information listed below in the MTF Transmission Provider Pages on the OASIS. MTF Service requests should be submitted by transmitting the Completed Application in accordance with the MTF Transmission Provider's rules, as posted on the MTF Transmission Provider Page on the OASIS.

5.2 Request for Firm MTF Service

- (a) Timing:** A request for Firm MTF Service for periods of one (1) year or longer must be made in an Application, delivered to the MTF Provider at their place of business. The request should be delivered at least sixty (60) days in advance of the calendar month in which service is requested to commence. The MTF Provider will consider requests for such Firm MTF Service on shorter notice when practicable. Requests for Firm MTF Service for periods of less than one (1) year will be subject to expedited procedures that will be negotiated between the MTF Provider and the party requesting service within the time constraints provided in this Schedule 18.
- (b) Completed Application:** A Completed Application for Firm Point-To-Point Service shall provide all of the information included at 18 C.F.R. § 2.20 of the Commission's regulations, including but not limited to the following:

 - (i)** The identity, address, telephone number and facsimile number of the entity requesting service;
 - (ii)** A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under this Schedule 18;
 - (iii)** The location of the Point(s) of Receipt and Point(s) of Delivery and the identities of the Delivering Parties and the Receiving Parties;

- (iv) An estimate of the capacity and energy expected to be delivered to the Receiving Party;
- (v) The Service Commencement Date and the term of the requested MTF transmission service; and
- (vi) The transmission capacity requested for each Point of Receipt and each Point of Delivery on the PTF, MTF or OTF. Customers may combine their requests for service in order to satisfy the minimum transmission capacity requirement.
- (vii) In addition to the information specified above and when required to properly evaluate the application for service, the MTF Provider also may request that the eligible Customer provider the following:
 - The location of the generating facility(ies) supplying the capacity and energy, and the location of the load ultimately served by the capacity and energy transmitted. The MTF Provider will treat this information as confidential in accordance with the MTF Provider's information policy except to the extent that disclosure of such information is required by this Schedule 18, by regulatory or judicial order, or for reliability purposes pursuant to Good Utility Practice; and
 - A description of the supply characteristics of the capacity and energy to be delivered.

The MTF Provider will treat this information in (vii) as confidential at the request of the Transmission Customer except to the extent that disclosure of this information is required by the MTF Transmission Service Agreement, MTF Provider's Business Practices, by regulatory or judicial order, or for reliability purposes pursuant to Good Utility Practice. The MTF Provider will treat this information consistent with the standards of conduct contained in 18 C.F.R. Part 37 of the Commission's regulations.

5.3 Request for Non-Firm MTF Service

- (a) **Timing:** When required, requests for monthly service shall be submitted no earlier than sixty (60) days before service is to commence; requests for weekly service shall be submitted no earlier than fourteen (14) days before service is to commence; requests for daily service shall be submitted no earlier than five (5) days before service is to

commence; and requests for hourly service shall be submitted no earlier than 9:00 a.m. the second day before service is to commence. Requests for service received later than noon of the day prior to the day service is scheduled to commence will be accommodated if practicable.

(b) Completed Application: A Completed Application for MTF Service shall provide all of the information included in 18 C.F.R. §2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under this Schedule 18;

(iii) The Point(s) of Receipt and the Point(s) of Delivery;

(iv) The maximum amount of capacity requested at each Point of Receipt and Point of Delivery; and

(v) The proposed dates and hours for initiating and terminating transmission service hereunder.

(vi) In addition to the information specified above, when required to properly evaluate the application for service, the MTF Provider also may ask the Transmission Customer to provide the following:

- The electrical location of the initial source of the power to be transmitted pursuant to the Transmission Customer's request for service; and
- The electrical location of the ultimate load.

The MTF Provider will treat this information in (vi.) as confidential at the request of the Transmission Customer except to the extent that disclosure of this information is required by the MTO pursuant to this Schedule 18, by regulatory or judicial order, or for reliability purposes pursuant to Good Utility Practice.

The MTF Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

5.4 Deposit: If required by the MTF Provider, a Completed Application for MTF Service by a Transmission Customer shall also include a deposit of no more than (a) one (1) month's charge for Reserved Capacity over the MTF for service requests of one (1) month or greater or (b) the full charge for Reserved Capacity over the MTF for service requests of less than one (1) month. If the Application for MTF Service is rejected by the MTF Provider because it does not meet the conditions for service as set forth herein, or in the case of requests for service arising in connection with losing bidders in a request for proposals (RFP), the deposit will be returned with Interest, less any reasonable administrative costs incurred by the MTF Provider, the ISO or any affected Transmission Owners in connection with the review of the Application for MTF Service. The deposit also will be returned with Interest, less any reasonable administrative costs incurred by the MTF Provider, the ISO or any affected Transmission Owners if the new facilities or upgrades needed to provide the service cannot be completed. If an Application for MTF Service is withdrawn or the Eligible Customer decides not to enter into a MTF Transmission Service Agreement, the deposit will be refunded in full, with Interest, less reasonable administrative costs incurred by the MTF Provider, the ISO or any affected Transmission Owners to the extent such costs have not already been recovered from the Eligible Customer. The MTF Provider will provide to the Eligible Customer a complete accounting of all costs deducted from the refunded deposit, which the Eligible Customer may contest if there is a dispute concerning the deducted costs. Deposits associated with construction of new facilities or upgrades are subject to the provisions of this OATT. If a MTF Transmission Service Agreement for MTF Service is executed, the deposit, with Interest, will be returned to the Transmission Customer upon expiration or termination of the MTF Transmission Service Agreement. Applicable Interest will be calculated from the day the deposit is credited to the MTF Provider's account.

5.5 Notice of Deficient Application: If an Application for MTF Service fails to meet the requirements of this Schedule 18, the MTF Provider will notify the entity requesting service within fifteen (15) days of the MTF Provider's receipt of the Application for MTF Service of the reasons for such failure. The MTF Provider will attempt to remedy minor deficiencies in the Application for MTF Service through informal communications with the Eligible Customer. If such efforts are unsuccessful, the MTF Provider will return the Application for MTF Service, along with any deposit (less the reasonable administrative costs incurred by the MTF Provider, the ISO or any affected Transmission Owners in connection with the Application for MTF Service), with Interest. Upon receipt of a new or revised

Application for MTF Service that fully complies with the requirements of this Schedule 18, the Eligible Customer will be assigned a new reservation priority based upon the date of receipt by the MTF Provider of the new or revised Application for MTF Service.

5.6 Response to a Completed Application: Following receipt of a Completed Application the Eligible Customer will be notified as soon as practicable, but not later than thirty (30) days after the date of receipt of a Completed Application for MTF Service. Responses by the MTF Provider must be made as soon as practicable to all Completed Applications for MTF Service and the timing of such responses must be made on a nondiscriminatory basis.

5.7 Execution of MTF Transmission Service Agreement: Whenever the MTF Provider determines that a System Impact Study is not required and that the requested service can be provided, it will notify the Eligible Customer as soon as practicable but no later than thirty (30) days after receipt of the Completed Application for MTF Service, and will tender a MTF Transmission Service Agreement to the Eligible Customer. Failure of an Eligible Customer to execute and return the MTF Transmission Service Agreement or request the filing of an unexecuted MTF Transmission Service Agreement, within fifteen (15) days after it is tendered by the MTF Provider shall be deemed a withdrawal and termination of the Application for MTF Service and any deposit (less the reasonable administrative costs incurred by the MTF Provider, the ISO and any affected Transmission Owners in connection with the Application for MTF Service) submitted will be refunded with Interest. Nothing herein limits the right of an Eligible Customer to file another Application for MTF Service after such withdrawal and termination. Where a System Impact Study is required, the provisions of this Schedule 18 will govern the execution of a MTF Transmission Service Agreement.

(a) Extensions for Commencement of Firm MTF Service: The Transmission Customer can obtain, subject to availability, up to five one-year extensions for the commencement of service. The Transmission Customer may postpone service by paying a non-refundable annual reservation fee equal to one-month's charge for Firm MTF Service for each year or fraction thereof within 15 days of notifying the MTF Provider that it intends to extend the commencement of service. If during any extension for the commencement of service an Eligible Customer submits a Completed Application for Firm MTF Service, and such request can be satisfied only by releasing all or part of the Transmission Customer's Reserved Capacity over the MTF, the original Reserved Capacity over the MTF will be released unless the following condition is satisfied: within thirty (30) days, the original Transmission Customer agrees to pay the applicable

rate for Firm MTF Service for its Reserved Capacity over the MTF for the period that its reservation overlaps the period covered by such Eligible Customer's Completed Application for MTF Service. In the event the Transmission Customer elects to release the Reserved Capacity over the MTF, the reservation fees or portions thereof previously paid will be forfeited.

5.8 Confidentiality of Information and Standards of Conduct. The MTF Provider will treat all information included in the Application as confidential in accordance with the MTF Provider's information policy except to the extent that disclosure of such information is required by this Schedule 18, by regulatory or judicial order, or for reliability purposes pursuant to Good Utility Practice. The MTF Provider will treat this information consistent with the standards of conduct contained in 18 C.F.R. Part 37 of the Commission's regulations.

6. Determination of Available Transfer Capability

Following approval of a tendered application for MTF Service, the MTF Provider will make a determination on a non-discriminatory basis of Available Transfer Capability pursuant to this Schedule 18 and Attachment C to this OATT. Such determination shall be made as soon as reasonably practicable after receipt, but not later than the following time periods for the following terms of service (i) thirty-five (35) minutes for hourly service, (ii) thirty-five (35) minutes for daily service, (iii) four (4) hours for weekly service, and (iv) two (2) days for monthly service.

7. Payment for MTF Service

A Transmission Customer shall pay the MTF Service Charge to the MTF Provider, or its designated agent, if the Customer: (i) receives Firm or Non-Firm MTF Service based upon an allocation of rights to transmission service over the MTF awarded to the Transmission Customer through a Commission-approved rights allocation process; (ii) reserves on the MTF Transmission Provider Page transfer capability over the MTF not initially allocated in the Commission-approved rights allocation process; or (iii) reserves on the MTF Transmission Provider Page transfer capability over the MTF made available as a result of an assignment by a rights holder of MTF transfer capability, a default release pursuant to rules filed with the Commission and business practices or a capability forfeiture by a rights holder for non-use consistent with the terms of a Commission-approved rights allocation. The Transmission Customer will be billed for its Reserved Capacity over the MTF under the terms of this Schedule 18 for MTF.

8. Changes in Service Specifications of MTF Service

8.1 Modification on a Firm Basis: Any request by a Transmission Customer to modify Point(s) of Receipt and Point(s) of Delivery on a firm basis shall be treated as a new request for MTF Service in accordance with this Schedule 18, except that such Transmission Customer shall not be obligated to pay any additional deposit if the capacity reservation over the MTF does not exceed the amount reserved in the existing MTF Transmission Service Agreement. While such new request is pending, the Transmission Customer shall retain its reservation priority for service at the firm Point(s) of Receipt and Point(s) of Delivery specified in the Transmission Customer's MTF Transmission Service Agreement.

8.2 Modifications on a Non-Firm Basis: The Transmission Customer taking Firm MTF Service may submit a request to the MTF Provider for transmission service on a non-firm basis over Point(s) of Receipt and Point(s) of Delivery other than those specified in the MTF Transmission Service Agreement ("Secondary Receipt and Delivery Points"), in amounts not to exceed the Transmission Customer's firm capacity reservation over the MTF, without incurring an additional Non-Firm MTF Service charge or executing a new MTF Transmission Service Agreement, subject to the following conditions:

- (a) service provided over Secondary Receipt and Delivery Points will be non-firm only, on an as-available basis, and will not displace any firm or non-firm service reserved or scheduled by Transmission Customers under this OATT or by the Transmission Customers on behalf of their Native Load Customers or Excepted Transactions;
- (b) the Transmission Customer shall retain its right to schedule Firm MTF Service at the Point(s) of Receipt and Point(s) of Delivery specified in the relevant MTF Transmission Service Agreement in the amount of the Transmission Customer's original capacity reservation over the MTF; and
- (c) service over Secondary Receipt and Delivery Points on a non-firm basis shall not require the filing of an Application for Non-Firm MTF Service under the OATT. However, all other requirements of this OATT (except as to transmission rates) shall apply to transmission service on a non-firm basis over Secondary Receipt and Delivery Points.

9. Sale, Assignment or Transfer of MTF Service

9.1 Procedures for Sale, Assignment or Transfer of Service: Pursuant to Commission-approved rules posted by the MTF Provider on the MTF Transmission Provider Pages on the OASIS, a Transmission Customer may sell, assign, or transfer all or a portion of its rights under its MTF Transmission Service Agreement, but only to another Eligible Customer (the “Assignee”). The Transmission Customer that sells, assigns or transfers its rights under its MTF Transmission Service Agreement is hereafter referred to as the “Reseller.” Compensation to the Reseller shall be at rates established by the Reseller and posted on the MTF Transmission Provider Page. The Assignee must execute a service agreement with the MTF Provider governing reassignments of transmission service prior to the date on which the reassigned service. If the Assignee does not request any change in the Point(s) of Receipt or the Point(s) of Delivery, or a change in any other term or condition set forth in the original MTF Transmission Service Agreement, the Assignee shall receive the same services as did the Reseller and the transmission priority of service for the Assignee shall be the same as that of the Reseller. A Reseller shall notify the MTF Provider as soon as possible after any sale, assignment or transfer of service occurs, but in any event, notification must be provided prior to any provision of service to the Assignee. The Assignee shall be subject to all terms and conditions of this Schedule 18. If the Assignee requests a change in service, the reservation priority of service will be determined by the MTF Provider pursuant to this Schedule 18.

9.2 Limitations on and Obligations of Assignment or Transfer of Service: If the Assignee requests a change in the Point(s) of Receipt or Point(s) of Delivery, or a change in any other specifications set forth in the original MTF Transmission Service Agreement, the MTF Provider will consent to such change subject to the provisions of this Schedule 18, provided that the change will not impair the operation and reliability of the Market Participants’ generation systems or TO’s transmission or distribution systems. The Assignee shall compensate the MTF Provider, the ISO and any affected Transmission Owner for performing any System Impact Study needed to evaluate the capability of the MTF to accommodate the proposed change and any additional costs resulting from such change. The Reseller shall remain liable for the performance of all obligations under the MTF Transmission Service Agreement, except as specifically agreed to by the MTF Provider, the Reseller and the Assignee through an amendment to the MTF Transmission Service Agreement.

9.3 Information on Assignment or Transfer of Service: All re-sales or assignments of capacity must be conducted through or otherwise posted on the MTF Transmission Provider Page on or before the date the reassigned service commences and are subject to Section 9.1 of this Schedule 18. In accordance with this

Schedule 18, Transmission Customers may also use the MTF Transmission Provider Page to post information regarding transmission capacity over the MTF available for resale.

10. Real Power Losses

Real power losses across MTF shall be allocated solely to Transmission Customers that use MTF. Such allocation for transactions across MTF shall be pursuant to the Transmission, Markets and Services Tariff.

11. No Obligation to Build

The MTF Provider status under the OATT shall not impose an obligation to build transmission facilities on the MTF Provider. The offering of MTF Service under this OATT shall not impose an obligation to build transmission facilities on the Market Participants, Transmission Owners or the ISO.

12. No Effect on Rates; No Allocation of Revenues

MTF and MTF Service shall not affect rates for service on the PTF under this OATT and MTF Providers shall not be allocated any revenues collected under this OATT for such service.

13. Ancillary Services

Ancillary Services costs associated with MTF Service shall be assessed pursuant to this Tariff.

14. Congestion Costs and FTRs

Pursuant to the Transmission, Markets and Services Tariff, Congestion Costs will not be calculated, and therefore FTRs will not be offered, between any set of points on the MTF, so long as it remains MTF. Transmission Customers taking MTF Service, however, shall be subject to applicable Congestion Costs for any use of the PTF.

SCHEDULE 18 - IMPLEMENTATION RULE
CROSS-SOUND CABLE COMPANY, LLC
PROCEDURES FOR THE REASSIGNMENT OF TRANSMISSION RIGHTS

The procedures for reassignment of CSC transmission rights are consistent with, and supplement, the provisions of the ISO-NE OATT governing the provision of MTF Service. The applicable ISO-NE OATT rules include ISO-NE OATT Schedule 18 and ISO-NE OATT Section II.44 . The following procedures will apply to the release of unused transfer capability to third parties:

1. Definitions

- (a) **“CSC”** means the Cross Sound Cable.
- (b) **“CSC LLC”** means Cross-Sound Cable Company, LLC.
- (c) **“CSC OASIS”** means the CSC node on the ISO-NE OASIS site of the CSC.
- (d) **“External Transaction”** means a transaction as defined under Market Rule 1.
- (e) **“Firm MTF Service”** means firm service held by the primary rights holder to the transmission rights over the CSC.
- (f) **“ISO-NE”** means ISO New England, Inc.
- (g) **“ISO-NE OATT”** means the ISO-NE Open Access Transmission Tariff (Section II of the ISO-NE Transmission, Markets and Services Tariff), on file with the Federal Energy Regulatory Commission, as modified and amended from time to time.
- (h) **“MTF Service”** means service over the CSC taken under Schedule 18 and other relevant portions of the ISO-NE OATT.
- (i) **“MTF Service Agreement”** refers to the service agreement contained in Attachment A to Schedule 18 in the ISO-NE OATT, as modified and amended from time to time.

- (j) **“New England OASIS”** means the OASIS site of the New England System Operator.
- (k) **“Non-Firm MTF Service”** refers to any service over the CSC that is not Firm MTF Service.
- (l) **“NYISO”** refers to the New York Independent System Operator, Inc.
- (m) **“OASIS”** means Open Access Same Time Information System.
- (n) **“Rights Holder”** refers to the entity or entities that have an executed MTF Service Agreement for Firm MTF Service.
- (o) **“System Operator”** refers to the ISO-NE or any other entity that in the future has operational control over the CSC.

2. Process for Release

The release of unused transfer capability will be facilitated through the posting of available transfer capability on the CSC OASIS site. The posting of such releases and notices of assignment shall be consistent with FERC procedures regarding OASIS postings.

3. Character of Service to be Released

Unless otherwise posted on the CSC OASIS, all releases of transfer capability will be for Non-Firm MTF Service. Such Non-Firm MTF Service may be released on a monthly, weekly, daily or hourly basis. MTF Service is unidirectional (i.e. scheduling from New Haven to Shoreham as an export transaction from New England or Shoreham to New Haven as an import transaction into New England). The characteristics of Firm MTF Service and Non-Firm MTF Service are set forth in Schedule 18 of the ISO-NE OATT.

4. Assignment of Rights Holders’ MTF Service Reservation

A Rights Holder may separately assign its advance reservation for MTF Service to third parties provided that notice of such assignment is provided to CSC LLC and ISO-NE with such information then posted on the CSC OASIS. The assignment of such advance reservation may be on either a firm or non-firm basis, be in whole or in part, in segments, on a full or partial term basis, with or without recall rights or any combination thereof.

5. Transmission Customers

Market participants seeking to acquire an advance reservation over the CSC must meet the creditworthiness and financial security standards established by CSC LLC and the relevant Rights Holder and have an executed MTF Service Agreement.

6. Timing of Release

Rights Holder(s) shall notify CSC LLC and ISO-NE of the release of any transfer capability on a Monthly, Weekly, Daily and Hourly basis in accordance with the deadlines set forth below. All releases of transfer capability shall be posted on the CSC OASIS through an automated notification procedure.

- a.** *Monthly Releases:*
 - No later than 7 calendar days

- b.** *Weekly Releases:*
 - No later than 3 calendar days

- c.** *Daily Releases:*
 - No later than Noon on the day before the Operating Day.

- d.** *Hourly Release:*
 - No later than Noon on the day before the Operating Day.

The deadlines set forth above address voluntary releases of a Rights Holders' transfer capability to facilitate full access to transfer capability for third parties. Automatic release of transfer capability due to a Rights Holders' failure to schedule transmission service over the CSC is governed by and set forth below in the "Default Release" provision.

7. Award of Reservations

Releases of advance reservations for CSC transfer capability and bids for such advance reservations shall be submitted to the Transmission Provider via the CSC OASIS. The award of reservations shall be accomplished through either: (1) a public auction process conducted by the Rights Holder, with the released capability awarded to the highest bidder; or (2) the posting of released capability at a specified rate on the CSC OASIS, with the award of such capability performed on a first-come, first served basis for bidders that meet the posted rate for such capability. The rate for assignment either through a public

auction process or through a posting on the CSC OASIS shall be as determined by Section 9 of Schedule 18 of the ISO-NE OATT, and shall be posted on the CSC OASIS.

8. Effect of Advance Reservation

The issuance of an advance reservation is a prerequisite to scheduling an External Transaction in the ISO-NE Real-Time Energy Market that involves the use of the CSC. A party holding an advance reservation for Firm MTF Service or Non-Firm MTF Service and otherwise meeting the qualifications for submitting transactions under the ISO-NE OATT may submit scheduling transactions with ISO-NE that involve the submission of a bid/offer at the Shoreham node.

9. Default Release

In the event that a Rights Holder or any other holder of an advance reservation for MTF Service fails to submit a schedule for its full MTF Service reservation by Noon of the day prior to the Operating Day, the difference between all remaining advance reservations for which accepted bids/offers have been submitted to the New England energy market by advance reservation holders and the Total Transfer Capability over the CSC in the scheduling hour shall be automatically released for scheduling by third parties and posted on the CSC as Available Transfer Capability. Advance reservations for released capability under default release rules will be issued on a first-come, first-served basis through the CSC OASIS.

10. Priority of Capability Released Under the Default Release Provisions

Reservations for CSC transfer capability released due to the default release provisions shall be deemed Non-Firm MTF Service and assigned the NERC transmission service priority “2” (Hourly Non-Firm).

11. Curtailment and Interruptions of Service over MTF

Curtailment and interruptions of service over the CSC required to be initiated by the System Operator pursuant to the ISO-NE system rules or in response to conditions or constraints within the New York Control Area identified by the NYISO as requiring curtailment or interruption of service shall be based upon transmission priority. For Firm MTF Service, curtailment or interruptions within each reservation classification will be performed on a pro rata basis. Curtailment and interruptions within each reservation classification of Non-Firm MTF Service (i.e. Monthly, Weekly, Daily, Hourly) will be based upon the time stamp associated with the submission of valid bids/offers to the ISO-NE Real-Time Market.

Curtailments and interruptions of service over the CSC that relate to conditions or constraints on the Pool Transmission Facilities that may otherwise affect service over the CSC will be conducted consistent with

the priorities established in the ISO-NE Operating Procedures. The NYISO is responsible for determining the need for any curtailments and interruptions of service relating to conditions or constraints within the New York Control Area consistent with the priorities established by the NYISO's administration of its tariffs and procedures and will communicate the need for such curtailments or interruptions to the System Operator for implementation in compliance with prescribed NERC Policies.

12. Liability

The Transmission Provider and any Rights Holder releasing its advance reservation through the voluntary or default release procedures of these rules shall be held harmless with regard to any claim which may be raised by any party regarding the selection of a bid, except to the extent that such party successfully establishes that the Transmission Provider or the Rights Holder, as the case may be, has incorrectly selected the bidder as the result of gross negligence or willful misconduct.

13. Billing

A party holding advance reservation through releases in accordance with these CSC Releases shall be billed by the Transmission Provider and shall make payments to the Transmission Provider in accordance with the terms of the Service Agreements and the Transmission Provider shall simultaneously credit (on a contingent basis) all reservation charges billed the party releasing such advance reservation. If party acquiring advance reservations through releases fails to pay the reservation charges by the due date, the Transmission Provider shall reverse the credit and bill the party releasing such advance reservation for said reservation charges, plus interest, and the advance reservation shall, at the election of the releasing party, revert to the releasing party for the remaining term of the release.

SCHEDULE 18 - ATTACHMENTS

SCHEDULE 18 - ATTACHMENT A

Form of Blanket Service Agreement for MTF Service over the Cross Sound Cable

Reserved via the Cross Sound Cable Transmission Provider Page

on the ISO New England Inc. OASIS Node

- 1.0** This Service Agreement, dated as of _____, is entered into, by and between Cross-Sound Cable Company, LLC ("CSC LLC") and _____ ("Transmission Customer").
- 2.0** The Transmission Customer has been determined by CSC LLC to have a Completed Application for [Firm] [Non-Firm] MTF Transmission Service under the ISO New England Inc. ("ISO-NE")

Transmission, Markets and Services Tariff (“Tariff”) and the Cross Sound Cable Business Practices.

- 3.0** If required, the Transmission Customer has provided to CSC LLC an Application deposit in accordance with the provisions of the Tariff and the Cross Sound Cable Business Practices.

- 4.0** MTF Service under this Service Agreement shall commence on the later of (1) the requested service commencement date, or (2) the date on which construction or any Direct Assignment Facilities and/or facility additions or upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. MTF Service under this Service Agreement shall terminate on such date as is mutually agreed upon by the parties. [The Service Agreement may include a blanket agreement for non-firm MTF service.]

- 5.0** CSC LLC agrees to provide, and the Transmission Customer agrees to take and pay for, Transmission Service in accordance with the provisions of Schedule 18 of the Tariff (or its successor tariff), the Cross Sound Cable Business Practices, the Schedule 18 Implementation Rule -Cross-Sound Cable Company, LLC Procedures for the Reassignment of Transmission Rights and this Service Agreement.

- 6.0** Any notice or request made to or by either party regarding this Service Agreement shall be made to the representative of the other party as indicated below, and shall be copied to the System Operator at the address below.

CSC LLC:

Cross-Sound Cable Company, LLC
200 Donald Lynch Blvd.
Marlborough, MA 01752

Transmission Customer:

System Operator:

ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040

- 7.0** The Tariff, including Schedule 18 and the Schedule 18 Implementation Rule, is incorporated in this Service Agreement and made a part hereof, except that all financial assurance requirements, billing arrangements, payment obligations and liabilities associated with MTF Service shall be solely the responsibility of CSC LLC and the Transmission Customer under this Service Agreement.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Cross-Sound Cable Company, LLC:

By: _____
Name Title Date

Transmission Customer:

By: _____
Name Title Date

**Specifications For MTF Service over the Cross Sound Cable
Reserved via the Cross Sound Cable Transmission Provider Page
on the ISO-NE OASIS Node**

A Transmission Customer must acquire an advance reservation for Firm MTF Service or Non-Firm MTF Service. The issuance of an advance reservation is a prerequisite to scheduling an External Transaction over the Cross Sound Cable in the ISO New England Real-Time Energy Market. While not required, an advance reservation for the ISO New England Day Ahead Market is highly recommended, as absent an advance reservation the financial transaction in the Day Ahead Market will not be supported by a corresponding External Transaction in the Real-Time Energy market, thus creating significant financial risks to the transacting party. A party holding an advance reservation and otherwise meeting the qualifications for submitting transactions under the ISO New England, Inc. (“ISO-NE”) Transmission, Markets and Services Tariff (“Tariff”) may submit scheduling transactions over the Cross Sound Cable with ISO-NE up to the total MW amount of the advance reservation.

- 1.0** Term of Transaction: As specified in the Transmission Customer’s advance reservation via the Cross Sound Cable Transmission Provider Page on the ISO-NE OASIS node
- Start Date: As specified in the Transmission Customer’s advance reservation via the Cross Sound Cable Transmission Provider Page on the ISO-NE OASIS node
- Termination Date: As specified in the Transmission Customer’s advance reservation via the Cross Sound Cable Transmission Provider Page on the ISO-NE OASIS node
- 2.0** Description of capacity and energy to be transmitted by Participants including the electric Control Area in which the transaction originates: As specified in the Transmission Customer’s advance reservation via the Cross Sound Cable Transmission Provider Page on the CSC OASIS node
- 3.0** Point(s) of Receipt: Either Shoreham Substation in Brookhaven, New York, or East Shore

Substation in New Haven, Connecticut, as specified in the Transmission Customer's advance reservation via the Cross Sound Cable Transmission Provider Page on the ISO-NE OASIS node

Delivering party: The Transmission Customer

- 4.0** Point(s) of Delivery: Either Shoreham Substation in Brookhaven, New York, or East Shore Substation in New Haven, Connecticut, as specified in the Transmission Customer's advance reservation via the Cross Sound Cable Transmission Provider Page on the ISO-NE OASIS node

Receiving party: The Transmission Customer

- 5.0** Maximum amount of capacity and energy to be transmitted (Reserved Capacity): As specified in the Transmission Customer's advance reservation via the Cross Sound Cable Transmission Provider Page on the ISO-NE OASIS node

- 6.0** Designation of party(ies) or other entity(ies) subject to reciprocal transmission service obligation: Not applicable

- 7.0** Name(s) of any intervening systems providing transmission service: New York ISO or ISO-NE pursuant to their respective tariffs

- 8.0** MTF Service under this Service Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of this Tariff.)

- 8.1** MTF Transmission Charge: As specified in the Transmission Customer's advance reservation via the Cross Sound Cable Transmission Provider Page on the ISO-NE OASIS node

- 8.2** System Impact Study and/or Facilities Study Charge(s): Not applicable

- 8.3** Direct assignment expansion charge: Not applicable

SCHEDULE 18 - ATTACHMENT C

Cross-Sound Cable TTC, CBM, TRM and ATC Methodology

Version 2.0; Issued: December 22, 2010

1. Introduction

Cross-Sound Cable (“CSC”) is an HVDC Transmission Facility located between New Haven, CT and Shoreham, NY (Long Island). The CSC is owned and operated by Cross-Sound Cable Company, LLC (“CSC LLC”). CSC LLC operates as Transmission Service Provider (“TSP”) for the CSC, which is a Merchant Transmission Facility (“MTF”) within the ISO New England (“ISO-NE”) regional transmission organization (“RTO”). ISO-NE serves the New England states through reliable minute to minute operation of the New England Bulk Power System; development, oversight, and fair administration of New England’s wholesale market; and management of comprehensive bulk electric power system and wholesale markets’ planning processes. ISO-NE serves as the Balancing Authority for the New England Area (“ISO-NE Area”). The ISO-NE Area is interconnected to three neighboring Balancing Authority Areas (“BAAs”): New Brunswick System Operator Balancing Authority Area (“NBSO BAA”), New York Independent System Operator Balancing Authority Area (“NYISO BAA”), and Hydro-Quebec TransEnergie Balancing Authority Area (“HQTE BAA”). As the RTO for New England, ISO-NE performs the reliability functions related to the calculation of Total Transfer Capability (“TTC”) for all of the external interfaces between the ISO Area and its neighboring Balancing Authority Areas and for the internal interfaces between the Pool Transmission Facilities (“PTF”), Other Transmission Facilities (“OTF”) and MTF such as the CSC. As a TSP offering MTF service pursuant to Schedule 18 of the ISO-NE Tariff, CSC LLC retains the responsibility for determining and posting the Available Transfer Capability (“ATC”) of its facilities.

1.1. Scope of Document

This document addresses the following items with respect to the CSC between ISO-NE and NYISO for Schedule 18 MTF Service:

- Total Transfer Capability (TTC) methodology
- Capacity Benefit Margin (CBM) methodology
- Transmission Reliability Margin (TRM) methodology
- Available Transfer Capability (ATC) methodology

1.2. Overview of Cross-Sound Cable

The Cross-Sound Cable is a 330 MW High Voltage Direct Current Merchant Transmission Facility with associated AC/DC converter stations that are directly interconnected with the 345 kV PTF in New Haven, CT at the East Shore substation, and 138 kV transmission facilities at the Shoreham substation in Long Island, NY. Firm Transmission Service for the entire transfer capability of the CSC was awarded to Long Island Power Authority (“LIPA”) through an allocation process approved by the Federal Energy Regulatory Commission (“FERC”). To the extent that the entire capacity of this firm Existing Transmission Commitment (“ETC_F”) is unused by LIPA, secondary rights to use the MTF service is offered on an hourly non-firm basis for the remaining ATC through non-firm Existing Transmission Commitment (“ETC_{NF}”). CSC ATC is described in section 5 below.

2. CSC Total Transfer Capability (“TTC”)

The Total Transfer Capability or TTC for an interface is the best engineering estimate of the total amount of electric power that can be transferred over the interface in a reliable manner in a given time frame. ISO-NE, acting as the Transmission Operator (“TOP”), determines the TTC for the Cross-Sound Cable based on the equipment ratings and availability provided by CSC LLC and system conditions, then posts the TTC on the ISO-NE OASIS Node. Due to the controllable and bi-directional nature of CSC, it is treated as two separate and independent transmission paths for scheduling purposes. Flow from ISO-NE to NYISO is treated as Export with a maximum TTC of 330 MW delivered, while flow from NYISO to ISO-NE is treated as Import with a maximum TTC of 346 MW received. Cross-Sound Cable is operated in accordance with the requirements of TTC methodology are addressed in Sections 1 and 3 of the ISO-NE document “Attachment C Available Transfer Capability Methodology”.

3. CSC Capacity Benefit Margin (“CBM”)

The use of Capacity Benefit Margin or CBM within the ISO-NE Area is governed by the overall ISO-NE approach to capacity planning requirements. Load Serving Entities (“LSEs”) operating within the ISO Area do not utilize CBM to ensure their capacity needs are met; therefore CBM is not applicable within the New England market design. Accordingly, for the purpose of ATC calculation, CBM for the New England Control Area, including CSC, is set to zero (0). For additional information on CBM, refer to Section 4 of the ISO-NE document “Attachment C Available Transfer Capability Methodology”.

4. CSC Transmission Reliability Margin (“TRM”)

The Transmission Reliability Margin or TRM is the amount of transmission transfer capability set aside to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as the system conditions change.

ISO-NE, acting as a Transmission Operator, calculates the TRM on the CSC MTF interface by taking into account any operational uncertainties with CSC in accordance with MOD-008. Typically the operational uncertainties associated with an external HVDC facility are minimal and result in a TRM value of zero (0), as is the case for CSC.

For additional information on TRM, refer to Section 5.2.1 Calculation of TRM for the MTF and OTF of the ISO-NE document “Attachment C Available Transfer Capability Methodology”.

5. CSC Available Transfer Capability (“ATC”)

This section defines the Available Transfer Capability calculations performed for MTF service over the CSC. The general equation for calculation of ATC is derived from MOD-029 as follows:

$$ATC = TTC - ETC - CBM - TRM + \text{Postbacks} + \text{Counterflows}$$

The CBM and TRM Values have been previously discussed (CBM = 0, TRM = 0). The purpose of the ETC component of the ATC equation is for the TSP to define all elements that are reducing the amount of ATC available to market participants. Details regarding the ETC component, Postbacks and Counterflows of the ATC calculation and its impact on Firm and Non-firm ATC are described below.

5.1. Firm ATC for MTF Transmission Services

Firm Available Transfer Capability (“ATC_F”) is defined as the capability for firm transmission reservations that remains after allowing for CBM, TRM and firm existing transmission commitments. As described in Section 1.2, CSC LLC has a long term contract with LIPA for Yearly Firm Transmission Service for the entire transfer capability of the CSC.

Firm ATC is calculated using the following equation:

$$ATC_F = TTC - ETC_F - CBM - TRM + \text{Postbacks}_F + \text{Counterflows}_F$$

Where

ATC_F is the firm Available Transfer Capability for the ATC path during the period.

TTC is the Total Transfer Capability for the ATC path during the period.

ETC_F is the sum of firm Existing Transmission Commitments scheduled by LIPA in the Day Ahead Market, under contractual agreement, for the ATC path during the period.

CBM is set to 0 by ISO-NE per section 3 of this document.

TRM is set to 0 by ISO-NE per section 4 of this document.

$Postbacks_S$ is set to 0 because any changes to the ATC_F would be released as secondary market capacity resulting in a change to the ETC_{NF} value used to determine the resulting ATC_{NF} .

$Counterflows_F$ is set to 0 because Export point-to-point flow and Import point-to-point flow are treated as two independent directional paths. Since CSC calculates ATC in both directions independently, there are no Counterflows by definition.

Essentially, ATC_F is equal to zero (0) as ETC_F owned by LIPA over both directions of flow is equal to the entire TTC. The ATC_F will be equal to the TTC until LIPA schedules their actual transfers in the Day Ahead Market. At this point, any portion of the ETC_F that LIPA does not schedule will get released into the hourly market as ATC_{NF} .

5.2. Non-Firm ATC for MTF Transmission Services

Non-firm Available Transfer Capability (“ ATC_{NF} ”) is defined as the capability for non-firm transmission reservations that remain after allowing for CBM, TRM, ETC_F and non-firm Existing Transmission Commitments (“ ETC_{NF} ”) that have been Confirmed and Accepted. Although the entire TTC of the CSC is contracted to LIPA for Yearly Firm Transmission Service, any portion of the capacity that is not scheduled by LIPA in the Day-Ahead market will be released on an hourly non-firm basis. Customers may then purchase capacity in the Hourly Market, creating an ETC_{NF} contract which will in turn reduce the ATC_{NF} . Incorporating this into the determination of ATC, non-firm ATC is calculated using the following equation:

$$ATC_{NF} = TTC - ETC_F - ETC_{NF} - CBM_S - TRM_U + Postbacks_{NF} + Counterflows_{NF}$$

Where

ATC_{NF} is the non-firm Available Transfer Capability for the ATC path during the period.

TTC is the Total Transfer Capability for the ATC path during the period.

ETC_F is the sum of firm Existing Transmission Commitments scheduled by LIPA in the Day Ahead

Market, under contractual agreement, for the ATC path during the period.

ETC_{NF} is the sum of non-firm Existing Transmission Commitments purchased by Secondary Market

Customers in the Hourly Market, for the ATC path during the period.

CBM is set to 0 by ISO-NE per section 3 of this document.

TRM is set to 0 by ISO-NE per section 4 of this document.

$Postbacks_{NF}$ is set to 0 because any changes to the non-firm ATC would be re-released as secondary market capacity resulting in a change to the ETC_{NF} value.

$Counterflows_{NF}$ is set to 0 because Export point-to-point flow and Import point-to-point flow are treated as two independent directional paths. Since CSC calculates ATC in both directions independently, there are no Counterflows by definition.

Additional capacity may be purchased for MTF service on an Hourly non-firm basis until the ATC_{NF} equals zero (0) for the subject path. Purchases may take place on both paths individually up to their full TTC, which would effectively result in no transfer across CSC. In no case would purchases on one path result in increased ATC on the other path.

6. Posting of CSC ATC

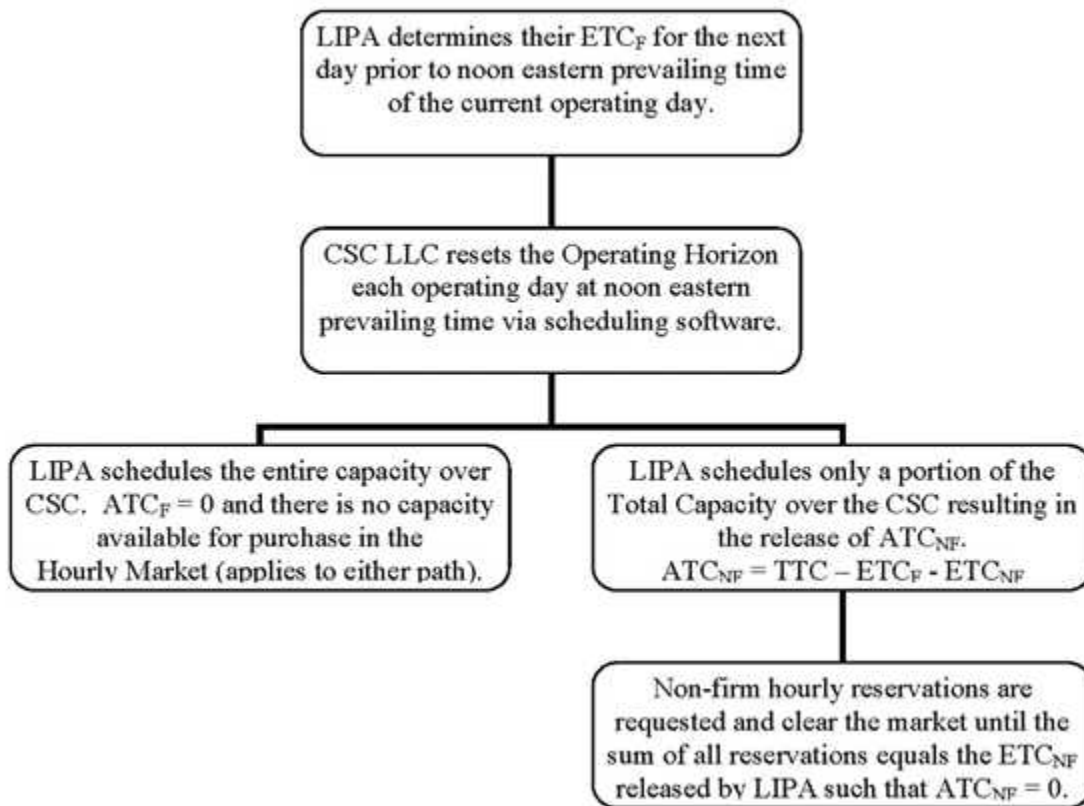
6.1. ATC Values

Using the process described in Section 5 above, the ATC calculations are performed for CSC automatically by the scheduling software. The ATC values for CSC are determined using the Mathematical Algorithms for Calculation of ATC (https://www.oasis.oati.com/CSC/CSCdocs/Algorithms_for_ATC_Calculation_for_CSC.pdf) and posted in accordance with NAESB standards on the CSC OASIS (<https://www.oasis.oati.com/csc/index.html>).

As discussed, firm ATC is equal to zero at all times. LIPA determines the ETC_F for the next day prior to noon eastern prevailing time of each operating day. CSC LLC then resets the Operating Horizon (“OH”) through the scheduling software. The OH spans from noon of the current day through midnight of the next day, or for the next 36 hours calculating ATC_{NF} based on the ETC_F selected by LIPA. ATC_{NF} is calculated from the TTC and ETC_F and offered as non-firm Hourly MTF in the OH. Subsequent Capacity purchases are considered ETC_{NF} , which is then subtracted from the ATC_{NF} . Any changes to the ATC_{NF} are updated in real time through the scheduling software.

6.2. Diagram of Energy Transactions

Below is a diagram that describes how energy transactions are processed over the CSC interface. The timing of the submittal of the energy transactions is governed by the ISO-NE Market Rules.



SCHEDULE 18 – ATTACHMENT L

Creditworthiness Procedures

I. Overview

The creditworthiness of each Transmission Customer seeking MTF Service must be established before receiving service from the MTF Provider. The MTF Provider shall make this credit review in accordance with procedures based on specific quantitative and qualitative criteria to determine the level of secured and unsecured credit required from the Transmission Customer. A summary of the MTF Provider's Creditworthiness Requirements are described in this Attachment L to Schedule 18. Detailed information regarding the MTF Provider's Creditworthiness Requirements is available in the MTF Provider's Business Practices as posted on the MTF Transmission Provider Page on the OASIS.

II. Financial Information

Transmission Customers requesting MTF Service will be required to provide credit rating and financial information as part of the Credit Application for MTF Service. Required information may include: (a) all current credit rating reports from commercially accepted credit rating agencies including Standard and Poor's Inc. ("S&P"), Moody's Investors Service ("Moody's"), and Fitch Ratings ("Fitch"); (b) financial statements audited by a registered independent auditor; and (c) references from banks and utilities/vendors.

III. Creditworthiness Requirements and Process

Transmission Customers, rated and un-rated, will be required to meet the creditworthiness requirements specified in this Attachment L to Schedule 18 and the MTF Business Practices. Credit rating and financial information provided by Transmission Customers that would be used to establish creditworthiness include investment grade ratings for senior unsecured long-term debt and ratio analyses of audited financial statements. If the Customer does not meet the MTF Provider's creditworthiness requirements, the MTF Provider (at its discretion) may establish a credit limit for that Customer equal to the financial assurance (i.e., the security deposit) required from all Transmission Customers, as specified in this Attachment L to Schedule 18 and the MTF Provider's Business Practices.

The MTF Provider shall use the following criteria in reviewing the creditworthiness of Transmission Customers:

1. The Transmission Customer must meet and maintain the credit and financial assurance requirements applicable to market participants as established by ISO New England Inc.; and
2. The Transmission Customer must not be in default of any amounts owed to any MTF Providers.

If the Transmission Customer does not qualify using the above requirements, the MTF Provider may consider other qualitative factors on a case-by-case basis. The specific factors will depend upon the MTF Provider's Business Practices, and may include billing history and the Transmission Customer's anticipated use of the MTF service.

A. Procedure for Determining Creditworthiness

The MTF Service Credit Application is posted on the MTF Provider's OASIS and is available for download. The Credit Application may be submitted along with the Application for MTF Transmission Service. Because the amount of time required to complete the credit review varies widely, it is recommended that credit applications be submitted at least ten (10) business days before the Transmission Customer takes service for the first time. As part of the credit review process, the MTF Provider will assign a credit limit to each Transmission Customer. For a customer that holds a below investment grade rating from either S&P, Moody's or Fitch, or is not rated by any of those three rating agencies, the assigned credit limit will be the amount of the security deposit posted by such customer. For a customer that is rated by one or more of S&P, Moody's or Fitch and holds an investment grade rating from each agency that rates that customer, the credit limit will be established using standard commercial practices on a case-by-case basis based on an estimate of the customer's anticipated use of MTF Service.

IV. Financial Assurance

All Transmission Customers requesting MTF Service are required to submit a security deposit to the MTF Provider. For customers executing a Blanket MTF Transmission Service Agreement, the minimum security deposit shall be \$100,000.00, provided, however, that customers may choose to provide a higher security deposit. For customers executing a transaction-specific MTF Transmission Service Agreement, the security deposit requirement shall be determined on a case-by-case basis, the maximum security deposit that may be charged is equal to the cost of the Reserved Capacity over the MTF for the duration of the specific transaction. Security deposits will be held in separate accounts. Account statements will be provided to the customer on an annual basis upon request.

V. Credit Levels

Transmission Customers meeting the above Creditworthiness Requirements will be extended credit based on levels specified in the MTF Provider's Business Practices. Transmission Customers that do not meet the MTF Provider's creditworthiness requirements will not receive unsecured credit from the MTF Provider. The MTF Provider will monitor the credit status of all approved customers and may modify credit limits (higher or lower) for such customer to the extent that company circumstances or service changes occur. In the event that a customer is downgraded such that it holds a below investment grade rating from S&P, Moody's or Fitch, or is not rated by any of the three agencies, the customer's credit limit shall be immediately reduced to the amount of security deposit posted by that customer.

VI. Contesting Creditworthiness Determination

Should the MTF Provider reject a credit application, the MTF Provider will provide the customer the reasons for the rejection and an opportunity to revise and resubmit the credit application to address the identified deficiencies. Transmission Customers may also contest the MTF Provider's determination of creditworthiness by submitting a written request for re-evaluation. Such request should provide information supporting the basis for a request to re-evaluate a Transmission Customer's creditworthiness. The MTF Provider will review and respond to the request under the procedures outlined in this Attachment L to Schedule 18 and the MTF Provider's Business Practices.

VII. Procedures for Changes in Credit Levels and Collateral Requirements

The MTF Provider will immediately notify customers of any modifications to credit limits or required security deposits. Upon request, the MTF Provider will provide customers a written explanation for any change in credit limits or required security deposits, including an opportunity to cure any credit deficiencies within a specified time period.

VIII. Posting Collateral Requirements

In the event that the MTF Providers revises the level of collateral required (e.g., security deposit) as a result of changes to the Transmission Customer's financial information, the MTF Provider's criteria, or other events that result in the Transmission Customer being determined to be non-creditworthy, the Transmission Customer shall have the opportunity to cure such deficiency consistent with the procedures in this Attachment L to Schedule 18 and the MTF Provider's Business Practices, as posted on the MTF Transmission Provider Page on the OASIS.

IX. Additional Requirements

Along with the above criteria for determining creditworthiness, the MTF Provider may require the Transmission Customer to fulfill additional conditions under the MTF Provider's Business Practices, as posted on the MTF Transmission Provider Page on the OASIS.

SCHEDULE 18 - ATTACHMENT Z
Incorporation By Reference of NAESB Standards

In accordance with Commission Order No. 676-H, the NAESB WEQ Version 003 Standards listed below are hereby incorporated by reference to the extent that the requirements therein apply to Cross Sound Cable:

- WEQ-000, Abbreviations, Acronyms, and Definition of Terms, WEQ Version 003, July 31, 2012, as modified by NAESB final actions ratified on Oct. 4, 2012, Nov. 28, 2012 and Dec. 28, 2012 (with minor corrections applied Nov. 26, 2013);
- WEQ-001, Open Access Same-Time Information Systems (OASIS), Version 2.0 WEQ Version 003, July 31, 2012, as modified by NAESB final actions ratified on Dec. 28, 2012 (with minor corrections applied Nov. 26, 2013) excluding Standards ,001-9.5, 001-10.5, 001-14.1.3, 001-15.1.2 and 001-106.2.5;
- WEQ-002, Open Access Same-Time Information Systems (OASIS) Business Practice Standards and Communication Protocols (S&CP), OASIS Version 2.0 WEQ Version 003, July 31, 2012, as modified by NAESB final actions ratified on Nov. 28, 2012 and Dec. 28, 2012 (with minor corrections applied Nov. 26, 2013);
- WEQ-003, Open Access Same-Time Information Systems (OASIS) Data Dictionary Business Practice Standards, OASIS Version 2.0, WEQ Version 003, July 31, 2012, as modified by NAESB final actions ratified on Dec. 28, 2012 (with minor corrections applied Nov. 26, 2013);
- WEQ-004, Coordinate Interchange WEQ Version 003, July 31, 2012 (as modified by NAESB final actions ratified on December 28, 2012);
- WEQ-005, Area Control Error (ACE) Equation Special Cases, WEQ Version 003, July 31 ,2012;
- WEQ-006, Manual Time Error Correction, WEQ Version 003, July 31, 2012;
- WEQ-007, Inadvertent Interchange Payback, WEQ Version 003, July 31, 2012;

- WEQ-008, Transmission Loading Relief (TLR) – Eastern Interconnection, WEQ Version 003, July 31, 2012 (with minor corrections applied November 28, 2012);
- WEQ-011, Gas/Electric Coordination, WEQ Version 003, July 31, 2012;
- WEQ-012, Public Key Infrastructure (PKI) WEQ Version 003, July 31, 2012, as modified by NAESB final actions ratified October 4, 2012);
- WEQ-013, Open Access Same-Time Information Systems (OASIS) Implementation Guide, OASIS Version 2.0, WEQ Version 003, July 31, 2012, as modified by NAESB final actions ratified on Dec. 28, 2012 (with minor corrections applied Nov. 26, 2013);
- WEQ-015, Measurement and Verification of Wholesale Electricity Demand Response, WEQ Version 003, July 31, 2012; and
- WEQ-021, Measurement and Verification of Energy Efficiency Products, WEQ Version 003, July 31, 2012.

SCHEDULE 19

SPECIAL CONSTRAINT RESOURCE SERVICE

In order to maintain area reliability, Transmission Owners or distribution companies may request the ISO to change the commitment of a generating Resource or the incremental loading on a previously committed generating Resource to provide relief for constraints not reflected in the ISO's systems for operating the New England Transmission System or adhering to the ISO's Operating Procedures. Requests will normally be made to the ISO via the appropriate Local Control Center unless emergency conditions justify immediate communications with the Resources.

Such out of merit operation of units for any reliability purposes to provide relief for constraints (thermal, voltage or stability) not reflected in the ISO's systems or Operating Procedures will result in the Resource(s) being designated as a Special Constraint Resource (SCR) and administered in accordance with the provisions of this Schedule. However, in the event a SCR is requested by a Transmission Owner or distribution company and the ISO also requires that unit to be on-line in accordance with the ISO's systems and procedures, the ISO will apply the appropriate flag to reflect the ISO's need for the unit and will only flag the unit as SCR when the ISO does not require the Resource (or when changed dispatch of the unit is requested by the Market Participant). When a unit would not be operating above its Economic Minimum Limit but for the request of the Transmission Owner or distribution company, it shall be flagged as SCR. In the event that the ISO requires that a unit, previously designated and flagged as SCR, becomes a unit required by the ISO to be on-line in accordance with the ISO's systems and procedures (including economic dispatch or for purposes of second contingency, first contingency or capacity), the SCR designation and flag will be removed.

I. DETERMINING THE AMOUNT TO BE PAID FOR SERVICE UNDER THIS SCHEDULE

Service under this Schedule is to be provided by the ISO. The Transmission Owner or distribution company making a request or on whose behalf a Local Control Center makes a request to change the commitment of a generating Resource or the incremental loading on a previously committed generating Resource must purchase such service from the ISO. The Transmission Owner or distribution company shall be charged an amount equal to the NCPC Credit (as calculated pursuant to Market Rule 1) associated with the Real-Time operation of the Special Constraint Resource.

II. DETERMINING A GENERATOR'S COMPENSATION FOR PROVIDING SERVICE UNDER THIS SCHEDULE

The Special Constraint Resource is compensated pursuant to Market Rule 1 in the same manner as other generating Resources dispatched to provide relief for constraints reflected in the ISO's systems for operating the New England Transmission System or the ISO's Operating Procedures. NCPC Credits associated with the scheduling of Special Constraint Resources compensate these Resources for helping to maintain New England Control Area reliability requirements and are collected as stated in the ISO Manual for Market Rule 1 Accounting, M-28.

ATTACHMENT A
SERVICE AGREEMENT FOR THROUGH OR OUT SERVICE

- 1.0 This Transmission Service Agreement, dated as of _____, is entered into, by and between the ISO and _____ (“Transmission Customer”).
- 2.0 The Transmission Customer has been determined by the ISO to have a Completed Application for Through or Out Service under this OATT.
- 3.0 If required, the Transmission Customer has provided to the ISO an Application deposit in accordance with the provisions of this OATT.
- 4.0 Service under this Transmission Service Agreement shall commence on the later of (1) the requested service commencement date, or (2) the date on which construction or any Direct Assignment Facilities and/or facility additions or upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service under this Transmission Service Agreement shall terminate on such date as is mutually agreed upon by the parties.
- 5.0 The ISO agrees to provide, and the Transmission Customer agrees to take and pay for, transmission service in accordance with the provisions of the Tariff and this Transmission Service Agreement and Transmission Customer agrees to pay all applicable charges under Section IV of the Transmission, Markets and Services Tariff.
- 6.0 Any notice or request made to or by either party regarding this Transmission Service Agreement shall be made to the representative of the other party as indicated below.

The ISO:

c/o ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841

Transmission Customer:

7.0 The OATT is incorporated in this Transmission Service Agreement and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Transmission Service Agreement to be executed by their respective authorized officials.

The ISO:

By: _____
Name Title Date

Transmission Customer:

By: _____
Name Title Date

Specifications For Through or Out Service

1.0 Term of Transaction: _____
Start Date: _____
Termination Date: _____

2.0 Description of capacity and energy to be transmitted by Transmission Customers including the electric Control Area in which the transaction originates.

3.0 Point(s) of Receipt: _____

Delivering party: _____

4.0 Point(s) of Delivery: _____

Receiving party: _____

5.0 Maximum amount of capacity and energy to be transmitted (Reserved
Capacity):_____

6.0 Designation of party(ies) or other entity(ies) subject to reciprocal service
obligation:_____

7.0 Name(s) of any intervening systems providing transmission
service:_____

8.0 Service under this Transmission Service Agreement may be subject to some combination of the
charges detailed below. (The appropriate charges for individual transactions will be determined in
accordance with the terms and conditions of this Tariff.)

8.1 Transmission Charge:_____

8.2 System Impact Study and/or Facilities Study Charge(s):

8.3 direct assignment expansion charge:

8.4 Special Condition: MTF Service shall also be provided in accordance with the terms and conditions
of the contract between the MTF Provider and the Eligible Customer as attached hereto.

ATTACHMENT B
SERVICE AGREEMENT FOR REGIONAL NETWORK SERVICE

- 1.0 This Transmission Service Agreement, dated as of _____, is entered into, by and between ISO New England (“ISO”), and _____ (“Transmission Customer”).
- 2.0 The Transmission Customer has been determined by the ISO to be a Transmission Customer under the OATT and has requested Regional Network Service under the OATT.
- 3.0 Regional Network Service under this Agreement shall be provided by the ISO upon request by an authorized representative of the Transmission Customer.
- 4.0 The Transmission Customer agrees to supply information the ISO deems reasonably necessary in accordance with Good Utility Practice in order for it to provide the requested service.
- 5.0 The ISO agrees to provide and the Transmission Customer agrees to take and pay for Regional Network Service in accordance with the provisions of the Tariff and this Transmission Service Agreement and Transmission Customer agrees to pay all applicable charges under Section IV of the Transmission, Markets and Services Tariff.
- 6.0 Any notice or request made to or by either party regarding this Transmission Service Agreement shall be made to the representative of the other party as indicated below.

The ISO:

c/o ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040-2841

Transmission Customer:

- 7.0 The OATT is incorporated herein and made a part hereof.

ATTACHMENT C

AVAILABLE TRANSFER CAPABILITY METHODOLOGY

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 - 6.1 ATC Algorithm: Process for ATC Calculation for PTF Interfaces
 - 6.2 Firm versus Non-Firm ATC on PTF Interfaces
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1. Introduction

ISO is the regional transmission organization (RTO) for the New England Control Area. The New England Control Area includes the transmission system located in the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont, but does not include the transmission system in northern Maine (i.e., Aroostook and parts of Penobscot and Washington Counties) that is radially connected to New Brunswick and administered by the Northern Maine Independent System Administrator. The New England Control Area is comprised of PTF, non-PTF, OTF, MTF, and is interconnected to three neighboring Balancing Authority Areas (“BAA”) with various interface types as shown in the Table 1. A graphical depiction of the New England Control Area and its interfaces is provided in Figure 1.

Table 1. New England Control Area interfaces with neighboring BAAs

Neighboring BAA (“NBAA”)	Interface	Interface Type
New Brunswick System Operator BAA	New England - New Brunswick	PTF – NBAA (external)
Hydro-Quebec TransEnergie BAA	New England – Hydro Quebec via the Phase I/II high voltage direct current (“HVDC”) Transmission Facilities	OTF – NBAA (external)
	New England PTF - Phase I/II HVDC Transmission Facilities	PTF – OTF (internal)
Hydro-Quebec TransEnergie BAA	New England - Hydro Quebec via the Highgate Transmission Facility	PTF – NBAA (external)
New York Independent System Operator BAA	New England - New York-AC	PTF – NBAA (external)
New York Independent System Operator BAA	New England - New York via the Northport - Norwalk Harbor Cable (“NNC”) Transmission Facility	PTF – NBAA (external)
New York Independent System Operator BAA	New England – New York via the Cross Sound Cable (“CSC”) transmission facility	MTF – NBAA (external)
	New England PTF – CSC transmission facility	PTF – MTF (internal)

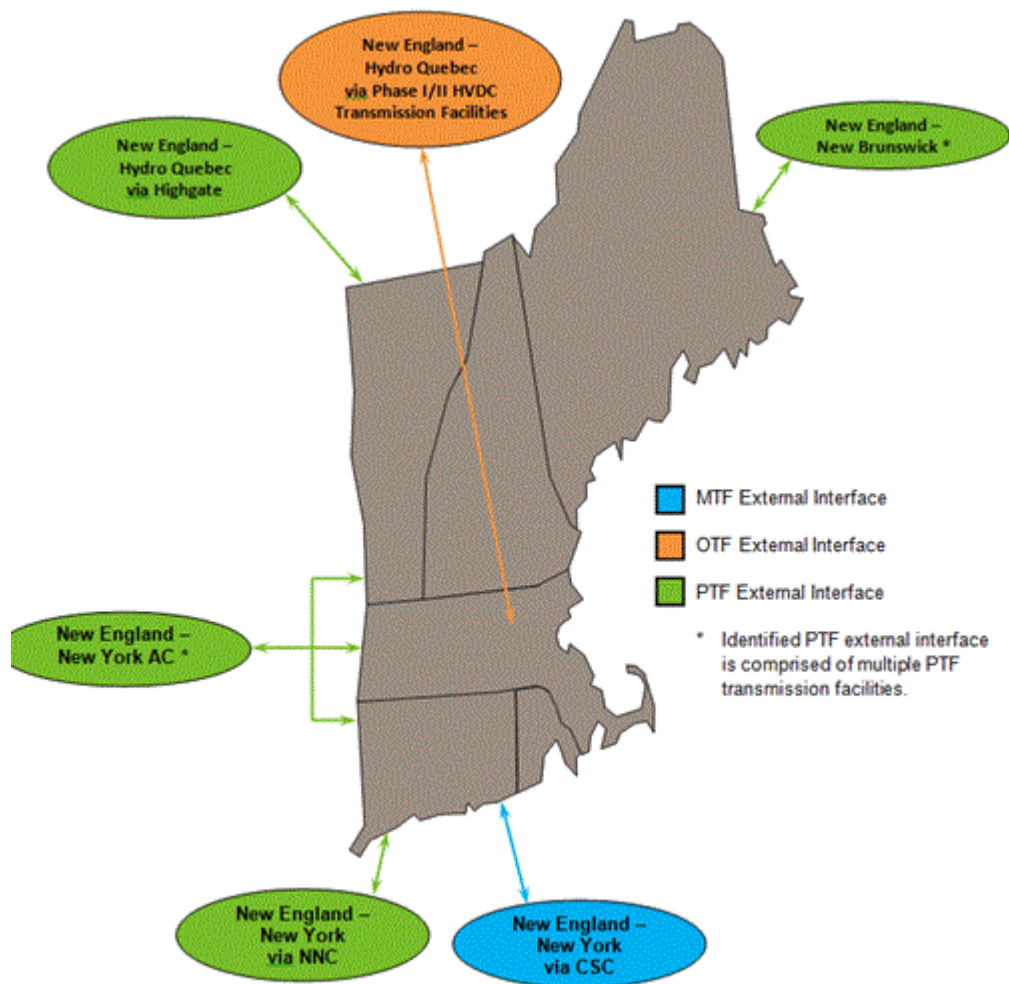


Figure 1. Graphical representation of New England Control Area external interfaces with neighboring BAs

1.1 ISO Responsibilities

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation (“NERC”) as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERC Standards: MOD-001 – Available Transmission System Capability (“MOD-001”), MOD-004 – Capability Benefit Margin (“MOD-004”), and MOD-008 - Transmission Reliability Margin Calculation Methodology (“MOD-008”). The extent of those responsibilities is based on various Commission approved transmission operating agreements and the provisions of the ISO New England Operating Documents. Table 2 below depicts those responsibilities as they apply to the interfaces associated with the New England Control Area and its neighboring BAAs for which the ISO is the Transmission Operator (“TOP”) and has varying responsibilities with respect to the calculation of ATC over those interfaces.

Table 2. New England Control Area Internal and External Interfaces

Interface	Interface Type	ATC	TTC	TRM
New England - New Brunswick	PTF – NBAA (external)	ISO as Transmission Service Provider (“TSP”)	ISO as TOP	ISO as TOP
New England – Hydro Quebec via the Phase I/II HVDC Transmission Facilities	OTF – NBAA (external)	Schedule 20A Service Providers (“SSPs”) as TSPs per Schedule 20A	ISO as TOP	ISO as TOP
New England PTF - Phase I/II HVDC Transmission Facilities	PTF – OTF (internal)	ISO as TSP	ISO as TOP	ISO as TOP
New England - Hydro Quebec via the Highgate Transmission Facility	PTF – NBAA (external)	ISO as TSP	ISO as TOP	ISO as TOP
New England - New York-AC	PTF – NBAA (external)	ISO as TSP	ISO as TOP	ISO as TOP
New England - New York via the Northport - NNC Transmission Facility	PTF – NBAA (external)	ISO as TSP	ISO as TOP	ISO as TOP
New England – New York via the CSC transmission facility	MTF – NBAA (external)	Cross Sound Cable Company, LLC (“CSC, LLC”) as TSP per Schedule 18	ISO as TOP	ISO as TOP
New England PTF – CSC transmission facility	PTF – MTF (internal)	ISO as TSP	ISO as TOP	ISO as TOP

1.2. Applicability of this Attachment C

This Attachment C describes the ATC methodology for RNS and Through or Out Service, and also describes the methodology for certain ATC components that are calculated by the ISO for use by other TSPs as described below:

- The TTC methodology for use by CSC, LLC under Schedule 18 and the SSPs under Schedule 20A.
- The CBM methodology for use by CSC, LLC under Schedule 18 and SSPs under Schedule 20A.
- The TRM methodology for use by CSC, LLC under Schedule 18 and the SSPs under Schedule 20A.

The manner in which these ISO-calculated ATC components are used by CSC, LLC and the SSPs for purposes of calculating a Schedule-specific ATC is governed by Schedules 18 and 20A, respectively.

2. Transmission Service in the New England Markets

Since the inception of the OATT for New England, the process by which generation located inside New England supplies energy to the bulk electric system has differed from the Commission pro forma OATT. The fundamental difference is that internal generation is dispatched in an economic, security-constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point transmission service. Through this process, internal generation provides offers that are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, entities may submit External Transactions to move energy into the New England Control Area, out of the New England Control Area or through the New England Control Area. The Real-Time Energy Market clears these External Transactions based on forecast LMPs and the transfer capability of the associated external interfaces. With those External Transactions in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region.

The process for submitting External Transactions into the Real-Time Energy Market does not require an advance physical reservation for use of the PTF. In the event that the net of the economic External

Transactions is greater than the transfer capability of the associated external interface, the External Transactions selected to flow are selected based on the rules specified in the Tariff. For any External Transactions that are confirmed to flow in Real-Time based on the economics of the system, a transmission reservation for RNS and Through or Out Service is created after-the-fact to satisfy the transparency needs of the market; however, entities who want to submit an External Transaction to flow energy over an MTF or OTF external interface must first obtain a confirmed transmission service reservation from the respective TSP prior to offering energy into the Real-Time Energy Market. Entities who want to submit an External Transaction to flow energy over an MTF or OTF external interface may refer to Schedule 18 or 20A for information regarding the calculation of ATC on the MTF and OTF external interfaces, respectively

The values resulting from the methodologies described in this Attachment C relate solely to the flow of energy in the Real-Time Energy Market, and shall not be construed as defining methodologies or limits for use in other New England markets.

3. Total Transfer Capability (TTC) for the New England Control Area

The TTCs on all of the New England Control Area external interfaces are calculated using the NERC Standard MOD-029 – Rated System Path Methodology (“MOD-029”). Consistent with the NERC definition, TTC is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. TTCs for the New England Control Area external interfaces are studied by the ISO based on thermal, voltage and stability limitations of the transmission lines that comprise the interface. Power flow and transient stability analysis is used to ensure that the interface’s physical limits will not be violated for credible system contingencies per NPCC and ISO reliability criteria. As required by MOD-029, reports are generated that contain the study results and the corresponding TTCs.

These reports are reviewed and updated seasonally, as needed, or as new equipment is placed in-service that impacts the interface. The studies identify the transmission facilities, generators and system conditions that can have a substantial impact upon the transfer capability and, where applicable, the report indicates the resulting impact upon the transfer capability of the external interfaces. These reports are available in a manner consistent with the ISO New England Information Policy.

The NPCC region maintains, on a confidential basis, a list of generation and transmission facilities that, if removed from service, may have a significant direct or indirect impact on a neighboring BAA, which is in accordance with *Appendix F – Procedure for Operational Planning Coordination (Appendix F) to NPCC Regional Reliability Reference Director #1 – Design and Operation of the Bulk Power System (Directory #1)*. If any facilities on that list have a planned outage, those outages are communicated between the neighboring BAAs. If there is a facility on that list in the New England Control Area that is submitted for an outage by an entity, the ISO conducts a study using an energy management system powerflow model and evaluates the impact on the TTC of the affected interface. The ISO applies its load forecast and generation dispatch for the relevant time frame to determine the TTCs for the given condition. In addition, on a daily basis, ISO evaluates the expected New England Control Area system conditions (e.g., generation availability, transmission outages, submitted External Transactions, resulting expected net flow across an external interface) for the following day to determine if there is a system operating limit that has a direct impact upon an external interface that is more restrictive than the previously calculated TTC and, if so, revises the TTC. TTCs impact the maximum megawatt (“MW”) amount of confirmed net flow in the Real-Time Energy Market, and may be adjusted prior to Real-Time to reflect Real-Time system operating limits. However, the TTCs in the direction opposite to the prevailing net flow are neither reviewed nor adjusted prior to Real-Time, since those values do not affect reliability.

4. Capacity Benefit Margin (CBM) for the New England Control Area

CBM is defined as the amount of firm transmission transfer capability set aside by a TSP for use by the Load Serving Entities. The ISO does not set aside any CBM for use by the Load Serving Entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents. Load Serving Entities operating within the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with ISO Tariff, Section III 13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of ATC calculation, CBM for the New England Control Area is set to zero (0).

5. Transmission Reliability Margin (TRM) for the New England Control Area

TRM is the amount of transmission transfer capability set aside to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system

conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.

5.1 TRM Calculation for the PTF

The ISO, acting as the TOP and TSP, does not set aside TRM on PTF external interfaces or PTF/MTF and PTF/OTF internal interfaces.

5.2 TRM Calculation for the MTF and OTF

The ISO, acting as the TOP, calculates the TRM on MTF and OTF external interfaces, which are both HVDC transmission facilities, by taking into account any operational uncertainties associated with the external facility in accordance with MOD-008.

The TSPs responsible for calculating the ATC and providing transmission service over the MTF or OTF dictate how the ISO-calculated TRM is applied in their respective Schedule-specific ATC calculations.

5.2.1 TRM Calculation for the MTF

Typically, the operational uncertainties associated with an external HVDC transmission facility are minimal and result in a TRM value of zero (0). Therefore, the TRM value for the MTF (i.e., CSC transmission facility) is zero (0).

5.2.2 TRM Calculation for the OTF

5.2.2.1 Quebec to New England TRM for the Phase I/II HVDC Transmission Facilities

There are operational uncertainties associated with the Phase I/II HVDC Transmission Facilities that arise out of neighboring and nearby BAAs such that the TRM on this facility is not zero (0). Due to the large transfer capability of the Phase I/II HVDC Transmission Facilities and the geographic location of the New England Control Area with respect to the rest of the Eastern Interconnection, the loss of this facility may have a substantial impact on the New York and Pennsylvania, New Jersey and Maryland (“PJM”) transmission systems. The inertial impact from the loss of the Phase I/II HVDC Transmission Facilities on the New York and PJM transmission systems will be dependent upon the simultaneous path

interactions and the generation dispatch on those transmission systems and within the New England Control Area.

As such, pursuant to Attachment G of the ISO Tariff, the Reliability Coordinators in New York and PJM can require the ISO to limit the amount of energy transferred into the New England Control Area over the Phase I/II HVDC Transmission Facilities (or the output from other large source contingencies within the New England Control Area) in Real-Time to a value as low as 1200 MW, which is referred to as the “largest single source contingency limit”. The amount of energy transferred into the New England Control Area over the Phase I/II HVDC Transmission Facilities is not always limited to 1200 MW; it is also dependent upon the dynamic state of the New York and PJM transmission systems, as well as, the additional room (or “available margin”) on those systems that can reliably sustain the inertial response following the loss of the Phase I/II HVDC Transmission Facilities (or other large source contingencies within the New England Control Area) when the amount of energy transferred into the New England Control Area over the Phase I/II HVDC Transmission Facilities (or the output from other large source contingencies within the New England Control Area) in Real-Time is in amounts greater than 1200 MW. For these reasons, the TRM value for the Phase I/II HVDC Transmission Facilities for all time horizons in the importing direction (North to South) shall be between zero (0) MW and 800 MW, where 800 MW is calculated from the “Phase I/II HVDC Transmission Facilities maximum transfer capability” (which is 2000 MW) minus the “largest single source contingency limit” (which is 1200 MW).

This range of TRM values is not dependent upon any databases, but instead is driven by the magnitude of the largest single source contingency in the New England Control Area that the New York and PJM transmission systems is able to sustain following the loss of the largest contingent resource.

5.2.2.2 New England to Quebec TRM for the Phase I/II HVDC Transmission Facilities:

When energy is flowing from the New England Control Area to the Hydro-Quebec TransEnergie BAA (South to North) over the Phase I/II HVDC Transmission Facilities, Hydro-Quebec TransEnergie may restrict the energy flow due to uncertainties on their Hydro-Quebec TransEnergie transmission system. The ISO considers whatever Hydro-Quebec TransEnergie restrictions are submitted to it in the calculation of the New England to Quebec TRM for the Phase I/II HVDC Transmission Facilities.

6. Available Transfer Capability (ATC) Calculation of PTF Interfaces

This section describes the process for the ATC calculations performed by the ISO pursuant to MOD-029 for the PTF external interfaces and the PTF/MTF and PTF/OTF internal interfaces. This section does not describe the process for the ATC calculations performed by other New England TSPs.

6.1 ATC Algorithm: Process for ATC Calculation for PTF Interfaces

Consistent with the NERC definition, the equation for Available Transfer Capability is: $ATC = (TTC - CBM - TRM - \text{Existing Transmission Commitments} + \text{Postbacks} + \text{counterflows})$. As discussed above, the CBM and TRM for the PTF interfaces for which the ISO calculates ATC are zero (0). The purpose of the Existing Transmission Commitments (“ETC”) component of the ATC equation is for the TSP to reduce the amount of ATC by the amount of existing firm transmission commitments that are not otherwise included in CBM or TRM. As described in Section 2 of this Attachment C, there is no requirement to purchase transmission service in advance of flowing energy in Real-Time, and there is no MW amount set aside by the ISO on any interface. Therefore there are no Existing Transmission Commitments to be applied in the ATC equation. For this reason, ETC equals zero (0) for the purposes of ATC calculation. Because Postbacks and counterflows are related to ETC and ETC is zero (0), both Postbacks and counterflows also are equal to zero (0).

Entities submit their bids and offers to move energy into, out of and through the Energy Market through External Transactions. As Real-Time approaches, the ISO determines which of the submitted External Transactions will be scheduled during the applicable scheduling interval in accordance with the rules set forth in the ISO New England Operating Documents. The ATC of the PTF external interfaces are equal to the TTC for all time horizons (i.e., scheduling, operating and planning). The ATC is equal to the amount of net External Transactions that the ISO will schedule on an interface for during the applicable scheduling interval. With this simplified version of ATC, the mathematical algorithm is simply “ATC equals TTC.” This mathematical algorithm can be found on the ISO New England OASIS site at: http://www.oatiaoasis.com/ISNE/ISNEdocs/isone_atc_algorithm.docx

The scheduling of External Transactions on a PTF interface will consider the net of all economic External Transactions and the transfer limits. For example, if the transfer limit on the interface is 1000 MW import, there could be 1300 MW of economic import External Transactions and 300 MW of economic export External Transactions scheduled for a given scheduling interval such that the net flow on the interface is 1000 MW.

Figure 2 describes how External Transactions are processed in the Real-Time Energy Markets where the timing of the submittal of the External Transactions is governed by Section III of the ISO Tariff.

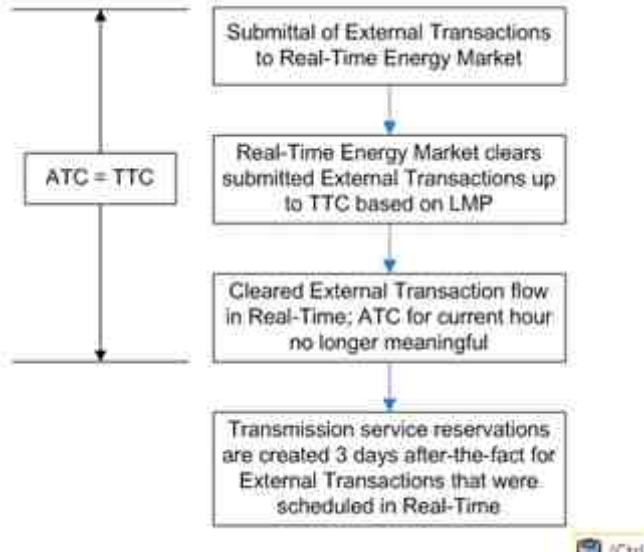


Figure 2. Processing of External Transactions in the Real-Time Energy Markets

6.2. Firm versus Non-Firm ATC on PTF Interfaces

As described in the preceding sections, the RNS and Through or Out Service provided over the PTF on an after-the-fact basis are the equivalent of firm transmission service. Therefore, the ATC calculation process described above results in a single ATC value. Where industry standards or software require the classification of ATC as Firm and non-Firm the ISO posts the single ATC value for both.

6.3. ATC Coordination for PTF Interfaces

As described in this Section 6 of this Attachment C, the ATC calculations for PTF external interfaces performed by the ISO are dependent solely on the TTC values. As such, the ISO does not coordinate ATC values with the neighboring BAAs. The ISO, however, has established procedures within the ISO New England Operating Procedures for coordinating outages with neighboring BAAs that could impact the resulting TTC on the external interface(s) with that neighbor. These procedures also include the timely communication of the resulting TTCs between the ISO and each of its neighboring BAAs.

IN WITNESS WHEREOF, the Parties have caused this Transmission Service Agreement to be executed by their respective authorized officials.

Transmission Customer:

By: _____
Name Title Date

ISO-NE:

By: _____
Name Title Date

ATTACHMENT D

METHODOLOGY FOR COMPLETING A SYSTEM IMPACT STUDY

The system impact study will be performed to evaluate the impact of the requested service on the reliability and operating characteristics of the ISO bulk power system, consistent with:

- Good utility practice
- ERO standards, guides, and procedures;
- NPCC criteria and guidelines;
- New England criteria, rules, procedures, and reliability standards;
- Applicable guides, standards, and criteria of the impacted Transmission Owner(s), whether PTF, MTF or OTF;
- Other applicable guidelines and standards which may need to be established from time to time.

As such, the study will examine the impact on the ISO regional bulk power system and its component systems and neighboring and external systems. Consistent with the aforementioned, the ability to operate the system subject to the following will be considered:

- All equipment within its applicable capabilities;
- Voltages and reactive reserves within acceptable levels;
- Stability maintained with adequate levels of damping;
- Frequency (Hz) within acceptable levels.

The study will consider the reliability requirements to meet existing and pending obligations of the Market Participants and the obligations of the impacted Transmission Owner(s).

The study will be performed using appropriate and suitable analysis tools and modeling data consistent with the nature and duration of the requested service. It is expected that the Eligible Customer will provide the information as prescribed in Exhibit 1 of Attachment I, and such other information as may be reasonably required and associated with the requested service and necessary for its study. It is also recognized that it may be determined that additional or specialized analysis tools or computer software are necessary for the study. The responsibility for the provision of these items will be subject to the System Impact Study Agreement.

The study will identify if the requested service or a portion of it can be provided without adverse impact on the reliability and operating characteristics of the system. The study will also identify if it appears that modification of the system is necessary to provide the service.

ATTACHMENT F

ANNUAL TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirements for each PTO will reflect the PTO's costs with respect to Pool Supported PTF and the HTF, including costs attributable to those PTOs deemed to own or support PTF pursuant to Section II.49 of the Tariff. The Transmission Revenue Requirements will be an annual calculation based on the previous year's calendar data as shown, in the case of PTOs that are subject to the Commission's jurisdiction, in the PTO's FERC Form 1 report for that year; provided, however, that if a PTO is deemed to own or support PTF pursuant to Section II.49 of the Tariff, such PTO may include the costs as incurred by its Related Person for PTF facilities and Transmission Support Expenses as the basis for establishing its initial and subsequent Annual Transmission Revenue Requirements, only until such PTO has a full calendar year of cost data under its ownership. Such PTO's costs will be determined from FERC Form 1 data if available, or if not available, from other supporting data certified by an auditor of the PTO or Related Person, and in a format comparable to that used to report such costs in FERC Form 1. Such costs shall be based on actual data in lieu of allocated data if specifically identified in the Form 1 report in accordance with the following formula and Schedule 12:

- I. The Transmission Revenue Requirement shall equal the sum of the PTO's (A) Return and Associated Income Taxes, (B) Transmission Depreciation and Amortization Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and General Expense, (I) Transmission Related Integrated Facilities Charges, minus (J) Transmission Support Revenue, plus (K) Transmission Support Expense, plus (L) Transmission Related Expense from Generators, plus (M) Transmission Related Taxes and Fees Charge, minus (N) Revenue for Short-Term service under the OATT and (O) Transmission Rents Received from Electric Property.

The details for implementation of Attachment F, as well as the definitions of the terms used in the Attachment F formula, shall be established in accordance with the Attachment F Implementation Rule contained in this OATT.

ATTACHMENT F IMPLEMENTATION RULE

This rule sets forth details with respect to the determination each year of the Transmission Revenue Requirements for each PTO. Such Transmission Revenue Requirements shall reflect the PTO's costs for Pool Transmission Facilities ("PTF") and the Highgate Transmission Facilities ("HTF"), including costs attributable to those PTOs deemed to own or support PTF pursuant to Section II.49 of the Tariff. The Transmission Revenue Requirements for each PTO will reflect the PTO's costs with respect to Pool Supported PTF and the HTF. The Transmission Revenue Requirements will be an annual calculation based on the previous year's calendar data as shown, in the case of PTOs which are subject to the Commission's jurisdiction, in the PTO's FERC Form 1 report for that year; provided, however, that if a PTO is deemed to own or support PTF, such PTO may include the costs as incurred by its Related Person for PTF facilities and Transmission Support Expenses as the basis for establishing its initial and subsequent Annual Transmission Revenue Requirements, only until such PTO has a full calendar year of cost data under its ownership. Such PTO's costs will be determined from FERC Form 1 data if available, or if not available, from other supporting data certified by an auditor of the PTO or Related Person, and in a format comparable to that used to report such costs in FERC Form 1. Such costs shall be based on actual data in lieu of allocated data if specifically identified in the Form 1 report in accordance with the following formula and Schedule 12. The HTF Transmission Revenue Requirements shall be subject to the limitations of inclusion of such costs as set forth in Appendix B to this Attachment. The owners of the HTF, or their designated agent, will submit the annual HTF Transmission Revenue Requirements calculation based on the previous calendar year's cost data from their FERC Form 1 or equivalent information from their official books and records, as appropriate.

The Post-96 Transmission Revenue Requirement for each PTO that is based on data for calendar year 2004 or later shall include an Incremental Return and Associated Income Taxes on the PTO's PTF transmission plant investments included in the Regional System Plan and placed in-service on or after January 1, 2004 (such investments referred to herein as "Post-2003 PTF Investment"). The Incremental Return and Associated Income Taxes for Post-2003 PTF Investment shall incorporate an incentive ROE adder of 100 basis points for plant investment placed in service by December 31, 2008 or as otherwise permitted in Docket Nos. ER04-157, et al. for any projects included in the RSP, and shall incorporate any incentive ROE adder approved by the FERC under Order No. 679 for other plant investments (however; the 125 basis point ROE incentive adder granted to NEEWS under Order No. 679 in Docket No. ER08-

1548 and the 50 basis point ROE incentive adder for RTO participation shall not apply to the costs related to the Central Connecticut Reliability Project, consistent with FERC's order) and for MPRP CWIP, NEEWS CWIP and Pequonnock CWIP. The total ROE for any project, including any authorized ROE incentives for Post-2003 PTF Investment and any other incentive ROE approved by FERC under Order No. 679 shall be capped by the top of the applicable zone of reasonableness determined by FERC for the relevant period. The data used in determining each PTO's Incremental Return and Associated Taxes for Post-2003 Investment shall be based on actual data in lieu of allocated data if specifically identified in the PTO's accounting records.

The Post-1996 Pool PTF Rate, as calculated pursuant to Schedule 9, shall include for each PTO a Forecasted Transmission Revenue Requirement calculated in accordance with Appendix C to this Attachment F Implementation Rule. Additionally, the Pre-1997 and Post-1996 Pool PTF Rates shall include an Annual True-up calculated in accordance with Appendix C to this Attachment F Implementation Rule.

The PTOs shall make an annual informational filing on or before July 31 of each year showing the Pool PTF Rate in effect for the period beginning June 1 of that year through May 31 of the subsequent year. Further, the informational filing with respect to the determination of the Pool PTF Rate will include a breakdown by PTO of the amount of the change in PTF and HTF investment during the prior year and the PTF and HTF retirements or additions causing such change to beginning and end-of-year PTF balances and HTF balances (although beginning-of-year PTF balances and HTF balances are not used in the formula itself), and any additions to PTF and HTF, retirements of PTF and HTF, and reclassifications of PTF and HTF during the year for each PTO. If there are any corrections made to the information reflected in the informational filing after it has been submitted, the PTOs will file corrections to the informational filing. At least forty-five days before the informational filing is made with the Commission, the PTOs shall make available to Transmission Customers and any other interested parties a draft of the proposed filing for review and comment prior to the filing by posting such draft on the ISO website. The filing of the information filing does not re-open the formula rate set forth below for review, but rather is contestable only with respect to the accuracy of the information contained in the informational filing.

The ISO shall have the discretion to conduct audits of such charges, with advisory Stakeholder input on the scope of audit, including on any agreed-upon procedures to be used by the auditor. In this provision,

the term “agreed-upon procedures” shall have the meaning afforded to it by the American Institute of Certified Public Accountants.

I. DEFINITIONS

Capitalized terms not otherwise defined in the Tariff and as used in this rule have the following definitions:

A. ALLOCATION FACTORS

1. Transmission Wages and Salaries Allocation Factor shall equal the ratio of Transmission-related direct wages and salaries including those of affiliated Companies to the PTO’s total direct wages and salaries including those of the Affiliates’ Companies and excluding administrative and general wages and salaries.
2. PTF/HTF Transmission Plant Allocation Factor shall equal the ratio of PTF/HTF Transmission Plant to Total Investment in Transmission Plant, excluding capital leases in the Phase I/II HVDC-TF (Phase I/II HVDC-TF Leases).
3. Plant Allocation Factor shall equal the ratio of the sum of Total Investment in Transmission Plant, excluding Phase I/II HVDC-TF Leases, and Transmission Related Intangible and General Plant to Total Plant in service excluding Phase I/II HVDC-TF Leases.

B. TERMS

Administrative and General Expense shall equal the PTO’s expenses as recorded in FERC Account Nos. 920-935, excluding FERC Account Nos. 924, 928 and 930.1 and excluding Merger-Related Costs included in FERC Account Nos. 920-935 (other than those in FERC Account Nos. 924, 928 and 930.1, which have already been excluded).

Amortization of Loss on Reacquired Debt shall equal the PTO’s expenses as recorded in FERC Account No. 428.1.

Amortization of Investment Tax Credits shall equal the PTO's credits as recorded in FERC Account No. 411.4.

Depreciation Expense for Transmission Plant shall equal the PTO's transmission expenses as recorded in FERC Account No. 403.

General Plant shall equal the PTO's gross plant balance as recorded in FERC Account Nos. 389-399.

General Plant Depreciation and Amortization Expense shall equal the PTO's general expenses as recorded in FERC Account No. 403 and NSTAR Electric's (East) FERC Account No. 404 for items subject to amortization.

General Plant Amortization Reserve shall equal NSTAR Electric's (East) general reserve balance as recorded in FERC Account No. 111.

HTF Transmission Plant shall equal the PTO's balance of investment in the Highgate Transmission Facilities as recorded in FERC Account Nos. 350-359.

Intangible Plant shall equal NSTAR Electric's (East) gross plant balance as recorded in FERC Account No. 303. The only allowable Intangible Plant for inclusion are software, patent or rights costs.

Intangible Plant Amortization Expense shall equal NSTAR Electric's (East) amortization expenses as recorded in FERC Account Nos. 404-405. The only allowable Intangible Plant Amortization Expense for inclusion is the amortization of software, patent or rights costs.

Intangible Plant Amortization Reserve shall equal NSTAR Electric's (East) amortization reserve balance as recorded in FERC Account No. 111. The only allowable Intangible Plant Amortization Reserve for inclusion is that related to the amortization of software, patent or rights costs.

Maine Power Reliability Program Construction Work In Progress ("MPRP CWIP") shall equal Central Maine Power Company's ("CMP's") MPRP CWIP balance as recorded in FERC Account No. 107 for costs determined to be Pool-Supported PTF in accordance with Schedule 12 of this OATT.

Merger-Related Costs shall equal NSTAR Electric Company's ("NSTAR Electric") (East and West), CL&P's and Public Service Company of New Hampshire's ("PSNH") amortized merger-related costs as authorized by FERC or by state regulatory order.

New England East-West Solution Construction Work in Progress ("NEEWS CWIP") shall equal the NEEWS CWIP balances of The Connecticut Light and Power Company ("CL&P") and NSTAR Electric (West) and New England Power Company ("NEP") as recorded in FERC Account No. 107 for costs determined to be Pool-Supported PTF in accordance with Schedule 12 of this OATT.

Other Regulatory Assets/Liabilities - FAS 106 shall equal the net of the PTO's FAS 106 balance as recorded in FERC Account 182.3 and any FAS 106 balance as recorded in the PTO's FERC Account No. 254.

Other Regulatory Assets/Liabilities - FAS 109 shall equal the net of the PTO's FAS 109 balance in FERC Account No. 182.3 and any FAS 109 balance as recorded in the PTO's FERC Account No. 254.

Payroll Taxes shall equal those payroll expenses as recorded in the PTO's FERC Account Nos. 408.1.

Pequonnock Substation Construction Work in Progress ("Pequonnock CWIP") shall equal the Pequonnock CWIP balance of The United Illuminating Company ("UI") as recorded in FERC Account No. 107 for costs determined to be Pool-Supported PTF in accordance with Schedule 12 of the OATT.

Phase I/II HVDC-TF Leases shall equal the PTO's balance in capital leases as recorded in FERC Account Nos. 350-359 and FERC Account Nos. 389-399.

Plant Held for Future Use shall equal the PTO's balance in FERC Account No.105.

Prepayments shall equal the PTO's prepayment balance as recorded in FERC Account No. 165.

Property Insurance shall equal the PTO's expenses as recorded in FERC Account No. 924.

PTF Transmission Plant shall equal the PTO's transmission plant as defined in the Section II.49 of the OATT and determined in accordance with Appendix A of this Rule, which is entitled "Rules for Determining Investment To be Included in PTF."

PTF/HTF Transmission Plant Investment shall equal the PTO's (a) PTF Transmission Plant plus (b) HTF Transmission Plant.

Total Accumulated Deferred Income Taxes shall equal the net of the PTO's deferred tax balance as recorded in FERC Account Nos. 281-283 and the PTO's deferred tax balance as recorded in FERC Account No. 190.

Total Loss on Reacquired Debt shall equal the PTO's expenses as recorded in FERC Account 189.

Total Municipal Tax Expense shall equal the PTO's municipal tax expenses as recorded in FERC Account Nos. 408.1.

Total Plant in Service shall equal the PTO's total gross plant balance as recorded in FERC Account Nos. 301-399.

Total Transmission Depreciation Reserve shall equal the PTO's transmission reserve balance as recorded in FERC Account 108.

Transmission Merger-Related Costs shall equal NSTAR Electric's, (East and West) CL&P's and PSNH's amortized merger-related transmission costs as authorized by FERC.

Transmission Operation and Maintenance Expense shall equal the PTO's expenses as recorded in FERC Account Nos. 560, 561.5-561.8, 562-564 and 566-573, and shall exclude all Phase I/II HVDC-TF expenses booked to accounts 560 through 573 and expenses already included in Transmission Support Expense, as described in Section K which are included in FERC Account Nos. 560-573.

Transmission Plant shall equal the PTO's Gross Plant balance as recorded in FERC Account Nos. 350-359.

Transmission Plant Materials and Supplies shall equal the PTO's balance as assigned to transmission, as recorded in FERC Account No. 154.

II. CALCULATION OF TRANSMISSION REVENUE REQUIREMENTS

The Transmission Revenue Requirement shall equal the sum of the PTO's (A) Return and Associated Income Taxes (including the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP, NEEWS CWIP and Pequonnock CWIP), (B) Transmission Depreciation and Amortization Expense, (C) Transmission Related Amortization of Loss on Reacquired Debt, (D) Transmission Related Amortization of Investment Tax Credits, (E) Transmission Related Municipal Tax Expense, (F) Transmission Related Payroll Tax Expense, (G) Transmission Operation and Maintenance Expense, (H) Transmission Related Administrative and General Expenses, (I) Transmission Related Integrated Facilities Charges, minus (J) Transmission Support Revenue, plus (K) Transmission Support Expense, plus (L) Transmission-Related Expense from Generators, plus (M) Transmission Related Taxes and Fees Charge, minus (N) Revenue for Short-Term service under the OATT, (O) Transmission Rents Received from Electric Property and (P) Transmission Revenues from MEPCO Grandfathered Transmission Service Agreements. The Incremental Return and Associated Income Taxes for Post-2003 PTF Investment for each PTO shall be calculated using the investment base components specifically identified in Section A. 1 of the formula below.

- A. **Return and Associated Income Taxes** shall equal the product of the Transmission Investment Base and the Cost of Capital Rate. To calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP, NEEWS CWIP and Pequonnock

CWIP, Transmission Investment Base will only include Sections II.A. 1 .(a), (d), (e), (k), and (l) in the manner indicated.

1. Transmission Investment Base

The Transmission Investment Base will be the year end balances of (a) PTF/HTF Transmission Plant, plus (b) Transmission Related Intangible and General Plant, plus (c) Transmission Plant Held for Future Use, less (d) Transmission Related Depreciation and Amortization Reserve, less (e) Transmission Related Accumulated Deferred Taxes, plus (f) Transmission Related Loss on Re-acquired Debt, plus (g) Other Regulatory Assets/Liabilities, plus (h) Transmission Prepayments, plus (i) Transmission Materials and Supplies, plus (j) Transmission Related Cash Working Capital, plus (k) MPRP CWIP, plus (l) NEEWS CWIP, plus (m) Pequonnock CWIP.

- (a) PTF Transmission Plant will equal the balance of the PTO's PTF Investment in (a) Transmission Plant plus (b) HTF Transmission Plant. This value excludes (i) the PTO's Phase I/II HVDC-TF Leases, (ii) the portion of any facilities, the cost of which is directly assigned under Schedule 11 to the OATT, to the Transmission Customer or a Generator Owner or Interconnection Requester, (iii) the Pre-1997 PTF gross plant investment associated with leased facilities occupied by the Phase II section of the Phase I/II HVDC-TF. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment, Post2003 PTF Transmission Plant shall be separately identified.
- (b) Transmission Related Intangible and General Plant shall equal the sum of the PTO's balance of investment in Intangible Plant and General Plant multiplied by the Transmission Wages and Salaries Allocation Factor and the PTF/HTF Transmission Plant Allocation Factor.
- (c) Transmission Plant Held for Future Use shall equal the PTO's balance of Transmission-related Plant Held for Future Use multiplied by the PTF/HTF Transmission Plant Allocation Factor.
- (d) Transmission Related Depreciation and Amortization Reserve shall equal the PTO's balance of Total Transmission Depreciation Reserve, plus the balance of Transmission

Related Intangible Plant Amortization Reserve, Transmission Related General Plant Depreciation Reserve and Transmission Related General Plant Amortization Reserve. Transmission Related Intangible Plant Amortization Reserve, Transmission Related General Plant Depreciation Reserve and Transmission Related General Plant Amortization Reserve shall equal the product of the sum of Intangible Plant Amortization Reserve, General Plant Depreciation Reserve and General Plant Amortization Reserve, and the Transmission Wages and Salaries Allocation Factor. This sum shall be multiplied by the PTF/HTF Transmission Plant Allocation Factor. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment, Transmission Depreciation Reserve associated with Post-2003 PTF Investment shall equal the PTO's balance of Total Transmission Depreciation Reserve multiplied by the ratio of Post-2003 PTF Transmission Plant to Total Investment in Transmission Plant, excluding capital leases in the Phase I/II HVDC-TF Leases.

- (e) Transmission Related Accumulated Deferred Taxes shall equal the PTO's electric balance of Total Accumulated Deferred Income Taxes, multiplied by the Plant Allocation Factor, further multiplied by the PTF/HTF Transmission Plant Allocation Factor. To calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment, Transmission Related Accumulated Deferred Income Taxes associated with Post-2003 PTF Investment shall equal the PTO's balance of total property-related accumulated deferred income taxes as recorded in FERC accounts 281 and 282, multiplied by the ratio of Total Investment in Transmission Plant, excluding Phase I/II HVDC-TF Leases, to Total Plant in Service excluding Phase I/II HVDC-TF Leases, further multiplied by the ratio of Post-2003 PTF Transmission Plant to Total Investment in Transmission Plant, excluding Phase I/II HVDC-TF Leases.
- (f) Transmission Related Loss on Reacquired Debt shall equal the PTO's electric balance of Total Loss on Reacquired Debt multiplied by the Plant Allocation Factor, further multiplied by the PTF/HTF Transmission Plant Allocation Factor.
- (g) Other Regulatory Assets/Liabilities shall equal the PTO's electric balance of any deferred rate recovery of FAS 106 expenses multiplied by the Transmission Wages and Salaries Allocation Factor, plus the PTO's electric balance of FAS 109 multiplied by the Plant

Allocation Factor. This sum shall be multiplied by the PTF/HTF Transmission Plant Allocation Factor.

- (h) Transmission Prepayments shall equal the PTO's electric balance of prepayments multiplied by the Transmission Wages and Salaries Allocation Factor and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.
- (i) Transmission Materials and Supplies shall equal the PTO's electric balance of Transmission Plant Materials and Supplies, multiplied by the PTF/HTF Transmission Plant Allocation Factor.
- (j) Transmission Related Cash Working Capital shall be a 12.5% allowance (45 days/360 days) of the PTO's Transmission Operation and Maintenance Expense, Transmission Related Administrative and General Expense and Transmission Support Expense, to the extent that Transmission Support Expense exceeds Transmission Support Revenue included in Paragraph J of the formula.
- (k) MPRP CWIP shall equal CMP's balance as recorded in FERC Account No. 107 for the MPRP as authorized by Commission order and in accordance with CMP's Accounting Procedures for MPRP CWIP. In order to calculate the Incremental Return and Associated Income Taxes for MPRP CWIP, MPRP CWIP shall be separately identified.
- (l) NEEWS CWIP shall equal CL&P, NSTAR Electric (West) and NEP's balances as recorded in FERC Account No. 107 for the NEEWS as authorized by Commission order and in accordance with the companies' respective Accounting Procedures for NEEWS CWIP. In order to calculate the Incremental Return and Associated Income Taxes for NEEWS CWIP, NEEWS CWIP shall be separately identified.
- (m) Pequonnock CWIP shall equal UI's balances as recorded in FERC Account No. 107 for the Pequonnock Substation as authorized by Commission order and in accordance with UI's respective Accounting Procedures for Pequonnock CWIP. In order to calculate the Incremental Return and Associated Income Taxes for Pequonnock CWIP, Pequonnock CWIP shall be separately identified.

2. Cost of Capital Rate

The Cost of Capital Rate will equal (a) the PTO's Weighted Cost of Capital, plus (b) Federal Income Tax plus (c) State Income Tax.

- (a) The Weighted Cost of Capital will be calculated based upon the capital structure at the end of each year and will equal the sum of (i), (ii), and (iii) below. The Cost of Capital Rate to be used in calculating the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP, NEEWS CWIP and Pequonnock CWIP, shall only reflect item (iii) below and shall apply in the manner indicated below.
- (i) the long-term debt component, which equals the product of the actual weighted average embedded cost to maturity of the PTO's long-term debt then outstanding and the ratio that long-term debt is to the PTO's total capital.
- (ii) the preferred stock component, which equals the product of the actual weighted average embedded cost to maturity of the PTO's preferred stock then outstanding and the ratio that preferred stock is to the PTO's total capital.
- (iii) the return on equity component, shall be the product of the allowed ROE of the PTO's common equity and the ratio that common equity is to the PTO's total capital. For pre-1997 and post-1996 assets, the ROE is 11.07%. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP, NEEWS CWIP and Pequonnock CWIP, the incremental return on equity shall be the product of: (1) the PTO's incremental return on equity of 1.0% for plant investments associated with projects included in the RSP and placed in service by December 31, 2008 or otherwise permitted in Docket Nos. ER04-157, et al.; (2) any ROE incentive approved by the FERC under Order No. 679 for other plant investments (however; the 125 basis point ROE incentive adder granted to NEEWS under Order No. 679 in Docket No. ER08-1548 and the 50 basis point ROE incentive adder for RTO participation shall not apply to the costs related to the Central Connecticut Reliability Project, consistent with FERC's order) and MPRP CWIP, NEEWS CWIP and Pequonnock CWIP, provided that the total ROE for any project, including any such ROE incentives, shall be capped by the top of

the applicable zone of reasonableness determined by FERC for the relevant period, and
 (3) the ratio that common equity is to the PTO's total capital) ¹

(b) Federal Income Tax shall equal

$$\frac{(A+[(C+B)/D])(FT)}{1-FT}$$

where FT is the Federal Income Tax Rate and A is the sum of the preferred stock component and the return on equity component, as determined in Sections II.A.2.(a)(ii) and (iii) above, B is Transmission Related Amortization of Investment Tax Credits, as determined in Section II.D., below, C is the Equity AFUDC component of Transmission Depreciation Expense, as defined in Section II.B., and D is Transmission Investment Base, as determined in Section II.A.1., above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP, NEEWS CWIP and Pequonnock CWIP, the incremental Federal Income Tax shall equal

$$\frac{(A' * FT)}{(1 - FT)}$$

where FT is the Federal Income Tax Rate and A' is the incremental return on equity component, as determined in Section II.A.2.(a)(iii) above.

(c) State Income Tax shall equal

$$\frac{(A+[(C+B)/D] + \text{Federal Income Tax})(ST)}{1 - ST}$$

where ST is the State Income Tax Rate, A is the sum of the preferred stock component and return on equity component determined in Sections II.A.2.(a)(ii) and (iii) above, B is the Amortization of Investment Tax Credits as determined in Section II.D.below, C is the

¹ FERC Form-730 contains a list of transmission projects for which FERC has granted incentives under Order No. 679.

equity AFUDC component of Transmission Depreciation Expense, as defined in Section II.B.. D is the Transmission Investment Base, as determined in II.A.1., above and Federal Income Tax is the rate determined in Section II.A.2.(b) above. In order to calculate the Incremental Return and Associated Income Taxes for Post-2003 PTF Investment and for MPRP CWIP, NEEWS CWIP and Pequonnock CWIP, the incremental State Income Tax shall equal

$$\frac{(A' + \text{Federal Income Tax})(ST)}{(1 - ST)}$$

where ST is the State Income Tax Rate, A' is the incremental return on equity component determined in Section II.A.2.(a)(iii) above, and Federal Income Tax is the rate determined in Section II.A.2.(b) above.

- B. Transmission Depreciation and Amortization Expense shall equal the PTF/HTF Transmission Plant Allocation Factor, multiplied by the sum of (i) the PTO's Depreciation Expense for Transmission Plant, plus (ii) an allocation of Intangible Plant Amortization Expense and (iii) General Plant Depreciation and Amortization Expense calculated by multiplying the sum of (a) Intangible Plant Amortization Expense and (b) General Plant Depreciation and Amortization Expense by the Transmission Wages and Salaries Allocation Factor.
- C. Transmission Related Amortization of Loss on Reacquired Debt shall equal the PTO's electric Amortization of Loss on Reacquired Debt multiplied by the Plant Allocation Factor, and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.
- D. Transmission Related Amortization of Investment Tax Credits shall equal the PTO's electric Amortization of Investment Tax Credits multiplied by the Plant Allocation Factor, and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.
- E. Transmission Related Municipal Tax Expense shall equal the PTO's total electric municipal tax expense multiplied by the Plant Allocation Factor, and further multiplied by the PTF/HTF Transmission Plant Allocation Factor.

- F. Transmission Related Payroll Tax Expense shall equal the PTO's total electric payroll tax expense, multiplied by the Transmission Wages and Salaries Allocation Factor, further multiplied by the PTF/HTF Transmission Plant Allocation Factor.
- G. Transmission Operation and Maintenance Expense shall equal the PTO's Transmission Operation and Maintenance Expenses multiplied by the PTF/HTF Transmission Plant Allocation Factor.
- H. Transmission Related Administrative and General Expenses shall equal the sum of the PTO's (1) Administrative and General Expenses multiplied by the Transmission Wages and Salaries Allocation Factor, (2) Property Insurance multiplied by the Transmission Plant Allocation Factor, and (3) Expenses included in Account 928 (excluding Merger-Related Costs included in Account 928) related to FERC Assessments multiplied by Plant Allocation Factor, plus any other Federal and State transmission related expenses or assessments, plus specific transmission related expenses included in Account 930.1 plus Transmission Merger-Related Costs. This sum shall be multiplied by the PTF/HTF Transmission Plant Allocation Factor.
- I. Transmission Related Integrated Facilities Charges shall equal the PTO's transmission payments to Affiliates for use of the PTF and HTF integrated transmission facilities of those Affiliates.
- J. Transmission Support Revenues shall equal the PTO's revenue received for PTF and HTF transmission support but excluding the support payments to PTOs or their designee pursuant to Schedule 11 and excluding the support payments to PTOs or their designee pursuant to Schedule 12 Part 1(a) and Part B.2, and excluding support payments, if any, made to PTOs or their respective designee pursuant to Part II.C of this OATT.
- K. Transmission Support Expense shall equal the expense paid by (1) PTOs, (2) Transmission Customers or (3) Related Persons pursuant to Section II.49 of the Tariff for PTF and HTF transmission support other than expenses for payments made for congestion rights or for transmission facilities or facility upgrades placed in service on or after January 1, 1997, where the support obligation is required to be borne by particular PTOs or other entities in accordance with the OATT. Transmission Support Expenses by any entity other than a PTO, included in this provision, shall be capped at that entity's annual payment for Regional Network Service or its

Point To Point Service for each individual Point To Point transaction from the resource with which the support payment is associated.

- L. Transmission-Related Expense from Generators shall equal the expenses from generators that both (1) the PTO Administrative Committee determines should be included as transmission expense as a result of the impact of such generators on reducing transmission costs that would otherwise be required to be paid by Transmission Customers and (2) are reflected in a filing made by the PTOs with the Commission under Section 205 of the Federal Power Act and accepted by the Commission for recovery under the OATT.
- M. Transmission Related Taxes and Fees Charge shall include any fee or assessment imposed by any governmental authority on service provided under this Section which is not specifically identified under any other section of this rule.
- N. Revenues for Short-Term service under the OATT shall be revenues distributed to each PTO for short term service provided under the OATT, received after March 1, 1999. These revenues will be credited pro-rata between pre-1997 and post-1996 PTF revenue requirements in proportion to pre-1997 and post-1996 PTF Transmission Plant.
- O. Transmission Rents Received from Electric Property shall equal any Account 454 Rents from electric property, associated with PTF and HTF Transmission Plant as defined in Section II.A.1.(a) above but not reflected as a credit in Transmission Support Revenues in paragraph K of this Attachment.
- P. Transmission Revenues from MGTSAs shall equal any MG TSA revenues recorded in Account 456.

APPENDIX A TO ATTACHMENT F
IMPLEMENTATION RULE RULES FOR DETERMINING
INVESTMENT TO BE INCLUDED IN PTF

Section A – Transmission Lines*

Section B – Terminal Facilities*

Section C – Right of Way*

Effective June 1, 1998

*The following provision shall apply to Sections A, B and C below:

Of those transmission facilities that are upgrades, modifications or additions to the New England Transmission System on and after January 1, 2004, only those that: (i) are rated 115kV or above, and (ii) otherwise meet the non-voltage criteria specified in Section II.49 of this OATT shall be classified as PTF. Those transmission facilities that were PTF on December 31, 2003, and any upgrades to such facilities that meet the definition of PTF specified in this OATT, shall remain classified as PTF for all purposes under the Transmission, Markets and Services Tariff.

Section A: Rules for Determining Transmission Line Investment to be Included in PTF

Pool Transmission Facilities (PTF) are the transmission facilities owned by PTO rated 69 kV or above required to allow energy from significant power sources to move freely on the New England transmission network, and include:

1. All transmission lines and associated facilities owned by the PTOs rated 69 kV and above, except:
 - a. those which are required to serve local load only, thereby contributing little or no parallel capability to the transmission network,
 - b. generator leads, which are defined as the radial transmission from a generator bus to the nearest point on the transmission network,

- c. lines that are normally operated open.
 - d. those that are classified as MTF.
2. Terminal facilities (including substation facilities such as transformers, circuit breakers, and associated equipment) required to interconnect the lines which constitute PTF (see Section B).
 3. If a PTO with significant generation in its system (initially 25 MW) is connected to the New England Transmission System and none of the transmission facilities owned by the PTO qualify to be included in PTF as defined in “1” and “2” above, then such PTO’s connection to PTF will constitute PTF if both of the following requirements are met for this connection:
 - a. The connection is rated 69 kV or above.
 - b. The connection is the principal transmission link between the PTO and the remainder of the ISO PTF network.

The PTF facilities covered by this provision shall consist of a single line from the point of connection on the transmission network to the first bus within the PTO’s system.

4. R/W and land required for the installation of PTF facilities listed in “1”, “2”, or “3” (see Section C).

The following examples indicate the intent of the above definitions:

- a. Radial tap lines to local load are excluded.
- b. Lines which loop, from two geographically separate points on the transmission network, the supply to the load bus from the transmission network are included.
- c. Lines which loop, from two geographically separate points on the transmission network, the connections between a generator bus, and the transmission network are included.

- d. Radial connection or connections from a generating station to a single substation or switching station on the transmission network are excluded unless the requirements of paragraph 3 above are met.
- e. The cost of a PTF line will include only those costs associated with that line. When other facilities require rebuilding or undergrounding to permit the construction of a PTF facility, the investment costs in the relocated or undergrounded facility will not be included.
- f. Where multiple circuit structures support a mixture of PTF and Non-PTF circuits, the total cost of the multiple circuit structures will be allocated between the circuits in accordance with the ratio of costs of comparable individual structures.

The PTOs shall review at least annually the status of transmission lines and related facilities and determine whether such facilities constitute PTF and shall prepare and keep current a schedule or catalog of PTF facilities.

All new facilities being installed should be properly classified at the time the facilities are approved under Section I.3.9 of the Transmission, Markets and Services Tariff.

Transmission facilities owned or supported by a Related Person of a PTO which are rated 69 kV or above and are required to allow Energy from significant power sources to move freely on the New England Transmission System shall also constitute PTF provided (i) such Related Person files with the ISO its consent to such treatment; and (ii) the ISO determines in consultation with the PTO Administrative Committee determines that treatment of the facility as PTF will facilitate accomplishment of the ISO's objectives. If such facilities constitute PTF pursuant to this paragraph, they shall be treated as "owned" or "supported," as applicable, by a PTO for purposes of the OATT and the other provisions of the TOA, including the ability to include the cost associated with such PTF and any Transmission Support Expenses for support of PTF made by its Related Person in that PTO's Annual Transmission Revenue Requirements pursuant to Attachment F of the OATT.

Section B: Rules for Determining Terminal Investment to be Included in PTF

Terminal Investment is investment associated with the terminal facilities of electrical lines, including substation facilities such as transformers, circuit breakers, disconnects and airbreaks, bus conductor, related protection equipment and other related facilities (see paragraph 7).

1. The investment in terminal facilities shall be included where these facilities are identifiable and serve directly for terminating and/or switching PTF lines.
2. In cases where a line terminal is used in conjunction with both PTF and Non-PTF lines and/or facilities, it will be considered a PTF facility providing the terminal facility is at 69 kV or above and carries any power flow at 69 kV or above through parallel paths within the interconnected network under normal operation. PTF equipment is any element of the transmission system in those parallel paths. Any equipment not in these parallel paths is Non-PTF.
3. Where line terminals are installed solely for Non-PTF facilities, and do not carry any power flow at 69 kV or above through parallel paths within the interconnected network under normal operation, such terminal cost shall not be included in PTF.
4. A two-winding transformer which connects PTF facilities at both terminals along with any switcher which can be identified as pertaining solely to the transformer, will be included in their entirety as PTF.
5. An autotransformer or three winding transformer which connects PTF facilities at two (2) or more terminals, along with any switchgear which can be identified as pertaining solely to the PTF-connected terminals of the transformer, will be included in their entirety as PTF. An autotransformer or three winding transformer which is connected to PTF at only one terminal will not be PTF.
6. When a transformer supplies only Non-PTF facilities, the entire transformer installation, including the high side disconnect switch or circuit breaker and associated structures or tap lines shall be excluded from PTF except for the portion of line terminal facilities covered by paragraph 2.

7. Other facilities – the investment in that portion of a multi-use substation or switching station which is identifiable as serving a PTF function shall be included in PTF, while the investment in such facilities which are identifiable as serving a Non-PTF function shall be excluded. The investment in land, structures, ground mats, fences, ducts, lighting, etc., can often be identified and thus allocated. The investment in other facilities in the substation or switching station, excluding transformers, which are not identifiable as serving either a PTF or a Non-PTF function and general overheads shall be allocated to PTF on the basis of the ratio of the investment in those facilities identified as PTF to the sum of the investments in the facilities which are identified as serving PTF and Non-PTF functions; the equipment cost of power transformers shall not be included in this calculation for determining the division of investment, since this would produce a distorted balance.
8. Alternate method of allocating the cost of terminal facilities – In those cases where the major portion of the investment has been lumped and utility plant records do not permit the accurate assignment of costs to specific terminals, the total investment may be prorated to PTF and Non-PTF according to the number of terminals serving PTF and Non-PTF facilities.
9. In cases where microwave facilities are used in whole or part for PTF purposes, a prorated portion of such investment shall be included in PTF based on the PTF and Non-PTF functions served by the microwave facilities except where these facilities are otherwise supported under the Microwave Sharing Agreement dated June 1, 1970 among some of the New England utilities.
10. Generator unit transformers and generator circuit breakers shall be excluded from PTF, unless otherwise included by paragraphs 1 or 5.
11. In cases where remote control (Supervisory Control) and telemetering facilities are used in whole or in part for PTF purposes, a prorated portion of such investment shall be included in PTF based on the PTF and Non-PTF functions served by these facilities.
12. The PTO Administrative Committee may designate appropriate facilities as PTF.

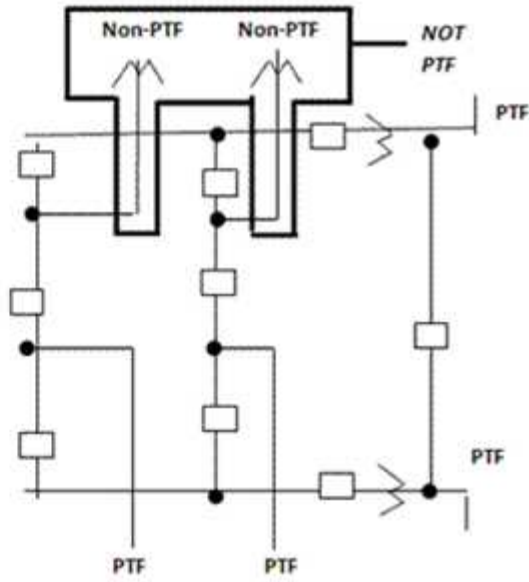
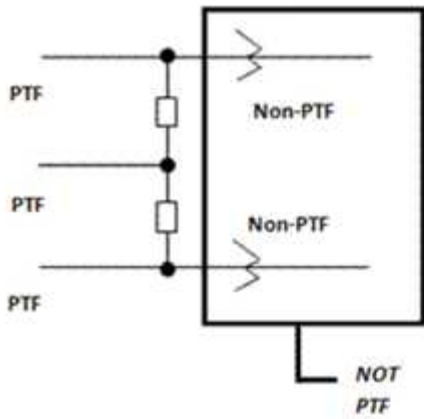
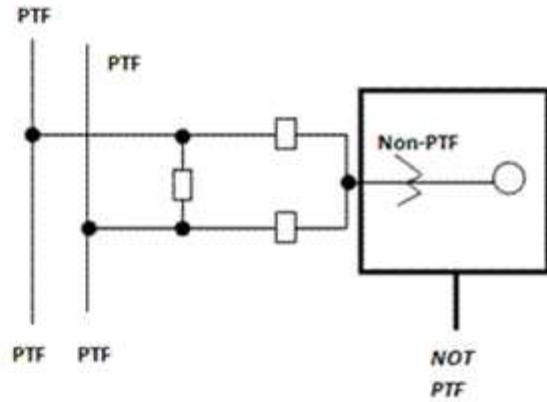
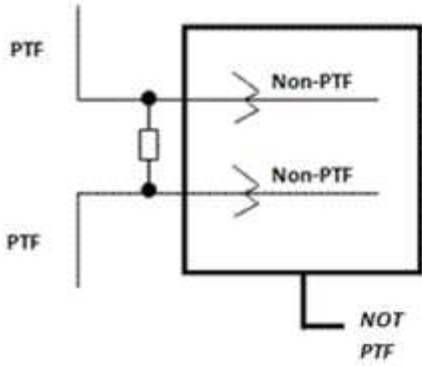
Section C: Rules for Determining PTF R/W Costs

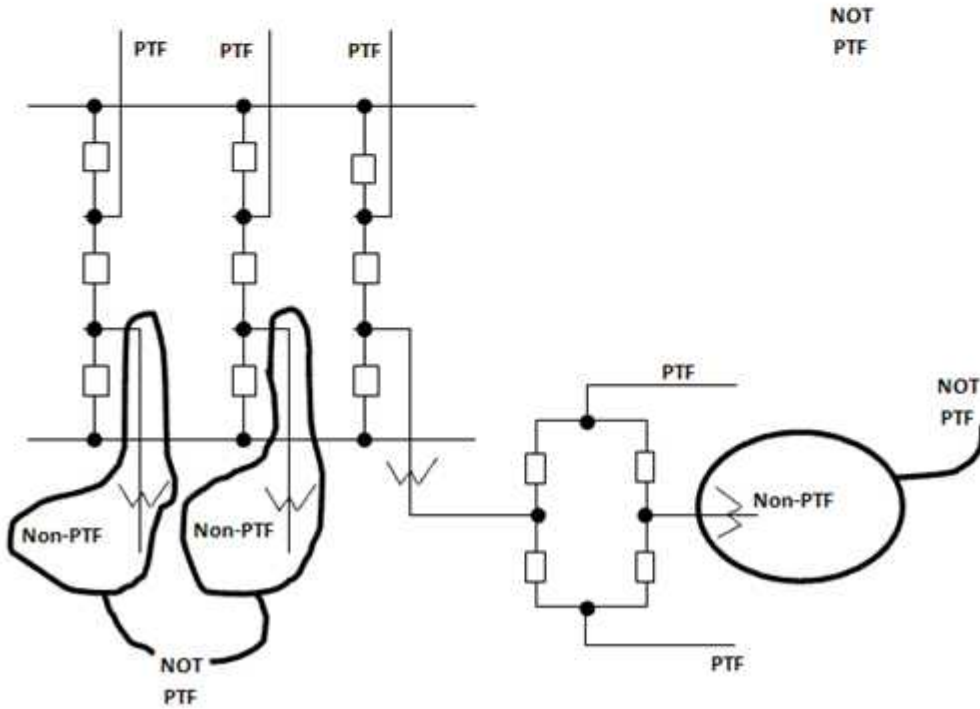
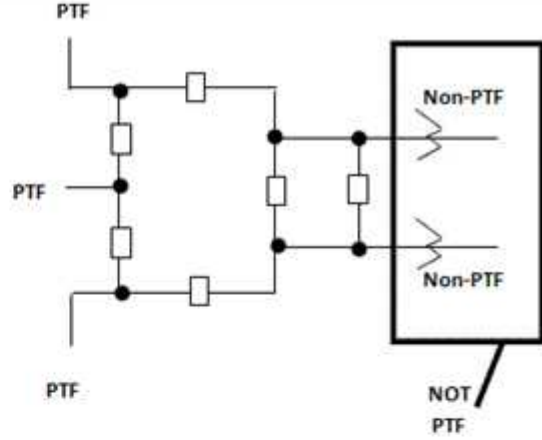
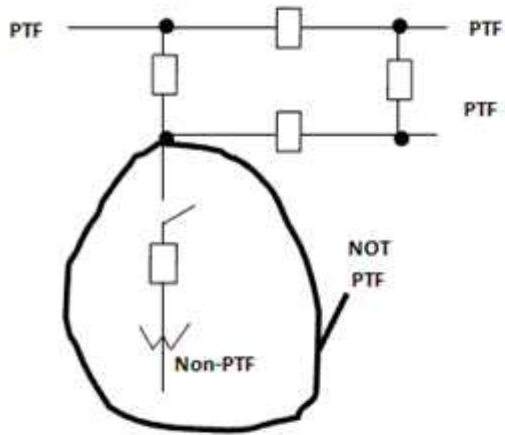
1. If a R/W has only PTF lines and no Non-PTF lines are expected to be added, the entire cost of the R/W is to be included as PTF.
2. If the R/W has only PTF lines but includes additional unused R/W which was purchased for future use by Non-PTF lines, the cost of the additional R/W is not to be included as PTF.
3. If the R/W contains both PTF and Non-PTF lines, the R/W cost to be assigned to PTF is to be determined as follows:
 - a. Where new or additional R/W is required to permit the construction of PTF line(s) and the added R/W is adequate to contain the new PTF, the cost of the new R/W is to be assigned to the PTF line(s), (even if the PTF line is located on the old R/W).
 - b. Where an existing R/W is used (without additional R/W), the amount allocated to PTF will be determined in accordance with paragraph 4.
 - c. Where a R/W is widened, but the new facilities, either PTF or Non-PTF, require partial use of the existing R/W, the incremental cost of the new R/W will be assigned to the new facilities. The width of the original R/W will be added to the width of the new R/W and the combined width will be allocated between PTF and Non-PTF as in paragraph 4. The cost of the old R/W and the combined width will be allocated between PTF and Non-PTF as in paragraph 4. The cost of the old R/W will be allocated to the new facilities in proportion to the width of the old R/W assigned to the new facilities. Thus, the R/W for the new facilities will be the additional R/W plus a share of the old R/W.
4. In allocating R/W between PTF and Non-PTF lines, each shall bear a share of the R/W in accordance with the following formulae.

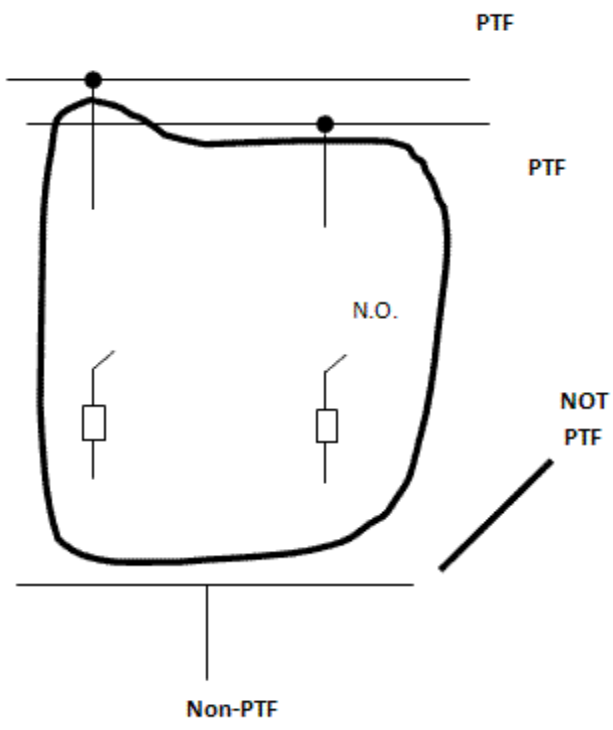
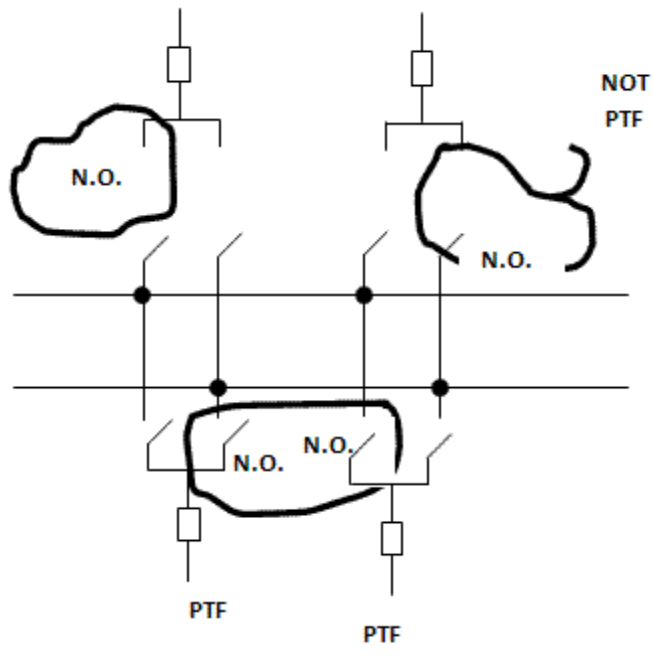
- a. Determine the R/W width required for each facility if constructed independently using appropriate type structures.
 - b. Allocate the actual R/W width to each facility in the proportion its independent R/W requirement would be to the sum of the independent R/W requirements.
5. R/W and land held for future PTF facilities may be included in PTF facilities only if specifically approved by the PTO Administrative Committee included under paragraph 1.

**ATTACHMENT 1 TO APPENDIX A TO
ATTACHMENT F IMPLEMENTATION RULE**

**Examples of the Methods for Distinguishing PTF
from Non-PTF Terminal Facilities
in a Number of Typical Substation Configurations**







APPENDIX B TO ATTACHMENT F IMPLEMENTATION RULE
HTF TRANSITION SCHEDULE

The inclusion of HTF Annual Transmission Revenue Requirements in Attachment F (and the calculation of the Pool PTF Rate) to this OATT will be limited by the provisions of this schedule.

VELCO, as a PTO and acting as agent for the HTF owners, may include the HTF Annual Transmission revenue Requirements (i.e., HTF Transmission Plant) within the Attachment F calculations. Additionally, the total HTF Annual Transmission Revenue Requirements included shall be limited to the following:

Year 1: A maximum of \$1.2M in Year 1. For the sole purpose of this Schedule, “Year 1” shall be defined as the first full year after the Operations Date:

Year 2: A maximum of \$2.0M in Year 2. For the sole purpose of this Schedule, “Year 2” shall be defined as the second full year after the Operations Date;

Year 3: A maximum of \$2.8M in Year 3. For the sole purpose of this Schedule, “Year 3” shall be defined as the third full year after the Operations Date;

Year 4: A maximum of \$3.5M in Year 4. For the sole purpose of this Schedule, “Year 4” shall be defined as the fourth full year after the Operations Date;

and

Year 5 and thereafter: All HTF Annual Transmission Revenue Requirements shall be included in Attachment F.

ATTACHMENT F IMPLEMENTATION RULE

APPENDIX C

I. DEFINITIONS

- (i) Adjusted Carrying Charge Factor (ACCF): shall equal the sum of the Carrying Charge Factor and the quotient of (i) the Cost of Capital Rate multiplied by the PTOs' Transmission Related Accumulated Deferred Taxes associated with Post-1996 PTF Transmission Plant for the most recently concluded calendar year, and (ii) Post-1996 PTF Transmission Plant for the most recently concluded calendar year, as shown:

$$\text{ACCF} = \text{CCF} + [(\text{COC} * \text{Transmission Related Accumulated Deferred Taxes associated with Post-1996 PTF Transmission Plant}) \div \text{Post-1996 PTF Transmission Plant}]$$

- (ii) Annual True-up – Pre-1997 (ATU): shall be the difference between the actual Pre-1997 Annual Transmission Revenue Requirements and the as-billed Pre-1997 Annual Transmission Revenue Requirements, adjusted to include interest pursuant to Part II below. The actual Pre-1997 Annual Transmission Revenue Requirements shall be an after-the-fact calculation and shall be determined at the conclusion of each rate-effective period, i.e. June 1 through May 31 of each year, by application of the Attachment F formula rate and each PTO's relevant Pre-1997 PTF cost data for the most recently concluded calendar year. The as-billed Pre-1997 Annual Transmission Revenue Requirements shall be those Pre-1997 Annual Transmission Revenue Requirements used to establish the RNS rates that were made effective on June 1 of the most recently concluded calendar year.
- (iii) Annual True-up – Post-1996 (ATU'): shall be the difference between the actual Post-1996 Annual Transmission Revenue Requirements and the as-billed Post-1996 Annual Transmission Revenue Requirements, adjusted to include interest pursuant to Part II below. The actual Post-1996 Annual Transmission Revenue Requirements shall be an after-the-fact calculation and shall be determined at the conclusion of each rate-effective period, i.e. June 1 through May 31 of each year, by application of the Attachment F formula rate and each PTO's relevant Post-1996 PTF cost data for the most recently concluded calendar year. The as-billed Post-1996 Annual Transmission Revenue Requirements shall be those Post-1996 Annual Transmission Revenue Requirements used to establish the RNS rates that were made effective on June 1 of the most

recently concluded calendar year and which included the sum of the Post-1996 Transmission Revenue Requirements for the year prior to the most recently concluded calendar year plus the Forecasted Transmission Revenue Requirements for the most recently concluded calendar year.

- (iv) Carrying Charge Factor (CCF): shall reflect the most recent calendar year data used in determining Post-1996 Annual Transmission Revenue Requirements and shall equal the sum of Attachment F Sections II.A, excluding MPRP CWIP and NEEWS CWIP, through II.H divided by Attachment F Section II.A.1.a.
- (v) Cost of Capital Rate (COC): shall be determined in accordance with Attachment F Section II.A.2.
- (vi) Forecast Period: The calendar year immediately following the calendar year for which the most recent FERC Form 1 data is available.
- (vii) Forecasted ADIT (FADIT): shall equal the PTOs' projected change in Accumulated Deferred Income Taxes from the most recently concluded calendar year related to accelerated depreciation and associated with PTF Transmission Plant for the Forecast Period calculated in accordance with Treasury regulation Section 1.167(l)-1(h)(6).
- (viii) Forecasted CL&P NEEWS CWIP (FCCWIP): shall equal CL&P's estimated incremental change in NEEWS CWIP for the Forecast Period.
- (ix) Forecasted MPRP CWIP (FCWIP): shall equal CMP's estimated incremental change in MPRP CWIP for the Forecast Period.
- (x) Forecasted NEP NEEWS CWIP (FNCWIP): shall equal NEP's estimated incremental change in NEEWS CWIP for the Forecast Period.
- (xi) Forecasted Pequonnock CWIP (FPCWIP): shall equal UI's estimated year-end balance of Pequonnock CWIP for the Forecast Period.
- (xii) Forecasted Transmission Plant Additions (FTPA): shall equal an estimate of the PTO's Post-1996 PTF plant additions for the Forecast Period.

- (xiii) Forecasted Transmission Revenue Requirement (FTRR): shall equal FTPA multiplied by the ACCF, minus FADIT multiplied by the COC, plus FCWIP multiplied by the MCOC, plus FCCWIP multiplied by CCOC, plus FWCWIP multiplied by WCOC, plus FNCWIP multiplied by NCOC, plus FPCWIP multiplied by PCOC, as shown:

$$\text{FTRR} = (\text{FTPA} * \text{ACCF}) - (\text{FADIT} * \text{COC}) + (\text{FCWIP} * \text{MCOC}) + (\text{FCCWIP} * \text{CCOC}) + (\text{FWCWIP} * \text{WCOC}) + (\text{FNCWIP} * \text{NCOC}) + (\text{FPCWIP} * \text{PCOC})$$

- (xiv) Forecasted NSTAR Electric (West) NEEWS CWIP (FWCWIP): shall equal NSTAR Electric's (West) estimated incremental change in NEEWS CWIP for the Forecast Period.
- (xv) MPRP Cost of Capital Rate (MCOC): shall be determined in accordance with Attachment F Section II.A.2.
- (xvi) NEEWS CL&P Cost of Capital Rate (CCOC): shall be determined in accordance with Attachment F Section II.A.2.
- (xvii) NEEWS NSTAR Electric (West) Cost of Capital Rate (WCOC): shall be determined in accordance with Attachment F Section II.A.2.
- (xviii) NEEWS NEP Cost of Capital Rate (NCOC): shall be determined in accordance with Attachment F Section II.A.2.
- (xix) Pequonnock Cost of Capital Rate (PCOC): shall be determined in accordance with Attachment F Section II.A.2.

II. INTEREST ON ANNUAL TRUE-UPS

Interest on the Annual True-up amounts (i.e., interest applicable to any over or under collection) shall be calculated in accordance with the methodology specified in the Commission's regulations at 18 C.F.R. § 35.19a (a) (2) (iii).

III. INFORMATIONAL FILINGS

The PTOs' annual informational filing shall include supporting documentation for their estimated capital additions to be placed in service during the current calendar year as well as supporting documentation pertaining to any annual true-up and interest calculations.

ATTACHMENT G

LIST OF EXCEPTED TRANSACTION AGREEMENTS

Attachment G is a listing of transmission agreements pertaining to certain point-to-point wheeling transactions across or out of a Local Network. In accordance with Section II.40 of the OATT, these agreements will continue to be in effect at the rates and terms thereunder rather than under the OATT. The original list of Items in the predecessor NEPOOL Open Access Transmission Tariff has been revised to remove transmission agreements that have terminated, thus the Item Number column does not reflect sequential Item Numbers.

Item #	PTO	Receiver	Description, Purpose or Service	Effective Date	End Date	Amount (MW's)	Comments FERC Docket #'s
5	NEP	CES	Long term non-firm wheeling of power from Boott Hydro (See note #1 in Notes to Attachment G)	7/9/96	Life of Unit	20	See note #1
16	NU	CES	Firm PTP Trans. Wheeling Service	10/1/84	8/31/13	2	Swift River – Chicopee 1 & 2 ER86-85-000/ER86-79-000
27	NU	Suncook	Firm PTP Trans. Wheeling Service	3/8/96	3/8/21	2.2	Suncook – ER96-1277-000

ATTACHMENT G-1

LIST OF EXCEPTED AGREEMENTS

Attachment G-1 is a listing of comprehensive network service agreements. In accordance with Section II.40 of the OATT, these agreements are to continue in effect and transmission service for the transactions covered by such agreements will continue to be provided at the rates and terms in effect thereunder rather than under the OATT. Further, service for the transactions covered by such agreements shall continue to be excepted for their respective terms from the requirement to pay a Local Network Service charge.

Item #	Parties to the Agreement	Description, Purpose or Service	Effective Date	End Date	Amount (MW's)	Comments FERC Docket #'s
11	All VT Utilities	1991 Transmission Agreement	1991		n/a	Transmission Service Agreement

ATTACHMENT G-2

LIST OF CERTAIN ARRANGEMENTS OVER EXTERNAL TIES

Attachment G-2 is a listing of agreements which relates to the use of the tie lines to New York.

All such agreements have terminated with respect to Attachment G-2.

Notes to Attachments G

1. NEP's long-term Point-To-Point transmission services will be grandfathered at a fixed rate of \$17.00/kW-yr. Distribution, transformation, and metering surcharges when applicable, will be subject to NEP's applicable point-to-point tariffs.

ATTACHMENT G-3

COMPLETE LIST OF EXCEPTED TRANSACTION (TRANSMISSION) AGREEMENTS OVER EXTERNAL TIES

Attachment G-3 is a comprehensive list of Excepted Transaction Agreements that relate to the use of ties with neighboring Control Areas (“External Ties”). The party responsible for paying the Congestion Cost associated with energy purchased under the Excepted Transactions listed in Attachment G-3 will retain their existing contract rights for physical scheduling of a transaction at the External Node associated with the Excepted Transaction until such party elects to be allocated Auction Revenue Rights pursuant to Market Rule 1. Until the party responsible for paying the Congestion Cost associated with energy purchased under an Excepted Transaction listed in Attachment G-3 elects to be allocated Auction Revenue Rights, the Excepted Transaction shall have physical scheduling and curtailment rights in accordance with Section II.44(1)(a) of this OATT. Once the party responsible for paying the Congestion Cost associated with energy purchased under the Excepted Transaction elects to be allocated Auction Revenue Rights, the party will not be able to revert back to using their contract rights for physical scheduling and curtailment.

All such agreements have terminated with respect to Attachment G-3.

ATTACHMENT H

MEPCO GRANDFATHERED TRANSMISSION SERVICE AGREEMENTS (“MGTSAs”)

MEPCO TSA No.	Original MG TSA Holder as of 12/1/08	Original Start Date	Renewed Through	Amount (MW's)	POR	POD	MG TSA Assignee Attachment H-1
TSA-MEPCO-4-1	Bayside Power LP	12/16/05	7/31/2014	200	NB_ME_BORDER	MXC_ISNE_INT	Emera Energy 387444 BPWR Effective 4-1-09
TSA-MEPCO-4-2	Bayside Power LP	12/16/05	7/31/2013	100	NB_ME_BORDER	MXC_ISNE_INT	Emera Energy 387445 BPWR Effective 4-1-09
MEPCO S.A-201	Borex Industries, Inc. (AVEC)	7/06/01	12/31/2013	26	NB_ME_BORDER	ORR_ISNE_INT	

ATTACHMENT H-1

**Form of Service Agreement For
The Resale, Reassignment Or Transfer Of
MEPCO Grandfathered Transmission Service Agreement (MGTSA)**

- 1.0 This Service Agreement, dated as of _____, is entered into, by and between MEPCO, and _____(the Assignee).
- 2.0 The Assignee has been determined by MEPCO to be an Eligible Customer under the Section II.45.1 of the ISO OATT.
- 3.0 The terms and conditions for the transaction entered into under this Service Agreement shall be subject to the terms and conditions of Section II.45.1 of the ISO OATT, except for those terms and conditions negotiated by the Reseller of the reassigned transmission capacity (pursuant to Section II.45.1 of the ISO OATT) and the Assignee, to include contract effective and termination dates and the amount of reassigned capacity or energy.
- 4.0 MEPCO shall credit the Reseller for the price reflected in the MGTSA.
- 5.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Maine Electric Power Company:

Assignee: _____

6.0 The ISO OATT is incorporated here and made a part hereof.

IN WITNESS WHEREOF, THE Parties have caused this Service Agreement to be executed by their respective authorized officials.

Maine Electric Power Company:

By: _____
Name: Title: Date:

Assignee:

By: _____
Name: Title: Date:

Specifications For The Resale, Reassignment Or Transfer
of MEPCO Grandfathered Transmission Service Agreement

- 1.0 Term of Transaction:
 - Start Date:
 - Termination Date:
- 2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Control Area in which the transaction originates.
- 3.0 Point(s) of Receipt: Delivering Party:
- 4.0 Point(s) of Delivery: Receiving Party:
- 5.0 Maximum amount of reassigned capacity;
- 6.0 Designation of party(ies) subject to reciprocal service obligation:
- 7.0 Name(s) of any Intervening Systems providing transmission service:
- 8.0 Service under this Agreement may be subject to some combination of the charges detailed below.
(The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the OATT.)
 - 8.1 Transmission Charge:
 - 8.2 System Impact and/or Facilities Study Charge(s):
 - 8.3 Direct Assignment Facilities Charge:
 - 8.4 Ancillary Service Charges:

9.0 Name of Reseller of the reassigned transmission capacity:

ATTACHMENT I

SYSTEM IMPACT STUDY AGREEMENT

This SYSTEM IMPACT STUDY AGREEMENT (the “Agreement”), dated _____, is entered into by _____ (the “Customer”) and ISO New England Inc. (“ISO”), for the purpose of setting forth the terms, conditions and costs for conducting a System Impact Study (the “Study”) relative to [the interconnection to the New England Transmission System of the Customer’s proposed _____ project (the “Project”) to be located in _____, _____,] [or] [the provision of transmission service requested in the Customer’s Application] in accordance with the Open Access Transmission Tariff (the “OATT”) included in the ISO Transmission, Markets and Services Tariff on file with the Federal Energy Regulatory Commission (“Commission”). The ISO and the Customer are sometimes referred to herein together as the “Parties” and individually as a “Party.”

1. Information Requirements

The Customer agrees to provide, in a timely and complete manner and in accordance with the ISO New England Planning Procedures, the information and technical data specified in Exhibit 1 to this Agreement for the ISO to conduct the Study. The Customer understands that it must provide all such information and data prior to the ISO’s commencement of the Study. The ISO will advise the Customer of any additional information as it may in its sole reasonable discretion deem necessary to complete the Study. Any such additional information shall be obtained only if required by Good Utility Practice and shall be subject to the Customer’s consent to proceed, such consent not to be unreasonably withheld.

2. Representatives

All work pertaining to the Study that is the subject of this Agreement will be approved and coordinated only through designated and authorized representatives of the Customer and the ISO, as they are identified in Article 12.5 hereof.

3. Duration and Results of Study

The ISO contemplates that its subcontractors and agents will require _____ to complete the Study, as more fully set forth in Exhibit 2, entitled “Study Timetable.” The Customer understands and agrees that such time periods are only an estimate and that the ISO makes no representations or warranties, either express or implied, that the Study will be completed within these time periods. Upon completion of the Study, the ISO will provide a report to the Customer based on the information provided and developed

as a result of this effort. If, upon review of the Study results and in accordance with the ISO New England Planning Procedures, the Customer decides to pursue interconnection, the ISO will, at the Customer's direction, tender a Facilities Study Agreement within thirty (30) days or other period as specified in the ISO New England Planning Procedures. The Study and the Facilities Study, together with any additional studies contemplated in Paragraph 1, shall form the basis for the Customer's proposed use of the relevant transmission system and shall be further utilized in obtaining necessary third-party approvals of any interconnection facilities and requested interconnection. The Customer understands and acknowledges that any use of the Study results by the Customer or its agents, whether in preliminary or final form, prior to the ISO's approval pursuant to Sections I.3.9 and I.3.10 of the Transmission, Markets and Services Tariff is completely at the Customer's sole risk.

4. Payment and Nature of Costs

- (a) The estimated costs contained within this Agreement are the ISO's good faith estimate of its costs to perform the Study contemplated by this Agreement. The estimates do not include any estimates for wheeling charges that may be associated with the transmission of facility output to third parties or with rates for station service. The actual costs charged to the Customer by the ISO may change as set forth in this Agreement. Prepayment will be required for all costs and expenses (including, without limitation, labor, materials, overheads, and administrative and general costs) the ISO will incur to perform its obligations under this Agreement, including, without limitation, all study, analysis, design, monitoring, and review work performed by the ISO or its designated agent's personnel under the terms of this Agreement ("Study Costs").
- (b) The estimated Study Costs required to be paid by the Customer to the ISO are shown on Exhibit 3, entitled "Prepayment Schedule." The initial prepayment requirement is _____ (\$____), which the Customer agrees to pay to the ISO upon execution of this Agreement. The initial prepayment and any subsequent prepayments will be applied against all Study Costs incurred by the ISO for work performed under this Agreement. The ISO will invoice the Customer for the costs and expenses that the ISO will incur as stated in Exhibit 3. Each invoice will show the detail of the work performed, the difference between the actual costs for such work and the prepayment amount for such work, and the amount of the prepayment for the costs of expected work. The Customer shall pay the invoiced amount to the ISO within thirty (30) days of the Customer's receipt of the ISO's invoice. During the term of this Agreement, the ISO will, in writing, advise the Customer in advance of any cost increases for work to be performed if the total amount increases by ten percent (10%) or more. Any such changes to the ISO's costs for the Study work shall be

subject to the Customer's consent, such consent not to be unreasonably withheld. The Customer shall, within thirty (30) days of the ISO's notice of increase, either authorize such increases and make payment in the amount set forth in such notice, or the ISO will suspend the Study and may terminate this Agreement. Any additional billings under this Agreement shall be subject to an interest charge computed in accordance with the provisions of the OATT. Prepayments for work expected to be performed shall not be subject to refunding except in accordance with Paragraph 4(d) below.

- (c) The ISO will invoice Customer for pre-contract Study Costs incurred by the ISO prior to the effective date of this Agreement. To the extent such pre-contract Study Costs exceed Customer's pre-contract cost deposit balance, the Customer will reimburse the ISO within twenty (20) days after receipt of the ISO's invoice. Pre-contract costs shall include, without limitation, costs for study, analysis and review work performed in connection with the Study and all costs associated with the development and negotiation of all associated agreements. Payment for pre-contract Study Costs shall not be subject to refunding to the Customer.
- (d) If the actual Study Costs for the work exceed prepaid estimated costs, the Customer shall make payment to the ISO for such actual Study Costs within thirty (30) days of the date of the ISO's invoice for such costs. If the actual Study Costs for the work are less than those prepaid, the ISO will credit such difference toward the ISO's expected additional costs, or, in the event there will be no additional billed expenses, the amount of the overpayment will be returned to the Customer with interest computed as stated in Paragraph 4(b) of this Agreement, from the date of reconciliation.
- (e) Nothing in this Agreement shall be interpreted to give the Customer immediate rights to wheel over or interconnect with any transmission or distribution system. Such rights shall be provided for under separate agreement and in accordance with the Transmission, Markets and Services Tariff.
- (f) Within one (1) year following the ISO's issuance of a final bill under this Agreement, the Customer shall have the right to audit the ISO's accounts and records at the offices where such accounts and records are maintained, during normal business hours; provided that appropriate notice shall be given prior to any audit and provided that the audit shall be limited to those portions of such accounts and records that relate to service under this Agreement. The ISO reserves the right to assess a reasonable fee to compensate for the use of its personnel time in assisting any inspection or audit of its books, records or accounts by the Customer or its agents.

5. Indemnification

The indemnification and liability provisions in Section I of the Transmission, Markets and Services Tariff are incorporated herein by reference, with the “Customer” under this Agreement being deemed a Customer for purposes of the Transmission, Markets and Services Tariff.

6. Disclaimer of Damages

NO PARTY SHALL BE LIABLE TO ANY OTHER PARTY FOR ANY INDIRECT, CONSEQUENTIAL, EXEMPLARY, SPECIAL, INCIDENTAL OR PUNITIVE DAMAGES, INCLUDING WITHOUT LIMITATION LOSS OF USE OR LOST BUSINESS, REVENUE, PROFITS OR GOODWILL, ARISING IN CONNECTION WITH THIS AGREEMENT, THE STUDY PROVIDED HEREUNDER, AND/OR THE INTENDED USE THEREOF, UNDER ANY THEORY OF TORT, CONTRACT, WARRANTY, STRICT LIABILITY OR NEGLIGENCE. The Parties agree this Section 6 will survive expiration, cancellation, or any termination of the Agreement.

7. Duration

This Agreement will remain in effect for a period of one (1) year from its effective date (the “Term”) and is subject to extension automatically to the extent the Study is not complete or by mutual agreement of the parties.

8. Termination

- (a) In addition to other termination provisions provided for herein, the ISO may terminate this Agreement immediately, upon notice to the Customer, if the ISO is unable to obtain or maintain any governmental license, waiver, consent, registration or approval needed to conduct the Study hereunder.
- (b) The ISO or the Customer may terminate this Agreement upon thirty (30) days’ written notice to the other party or seven (7) days after providing written notice to the other party that it has breached one of its obligations hereunder, if the breach has not been cured within such seven day period.
- (c) If not terminated pursuant to (a) or (b) above, this Agreement will automatically terminate (except for Section 11 hereof) upon the later of the delivery to the Customer of the final Study report and receipt by the ISO of final payment from the Customer.

9. Dispute Resolution and Voluntary Arbitration

The dispute resolution provisions of Section I of the Transmission, Markets and Services Tariff are incorporated herein by reference, with the “Customer” under this Agreement being deemed a Customer for purposes of the Transmission, Markets and Services Tariff.

10. Commission Jurisdiction Over Certain Disputes; Equitable Relief

- (a) Nothing in this Agreement shall preclude, or be construed to preclude, any Party from filing a petition or complaint with the Federal Energy Regulatory Commission with respect to any matter over which the Commission has jurisdiction.
- (b) The Parties specifically reserve the right to seek a temporary restraining order, preliminary or permanent injunction, or other similar equitable relief with respect to (i) violations of confidentiality provisions of this Agreement, (ii) any failures by the parties to comply with any applicable post-termination obligations for which monetary compensation would not be adequate, or (iii) to preserve the status quo or prevent irreparable harm.

11. Confidential Information

- (a) During and after the term of this Agreement, neither party or its employees or agents shall divulge or use for any purpose other than as specified in this Agreement Confidential Information received from the other party (the “Disclosing Party”). “Confidential Information” shall mean all of the following except to the extent excluded below: (i) all information about the Disclosing Party whether furnished before or after the date hereof, whether oral, written or recorded/electronic, and regardless of the manner in which it is furnished, which is marked “Confidential” or “Proprietary” or which under all of the circumstances should be treated as confidential or proprietary; (ii) all reports, summaries, compilations, analyses, notes or other information which are based on, contain or reflect any Confidential Information; (iii) any and all Confidential Information as that term is defined in the ISO New England Information Policy; and (iv) any information which, if disclosed by a transmission function employee of a utility regulated by the Commission to a market function employee of the same utility system, other than by public posting, would violate the Commission’s open access same time information regulations.
- (b) The foregoing restrictions on use and disclosure of Confidential Information do not apply to information that: (i) is already in the possession of the party receiving the information (the “Receiving Party”) at the time of the information’s disclosure hereunder and not otherwise subject

to obligations of confidentiality; (ii) is, or becomes publicly known, through no wrongful act or omission of the Receiving Party or breach of this Agreement; (iii) is received by the Receiving Party without restriction from a third party free to disclose it without obligation to the Disclosing Party; (iv) is developed independently by the Receiving Party without reference to the Confidential Information or other information of the Disclosing Party; or (v) is required to be disclosed by subpoena, law or other directive or a court, administrative agency or arbitration panel. In addition, nothing in this Section 11 shall prohibit the Customer from disclosing Confidential Information to its lenders, consultants, agents, directors, officers, employees, and attorneys (the “Representatives”) for the purpose of advising the Customer with respect to the project, provided that the Representatives shall be informed by the Customer that such information is Confidential Information and shall agree to treat it confidentially in accordance with this Section 11.

- (c) At the Disclosing Party’s option, the Receiving Party shall promptly either destroy all Confidential Information in tangible form in its possession, or return all such copies, and in either event, provide a written officer’s certification confirming the same promptly upon the earlier of: (i) the Disclosing Party’s written request; or (ii) the expiration or earlier termination of this Agreement.

12. Miscellaneous

12.1 Assignment. The Customer may not assign this Agreement or any of its rights or obligations hereunder without the prior written consent of the ISO, which consent shall not be unreasonably withheld. Any attempted assignment without such prior written consent shall be void. Notwithstanding the foregoing, the Customer may assign this Agreement as collateral security under its financing documents and the ISO hereby consents to such assignment.

12.2 Governing Law. This Agreement shall be construed and governed in accordance with the laws of the Commonwealth of Massachusetts, and with Part II of the Federal Power Act, 16 U.S.C. §§ 824d, et seq., and with Part 35 of Title 18 of the Code of Federal Regulations, 18 C.F.R. §§ 35, et seq., each as may be modified from time to time.

12.3 Enforceability. If any section or clause of this Agreement shall be held to be invalid or unenforceable by any body or entity of competent jurisdiction, then the remainder of the Agreement shall remain in full force and effect and the parties shall promptly negotiate a replacement provision or agree that no replacement is necessary.

12.4 No Waiver. Any term or provision of this Agreement may be waived only in writing by the party who is entitled to the benefits being waived. No waiver by any party shall operate as a waiver of any future exercise of that right, nor shall any single or partial exercise of any right hereunder preclude any other or future exercise of that right or any other right hereunder. All rights and remedies evidenced hereby are in addition to and cumulative to rights and remedies available at law.

12.5 Notice. Any notice required to be given under this Agreement shall be in writing and transmitted via facsimile, overnight courier, hand delivery or certified or registered mail, postage prepaid and return receipt requested, to the parties at the addresses below or such other addresses as may be specified by written notice. Notice sent in accordance with this Section shall be deemed effective when received.

If to the ISO:

ISO New England Inc.
One Sullivan Road
Holyoke, MA 01040
Attn: [name]

If to the Customer:

12.6 Force Majeure. The force majeure provisions of Section I of the Transmission, Markets and Services Tariff are incorporated herein by reference, with the “Customer” under this Agreement being deemed a Customer for purposes of the Transmission, Markets and Services Tariff.

12.7 Use of Subcontractors. Nothing in this Agreement shall prevent a Party from utilizing the services of subcontractors, as it deems appropriate, to perform its obligations under this Agreement. Notwithstanding the foregoing, each Party shall remain responsible for the accuracy of such work performed by its subcontractors.

12.8 No Third Party Beneficiary. Nothing in this Agreement, express or implied, is intended to confer on any person, other than the parties, any rights or remedies under or by reason of this Agreement.

12.9 Entire Agreement. This Agreement, including the Attachments, constitutes the entire agreement between the Parties with respect to its subject matter. No amendment to this Agreement shall be valid unless in writing and signed by all Parties.

12.10 Signature Authorization. The Parties have duly executed and agreed to be bound by this Agreement as evidenced by the signatures of their authorized representatives below. Each Party represents and warrants to the other that the signatory identified beneath its name below has full authority to execute this Agreement on its behalf.

12.11 Definitions. Capitalized terms not defined herein shall have the meanings ascribed to them in the Transmission, Markets and Services Tariff.

12.12 Counterparts. This Agreement may be executed in two or more counterparts, each of which shall be deemed an original but all of which together shall constitute one and the same instrument.

Customer:

ISO New England Inc.

Name: _____

Name: _____

Title: _____

Title: _____

Date: _____

Date: _____

EXHIBIT 1
INFORMATION FOR SYSTEM IMPACT STUDY

1.0 Facilities Identification

- 1.1 Requested capability in MW and MVA; summer and winter
- 1.2 Site location and plot plan with clear geographical references
- 1.3 Preliminary one-line diagram showing major equipment and extent of Customer ownership
- 1.4 Auxiliary power system requirements
- 1.5 Back-up facilities such as standby generation or alternate supply sources

2.0 Major Equipment

- 2.1 Power transformer(s): rated voltage, MVA and BIL of each winding, LTC and or NLTC taps and range, Z1 (positive sequence) and Zo (zero sequence) impedances, and winding connections. Provide normal, long-time emergency and short-time emergency thermal ratings.

- 2.2 Generator(s): rated MVA, speed and maximum and minimum MW output, reactive capability curves, open circuit saturation curve, power factor (V) curve, response (ramp) rates, H (inertia), D (speed damping), short circuit ratio, X1 (leakage), X2:(negative sequence), and Xo (zero sequence) reactances and other data:

	Direct	Quadrature
	Axis	Axis
Saturated synchronous reactance	X_{dv}	X_{qv}
unsaturated synchronous reactance	X_{di}	X_{qt}
saturated transient reactance	X'_{dv}	X'_{qv}
unsaturated transient reactance	X'_{di}	X'_{qi}
saturated subtransient reactance	X''_{dv}	X''_{qv}
unsaturated subtransient reactance	X''_{di}	X''_{qi}
transient open-circuit time constant	T'_{do}	T'_{qo}
transient short-circuit time constant	T''_d	T''_q
subtransient open-circuit time constant	T''_{do}	T''_{qo}
subtransient short-circuit time constant	T''_d	T''_q

- 2.3 Excitation system, power system stabilizer and governor: manufacturer's data in sufficient detail to allow modeling in transient stability simulations.
 - 2.4 Prime mover: manufacturer's data in sufficient detail to allow modeling in transient stability simulations, if determined necessary.
 - 2.5 Busses: rated voltage and ampacity (normal, long-time emergency and short-time emergency thermal ratings), conductor type and configuration.
 - 2.6 Transmission lines: overhead line or underground cable rated voltage and ampacity (normal, long-time emergency and short-time emergency thermal ratings), Z1 (positive sequence) and Zo (zero sequence) impedances, conductor type, configuration, length and termination points.
 - 2.7 Motors greater than 150 kW 3-phase or 50 kW single-phase: type (induction or synchronous), rated hp, speed, voltage and current, efficiency and power factor at 1/2, 3/4 and full load, stator resistance and reactance, rotor resistance and reactance, magnetizing reactance.
 - 2.8 Circuit breakers and switches: rated voltage, interrupting time and continuous, interrupting and momentary currents. Provide normal, long-time emergency and short-time emergency thermal ratings.
 - 2.9 Protective relays and systems: ANSI function number, quantity manufacturer's catalog number, range, descriptive bulletin, tripping diagram and three-line diagram showing AC connections to all relaying and metering.
 - 2.10 CT's and VT's: location, quantity, rated voltage, current and ratio.
 - 2.11 Surge protective devices: location, quantity, rated voltage and energy capability.
- 3.0 Other

- 3.1 Additional data reasonably necessary to perform the System Impact Study will be provided by the Customer as requested by the ISO.

- 3.2 The ISO reserves the right to require that the Customer accept the use in the study of specific equipment settings or characteristics necessary to meet criteria and standards specified in the ISO New England Operating Documents.

EXHIBIT 2
STUDY TIMETABLE

EXHIBIT 3
PREPAYMENT SCHEDULE

ATTACHMENT J

FACILITIES STUDY AGREEMENT

This Facilities Study Agreement (“Agreement”), dated _____, 200_, is entered into by _____ (the “Customer”) and ISO New England Inc. (“ISO”) for the purpose of setting forth the terms, conditions, and costs for conducting a Facilities Study (the “Study”) on [both] the systems of _____ [and] _____ (“the Transmission Operator(s)”) relative to [the Customer’s proposed _____ project (the “Project”) to be located in _____, _____.] [or] [the transmission service requested in the Customer’s Application] in accordance with the Open Access Transmission Tariff (the “OATT”) included in the ISO Transmission, Markets and Services Tariff on file with the Federal Energy Regulatory Commission. The ISO and the Customer are sometimes referred to herein together as the “Parties” and individually as a “Party.”

1. Purposes and Elements of the Study

The Study will determine the detailed engineering, design and cost of the facilities, upgrades, and special protection systems necessary to [satisfy the Customer’s interconnection for the Project] [or] [provide the transmission service] as indicated by the System Impact Study (the “SIS”).

2. Information Requirements

The Customer agrees to provide, in a timely and complete manner, all required information and technical data necessary for the ISO or its designated agent to conduct the Study. Where such information and technical data were previously provided by the Customer for purposes of the SIS, or otherwise, the Customer should review and update the information and provide the ISO with current information, as required. The ISO will advise the Customer of additional information or studies that may be deemed necessary to complete the Study. Any such additional information or studies shall be obtained or conducted only if required by Good Utility Practice and shall be subject to the Customer’s consent to proceed, such consent not to be unreasonably withheld. The cost of such additional studies shall be paid for by the Customer.

3. Representatives

All work pertaining to the Study that is the subject of this Agreement will be approved only through designated and authorized representatives of the Customer and the ISO, as they are identified in Article 14.5 hereof.

4. Scope, Duration, and Results of Study

The Scope of Work for the Study is set forth in Exhibit 1, entitled “Scope of Work.” The ISO estimates that the Study will require approximately _____ (___) [time period] to complete, as more fully set forth in Exhibit 2, entitled “Study Timetable.” The Customer understands and agrees that such time periods are only an estimate and that the ISO makes no representations or warranties, either express or implied, that the Study will be completed within these time periods. The ISO will provide the Customer with periodic status reports, which describe preliminary Study results, if available. Upon completion of the Study, the ISO will provide a report on the Study to the Customer based on the information provided and developed as a result of this effort. The Customer understands and acknowledges that any use of the Study results by the Customer or its agents, whether in preliminary or final form, prior to the ISO’s approval pursuant to Sections I.3.9 and I.3.10 of the Transmission, Markets and Services Tariff is completely at the Customer’s sole risk.

5. Payment and Nature of Costs

- (a) The estimated costs contained within this Agreement are the ISO’s good faith estimate of its costs to perform the Study contemplated by this Agreement. The ISO does not include any estimates for wheeling charges that may be associated with the transmission of facility output to third parties or with rates for station service. The actual costs charged to the Customer by the ISO may change as set forth in this Agreement. Prepayment will be required for all costs and expenses (including, without limitation, labor, materials, overheads, and administrative and general costs) the ISO will incur to perform its obligations under this Agreement, including, without limitation, all study, analysis, design, monitoring, and review work performed by the ISO or its designated agent’s personnel under the terms of this Agreement (“Study Costs”).
- (b) The estimated Study Costs required to be paid by the Customer to the ISO are shown on Exhibit 3, entitled “Prepayment Schedule.” The initial prepayment requirement is _____ (\$____), which the Customer agrees to pay to the ISO upon execution of this Agreement. The initial prepayment and any subsequent prepayments will be applied against all Study Costs incurred by the ISO for work performed under this Agreement. The ISO will invoice the Customer for the costs and expenses that the ISO will incur as stated in Exhibit 3. Each invoice will show the detail of the work performed, the difference between the actual costs for such work and the prepayment amount for such work, and the amount of the prepayment for the costs of the expected work. The Customer shall pay the invoiced

amount to the ISO within thirty (30) days of the Customer's receipt of the ISO's invoice. During the term of this Agreement, the ISO will, in writing, advise the Customer in advance of any changes in the cost estimate for work to be performed if the total amount increases by ten percent (10%) or more. Any such change to the Study Costs for the ISO's work performed under this Agreement shall be subject to the Customer's consent, such consent not to be unreasonably withheld. The Customer shall, within thirty (30) days of the ISO's notice of a cost increase, either authorize such cost increase and make payment in the amount set forth in such notice, or the ISO will suspend its performance and may terminate this Agreement. Payments for work performed by the ISO shall not be subject to refunding to the Customer except in accordance with Section 5(d) below.

- (c) The ISO will invoice Customer for pre-contract Study Costs incurred by the ISO prior to the effective date of this Agreement. To the extent such pre-contract Study Costs exceed Customer's pre-contract cost deposit balance, the Customer will reimburse the ISO within twenty (20) days after receipt of the ISO's invoice. Pre-contract costs shall include, without limitation, costs for study, analysis and review work performed in connection with the Study and all costs associated with the development and negotiation of all associated agreements. Payment for pre-contract Study Costs shall not be subject to refunding to the Customer.
- (d) If the actual Study Costs for the work exceed prepaid estimated costs, the Customer shall make payment to the ISO for such actual Study Costs within thirty (30) days of the date of the invoice for such costs. If the actual costs for the work are less than that prepaid, the ISO will credit such difference toward its expected additional costs, or in the event there will be no additional billed costs, will refund to Customer the amount of the overpayment. Any additional payments or refunding under this Agreement shall be subject to an interest charge computed in accordance with the provisions of the OATT.
- (e) Within one (1) year following the issuance of a final bill under this Agreement, the Customer shall have the right to audit the ISO's accounts and records at the offices where such accounts and records are maintained during normal business hours; provided that appropriate notice shall have been given prior to any audit and provided that the audit shall be limited to those portions of such accounts and records that relate to service under this Agreement. The ISO reserves the right to assess a reasonable fee to compensate for the use

of its personnel's time in assisting any inspection or audit of its books, records or accounts by the Customer or its designated agent.

6. No Interconnection or Wheeling Rights; No Interruption of Service

- (a) Nothing in this Agreement shall be interpreted to give the Customer the right to have electricity wheeled over, or to interconnect with, the ISO's or the Transmission Operator's transmission or distribution system. Such rights may be provided for under separate agreement.
- (b) Before the ISO will take any portion of the transmission system out of service to accommodate any work by, or on behalf of, the Customer, such action must first be fully evaluated and approved by the ISO and the Transmission Operator.

7. Indemnification

The indemnification and liability provisions in Section I of the Transmission, Markets and Services Tariff are incorporated herein by reference, with the "Customer" under this Agreement being deemed a Customer for purposes of the Transmission, Markets and Services Tariff.

8. Disclaimer of Damages

NO PARTY SHALL BE LIABLE TO ANY OTHER PARTY(IES) FOR ANY INDIRECT, CONSEQUENTIAL, EXEMPLARY, SPECIAL, INCIDENTAL OR PUNITIVE DAMAGES, INCLUDING WITHOUT LIMITATION LOSS OF USE OR LOST BUSINESS, REVENUE, PROFITS OR GOODWILL, ARISING IN CONNECTION WITH THIS AGREEMENT, THE STUDY PROVIDED HEREUNDER, AND/OR THE INTENDED USE THEREOF, UNDER ANY THEORY OF TORT, CONTRACT, WARRANTY, STRICT LIABILITY OR NEGLIGENCE. The Parties agree this Section 8 will survive expiration, cancellation, or any termination of the Agreement.

9. Duration

This Agreement will remain in effect for a period of one (1) year from its effective date (the "Term") and is subject to extension automatically if the final Study report has not been completed or by mutual agreement of the Parties.

10. Termination

- (a) In addition to other termination provisions provided for herein, the ISO may terminate this Agreement immediately, upon notice to the Customer, if the ISO is unable to obtain or maintain any governmental license, waiver, consent, registration or approval needed to conduct the Study hereunder.
- (b) The ISO or the Customer may terminate this Agreement upon thirty (30) days' written notice to the other Party or seven (7) days after providing written notice to the other Party that it has breached one of its obligations hereunder, if the breach has not been cured within such seven day period.

11. Dispute Resolution and Voluntary Arbitration

The dispute resolution provisions of Section I of the Transmission, Markets and Services Tariff are incorporated herein by reference, with the "Customer" under this Agreement being deemed a Customer for purposes of the Transmission, Markets and Services Tariff.

12. Commission Jurisdiction Over Certain Disputes; Equitable Relief

- (a) Nothing in this Agreement shall preclude, or be construed to preclude, any Party from filing a petition or complaint with the Federal Energy Regulatory Commission "Commission" with respect to any matter over which the Commission has jurisdiction.
- (b) The Parties specifically reserve the right to seek a temporary restraining order, preliminary or permanent injunction, or other similar equitable relief with respect to (i) violations of confidentiality provisions of this Agreement, (ii) any failures by the Parties to comply with any applicable post-termination obligations for which monetary compensation would not be adequate, or (iii) to preserve the status quo or prevent irreparable harm.

13. Confidential Information

- (a) During and after the term of this Agreement, neither Party or its employees or agents shall divulge or use for any purpose other than as specified in this Agreement Confidential Information received from the other Party (the "Disclosing Party"). "Confidential Information" shall mean all of the following except to the extent excluded below: (i) all information about the Disclosing Party whether furnished before or after the date hereof, whether oral, written or recorded/electronic, and regardless of the manner in which it is furnished, which is marked "Confidential" or "Proprietary" or which under all of the circumstances should be treated as confidential or proprietary; (ii) all reports, summaries,

compilations, analyses, notes or other information which are based on, contain or reflect any Confidential Information; (iii) any and all Confidential Information as that term is defined in the ISO New England Information Policy; and (iv) any information which, if disclosed by a transmission function employee of a utility regulated by the Commission to a market function employee of the same utility system, other than by public posting, would violate the Commission's open access same time information regulations.

- (b) The foregoing restrictions on use and disclosure of Confidential Information do not apply to information that: (i) is already in the possession of the Party receiving the information (the "Receiving Party") at the time of the information's disclosure hereunder and not otherwise subject to obligations of confidentiality; (ii) is, or becomes publicly known, through no wrongful act or omission of the Receiving Party or breach of this Agreement; (iii) is received by the Receiving Party without restriction from a third party free to disclose it without obligation to the Disclosing Party; (iv) is developed independently by the Receiving Party without reference to the Confidential Information or other information of the Disclosing Party; or (v) is required to be disclosed by subpoena, law or other directive or a court, administrative agency or arbitration panel. In addition, nothing in this Section 13 shall prohibit the Customer from disclosing Confidential Information to its lenders, consultants, agents, directors, officers, employees, and attorneys (the "Representatives") for the purpose of advising the Customer, provided that the Representatives shall be informed by the Customer that such information is Confidential Information and shall agree to treat it confidentially in accordance with this Section 13.
- (c) At the Disclosing Party's option, the Receiving Party shall promptly either destroy all Confidential Information in tangible form in its possession, or return all such copies, and in either event, provide a written officer's certification confirming the same promptly upon the earlier of: (i) the Disclosing Party's written request; or (ii) the expiration or earlier termination of this Agreement.

14. Miscellaneous

14.1 Assignment. The Customer may not assign this Agreement or any of its rights or obligations hereunder without the prior written consent of the ISO, which consent shall not be unreasonably withheld. Any attempted assignment without such prior written consent shall be void.

Notwithstanding the foregoing, the Customer may assign this Agreement as collateral security under its financing documents and the ISO hereby consents to such assignment.

14.2 Governing Law. This Agreement shall be construed and governed in accordance with the laws of the Commonwealth of Massachusetts, and with Part II of the Federal Power Act, 16 U.S.C. §§ 824d, et seq., and with Part 35 of Title 18 of the Code of Federal Regulations, 18 C.F.R. Part 35, each as may be modified from time to time.

14.3 Enforceability. If any section or clause of this Agreement shall be held to be invalid or unenforceable by any body or entity of competent jurisdiction, then the remainder of the Agreement shall remain in full force and effect and the Parties shall promptly negotiate a replacement provision or agree that no replacement is necessary.

14.4 No Waiver. Any term or provision of this Agreement may be waived only in writing by the Party who is entitled to the benefits being waived. No waiver by any Party shall operate as a waiver of any future exercise of that right, nor shall any single or partial exercise of any right hereunder preclude any other or future exercise of that right or any other right hereunder. All rights and remedies evidenced hereby are in addition to and cumulative to rights and remedies available at law.

14.5 Notice. Any notice required to be given under this Agreement shall be in writing and transmitted via facsimile, overnight courier, hand delivery or certified or registered mail, postage prepaid and return receipt requested, to the Parties at the addresses below or such other addresses as may be specified by written notice. Notice sent in accordance with this Section shall be deemed effective when received.

14.6 Force Majeure. The force majeure provisions of Section I of the Transmission, Markets and Services Tariff are incorporated herein by reference, with the “Customer” under this Agreement being deemed a Customer for purposes of the Transmission, Markets and Services Tariff.

14.7 Use of Subcontractors. Nothing in this Agreement shall prevent a Party from utilizing the services of subcontractors, as it deems appropriate, to perform its obligations under this

Agreement. Notwithstanding the foregoing, each Party shall remain responsible for the accuracy of such work performed by its subcontractors.

14.8 No Third Party Beneficiary. Nothing in this Agreement, express or implied, is intended to confer on any person, other than the Parties, any rights or remedies under or by reason of this Agreement.

14.9 Entire Agreement. This Agreement, including the Attachments, constitutes the entire agreement between the Parties with respect to its subject matter. No amendment to this Agreement shall be valid unless in writing and signed by all Parties.

14.10 Signature Authorization. The Parties have duly executed and agreed to be bound by this Agreement as evidenced by the signatures of their authorized representatives below. Each Party represents and warrants to the other that the signatory identified beneath its name below has full authority to execute this Agreement on its behalf.

14.11 Definitions. Capitalized terms not defined herein shall have the meanings ascribed to them in the Transmission, Markets and Services Tariff.

14.12 Counterparts. This Agreement may be executed in two or more counterparts, each of which shall be deemed an original but all of which together shall constitute one and the same instrument.

[CUSTOMER]

Name: _____

Title: _____

Date: _____

ISO NEW ENGLAND INC.

Name: _____

Title: _____

Date: _____

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ATTACHMENT K
REGIONAL SYSTEM PLANNING PROCESS

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APPENDIX 1 – ATTACHMENT K – LOCAL: LOCAL SYSTEM PLANNING PROCESS

APPENDIX 2 – LIST OF ENTITIES ENROLLED IN THE TRANSMISSION PLANNING REGION

APPENDIX 3 – LIST OF QUALIFIED TRANSMISSION PROJECT SPONSORS

1. Overview

This Attachment describes the regional system planning process conducted by the ISO, as well as the coordination with transmission-owning entities in, or other entities interconnected to, the New England Transmission System and neighboring systems to ensure the reliability of the New England Transmission System and compliance with national and regional planning standards, criteria and procedures, while accounting for market performance, economic, environmental, and other considerations, as may be agreed upon from time to time. The New England Transmission System is comprised of PTF, Non-PTF, OTF and MTF within the New England Control Area that is under the ISO's operational authority or control pursuant to the ISO Tariff and/or various transmission operating agreements. This Attachment describes the regional system planning process for the PTF conducted by the ISO, and local system planning process conducted by the PTOs, pursuant to their responsibilities defined in the Tariff, the various transmission operating agreements and this Attachment. Additional details regarding the regional system planning process are also provided in the ISO New England Planning Procedures and ISO New England Operating Procedures, which are available on the ISO's website.

The ISO shall conduct the regional system planning process for the PTF in coordination with the transmission-owning entities in, or other entities interconnected to, the New England Transmission System and neighboring systems, consistent with the rights and obligations defined in the Tariff, applicable transmission operating agreements and this Attachment. As described in this Attachment's Section 6 and Appendix 1, entitled "Attachment K -Local System Planning Process", the PTOs are responsible for the Local System Planning ("LSP") process for the Non-PTF in the New England Transmission System. As also described in Section 6, and pursuant to the Tariff and/or transmission operating agreements, the OTOs and MTOs are required to participate in the ISO's regional system planning process for reliability purposes and to perform and/or support studies of the impact of regional system planning projects on their respective OTF and MTF.

The regional system planning process described in this Attachment provides for the ISO to undertake assessments of the needs of the PTF system on a systemwide or specific area basis. These assessments shall be referred to as Needs Assessments, as described in Section 4.1 of this Attachment. The ISO shall incorporate market responses that have met the criteria specified in Sections 4.1(f) and 4A.3(b) of this

Attachment into the Needs Assessments, Public Policy Transmission Studies or the Regional System Plan (“RSP”), described below. Where market responses incorporated into the Needs Assessments or Public Policy Transmission Studies do not eliminate or address the needs identified by the ISO in Needs Assessments, Public Policy Transmission Studies or the RSP, the ISO shall develop or evaluate, pursuant to Sections 4.2(b), 4.3, or 4A of this Attachment, as applicable, regulated transmission solutions proposed in response to the needs identified by the ISO.

Pursuant to Sections 3 and 7 of this Attachment, the ISO shall develop the RSP for approval by the ISO Board of Directors following stakeholder input through the Planning Advisory Committee established pursuant to Section 2 of this Attachment. The RSP is a compilation of the regional system planning process activities conducted by the ISO. The RSP shall address needs of the PTF system determined by the ISO through Needs Assessments initiated and updated on an ongoing basis by the ISO to: (i) account for changes in the PTF system conditions; (ii) ensure reliability of the PTF system; (iii) comply with national and regional planning standards, criteria and procedures; and (iv) account for market performance, economic, environmental and other considerations as may be agreed upon from time to time.

As more fully described in Section 3 of this Attachment, the RSP shall identify:

- (i) PTF system reliability and market efficiency needs,
- (ii) the requirements and characteristics of the types of resources that may satisfy PTF system reliability and market efficiency needs to provide stakeholders an opportunity to develop and propose efficient market responses to meet the needs identified in Needs Assessments;
- (iii) regulated transmission solutions to meet the needs identified in Needs Assessments where market responses do not address such needs or additional transmission infrastructure may be required to comply with national and regional planning standards, criteria and procedures or provide market efficiency benefits in accordance with Attachment N of this OATT; and
- (iv) those projects identified through the Public Policy procedures described in Section 4A of this Attachment K.

In addition, the RSP shall also provide information on a broad variety of power system requirements that serves as input for reviewing the design of the markets and the overall economic performance of the system. The RSP shall also describe the coordination of the ISO's regional system plans with regional, local and inter-area planning activities.

Pursuant to Section 3.6 of this Attachment, the ISO shall also develop, maintain and post on its website a cumulative list reflecting the regulated transmission solutions proposed in response to Needs Assessments (the "RSP Project List"). The RSP Project List shall be a cumulative representation of the regional transmission planning expansion efforts ongoing in New England.

1.1 Enrollment

For purposes of participating as a transmission provider in the New England transmission planning region pursuant to this Attachment K, and distinct from Transmission Providers as defined in Section I of this Tariff, an entity chooses to enroll by executing (or having already executed) a: (i) transmission operating agreement with the ISO, or (ii) a Market Participant Service Agreement coupled with a written notification to the ISO that the entity desires to be a transmission provider in the New England region. Such enrollment in the transmission planning region is not necessary to participate in the Planning Advisory Committee, which is open to any entity as described in Section 2.3 of this Attachment K.

1.2 A List of Entities Enrolled in the Planning Region

A list of entities enrolled in the transmission planning region as transmission providers as described in Section 1.1. above, is included as Appendix 2 of this Attachment K.

2. Planning Advisory Committee

2.1 Establishment

A Planning Advisory Committee shall be established by the ISO to perform the functions set forth in Section 2.2 of this Attachment. It shall have a Chair and Secretary, who shall be appointed by the chief executive officer of the ISO or his or her designee. Before appointing an individual to the position of the Chair or Secretary, the ISO shall notify the Planning Advisory Committee of the proposed assignment and, consistent with its personnel practices, provide any other information about the individual reasonably requested by the Planning Advisory Committee. The chief executive officer of the ISO or his or her

designee shall consider the input of the members of the Planning Advisory Committee in selecting, removing or replacing such officers. The Planning Advisory Committee shall be advisory only and shall have no formal voting protocol.

The ISO may form subcommittees that, at the discretion of the ISO, may report to the Planning Advisory Committee.

2.2 Role of Planning Advisory Committee

The Planning Advisory Committee may provide input and feedback to the ISO concerning the regional system planning process, including the development of and review of Needs Assessments, the conduct of Solutions Studies, the development of the RSP, and updates to the RSP Project List. Specifically, the Planning Advisory Committee serves to review and provide input and comment on: (i) the development of the RSP, (ii) assumptions for studies, (iii) the results of Needs Assessments, Solutions Studies, and competitive solutions developed pursuant to Section 4.3 of this Attachment, (iv) potential market responses to the needs identified by the ISO in a Needs Assessment or the RSP, and (v) Cluster Enabling Transmission Upgrades Regional Planning Studies. The Planning Advisory Committee, with the assistance of and in coordination with the ISO, serves also to identify and prioritize requests for Economic Studies to be performed by the ISO, and provides input and feedback to the ISO concerning the conduct of Economic Studies and Public Policy Transmission Studies, including the criteria and assumptions for such studies. Based on input and feedback related to the regional system planning process provided by the Planning Advisory Committee to the ISO, the ISO shall consult with the appropriate NEPOOL technical committees, including but not limited to, the Markets, Reliability and Transmission Committees, on issues and concerns identified by the Planning Advisory Committee as requiring further investigation and consideration of potential changes to ISO New England Operating Documents.

2.3 Membership

There are no membership requirements to become part of the Planning Advisory Committee. Meetings are open to members of any entity, including State regulators or agencies and NESCOE, subject to the Critical Energy Infrastructure Information (“CEII”) policy as further described in Section 2.4(d) of this Attachment. To be added to the Planning Advisory Committee email distribution list, an email address shall be provided to the Secretary of the Committee. Throughout this Attachment K, a member of the

Planning Advisory Committee refers to any individual, whether they attend Planning Advisory Committee meetings or are included on the email distribution list.

2.4 Procedures

(a) Notice of Meetings

Prior to the beginning of each year, the ISO shall list on the ISO Calendar, which is available on the ISO's website, the proposed meeting dates for the Planning Advisory Committee for each month of the year. Prior to a Planning Advisory Committee meeting, the ISO shall provide notice to the Planning Advisory Committee by electronic email with the date, time, format for the meeting (i.e., in person or teleconference), and the purpose for the meeting.

(b) Frequency of Meetings

Meetings of the Planning Advisory Committee shall be held as frequently as necessary to serve the purposes stated in Section 2.2 of this Attachment and as further specified elsewhere in this Attachment, generally expected to be no less than four (4) times per year.

(c) Availability of Meeting Materials

The ISO shall post materials for Planning Advisory Committee meetings on the Planning Advisory Committee section on the ISO's website prior to meetings. The materials for the Planning Advisory Committee meetings shall be made available to the members of the Planning Advisory Committee subject to protections warranted by confidentiality requirements of the ISO New England Information Policy set forth in Attachment D of the ISO Tariff and Critical Energy Infrastructure Information ("CEII") policy as further described in Section 2.4(d) of this Attachment.

(d) Access to Planning-Related Materials that Contain CEII

CEII is defined as specific engineering, vulnerability, or detailed design information about proposed or existing critical infrastructure (physical or virtual) that:

- (i) Relates details about the production, generation, transportation, transmission, or distribution of energy;
- (ii) Could be useful to a person in planning an attack on critical infrastructure;
- (iii) Is exempt from mandatory disclosure under the Freedom of Information Act, 5 U.S.C. 552; and
- (iv) Does not simply give the location of critical infrastructure.

CEII pertains to existing and proposed system and assets, whether physical or virtual, the incapacity or destruction of which would negatively affect security, economic security, public health or safety, or any combination of those matters. CEII does not include information that is otherwise publicly available. Simplified maps and general information on engineering, vulnerability, or design that relate to production, generation, transportation, transmission or distribution of energy shall not constitute CEII.

Planning-related materials determined to be CEII will be posted on the ISO's password-protected website. To obtain access to planning-related materials determined to be CEII, the entity seeking to obtain such access must contact the ISO's Customer Service department. Authorized Market Participants or their representatives, such as consultants, are bound by the ISO New England Information Policy and will be able to access CEII materials through the ISO's password-protected website. State and federal governmental agency employees and their consultants will be able to access such materials through the ISO's password-protected website upon submittal of a signed non-disclosure agreement, which is available on the ISO's website. Personnel of the ERO, NPCC, other regional transmission organizations or independent system operators, and transmission owners from neighboring regions will be able to access CEII materials pursuant to governing agreements, rules and protocols. All external requests by other persons for planning-related materials determined to be CEII shall be recorded and tracked by ISO's Customer Services staff. Such requestors will be able to obtain access to CEII documents filed with the Commission pursuant to the Commission's regulations governing access to CEII. To the extent a requestor seeks access to planning-related material that is not filed with the Commission, such requestor shall comply with the requirements provided in the CEII procedures of the ISO, available on the ISO's website, prior to receiving access to CEII

information. Upon compliance with the ISO's CEII procedures, the ISO shall grant the requestor access to the planning-related CEII document through direct distribution or access to the ISO password-protected website.

2.5 Local System Planning Process

The LSP process described in Appendix 1 to this Attachment applies to the transmission system planning for the Non-PTF in the New England Transmission System. The PTOs will utilize interested members of the Planning Advisory Committee for advisory stakeholder input in the LSP process that will meet, as needed, at the conclusion of, or independent of, scheduled Planning Advisory Committee meetings. The LSP meeting agenda and meeting materials will be developed by representatives of the pertinent PTOs and PTO representatives will chair the LSP meeting. The ISO will post the LSP agenda and materials for LSP.

3. RSP: Principles, Scope, and Contents

3.1 Description of RSP

The ISO shall develop the RSP based on periodic comprehensive assessments (conducted not less than every third year) of the PTF systemwide needs to maintain the reliability of the New England Transmission System while accounting for market efficiency, economic, environmental, and other considerations, as agreed upon from time to time. The ISO shall update the RSP to reflect the results of ongoing Needs Assessments conducted pursuant to Section 4.1 of this Attachment. The RSP shall also account for projected improvements to the PTF that are needed to maintain system reliability in accordance with national and regional standards and the operation of efficient markets under a set of planning assumptions.

The RSP shall, among other things:

- (i) describe, in a consolidated manner, the assessment of the PTF system needs, the results of such assessments, and the projected improvements;
- (ii) provide the projected annual and peak demands for electric energy for a five-to ten-year horizon, the needs for resources over this period and how such resources are expected to be provided;

- (iii) specify the physical characteristics of the physical solutions that can meet the needs defined in the Needs Assessments and include information on market responses that can address them; and
- (iv) provide sufficient information to allow Market Participants to assess the quantity, general locations, operating characteristics and required availability criteria of the type of incremental supply or demand-side resources, or merchant transmission projects, that would satisfy the identified needs or that may serve to modify, offset or defer proposed regulated transmission upgrades.

The RSP shall also include a description of proposed regulated transmission solutions that, based on the Solutions Studies described in Section 4.2 of this Attachment and the competitive solution process described in Section 4.3 of this Attachment, meets the needs identified in the Needs Assessments. To this end, as further described in Section 3.6 below, the ISO shall develop and maintain a RSP Project List, a cumulative listing of proposed regulated transmission solutions classified, to the extent known, as Reliability Transmission Upgrades, Market Efficiency Transmission Upgrades, and Public Policy Transmission Upgrades (which, for the foregoing types of upgrades, may include the portions of Interregional Transmission Projects located within the New England Control Area) and of External Transmission Projects. The RSP shall also provide reasons for any new regulated transmission solutions or Transmission Upgrades included in the RSP Project List, any change in status of a regulated transmission solution or Transmission Upgrade in the RSP Project List, or for any removal of regulated transmission solutions or Transmission Upgrades from the RSP Project List that are known as of that time.

Each RSP shall be built upon the previous RSP.

3.2 Baseline of RSP

The RSP shall account for: (i) all projects that have met milestones, including market responses and regulated transmission solutions (e.g., planned demand-side projects, generation and transmission projects and Elective Transmission Upgrades) as determined by the ISO, in collaboration with the Planning Advisory Committee, pursuant to Sections 4.1, 4.2, 4.3, and 4A of this Attachment; and (ii) the

requirements for system operation and restoration services, not including the development of a system operations or restoration plan, which is outside the scope of the regional system planning process.

3.3 RSP Planning Horizon and Parameters

The RSP shall be based on a five-to ten-year planning horizon, and reflect five-to ten-year capacity and load forecasts.

The RSP shall conform to: Good Utility Practice; applicable Commission compliance requirements related to the regional system planning process; applicable reliability principles, guidelines, criteria, rules, procedures and standards of the ERO, NPCC, and any of their successors; planning criteria adopted and/or developed by the ISO; Transmission Owner criteria, rules, standards, guides and policies developed by the Transmission Owner for its facilities consistent with the ISO planning criteria, the applicable criteria of the ERO and NPCC; local transmission planning criteria; and the ISO New England Planning Procedures and ISO New England Operating Procedures, as they may be amended from time to time (collectively, the “Planning and Reliability Criteria”).

The revisions to this Attachment K submitted to comply with FERC’s Order No. 1000 shall not apply to any Proposed or Planned project included in an RSP approved by the ISO Board of Directors (or in an RSP Project List update) prior to the May 18, 2015 effective date of the Order No. 1000 compliance filing of the ISO and the PTOs, unless the ISO is re-evaluating the solution design for such project as of that effective date, or subsequently determines that the solution design for such project requires re-evaluation.

3.4 Other RSP Principles

The RSP shall be designed and implemented to: (i) avoid unnecessary duplication of facilities; (ii) identify facilities that are necessary to meet Planning and Reliability Criteria; (iii) avoid the imposition of unreasonable costs upon any Transmission Owner, Transmission Customer or other user of a transmission facility; (iv) take into account the legal and contractual rights and obligations of the Transmission Owners and the transmission-related legal and contractual rights and obligations of any other entity; (v) provide for coordination with existing transmission systems and with appropriate inter-area and local expansion plans; and (vi) properly coordinate with market responses, including, but not limited to generation, merchant transmission and demand-side responses.

3.5 Market Responses in RSP

Market responses shall include investments in resources (e.g., demand-side projects, generation and distributed generation) and Elective Transmission Upgrades and shall be evaluated by the ISO, in consultation with the Planning Advisory Committee, pursuant to Sections 4.1(f), 4A.3(b), and 7 of this Attachment.

In developing the RSP, the ISO shall account for market responses: (i) proposed by Market Participants as addressing needs (and any critical time constraints for addressing such needs) identified in an RSP, Needs Assessment, or Public Policy Transmission Study; and (ii) that have proved to be viable by meeting the criteria specified in Section 4.1(f) or 4A.3(b) of this Attachment, as applicable.

Specifically, market responses that are identified to the ISO and are determined by the ISO, in consultation with the Planning Advisory Committee, to be sufficient to alleviate the need for a particular regulated transmission solution or Transmission Upgrade, based on the criteria specified in the pertinent Needs Assessment or RSP, and are judged by the ISO to be achievable within the required time period, shall be reflected in the next RSP and/or in a new or updated Needs Assessment. That particular regulated transmission solution or Transmission Upgrade may continue to be included in the appropriate category on the RSP Project List (as described in Section 3.6 below), subject to the ISO having the flexibility to indicate that the project should proceed at a later date or it may be removed if it is determined to be no longer needed. If the market response does not fully address the defined needs, or if additional transmission infrastructure is required to facilitate the efficient operation of the market, the RSP shall also include that particular regulated transmission solution or Transmission Upgrade, subject to the ISO having the flexibility to indicate that the Transmission Upgrade or regulated transmission solution should proceed at a later date and be modified, if necessary.

3.6 The RSP Project List

(a) Elements of the RSP Project List

The RSP Project List shall identify regulated transmission solutions proposed in response to the needs identified in a RSP or Needs Assessments conducted pursuant to Section 4.1 of this Attachment, and shall identify Public Policy Transmission Upgrades identified pursuant to Section 4A of this Attachment. The RSP Project List shall identify the proposed regulated transmission solutions separately as a Reliability Transmission

Upgrade, a Market Efficiency Transmission Upgrade, or a Public Policy Transmission Upgrade.

With regard to Reliability Transmission Upgrades and Market Efficiency Transmission Upgrades, the following subcategories will be utilized to indicate the status of each proposed regulated transmission solution in the evaluation process. These subcategories include: (i) Proposed; (ii) Planned; (iii) Under Construction; and (iv) In-Service. A Public Policy Transmission Upgrade will be identified in the RSP Project List as (i) Proposed; (ii) Planned; (iii) Under Construction; or (iv) In-Service.

The regulated transmission solution subcategories are defined as follows:

(i) For purposes of Reliability Transmission Upgrades and Market Efficiency Transmission Upgrades, “Proposed” shall include a regulated transmission solution that (a) has been proposed in response to a specific need identified by the ISO in a Needs Assessment or the RSP and (b) has been evaluated or further defined and developed in a Solutions Study, as specified in Section 4.2(a) of this Attachment, or in the competitive solutions process specified in Section 4.3 of this Attachment, such that there is significant analysis that supports a determination by the ISO, as communicated to the Planning Advisory Committee, that the proposed regulated transmission solution would likely meet the need identified by the ISO in a Needs Assessment or the RSP, but has not received approval by the ISO under Section I.3.9 of the Tariff.

For purposes of Public Policy Transmission Upgrades, “Proposed” means that the ISO has included the project in the RSP Project List pursuant to the procedures described in Section 4A of this Attachment K, but that the project has not yet been approved by the ISO under Section I.3.9 of the Tariff.

(ii) “Planned” shall include a Transmission Upgrade that has met the requirements for a Proposed project and has been approved by the ISO under Section I.3.9 of the Tariff.

(iii) “Under Construction” shall include a Transmission Upgrade that has received the approvals required under the Tariff and engineering and construction is underway.

(iv) “In Service” shall include a Transmission Upgrade that has been placed in commercial operation.

The RSP Project List shall also list External Transmission Projects for which cost allocation and, if applicable, operating agreements have been accepted by the Commission, and indicate whether such External Transmission Projects are proposed, under construction or in service.

Each Reliability Transmission Upgrade and Market Efficiency Transmission Upgrade shall be cross-referenced to the specific systemwide or area needs identified in a Needs Assessment or RSP. Each proposed Public Policy Transmission Upgrade shall be cross-referenced in the RSP Project List to a specific Public Policy Transmission Study.

For completeness, the RSP Project List shall also include Elective Transmission Upgrades and transmission facilities (as determined under the ISO interconnection process specified in this OATT) to be built to accommodate new generation, and Elective Transmission Upgrades that have satisfied the requirements of this OATT.

An Interregional Transmission Project developed pursuant to Section 6.3 of this Attachment K may displace a regional Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade on the RSP Project List where the ISO has determined that the Interregional Transmission Project is a more efficient or cost-effective solution. In the case of an Interregional Transmission Project that could meet the needs met by a Public Policy Transmission Upgrade, the associated Public Policy Transmission Upgrade may be removed from the RSP Project List in the circumstances described, and using the procedures specified, in Section 4A of Attachment K.

(b) Periodic Updating of RSP Project List

The RSP Project List will be updated by the ISO periodically by adding, removing or revising regulated transmission solutions or Transmission Upgrades in consultation with the Planning Advisory Committee and, as appropriate, the Reliability Committee.

Updating of the RSP Project List shall be considered an update of the RSP to be reflected in the next RSP, as appropriate, pursuant to Section 3.1 of this Attachment.

(c) RSP Project List Updating Procedures and Criteria

As part of the periodic updating of the RSP Project List, the ISO: (i) shall modify (in accordance with the provisions of this Attachment) regulated transmission solutions or Transmission Upgrades to reflect changes to the PTF system configurations, including ongoing investments by Market Participants or other stakeholders; (ii) may add to and classify accordingly, regulated transmission solutions; (iii) may remove from the RSP Project List regulated transmission solutions or Transmission Upgrades previously identified in the RSP Project List if the ISO determines that the need for the proposed regulated transmission solution or the approved Transmission Upgrade no longer exists or is no longer feasible; and (iv) may remove from the RSP Project List regulated transmission solutions or Transmission Upgrades that have been displaced by an Interregional Transmission Project in the circumstances described in Section 3.6(a) of this Attachment. With regard to (iii) above, this may include a removal of a regulated transmission solution or Transmission Upgrade because a market response meeting the need reaches the maturity specified in Sections 4.1(f) or 4A.3(b) of this Attachment and has been determined, pursuant to Sections 4.1(f) or 4A.3(b) of this Attachment, to meet the need described in the pertinent Needs Assessment, Public Policy Transmission Study or RSP, as applicable. In doing so, the ISO shall consult with and consider the input from the Planning Advisory Committee and, as appropriate, the Reliability Committee. In addition, the ISO shall remove from the RSP Project List any Public Policy Transmission Upgrade if the ISO determines, with input from the Planning Advisory Committee, that the need to which the Public Policy Transmission Upgrade responds no longer exists.

If a regulated transmission solution or Transmission Upgrade is removed from the RSP Project List by the ISO, the entity responsible for the construction of the regulated

transmission solution or Transmission Upgrade shall be reimbursed for any costs prudently incurred or prudently committed to be incurred (plus a reasonable return on investment at existing Commission-approved ROE levels) in connection with the planning, designing, engineering, siting, permitting, procuring and other preparation for construction, and/or construction of the regulated transmission solution or Transmission Upgrade proposed for removal from the RSP Project List. The provisions of Schedule 12, Schedule 13 and Schedule 14 of this OATT shall apply to any cost reimbursement under this Section. Prior to finalizing the RSP, the ISO shall provide the Planning Advisory Committee with written information explaining the reasons for any removal under this Section.

(d) Posting of LSP Project Status

Each PTO will be individually responsible for publicly posting and updating the status of its respective LSP and the transmission projects arising therefrom on its company website. The ISO's posting of the RSP Project Lists will include links to each PTO's specific LSP posting to be provided to the ISO by the PTOs.

4. Procedures for the Conduct of Needs Assessments, Treatment of Market Responses and Evaluation of Regulated Transmission Solutions

4.1 Needs Assessments

The reliability planning process established in this Attachment K shall apply to all transmission solutions adopted to resolve a reliability need. The market efficiency planning process established in this Attachment K shall apply to all transmission solutions adopted to resolve a market efficiency need. The public policy planning process established in this Attachment K shall apply to all transmission solutions adopted to resolve a public policy need. For needs identified initially as reliability, market efficiency or public policy needs, the collateral benefits of potential solutions to those needs shall not change the planning process applicable to those identified needs; notwithstanding the foregoing, the ISO shall report its views as to whether a project or preferred solution may also satisfy identified reliability needs of the system as described in Section 4A.8 of this Attachment K. Sections 4.1 through 4.3 of this Attachment are not applicable to the planning of Public Policy Transmission Upgrades, which is governed instead by Section 4A of this Attachment.

On a regular and ongoing basis, the ISO, in coordination with the PTOs and the Planning Advisory Committee, shall conduct assessments (i.e., Needs Assessments) of the adequacy of the PTF system, as a whole or in part, to maintain the reliability of such facilities while promoting the operation of efficient wholesale electric markets in New England. A Needs Assessment shall analyze whether the PTF in the New England Transmission System: (i) meet applicable reliability standards; (ii) have adequate transfer capability to support local, regional, and inter-regional reliability; (iii) support the efficient operation of the wholesale electric markets; (iv) are sufficient to integrate new resources and loads on an aggregate or regional basis; or (v) otherwise examine various aspects of its performance and capability. A Needs Assessment shall also identify: (i) the location and nature of any potential problems with respect to the PTF and (ii) situations that significantly affect the reliable and efficient operation of the PTF along with any critical time constraints for addressing the needs of the PTF to facilitate the development of market responses and to initiate the pursuit of regulated transmission solutions.

(a) Triggers for Needs Assessments

The ISO, in coordination with the PTOs and the Planning Advisory Committee, shall perform Needs Assessments, inter alia, as needed to:

- Assess compliance with reliability standards and criteria (including those established by the ISO, NERC, and NPCC) consistent with the long term needs of the system.
- Assess the adequacy of the transmission system capability, such as transfer capability, to support local, regional and interregional reliability.
- Assess the efficient operation of the wholesale electric market. (See Attachment N regarding the identification of market efficiency upgrades).
- Assess sufficiency of the system to integrate new resources and loads on an aggregate or regional basis as needed for the reliable and efficient operation of the system.
- Analyze various aspects of system performance. (Including but not limited to, transient network analysis, small signal analysis, electromagnetic transients program analysis, or delta P analysis).
- Examine short circuit performance of the system.

- Assess the ability to efficiently operate and maintain the transmission system.
- Address requests for an economic study consistent with section 4.1.b of Attachment K.
- Address system performance in consideration of de-list bids and cleared demand bids consistent with sections 4.1(c) and 4.1(f) of Attachment K.
- Address system performance as otherwise deemed appropriate by the ISO.

(b) Requests by Stakeholders for Needs Assessments for Economic Considerations

The ISO's stakeholders may request the ISO to initiate a Needs Assessment to examine situations where potential regulated transmission solutions or market responses or investments could result in (i) a net reduction in total production cost to supply system load based on the factors specified in Attachment N of this OATT, (ii) reduced congestion, or (iii) the integration of new resources and/or loads on an aggregate or regional basis (an "Economic Study").

Requests for Economic Studies shall be submitted, considered and prioritized as follows:

- (i) By no later than April 1 of each year, any stakeholder may submit to the ISO for public posting on the ISO's website a request for an Economic Study.
- (ii) The ISO shall thereafter add any of its own proposals for Economic Studies. The ISO shall also develop a rough work scope and cost estimate for all requested Economic Studies, and develop preliminary prioritization based on the ISO's perceived regional and/or, as coordinated with the applicable neighboring system, inter-area benefits to assist stakeholders in the prioritization of Economic Studies.
- (iii) By no later than May 1 of each year, the ISO shall provide the foregoing information to the Planning Advisory Committee, and a Planning Advisory Committee meeting shall be held at which Economic Study proponents will provide an explanation of their request.
- (iv) By no later than June 1 of each year, the ISO shall hold a meeting of the Planning Advisory Committee for the members of the Planning Advisory Committee to discuss,

identify and prioritize, as further facilitated by the ISO's preparation of a straw priority list to be further discussed at such meeting, up to two (2) Economic Studies (the costs of which will be recovered by the ISO pursuant to Schedule 1 of Section IV.A of the Tariff) to be performed by the ISO in a given year taking into consideration their impact on the ISO budget and other priorities. The ISO may consider performing up to three (3) Economic Studies if a Public Policy Transmission Study will not be concurrently performed.

- (v) The ISO and the Planning Advisory Committee may agree to hold additional meetings to further discuss and resolve any issue concerning the substance of the Economic Studies themselves and/or their prioritization.
- (vi) If the Planning Advisory Committee, after discussions between the Planning Advisory Committee and ISO management, is not able to prioritize the Economic Studies to be performed by the ISO in a given year, any member of the Planning Advisory Committee must submit a request for Regional Planning Dispute Resolution Process pursuant to Section 12 of this Attachment, such request to be submitted no later than August 30, to resolve the issues concerning the substance of the Economic Studies themselves and/or their prioritization.
- (vii) The ISO will issue a notice to the Planning Advisory Committee detailing the prioritization of the Economic Studies as identified by the Planning Advisory Committee or, if a request for Regional Planning Dispute Resolution Process is submitted pursuant to Section 4.1.(b)(vi), as determined through that Process.

The foregoing timelines are subject to adjustment as determined by the ISO in coordination with the Planning Advisory Committee. The ISO will provide periodic updates on the status of Economic Studies to the Planning Advisory Committee.

Economic Study requests not within the three studies identified in Section 4.1(b)(iv) to be performed in a given year may be requested and paid for by the study proponent.

(c) Conduct of a Needs Assessment for Rejected De-List Bids

- (i) In the case of a rejected Static De-List Bid or Dynamic De-List Bid, the ISO may as warranted, with advisory input from the Reliability Committee, examine the unavailability of the resource(s) with the rejected bid as a sensitivity in a Needs Assessment, or examine the unavailability of the resource(s) in the base representation in a Needs Assessment. The ISO may as warranted, with advisory input from the Reliability Committee, initiate a Needs Assessment for the purpose of modeling rejected Static De-List Bids or Dynamic De-List Bids where the ISO believes that the initiation of such a study is warranted.
- (ii) Prior to the start of each New Capacity Show of Interest Submission Window, the ISO shall present to the Reliability Committee the status of any prior rejected Dynamic De-List Bids, Static De-List Bids, Permanent De-List Bids or Retirement De-List Bids being studied in the regional system planning process.

(d) Notice of Initiation of Needs Assessments

Prior to its commencement, the ISO shall provide notice of the initiation of a Needs Assessment to the Planning Advisory Committee consistent with Section 2 of this Attachment.

(e) Preparation of Needs Assessment

Needs Assessments may examine resource adequacy, transmission adequacy, projected congestion levels and other relevant factors as may be agreed upon from time to time. Needs Assessments shall also consider the views, if any, of the Planning Advisory Committee, State regulators or agencies, NESCOE, the Market Advisor to the ISO Board of Directors, and the ISO Board of Directors. A corresponding assessment shall be performed by the PTOs to identify any needs relating to the Non-PTF transmission facilities (of whatever voltage) that could affect the provision of Regional Transmission Service over the PTF.

(f) Treatment of Market Responses in Needs Assessments

The ISO shall reflect proposed market responses in the regional system planning process. Market responses may include, but are not limited to, resources (e.g., demand-side projects and distributed generation), and Elective Transmission Upgrades.

Specifically, the ISO shall incorporate or update information regarding resources in Needs Assessments that have been proposed and (i) have cleared in a Forward Capacity Auction pursuant to Market Rule 1 of the ISO Tariff, (ii) have been selected in, and are contractually bound by, a state-sponsored Request For Proposals, or (iii) have a financially binding obligation pursuant to a contract. The ISO will model out-of-service all submitted Retirement De-List Bids, submitted Permanent De-List Bids, and demand bids that have cleared in a substitution auction, and may model out-of-service rejected-for-reliability Static De-List Bids and rejected-for-reliability Dynamic De-List Bids from the most recent Forward Capacity Auction. With respect to (ii) or (iii) above, demonstration of such contracts is accomplished through submittal for ISO review of an order or other similar authorization from the appropriate state regulatory agency, along with a copy of the contract, that together demonstrate the contractual requirements. These documents may be submitted by: the Project Sponsor; the state regulatory agency authorizing the contract; a transmission company that is a counterparty to the contract; or by a third-party organization representing the interests of the New England states regarding energy related issues, such as NESCOE. The ISO shall incorporate or update information regarding a proposed Elective Transmission Upgrade in a Needs Assessment at a time after the studies corresponding to the Elective Transmission Upgrade are completed (including receipt of approval under Section I.3.9 of the Tariff), a commercial operation date has been ascertained, and for which the certification has been accepted in accordance with Section III.12 of the Tariff. In the case where the Elective Transmission Upgrades are proposed in conjunction with the interconnection of a resource, these Elective Transmission Upgrades shall be considered at the same time as the proposed resource is considered in the Needs Assessment provided that the studies corresponding to the Elective Transmission Upgrade are completed (including receipt of approval under Section I.3.9 of the Tariff), a commercial operation date has been ascertained, and for which the certification has been accepted in accordance with Section III.12 of the Tariff.

(g) Needs Assessment Support

For the development of the Needs Assessments, the ISO will coordinate with the PTOs and the Planning Advisory Committee to support the ISO's performance of Needs Assessments. To facilitate this support, the ISO will post on its website the models, files, cases, contingencies, assumptions and other information used to perform Needs Assessments. The ISO may establish requirements that any PTO or member of the Planning Advisory Committee must satisfy in order to access certain information used to perform Needs Assessments, due to ISO New England Information Policy and CEII constraints. The ISO may ask PTOs or Planning Advisory Committee members with special expertise to provide technical support or perform studies required to assess one or more potential needs that will be considered in the Needs Assessments process. These entities will provide, and the ISO will post on its website, the models, files, cases, contingencies, assumptions and other information used by those entities to perform studies. The ISO will post the draft results of any such Needs Assessment studies on its website. The ISO will convene meetings open to any representative of an entity that is a member of the Planning Advisory Committee to facilitate input on draft Needs Assessments studies and the inputs to those studies prior to the ISO's completion of a draft Needs Assessment report to be reviewed by the entire Planning Advisory Committee pursuant to Section 4.1(i) of this Attachment. All provisions of this subsection (g) relating to the provision and sharing of information shall be subject to the ISO-NE Information Policy.

(h) Input from the Planning Advisory Committee

Meetings of the Planning Advisory Committee shall be convened to identify additional considerations relating to a Needs Assessment that were not identified in support of initiating the assessment, and to provide input on the Needs Assessment's scope, assumptions and procedures, consistent with the responsibilities of the Planning Advisory Committee as set forth in Section 2.2 of this Attachment.

(i) Publication of Needs Assessment and Response Thereto

The ISO shall report the results of Needs Assessments to the Planning Advisory Committee, subject to CEII constraints. Needs Assessments containing CEII will be posted on the ISO's password-protected website consistent with Section 2.4(d) of this Attachment. Needs Assessments will identify high-level functional requirements and characteristics for regulated transmission solutions and market responses that can meet the needs described in the assessment.

Where the ISO forecasts that a solution is needed to solve reliability criteria violations in three years or less from the completion of a Needs Assessment (unless the solution to the Needs Assessment will likely be a Market Efficiency Transmission Upgrade), and the requirements of Section 4.1(j) of this Attachment have been met or where there is only one Phase One Proposal submitted in response to a request for proposal issued under Sections 4.3(a) of this Attachment or only one proposed solution that is selected to move on as a Phase Two Solution, the ISO will evaluate the adequacy of proposed regulated solutions by performing Solutions Studies, as described in Section 4.2 of this Attachment. Where the solution to a Needs Assessment will likely be a Market Efficiency Transmission Upgrade, or where the forecast year of need for a solution that is likely to be a Reliability Transmission Upgrade is more than three years from the completion of a Needs Assessment, the ISO will conduct a solution process based on a two-stage competitive solution process, as described in Section 4.3 of this Attachment.

(j) Requirements for Use of Solutions Studies Rather than Competitive Solution Process for Projects Based on Year of Need

The following requirements must be met in order for the ISO to use Solutions Studies in the circumstances described in Section 4.1(i) based on the solution's year of need:

- (i) The ISO shall separately identify and post on its website an explanation of the reliability criteria violations and system conditions that the region has a time-sensitive need to solve within three years of the completion of the relevant Needs Assessment. The explanation shall be in sufficient detail to allow stakeholders to understand the need and why it is time-sensitive.
- (ii) In deciding whether to utilize Solutions Studies, such that the regulated transmission solution will be developed through a process led by the ISO and built by the PTO(s), the ISO shall:
 - (A) Provide to the Planning Advisory Committee and post on its website a full and supported written description explaining the decision to designate a PTO as the entity responsible for construction and ownership of the reliability project, including an explanation of other transmission or non-transmission options that the region considered but concluded would not sufficiently address the

immediate reliability need, and the circumstances that generated the reliability need and an explanation of why that reliability need was not identified earlier.

(B) Provide a 15-day period during which comments from stakeholders on the posted description may be sent to the ISO, which comments will be posted on the website, as well.

(iii) The ISO shall maintain and post on its website a list of prior year designations of all projects in the limited category of transmission projects for which the PTO(s) was designated as the entity responsible for construction and ownership of the project following the performance of Solutions Studies. The list must include the project's need-by date and the date the PTO(s) actually energized the project, i.e., placed the project into service. The ISO shall file such list with the Commission as an informational filing in January of each calendar year covering the designations of the prior calendar year, when applicable.

4.2 Evaluation of Regulated Transmission Solutions in Solutions Studies, Where Competitive Solution Process of Section 4.3 Is Not Applicable

The procedures described in this Section 4.2 shall be utilized for the evaluation of regulated transmission solutions for reliability and market efficiency needs where the requirements of Sections 4.1(i) and/or (j) of this Attachment are satisfied. Otherwise, the procedures of Section 4.3 shall be utilized for that purpose.

(a) Evaluation and Development of Regulated Transmission Solutions in Solutions Studies for Market Efficiency Transmission Upgrades and Reliability Transmission Upgrades

In the case of Market Efficiency Transmission Upgrades and Reliability Transmission Upgrades, the ISO, in coordination with the proponents of regulated transmission solutions and other interested or affected stakeholders, shall conduct or participate in studies ("Solutions Studies") to evaluate whether proposed regulated transmission solutions meet the PTF system needs identified in Needs Assessments. The ISO, in coordination with affected stakeholders shall also identify regulated transmission projects for addressing the needs identified in Needs Assessments.

The ISO may form ISO-led targeted study groups to conduct Solutions Studies. Such study groups will include representatives of the proponents of regulated transmission solutions and other interested or affected stakeholders. Through this process, the ISO may identify the solutions for the region that offer the best combination of electrical performance, cost, future system expandability, and feasibility to meet a need identified in a Needs Assessment in the required time frame. These solutions may differ from a transmission solution proposed by a transmission owner.

Proponents of regulated transmission proposals in response to Needs Assessments shall also identify any LSP plans that require coordination with their regulated transmission proposals addressing the PTF system needs.

(b) Notice of Initiation of a Solutions Study

The ISO shall provide notice of the initiation and scope of a Solutions Study to the Planning Advisory Committee.

(c) Classification of Regulated Transmission Solutions as Market Efficiency Transmission Upgrades or Reliability Transmission Upgrades

As described in Section 3.1 and 3.6(a) of this Attachment, proposed regulated transmission solutions determined by the ISO, in consultation with the Planning Advisory Committee, to address needs identified in Needs Assessments shall be classified as a Reliability Transmission Upgrade and/or a Market Efficiency Transmission Upgrade pursuant to the standards set forth in Attachment N of this OATT.

(d) Evaluation Factors Used for Identification of the Preferred Solution

Factors to be considered during the evaluation process for identification of the preferred solution may include, but are not limited to, the following which are listed in no particular order:

- Installed cost;
- Life-cycle cost, including all costs associated with right of way acquisition, easements, and associated real estate;
- System performance;

- Cost cap or cost containment provisions;
- In-service date of the project or portion(s) thereof;
- Project constructability;
- Generation and transmission facility outages required during construction;
- Extreme contingency performance;
- Operational impacts;
- Incremental costs for potential resource retirements;
- Interface impacts;
- Future expandability;
- Consistency with Good Utility Practice;
- Potential siting/permitting issues or delays;
- Loss savings;
- Replacement of aging infrastructure;
- Environmental impact;
- Design standards; and
- Impact on NPCC Bulk Power System classification.

(e) Identification of the Preferred Solution and Inclusion of Results of Solutions Studies for Market Efficiency Transmission Upgrades and Reliability Transmission Upgrades in the RSP

The results of Solutions Studies related to Market Efficiency Transmission Upgrades and Reliability Transmission Upgrades will be reported to the Planning Advisory Committee. After receiving feedback from the Planning Advisory Committee, the ISO will identify the preferred solution. The ISO will inform the appropriate Transmission Owners in writing regarding the identification of the preferred solution.

Once identified, the preferred solution, as appropriate, will be reflected (with an overview of why the solution is preferred) in the RSP and/or its Project List, as it is updated from time to time in accordance with this Attachment. Where external impacts of regional projects are identified through coordination by the ISO with neighboring entities, those impacts will be identified in the RSP. Costs associated with such impacts will be addressed as set forth in Schedule 15.

(f) Cancellation of a Solutions Study

The ISO may cancel a Solutions Study at any time. Such cancellation may be due to new or different assumptions which may change or eliminate the identified needs. Any costs associated with Solutions Study development shall be recovered pursuant to Section 3.6(c) of this Attachment.

4.3 Competitive Solution Process for Reliability Transmission Upgrades and Market Efficiency Transmission Upgrades

(a) Initiating the Competitive Solution Process

The ISO will publicly issue a request for proposal with respect to each Needs Assessment for which, pursuant to Section 4.1(i) of this Attachment, a competitive solution process will be utilized. The request for proposal will indicate that Qualified Transmission Project Sponsors may submit Phase One Proposals offering solutions that comprehensively address the identified needs. A Qualified Transmission Project Sponsor may propose a comprehensive solution to address the identified needs that includes an upgrade(s) located on or connected to a PTO's existing transmission system where the Qualified Transmission Project Sponsor is not the PTO for the existing system element(s). In such cases, the Qualified Transmission Project Sponsor's proposed solution relating to the upgrade(s) of an existing transmission system element(s) must provide all data available to the Qualified Transmission Project Sponsor as part of its response to the request for proposal. The Qualified Transmission Project Sponsor is not required to procure agreements with the PTO for implementation of such upgrades as the PTO is required to implement the upgrade(s) in accordance with Schedule 3.09(a) of the Transmission Operating Agreement if the proposed solution is selected through the competitive process.

A PTO or PTOs identified by the ISO as the Backstop Transmission Solution provider(s) shall submit an individual or joint Phase One Proposal (if more than one PTO is identified) as a Backstop Transmission Solution for any need identified in the request for proposal that would be solved by a project located within or connected to its/their existing electric system, and which it/they would therefore have an obligation to build under Schedule 3.09(a) of the TOA. Such PTOs may recover the costs of preparing Phase One Proposals in accordance with the mechanisms reflected in the OATT and the terms of the TOA.

A member of the Planning Advisory Committee that is not a Qualified Transmission Project Sponsor but would like the ISO to consider a Phase One Proposal reflecting its concept for a project in response to a Needs Assessment (that is, a project that is “unsponsored”) must, before the deadline for the submission of Phase One Proposals, identify a Qualified Transmission Project Sponsor willing to submit a corresponding Phase One Proposal and Phase Two Solution (and to develop and construct the project, if selected in the competitive solution process) in order for the unsponsored project to be submitted in response to an ISO solicitation in Phase One. Upon request by the pertinent Planning Advisory Committee member for assistance in identifying a sponsor, the ISO shall post on its website and distribute to the Planning Advisory Committee a notice that solicits expressions of interest by Qualified Transmission Project Sponsors for sponsorship of the member’s conceptual project. All expressions of interest shall include a detailed explanation of why the Qualified Transmission Project Sponsor is best qualified to construct, own and operate the unsponsored project. If only one Qualified Transmission Project Sponsor expresses interest, the ISO shall designate it as the Qualified Transmission Project Sponsor. If more than one Qualified Transmission Project Sponsor expresses interest, the Planning Advisory Committee member shall select the Qualified Transmission Project Sponsor. In either case, the designated Qualified Transmission Project Sponsor shall thereafter comply with the requirements of this Attachment K and the ISO Tariff with respect to the project. If no Qualified Transmission Project Sponsor expresses interest, the unsponsored project may not be submitted as a Phase One Proposal.

(b) Use and Control of Right of Way

Neither the submission of a project by a Qualified Transmission Project Sponsor nor the selection by the ISO of a project submitted by a Qualified Transmission Project Sponsor for inclusion in the RSP Project List shall alter a PTO’s use and control of an existing right of way, the retention, modification, or transfer of which remain subject to the relevant law or regulation, including property or contractual rights, that granted the right-of-way. Nothing in the processes described in this Attachment K requires a PTO to relinquish any of its rights-of-way in order to permit a Qualified Transmission Project Sponsor to develop, construct or own a project.

(c) Information Required for Phase One Proposals; Study Deposit; Timing

Phase One Proposals shall provide the following information:

- (i) a detailed description of the proposed solution, in the manner specified by the ISO, including an identification of the proposed route for the solution and technical details of the project, such as interconnection into the existing transmission system;
- (ii) a detailed explanation of how the proposed solution addresses the identified need;
- (iii) the proposed schedule, including key high-level milestones, for development, siting, procurement of real estate rights, permitting, construction and completion of the proposed solution;
- (iv) right, title, and interest in rights of way, substations, and other property or facilities, if any, that would contribute to the proposed solution or the means and timeframe by which such would be obtained; and
- (v) the estimated life-cycle and installed costs of the proposed solution, including a high-level itemization of the components of the cost estimate, a description of the financing being used, and any cost containment or cost cap measures.

With each proposal, the Qualified Transmission Project Sponsor must include payment of a \$100,000 study deposit per submitted Phase One Proposal to support the cost of Phase One Proposal and Phase Two Solution study work by the ISO. The study deposit of \$100,000 shall be applied towards the costs incurred by the ISO associated with the study of the Phase One Proposal and Phase Two Solution.

Phase One Proposals must be submitted by the deadline specified in the public posting by the ISO of the request for proposal described in Section 4.3(a) of this Attachment, which shall not be less than 60 days from the posting date of the request for proposal. The ISO may reject submittals which are insufficient or not adequately supported.

(d) LSP Coordination

Qualified Transmission Project Sponsors of Phase One Proposals shall also identify any LSP plans that require coordination with their Phase One Proposals.

(e) Preliminary Review by ISO

If the sole Phase One Proposal in response to a given Needs Assessment is the Backstop Transmission Solution, the ISO shall proceed under Section 4.2 of this Attachment, rather than pursuant to the procedures set forth in the remainder of this Section 4.3.

If more than one Phase One Proposal has been submitted in response to the request for proposal described in Section 4.3(a) of this Attachment K, the ISO shall perform a preliminary feasibility review of each proposal to determine whether the proposed solution:

- (i) provides sufficient data and that the data is of sufficient quality to satisfy Section 4.3(c) of this Attachment;
- (ii) appears to satisfy the needs described in the Needs Assessment;
- (iii) is technically practicable and indicates possession of, or an approach to acquiring, the necessary rights of way, property and facilities that will make the proposal reasonably feasible in the required timeframe; and
- (iv) is eligible to be constructed only by an existing PTO in accordance with Schedule 3.09(a) of the TOA because the proposed solution is an upgrade to existing PTO facilities, or because the costs of the proposed solution are not eligible for regional cost allocation under the OATT and will be allocated only to the local customers of a PTO.

(f) Proposal Deficiencies; Further Information

If the ISO identifies any minor deficiencies in meeting the requirements of Section 4.3(e) in the information provided in connection with a proposed Phase One Proposal, the ISO will notify the Phase One Proposal Qualified Transmission Project Sponsor and provide an opportunity for the sponsor to cure the deficiencies within the timeframe specified by the ISO. Upon request, Qualified Transmission Project Sponsors of Phase One Proposals shall provide the ISO with

additional information reasonably necessary for the ISO's evaluation of the proposed Phase One Proposals. This identification and notification will occur prior to the publication by the ISO of any Phase One Proposals. In providing information under this subsection (f), or in Phase Two Solutions, the Qualified Transmission Project Sponsor may not modify its project materially or submit a new project, but instead may clarify its Phase One Proposal. Phase Two Solutions reflecting a material modification to a Phase One Proposal or representing a new project will be rejected.

(g) Listing of Qualifying Phase One Proposals

For each Needs Assessment, the ISO will provide the Planning Advisory Committee with, and post on the ISO's website, a listing of Phase One Proposals that meet the criteria of Section 4.3(e). A meeting of the Planning Advisory Committee will be held thereafter in order to solicit stakeholder input on the listing, and the listed proposals. The ISO with input from the Planning Advisory Committee may exclude projects from the list, and from consideration in Phase Two Solutions, based on a determination that the Phase One Proposal is not competitive with other projects that have been submitted in terms of cost, electrical performance, future system expandability, or feasibility. Information on Phase One Proposals containing CEII will be posted on the ISO's protected website consistent with Section 2.4(d) of this Attachment. The ISO may amend its listing based on stakeholder input. The ISO shall post on its website an explanation of why it has determined to exclude a Phase One Proposal from consideration in the Phase Two Solution process.

(h) Information Required for Phase Two Solutions; Identification and Reporting of Preliminary Preferred Phase Two Solution

Qualified Transmission Project Sponsors of Phase One Proposals reflected on the final listing developed pursuant to Section 4.3(g) of this Attachment shall provide the following information in their proposed Phase Two Solutions:

- (i) updates of the information provided in Phase One Proposals, or a certification that the information remains current and correct;

- (ii) list of required major Federal, State and local permits;

- (iii) description of construction sequencing, a conceptual plan for the anticipated transmission and generation outages necessary to construct the Phase Two Solution and their respective durations, and possible constraints;
- (iv) project schedule, with additional detail compared with Phase One Proposals, as specified by the ISO;
- (v) detailed cost component itemization and life-cycle cost including any clarifications to cost containment or cost cap measures that were not included as part of the Phase One Proposal;
- (vi) design and equipment standards to be used;
- (vii) description of the authority the Qualified Transmission Project Sponsor has to acquire necessary rights of way;
- (viii) experience of the Qualified Transmission Project Sponsor in acquiring rights of way;
- (ix) status of acquisition of right, title, and interest in rights of way, substations, and other property or facilities, if any, that are necessary for the proposed Phase Two Solution;
- (x) detailed explanation of project feasibility and potential constraints and challenges;
- (xi) description of the means by which the sponsor proposes to satisfy state legal or regulatory requirements for siting, constructing, owning and operating transmission projects; and
- (xii) detailed explanation of potential future expandability.

Phase Two Solutions must be submitted to the ISO by the deadline specified in the posting of the final listing (following stakeholder input) of Phase One Proposals described in Section 4.3(g). The deadline for submittal of Phase Two Solutions shall not be less than 60 days from the posting

date of the final listing. The ISO may reject Phase Two Solution submittals which are insufficient or not adequately supported.

The ISO will identify the Phase Two Solution that offers the best combination of electrical performance, cost, future system expandability and feasibility to meet the need in the required timeframe as the preliminary preferred Phase Two Solution in response to each Needs Assessment. The ISO will report the preliminary preferred Phase Two Solution, together with explanatory materials, to the Planning Advisory Committee and seek stakeholder input on the preliminary preferred Phase Two Solution.

The ISO will consider several factors during the evaluation process for identification of the preliminarily preferred Phase Two Solution. These factors may include, but are not limited to, the following which are listed in no particular order:

- Life-cycle cost, including all costs associated with right of way acquisition, easements, and associated real estate;
- System performance;
- Cost cap or cost containment provisions;
- In-service date of the project or portion(s) thereof;
- Project constructability;
- Generation and transmission facility outages required during construction;
- Extreme contingency performance;
- Operational impacts;
- Incremental costs for potential resource retirements;
- Interface impacts;
- Future expandability;
- Consistency with Good Utility Practice;
- Potential siting/permitting issues or delays;
- Loss savings;
- Replacement of aging infrastructure;
- Environmental impact;
- Design standards;

- Impact on NPCC Bulk Power System classification; and
- Qualified Transmission Project Sponsor capabilities.

(i) Reimbursement of Phase Two Solution Costs; Collection and Refund of ISO Study Costs

Qualified Transmission Project Sponsors whose Phase One Proposals are listed pursuant to Section 4.3(g) for review as Phase Two Solutions shall be entitled to recover, pursuant to rates and appropriate financial arrangements set forth in the Tariff (and, as applicable, the TOA and NTDOA), all prudently incurred costs associated with developing a Phase Two Solution. PTOs shall be entitled to recover, pursuant to rates and appropriate financial arrangements set forth in the Tariff, all prudently incurred study costs and costs associated with developing any upgrades or modifications to such PTOs' existing facilities necessary to facilitate the development of a listed Phase One Proposal proposed by any other Qualified Transmission Project Sponsor.

Any difference between a Qualified Transmission Project Sponsor's study deposit and the actual cost of the Phase One Proposal and Phase Two Solution studies shall be paid by or refunded to the Qualified Transmission Project Sponsor, as appropriate, with interest calculated in accordance with Section 35.19a(a)(2) of the FERC regulations. Any refund payment shall be accompanied by a detailed and itemized accounting of the actual study costs incurred. Any invoice to collect funds in addition to the deposit shall be accompanied by a detailed and itemized accounting of the actual study costs incurred. Any disputes arising from the study process shall be addressed under the dispute resolution process specified in Section I.6 of the ISO Tariff.

(j) Selection of the Preferred Phase Two Solution

Following receipt of stakeholder input, the ISO will identify the preferred Phase Two Solution (with an overview of why the solution is preferred) by a posting on its website. The ISO's identification will select the project that offers the best combination of electrical performance, cost, future system expandability and feasibility to meet the need in the required timeframe. The ISO will also notify the Qualified Transmission Project Sponsor that proposed the preferred Phase Two Solution that its project has been selected for development. The preferred Phase Two Solution may include an upgrade(s) located on or connected to a PTO's existing transmission system where the Qualified Transmission Project Sponsor is not the PTO for the existing system

element(s). In such cases the ISO will notify the PTO that have upgrades required by the preferred Phase Two Solution to proceed in accordance with Schedule 3.09(a) of the Transmission Operating Agreement. Once the ISO has identified the preferred Phase Two Solution, any remaining Phase Two Solutions, along with the Backstop Transmission Solution, must stop all development. The ISO will include the project as a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade, as appropriate, in the RSP and/or its Project List, as it is updated from time to time in accordance with this Attachment. Where external impacts of regional projects are identified through coordination by the ISO with neighboring entities, those impacts will be identified in the RSP. Costs associated with such impacts will be addressed as set forth in Schedule 15.

(k) Execution of Selected Qualified Transmission Project Sponsor Agreement

Within 30 days of its receiving notification pursuant to Section 4.3(j) of this Attachment, the Qualified Transmission Project Sponsor shall submit to the ISO its acceptance of responsibility to proceed with the preferred Phase Two Solution by execution of the Selected Qualified Transmission Project Sponsor Agreement (Attachment P to the OATT). Any cost cap or cost containment provisions shall be included in the Selected Qualified Transmission Project Sponsor Agreement.

(l) Failure to Proceed

If the ISO finds, after consultation with a non-PTO Qualified Transmission Project Sponsor, that the sponsor is failing to pursue approvals or construction in a reasonably diligent fashion, or that the sponsor is unable to proceed with the project due to forces beyond its reasonable control, the ISO shall request the applicable PTO(s) to execute the Selected Qualified Transmission Project Sponsor Agreement (Attachment P to the OATT) and implement the Backstop Transmission Solution. In such cases the ISO shall prepare a report explaining why it has reassigned the project. If the Qualified Transmission Project Sponsor that is failing or unable to proceed is a PTO, the report shall be consistent with the provisions of Section 1.1(e) of Schedule 3.09(a) of the Transmission Operating Agreement, including the ISO's proposed course of action. If prepared with respect to a Qualified Transmission Project Sponsor that is not a PTO, the report shall include a report from that sponsor. The ISO shall file its report (whether with respect to a PTO or non-PTO Qualified Transmission Project Sponsor) with the Commission.

(m) Cancellation of a Request for Proposal

The ISO may cancel a request for proposal at any time. Such cancellation may be due to new or different assumptions which may change or eliminate the identified needs. Any costs associated with solution development shall be recovered pursuant to Sections 3.6(c), 4.3(a) and 4.3(i) of this Attachment.

4A. Public Policy Transmission Studies; Public Policy Transmission Upgrades

4A.1 NESCOE Requests for Public Policy Transmission Studies

No less often than every three years, by January 15 of that year, the ISO will post a notice indicating that members of the Planning Advisory Committee may, no later than 45 days after the posting of the notice: (i) provide NESCOE, via the process described below, with input regarding state and federal Public Policy Requirements identified as driving transmission needs relating to the New England Transmission System, and regarding particular transmission needs driven by those Public Policy Requirements, and (ii) provide the ISO with input regarding local (e.g., municipal and county) Public Policy Requirements identified as driving transmission needs relating to the New England Transmission System, and regarding particular transmission needs driven by those Public Policy Requirements. A meeting of the Planning Advisory Committee may be held for this purpose. Members of the Planning Advisory Committee shall direct all such input related to state, federal, and local Public Policy Requirements that drive transmission needs to the ISO and the ISO will post such input on the ISO's website. By no later than May 1 of that year, NESCOE may submit to the ISO in writing a request for a new Public Policy Transmission Study, or an update of a previously conducted study. The request will identify the Public Policy Requirements identified as driving transmission needs relating to the New England Transmission System, and may identify particular NESCOE-identified public policy-related transmission needs as well. Along with any such request, NESCOE will provide the ISO with a written explanation of which transmission needs driven by state or federal Public Policy Requirements the ISO will evaluate for potential solutions in the regional planning process, including why other suggested transmission needs will not be evaluated. The ISO will post the NESCOE request and explanation on the ISO's website. If NESCOE does not provide that listing of identified transmission needs (which may consist of a NESCOE statement of its determination that no transmission needs are driven by state or federal Public Policy Requirements identified during the

stakeholder process) and that explanation (which may consist of a NESCOE explanation of why no transmission needs are driven by state or federal Public Policy Requirements identified during the stakeholder process), the ISO will note on its website that a NESCOE listing and explanation have not been provided. In that circumstance, the ISO will determine subsequently (after opportunity for Planning Advisory Committee input), and post on its website an explanation of, which transmission needs driven by state or federal Public Policy Requirements the ISO will evaluate in the regional planning process, including why other suggested transmission needs will not be evaluated.

4A.1.1 Study of Federal Public Policy Requirements Not Identified by NESCOE; Local Public Policy Requirements

If a stakeholder believes that a federal Public Policy Requirement that may drive transmission needs relating to the New England Transmission System has not been appropriately addressed by NESCOE, it may file with the ISO, no later than 15 days after the posting of NESCOE's explanation as described in Section 4A.1 of this Attachment, a written request that explains the stakeholder's reasoning and that seeks reconsideration by the ISO of NESCOE's position regarding that requirement. The ISO will post the stakeholder's written request on the ISO's website. Where the ISO agrees with a stated stakeholder position, or on its own finding, the ISO may perform an evaluation under Sections 4A.2 through 4A.4 of this Attachment of a federal Public Policy Requirement not otherwise identified by NESCOE. The ISO will post on its website an explanation of those transmission needs driven by federal Public Policy Requirements not identified by NESCOE that will be evaluated for potential transmission solutions in the regional system planning process, and why other suggested transmission needs driven by federal Public Policy Requirements not identified by NESCOE will not be evaluated. In addition, the ISO will post on its website an explanation of those transmission needs driven by local Public Policy Requirements that will be evaluated for potential transmission solutions in the regional system planning process, and why other suggested transmission needs driven by local Public Policy Requirements will not be evaluated.

4A.2 Preparation for Conduct of Public Policy Transmission Studies; Stakeholder Input

Upon receipt of the NESCOE request, or as the result of the ISO's consideration of a federal or local Public Policy Requirement pursuant to Section 4A.1.1, the ISO will prepare and post on its

website a proposed scope for the Public Policy Transmission Study, and associated parameters and assumptions (including resource assumptions), and provide the foregoing to the Planning Advisory Committee by no later than September 1 of the request year. A meeting of the Planning Advisory Committee will be held promptly thereafter in order to solicit stakeholder input for consideration by the ISO on the study's scope, parameters and assumptions.

4A.3 Public Policy Transmission Studies

(a) Conduct of Public Policy Transmission Studies; Stakeholder Input

With input from Planning Advisory Committee and potentially impacted PTOs, the ISO will perform the initial phase of the Public Policy Transmission Study to develop a rough estimate of the costs and benefits of high-level concepts that could meet transmission needs driven by Public Policy Requirements. The study's results will be posted on the ISO's website, and a meeting of the Planning Advisory Committee will be held promptly thereafter in order to solicit input on the results of the initial phase of the study, and the scope, parameters and assumptions (including resource assumptions) for any follow-on phase of the study. The ISO may – as a follow-on phase of the Public Policy Transmission Study – perform more detailed analysis and engineering work on the high-level concepts.

(b) Treatment of Market Solutions in Public Policy Transmission Studies

The ISO shall reflect proposed market responses in the Public Policy Transmission Study. Market responses may include, but are not limited to, resources (e.g., demand-side projects and distributed generation), Merchant Transmission Facilities and Elective Transmission Upgrades.

Specifically, the ISO shall incorporate in the Public Policy Transmission Study information regarding resources that have been proposed and (i) have cleared in a Forward Capacity Auction pursuant to Market Rule 1 of the ISO Tariff, (ii) have been selected in, and are contractually bound by, a state-sponsored Request For Proposals, or (iii) have a financially binding obligation pursuant to a contract. The ISO will model out-of-service all submitted Retirement De-List Bids, submitted Permanent De-List Bids, and demand bids that have cleared in a substitution auction, and may model out-of-service rejected-for-reliability Static De-List Bids and rejected-for-reliability Dynamic De-List Bids from the most recent Forward Capacity Auction. With respect to (ii) or (iii) above, demonstration of such contracts is accomplished through submittal for ISO

review of an order or other similar authorization from the appropriate state regulatory agency, along with a copy of the contract, that together demonstrate the contractual requirements. These documents may be submitted by: the Project Sponsor; the state regulatory agency authorizing the contract; a transmission company that is a counterparty to the contract; or by a third-party organization representing the interests of the New England states regarding energy related issues, such as NESCOE. The ISO shall incorporate information regarding a proposed Merchant Transmission Facility or Elective Transmission Upgrade in a Needs Assessment at a time after the studies corresponding to the Merchant Transmission Facility or Elective Transmission Upgrade are completed (including receipt of approval under Section I.3.9 of the Tariff), and a commercial operation date has been ascertained, with the exception of Elective Transmission Upgrades that are proposed in conjunction with the interconnection of a resource, which shall be considered at the same time as the proposed resource is considered in the Public Policy Transmission Study.

4A.4 Response to Public Policy Transmission Studies

The results of the Public Policy Transmission Study will be provided to the Planning Advisory Committee and posted on the ISO's website, and a meeting of the Planning Advisory Committee will be held promptly thereafter in order to solicit input for the ISO on those results, including any updates from the states on any methods by which they are satisfying their respective Public Policy Requirements included in the Public Policy Transmission Study. The ISO's costs of performing the Public Policy Transmission Study described in Section 4A.3 will be collected by the ISO pursuant to Schedule 1 of Section IV.A of the Tariff. Any prudently incurred PTO costs for assistance requested by the ISO to support the Public Policy Transmission Study will be recovered by the applicable PTO(s) in accordance with Attachment F and Schedule 21 of the Tariff.

The ISO will evaluate the input from the Planning Advisory Committee and provide the results of the Public Policy Transmission Study to Qualified Transmission Project Sponsors for their use in preparing Stage One Proposals to develop, build and operate one or more projects consistent with the general design requirements identified by the ISO in the study.

4A.5 Use and Control of Right of Way

Neither the submission of a project by a Qualified Transmission Project Sponsor nor the selection by the ISO of a project submitted by a Qualified Transmission Project Sponsor for inclusion in the RSP Project List shall alter a PTO's use and control of an existing right of way, the retention, modification, or transfer of which remain subject to the relevant law or regulation, including property or contractual rights, that granted the right-of-way. Nothing in the processes described in this Attachment K requires a PTO to relinquish any of its rights-of-way in order to permit a Qualified Transmission Project Sponsor to develop, construct or own a project.

4A.6 Stage One Proposals

(a) Information Required for Stage One Proposals

The ISO will publicly post on its website a request for proposal inviting, for each high-level general project concept identified by the ISO pursuant to Section 4A.3(a) above, Qualified Transmission Project Sponsors to submit (by the deadline specified in the request for proposal, which shall be not less than 60 days from the date of posting the request for proposal) a Stage One Proposal providing the following information:

- (i) a detailed description of the proposed solution, in the manner specified by the ISO, including an identification of the proposed route for the solution and technical details of the project, such as interconnection into the existing transmission system;
- (ii) a detailed explanation of how the proposed solution addresses the identified need;
- (iii) the proposed schedule, including key high-level milestones, for development, siting, procurement of real estate rights, permitting, construction and completion of the proposed solution;
- (iv) right, title, and interest in rights of way, substations, and other property or facilities, if any, that would contribute to the proposed solution or the means and timeframe by which such would be obtained; and
- (v) the estimated life-cycle and installed costs of the proposed solution, including a high-level itemization of the components of the cost estimate, a description of the financing being used, and any cost containment or cost cap measures.

A Qualified Transmission Project Sponsor may submit a proposed solution that includes an upgrade(s) located on or connected to a PTO's existing transmission system where the Qualified Transmission Project Sponsor is not the PTO for the existing system element(s). In such cases, the Qualified Transmission Project Sponsor's proposed solution relating to the upgrade(s) of an existing transmission system element(s) must provide all data available to the Qualified Transmission Project Sponsor as part of its response to the request for proposal. The Qualified Transmission Project Sponsor is not required to procure agreements with the PTO for implementation of such upgrades as the PTO is required to implement the upgrade(s) in accordance with Schedule 3.09(a) of the Transmission Operating Agreement if the proposed solution is selected through the competitive process.

A member of the Planning Advisory Committee that is not a Qualified Transmission Project Sponsor but would like the ISO to consider a Stage One Proposal reflecting its concept for a project in response to a Public Policy Transmission Study (that is, a project that is "unsponsored") must identify a Qualified Transmission Project Sponsor willing to submit a corresponding Stage One Proposal and Stage Two Solution (and to develop and construct the project, if selected in the competitive solution process) in order for the unsponsored project to be submitted in response to an ISO solicitation in Stage One Proposal. Upon request of the pertinent Planning Advisory Committee member for assistance in identifying a sponsor, the ISO shall post on its website and distribute to the Planning Advisory Committee a notice that solicits expressions of interest by Qualified Transmission Project Sponsors for sponsorship of the member's conceptual project. All expressions of interest shall include a detailed explanation of why the Qualified Transmission Project Sponsor is best qualified to construct, own and operate the unsponsored project. If only one Qualified Transmission Project Sponsor expresses interest, the ISO shall designate it as the Qualified Transmission Project Sponsor. If more than one Qualified Transmission Project Sponsor expresses interest, the Planning Advisory Committee member shall select the Qualified Transmission Project Sponsor. In either case, the designated Qualified Transmission Project Sponsor shall thereafter comply with the requirements of this Attachment K and the ISO Tariff with respect to the project. If no Qualified Transmission Project Sponsor expresses interest, the unsponsored project may not be submitted as a Stage One Proposal.

With each proposal, the Qualified Transmission Project Sponsor must include payment of a \$100,000 study deposit per submitted project to support the cost of Stage One Proposal and Stage Two Solution study work by the ISO. The study deposit of \$100,000 shall be applied towards the costs incurred by the ISO associated with the study of the Stage One Proposal and Stage Two Solution.

(b) LSP Coordination

Qualified Transmission Project Sponsors of Stage One Proposals shall also identify any LSP plans that require coordination with their Stage One Proposals.

(c) Preliminary Review by ISO

Upon receipt of Stage One Proposals, the ISO shall perform a preliminary feasibility review of each proposal to determine whether the proposed solution:

- (i) provides sufficient data and that the data is of sufficient quality to satisfy Section 4A.6(a);
- (ii) appears to satisfy the needs driven by Public Policy Requirements, as reflected in the Public Policy Transmission Study;
- (iii) is technically practicable and indicates possession of, or an approach to acquiring, the necessary rights of way, property and facilities that will make the proposal reasonably feasible in the required timeframe; and;
- (iv) is eligible to be constructed only by an existing PTO in accordance with Schedule 3.09(a) of the TOA because the proposed solution is an upgrade to existing PTO facilities or because the costs of the proposed solution are not eligible for regional cost allocation under the OATT and will be allocated only to the local customers of a PTO.

(d) Proposal Deficiencies; Further Information

If the ISO identifies any deficiencies (compared with the requirements of Section 4A.6(a)) in the information provided in connection with a proposed Stage One Proposal, the ISO will notify the Stage One Proposal Qualified Transmission Project Sponsor and provide an opportunity for the Qualified Transmission Project Sponsor to cure the deficiencies within the timeframe specified by the ISO. Upon request, Qualified Transmission Project Sponsors of Stage One Proposals shall

provide the ISO with additional information reasonably necessary for the ISO's evaluation of the proposed solutions. This identification and notification will occur prior to the publication by the ISO of any Stage One Proposals. In providing information under this subsection (d), or in Stage Two Solutions, the Qualified Transmission Project Sponsor may not modify its project materially or submit a new project, but instead may clarify its project. Stage Two Solutions reflecting a material modification to a Stage One Proposal or representing a new project will be rejected.

(e) List of Qualifying Stage One Proposals

The ISO will provide the Planning Advisory Committee with, and post on the ISO's website, a list of Stage One Proposals that meet the criteria of Section 4A.6(c). A meeting of the Planning Advisory Committee will be held promptly thereafter in order to solicit input for the ISO on that list. The ISO shall also indicate whether any of the Stage One Proposals may also satisfy identified reliability needs of the system. The ISO with input from the Planning Advisory Committee may exclude Stage One Proposals from the list, and from consideration in Stage Two Solutions, based on a determination that the Stage One Proposal is not competitive with other Stage One Proposals that have been submitted in terms of cost, electrical performance, future system expandability, or feasibility. Information on Stage One Proposals containing CEII will be posted on the ISO's protected website consistent with Section 2.4(d) of this Attachment. The ISO may amend its listing based on stakeholder input.

4A.7 Reimbursement of Stage One Proposal and Stage Two Solution Costs; Collection and Refund of ISO Study Costs

Qualified Transmission Project Sponsors that are requested by NESCOE in writing or by one or more states' governors or regulatory authorities directly to submit a Stage One Proposal shall be entitled to recover, pursuant to rates and appropriate financial arrangements set forth in the Tariff and the TOA, their prudently incurred costs from the Regional Network Load of the states identified by NESCOE in the written communication as having made the request or from the Regional Network Load of the states that made the request directly. Stage One Proposal costs shall otherwise not be subject to recovery under the ISO Tariff.

Qualified Transmission Project Sponsors whose projects are listed by the ISO pursuant to Section 4A.6(e) shall be entitled to recover, pursuant to rates and appropriate financial arrangements set

forth in the Tariff and, as applicable, the TOA and NTDOA, all prudently incurred costs associated with developing a Stage Two Solution. PTOs shall be entitled to recover, pursuant to rates and appropriate financial arrangements set forth in the Tariff, all prudently incurred study costs and costs associated with developing any upgrades or modifications to such PTOs' existing facilities necessary to facilitate the development of a listed Stage Two Solution proposed by any other Qualified Transmission Project Sponsor.

Any difference between a Qualified Transmission Project Sponsor's study deposit and the actual cost of the Stage One Proposal and Stage Two Solutions studies shall be paid by or refunded to the Qualified Transmission Project Sponsor, as appropriate, with interest calculated in accordance with Section 35.19a(a)(2) of the FERC regulations. Any refund payment shall be accompanied by a detailed and itemized accounting of the actual study costs incurred. Any invoice to collect funds in addition to the deposit shall be accompanied by a detailed and itemized accounting of the actual study costs incurred. Any disputes arising from the study process shall be addressed under the dispute resolution process specified in Section I.6 of the Tariff.

4A.8 Information Required for Stage Two Solutions; Identification and Reporting of Preliminary Preferred Stage Two Solution

Qualified Transmission Project Sponsors of Stage One Proposals listed pursuant to Section 4A.6(e) of this Attachment shall provide the following information in their proposed Stage Two Solutions:

- (i) updates of the information provided in Stage One Proposals, or a certification that the information remains current and correct;
- (ii) list of required major Federal, State and local permits;
- (iii) description of construction sequencing, a conceptual plan for the anticipated transmission and generation outages necessary to construct the Stage Two Solution and their respective durations, and possible constraints;

- (iv) project schedule, with additional detail compared with Stage One Proposals, as specified by the ISO;
- (v) detailed cost component itemization and life-cycle cost including any clarifications to cost containment or cost cap measures that were not included as part of the Stage One Proposal;
- (vi) design and equipment standards to be used;
- (vii) description of the authority the Qualified Transmission Project Sponsor has to acquire necessary rights of way;
- (viii) experience of the Qualified Transmission Project Sponsor in acquiring rights of way;
- (ix) status of acquisition of right, title, and interest in rights of way, substations, and other property or facilities, if any, that are necessary for the proposed Stage Two Solution;
- (x) detailed explanation of project feasibility and potential constraints and challenges;
- (xi) description of the means by which the sponsor proposes to satisfy state legal or regulatory requirements for siting, constructing, owning and operating transmission projects; and
- (xii) detailed explanation of potential future expandability.

Stage Two Solutions must be submitted to the ISO by the deadline specified in the posting of the final listing (following stakeholder input) of Stage One Proposals described in Section 4A.6(e). The deadline for submittal of Stage Two Solutions shall not be less than 60 days from the posting date of the final listing. The ISO may reject Stage Two Solution submittals which are insufficient or not adequately supported.

The ISO will consider several factors during the evaluation process for identification of the preliminarily preferred Stage Two Solution. These factors may include, but are not limited to, the following which are listed in no particular order:

- Life-cycle cost, including all costs associated with right of way acquisition, easements, and associated real estate;
- System performance;
- Cost cap or cost containment provisions;
- In-service date of the project or portion(s) thereof;
- Project constructability;
- Generation and transmission facility outages required during construction;
- Extreme contingency performance;
- Operational impacts;
- Incremental costs for potential resource retirements;
- Interface impacts;
- Future expandability;
- Consistency with Good Utility Practice;
- Potential siting/permitting issues or delays;
- Loss savings;
- Replacement of aging infrastructure;
- Environmental impact;
- Design standards;
- Impact on NPCC Bulk Power System classification; and
- Qualified Transmission Project Sponsor capabilities

The ISO will report the preliminary preferred Stage Two Solution(s), along with its views as to whether the preliminary preferred solution(s) also satisfies identified reliability needs of the system, to the Planning Advisory Committee and seek stakeholder input on the preliminary preferred Stage Two Solution(s).

4A.9 Inclusion of Public Policy Transmission Upgrades in the Regional System Plan and RSP Project List; Milestone Schedules; Removal from RSP Project List

(a) Inclusion of Public Policy Transmission Upgrades in the Regional System Plan and RSP Project List

Following receipt of stakeholder input, the ISO will identify the preferred Stage Two Solution (with an overview of why the solution is preferred) by a posting on its website. The ISO's identification will select the Stage Two Solution that best addresses the identified Public Policy Requirement while utilizing the best combination of electrical performance, cost, future system expandability and feasibility to meet the need in the required timeframe. The ISO will also notify the Qualified Transmission Project Sponsor that proposed the preferred Stage Two Solution that its project has been selected for development, and include the project as a Public Policy Transmission Upgrade in the Regional System Plan and RSP Project List, as it is updated from time to time in accordance with this Attachment. The preferred Stage Two Solution may include an upgrade(s) located on or connected to a PTO's existing transmission system where the Qualified Transmission Project Sponsor is not the PTO for the existing system element(s). In such cases the ISO will notify the PTO that have upgrades required by the preferred Stage Two Solution to proceed in accordance with Schedule 3.09(a) of the Transmission Operating Agreement. Once the ISO has identified the preferred Stage Two Solution, any remaining Stage Two Solutions must stop all development. Where external impacts of regional Public Policy Transmission Upgrades are identified through coordination by the ISO with neighboring entities, those impacts will be identified in the RSP. Costs associated with such impacts will be addressed as set forth in Schedule 15.

(b) Execution of Selected Qualified Transmission Project Sponsor Agreement

Within 30 days of its receiving notification pursuant to Section 4A.9(a) of this Attachment, the Qualified Transmission Project Sponsor shall submit to the ISO its acceptance of responsibility to proceed with the preferred Stage Two Solution by execution of the Selected Qualified Transmission Project Sponsor Agreement

(Attachment P to the OATT). Any cost cap or cost containment provisions shall be included in the Selected Qualified Transmission Project Sponsor Agreement.

(c) Failure to Proceed

If the ISO finds, after consultation with a non-PTO Qualified Transmission Project Sponsor, that the sponsor is failing to pursue approvals or construction in a reasonably diligent fashion, or that the sponsor is unable to proceed with the project due to forces beyond its reasonable control, the ISO shall, after consultation with the Planning Advisory Committee, prepare a report, including a proposed course of action. If the Qualified Transmission Project Sponsor that is failing or unable to proceed is a PTO, the ISO shall, after consultation with the Planning Advisory Committee, prepare a report consistent with the provisions of Section 1.1(e) of Schedule 3.09(a) of the Transmission Operating Agreement, including the ISO's proposed course of action. The proposed course of action may include, for example, a consideration and selection of another Stage Two Proposal relating to the pertinent Public Policy Requirement, or the re-solicitation of Stage One Proposals to meet the pertinent Public Policy Requirement. If prepared with respect to a Qualified Transmission Project Sponsor that is not a PTO, the report shall include a report from that sponsor. The ISO shall file its report (whether with respect to a PTO or a non-PTO Qualified Transmission Project Sponsor) with the Commission.

4A.10 Cancellation of a Request for Proposal

The ISO may cancel a request for proposal at any time. Such cancellation may be due to new or different assumptions which may change or eliminate the identified needs. Any costs associated with solutions development shall be recovered pursuant to Sections 3.6(c) and 4A.7 of this Attachment.

4A.11 Local Public Policy Transmission Upgrades

The costs of Local Public Policy Transmission Upgrade(s) that are required in connection with the construction of a Public Policy Transmission Upgrade approved for inclusion in the Regional System Plan in accordance with Section 4A.9 shall be allocated in accordance with Schedule 21 of the ISO OATT.

4B. Qualified Transmission Project Sponsors

4B.1 Evaluation of Applications

The ISO will evaluate applications submitted by an entity that seeks to qualify as a sponsor of a proposed Reliability Transmission Upgrade, Market Efficiency Transmission Upgrade or Public Policy Transmission Upgrade.

4B.2 Information To Be Submitted

The application to be submitted to the ISO by an entity desiring to be a Qualified Transmission Project Sponsor will include the following information:

- (i) the current and expected capabilities of the applicant to finance and construct a Reliability Transmission Upgrade, Market Efficiency Transmission Upgrade or Public Policy Transmission Upgrade and operate and maintain it for the life of the project;
- (ii) the financial resources of the applicant;
- (iii) the technical and engineering qualifications and experience of the applicant;
- (iv) if applicable, the previous record of the applicant regarding construction and maintenance of transmission facilities;
- (v) demonstrated capability of the applicant to adhere to construction, maintenance and operating Good Utility Practices, including the capability to respond to outages;
- (vi) the ability of the applicant to comply with all applicable reliability standards; and
- (vii) demonstrated ability of the applicant to meet development and completion schedules.

4B.3 Review of Qualifications

The ISO shall review each application for completeness. The ISO will notify each applicant within 30 calendar days of receipt of such application whether the application is complete, or identify any deficiencies in provision of the information required by Section 4B.2 of this Attachment. An applicant notified of deficiencies must provide any remedial information within 30 calendar days of the receipt of such notice. Thereafter, the ISO will determine whether the applicant is physically, technically, legally, and financially capable of constructing a Reliability Transmission Upgrade, Market Efficiency Transmission Upgrade or Public Policy Transmission Upgrade in a timely and competent manner, and operating and maintaining the facilities consistent with Good Utility Practice and applicable reliability criteria for the life of the project,

and use its best efforts to inform the applicant within 90 days from the date on which it has a completed application on file with the ISO whether it has met all of these criteria. A PTO determined by the ISO to meet all of these criteria will be deemed a Qualified Transmission Project Sponsor. A non-PTO entity determined by the ISO to meet all of these criteria will, upon its execution of the Non-incumbent Transmission Developer Operating Agreement (in the form specified in Attachment O of the OATT) and the Market Participant Service Agreement, be deemed a Qualified Transmission Project Sponsor.

4B.4 List of Qualified Transmission Project Sponsors

Qualified Transmission Project Sponsors are listed in Appendix 3 of this Attachment K.

4B.5 Annual Certification

Each Qualified Transmission Project Sponsor shall submit to the ISO annually a certification that the information initially submitted in response to Section 4B.2 of this Attachment K has not changed adversely in a material fashion, or (if a material adverse change has occurred in the intervening year) submit instead a new application for qualification as a project sponsor. In the latter case, the entity shall not be a Qualified Transmission Project Sponsor unless and until the ISO approves its new application.

5. Supply of Information and Data Required for Regional System Planning

The Transmission Owners, Generator Owners, Transmission Customers, Market Participants and other entities requesting transmission or interconnection service or proposing the integration of facilities to PTF in the New England Transmission System or alternatives to such facilities, and stakeholders requesting a Needs Assessment pursuant to Section 4.1 of this Attachment, shall supply, as required by the Tariff, the Participants Agreement, MPSAs, applicable transmission operating agreements, and/or other existing agreements, protocols and procedures, or upon request by the ISO, and subject to required CEII and confidentiality protections as specified in Section 2.4 of this Attachment, any information (including cost estimates) and data that is reasonably required to prepare an RSP or to perform a Needs Assessment or Solutions Study.

6. Regional, Local and Interregional Coordination

6.1 Regional Coordination

The ISO shall conduct the regional system planning process for the PTF in coordination with the transmission-owning entities in, or other entities interconnected to, the New England Transmission System consistent with the rights and obligations defined in the ISO OATT, applicable transmission operating agreements or protocols, and/or this Attachment. Pursuant to Section II.49 of this OATT and Sections 3.02, 3.05 and 3.09 of the TOA, the ISO has Operating Authority or control over all PTF and Non-PTF within the New England Control Area, which are utilized for the provision of transmission service under this OATT. The ISO also has Operating Authority or control over the United States portions of the HVDC ties to Quebec and over Merchant Transmission Facilities and Other Transmission Facilities, pursuant to this OATT or applicable transmission operating agreements or protocols. The ISO, however, is not responsible for the planning of the Non-PTF, OTF and MTF. As provided in Section 6.2 and Appendix 1 of this Attachment, the PTOs are responsible for the planning of the Non-PTF and coordinating such planning efforts with the ISO. Pursuant to the OATT and/or applicable transmission operating agreements or protocols, the transmission owners of OTF and MTF are required to participate in the ISO's regional system planning process and perform and/or support studies of the impacts of regional system projects on their respective facilities.

6.2 Local Coordination

The regional system planning process shall be conducted and the RSP shall be developed in coordination with the local system plans of the PTOs. In accordance with the TOA and OATT provisions identified in Section 6.1 of this Attachment, the PTOs have responsibility for planning Non-PTF. The PTOs conduct planning of Non-PTF using the LSP process outlined in Section 2.5 and Appendix 1 of this Attachment, in coordination with the ISO, other entities interconnected with the New England Transmission System, Transmission Customers and stakeholders, and in accordance with the provisions in the TOA, the OATT and the Planning and Reliability Criteria. The openness and transparency of the LSP process is intended to be consistent with the regional system planning process.

6.3 Interregional Coordination

The regional system planning process shall be conducted and the RSP shall be developed in coordination with the similar plans of the surrounding ISOs/RTOs and Control Areas pursuant to the Northeastern Planning Protocol and other agreements with neighboring systems (including entities that are not Parties to the Northeastern Planning Protocol) and NPCC.

(a) Interregional Coordination and Cost Allocation Among ISO, New York Independent System Operator, Inc. (“NYISO”) and PJM Interconnection, L.L.C. (“PJM”) Under Order No. 1000

Pursuant to Section 7 of the Northeastern Planning Protocol (which is posted on the web at www.iso-ne.com/static-assets/documents/2015/07/northeastern_protocol_dmeast.doc, the Joint ISO/RTO Planning Committee (“JIPC”) reviews regional needs and solutions identified in the regional planning processes of the ISO, NYISO and PJM in order to identify, with input from the Interregional Planning Stakeholder Advisory Committee (“IPSAC”), the potential for Interregional Transmission Projects that could meet regional needs more efficiently or cost-effectively than regional transmission projects. All members of the Planning Advisory Committee shall be considered IPSAC members. The JIPC will coordinate studies deemed necessary to allow the effective consideration by the regions, in the same general timeframe, of a proposed Interregional Transmission Project in comparison to regional transmission solutions. Any stakeholder may propose in the New England planning process, for evaluation under Section 4.2, 4.3, or 4A (as applicable) of Attachment K, an Interregional Transmission Project (or project concept) that may be more efficient or cost-effective than a regional transmission solution. If a proposed Interregional Transmission Project is approved in each region in which the project is located, the corresponding New England regional transmission project(s) will be displaced in the circumstances described in Section 3.6(a) of this Attachment, and the costs of the Interregional Transmission Project will be allocated among the regions based on the formula provided in Schedule 15 of this OATT, or in accordance with another funding arrangement filed with and accepted by the Commission. The amount of the costs of an Interregional Transmission Project allocated as the responsibility of New England pursuant to the methodology referenced in Section 6.3(a) of this Attachment shall be allocated within New England as specified in Schedule 15 of the ISO OATT.

(b) Other Interregional Assessments and Other Interregional Transmission Projects

Interregional system assessments and/or interregional system expansion planning studies may be performed periodically by the ISO with Planning Authorities who are not parties to the Northeastern Planning Protocol, or with the JIPC pursuant to Section 6 of the Northeastern Planning Protocol, or both. The ISO shall convene periodic meetings of the Planning Advisory Committee (which may be combined with meetings of the IPSAC), to provide input and feedback

to the ISO concerning such assessments and studies. To the extent that an Interregional Transmission Project is agreed to by ISO and by another region (not a Party to the Northeastern Planning Protocol) in which a portion of the project is located, the related cost allocation and operating agreements will be filed with the Commission (and, as applicable, with Canadian jurisdictional agencies) in accordance with existing filing rights.

7. Procedures for Development and Approval of the RSP

7.1 Initiation of RSP

No less often than once every three years, the ISO shall initiate an effort to develop its RSP and solicit input on regional system needs for the RSP from the Planning Advisory Committee. The Planning Advisory Committee shall meet to perform its respective functions in connection with the preparation of the RSP, as specified in Section 2 of this Attachment. The ISO shall issue the periodic planning reports that support the RSP, such as Needs Assessments, as those reports are completed.

7.2 Draft RSP; Public Meeting

The ISO shall provide a draft of the RSP to the Planning Advisory Committee and input from that Committee shall be received and considered in preparing and revising subsequent drafts. The ISO shall post the draft RSP and provide notice to the Planning Advisory Committee of a meeting to review the draft RSP as specified in Section 2.2 of this Attachment.

After the ISO has provided a draft of the RSP to the Planning Advisory Committee, the ISO shall issue a second draft of the RSP to be presented by the ISO staff to the ISO Board of Directors for approval. The draft RSP shall incorporate the results of any Needs Assessment, and corresponding Solutions Studies, performed since the last RSP was approved. A subcommittee of that Board shall hold a public meeting, at their discretion, to receive input directly and to discuss any proposed revisions to the RSP. The final recommended RSP shall be presented to the ISO Board of Directors and shall be acted on by the ISO Board of Directors within 60 days of receipt. The foregoing timeframes are subject to adjustment as determined by the ISO in coordination with the Planning Advisory Committee.

7.3 Action by the ISO Board of Directors on RSP; Request for Alternative Proposals

(a) Action by ISO Board of Directors on RSP

The ISO Board of Directors may approve the recommended draft RSP as submitted, modify the RSP or remand all or any portion of it back with guidance for development of a revised recommendation. The Board of Directors may consider the RSP in executive session, and shall consider in its deliberations the views of the subcommittee of the Board of Directors reflecting the public meeting held pursuant to Section 7.2 of this Attachment. In considering whether to approve the draft RSP, the Board of Directors may, if it finds a proposed Reliability Benefit Upgrade not to be viable, or if no Reliability Benefit Upgrade has been proposed, direct the ISO staff to meet with the affected load serving entities and State entities in order to develop an interim solution. Should that effort fail, and as a last resort, the Board of Directors may direct the ISO to issue a Request For Alternative Proposal (“RFAP”), subject to the procedures described below, and may withhold approval of the draft RSP, or portions thereof, pending the results of that RFAP and any Commission action on any resulting jurisdictional contract or funding mechanism. The ISO shall provide a written explanation as to any subsequent changes or modification made in the final version of the RSP.

(b) Requests For Alternative Proposals

- (i) The RFAP shall seek generation, demand-side and merchant transmission alternatives that can be implemented rapidly and provide substantial reliability benefits over the period solicited in the RFAP, and normally will focus on an interim (“gap”) solution until an identified Reliability Transmission Upgrade has been placed in-service. The ISO will file a proposed RFAP with the Commission for approval at least 60 days prior to its issuance. The filing shall explain why the issuance of an RFAP is necessary.
- (ii) The ISO staff shall provide the Board of Directors and subject to confidentiality requirements, the Planning Advisory Committee with an analysis of the alternatives offered in response to the RFAP, and provide a recommendation together with a funding mechanism reflecting input from the Planning Advisory Committee.
- (iii) The ISO may enter into contracts awarded pursuant to an RFAP process, and/or propose a funding mechanism. Bidders that are awarded contracts through the RFAP process shall file those contracts with the Commission for approval of the rates to be charged thereunder to the extent that such contracts are for services that are jurisdictional

to the Commission. The ISO shall file related or separate funding mechanisms with the Commission as well. All other contracts entered into pursuant to an RFAP shall be filed with the Commission for informational purposes.

(iv) The Board of Directors will reflect the results of the RFAP process in the approved RSP.

8. Obligations of PTOs to Build; PTOs' Obligations, Conditions and Rights

In accordance with the TOA, PTOs designated by the ISO as the appropriate entities to construct and own or finance Transmission Upgrades included in the RSP shall construct and own or finance such facilities or enter into appropriate contracts to fulfill such obligations. In the event that a PTO: (i) does not construct or indicates in writing that it does not intend to construct a Transmission Upgrade included in the RSP; or (ii) demonstrates that it has failed (after making a good faith effort) to obtain necessary approvals or property rights under applicable law, the ISO shall promptly file with the Commission a report on the results of the planning process, which report shall include a report from the PTO responsible for the planning, design or construction of such Open Access Transmission Tariff Section II – Attachment K – Regional System Planning Process Transmission Upgrade, in order to permit the Commission to determine what action, if any, it should take.

In connection with regional system planning, the ISO will not propose to impose on any PTO obligations or conditions that are inconsistent with the explicit provisions of the TOA or deprive any PTO of any of the rights set forth in the TOA.

Subject to necessary approvals and compliance with Section 2.06 of the TOA, nothing in this OATT shall affect the right of any PTO to expand or modify its transmission facilities in the New England Transmission System on its own initiative or in response to an order of an appropriate regulatory authority. Such expansions or modifications shall conform with: (a) Good Utility Practice; (b) applicable reliability principles, guidelines, criteria, rules, procedures and standards of national, regional, and local reliability councils that may be in existence; and (c) the ISO and relevant PTO criteria, rules, standards, guides and policies. The ISO reserves its right to challenge the permitting of such expansions or modifications.

9. Merchant Transmission Facilities

9.1 General

Subject to compliance with the requirements of the Tariff and any other applicable requirements with respect to the interconnection of bulk power facilities with the New England Transmission System, any entity shall have the right to propose and construct the addition of transmission facilities (“Merchant Transmission Facilities”), none of the costs of which shall be covered under the cost allocation provisions of this OATT. Any such Merchant Transmission Facilities shall be subject to the requirements of Section 9.2 of this Attachment. In performing studies in connection with the RSP, the prospect that proposed Merchant Transmission Facilities will be completed shall be accounted for as will the prospect that proposed generating units will be completed.

9.2 Operation and Integration

All Merchant Transmission Facilities shall be subject to: (i) an agreement to transfer to the ISO operational control authority over any facilities which constitute part of the Merchant Transmission Facilities that are to be integrated with, or that will affect, the New England Transmission System; and (ii) taking such other action as may be required to make the facility available for use as part of the New England Transmission System.

9.3 Control and Coordination

Until such time as a Merchant Transmission Owner has transferred operational control over its Merchant Transmission Facilities to the ISO pursuant to Section 9.2(i), all such Merchant Transmission Facilities shall be subject to the operational control, scheduling and maintenance coordination of the System Operator in accordance with the Tariff.

10. Cost Responsibility for Transmission Upgrades

The cost responsibility for each upgrade, modification or addition to the transmission system in New England that is included with the status of “Planned” in the RSP Project List as defined in Section 3.6 of this Attachment shall be determined in accordance with Schedule 12 of this OATT.

11. Allocation of ARRs

The allocation of ARRs in connection with Transmission Upgrades is addressed in Section III.C.8 of the Tariff.

12. Dispute Resolution Procedures

12.1 Objective

Section 12 of this Attachment sets forth a dispute resolution process (the “Regional Planning Dispute Resolution Process”) through which regional transmission planning-related disputes may be resolved as expeditiously as possible.

12.2 Confidential Information and CEII Protections

All information disclosed in the course of the Regional Planning Dispute Resolution Process shall be subject to the protection of confidential information and CEII consistent with the ISO New England Information Policy and CEII policy.

12.3 Eligible Parties

Any member of the Planning Advisory Committee that has been adversely affected by a Reviewable Determination, defined in Section 12.4(a) of this Attachment, with respect to the regional system planning process described in this Attachment is eligible to raise its dispute, as appropriate, under this Dispute Resolution Process (“Disputing Party”).

12.4 Scope

In order to ensure that the regional transmission planning process set forth under this Attachment moves expeditiously forward, the scope of issues that may be subject to the Regional Planning Dispute Resolution Process under this Section 12 shall be limited to certain key procedural and substantive decisions made by the ISO within its authority as specified in documents on file with the Commission. That is, decisions not subject to resolution within the jurisdiction of the Commission are not within the scope of the Regional Planning Dispute Resolution Process. Examples of matters not within the scope of the Regional Planning Dispute Resolution Process include planning to serve retail native load or state siting issues. Additionally, the Tariff already explicitly provides specific dispute resolution procedures for various matters. To this end, any matter regarding the review and approval of applications pursuant to Section I.3.9 of the Tariff, which is subject to the dispute resolution process under Section I.6 of the Tariff, shall not be within the scope of this Regional Planning Dispute Resolution Process. Similarly, any matter regarding Transmission Cost Allocation shall be governed by the dispute resolution process under

Schedule 12 of the OATT, and shall be outside the scope of this Regional Planning Dispute Resolution Process.

(a) Reviewable Determinations

The determinations that may be subject to the Regional Planning Dispute Resolution Process under this Section 12 that include certain procedural and substantive challenges that may arise at limited designated key decision points in the regional transmission planning process for PTF. Procedural challenges will be limited to whether or not the steps taken up to a designated key decision point conform to the requirements set forth in this Attachment. Substantive challenges will be limited to whether or not a determination or conclusion rendered at a designated key decision point was supported by adequate basis in fact.

The designated key decision points for Reviewable Determinations shall be limited to the following:

- (i) Results of a Needs Assessment conducted and communicated by the ISO to the Planning Advisory Committee as specified in Section 4.1 of this Attachment;
- (ii) Updates to the RSP Project List, including adding, removing or revising regulated transmission solutions included thereunder, as presented at the Planning Advisory Committee and as specified in Section 3.6 of this Attachment;
- (iii) Results of Solutions Studies conducted and communicated by the ISO to the Planning Advisory Committee as specified in Section 4.2 of this Attachment;
- (iv) Consideration of market responses in Needs Assessments as specified in Section 4.1(f) of this Attachment;
- (v) Substance of Economic Studies to be conducted by the ISO in a given year as specified in Section 4.1(b) of this Attachment; and

- (vi) Prioritization of Economic Studies to be performed in a given year where the Planning Advisory Committee is not able to prioritize them as specified in Section 4.1(b) of this Attachment.

(b) Material Adverse Impact

In order to prevail in a challenge to a procedural-based Reviewable Determination, the Disputing Party must show that the alleged procedural error had a material adverse impact on the determination or conclusion. In order to prevail in a challenge to a substantive-based Reviewable Determination, the Disputing Party must show that either (i) the determination is based on incorrect data or assumptions or (ii) incorrect analysis was performed by the ISO, and (iii) as a result the ISO made an incorrect decision or determination.

12.5 Notice and Comment

A Disputing Party aggrieved by a Reviewable Determination shall have fifteen (15) calendar days upon learning of the Reviewable Determination following the ISO's presentation of such Reviewable Determination at the Planning Advisory Committee to request dispute resolution by giving notice to the ISO ("Request for Dispute Resolution"). A Request for Dispute Resolution shall be in writing and shall be addressed to the ISO's Chair of the Planning Advisory Committee and, as appropriate, the affected Transmission Owner. Within three (3) Business Days of the receipt by the ISO of a Request for Dispute Resolution, the ISO shall prepare and distribute to all members of the Planning Advisory Committee a notice of the Request for Dispute Resolution including, subject to the protection of Confidential Information and CEII, the specifics of the Request for Dispute Resolution and providing the name of an ISO representative to whom any comments may be sent. Any member of the Planning Advisory Committee may submit to the ISO's designated representative, on or before the tenth (10th) Business Day following the date the ISO distributes the notice of the Request for Dispute Resolution, written comments to the ISO with respect to the Request for Dispute Resolution. The party filing the Request for Dispute Resolution may respond to any such comments by submitting a written response to the ISO's designated representative and to the commenting party on or before the fifteenth (15th) Business Day following the date the ISO distributes the notice of the Request for Dispute Resolution. The ISO may, but is not required to, consider any written comments.

12.6 Dispute Resolution Procedures

(a) Resolution Through the Planning Advisory Committee

The Planning Advisory Committee shall discuss and resolve any dispute arising under this Attachment involving a Reviewable Determination, as defined in Section 12.4 of this Attachment, between and among the ISO, the Disputing Party, and, as appropriate, the affected Transmission Owner (collectively, “Parties”) (excluding applications for rate changes or other changes to the Tariff, or to any Service Agreement entered into under the Tariff, which shall be presented directly to the Commission for resolution).

(b) Resolution Through Informal Negotiations

To the extent that the Planning Advisory Committee is not able to resolve a dispute arising under this Attachment involving a Reviewable Determination, as defined in Section 12.4 of this Attachment, between and among the ISO, the Disputing Party, and, as appropriate, the affected Transmission Owner, such dispute shall be the subject of good-faith negotiations among the Parties. Each Party shall designate a fully authorized senior representative for resolution on an informal basis as promptly as practicable.

(c) Resolution Through Alternative Dispute Resolution

In the event the designated representatives are unable to resolve the dispute through informal negotiation within thirty (30) days, or such other period as the Parties may agree upon, by mutual agreement of the Parties, such dispute may be submitted to mediation or any other form of alternative dispute resolution upon the agreement of all Parties to participate in such mediation or other alternative dispute resolution process. Such form of alternative dispute resolution shall not include binding arbitration.

If a Party identifies exigent circumstances reasonably requiring expedited resolution of the dispute, such Party may file a Complaint with the Commission or seek other appropriate redress before a court of competent jurisdiction.

12.7 Notice of Dispute Resolution Process Results

Within three (3) Business Days following the resolution of a dispute pursuant to either Section 12.6(b) or Section 12.6(c) of this Attachment, the ISO shall distribute to the Planning Advisory Committee a document reflecting the resolution.

13. Rights Under The Federal Power Act

Nothing in this Attachment shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act.

14. Annual Assessment of Transmission Transfer Capability

Each year, the ISO shall issue the results of the annual assessment of transmission transfer capability, conducted pursuant to applicable NERC, NPCC and ISO New England standards and criteria and the identification of potential future transmission system weaknesses and limiting facilities that could impact the transmission system's ability to reliably transfer energy in the planning horizon. Each annual assessment will identify those portions of the New England system, along with the associated interface boundaries, that should be considered in the assessment of Capacity Zones to be modeled in the Forward Capacity Market pursuant to ISO Tariff Section III.12. This report will be posted on the ISO website. Each annual assessment will model out-of-service resources associated with the following bids, if the ISO determines the removal of the resource is likely to have an impact on the transmission transfer limits for the relevant period: Retirement De-List Bids, Permanent De-List Bids, demand bids submitted for the upcoming substitution auction, and rejected for reliability Static De-List Bids and rejected for reliability Dynamic De-List Bids from the most recent Forward Capacity Auction.

15. Procedures for the Conduct of Cluster Enabling Transmission Upgrades Regional Planning Study

The purpose of this Section 15 is to support the conduct of Interconnection Studies under the Interconnection Procedures set forth in Schedules 22, 23 and 25 of Section II of the Tariff. Other than Section 2 of this Attachment K regarding the responsibilities of the Planning Advisory Committee and this Section 15, none of the other provisions in this Attachment K apply to the conduct of the Cluster Enabling Transmission Upgrade Regional Planning Study or the results of the study.

15.1 Notice of Initiation of Cluster Enabling Transmission Upgrade Regional Planning Study in Support of Cluster Studies under the Interconnection Procedures.

Pursuant to Section 4.2.2 of Schedule 22, Section 1.5.3.2 of Schedule 23, and Section 4.2.2 of Schedule 25 of Section II of this Tariff, the ISO shall provide notice to the Planning Advisory Committee of the initiation of a cluster for studying certain Interconnection Requests. The cluster study process, known as Clustering, shall consist of two phases. This notice shall trigger the first phase of Clustering, during

which the ISO shall conduct a Cluster Enabling Transmission Upgrade (“CETU”) Regional Planning Study (“CRPS”) (the cost of which will be recovered by the ISO pursuant to Schedule 1 of Section IV.A of the Tariff). In the second phase of Clustering, the ISO shall conduct Interconnection System Impact Studies and Interconnection Facilities Studies in clusters pursuant to Schedules 22, 23 and 25 of Section II of the Tariff.

15.2 Preparation for Conduct of CRPS; Stakeholder Input

The purpose of the CRPS shall be to identify the new transmission infrastructure and any associated system upgrades to enable the interconnection of potentially all of the resources proposed in the Interconnection Requests for which the conditions identified in Section 4.2.1 of Schedule 22, Section 1.5.3.1 of Schedule 23, and Section 4.2.1 of Schedule 25 of Section II of the Tariff have been triggered. The ISO will prepare and post on its website, consistent with Section 2.4(d) of this Attachment K, a proposed scope of the CRPS and associated parameters and assumptions, and provide the foregoing to the Planning Advisory Committee. A meeting of the Planning Advisory Committee will be held promptly thereafter in order to solicit stakeholder input for consideration by the ISO on the CRPS’s scope, parameters and assumptions, consistent with the responsibilities of the Planning Advisory Committee as set forth in Section 2.2 of this Attachment. As part of the CRPS’s scope, the ISO will describe the circumstances that triggered the conditions in Section 4.2.1 of Schedule 22, Section 1.5.3.1 of Schedule 23, and Section 4.2.1 of Schedule 25 of Section II of the Tariff. In addition, the ISO will identify: (i) the Interconnection Requests, to be referenced by Queue Position, that are expected to be eligible to participate in the Cluster Interconnection System Impact Study, and (ii) the preliminary transmission upgrade concepts proposed to be considered in the CRPS. The preliminary transmission upgrade concepts may account for previously conducted transmission reinforcement studies and previously identified concepts for transmission upgrades in the relevant electrical area, including Elective Transmission Upgrades with Interconnection Requests pending in the interconnection queue prior to the initiation of the CRPS.

A member of the Planning Advisory Committee or an Interconnection Customer may make a written submission to the ISO, requesting that Clustering be considered for specific Interconnection Requests in the ISO New England interconnection queue. In response to such a request, the ISO will either develop a notice of initiation of a cluster pursuant to Section 15.1 of this Attachment K, or identify, in writing, to

the Planning Advisory Committee why the conditions in Section 4.2.1 of Schedule 22, Section 1.5.3.1 of Schedule 23, and Section 4.2.1 of Schedule 25 of Section II of the Tariff have not been triggered.

15.3 Conduct of the CRPS

The CRPS will consist of analyses performed under the conditions used in the conduct of an Interconnection System Impact Study under the Interconnection Procedures. The CRPS will consist of steady state thermal analysis, voltage and transient stability analysis, and, as appropriate, other analysis, such as weak-grid-related analyses. The ISO will use Reasonable Efforts to complete the CRPS within twelve (12) months from the notice of the cluster initiation to the Planning Advisory Committee. If less than two (2) Interconnection Requests identified pursuant to Section 4.2.1 of Schedule 22, Section 1.5.3.1 of Schedule 23, and Section 4.2.1 of Schedule 25 of Section II of the Tariff remain in the interconnection queue prior to the completion of the CRPS, the ISO will terminate the CRPS.

15.4 Publication of the CRPS

The ISO shall post a draft report of the CRPS to the Planning Advisory Committee, consistent with Section 2.4(d) of this Attachment K, and a meeting of the Planning Advisory Committee will be held promptly thereafter in order to discuss the results of the CRPS. A comment period will follow the Planning Advisory Committee meeting. The ISO will post on its website any comments received and the ISO's responses to those comments.

The CRPS report will provide:

- (i) a planning level description of the CETU(s) and a non-binding good faith order-of-magnitude estimate, developed by the applicable Transmission Owner(s), of the costs for the CETU(s);
- (ii) a list of other facilities that may be needed in addition to the CETU(s) and a non-binding good faith order-of-magnitude estimate, developed by the applicable Transmission Owner(s), of the costs for those facilities (the CRPS will not provide descriptions of expected Interconnection Facilities for specific Interconnection Requests in the cases where the Interconnection Facilities cannot be finalized until the actual Interconnection Requests that will be moving forward in the cluster are known);

- (iii) the approximate megawatt quantity (or quantities if more than one level of megawatt injection was studied in the CRPS) of resources that could be interconnected in a manner that meets the Network Capability Interconnection Standard and the Capacity Capability Interconnection Standard in accordance with Schedules 22, 23 and 25 of Section II of the Tariff; and,
- (iv) a list of the Interconnection Requests, to be referenced by Queue Position, that at the sole discretion of the ISO are identified as eligible to participate in the Cluster Interconnection System Impact Study that will be conducted by the ISO in accordance with Section 4.2.3 of Schedule 22, Section 1.5.3.3 of Schedule 23, and Section 4.2.3 of Schedule 25 of Section II of the Tariff. The list shall include the expected cost allocation for the eligible Interconnection Requests, calculated in accordance with Schedule 11 of Section II of the Tariff.

The non-binding good faith order-of-magnitude estimates under Section 15.4(i)-(ii) of this Attachment will be developed by the applicable Transmission Owner(s), and the costs of developing such estimates shall be recovered as specified in Sections 3.3.1, 6.1 and 7.2 of Schedule 22, Section 3.3.1, 3.4.2, and Attachment 1 of Schedule 23, and Section 3.3.1, 6.1 and 7.2 of Schedule 25.

The posting, consistent with Section 2.4 (d) of this Attachment K, of the final CRPS report on the ISO website will trigger the Cluster Interconnection System Impact Study Entry Deadline specified in Section 4.2.3.1 of Schedule 22, Section 1.5.3.3.1 of Schedule 23, and Section 4.2.3.1 of Schedule 25 of Section II of the Tariff. The Cluster Interconnection System Impact Study Entry Deadline shall be 30 days from the posting of the final CRPS report.

Notwithstanding any other provision in this Section 15, the final Maine Resource Integration Study shall be the first CRPS and will form the basis for the first Cluster Interconnection System Impact Study to be conducted in accordance with Section 4.2.3 of Schedule 22, Section 1.5.3.3 of Schedule 23, and Section 4.2.3 of Schedule 25 of Section II of the Tariff.

ATTACHMENT K APPENDIX 1
ATTACHMENT K -LOCAL
LOCAL SYSTEM PLANNING PROCESS

APPENDIX 1
ATTACHMENT K -LOCAL
LOCAL SYSTEM PLANNING PROCESS

1. Local System Planning Process

1.1 General

In circumstances where transmission system planning for Non-Pool Transmission Facilities (“Non-PTF”)¹, including Local Public Policy Transmission Upgrades, is taking place in New England that is not incorporated into the RSP planning process, the following Local System Plan (“LSP”) process will be utilized for transmission planning purposes. The purpose of the LSP is to enable formal stakeholder input to planning for Non-PTF that is not incorporated into the RSP. The LSP shall ensure the opportunity for Planning Advisory Committee participation in the LSP process. The LSP will not be subject to approval by the ISO or the ISO Board under the RSP.

1.2 Planning Advisory Committee Review

The Planning Advisory Committee shall periodically provide input and feedback to the PTOs concerning the development of the LSP and the conduct of associated system enhancement and expansion studies. It is contemplated that LSP issues for identified local areas will be periodically addressed at the end of regularly scheduled Planning Advisory Committee meetings. Regular meetings of the Planning Advisory Committee shall be extended as necessary to serve the purposes of this section. Each PTO contemplating the addition of new Non-PTF will present its respective LSP to the Planning Advisory Committee not less than once per year. Not less than every three years, each PTO will post a notice as part of its LSP process indicating that members of the Planning Advisory Committee, NESCOE, or any state may provide the PTO with input regarding state and federal Public Policy Requirements identified as driving transmission needs relating to Non-PTF and regarding particular local transmission needs driven by Public Policy Requirements. The PTO will provide a written explanation, to be posted on the ISO website, of why suggested transmission needs driven by Public Policy Requirements will or will not be evaluated for potential solutions in the LSP planning process.

¹ For absence of doubt, the PTOs clarify that Non-PTF is meant to include Category B and Local Area Facilities as defined by the TOA.

1.3 Role of the PTOs

Each PTO will be responsible for administering the LSP process pertaining to its own Non-PTF, including Local Public Policy Transmission Upgrades, by presenting LSP information to the Planning Advisory Committee, developing an appropriate needs analysis and addressing LSP needs within its local area. In developing its LSP, each PTO will ensure comparable treatment of similarly situated customers or potential customers and will take into consideration data, comments and specific requests supplied by the Planning Advisory Committee, Transmission Customers and other stakeholders. To the extent that generation and/or demand resources are identified that could impact planning for Non-PTF, each PTO will take such resources into account when developing the LSP for its facilities, consistent with Good Utility Practice. Each PTO will also be responsible for addressing issues or concerns arising out of Planning Advisory Committee review of its proposed LSP and posting its LSP and the LSP Project List.

1.4 Description of LSP

The LSP shall describe the projected improvements to Non-PTF that are needed to maintain system reliability or as Local Public Policy Transmission Upgrades, and shall reflect the results of such reviews within the limited geographical areas that pertain to the LSP, as determined by each PTO (“LSP Needs Assessments”), and corresponding system planning and expansion studies. The LSP Needs Assessments will be coordinated with the RSP and include the information that the ISO-NE incorporates into the RSP plans, as applicable. The proponents of regulated transmission proposals in response to LSP Needs Assessments shall also identify any RSP plans that require coordination with their regulated transmission proposals addressing the Non-PTF system needs.

The LSP shall identify the planning process, criteria, data, and assumptions used to develop the LSP. To the extent the current LSP utilizes data, assumptions or criteria used by the ISO in the RSP, any such data, assumptions or criteria will also be identified in the LSP.

Each PTO shall consult with NESCOE and applicable states, local authorities and stakeholders to consider their views prior to including a Local Public Transmission Upgrade in its LSP, as described in Section 1.6.

Each PTO's LSP will be made available on a website for review by the Planning Advisory Committee, Transmission Customers and other stakeholders, subject to the ISO New England Information Policy and CEII restrictions or requirements. The ISO's posting of the RSP and the RSP Project List will include links to each PTO's specific LSP posting.

The LSP of a particular PTO shall be posted not less than 3 business days prior to its presentation by the PTO to the Planning Advisory Committee. The Planning Advisory Committee, Transmission Customers, and other stakeholders will have 30 days from the date of the PTO's presentation to the Planning Advisory Committee to provide any written comments for consideration by the PTO. The LSP shall specify the physical characteristics of the solutions that can meet the needs identified in the LSP. The LSP shall provide sufficient information to allow Market Participants to assess the quantity, general locations and operating characteristics of the type of incremental supply or demand-side resources, or merchant transmission projects, that would satisfy the identified needs or that may serve to modify, offset or defer proposed regulated transmission upgrades.

Each year's LSP shall be based upon the LSP completed in the prior year by either recertifying the results of the prior LSP or providing specific updates.

1.5 Economic Studies

To the extent that the ISO selects any Economic Studies pursuant to Section 4.1(b) of Attachment K or otherwise performs Economic Studies that will impact Non-PTF, the PTOs will coordinate with the ISO in the performance of such Economic Studies.

1.6 Public Policy Studies

As part of the LSP process, each PTO will evaluate potential transmission solutions on its Non-PTF system that are likely to be both efficient and cost-effective for meeting Public Policy Requirements.

1.6A Process to Identify Public Policy Requirements Driving Non-PTF Transmission Needs

Within six months of publication, each PTO will review the Public Policy Requirements posted by the ISO to determine and evaluate at a high level any public policy needs potentially driving transmission needs on their respective Non-PTF systems. Such evaluations will also include potential public policy

needs suggested by third parties. Each PTO will review NESCOE's written explanation of which transmission needs driven by state or federal Public Policy Requirements will be evaluated by the ISO and why other suggested transmission needs will not be evaluated. If NESCOE does not provide a listing of identified transmission needs and explanation, each PTO will review the ISO's explanations of which transmission needs driven by state or federal Public Policy Requirements will be evaluated by the ISO and why other suggested transmission needs will not be evaluated. In addition, each PTO will review the ISO's explanation of which transmission needs driven by local Public Policy Requirements will be evaluated in the regional system planning process and why other suggested transmission needs driven by local Public Policy requirements will not be evaluated. Each PTO will then determine if any of the posted state, federal or local Public Policy Requirements are driving a need on its Non-PTF transmission system and will include the non-PTF needs in its local planning process.

As part of the local planning process, each PTO will list the identified transmission needs on its non-PTF transmission system driven by state, federal, or local Public Policy Requirements that will be evaluated, and provide an explanation of why any identified transmission needs will not be evaluated as part of its LSP. The list will be posted in the PTO's LSP and presented at the annual PAC meeting. The PTO will seek input at the PAC meeting from stakeholders about whether further study is warranted to identify solutions for local transmission system needs and seek recommendations about whether to proceed with such studies. A stakeholder may provide written input on the list within 30 days from the date of presentation for consideration by the PTO. Each PTO will then confirm, or modify if appropriate, its determination of which identified transmission needs on its non-PTF transmission system driven by state, federal, or local Public Policy Requirements will be evaluated and which will not be evaluated, and revise its annual LSP accordingly. If the potential Non-PTF transmission needs identified would affect the Non-PTF facilities of more than one PTO, the affected PTOs will coordinate their efforts with other affected PTOs, as necessary.

1.6B Procedure for Evaluating Potential Public Policy Solutions on the Non-PTF

Once it has been determined that a non-PTF need driven by state, federal or local Public Policy Requirements will be evaluated, each PTO will prepare a scope and associated assumptions as part of a Public Policy Local Transmission Study. For those needs where a scope is available, a PTO may present the proposed scope for the Public Policy Local Transmission Study within its LSP and as part of its LSP

presentation described in Section 1.6A. A stakeholder may provide written input to the scope within 30 days after the LSP presentation for the PTO to consider.

Each PTO will schedule a follow-up PAC meeting presentation for additional stakeholder input within 4 months after the PTO's LSP presentation as described in Section 1.6A if the proposed scope for a Public Policy Local Transmission Study was not included in its annual LSP presentation. Within 30 days after the follow-up meeting, a stakeholder may provide written input to the scope for the PTO to consider. Subsequently, the PTO will determine the study scope for the Public Policy Local Transmission Study and revise its annual LSP.

In preparation of a Public Policy Local Transmission Study that will be presented to the PAC as part of the LSP for the following year, the PTO will undertake the following: First, the PTO will perform the initial phase of the Public Policy Local Transmission Study to develop an estimate of costs and benefits and post its preliminary results on a website. Second, the PTO will use good faith efforts to contact stakeholders and the appropriate state and/or local authorities informing them of the posting, requesting input on whether further study is warranted to identify solutions for local transmission system needs, and seeking recommendations about whether to proceed with further planning and construction of a Local Public Policy Transmission Upgrade. Each PTO will then make a determination of whether further study is warranted to identify solutions for local transmission system needs, or will select its final solution, and revise its annual LSP accordingly. If the potential Non-PTF transmission needs identified would affect the Non-PTF facilities of more than one PTO, the affected PTOs will coordinate their efforts with other affected PTOs, as necessary. Results of a Public Policy Local Transmission Study will be provided to the PAC as part of the LSP for the following year.

2. Posting of LSP Project List

Each PTO shall develop, maintain and make available on a website, a cumulative listing of proposed regulated transmission solutions that may meet LSP needs (the "LSP Project List"). The LSP Project List will be updated at least annually. The LSP Project List shall also provide reasons for any new Non-PTF, including Local Public Policy Transmission Upgrades, any change in status of proposed Non-PTF, including Local Public Policy Transmission Upgrades, or any removal of proposed Non-PTF, including Local Public Policy Transmission Upgrades, from the LSP Project List. Each PTO will be individually responsible for publicly posting and updating the status of its respective LSP and the transmission projects arising therefrom on a website in a format comparable to the manner in which RSP plans and

projects are posted on the RSP Project List. The ISO's posting of the RSP and RSP Project List will include links to each PTO's specific LSP Project List.

3. Posting of Assumptions and Criteria

Each PTO will make available on a website the planning criteria and assumptions used in its current LSP. A link to each PTO's planning criteria and assumptions will be posted on the ISO website.

4. Cost Responsibility for Transmission Upgrades

The cost responsibility for each upgrade, modification or addition to the transmission system in New England that is included in the LSP Project List of this Appendix 1 shall be determined in accordance with Schedule 21 of this OATT.

5. LSP Dispute Resolution Procedures

5.1 Objective

Section 5 of this Appendix 1 sets forth an LSP dispute resolution process (the "LSP Dispute Resolution Process") through which LSP-related transmission planning-related disputes may be resolved as expeditiously as possible.

5.2 Confidential Information and CEII Protections

All information disclosed in the course of the LSP Dispute Resolution Process shall be subject to the protection of confidential information and CEII consistent with the ISO New England Information Policy and CEII policy.

5.3 Eligible Parties

Any member of the Planning Advisory Committee that has been adversely affected by a PTO's Reviewable Determination with respect to the LSP transmission planning process described in this Appendix 1 is eligible to raise its dispute, as appropriate, under this LSP Dispute Resolution Process ("Disputing Party").

5.4 Scope

In order to ensure that the LSP transmission planning process set forth under this Appendix 1 moves expeditiously forward, the scope of issues that may be subject to the LSP Dispute Resolution Process under this Section 5 shall be limited to certain key procedural and substantive decisions made by the applicable PTO within its authority as specified in documents on file with the Commission. That is, decisions not subject to resolution within the jurisdiction of the Commission are not within the scope of this LSP Dispute Resolution Process. Examples of matters not within the scope of the LSP Dispute Resolution Process include planning to serve retail native load or state siting issues. Additionally, the Tariff already explicitly provides specific dispute resolution procedures for various matters. To this end, any matter regarding the review and approval of applications pursuant to Section I.3.9 of the Tariff, which is subject to the dispute resolution process under Section I.6 of the Tariff, shall not be within the scope of this LSP Dispute Resolution Process. Similarly, any matter regarding Transmission Cost Allocation shall be governed by the dispute resolution process under Schedule 12 of the OATT, and shall be outside the scope of this LSP Dispute Resolution Process.

(a) Reviewable Determinations:

The LSP determinations made by the applicable PTO that may be subject to the LSP Dispute Resolution Process under this Section 5 ("Reviewable LSP Determination") shall include certain procedural and substantive challenges at designated key decision points during the LSP transmission planning process for Non-PTF, including Local Public Policy Transmission Upgrades ("Key LSP Decision Points"). Procedural challenges will be limited to whether or not the steps taken up to a Key LSP Decision Point conform to the requirements set forth in this Appendix 1. Substantive challenges will be limited to whether or not a determination or conclusion rendered at a Key LSP Decision Point was supported by adequate basis in fact. The Key LSP Decision Points shall be limited to the following:

- (i) Results of an LSP Needs Assessment conducted and communicated by a PTO to the Planning Advisory Committee as specified in this Appendix 1;
- (ii) Updates to the LSP Project List, including adding, removing or revising regulated Non-PTF transmission solutions included thereunder, as presented at the Planning Advisory Committee and as specified in this Appendix 1;

- (iii) Results of Non-PTF transmission solutions studies, including any Local Public Policy Transmission Upgrade studies, conducted and communicated by the PTO to the Planning Advisory Committee as specified in this Appendix 1; and
- (iv) Consideration of market responses in LSP Needs Assessments as specified in this Appendix 1.

(b) Material Adverse Impact

In order to prevail in a challenge to a procedural-based Reviewable LSP Determination, the Disputing Party must show that the alleged procedural error had a material adverse impact on the determination or conclusion made by the applicable PTO. In order to prevail in a challenge to a substantive-based Reviewable LSP Determination, the Disputing Party must show that either (i) the determination is based on incorrect data or assumptions or (ii) incorrect analysis was performed by the PTO, and (iii) as a result thereof, the PTO made an incorrect decision or determination.

5.5 Notice and Comment

A Disputing Party aggrieved by a PTO's Reviewable LSP Determination shall have fifteen (15) calendar days upon learning of the Reviewable LSP Determination following the PTO's presentation of such LSP Reviewable Determination at the Planning Advisory Committee to request dispute resolution by giving notice to the Applicable PTO ("Request for LSP Dispute Resolution").

A Request for LSP Dispute Resolution shall be in writing and shall be provided to the applicable PTO and, as appropriate, other affected Transmission Owners. Within three (3) Business Days of the receipt by a PTO of a Request for Dispute Resolution, the PTO, in coordination with the ISO, shall prepare and distribute to all members of the Planning Advisory Committee a notice of the Request for Dispute Resolution including, subject to the protection of Confidential Information and CEII, the specifics of the Request for Dispute Resolution and providing the name of a PTO representative to whom any comments may be sent. Any member of the Planning Advisory Committee may submit to the PTO's designated representative, on or before the tenth (10th) Business Day following the date the PTO distributes the notice of the Request for Dispute Resolution, written comments to the PTO with respect to the Request for Dispute Resolution. The Disputing Party filing the Request for Dispute Resolution may respond to

any such comments by submitting a written response to the PTO's designated representative and to the commenting party on or before the fifteenth (15th) Business Day following the date the PTO distributes the notice of the Request for Dispute Resolution. The PTO may, but is not required to, consider any written comments.

5.6 Dispute Resolution Procedure

(a) Resolution Through the Planning Advisory Committee

The Planning Advisory Committee shall discuss and resolve any LSP related dispute arising under this Appendix 1 involving a Reviewable LSP Determination, as defined in Section 5.4 of this Appendix 1, between and among the applicable PTO, the Disputing Party, and, as appropriate, other affected Transmission Owners and the ISO (collectively, "Parties") (excluding applications for rate changes or other changes to the Tariff, or to any Service Agreement entered into under the Tariff, which shall be presented directly to the Commission for resolution).

(b) Resolution Through Informal Negotiation

To the extent that the Planning Advisory Committee is not able to resolve a dispute arising under this Appendix 1 involving a Reviewable LSP Determination, as defined in Section 5.4 of this Appendix 1, between and among the Parties, such dispute shall be the subject of good-faith negotiations among the Parties. Each Party shall designate a fully authorized senior representative for resolution on an informal basis as promptly as practicable.

(c) Resolution Through Alternative Dispute Resolution

In the event the designated representatives are unable to resolve the dispute through informal negotiations within thirty (30) days, or such other period as the Parties may agree upon, by mutual agreement of the Parties, such LSP related dispute may be submitted to mediation or any other form of alternative dispute resolution upon the agreement of all Parties to participate in such mediation or other alternative dispute resolution process. Such form of alternative dispute resolution shall not include binding arbitration.

If a Party identifies exigent circumstances reasonably requiring expedited resolution of the LSP related dispute, such Party may file a Complaint with the Commission or seek other appropriate redress before a court of competent jurisdiction

5.7 Notice of Results of Dispute Resolution

Within three (3) Business Days following the resolution of a dispute pursuant to either Section 5.6(b) or 5.6(c) of this Appendix 1, the PTO shall distribute to members of the Planning Advisory Committee a document reflecting the resolution.

5.8 Rights under the Federal Power Act:

Nothing in this Appendix 1 shall restrict the rights of any party to file a complaint with the Commission under relevant provisions of the Federal Power Act.

ATTACHMENT K APPENDIX 2
LIST OF ENTITIES ENROLLED IN THE TRANSMISSION PLANNING REGION
ENTITIES

APPENDIX 2

ATTACHMENT K

LIST OF ENTITIES ENROLLED IN THE TRANSMISSION PLANNING REGION

The entities listed in this Appendix 2 are those enrolled for the purpose of participating as a transmission provider in the New England transmission planning region pursuant to Attachment K as of the date the revisions to this Appendix 2 were filed with the Commission. The most current list of entities enrolled for the purpose of participating as a transmission provider in the New England transmission planning region pursuant to Attachment K is available on the ISO-NE website. This Appendix 2 will be updated to reflect any subsequent enrollments as part of unrelated OATT filings at the time ISO-NE undertakes such unrelated filings.

Town of Braintree Electric Light Department
Central Maine Power Company
The City of Chicopee Municipal Lighting Department
The City of Holyoke Gas and Electric Department
The Connecticut Light and Power Company
Connecticut Municipal Electric Energy Cooperative
Connecticut Transmission Municipal Electric Energy Cooperative
Cross-Sound Cable Company, LLC
Emera Maine
Fitchburg Gas and Electric Light Company
Green Mountain Power Corporation
Hudson Light & Power Department
Massachusetts Municipal Wholesale Electric Company
Maine Electric Power Company
Middleborough Gas and Electric Department
New England Electric Transmission Corporation
New England Energy Connection, LLC
New England Hydro-Transmission Corporation

New England Hydro-Transmission Electric Company Inc.

New England Power Company

New Hampshire Electric Cooperative, Inc.

New Hampshire Transmission, LLC

Eversource Energy Service Company as agent for: The Connecticut Light and Power Company, NSTAR Electric Company, Public Service Company of New Hampshire, and Western Massachusetts Electric Company

Norwood Municipal Light Department

NSTAR Electric Company

Public Service Company of New Hampshire

Shrewsbury Electric & Cable Operations

Taunton Municipal Lighting Plant

Town of Reading Municipal Light Department

The United Illuminating Company

Unitil Energy Systems, Inc.

Vermont Electric Cooperative, Inc.

Vermont Electric Power Company, Inc.

Vermont Electric Transmission Company

Vermont Public Power Supply Authority

Vermont Transco LLC

Town of Wallingford CT Dept of Public Utilities – Electric Division

Western Massachusetts Electric Company

ATTACHMENT K APPENDIX 3

LIST OF QUALIFIED TRANSMISSION PROJECT SPONSORS

The entities listed in this Appendix 3 are those approved by ISO-NE as Qualified Transmission Project Sponsors as of the date the revisions to this Appendix 3 were filed with the Commission. The most current list of entities approved as Qualified Transmission Project Sponsors is available on the ISO-NE website. This Appendix 3 will be updated to reflect any subsequent enrollments as part of unrelated OATT filings at the time ISO-NE undertakes such unrelated filings.

Braintree Electric Light Department
Central Maine Power Company
City of Holyoke Gas and Electric Department
The Connecticut Light and Power Company
The Connecticut Transmission Municipal Electric Cooperative
Emera Maine
Eversource Energy Transmission Ventures, Inc.
Grid America Holdings, Inc.
Hudson Light and Power Department
Maine Electric Power Company
Middleboro Gas & Electric Department
New England Energy Connection, LLC
New England Power Company
New Hampshire Transmission, LLC
Norwood Municipal Light Department
NSTAR Electric Company
Public Service Company of New Hampshire
Taunton Municipal Light Plant
United Illuminating Company

Vermont Transco, LLC

Western Massachusetts Electric Company

ATTACHMENT L1
ISO NEW ENGLAND FINANCIAL ASSURANCE POLICY

See Exhibit IA to Section I of the Tariff.

ATTACHMENT L2

[Reserved for future use.]

ATTACHMENT L3
[Reserved for future use.]

ATTACHMENT L4
ISO NEW ENGLAND BILLING POLICY

See Exhibit ID to Section I of the Tariff.

ATTACHMENT M

ROLE OF INDEPENDENT TRANSMISSION COMPANIES

This Attachment sets forth a general framework for the development and operation of Independent Transmission Companies (“ITC’s”) within the ISO, pursuant to the process set forth herein. Certain responsibilities specified in this Attachment may be assigned to an ITC, if the ITC chooses to accept those responsibilities and if the Commission’s acceptance or approval of the assignment of those responsibilities to the ITC, including a determination of the capability of the ITC to carry out those responsibilities, is obtained as provided herein.

This Attachment governs the rights, responsibilities, and functions of the ITC and the relationship between the ISO and the ITC, which shall be set forth in greater detail and on a binding basis in an agreement between the ISO and the ITC governing the allocation of responsibilities between such ITC and the ISO and other matters necessary for the coordinated operation of the ITC and the ISO (an “ITC Agreement”). Any modifications to the rights, responsibilities and functions of PTOs under the TOA shall not affect the rights, responsibilities and functions of the ITC under this Attachment or an executed and effective ITC Agreement, unless this Attachment or such ITC Agreement, respectively, is similarly modified. To the extent that the rights and responsibilities of an ITC with respect to a particular function or subject matter are not described in this Attachment (or an ITC Agreement developed pursuant to the process described in this Attachment) in a manner different in substance from the TOA’s description of the rights and responsibilities of a PTO with respect to that particular function or subject matter, then: (x) an ITC shall have the same rights and responsibilities as a PTO under the TOA, (y) the rights and responsibilities of the ISO shall be the same in relation to an ITC as to a PTO under the TOA, and (z) the terms and conditions of the TOA shall govern the relationship between the ITC and the ISO and shall be given effect in the ITC Agreement. Nothing in this Attachment shall modify the relationship between the ISO and any PTO that has not agreed to transfer operational authority or ownership of its transmission facilities to the ITC, or the rights, responsibilities and functions of such PTO under the TOA. Unless otherwise defined herein, all capitalized terms used in this Attachment are used as defined in the Tariff.

Any PTO or PTOs desiring to participate in, join, or become an ITC shall provide notice to the ISO that they desire to commence negotiation of an ITC Agreement. Such notice shall be accompanied by a resolution of the Board of Directors of each such PTO or a letter executed by the chief executive officer or senior officer of each such PTO indicating a commitment to participate in, join, or become an ITC. The ISO and the PTO(s) desiring to participate in, join or become an ITC shall negotiate in good faith over the terms of

an ITC Agreement. This Attachment shall constitute the framework for those negotiations, provided that the ISO and the PTO(s) proposing to participate in, join, or become an ITC may agree that such ITC may assume additional or fewer rights or responsibilities, provided that the ITC's assumption of additional or fewer rights or responsibilities does not adversely affect any other PTO. If the ISO and the negotiating PTO(s) reach agreement on the terms of an ITC Agreement, the ISO and the negotiating PTO(s) shall jointly file the ITC Agreement with the Commission under Section 205. If the ISO and the negotiating PTO(s) are unable to reach agreement on the terms of an ITC Agreement within one hundred and twenty (120) days, or such shorter or longer period as they may mutually agree, the ISO and the negotiating PTO(s) shall jointly file a proposed ITC Agreement with the Commission under Section 205, showing their respective positions on any provisions (including those that specify the ISO or ITC rights and responsibilities) with respect to which they disagree. The Commission's resolution of any such disagreements shall establish the terms upon which such ITC may be established, if the negotiating PTO(s) decide to proceed with the establishment of an ITC. The negotiating PTO(s) may elect to proceed with the establishment of an ITC, and the ISO may execute or implement an ITC Agreement, without foregoing the right to seek appellate review by courts of competent jurisdiction of any condition established or ruling made by the Commission or any other governmental Authority.

Any pro forma ITC Agreement filed by the ISO with the Commission to become effective on or after the Operations Date shall be the starting point for any negotiations commenced thereafter between the ISO and any PTO(s) and shall be based on and consistent with the allocation of rights and responsibilities and other provisions contained in this Attachment. If this Attachment is change after a pro forma ITC Agreement has been filed with the Commission, such pro forma ITC Agreement shall be modified to conform to any subsequent changes to this Attachment.

1. COMMISSION APPROVAL

In order for an ITC to assume rights, responsibilities and functions specified in this Attachment, the PTO(s) that are proposing to participate in, join, or become an

ITC must apply for, and receive, a Commission order finding that: (1) the proposed ITC satisfies the Commission's independence criteria; (2) the ITC has the necessary capabilities to carry out the responsibilities and functions, and (3) the ITC meets any other applicable Commission criteria. The ISO (except to the extent the ISO reaches agreement with the PTO(s) that are proposing to participate in, join, or become the ITC on the foregoing items) and others shall have the rights to intervene, comment, or protest

any such filing or to file a complaint under Section 206 of the Federal Power Act with regard to any such ITC filing or document.

Once the Commission issues an order accepting the filing and providing the finding required under this Section 1, then the ITC may operate within the ISO consistent with the rights, responsibilities, and functions that have been accepted or approved by the Commission. In addition, the TOA shall be superseded or amended with respect to any PTO whose transmission facilities are owned or operated by the approved ITC, and the ITC shall enter into an ITC Agreement with the ISO, consistent with Section 10.05 of the TOA and this Attachment, as appropriate to reflect the assumption of rights, functions and responsibilities by the ITC and the ISO's Operational Authority for such transmission facilities.

2. RELIABILITY COORDINATION

2.1 Regional Reliability Authority. The ISO shall be the regional Reliability Authority for the New England Transmission System, including any ITC transmission systems. The ISO shall be responsible for system reliability and operation of the New England Markets. As the Reliability Authority, the ISO is responsible for ensuring the reliability of the bulk power transmission system in the Region. Certain functions may be performed by an ITC in coordination with the ISO and subject to the ultimate authority of the ISO as the Reliability Authority.

2.2 Security Analysis and Real-Time Monitoring. The ISO shall perform real-time monitoring and security assessment of the New England Transmission System. An ITC may perform security analysis and real-time monitoring of the ITC System. As to each ITC, the "ITC System" shall consist of all transmission facilities owned or operated by the ITC and all generation and loads interconnected to such transmission facilities either directly or through one or more sub-transmission and/or distribution facilities directly interconnected to such transmission facilities.

2.3 ITC Actions. An ITC may take actions to preserve the security of the ITC System, including but not limited to voltage management, the determination of active and passive transmission device settings, changes in topology, outage management, and other operating actions affecting the ITC transmission system, in accordance with applicable ISO New England Operating Procedures pursuant to Section 15 of this Attachment.

2.4 Ultimate Authority. The ISO may intercede and direct appropriate near-term operational actions in its role as regional Reliability Authority, provided that nothing in this Section 2.4 shall require any ITC to

undertake an action contrary to applicable Law or shall limit the right of the ITC to adopt and implement, consistent with Good Utility Practice, procedures and to take such actions it deems necessary to protect its facilities from physical damage or to prevent injury or damage to persons or property. If such ISO action is disputed, the ISO's position shall control pending resolution of the dispute.

2.5 Information. The ISO and the ITC shall share information to enable them to perform their respective functions in accordance with Section 17 of this Attachment.

3. TRANSMISSION RATES

3.1 Right to File Rate Changes and ITC Rate Schedules. The ITC shall possess the unilateral right, without receiving any ISO approval, to make filings at the Commission pursuant to FPA Section 205 proposing rate or rate structure changes (including incentive rate structures related to Section 5.2 of this Attachment or other incentive or performance-based rate structures) involving transmission charges for service to load within the ITC System, provided that: (a) the ITC shall consult with the ISO and the PTO AC at least thirty days prior to submitting any such filing to the Commission; (b) no such rate or rate structure changes shall abridge the rights granted to the ISO in Section 3.04(c) of the TOA, reserved in Section 3.14 of the TOA, or reflected in this Attachment; and (c) if the ISO identifies to the ITC any concerns relating to the modification of software necessary to implement any such rate or rate structure change, the ITC shall so indicate in its filing, the ISO shall use commercially reasonable efforts to implement any software modifications by the effective date of the ITC's filing, and any failure to complete the modifications by such date, notwithstanding commercially reasonable efforts, shall not constitute a default by the ISO or a basis for financial damages and the ISO shall, if necessary, run retroactive settlements consistent with such effective date. Such rate or rate structure changes shall be included in discrete schedules or portions of the OATT (hereafter, such discrete schedules or portions of the OATT shall be the "ITC Rate Schedule"). In its filing with the Commission, the ITC shall comply with all applicable Commission requirements. The ITC shall also include in any filing a statement that, in the good faith judgment of the ITC, the proposal will not be inconsistent with the design of the New England Markets. The ISO and others shall have the rights to intervene, comment, or protest any such filing (including incentive rate filings) or to file a complaint under Section 206 of the Federal Power Act with regard to any such ITC filing. The ISO shall not have the right to submit changes to an ITC Rate Schedule pursuant to FPA Section 205. In the event the ISO believes that an ITC's proposed rate or rate structure change (x) would be inconsistent with the design of the New England Markets, or (y) could have a material adverse effect on the efficiency or competitiveness of the New England Markets, the ability of the ISO to provide transmission access on a not unduly discriminatory or preferential basis; or the reliability of the ISO bulk power system; then the ITC's filing shall include any

written statement provided by the ISO setting forth the basis for the ISO's concerns. All other service to load outside the ITC System and for "wheeling through" or "wheeling out" service with respect to the ISO region or a portion thereof is subject to all applicable ISO transmission charges under the OATT, not including those in the ITC Rate Schedule, provided that the ITC shall have the right to propose any changes in the level of the ITC costs reflected in applicable ISO transmission charges not included in the ITC Rate Schedule for such service. The PTO AC or the ISO, as applicable pursuant to Section 3.04 of the TOA, shall consult with the ITC at least thirty days prior to proposing any rate or rate structure changes to enable the ITC to consider the need for any corresponding changes to its own transmission charges.

3.2 No Rate Pancaking. Notwithstanding its rights under Section 3.1, the ITC shall not implement rates or a rate structure which results in a transmission customer paying a pancaked transmission charge for any one transaction within the ISO region.

4. REVENUE DISTRIBUTION

4.1 ITC Receipt of Transmission Revenues. The ITC shall receive and/or retain revenues resulting from the provision of transmission service under the OATT or the ITC Rate Schedule if applicable in accordance with Section 7 of this Attachment. The ITC may take no unilateral action which interferes with or affects the revenue distribution provided for in Section 3.10 of the TOA or which interferes with the collection of the revenues due under the OATT for services it provides or arranges. The ITC shall redirect to the ISO any payments due to the ISO but erroneously paid to the ITC as soon after discovery of the mispayment as practicable and shall provide the ISO with notification of the erroneous payments within five (5) Business Days of discovery of the mispayment. The ISO shall redirect any payments due to an ITC but erroneously paid to the ISO as soon after discovery of mispayment as practicable and shall provide the ITC with notification of the erroneous payments within five (5) Business Days of discovery of the mispayment.

4.2 Redistribution of Revenues. The ITC may redistribute the revenues that it receives pursuant to the OATT or the ITC Rate Schedule, if applicable, in any manner it wishes subject to receiving any necessary regulatory approvals, without involvement of the ISO.

5. ITC OPERATING ACTIONS TO REDUCE CONGESTION

5.1 ISO Responsibility for New England Markets, including Congestion Pricing. Subject to Commission approval or acceptance, the ISO shall have the rights and obligations to design, develop, operate, maintain and administer the New England Markets, including the authority to determine the

congestion pricing methodology for the ISO region and will have the authority to calculate congestion prices for the region in accordance with the approved or accepted methodology.

5.2 ITC Operating Actions to Reduce Congestion. An ITC may take actions to reduce congestion on the ITC System in accordance with applicable ISO New England Operating Procedures as such ISO New England Operating Procedures may be modified pursuant to Section 15 of this Attachment, including but not limited to voltage management, the determination of active and passive transmission device settings, changes in topology, outage management, and other operating actions affecting the ITC System. The ISO shall modify the applicable ISO New England Operating Procedures as necessary to allow for the implementation of any Commission-accepted or -approved incentive mechanism. The ITC shall coordinate such operating actions with the ISO so as to minimize, to the extent practicable, Congestion Costs and Local Second Contingency Protection Resource NCPC Charges.

5.3 Information. The ISO and the ITC shall share information required for them to fulfill their respective functions under this Section 5 in accordance with Section 17 of this Attachment.

6. LOSSES

To the extent the ITC is responsible for the costs of losses, the ITC shall possess the unilateral right to file at the Commission, without any ISO approval, a mechanism for determining loss responsibility within the ITC System, provided that this method does not affect the costs of losses assigned to entities other than the ITC in areas outside of the ITC System and is not inconsistent with design of the markets administered by the ISO including the congestion pricing methodology for the New England region approved by the Commission and any provision for losses contained therein.

7. TARIFF ADMINISTRATION

7.1 Agreements. The ISO will be the Transmission Provider under the OATT of nondiscriminatory, open access transmission services over the ITC System, consistent with this Attachment. The ISO will execute the agreements with the customers for transmission service under the OATT on the New England Transmission System (including the ITC System). The ISO and the ITC jointly shall enter into agreements for studies conducted by the ITC with respect to the ITC System in accordance with Section 7.3. The ITC shall enter into interconnection agreements with all entities interconnecting to the ITC System, provided that, with respect to the interconnection of a Small or Large Generating Unit to any transmission facility of an ITC, the Interconnection Agreement shall be a multi-party agreement among the ITC, the ISO, and the interconnecting non-Party based on the *pro forma* Small or Large Generator Interconnection Agreement in

the OATT, and that with respect to the interconnection of other Generating Units to any transmission facility of an ITC, the ISO shall be a party to Interconnection Agreements if and to the extent that Commission regulations require the ISO to be a party. To the extent applicable under the rate design for the ITC Rate Schedule, and to the extent rate discounting is authorized as to such transmission services, the ITC shall make all decisions on rate discounts for transmission service for load within the ITC System under the ITC Rate Schedule.

7.2 OASIS. Customers will be able to receive information and apply for transmission service over the entire New England Transmission System (including the ITC System) by accessing a single OASIS interface maintained by the ISO. If and to the extent the approach to transmission access employed by the ISO involves transmission service reservations, the ITC shall possess the right to administer transmission service reservations made for transmission service under the ITC Rate Schedule or within the ITC System using the single OASIS interface.

7.3 Studies. If a system impact or other study is required to evaluate the ability of the ITC to provide the transmission service and the requested service is within the ITC System, then the ITC shall possess the right to assume full responsibility for the study, subject to coordination with the ISO and satisfaction of New England reliability criteria for such studies. If a Facilities Study is required to study a constraint within the ITC System, then the ITC shall possess the right to assume responsibility for the study subject to coordination with the ISO and satisfaction of New England reliability criteria for such studies. The ITC shall conduct all such studies in accordance with ITC System Planning Procedures pursuant to Section 15 of this Attachment. The ISO shall have the authority to require modifications to such studies if it determines that such studies do not adequately address Material Adverse Impacts outside the ITC System or do not satisfy New England reliability criteria for such studies. Nothing in this Attachment shall preclude the performance of studies related to the interconnection of Generating Units to the ITC System by a third party consultant to the extent permitted by applicable procedures in the OATT (including procedures governing the treatment of confidential information) and provided that such studies performed by any third party consultant must include the ITC's reasonable estimates of the costs of upgrades to the ITC System needed to implement the conclusions of such studies and the ITC's reasonable anticipated schedule for the construction of such upgrades.

7.4 Long-Term TTC. Where the ITC System encompasses an entire interface within a New England Control Area, the ITC shall calculate the long-term TTC of such interface based on seasonal operating studies conducted by the ITC that take into account information on anticipated peak loads, facility ratings,

scheduled transmission outages, and generator maintenance schedules throughout the Region in accordance with formulas and methodology developed jointly with the ISO and subject to coordination with the ISO.

7.5 Short Term TTC and ATC. The ISO shall adjust short-term TTC on interfaces throughout the ISO system (including the ITC System) based on daily forecasts that take into account changes in transmission facility ratings, transmission facility and generation outages, and load forecasts. The ISO shall administer the ATC calculation and shall calculate, to the extent required, CBM and TRM, based on facility ratings of ITC facilities established by the ITC pursuant to Section 9.2 and ISO New England Operating Procedures and other assumptions established for the ITC facilities.

8. CURTAILMENTS

8.1 ITC Responsibilities. The ITC shall develop protocols for the coordination of transmission service curtailments on the ITC System, subject to coordination with the ISO and in accordance with all applicable OATTs, and applicable ISO New England Operating Procedures pursuant to Section 15 of this Attachment.

8.2 ISO Responsibilities. The ISO will curtail transmission service in accordance with applicable ISO New England Operating Procedures pursuant to Section 15 of this Attachment.

9. OPERATIONS

9.1 Operations Under ISO Hierarchical Control. The ISO shall be responsible for day-to-day ISO operations in matters pertaining to the central dispatch of transmission facilities under the ISO's Operating Authority, dispatchable and interruptible load, interchange scheduling, and all generating resources committed by the ISO Participants in accordance with applicable ISO New England Operating Procedures, as such ISO New England Operating Procedures may be modified pursuant to Section 15 of this Attachment. The ITC may operate a Local Control Center, which shall carry out the ISO instructions, orders and directions in accordance with applicable ISO New England Operating Procedures, as such ISO New England Operating Procedures may be modified pursuant to Section 15 of this Attachment.

9.2 Ratings and Rating Procedures. The ITC will establish ratings and rating procedures for its facilities within the ITC System in accordance with Good Utility Practice, provided that such responsibility has been transferred to the ITC by the applicable PTO.

9.3 Transmission Maintenance. The ITC will develop transmission maintenance and outage schedules for the ITC System and shall coordinate scheduled transmission maintenance outage schedules with the

ISO with an objective of enhancing market efficiency, including the objective of coordinating generation and transmission maintenance outage schedules to minimize, to the extent practicable, Congestion Costs and Local Second Contingency Protection Resource NCPD Charges. The ISO shall have the authority to disapprove transmission maintenance outages on the ITC System if it determines that such outages reasonably could be expected to result in a violation of reliability criteria. The ISO shall have the authority to revoke its previously granted approval of transmission maintenance outages if forced transmission outages or emergency circumstances reasonably could be expected to result in a violation of reliability criteria for the New England Transmission System and cancellation of the planned outage reasonably could be expected to improve reliability. The ISO shall notify the ITC of the decision to reschedule or revoke approval of the transmission maintenance outage as soon as possible after the circumstances arise that create the need for the rescheduling or revocation. The ISO shall compensate the ITC for any direct costs incurred by the ITC due to the ISO's rescheduling or revocation of previously approved transmission maintenance outages in accordance with and to the extent required by Commission directives.

If the ISO and the PTO(s) proposing an ITC are unable to reach agreement on the terms of any Market-related outage authority for ITC transmission facilities, the ISO and the negotiating PTO(s) shall set forth their respective positions on such provisions when the ITC Agreement is filed at the Commission.

9.4 Generation Maintenance. The ITC may coordinate generator maintenance schedules for generators within the ITC System with planned transmission outage schedules in accordance with applicable ISO New England Operating Procedures pursuant to Section 15 of this Attachment. The ITC may modify its planned transmission outage schedules in coordination with generator outage schedules to maximize throughput and minimize exposure to congestion while maintaining safe and reliable operation of the ITC System. The ITC shall submit any modifications to its planned transmission outage schedules to the ISO, and the ISO shall have the authority to disapprove those modifications as specified in Section 9.3. The ITC may also enter into agreements with generators with respect to coordination of generator outage schedules and transmission outage schedules. The ISO shall have the authority to revoke its previously granted approval of generation maintenance outages in accordance with the ISO procedures. The ISO shall notify the generators and the ITC of the decision to revoke approval of the generation maintenance outage as soon as possible after the circumstances arise that create the need for the revocation.

9.5 Scheduling and Dispatch. The ISO will schedule and dispatch generation and load within the New England Transmission System, including the ITC System. The ITC will manage the configuration and topology of transmission facilities on the ITC System, including the scheduling and performance of

transmission operations actions in accordance with applicable ISO New England Operating Procedures, as such ISO New England Operating Procedures may be developed or modified pursuant to Section 15 of this Attachment to address reliability and/or to improve market or operational efficiency, subject to the ISO's ultimate authority to intercede and direct appropriate actions in its role as the regional Reliability Authority.

9.6 Information. The ISO and the ITC shall share information required for them to fulfill their respective functions under this Section 9 in accordance with Section 17 of this Attachment.

10. PLANNING

10.1 Needs Assessment. The ISO has the responsibility for the development of a regional needs assessment for the ISO region. The ITC shall have the right to participate in the development of such regional needs assessment and shall have the responsibility for developing a system needs assessment for the ITC System.

The ITC shall provide the technical and analytical studies for the ITC System in accordance with ITC System Planning Procedures developed pursuant to Section 15 of this Attachment. The ITC may also provide technical and analytical studies in coordination with the ISO for the ISO region, if requested by the ISO. The ISO will adopt and/or develop planning criteria for the ISO system. The ITC, in consultation with the ISO, shall develop the transmission planning criteria for the ITC System consistent with the ISO planning criteria, the applicable criteria of ERO and the criteria of area reliability councils. The ISO shall publish the completed needs assessment for the ISO region on its website. The completed needs assessment shall include the system needs assessment for the ITC System developed by the ITC in consultation with the ISO as well as any needs within the ITC System identified by the ISO and not included in the ITC System needs assessment. If the ITC or the ISO disagrees with the inclusion or exclusion of particular needs as to the ITC System, the party shall so note in the final needs assessment.

10.2 Development of the ITC Plan. The ITC shall develop, with respect to the ITC System, options for new transmission projects, the use of innovative technology, and improved utilization of existing transmission facilities in response to the needs assessment. The ITC may also identify additional needs in the process of analysis and incorporate such needs in the development of the ITC plan. The ITC shall develop the ITC plan in accordance with ITC System Planning Procedures developed pursuant to Section 15 of this Attachment. Under the regional planning process, Market Participants will have the opportunity to propose other projects such as generation, merchant transmission and demand response programs that may eliminate the need for new transmission within the ITC System in response to the needs assessment.

The ITC shall issue its draft plan for the construction of transmission facilities within the ITC System to meet ITC System needs identified in the needs assessment phase.

10.3 ISO Evaluation, Refinement and Approval. In accordance with the procedures established for public review and ISO assessment of the Regional System Plan, the ISO shall provide a draft report on the recommendations for the Regional System Plan, including the draft ITC plan, for public review and comment. Following review and consideration of comments, the ISO shall provide its assessment of whether proposals submitted by Market Participants are likely to adequately and appropriately meet the regional needs identified in the needs assessment phase, including needs within the ITC System. Where more than one market-based proposal appropriately meets the needs to solve a potential ITC System deficiency, the ISO shall not choose between the proposals. The decision to proceed with market-based proposals (including merchant transmission) will be made by the market. The ISO shall provide the ITC its final assessment as to whether it believes transmission projects included in the draft ITC plan are likely to adequately and appropriately meet the regional needs identified in the needs assessment phase, including needs within the ITC System.

If the ISO determines that one or more projects in the draft ITC plan adequately and appropriately meets needs identified in the ISO needs assessment or an ITC needs assessment with which the ISO agrees, then the projects in the ITC plan addressing those needs shall become part of the final Regional System Plan. If the ISO determines that projects in the draft ITC plan do not fully meet needs identified in the ISO needs assessment or an ITC needs assessment with which the ISO agrees but are nonetheless appropriate, then the projects in the draft ITC plan shall become part of the final Regional System Plan. In the event that: (i) the ISO determines that any of the projects identified in the ITC plan do not adequately or appropriately meet the ISO needs assessment or an ITC needs assessment with which the ISO agrees, or (ii) the ISO disagrees with the ITC needs assessment, then the ITC may determine whether such projects in the ITC plan shall be listed in the Regional System Plan, provided that the ISO may designate such projects as “not approved.” In making a determination that an ITC project is “not approved,” the ISO shall identify the reasons for making such designation.

The ISO will review all of the projects identified in a draft ITC plan in order to determine if any of the projects would cause a Material Adverse Impact on facilities that are not a part of the ITC System that are within the New England Transmission System . If the ISO determines that a project identified in the ITC plan would cause a Material Adverse Impact on facilities that are not a part of the ITC System that are within the New England Transmission System, that project may not be included in the ISO System Plan.

If such a project within an ITC Plan is designated as “not approved” by the ISO or is not included in the Regional System Plan, then the costs of such projects shall not be included in rates under the OATT (including the ITC Rate Schedule) unless the ITC applies to the Commission for the inclusion of the costs of any such transmission project in rates under the OATT (including the ITC Rate Schedule), and the Commission approves or accepts such filing. The ISO shall have the right to intervene in, comment on, or file a protest in such proceeding before the Commission.

The ISO may direct the ITC to construct a transmission project within the ITC System that is not included in the draft ITC plan if the ISO determines that such transmission project is needed to adequately and appropriately address a regional need. The ITC shall be obligated to construct such transmission project pursuant to the same terms and conditions as set forth in Schedule 3.09(a) to the TOA. Such transmission projects shall be identified in the Regional System Plan.

10.4 Information. The ITC and the ISO shall share information required for them to fulfill their respective functions under this Section 10 in accordance with Section 17 of this Attachment.

11. BILLING AND SETTLEMENT

The ITC possesses the right to perform the billing, settlement, and accounting responsibilities for those transactions under its Rate Schedule under the OATT. The ITC may elect to contract for the performance of those functions by the ISO or another third party.

12. MARKET MONITORING

12.1 ISO Responsibilities. The Market Monitoring Unit of the ISO shall, among its other functions, perform market monitoring functions for market transactions involving the use of the ITC facilities.

12.2 Monitoring and Assessment of the ITC. The ITC-ISO relationship shall be monitored to determine if the division of functions creates a competitive or reliability problem that affects the ISO’s ability to provide efficient, reliable, and non-discriminatory transmission service and administration of markets within the ISO region. The ITC’s administration of its responsibilities shall also be monitored to determine whether its administration adversely affects the system reliability or the competitiveness or efficiency of any market administered by the ISO.

13. DISPUTE RESOLUTION

Any dispute arising under this Attachment M shall be the subject of good-faith negotiations among the ISO, the affected ITC and affected market participants, if any. The ISO, each affected ITC, and each affected market participant shall designate one or more representatives with the authority to negotiate the matter in dispute to participate in such negotiations. The ISO, each affected ITC, and each affected market participant shall engage in such good-faith negotiations for a period of not less than 60 calendar days, unless: (a) the ISO, an affected ITC, or an affected market participant identifies exigent circumstances reasonably requiring expedited resolution of the dispute by the Commission or a court or agency with jurisdiction over the dispute. Any other dispute that is not resolved through good-faith negotiations may, by the ISO, any ITC, or any market participant, be submitted for resolution by the Commission or a court or agency with jurisdiction over the dispute upon the conclusion of such negotiations. The ISO, any ITC, or any market participant may request that any dispute submitted to the Commission for resolution be subject to the Commission settlement procedures. Notwithstanding the foregoing, any dispute arising under this Attachment M may be submitted to arbitration or any other form of alternative dispute resolution upon the agreement of the ISO, all affected ITCs and all affected market participants to participate in such an alternative dispute resolution process.

14. NOTIFICATION OF ASSUMPTION OF RESPONSIBILITIES

The ITC shall provide notice to the ISO of its election to assume the responsibilities set forth herein or in a Commission-approved ITC Agreement. Following receipt of required approvals, the ITC and the ISO will allow, prior to the ITC's assumption of responsibilities, sufficient time to implement modifications to procedures and, if necessary, software, to allow coordinated operation of the ITC together with the ISO.

15. OPERATING, START-UP, AND SYSTEM PLANNING PROCEDURES

15.1 ISO New England Operating Procedures. The ISO and the ITC shall initially utilize the existing ISO New England Operating Procedures relating to the operation of the ITC System. Prior to startup, and from time to time after the ITC commences operations, the ITC shall review such ISO New England Operating Procedures and shall timely notify the ISO of any modifications or new ISO New England Operating Procedures desired by the ITC to reflect the operational actions of the ITC or to address specific conditions or on the ITC System. The ITC and the ISO will jointly develop and establish such modifications to the ISO New England Operating Procedures or new ISO New England Operating Procedures for the operation of the ITC System. In the event that the ITC and the ISO disagree about the ISO New England Operating Procedures relating to the operation of ITC facilities under the ISO's operational control, the ITC will have the opportunity to submit its proposed operating manuals, procedures, or protocols to the Commission for resolution of the dispute. Pending such resolution, the ISO shall have the authority, as the

System Operator with ultimate authority for the real-time operation of the New England Transmission System, to implement its proposed version(s) of the disputed operating manuals, procedures, or protocols.

15.2 ITC Start-Up Procedures and Protocols. The ITC and the ISO shall cooperate and use their best efforts to develop the necessary start-up procedures and protocols to allow timely start-up of the ITC pursuant to this Attachment. In the event that the ITC and the ISO disagree about such start-up procedures and protocols, the ITC will have the opportunity to submit its proposed start-up procedures and protocols to the Commission for resolution of the dispute. If the ITC elects to commence operations prior to such resolution of the dispute, the ISO shall have the authority, as the System Operator with ultimate authority for the real-time operation of the New England Transmission System, to implement its proposed version(s) of the disputed start-up procedures and protocols. Once such procedures and protocols have been developed, the ISO shall post such procedures and protocols on its website.

15.3 Real-Time Operations. The ITC and the ISO shall seek agreement, where time limitations do not make it impracticable to do so, on real-time operational decisions affecting the ITC System not otherwise specified in the operating manuals or procedures developed in accordance with this Section 15. In the absence of such agreement, or if time limitations do not permit reaching agreement, the ISO shall implement its operational decision.

15.4 ITC System Planning Procedures for the ITC System. Prior to start-up, the ITC and the ISO shall jointly develop and establish ITC System Planning Procedures encompassing all aspects of the ITC's development of a plan for the ITC System and the ITC's study of facilities or system impacts on the ITC System. In the event that the ITC and the ISO disagree about such ITC System Planning Procedures, the ISO will have the opportunity to submit its proposed procedures or protocols to the Commission for resolution of the dispute. Pending such resolution, the ITC shall have the authority to implement its proposed version(s) of the disputed ITC System Planning Procedures.

16. ANCILLARY SERVICES

16.1 System Restoration Plan and Blackstart Generation. The ISO and the ITC shall coordinate in the preparation of a workable system restoration plan for the ITC System. The ITC shall evaluate equipment capabilities, switching procedures and assist the ISO with transient studies to develop a system restoration plan. The ISO shall have final authority to approve the system restoration plan. The ITC may procure system restoration and blackstart services in accordance with the plan and provide them to customers under the ITC Rate Schedule included in the OATT. Any ITC filing to modify the ITC Rate Schedule in

connection with the procurement of system restoration and black-start services shall address the interaction between the ITC Rate Schedule and any provisions of the OATT applicable to system restoration and blackstart services, the ISO shall implement the system restoration plan.

16.2 Reactive Support. The ISO shall obtain reactive support from generators under the OATT, provided that the ITC may provide long-term supply of reactive support in accordance with the ITC Rate Schedule included in the OATT. Any ITC filing to modify the ITC Rate Schedule in connection with the provision of reactive support shall address the interaction between the ITC Rate Schedule and any provisions of the OATT applicable to reactive support.

17. INFORMATION SHARING

17.1 The ISO shall, upon the ITC's request, make available to the ITC any and all information within the ISO's custody or control that is necessary for such ITC to perform its responsibilities and obligations under this Attachment, provided that such information shall be made available to such ITC only to the extent permitted under the ISO New England Information Policy and subject to any restrictions in the ISO New England Information Policy applicable to an ITC, including provisions of the ISO New England Information Policy governing the confidential treatment of non-public information, and provided further that any ITC employee or employee of an ITC's Local Control Center shall comply with such ISO New England Information Policy and any applicable standards of conduct to prevent the disclosure of such information to any unauthorized Person. Any dispute concerning what information is necessary for a ITC to perform its responsibilities and obligations shall be subject to dispute resolution.

17.2 The ITC shall, upon the ISO's request, make available to the ISO any and all information within the ITC's custody or control that is necessary for the ISO to perform its responsibilities and obligations under this Attachment, provided that such information shall be made available to the ISO only to the extent permitted under the ISO New England Information Policy and subject to any restrictions in the ISO New England Information Policy applicable to the RTO, including provisions of the ISO New England Information Policy governing the confidential treatment of non-public information, and provided further that any ISO employee shall comply with such ISO New England Information Policy and any applicable standards of conduct to prevent the disclosure of such information to any unauthorized Person. Any dispute concerning what information is necessary for the ISO to perform its responsibilities and obligations shall be subject to dispute resolution.

ATTACHMENT N

PROCEDURES FOR REGIONAL SYSTEM PLAN UPGRADES

I. INTRODUCTION

Pursuant to Part II.G of the ISO New England Open Access Transmission Tariff (Sections II.46 – II.47), Attachment K and this Attachment, the ISO shall classify upgrades as Reliability Transmission Upgrades, Market Efficiency Transmission Upgrades or Public Policy Transmission Upgrades during the Regional System Plan (“RSP”) process. Pursuant to established standards, that process is designed to collect and reflect broad input from all stakeholders through the Planning Advisory Committee (“PAC”). The PAC is composed of a wide variety of regional stakeholders, including Governance Participants (such as generator owners, marketers, load serving entities, merchant transmission owners and participating transmission owners), governmental representatives, public interest groups, state agencies (including those participating in the New England Conference of Public Utilities Commissioners), retail customers, representatives of local communities, and consultants. The PAC meets regularly throughout the year.

This procedure describes the standards used by the ISO to identify Reliability Transmission Upgrades, Market Efficiency Transmission Upgrades and Public Policy Transmission Upgrades and the process for making such identifications pursuant to Part II.G and Attachment K of the OATT.

The ISO may amend these standards and procedures from time to time, as appropriate, with input from the Reliability Committee and PAC.

II. STANDARDS FOR IDENTIFYING RELIABILITY TRANSMISSION UPGRADES, MARKET EFFICIENCY TRANSMISSION UPGRADES AND PUBLIC POLICY TRANSMISSION UPGRADES

A. Identification of Reliability Transmission Upgrades

Reliability Transmission Upgrades are those upgrades necessary to ensure the continued reliability of the New England Transmission System based on applicable reliability standards. In applying the applicable reliability standards, some of the considerations that will be taken into account are as follows:

- available supply and transmission (i.e., known resource changes, which includes anticipated transmission enhancements (considering Elective Transmission Upgrades and Merchant Transmission Facilities), demand side resources, and new, retired or unavailable generators);

- load growth;
- acceptable stability response;
- acceptable short circuit capability;
- acceptable voltage levels;
- adequate thermal capability; and
- acceptable system operability and responses (e.g. automatic operations, voltage changes).

To identify the transmission system facilities required to maintain reliability and system performance consistent with the applicable reliability standards, the ISO shall:

- determine whether the above factors are met using reasonable assumptions for certain amounts of forecasted load growth, and generation and transmission facility availability (due to maintenance, forced outages, or other unavailability); and
- rely on Good Utility Practice, applicable reliability standards, and the ISO System Rules.

A Reliability Transmission Upgrade is not an upgrade required by the interconnection of a generator except to the extent determined under the terms of Schedule 11 of the OATT. A Reliability Transmission Upgrade may also provide market efficiency benefits.

B. Identification of Market Efficiency Transmission Upgrades

Market Efficiency Transmission Upgrades are upgrades designed primarily to provide a net reduction in total production cost to supply the system load. Proposed Market Efficiency Transmission Upgrades shall be identified by the ISO where the net present value of the net reduction in total cost to supply the system load, as determined by the ISO, exceeds the net present value of the carrying cost of the identified transmission upgrade.

An upgrade identified as a Reliability Transmission Upgrade may qualify for interim treatment as a Market Efficiency Transmission Upgrade if market efficiency is used to influence the schedule for the implementation of the upgrade. Such opportunities shall be identified by the ISO when the net present value of the reduction to total production cost to supply the system load, as determined by the ISO, exceeds the net present value of the Reliability Transmission Upgrade after it is advanced less the net present value of the upgrade for when it is projected to be needed for reliability.

1. Base Economic Evaluation Model

In making a determination of the net present value of bulk power system resource costs, the ISO shall take into account applicable economic factors that shall include the following projected factors:

- energy costs;
- Capacity Costs;
- cost of supplying total operating reserve;
- system losses;
- available supply and transmission (i.e., known resource changes, which includes anticipated transmission enhancements (considering Elective Transmission Upgrades and Merchant Transmission Facilities), demand side resources and new, retired or unavailable generators);
- load growth;
- fuel costs;
- fuel availability;
- generator availability;
- release of bottled generating resources;
- present worth factors for each project specific to the owner of the project;
- present worth period not to exceed ten years; and
- cost of the project.

Analysis may include utilization of historical information such as may be included in market reports as well as special studies and should report cumulative net present value annually over the study period.

2. Other Data Provided to Stakeholders

Although not used to evaluate the net economic benefit of the system upgrade, analysis may be provided to illustrate the net cost to load with and without the transmission upgrade – considering additional factors such as locational installed capacity, congestion costs, and impacts on bilateral prices for electricity.

Summary

Based on information provided through such analysis and pursuant to the factors listed in (1) above, the ISO, in consultation with the PAC, will identify Market Efficiency Transmission Upgrades to be included in the RSP. If however, during the course of their analysis, the ISO determines that without the project the

applicable reliability standards will not be met, then the project will be designated as a Reliability Transmission Upgrade and included in the RSP as such.

C. Identification of Public Policy Transmission Upgrades

Public Policy Transmission Upgrades are upgrades designed to meet transmission needs driven by public policy requirements, including such needs identified by NESCOE. Proposed Public Policy Transmission Upgrades shall be assessed and identified by the ISO in accordance with Section 4A of Attachment K to the OATT.

III. PROCEDURES FOR IDENTIFYING RELIABILITY TRANSMISSION UPGRADES, MARKET EFFICIENCY TRANSMISSION UPGRADES AND PUBLIC POLICY TRANSMISSION UPGRADES

A. ISO Identification of Needs for Reliability Transmission Upgrades, Market Efficiency Transmission Upgrade and Public Policy Transmission Upgrades

1. An assessment of the adequacy of the region's electric system.

On a regular and on-going basis, the ISO shall conduct studies to identify the location and nature of any potential problems on the New England Transmission System. These assessments shall be conducted to identify those factors relevant to the standards for identifying needs which might be solved or mitigated by Reliability Transmission Upgrades and Market Efficiency Transmission Upgrades, as specified in Section II of this Attachment.

The ISO will publish its identification of such relevant factors on the New England Transmission System on its website and to the PAC, thereby providing market signals for generation, merchant transmission and load responses to develop and implement market-based solutions for the relief of actual and projected system reliability concerns, transmission constraints and market inefficiencies. The ISO will also present the results of its assessments in appropriate market forums to facilitate market responses to those needs. Market responses having met appropriate milestones pursuant to Attachment K to the OATT will be included in studies to assess the effects of such market responses on the identified problems with reliability and market inefficiencies.

Based on input and feedback provided by the PAC, the ISO shall refer to the Markets Committee and Reliability Committee issues and concerns identified by the PAC for further investigations and consideration of potential changes to rules and procedures.

2. Conduct of Public Policy Transmission Studies

The ISO will conduct the public policy transmission planning process pursuant to the timelines and procedures set out in Section 4A of Attachment K to this OATT.

B. Adequacy of the market responses, and as necessary, adequacy of Reliability Transmission Upgrades and Market Efficiency Transmission Upgrades

The ISO shall assess the adequacy of proposed market responses in addressing identified system needs. The ISO shall also ensure that there are no significant adverse effects associated with such market responses, pursuant to Section I.3.9 of the Tariff and Planning Procedure 5-3, “Guidelines for Conducting and Evaluating Proposed Plan Application Analysis”.

If the market does not respond with adequate solutions to address the system needs identified by the ISO, the ISO shall present a coordinated transmission plan in the RSP that identifies appropriate projects for addressing both reliability, and market efficiency needs.

This coordinated plan is updated by the ISO as market responses to identified problems are developed. Reliability Transmission Upgrades and Market Efficiency Transmission Upgrades are implemented only after market solutions have been given first consideration.

C. Periodic Updates to the RSP

A Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade may be added to the RSP at any time in a given year, and a Public Policy Transmission Upgrade project may be added to the RSP in accordance with Sections 3.6 and 4A of Attachment K to the OATT. In doing so, the ISO shall consult with and consider input from the PAC and the Reliability Committee, within the scope of their respective functions.

The time required to implement transmission projects, however, is often longer than that needed for market-based solutions. Thus, the RSP process recognizes that a new market response could result in a deferral or a significant change in the proposed timing and/or configuration of a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrades. Also, a needed Reliability

Transmission Upgrade or Market Efficiency Transmission Upgrade may become delayed due to other factors.

As a result, the ISO may remove or defer a Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade project from the RSP at any time in a given year, if the market responds by developing credible market-based solutions, or other circumstances arise that impact the need for the Transmission Upgrade. If market-based solutions have not met appropriate milestones prior to significant sunk transmission expense being made to provide the Reliability Transmission Upgrade or Market Efficiency Transmission Upgrade, then the ISO will assess the risks and costs associated with adding or advancing a transmission project from the RSP. The ISO may remove a Public Policy Transmission Upgrade project from the RSP in accordance with Sections 3.6 and 4A of Attachment K to the OATT. The ISO shall consult with and consider input from the PAC and the Reliability Committee with regard to such changes in the RSP. In the event that a transmission project is removed, deferred, added or advanced, the ISO shall promptly notify the affected Participating Transmission Owners and Non-Incumbent Transmission Developers.

IV. COST-EFFECTIVENESS AND COST ALLOCATION DETERMINATION OF RELIABILITY TRANSMISSION UPGRADES AND MARKET EFFICIENCY TRANSMISSION UPGRADES

The cost-effectiveness and cost allocation of identified Reliability Transmission Upgrades and Market Efficiency Transmission Upgrades will be determined pursuant to the Tariff, Attachment K; Schedule 12; and Planning Procedure 4. The level of detail needed to fulfill the requirements of the RSP process and Planning Procedure 4 will ensure that, in addition to a determination of Pool-supported PTF costs and Localized Costs, the planning and stakeholder review processes will include a comprehensive examination of all Transmission Upgrade construction alternatives and their associated costs and will thus evaluate the cost-effectiveness of each Transmission Upgrade and its potential alternatives.

ATTACHMENT O

NON-INCUMBENT TRANSMISSION DEVELOPER OPERATING AGREEMENT

NON-INCUMBENT TRANSMISSION DEVELOPER OPERATING AGREEMENT

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NON-INCUMBENT TRANSMISSION DEVELOPER OPERATING AGREEMENT

This Operating Agreement (this “Agreement”), dated as of [date], is made and entered into by _____, a [STATE] [TYPE OF ENTITY] (“NTD”), and ISO New England Inc. (“ISO”), a Delaware corporation (NTD and the ISO are collectively referred to herein as the “Parties”).

WHEREAS, the ISO is a regional transmission organization (“RTO”) authorized by the Federal Energy Regulatory Commission (“FERC”) to exercise the functions required of RTOs pursuant to FERC’s Order No. 2000 (“Order 2000”) and FERC’s RTO regulations;

WHEREAS, NTD has been approved as a “Qualified Transmission Project Sponsor” pursuant to the ISO Open Access Transmission Tariff (the “ISO OATT”), which is Section II of the ISO New England Inc. Transmission, Markets and Services Tariff (the “ISO Tariff”);

WHEREAS, in accordance with the requirements of Order 2000, the ISO will be the transmission provider under the ISO OATT of non-discriminatory, open access transmission services over the transmission facilities of NTD, once placed in service, that become part of the New England Transmission System (“Transmission Service”);

WHEREAS, the ISO OATT will be designed to provide for the payment by transmission customers for Transmission Service at rates designed to recover the revenue requirements of NTD in supporting the provision of such transmission service by the ISO under the ISO OATT;

WHEREAS, the ISO will be responsible for system planning within the ISO region subject to certain rights and obligations of NTD, all as set forth in this Agreement;

WHEREAS, the functions to be performed by the ISO and Order 2000 require that the ISO have the requisite operational authority over NTD’s transmission facilities;

WHEREAS, in accordance with the terms set forth herein, NTD desires for the ISO to exercise, and the ISO desires to exercise, Operating Authority (as defined in Section 3.02 of this Agreement) over the NTD Transmission Facilities (as defined in this Agreement) consistent with the requirements of Order 2000, once those facilities are placed in service;

WHEREAS, NTD will among other things, continue to own, physically operate, and maintain its transmission facilities; and

WHEREAS, references to the PTOs in this Agreement are not intended to impose additional requirements or obligations on the PTOs in addition to those in the TOA;

NOW, THEREFORE, in consideration of the promises, and the mutual representations, warranties, covenants and agreements hereinafter set forth, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, and intending to be legally bound, NTD and the ISO agree as follows:

ARTICLE I

DEFINITIONS; INTERPRETATIONS

1.01 **Definitions; Interpretations.** Each of the capitalized terms and phrases used in this Agreement (including the foregoing recitals) and not otherwise defined herein shall have the meaning specified in Schedule 1.01. In this Agreement, unless otherwise provided herein:

- (a) words denoting the singular include the plural and vice versa;
- (b) words denoting a gender include all genders;
- (c) references to a particular part, clause, section, paragraph, article, exhibit, schedule, appendix or other attachment shall be a reference to a part, clause, section, paragraph, or article of, or an exhibit, schedule, appendix or other attachment to, this Agreement;
- (d) the exhibits, schedules and appendices attached hereto are incorporated herein by reference and shall be construed with and as an integral part of this Agreement to the same extent as if they were set forth verbatim herein;
- (e) a reference to any statute, regulation, proclamation, ordinance or law includes all statutes, regulations, proclamations, amendments, ordinances or laws varying, consolidating or replacing the same from time to time, and a reference to a statute includes all regulations, policies, protocols, codes, proclamations and ordinances issued or otherwise applicable under that statute unless, in any such case, otherwise expressly provided in any such statute or in this Agreement;

(f) a reference to a particular section, paragraph or other part of a particular statute shall be deemed to be a reference to any other section, paragraph or other part substituted therefor from time to time;

(g) a definition of or reference to any document, instrument or agreement includes any amendment or supplement to, or restatement, replacement, modification or novation of, any such document, instrument or agreement unless otherwise specified in such definition or in the context in which such reference is used;

(h) a reference to any Person (as hereinafter defined) includes such Person's successors and permitted assigns in that designated capacity;

(i) any reference to "days" shall mean calendar days unless "Business Days" (as hereinafter defined) are expressly specified;

(j) if the date as of which any right, option or election is exercisable, or the date upon which any amount is due and payable, is stated to be on a date or day that is not a Business Day, such right, option or election may be exercised, and such amount shall be deemed due and payable, on the next succeeding Business Day with the same effect as if the same was exercised or made on such date or day (without, in the case of any such payment, the payment or accrual of any interest or other late payment or charge, provided such payment is made on such next succeeding Business Day);

(k) words such as "hereunder", "hereto", "hereof" and "herein" and other words of similar import shall, unless the context requires otherwise, refer to this Agreement as a whole and not to any particular article, section, subsection, paragraph or clause hereof;

(l) a reference to "include" or "including" means including without limiting the generality of any description preceding such term, and for purposes hereof the rule of ejusdem generis shall not be applicable to limit a general statement, followed by or referable to an enumeration of specific matters, to matters similar to those specifically mentioned; and

(m) neither this Agreement nor any other agreement, document or instrument referred to herein or executed and delivered in connection herewith shall be construed against any Person as the principal draftsman hereof or thereof.

ARTICLE II
TRANSMISSION FACILITIES

2.01 **Transmission Facilities.** As to NTD, the transmission facilities over which the ISO shall exercise Operating Authority (as of the date the facilities are placed in service) in accordance with the terms set forth herein shall be:

(a) those facilities of NTD listed in Schedule 2.01(a) (hereinafter “NTD Category A Facilities”), as such list of facilities may be added to or deleted from in accordance with Sections 2.01(d) and 2.02 below;

(b) those facilities of NTD listed in Schedule 2.01(b) (hereinafter “NTD Category B Facilities”), as such list of facilities may be added to or deleted from, in accordance with Sections 2.01(d) and 2.02 below; and

(c) those transmission facilities of NTD within the New England Transmission System with a voltage level of less than 69 kV and all transformers that have no NTD Category A Facilities or NTD Category B Facilities connected to the lower voltage side of the transformer that are not listed on Schedule 2.01(a) and Schedule 2.01(b) (hereinafter “NTD Local Area Facilities”), provided that any excluded facilities of NTD listed on Schedule 4.01(d) shall not be NTD Local Area Facilities.

(d) The transmission facilities included on any of the lists of the NTD Category A Facilities or the NTD Category B Facilities contained in Schedule 2.01(a) and Schedule 2.01(b), respectively, may be redesignated on another of those two lists, deleted from such list, or redesignated as a NTD Local Area Facility without the necessity of an amendment to this Agreement, but only in the following manner:

(i) at the direction of a Governmental Authority with jurisdiction over the Transmission Facilities in question, provided that the ISO and NTD shall be provided prior written notice of such changes;

(ii) as agreed between the ISO and NTD; or

(iii) where the operational characteristics of a transmission facility have been materially modified (including a change from a radial transmission facility to a looped

transmission facility that contributes to the parallel carrying capability of the New England Transmission System) in accordance with Section 2.01(e); provided that any such changes shall also be subject to ISO review consistent with Section 2.06.

(e) All transmission facilities to be redesignated as NTD Category A Facilities, NTD Category B Facilities, or Local Area Facilities or deleted from the lists in Schedule 2.01(a) and Schedule 2.01(b) in accordance with Section 2.01(d)(iii), and all transmission facilities to be added to the lists in Schedule 2.01(a) and Schedule 2.01(b) in accordance with Section 2.02 shall be classified in accordance with the following standards:

(i) NTD Category A Facilities shall consist of: all transmission lines with a voltage level of 115 kV and above, except for those 115 kV transmission facilities specifically designated as NTD Category B Facilities in accordance with Section 2.01(e)(ii); all transmission interties between Control Areas; all transformers that have NTD Category A Facilities connected to the lower voltage side of the transformer; all transformers that require an NTD Category A Facility to be taken out of service when the transformer is taken out of service; and all breakers and disconnects connected to, and all shunts, relays, reclosing and associated equipment, dynamic reactive resources, FACTS controllers, special protection systems, PARS, and other equipment specifically installed to support the operation of such transmission lines, interties, and transformers.

(ii) NTD Category B Facilities shall consist of: all 115 kV radial transmission lines and all 69 kV transmission lines that are not interties between Control Areas; all transformers that have any NTD Category B Facilities and no NTD Category A Facilities connected to the lower voltage side of the transformer except to the extent such transformers are designated as NTD Category A Facilities in accordance with Section 2.01(e)(i); and all breakers and disconnects connected to, and all shunts, relays, reclosing and associated equipment, dynamic reactive resources, FACTS controllers, special protection systems, PARS, and other equipment specifically installed to support the operation of such NTD Category B Facilities.

(iii) NTD Local Area Facilities shall consist of all transmission facilities with a voltage level of less than 69 kV and all transformers that have no NTD Category A

Facilities or NTD Category B Facilities connected to the lower voltage side of the transformer.

(iv) To the extent there is any dispute between the ISO and NTD as owner of a transmission facility concerning classification of such transmission facility under these standards, such disagreement shall be subject to the dispute resolution provisions of this Agreement, provided that the ISO's classification of a transmission facility under the standards shall govern pending resolution of the dispute.

Collectively, all NTD Category A Facilities, NTD Category B Facilities, and NTD Local Area Facilities shall hereinafter be referred to as the "Transmission Facilities," provided that "Transmission Facilities" shall not include Excluded Assets as defined in Section 2.04 of this Agreement or Merchant Facilities. The ISO shall maintain on its OASIS a posting of the current versions of Schedule 2.01(a) and Schedule 2.01(b), in each instance, reflecting each such change promptly after such change is made.

(f) The classifications set forth in this Section 2.01 are for operational purposes. Rate treatment of Transmission Facilities shall be governed by the ISO OATT, provided that filings for rate treatment under the ISO OATT shall be subject to Section 3.04 of this Agreement.

2.02 New and Acquired Transmission Facilities and Transmission Upgrades.

(a) Any New Transmission Facility or Transmission Upgrade shall be considered a "Transmission Facility" under this Agreement once it is included as "Proposed" in the RSP Project List and, unless otherwise agreed by the ISO and NTD, shall thereafter be added to Schedule 2.01(a) and/or (b), as applicable.

(b) Any Merchant Facility interconnected to or within the New England Transmission System shall not be the subject of this Agreement. Any Merchant Facility interconnected to or within the New England Transmission System constructed and placed in commercial operation after the Operations Date shall be subject to the authority of the ISO under a separate agreement in accordance with Section 2.03 and any applicable provisions of the ISO OATT.

2.03 Merchant Facilities. The terms and conditions under which NTD, an Affiliate of NTD or any other entity grants authority over any Merchant Facilities to the ISO shall not be governed by this Agreement, it being understood that NTD shall enter into operating agreements relating to its Merchant

Facilities directly with the ISO in accordance with applicable provisions of the ISO OATT. Nothing in this Agreement is intended to limit or expand the right of NTD, the Affiliate of NTD, or any other entity to propose, construct, or own Merchant Facilities interconnected to the New England Transmission System. No Merchant Facility may become an Acquired Transmission Facility.

2.04 **Excluded Assets.** The “Excluded Assets” of NTD shall consist of those assets and/or facilities of NTD set forth in Section 2.04(a) and (b). These Excluded Assets are expressly excluded from the definition of Transmission Facilities under this Agreement, and the ISO shall not have Operating Authority over NTD’s Excluded Assets. Nothing in this Section 2.04 is intended to address the rate treatment of the Transmission Facilities or any other asset of NTD. Rate treatment of Transmission Facilities shall be governed by the ISO OATT, provided that filings for rate treatment under the ISO OATT shall be subject to Section 3.04 of this Agreement:

(a) Excluded Assets are any assets, facilities, and/or portions of facilities owned by NTD that are connected with or associated with Transmission Facilities to the extent specifically excluded pursuant to the following items (i) through (vii) of this Section 2.04(a):

(i) proceeds from the use or disposition of Transmission Facilities;

(ii) any payment, refund or credit (1) relating to Taxes in respect of the Transmission Facilities, (2) arising under any contracts or tariffs of NTD and relating to services provided prior to the beginning of the Term, or (3) arising under any contract or tariff that provides for rates that are subject to regulation by an agency other than FERC.

(iii) any rights, ownership, title or interest NTD may have with respect to telecommunications assets and equipment, provided that the ISO shall continue to have the right to use such telecommunication assets and equipment attached to or associated with Transmission Facilities solely to the extent needed for the exercise of the ISO’s Operating Authority and further provided that such use right shall not be assignable by the ISO;

(iv) any existing contracts or contract rights of NTD related in any manner to Transmission Facilities unless NTD agrees to assign or transfer such contracts to the ISO;

(v) any assets, property rights, licenses, permits or facilities that are used for or in (1) the distribution, generation, trading or marketing of electricity (except for

facilities specifically defined as Transmission Facilities that are used for such activities), (2) gas transportation, gas, water, petroleum, chemical, real estate development, or cable business, or (3) any other activity unrelated to the transmission of electricity located on, or making use of, the Transmission Facilities;

(vi) any causes of action or claims related to Transmission Facilities, provided, that, upon the written agreement of NTD and the ISO to the assumption by the ISO of the management of such claims under mutually agreed terms and conditions, the ISO may manage NTD's causes of action or claims against a third party relating to such Transmission Facilities, and provided further that the ISO shall have the right to pursue causes of action or claims against third parties to the extent necessary for the ISO to fulfill its responsibilities for invoicing, collection and disbursement of customer payments in accordance with Section 3.10; and

(vii) any asset or facility for which Operating Authority may not be lawfully transferred or assigned.

(b) Excluded assets are any assets or facilities of NTD that are not specifically defined as Transmission Facilities, including without limitation the facilities or portions of facilities described in items (i) through (xii) of this Section 2.04(b):

(i) all cash, cash equivalents, bank deposits, accounts receivable, and any income, sales, payroll, property or other Tax receivables;

(ii) proceeds from the use or disposition of any facilities or assets owned by NTD;

(iii) certificates of deposit, shares of stock, securities, bonds, debentures, and evidences of indebtedness;

(iv) any rights or interest in trade names, trademarks, service marks, patents, copyrights, domain names or logos;

(v) any payment, refund or credit (1) relating to Taxes, (2) arising under any contracts or tariffs of NTD and relating to services provided prior to the beginning of the

Term, or (3) arising under any contract or tariff that provides for rates that are subject to regulation by an agency other than FERC;

(vi) any facilities, including transmission facilities, located outside the New England Transmission System;

(vii) any rights, ownership, title or interest NTD may have with respect to telecommunications assets and equipment;

(viii) any existing contracts or contract rights of NTD unless NTD agrees to assign or transfer such contracts to the ISO;

(ix) any assets, property rights, licenses, permits or facilities that are used for or in (1) the distribution, generation, trading or marketing of electricity or (2) gas transportation, gas, water, petroleum, chemical, real estate development, or cable business, or (3) any other activity unrelated to the transmission of electricity whether or not located on, or making use of, the Transmission Facilities;

(x) any causes of action or claims;

(xi) any asset or facility for which Operating Authority may not be lawfully transferred or assigned; and

(xii) any interests of any kind in NTD's real property, provided that nothing in this Section 2.04 shall restrict NTD from conveying interests in real property in any future written agreement into which the ISO and NTD may, in their sole discretion, enter.

2.05 **Connection with Non-Parties.**

(a) NTD shall connect its Transmission Facilities (once placed in service) with the facilities of any entity that is not a Party, including the facilities of a current or proposed Transmission Customer, and shall install (or cause to be installed) and construct (or cause to be constructed) any transmission facilities required to connect the facilities of a non-Party to the Transmission Facilities to the extent such connection or construction is required by applicable law, including the Federal Power Act and any applicable regulations issued by FERC and provided that the construction of any such transmission

facilities shall be subject to the conditions associated with NTD's obligation to build set forth in Schedule 3.09(a). Any such connection shall be subject further to: (1) the receipt of any necessary regulatory approvals, (2) compliance with the procedures set forth in the ISO OATT for review of the reliability and operational impacts of a proposed interconnection (including the procedures for interconnection of a Generating Unit under the Interconnection Standard); and (3) execution of an Interconnection Agreement with such entity containing provisions for the safe and reliable operation of each interconnection with respect to such entity's facilities in accordance with Good Utility Practice, applicable NERC/NPCC Requirements, and applicable Law (including the Federal Power Act); provided that

(i) Except as provided in 2.05(a)(ii) below, NTD shall engage in good faith negotiations as to the terms and conditions of such Interconnection Agreement with any such non-Party, but, except as may be required pursuant to regulations issued by FERC, NTD shall not be required to enter into any Interconnection Agreement containing terms and conditions unacceptable to NTD and shall reserve the right to resolve any disputes, and/or make any filings with FERC, with respect thereto.

(ii) With respect to the interconnection of a Large Generating Facility or a Small Generating Facility to any Transmission Facility, the Interconnection Agreement shall be a three-party agreement among NTD, the ISO, and the interconnecting non-Party based on the Schedule 22 Large Generator Interconnection Agreement or Schedule 23 Small Generator Interconnection Agreement, respectively, in the ISO OATT. With respect to the interconnection of other Generating Units to any Transmission Facility of NTD, the ISO shall be a party to Interconnection Agreements if and to the extent that FERC regulations require the ISO to be a party. Either the ISO or the PTOs (working with NTD as a party to the Disbursement Agreement), may propose amendments to the Schedule 22 Large Generator Interconnection Agreement or Schedule 23 Small Generator Interconnection Agreement under Section 205 of the Federal Power Act and shall include in such proposal the views of the ISO and NTD and PTOs, as applicable, provided that the standard applicable under Section 205 of the Federal Power Act shall apply only to the NTD and/or PTOs' position on any financial obligations of the PTOs and/or NTD (as applicable) or the interconnecting non-Party, and any provisions related to physical impacts of the interconnection on the Transmission Facilities or other assets. If NTD, the ISO and the interconnecting non-Party agree to the terms and conditions of a specific Large

Generator Interconnection Agreement or Small Generator Interconnection Agreement, as applicable, or any amendments to such an Interconnection Agreement, then NTD and the ISO shall jointly file the executed Interconnection Agreement, or amendment thereto, with FERC under Section 205 of the Federal Power Act. To the extent NTD, the ISO and such interconnecting non-Party cannot agree to proposed variations from the Schedule 22 or 23 Interconnection Agreement applicable to a Large Generating Facility or Small Generating Facility, respectively, or cannot otherwise agree to the terms and conditions of the Interconnection Agreement, or any amendments to such an Interconnection Agreement, then NTD and the ISO shall jointly file an unexecuted Interconnection Agreement, or amendment thereto, with FERC under Section 205 of the Federal Power Act and shall identify the areas of disagreement in such filing, provided that, in the event of disagreement on terms and conditions of the Interconnection Agreement related to the costs of upgrades to the Transmission Facilities, the anticipated schedule for the construction of such upgrades, any financial obligations of NTD, and any provisions related to physical impacts of the interconnection on the Transmission Facilities or other assets, then the standard applicable under Section 205 of the Federal Power Act shall apply only to NTD's position on such terms and conditions.

The costs of interconnection facilities shall be allocated in the manner specified in the ISO OATT.

(b) NTD shall also connect its Transmission Facilities (once placed in service) with the facilities of any entity that is not a Party upon satisfaction of the "Elective Transmission Upgrade" provisions of the ISO OATT, provided that NTD shall only connect the facilities of such entity (the "Elective Transmission Upgrade Applicant") upon satisfaction of the following conditions:

(i) The Elective Transmission Upgrade Applicant shall enter into an Interconnection Agreement with the affected PTO(s) and NTD and, to the extent necessary and appropriate, enter into support agreements with the affected PTO(s) and NTD, provided that the Elective Transmission Upgrade Applicant may request, upon providing the security, credit assurances, and/or deposits required by the affected PTO, the filing with the Commission by NTD and/or affected PTOs of unexecuted Interconnection Agreements and support agreements.

(ii) The Elective Transmission Upgrade Applicant shall obtain all necessary legal rights and approvals for the construction and maintenance of the upgrade and shall cooperate with NTD in obtaining all necessary legal rights and approvals for the construction and maintenance of additions or modifications, if any, required in conjunction with the upgrade.

(iii) The Elective Transmission Upgrade Applicant shall be responsible for 100% of all of the costs of said upgrade and of any additions to or modifications of the Transmission Facilities that are required to accommodate the Elective Transmission Upgrade. A request for rate treatment of an Elective Transmission Upgrade, if any, shall be determined by FERC in the appropriate proceeding.

2.06 **Review of Transmission Plans.** NTD shall submit to the ISO in such form, manner and detail as the ISO may reasonably prescribe: (i) any new or materially changed plans for retirements of or changes in the capacity of such Transmission Facilities rated 69 kV or above or plans for construction of New Transmission Facilities or Transmission Upgrades rated 69 kV or above; and (ii) any new or materially changed plan for any other action to be taken by NTD which may have a significant effect on the stability, reliability or operating characteristics of the Transmission Facilities, the facilities of any Transmission Owner, or the system of a Participant. The ISO shall provide notification of any such NTD submissions to the appropriate Technical Committee(s). Unless prior to the expiration of ninety (90) days, the ISO notifies NTD in writing that it has determined that implementation of the plan will have a significant adverse effect upon the reliability or operating characteristics of the Transmission Facilities, the facilities of any Transmission Owner, or the system of a Participant, NTD shall be free to proceed. If the ISO notifies NTD that implementation of such plan has been determined to have a significant adverse effect upon the reliability or operating characteristics of the Transmission Facilities, the facilities of any Transmission Owner, or the system of a Participant, NTD shall not proceed to implement such plan unless NTD takes such action or constructs such facilities as the ISO determines to be reasonably necessary to avoid such adverse effect.

2.07 **Condemnation.** If, at any time, any Governmental Authority commences any process to acquire any Transmission Facilities or any other interest in Transmission Facilities then held by NTD through condemnation or otherwise through the power of eminent domain, (i) NTD shall provide the ISO with written notice of such process, (ii) NTD shall, at its cost, direct any litigation or proceeding regarding

such condemnation or eminent domain matter, (iii) NTD shall have the right to settle any such proceeding without the consent of the ISO, and (iv) any award in condemnation or eminent domain shall be paid to NTD without any claim to such award by the ISO.

ARTICLE III

OPERATING AUTHORITY

3.01 **Grant of Operating Authority.** Subject to the terms set forth in this Agreement, including Article III and Article X hereof, NTD hereby authorizes the ISO, through its officers, employees, consultants, independent contractors and other personnel, to exercise Operating Authority over the Transmission Facilities once they are placed in service, including provision of Transmission Service over the Transmission Facilities under the TOA and ISO OATT, and the ISO hereby agrees to assume and exercise Operating Authority over the Transmission Facilities in accordance with the TOA once they are placed in service. Coincident with the NTD's Transmission Facilities being placed in service or the acquisition of operational Transmission Facilities, the NTD shall execute the TOA pursuant to Section 10.05 hereof, list such Transmission Facilities under the TOA and, by doing so, authorize the ISO to exercise Operating Authority over such Transmission Facilities via the TOA.

3.02 **[reserved]**

3.03 **Transmission Services and OATT Administration.**

(a) The ISO shall administer the ISO OATT in the manner specified in this Section 3.03. The ISO's OATT administration responsibilities shall include those enumerated below:

(i) The ISO shall receive, post on OASIS as required by Commission regulations, and respond to requests by Large Generating Facilities and Small Generating Facilities to be interconnected under the ISO OATT, and all Transmission Service. Except as provided in Section 3.03(a)(ii), the ISO shall perform the system impact studies and facilities studies (and execute and administer agreements for such studies) in connection with such requests to the Administered Transmission System. Notwithstanding the foregoing, (A) the ISO shall consult with NTD prior to completion of system impact studies and facilities studies in connection with requests that affect the Transmission Facilities and distribution facilities and shall include in any such studies

NTD's reasonable estimates of the costs of upgrades to the Transmission Facilities needed to implement the conclusions of such studies and NTD's reasonable anticipated schedule for the construction of such upgrades; (B) nothing in this Agreement shall preclude the ISO from entering into a separate agreement(s) with NTD for such studies, pursuant to the ISO's supervision and the ISO's authority to require modifications to such studies, to perform system impact studies and facilities studies; (C) except as provided in Section 3.03(a)(ii) with respect to interconnection of Generating Units that would not have an impact on facilities used for the provision of regional transmission service, nothing in this Agreement shall preclude the performance of studies related to the interconnection of Generating Units by a third party consultant to the extent permitted by applicable procedures in the ISO OATT (including procedures governing the treatment of confidential information) and provided that such studies performed by any third party consultant must include NTD's reasonable estimates of the costs of upgrades to such Transmission Facilities needed to implement the conclusions of such studies and NTD's reasonable anticipated schedule for the construction of such upgrades; and (D) NTD shall, upon request by the ISO, conduct any necessary studies related to the Transmission Facilities, including system impact studies and facilities studies, and shall assist in the performance of any such studies, including the provision of information and data in accordance with Section 11.07 of this Agreement.

(ii) The ISO shall review applications for Transmission Service or requests for the interconnection of Large Generating Facilities and Small Generating Facilities to be interconnected to a Transmission Facility to determine whether the service or interconnection would have an impact on facilities used for the provision of regional transmission service. If so, and the interconnection is to a Transmission Facility, the ISO will perform a system impact study and facilities study, as necessary to address the impacts on facilities used for the provision of regional transmission service.

(iii) The ISO shall operate and maintain the OASIS (or a successor system) as required by FERC. NTD shall provide updates to the NTD-specific pages on the OASIS site, subject to the ISO's review of such updates. The ISO shall have the authority to direct any changes to such NTD-specific pages that it deems appropriate to conform to FERC requirements and the terms and conditions of the ISO OATT.

(b) Notwithstanding Section 3.03(a), retail load customers requesting to interconnect with the Transmission Facilities of NTD shall submit service requests to NTD. Such service requests submitted to the ISO shall be forwarded to NTD. NTD shall execute and administer the agreements, and shall be responsible for billing, collections, dispute resolution and the performance of system impact studies and facilities studies, in coordination with the ISO as necessary, in connection with such requests.

(c) Transmission Service Agreements. The ISO and NTD shall enter into all agreements for Transmission Service over the Transmission Facilities; provided that:

(i) A pro forma regional transmission service agreement (or service agreements) shall be attached to the ISO OATT and such pro forma service agreement(s) shall set forth the respective rights and responsibilities of the Transmission Customer, the ISO, the PTOs and NTD. The ISO shall have the authority, pursuant to Section 205 of the Federal Power Act, to amend the pro forma service agreement(s) or the Market Participant Service Agreement (“MPSA”) or executed service agreements related to the terms and conditions of regional Transmission Service.

(ii) The ISO shall be responsible for filing with the FERC, or electronically reporting to the FERC as applicable, all new agreements for Transmission Service over the Transmission Facilities. In the event of any dispute between the ISO or NTD and a Transmission Customer concerning the terms and conditions of such service agreements, the ISO shall file an unexecuted copy of the pro forma service agreement set forth in the ISO OATT and shall include in such filing any statement provided by NTD, affected PTO(s) and the Transmission Customers concerning their respective positions on any proposed changes or additions to the pro forma service agreement.

3.04 Application Authority.

(a) NTD shall have the authority to submit filings under Section 205 of the Federal Power Act to establish and to revise (pursuant to an NTD rate schedule filed under Schedules 13 or 14, as applicable, of the ISO OATT):

(i) charges for costs permitted to be recovered under Sections 4.3 and 4A of Attachment K to the ISO OATT;

(ii) once its project is listed as “Proposed” in the RSP Project List, charges for the costs of Commission-approved construction work in process; and

(iii) once its project is listed as “Proposed” in the RSP Project List, any rates, charges, terms or conditions for transmission services that are based solely on the revenue requirements of the Transmission Facilities (including Transmission Facilities leased to NTD or to which NTD has contractual entitlements).

NTD shall not have the authority to revise such rates, terms and conditions in a manner that would abridge the rights granted to the ISO in Section 3.04(b). NTD shall provide written notification to the ISO and stakeholders of any filing described in sub-paragraph (i) through (iv), above, which notification shall include a detailed description of the filing, at least 30 days in advance of a filing. NTD shall consult with interested stakeholders upon request. NTD shall retain the right to modify aspects of any filing authorized by this Section 3.04(a) after it provides written notification to the ISO and stakeholders, and shall provide notification to the ISO and stakeholders of any material modification to such filings.

With respect to any filing described in sub-paragraph (iii) above, NTD shall include in any filing a statement that, in the good faith judgment of NTD, the proposal will not be inconsistent with the design of the New England Markets, as accepted or approved by FERC. In the event the ISO believes that a proposed filing described in sub-paragraph (iii) above, would have such an inconsistency, it shall so advise NTD and NTD and the ISO shall consult in good faith to resolve any ISO concerns, but, if such disagreement cannot be resolved, NTD may submit a filing under Section 205, provided that NTD’s filing (including the transmittal letter for such filing) to FERC shall include any written statement provided by the ISO setting forth the basis for the ISO’s concerns.

NTD shall consult with the ISO to determine whether the ISO will need to make any software modifications in order to implement any filing authorized by this Section 3.04(a) and when any needed software modifications could reasonably be expected to be implemented. NTD’s filing to FERC (and the transmittal letter for such a filing) shall include any written statement provided by the ISO setting forth the basis for any software-related implementation concerns raised by the ISO. The ISO shall make Commercially Reasonable Efforts to implement any needed software modifications by the effective date accepted by the FERC for a filing authorized by this Section 3.04(a), provided that, if the ISO has exercised such Commercially Reasonable Efforts, a failure to implement needed software modifications by the FERC-accepted effective date shall not constitute an event of default by the ISO under this Agreement or

subject the ISO to financial damages, and further provided that the ISO shall run retroactive settlements consistent with the FERC-accepted effective date for a filing authorized by this Section 3.04(a) once such software modifications have been implemented.

(b) The ISO has the authority to submit filings under Section 205 of the Federal Power Act as set forth in the TOA.

(c) NTD shall have no authority to submit a filing under Section 205 of the Federal Power Act to modify any provision of the ISO OATT that implements any of the items listed in Section 3.04(b) of the TOA.

3.05 **The ISO's Responsibilities.**

(a) In addition to its other obligations under this Agreement, in performing its obligations and responsibilities hereunder, and in accordance with Good Utility Practice, the ISO shall:

(i) maintain system reliability; and

(ii) in all material respects, act in accordance with applicable Laws and conform to, and implement, all applicable reliability criteria, policies, standards, rules, regulations, orders, license requirements and all other applicable NERC/NPCC Requirements, and other applicable reliability organizations' reliability rules, and all applicable requirements of federal or state laws or regulatory authorities.

(b) The ISO shall obtain and retain all necessary authorizations of FERC and other regulatory authorities to function as the New England RTO and shall possess the characteristics and perform the functions required for that purpose.

3.06 **NTD's Responsibilities.**

(a) NTD shall, in accordance with Good Utility Practice:

(i) collaborate with the ISO with respect to:

(A) the development of Rating Procedures,

- (B) the establishment of ratings for New Transmission Facilities;
- (C) the establishment of ratings for Acquired Transmission Facilities that do not have an existing rating; and
- (D) the establishment of any changes to existing ratings for Transmission Facilities in effect as of the Operations Date.

To the extent there is any disagreement between the ISO and NTD concerning Rating Procedures or the rating of a Transmission Facility, such disagreement shall be the subject of good faith negotiations between NTD and the ISO, provided that (x) NTD's position concerning such Rating Procedures or Transmission Facility ratings shall govern until NTD and the ISO agree on a resolution to such disagreement; and (y) nothing in this Section 3.06(a)(iv) shall limit the rights of the ISO or of NTD to submit a filing under Section 206 of the Federal Power Act with respect to Transmission Facility ratings or Rating Procedures. During any collaboration or discussions concerning Transmission Facility ratings, NTD shall continue to provide the ISO with up-to-date ratings information in accordance with the applicable Rating Procedures.

(ii) cooperate with actions taken by PTOs' Local Control Centers with respect to the Transmission Facilities; and

(iii) in all material respects, comply with all applicable laws, regulations, orders and license requirements, and with all applicable requirements, and with all applicable NERC/NPCC Requirements, other applicable reliability organizations' local reliability rules, and all applicable requirements of federal or state laws or regulatory authorities.

3.07 **Reserved Rights of NTD.**

(a) Notwithstanding any other provision of this Agreement to the contrary, NTD shall retain all of the rights set forth in this Section 3.07; provided, however, that such rights shall be exercised in a manner consistent with applicable NERC/NPCC Requirements and applicable regulatory standards. This Section 3.07 is not intended to reduce or limit any other rights of NTD as a signatory to this Agreement or under the ISO OATT.

(i) Nothing in this Agreement shall restrict any rights: (A) of NTD if it is a party to a merger, acquisition or other restructuring transaction to make filings under Section 205 of the Federal Power Act with respect to NTD's reallocation or redistribution of revenues or the assignment of such NTD's rights or obligations, to the extent the Federal Power Act requires such filings; or (B) of NTD to terminate its participation in this Agreement pursuant to Article X of this Agreement.

(ii) Except as expressly provided in the grant of Operating Authority to the ISO, NTD retains all rights that it otherwise has incident to its ownership of, and legal and equitable title to, its assets, including its Transmission Facilities and all land and land rights, including the right to build, acquire, sell, lease, merge, dispose of, retire, use as security, or otherwise transfer or convey all or any part of its assets, subject to NTD's compliance with Section 2.06 of this Agreement. Subject to Article X, NTD may, directly or indirectly, by merger, sale, conveyance, consolidation, recapitalization, operation of law, or otherwise, transfer all or any portion of the Transmission Facilities subject to this Agreement but only if such transferee or successors shall agree in writing to be bound by terms of this Agreement.

(iii) NTD shall have the right to adopt and implement, consistent with Good Utility Practice, procedures and to take such actions it deems necessary to protect its facilities from physical damage or to prevent injury or damage to persons or property.

(iv) NTD retains the right to take whatever actions, consistent with Good Utility Practice, it deems necessary to fulfill its obligations under applicable Law.

(v) Nothing in this Agreement shall be construed as limiting in any way the rights of NTD to make any filing with any applicable state or local regulatory authority.

(vi) NTD shall have the right to retain one or more subcontractors to perform any or all of its obligations under this Agreement. The retention of a subcontractor pursuant to the terms of this Section 3.07 shall not relieve NTD of its primary liability for the performance of any of its obligations under this Agreement.

(b) Any and all other rights and responsibilities of NTD related to the ownership or operation of its Transmission Facilities not expressly assigned to the ISO under this Agreement will remain with NTD.

(c) Nothing in this Agreement shall be deemed to impair or infringe on any rights or obligations of NTD under the Federal Power Act and FERC's rules and regulations thereunder, provided that any such rights are not inconsistent with the express terms of this Agreement. Nothing contained in this Agreement shall be construed to limit in any way the right of NTD to take any position, including opposing positions, in any administrative or judicial proceeding or filing by NTD or the ISO, notwithstanding that such proceeding or filing may be undertaken or made, explicitly or implicitly, pursuant to this Agreement.

3.08 [reserved]

3.09 [reserved]

3.10 **Invoicing, Collection and Disbursement of Payments.**

(a) **Invoicing.** Except as provided in Section 3.10(a)(ii), the ISO will administer its current net settlement system, including invoicing of charges to Transmission Customers for Transmission Services on the Transmission Facilities as follows:

(i) The charges invoiced by the ISO on behalf of NTD shall include the following (each, an "**Invoiced Amount**"):

- (A) all charges listed in NTD's Commission-accepted rate schedule under Schedules 13 and 14 of the ISO OATT; and
- (B) any and all rates, charges, fees and/or penalties under interconnection agreements which have been filed with and accepted by FERC, other than amounts billed directly by NTD pursuant to Section 3.10(a)(ii) below.

(ii) Payments relating to all services provided by NTD outside of Schedules 13 and 14 that provide for payment to NTD, and any other payments shall be invoiced by

NTD and shall not be invoiced by the ISO; provided that, notwithstanding the foregoing, NTD and the ISO may enter into separate agreements such that the ISO provides invoicing services for such payments.

(iii) The ISO shall remit or credit to NTD, consistent with the ISO Tariff and the net settlement system, any and all payments received or collected from Transmission Customers for Invoiced Amounts in accordance with this Agreement. NTD shall designate (and notify the ISO of the identity of) a single authorized individual to provide such directions to the ISO. This individual shall also respond to any ISO questions or requests for clarification concerning such directions; provided that the ISO shall be able to rely upon the direction of the designated individual unless and until it receives notification from NTD or from a Governmental Authority of reversal of such direction by any Governmental Authority with jurisdiction over this Agreement.

(b) The ISO's Collection Obligations and Application of Financial Assurances Policies. If a Transmission Customer defaults on any payment of any Invoiced Amount (the "Owed Amounts"), the ISO shall take all necessary actions to execute or call upon any Financial Assurances held by the ISO attributable to such Transmission Customer.

(c) No Pledge of Invoiced Amounts. The ISO shall not create, incur, assume or suffer to exist any lien, pledge, security interest or other charge or encumbrance, or any other type of preferential arrangement (including a banker's right of set off) against any Invoiced Amounts, any accounts receivables representing Invoiced Amounts, the settlement account maintained by the ISO into which payments on Invoiced Amounts are made and from which remittances are made to NTD or any Financial Assurances.

3.11 Subcontractors. NTD acknowledges and agrees that, subject to the terms set forth herein, the ISO has the right to retain one or more subcontractors to perform any or all of its obligations under this Agreement. The retention of a subcontractor pursuant to the terms of this Section 3.11 shall not relieve the ISO of its primary liability for the performance of any of its obligations under this Agreement.

3.12 No Impairment of the ISO's Other Legal Rights and Obligations. Nothing in this Agreement shall be deemed to impair or infringe on any rights or obligations of the ISO under the Federal

Power Act and FERC's rules and regulations thereunder, including the ISO's rights and obligations to submit filings to recover its administrative, capital, and other costs.

ARTICLE IV
REPRESENTATIONS AND WARRANTIES OF THE PARTIES

4.01 **Representations and Warranties of NTD.** NTD represents and warrants to the ISO as follows:

(a) **Organization.** It is duly organized, validly existing and in good standing under the laws of the state of its organization.

(b) **Authorization.** It has all requisite power and authority to execute, deliver and perform this Agreement; the execution, delivery and performance by NTD of this Agreement have been duly authorized by all necessary and appropriate action on the part of NTD; and this Agreement has been duly and validly executed and delivered by NTD and constitutes the legal, valid and binding obligations of NTD, enforceable against NTD in accordance with its terms.

(c) **No Breach.** The execution, delivery and performance by NTD of this Agreement will not result in a breach of any terms, provisions or conditions of any agreement to which NTD is a party which breach has a reasonable likelihood of materially and adversely affecting NTD's performance under this Agreement.

4.02 **Representations and Warranties of the ISO.** The ISO represents and warrants to NTD as follows:

(a) **Organization.** It is duly organized, validly existing and in good standing under the laws of the state of its organization.

(b) **Authorization.** It has all requisite power and authority to execute, deliver and perform this Agreement; the execution, delivery and performance by the ISO of this Agreement have been duly authorized by all necessary and appropriate action on the part of the ISO; and this Agreement has been duly and validly executed and delivered by the ISO and constitutes the legal, valid and binding obligation of the ISO, enforceable against the ISO in accordance with its terms.

(c) **No Breach.** The execution, delivery and performance by the ISO of this Agreement will not result in a breach of any of the terms, provisions or conditions of any agreement to which the ISO is a party which breach has a reasonable likelihood of materially and adversely affecting the ISO's performance under this Agreement.

ARTICLE V

COVENANTS OF NTD

5.01 **Covenants of NTD.** NTD covenants and agrees that during (i) the Term, or (ii) the period expressly specified herein, as applicable, NTD shall comply with all covenants and provisions of this Article V, except to the extent the ISO waives such covenants or performance is excused pursuant to Section 11.11(b).

5.02 **[reserved]**

5.03 **Expenses.** Except to the extent specifically provided herein, all costs and expenses incurred by NTD in connection with the negotiation of this Agreement shall be borne by NTD; provided that nothing herein shall prevent NTD from recovering such expenses in accordance with applicable law.

5.04 **Consents and Approvals.**

(a) NTD shall exercise Commercially Reasonable Efforts to promptly prepare and file all necessary documentation to effect all necessary applications, notices, petitions, filings and other documents, and shall exercise Commercially Reasonable Efforts to obtain (and will cooperate with each other in obtaining) any consent, acquiescence, authorization, order or approval of, or any exemption or nonopposition by, any Governmental Authority required to be obtained or made by NTD in connection with this Agreement or the taking of any action contemplated by this Agreement.

(b) NTD shall exercise Commercially Reasonable Efforts to obtain consents of all other third parties necessary to the performance of this Agreement by NTD. NTD shall promptly notify the ISO of any failure to obtain any such consents and, if requested by the ISO, shall provide copies of all such consents obtained by NTD.

(c) Nothing in this Section 5.04 shall require NTD to pay any sums to a third party, including any Governmental Authority, excluding filing fees paid to any Governmental Authority in connection with a filing necessary or appropriate to further action.

5.05 **Notice and Cure.** NTD shall notify the ISO in writing of, and contemporaneously provide the ISO with true and complete copies of any and all information or documents relating to, any event, transaction or circumstance, as soon as practicable after it becomes Known to NTD, that causes or shall cause any covenant or agreement of NTD under this Agreement to be breached or that renders or shall render untrue any representation or warranty of NTD contained in this Agreement as if the same were made on or as of the date of such event, transaction or circumstance. NTD shall use all Commercially Reasonable Efforts to cure such event, transaction or circumstance as soon as practicable after it becomes Known to NTD. No notice given pursuant to this Section 5.05 shall have any effect on the representations, warranties, covenants or agreements contained in this Agreement for purposes of determining satisfaction of any condition contained herein or shall in any way limit the ISO's right to seek indemnity under Article IX.

ARTICLE VI

COVENANTS OF THE ISO

6.01 **Covenants of the ISO.** The ISO covenants and agrees that during (i) the Term, or (ii) the period expressly specified herein, as applicable, the ISO shall comply with all covenants and provisions of this Article VI, except to the extent the Parties consent in writing to a waiver of such covenants or performance is excused pursuant to Section 11.11(b).

6.02 **[reserved]**

6.03 **Expenses.** Except to the extent specifically provided herein, all costs and expenses incurred by the ISO in connection with the negotiation of this Agreement shall be borne by the ISO; provided that nothing herein shall prevent the ISO from recovering such expenses in accordance with applicable law.

6.04 **[reserved]**

6.05 **Notice and Cure.** The ISO shall notify NTD in writing of, and contemporaneously shall provide NTD with true and complete copies of any and all information or documents relating to, any event,

transaction or circumstance, as soon as practicable after it becomes Known to the ISO, that causes or shall cause any covenant or agreement of the ISO under this Agreement to be breached or that renders or shall render untrue any representation or warranty of the ISO contained in this Agreement as if the same were made on or as of the date of such event, transaction or circumstance. The ISO shall use all Commercially Reasonable Efforts to cure such event, transaction or circumstance as soon as practicable after it becomes Known to the ISO. No notice given pursuant to this Section 6.05 shall have any effect on the representations, warranties, covenants or agreements contained in this Agreement for purposes of determining satisfaction of any condition contained herein or shall in any way limit any right of NTD to seek indemnity under Article IX.

ARTICLE VII

TAX MATTERS

7.01 **Responsibility for NTD Taxes.** NTD shall prepare and file all Tax Returns and other filings related to its Transmission Business and Transmission Facilities and pay any Tax liabilities related to its Transmission Business and Transmission Facilities. The ISO shall not be responsible for, or required to file, any Tax Returns or other reports for NTD and shall have no liability for any Taxes related to NTD's Transmission Business or Transmission Facilities. The ISO and NTD hereby agree that, for tax purposes, the Transmission Facilities shall be deemed to be owned by NTD.

7.02 **Responsibility for ISO Taxes.** The ISO shall prepare and file all Tax Returns and other filings related to its operations and pay any Tax liabilities related to its operations. NTD shall not be responsible for, or required to, file any Tax Returns or other reports for the ISO and shall have no liability for any Taxes related to the ISO's operations.

ARTICLE VIII

RELIANCE; SURVIVAL OF AGREEMENTS

8.01 **Reliance; Survival of Agreements.** Notwithstanding any right of any Party (whether or not exercised) to investigate the accuracy of any of the matters subject to indemnification by any other Party contained in this Agreement, each of the Parties has the right to rely fully upon the representations, warranties, covenants and agreements of the other Party contained in this Agreement. The provisions of Sections 11.01, 11.07, 11.11 and 11.15 and Articles VII and IX shall survive the termination of this

Agreement. With regard to Section 3.10 of this Agreement, the ISO will perform final billing consistent with Section 3.10 of this Agreement for all services provided until the Termination Date.

ARTICLE IX
INSURANCE; LIMITATION OF LIABILITIES

9.01 **Hold Harmless.** NTD will indemnify and hold harmless all affected PTOs from any and all liability (except for that stemming from an affected PTO's negligence, gross negligence or willful misconduct), resulting from the NTD's failure to timely complete (based on the milestone provisions contained in the ISO OATT) a Reliability Transmission Upgrade (as defined in the ISO OATT) that the NTD was chosen in the Regional System Plan to construct. As used herein, an "affected PTO" is one that would be subject to penalties assessed by NERC or FERC or adverse regulatory orders or monetary claims or damages due to the NTD's failure to timely complete the Reliability Transmission Upgrade.

9.02 – 9.04 [**Reserved**]

9.05 **Insurance.**

(a) NTD will maintain property insurance on its Transmission Facilities and liability insurance in accordance with good utility practice.

(b) All insurance required under this Section 9.05 by outside insurers shall be maintained with insurers qualified to insure the obligations or liabilities under this Agreement and having a Best's rating of at least B+ VIII (or an equivalent Best's rating from time to time of B+ VIII), or in the event that from time to time Best's ratings are no longer issued with respect to insurers, a comparable rating by a nationally recognized rating service or such other insurers as may be agreed upon by the Parties.

(c) Upon execution of this Agreement, and when requested thereafter, NTD shall furnish the ISO with certificates of all such insurance policies setting forth the amounts of coverage, policy numbers, and date of expiration for such insurance in conformity with the requirements of this Agreement.

9.06 **Liability.**

(a) Neither Party shall be liable to the other Party for any incidental, indirect, special, exemplary, punitive or consequential damages, including lost revenues or profits, even if such damages are

foreseeable or the damaged Party has advised such Party of the possibility of such damages and regardless of whether any such damages are deemed to result from the failure or inadequacy of any exclusive or other remedy.

(b) Nothing in this Agreement shall be deemed to affect the right of the ISO to recover its costs due to liability under this Article IX through the ISO Participants Agreement or the ISO Administrative Tariff.

ARTICLE X

TERM; DEFAULT AND TERMINATION

10.01 Term; Termination Date.

(a) **Term.** Subject to the terms set forth in this Section 10.01, the term of this Agreement (the "Term") shall commence on the Effective Date and shall continue in force until terminated pursuant to Article X hereof. The date of such termination shall be referred to herein as the "Termination Date."

(b) **Termination by NTD.** NTD may terminate this Agreement:

(i) upon no less than 180 day's prior notice to the ISO; or

(ii) upon an ISO event of default in accordance with Section 10.03(a), provided that NTD shall exercise this right in accordance with Section 10.03(b)(i).

(c) **Termination By the ISO.** By notice to NTD, the ISO may terminate its obligations under this Agreement:

(i) upon the withdrawal of one or more PTOs from the Transmission Operating Agreement and the ISO has given notice to the PTOs that it is terminating the Transmission Operating Agreement pursuant to Section 10.01(c)(i) thereof;

(ii) if FERC issues an order putting into effect material changes in the liability and indemnification protections afforded to the ISO under this Agreement or the ISO Tariff;

(iii) if FERC issues an order putting into effect an amendment or modification of this Agreement that materially adversely affects the ISO's ability to carry out its responsibilities under this Agreement, unless the ISO has agreed to such changes in accordance with Section 11.04;

(iv) upon a NTD event of default in accordance with Section 10.04(a), provided that the ISO shall exercise this right in accordance with Section 10.04(b)(i); or

(v) if, within the period of ten years from the Effective Date, no NTD project has been listed by the ISO on the RSP Project List as "Proposed."

(d) Continuing Obligations. The withdrawing or terminating Party shall have the following continuing obligations following withdrawal from this Agreement: All financial obligations incurred and payments applicable to the time period prior to the Termination Date shall be honored by the terminating or withdrawing Party and the other Party in accordance with the terms of this Agreement, and each Party shall remain liable for all obligations arising hereunder prior to the Termination Date.

10.03 **[reserved]**

10.03 **Events of Default of the ISO.**

(a) Events of Default of the ISO. Subject to the terms and conditions of this Section 10.03, the occurrence of any of the following events shall constitute an event of default of the ISO under this Agreement:

(i) Failure by the ISO to perform any material obligation set forth in this Agreement and continuation of such failure for longer than thirty (30) days after the receipt by the ISO of written notice of such failure from NTD; provided, however, that if the ISO is diligently pursuing a remedy during such thirty (30) day period, said cure period shall be extended for an additional thirty (30) days or as otherwise agreed by NTD;

(ii) If there is a dispute between the ISO and NTD as to whether the ISO has failed to perform a material obligation, the cure period(s) provided in Section 10.03(a)(i) above shall run from the point at which a finding of failure to perform has been made by a Governmental Authority;

(iii) Any attempt (not including consideration of strategic options or entering into exploratory discussions) by the ISO to transfer an interest in, or assign its obligations under, this Agreement, except as otherwise permitted hereunder;

(iv) Failure of the ISO (if it has received the necessary corresponding funds from ISO customers) to pay when due any and all amounts payable to NTD by the ISO as part of the settlement process pursuant to Section 3.10 within three (3) Business Days;

(v) With respect to the ISO, (A) the filing of any petition in bankruptcy or insolvency, or for reorganization or arrangement under any bankruptcy or insolvency laws, or voluntarily taking advantage of any such laws by answer or otherwise or the commencement of involuntary proceedings under any such laws, (B) assignment by the ISO for the benefit of creditors; or (C) allowance by the ISO of the appointment of a receiver or trustee of all or a material part of its property if such receiver or trustee is not discharged within thirty (30) days after such appointment.

(b) Remedies for Default. If an event of default by the ISO occurs, NTD shall have the right to avail itself of any or all of the following remedies, all of which shall be cumulative and not exclusive:

(i) To terminate this Agreement in accordance with Section 10.01(b)(ii); provided that if the ISO contests such allegation of an ISO event of default, this Agreement shall remain in effect pending resolution of the dispute, but any applicable notice period shall run during the pendency of the dispute;

(ii) To demand that the ISO shall terminate any right of the ISO, immediately make arrangements for the orderly transfer of the ISO's invoicing and collection functions with respect to NTD and assist NTD or NTD's designee in resuming performance of the functions the later of 20 days from the date of making such demand or the start of the next billing cycle.

10.04 Events of Default of NTD.

(a) Events of Default of NTD. Subject to the terms and conditions of this Section 10.04, the occurrence of any of the events listed below shall constitute an event of default of NTD under this Agreement (in each instance, a “NTD Default”):

(i) Failure by NTD to perform any material obligation set forth in this Agreement and continuation of such failure for longer than thirty (30) days after the receipt by NTD of written notice of such failure from the ISO, provided, however, that if NTD is diligently pursuing a remedy during such thirty (30) day period, said cure period shall be extended for an additional thirty (30) days or as otherwise agreed by the ISO and NTD;

(ii) If there is a dispute between NTD and the ISO as to whether NTD has failed to perform a material obligation, the cure period(s) provided in Section 10.04(a)(i) above shall run from the point at which a finding of failure to perform has been made by a Governmental Authority; or

(iii) With respect to NTD, (A) the filing of any petition in bankruptcy or insolvency, or for reorganization or arrangement under any bankruptcy or insolvency laws, or voluntarily taking advantage of any such laws by answer or otherwise or the commencement of involuntary proceedings under any such laws, (B) assignment by NTD for the benefit of creditors; or (C) allowance by NTD of the appointment of a receiver or trustee of all or a material part of its property if such receiver or trustee is not discharged within thirty (30) days after such appointment.

(b) Remedies for Default. If an event of default by NTD occurs, the ISO shall have the following remedy: to terminate this Agreement in accordance with Section 10.01(c)(iv); provided that if NTD contests such allegation of an NTD event of default, this Agreement shall remain in effect pending resolution of the dispute, but any applicable notice period shall run during the pendency of the dispute.

10.05 Transmission Operating Agreement and Disbursement Agreement; Registration.

On the date on which (1) any of the Transmission Facilities or a New Transmission Facility is placed into service or (2) NTD’s acquisition of Acquired Transmission Facilities is consummated, whichever occurs earlier:

(a) NTD shall execute and deliver to the ISO a counterpart of the Transmission Operating Agreement as an Additional PTO (as defined therein). Upon such execution and delivery, this Agreement shall terminate automatically.

(b) NTD shall promptly execute a signature page for the Disbursement Agreement and deliver it to the parties thereto and shall become a party to the Disbursement Agreement.

(c) NTD shall register with NPCC as a Transmission Owner [and Transmission Service Provider][under discussion].

ARTICLE XI

MISCELLANEOUS

11.01 **Notices.** Unless otherwise expressly specified or permitted by the terms hereof, all communications and notices provided for herein shall be in writing and any such communication or notice shall become effective (a) upon personal delivery thereof, including by overnight mail or courier service, (b) in the case of notice by United States mail, certified or registered, postage prepaid, return receipt requested, upon receipt thereof, or (c) in the case of notice by facsimile, upon receipt thereof; provided that such transmission is promptly confirmed by either of the methods set forth in clauses (a) or (b) above, in each case addressed to the relevant party and copy party hereto at its address set forth in Schedule 11.01 or at such other address as such party or copy party may from time to time designate by written notice to the other party hereto; further provided that a notice given in connection with this Section 11.01 but received on a day other than a Business Day, or after business hours in the situs of receipt, will be deemed to be received on the next Business Day.

11.02 **Supersession of Prior Agreements.** With respect to the subject matter hereof, this Agreement (together with all schedules and exhibits attached hereto) constitutes the entire agreement and understanding among the Parties with respect to all subjects covered by this Agreement and supersedes all prior discussions, agreements and understandings among the Parties with respect to such matters.

11.03 **Waiver.** Any term or condition of this Agreement may be waived at any time by the Party that is entitled to the benefit thereof, but no such waiver shall be effective unless set forth in a written instrument duly executed by or on behalf of the Party waiving such term or condition. No waiver by a Party of any term or condition of this Agreement, in any one or more instances, shall be deemed to be or

construed as a waiver of the same or any other term or condition of this Agreement on any future occasion. All remedies, either under this Agreement or by Law or otherwise afforded, shall be cumulative and not alternative.

11.04 **Amendment; Limitations on Modifications of Agreement.**

(a) This Agreement shall only be subject to modification or amendment by agreement of the Parties and the acceptance of any such amendment by FERC.

(b) In light of the foregoing, the Parties agree that they shall not rely to their detriment on any purported amendment, waiver or other modification of any rights under this Agreement unless the requirements of this Section 11.04 are satisfied and further agree not to assert equitable estoppel or any other equitable theory to prevent enforcement of this provision in any court of law or equity, arbitration or other proceeding.

11.05 **No Third Party Beneficiaries.** Except as provided in Article IX, it is not the intention of this Agreement or of the Parties to confer a third party beneficiary status or rights of action upon any Person or entity whatsoever other than the Parties and nothing contained herein, either express or implied, shall be construed to confer upon any Person or entity other than the Parties any rights of action or remedies either under this Agreement or in any manner whatsoever.

11.06 **No Assignment; Binding Effect.** Neither this Agreement nor any right, interest or obligation hereunder may be assigned by a Party, (including by operation of law) law (an "Assignment")-, without the prior written consent of the other Party in its sole discretion and any attempt at Assignment in contravention of this Section 11.06 shall be void, provided, however, that NTD may assign its rights and interests hereunder as security in connection with any financing for the construction or operation of NTD's Transmission Facilities (a "Collateral Assignment") without prior written consents or approvals. NTD may assign or transfer any or all of its rights, interests and obligations hereunder upon the transfer of its assets through sale, reorganization, or other transfer, provided that:

(a) NTD's successors and assigns shall agree to be bound by the terms of this Agreement except that NTD's successors and assigns shall not be required to be bound by any obligations hereunder to the extent that NTD has agreed to retain such obligations; and

(b) notwithstanding (a), NTD shall assign or transfer to any new owner of Transmission Facilities subject to this Agreement all of the rights, responsibilities and obligations associated with the physical operation of such Transmission Facilities as well as all of the rights, responsibilities and obligations associated with the ISO's Operating Authority with respect to such Transmission Facilities, further provided that the new owner shall have the right to retain one or more subcontractors to perform any or all of its responsibilities or obligations under this Agreement.

Subject to the foregoing, this Agreement is binding upon, inures to the benefit of and is enforceable by the Parties and their respective permitted successors and assigns. No Assignment shall be effective until NTD receives all required regulatory approvals for such Assignment.

11.07 Further Assurances; Information Policy; Access to Records.

(a) Each Party agrees, upon the other Party's request, to make Commercially Reasonable Efforts to execute and deliver such additional documents and instruments, provide information, and to perform such additional acts as may be necessary or appropriate to effectuate, carry out and perform all of the terms, provisions, and conditions of this Agreement and of the transactions contemplated hereby.

(b) The ISO shall, upon NTD's request, make available to NTD any and all information within the ISO's custody or control that is necessary for NTD to perform its responsibilities and obligations or enforce its rights under this Agreement, provided that such information shall be made available to NTD only to the extent permitted under the ISO Information Policy and subject to any applicable restrictions in the ISO Information Policy, including provisions of the ISO Information Policy governing the confidential treatment of non-public information, and provided further that any NTD employee or employee of NTD's Local Control Center shall comply with such ISO Information Policy and any applicable standards of conduct to prevent the disclosure of such information to any unauthorized Person. Any dispute concerning what information is necessary for NTD to perform its responsibilities and obligations or enforce its right under this Agreement shall be subject to dispute resolution under Section 11.12 of this Agreement.

(c) NTD shall, upon the ISO's request, make available to the ISO any and all information within NTD's custody or control that is necessary for the ISO to perform its responsibilities and obligations or enforce its rights under this Agreement, provided that such information shall be made available to the ISO only to the extent permitted under the ISO Information Policy and subject to any

applicable restrictions in the ISO Information Policy, including provisions of the ISO Information Policy governing the confidential treatment of non-public information, and provided further that any ISO employee shall comply with such ISO Information Policy and any applicable standards of conduct to prevent the disclosure of such information to any unauthorized Person. Any dispute concerning what information is necessary for the ISO to perform its responsibilities and obligations or enforce its right under this Agreement shall be subject to dispute resolution under Section 11.12 of this Agreement.

(d) If, in order to properly prepare its Tax Returns, other documents or reports required to be filed with Governmental Authorities or its financial statements or to fulfill its obligations hereunder, it is necessary that the ISO or NTD be furnished with additional information, documents or records not referred to specifically in this Agreement, and such information, documents or records are in the possession or control of the other Party, the other Party shall use its best efforts to furnish or make available such information, documents or records (or copies thereof) at the ISO's or NTD's request, cost and expense. Any information obtained by the ISO or NTD in accordance with this paragraph shall be subject to any applicable provisions of the ISO Information Policy

(e) Notwithstanding anything to the contrary contained in this Section 11.07:

(i) no Party shall be obligated by this Section 11.07 to undertake studies or analyses that such Party would not otherwise be required to undertake or to incur costs outside the normal course of business to obtain information that is not in such Party's custody or control at the time a request for information is made pursuant to this Section 11.07;

(ii) if NTD and the ISO are in an adversarial relationship in litigation or arbitration (other than with respect to litigation or arbitration to enforce this Section 11.07), the furnishing of information, documents or records by the ISO or NTD in accordance with this Section 11.07 shall be subject to applicable rules relating to discovery;

(iii) no Party shall be compelled to provide any privileged and/or confidential documents or information that are attorney work product or subject to the attorney/client privilege; and

(iv) no Party shall be required to take any action that impairs or diminishes its rights under this Agreement or otherwise lessens the value of this Agreement to such Party.

11.08 **Business Day.** Notwithstanding anything herein to the contrary, if the date on which any payment is to be made pursuant to this Agreement is not a Business Day, the payment otherwise payable on such date shall be payable on the next succeeding Business Day with the same force and effect as if made on such scheduled date and, provided such payment is made on such succeeding Business Day, no interest shall accrue on the amount of such payment from and after such scheduled date to the time of such payment on such next succeeding Business Day.

11.09 **Governing Law.** This Agreement shall be governed by and construed in accordance with the laws of the State of Delaware including all matters of construction, validity and performance without regard to the conflicts-of-laws provisions thereof.

11.10 **Consent to Service of Process.** Each of the Parties hereby consents to service of process by registered mail, Federal Express or similar courier at the address to which notices to it are to be given, it being agreed that service in such manner shall constitute valid service upon such Party or its successors or assigns in connection with any such action or proceeding; provided, however, that nothing in this Section 11.10 shall affect the right of any Party or its successors and permitted assigns to serve legal process in any other manner permitted by applicable Law or affect the right of any such Party or its successors and assigns to bring any action or proceeding against the other Party or its property in the courts of other jurisdictions.

11.11 **Force Majeure.** A Party shall not be considered to be in default or breach under this Agreement, and shall be excused from performance or liability for damages to any other party, if and to the extent it shall be delayed in or prevented from performing or carrying out any of the provisions of this Agreement, except the obligation to pay any amount when due, in consequence of any act of God, labor disturbance, failure of contractors or suppliers of materials (not including as a result of non-payment), act of the public enemy or terrorists, war, invasion, insurrection, riot, fire, storm, flood, ice, explosion, breakage or accident to machinery or equipment or by any other cause or causes (not including a lack of funds or other financial causes) beyond such Party's reasonable control, including any order, regulation, or restriction imposed by governmental, military or lawfully established civilian authorities. A Party claiming a force majeure event shall use reasonable diligence to remove the condition that prevents performance, except that the settlement of any labor disturbance shall be in the sole judgment of the affected Party.

11.12 **Dispute Resolution.** The Parties agree that any dispute arising under this Agreement shall be the subject of good-faith negotiations among the Parties and affected market participants, if any. Each Party and each affected market participant shall designate one or more representatives with the authority to negotiate the matter in dispute to participate in such negotiations. The Parties and affected market participants shall engage in such good-faith negotiations for a period of not less than 60 calendar days. Notwithstanding the foregoing, any dispute arising under this Agreement may be submitted to arbitration or any other form of alternative dispute resolution upon the agreement of the Parties and all affected market participants to participate in such an alternative dispute resolution process. Nothing in this Agreement shall, however, restrict a Party's right to file a complaint with FERC under the relevant provisions of the Federal Power Act.

11.13 **Invalid Provisions.** If any provision of this Agreement is held to be illegal, invalid or unenforceable under any present or future Law, and if the rights or obligations of any Party under this Agreement shall not be materially and adversely affected thereby, (a) such provision shall be fully severable, (b) this Agreement shall be construed and enforced as if such illegal, invalid or unenforceable provision had never comprised a part hereof, (c) the remaining provisions of this Agreement shall remain in full force and effect and shall not be affected by the illegal, invalid or unenforceable provision or by its severance herefrom, and (d) the court holding such provision to be illegal, invalid or unenforceable may in lieu of such provision add as a part of this Agreement a legal, valid and enforceable provision as similar in terms to such illegal, invalid or unenforceable provision as it deems appropriate.

11.14 **Headings and Table of Contents.** The headings of the sections of this Agreement and the Table of Contents are inserted for purposes of convenience only and shall not be construed to affect the meaning or construction of any of the provisions hereof.

11.15 **Liabilities; No Joint Venture.**

(a) The obligations and liabilities of the ISO and NTD arising out of or in connection with this Agreement shall be several, and not joint, and each Party shall be responsible for its own debts, including Taxes. No Party shall have the right or power to bind any other Party to any agreement without the prior written consent of such other Party. The Parties do not intend by this Agreement to create nor does this Agreement constitute a joint venture, association, partnership, corporation or an entity taxable as a corporation or otherwise. No express or implied term, provision or condition of this Agreement shall be deemed to constitute the parties as partners or joint venturers.

(b) To the extent any Party has claims against the other Party, such Party may only look to the assets of the other Party for the enforcement of such claims and may not seek to enforce any claims against the directors, members, officers, employees, affiliates, or agents of such other Party who, each Party acknowledges and agrees, have no liability, personal or otherwise, by reason of their status as directors, members, officers, employees, affiliates, or agents of that Party, with the exception of fraud or willful misconduct.

11.16 **Counterparts.** This Agreement may be executed in any number of counterparts, each of which shall be deemed an original, but all of which together shall constitute but one and the same instrument. The parties hereto agree that any document or signature delivered by facsimile transmission shall be deemed an original executed document for all purposes hereof.

11.17 **Effective Date.**

This Agreement shall become effective on the date of execution (the “Effective Date”).

IN WITNESS WHEREOF, this Agreement has been duly executed and delivered by the duly authorized officer of each Party as of the date written below.

For ISO New England Inc.

Name: _____

Title: _____

Date: _____

For [NTD]

Name: _____

Title: _____

Date: _____

Schedule 1.01

Schedule of Definitions

Acquired Transmission Facilities. Any transmission facility acquired within the New England Control Area by NTD after the Operations Date that meets the classification standards set forth in Section 2.02(a).

Additional Term. “Additional Term” shall have the meaning ascribed thereto in Section 10.01(a) of this Agreement.

Affiliate. Any person or entity which controls, is controlled by, or is under common control by another person or entity. For purposes of this definition, "control" shall mean the possession, directly or indirectly and whether acting alone or in conjunction with others, of the authority to direct the management or policies of a person or entity. A voting interest of ten percent or more shall create a rebuttable presumption of control.

Agreement. This Operating Agreement between the ISO and NTD, as it may be amended from time to time.

Ancillary Service. Those services that are necessary to support the transmission of electric capacity and energy from resources to loads while maintaining reliable operation of the transmission system in accordance with Good Utility Practice.

Approved Outages. “Approved Outages” shall have the meaning ascribed thereto in Market Rule 1 of the ISO Tariff.

Best’s. The A.M. Best Company.

Business Day. Any day other than a Saturday or Sunday or an ISO holiday, as posted by the ISO on its website.

Commercially Reasonable Efforts. A level of effort which, in the exercise of prudent judgment in the light of facts or circumstances known or which should reasonably be known at the time a decision is made, can be expected by a reasonable person to accomplish the desired result in a manner consistent with Good Utility Practice and which takes the performing party's interests into consideration. "Commercially

Reasonable Efforts" will not be deemed to require a Person to undertake unreasonable measures or measures that have a significant adverse economic affect on such Person, including the payment of sums in excess of amounts that would be expended in the ordinary course of business for the accomplishment of the stated purpose.

Commission. The Federal Energy Regulatory Commission.

Control Area. An electric power system or combination of electric power systems, bounded by metering, to which a common automatic generation control scheme is applied in order to:

(a) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice and applicable NERC/NPCC Requirements; and

(d) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

Coordination Agreement. An agreement between the ISO and the operator(s) of one or more neighboring Control Areas addressing issues including interchange scheduling, operational arrangements, emergency procedures, energy for emergency and reliability needs, the exchange of information among Control Areas, and other aspects of the coordinated operation of the Control Areas.

Disbursement Agreement. The Rate Design and Funds Disbursement Agreement among the PTOs, as amended and restated from time to time.

Effective Date. "Effective Date" shall have the meaning ascribed thereto in Section 11.18(a) of this Agreement.

Elective Transmission Upgrade. A Transmission Upgrade constructed by any Person which is not required to be constructed pursuant to any applicable requirement of this Agreement, but which may be subject to applicable requirements set forth in the ISO OATT and this Agreement.

Elective Transmission Upgrade Applicant. “Elective Transmission Upgrade Applicant” shall have the meaning ascribed thereto in Section 2.05 of this Agreement.

Environment. Soil, land surface or subsurface strata, surface waters (including navigable waters, ocean waters, streams, ponds, drainage basins, and wetlands), groundwaters, drinking water supply, stream sediments, ambient air (including indoor air), plant and animal life, and any other environmental medium or natural resource.

Environmental Damages. “Environmental Damages” shall mean any cost, damages, expense, liability, obligation or other responsibility arising from or under Environmental Law consisting of or relating to:

- (a) any environmental matters or conditions (including on-site or off-site contamination, occupational safety and health, and regulation of chemical substances or products);
- (b) fines, penalties, judgments, awards, settlements, legal or administrative proceedings, damages, losses, claims, demands and response, investigative, remedial or inspection costs and expenses arising under Environmental Law;
- (c) financial responsibility under Environmental Law for cleanup costs or corrective action, including any investigation, cleanup, removal, containment or other remediation or response actions (“Cleanup”) required by applicable Environmental Law (whether or not such Cleanup has been required or requested by any Governmental Authority or any other Person) and for any natural resource damages; or
- (d) any other compliance, corrective, investigative, or remedial measures required under Environmental Law.

Environmental Laws. Any Law now or hereafter in effect and as amended, and any judicial or administrative interpretation thereof, including any judicial or administrative order, consent decree or judgment, relating to pollution or protection of the Environment, health or safety or to the use, handling, transportation, treatment, storage, disposal, release or discharge of Hazardous Materials.

Excluded Assets. “Excluded Assets” shall have the meaning ascribed thereto in Section 2.04 of this Agreement.

Existing Operating Procedures. “Existing Operating Procedures” shall have the meaning ascribed thereto in Section 3.02(d) of this Agreement.

External Transactions. Interchange transactions between the New England Transmission System and neighboring Control Areas.

FACTS. Flexible AC Transmission Systems.

FERC. The Federal Energy Regulatory Commission.

Final Order. An order issued by a Governmental Authority in a proceeding after all opportunities for rehearing are exhausted (whether or not any appeal thereof is pending) that has not been revised, stayed, enjoined, set aside, annulled or suspended, with respect to which any required waiting period has expired, and as to which all conditions to effectiveness prescribed therein or otherwise by law, regulation or order have been satisfied.

Financial Assurances. “Financial Assurances” shall have the meaning ascribed thereto in Section 3.10(b) of this Agreement.

FPA. The Federal Power Act.

FTR. A Financial Transmission Right, as defined in the ISO OATT.

Generally Accepted Accounting Principles. The widely accepted set of rules, conventions, standards, and procedures for reporting financial information, as established by the Financial Accounting Standards Board.

Generating Unit. A device for the production of electricity.

Good Utility Practice. Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good

business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather includes all acceptable practices, methods, or acts generally accepted in the region.

Governmental Authority. The government of any nation, state or other political subdivision thereof, including any entity exercising executive, military, legislative, judicial, regulatory, or administrative functions of or pertaining to a government, not including NTD or the ISO.

Hazardous Materials. Any waste or other substance that is listed, defined, designated, or classified as, or otherwise determined to be, hazardous, radioactive, or toxic or a pollutant or a contaminant under or pursuant to any Environmental Law, including any admixture or solution thereof, and specifically including petroleum and all derivatives thereof or synthetic substitutes therefor and asbestos or asbestos-containing materials.

Indemnifiable Loss. “Indemnifiable Loss” shall have the meaning ascribed thereto in Section 9.01(a)(i) of this Agreement.

Indemnifying Party. “Indemnifying Party” shall have the meaning ascribed thereto in Section 9.02 of this Agreement.

Indemnitee. “Indemnitee” shall have the meaning ascribed thereto in Section 9.02 of this Agreement.

Interconnection Agreement. An agreement or agreements for the interconnection of any entity to the Transmission Facilities of NTD.

Interconnection Standard. The applicable interconnection standards set forth in the ISO OATT.

Invoiced Amount. “Invoiced Amount” shall have the meaning ascribed thereto in Section 3.10(a)(i) of the Agreement.

ISO. ISO New England Inc., the RTO for New England authorized by the Federal Energy Regulatory Commission to exercise the functions required pursuant to FERC’s Order No. 2000 and FERC’s corresponding regulations.

ISO Control Center. The primary control center established by the ISO for the exercise of its Operating Authority and the performance of functions as an RTO.

ISO Information Policy. The information policy set forth in the ISO OATT.

ISO-NE. ISO New England Inc.

ISO OATT. The ISO Open Access Transmission Tariff, as in effect from time to time.

ISO Participants Agreement. The agreement among the ISO and stakeholder participants addressing, inter alia, the stakeholder process for the ISO.

ISO Planning Process. The process set forth in the ISO OATT, for the coordinated planning and expansion of the New England Transmission System with provision for the participation of all state regulatory authorities with jurisdiction over retail rates in the ISO region acceptable to those authorities, which process shall be subject to certain terms and conditions set forth in Schedule 3.09(a).

ISO System Plan. The “Regional System Plan” as defined in the ISO OATT.

ISO Tariff. The ISO Transmission, Markets and Services Tariff, as amended from time to time, on file with FERC.

Large Generating Facility. “Large Generating Facility” shall have the meaning ascribed thereto in the ISO OATT.

Law. Any federal, state, local or foreign statute, law, ordinance, regulation, rule, code, order, other requirement or rule of law.

Load Shedding. The systematic reduction of system demand by temporarily decreasing load.

Market Monitoring Unit. Any market monitoring unit established by the ISO, including any internal market monitoring unit of the ISO and any independent market monitoring unit of the ISO.

Market Participant Service Agreement. The agreement among the ISO and market participants addressing, inter alia, the requirements for participating in the New England Markets.

Market Rules. The rules describing how the New England Markets are administered.

Merchant Facility. A transmission facility constructed by an entity that assumes all market risks associated with the recovery of costs for the facility and whose costs are not recovered through traditional

cost-of-service based rates, but instead are recovered either through negotiated agreements with customers or through market revenues.

NTD Category A Facilities. Those transmission facilities listed in Schedule 2.01(a) of the Agreement, as that list may be modified from time to time in accordance with the terms of this Agreement.

NTD Category B Facilities. Those transmission facilities listed in Schedule 2.01(b) of the Agreement, as that list may be modified from time to time in accordance with the terms of this Agreement.

NTD Local Area Facilities. “Local Area Facilities” shall have the meaning ascribed thereto in Section 2.01 of this Agreement.

NTD Local Restoration Plan. The restoration plan developed by NTD with respect to the Transmission Facilities.

NERC. The North American Electric Reliability Corporation.

NERC/NPCC Requirements. NPCC criteria, guides, and procedures, NERC reliability standards, and NERC operating policies and planning standards (until such time as they are replaced by NERC reliability standards) and any successor documents.

New England Control Area. The Control Area consisting of the interconnected electric power system or combination of electric power systems in the geographic region consisting of Vermont, New Hampshire, Maine, Massachusetts, Connecticut and Rhode Island.

New England Markets. Markets or programs (including congestion pricing and design and implementation of FTRs) for the purchase of energy, capacity, ancillary services, demand response services or other related products or services that are offered in the New England Control Area and that are administered by the ISO pursuant to rules, rates, or agreements on file from time to time with the Commission.

New England Transmission System. The system comprised of the transmission facilities over which the ISO has operational jurisdiction, including the Transmission Facilities of NTD and the PTOs and the transmission system of any ITC formed pursuant to Attachment M to the ISO OATT.

New Transmission Facility. Any new transmission facility constructed within the New England Transmission System that is owned by NTD and that goes into commercial operation after the Effective Date. For the avoidance of doubt, in the case of a high-voltage, direct-current system, a New Transmission Facility shall include the transmission cable and the AC/DC converter stations as a single project.

Non-PTF. “Non-PTF” shall have the meaning ascribed thereto in the ISO OATT.

NPCC. The Northeast Power Coordinating Council.

OASIS. The Open Access Same-Time Information System of the ISO.

Operating Authority. “Operating Authority” shall have the meaning ascribed thereto in the TOA.

Operating Limits. The transfer limits for a transmission interface or generation facility.

Operating Procedures. The operating manuals, procedures, and protocols relating to the exercise of Operating Authority over the Transmission Facilities, as such manuals, procedures, and protocols may be modified from time to time in accordance with this Agreement.

Order 2000. FERC’s Order No. 2000, *i.e.*, *Regional Transmission Organizations*, Order No. 2000, 65 Fed. Reg. 809 (January 6, 2000), FERC Stats. & Regs. ¶31,089 (1999), *order on reh’g*, Order No. 2000-A, 65 Fed. Reg. 12,088 (March 8, 2000), FERC Stats. & Regs. ¶31,092 (2000), *petitions for review dismissed sub nom.*, Public Utility District No. 1 of Snohomish County, Washington v. FERC, 272 F.3d 607 . (D.C. Cir. 2001).

Owed Amounts. “Owed Amounts” shall have the meaning ascribed thereto in Section 3.10(c) of this Agreement.

PARS. Phase angle regulators.

Participant. A participant in the New England Markets, Transmission Customer, or other entity that has entered into the ISO Participants Agreement.

Participants Committee. “Participants Committee” shall mean the stakeholder participants committee established pursuant to the ISO Participants Agreement.

Party or Parties. A “Party” shall mean the ISO or NTD, as the context requires. “Parties” shall mean NTD and the ISO.

Person. An individual, partnership, joint venture, corporation, business trust, limited liability company, trust, unincorporated organization, government or any department or agency thereof, or any other entity.

Planned Outages. “Planned Outages” shall have the meaning ascribed thereto in Market Rule 1 of the ISO Tariff.

Planning Procedures. The manuals, procedures and protocols for planning and expansion of the New England Transmission System, as such manuals, procedures, and protocols may be modified from time to time in accordance with this Agreement.

Prime Rate. The interest rate that commercial banks charge their most creditworthy borrowers, as published in the most recent Wall Street Journal in its “Monday Rates” column.

PTF. “PTF” shall have the meaning ascribed thereto in the ISO OATT.

PTO or Participating Transmission Owner. “PTO” shall have the meaning ascribed thereto in the opening paragraph of the TOA. “Participating Transmission Owner” shall have the same meaning as “PTO.”

Rating Procedures. “Rating Procedures” shall have the meaning ascribed thereto in Section 3.02(d) of this Agreement.

Regulation and Frequency Response Service. An Ancillary Service as defined in the ISO OATT.

Reliability Authority. “Reliability Authority” shall have the meaning established by NERC, as such definition may change from time to time, provided such definition of Reliability Authority shall not be inconsistent with the specific rights and responsibilities of the ISO and the PTOs under this Agreement.

Restoration Plans. The System Restoration Plan, all PTO Local Restoration Plans and the NTD Local Restoration Plan.

RSP Project List. “RSP Project List” shall have the meaning ascribed thereto in the ISO OATT.

RTO. An independent entity that complies with Order No. 2000 and FERC’s corresponding regulations (or an entity that complies with all such requirements except for the scope and regional configuration requirements), as determined by the FERC.

Schedule 22 Large Generator Interconnection Agreement. The interconnection agreement included in Schedule 22 of the ISO OATT.

Schedule 23 Small Generator Interconnection Agreement. The interconnection agreement included in Schedule 23 of the ISO OATT.

Scheduled Outages. “Scheduled Outages” shall have the meaning ascribed thereto in Market Rule 1 of the ISO Tariff.

Small Generating Facility. “Small Generating Facility” shall have the meaning ascribed thereto in the ISO OATT.

System Failure. Widespread telecommunication, hardware or software failure or systemic the ISO hardware or software failures that makes it impossible to receive or process bid information, dispatch resources, or exercise Operating Authority over the Transmission Facilities.

Tax or Taxes. All taxes, charges, fees, levies, penalties or other assessments imposed by any United States federal, state or local or foreign taxing authority, including, but not limited to, income, excise, property, sales, transfer, franchise, payroll, withholding, social security or other taxes, including any interest, penalties or additions attributable thereto.

Tax Return. Any return, report, information return, or other document (including any related or supporting information) required to be supplied to any authority with respect to Taxes.

Technical Committees. “Technical Committee” shall mean the stakeholder technical committees established pursuant to the ISO Participants Agreement.

Term. “Term” shall have the meaning ascribed thereto in Section 10.01 of this Agreement.

Third Party. “Third Party” shall have the meaning ascribed thereto in Section 9.01(a) of this Agreement.

Termination Date. “Termination Date” shall have the meaning ascribed thereto in Section 10.01(a) of this Agreement.

TOA. The Transmission Operating Agreement entered into by the ISO and the PTOs, effective February 1, 2005, as it may be amended from time to time.

Transmission Business. The business activities of each PTO related to the ownership, operation and maintenance of its Transmission Facilities.

Transmission Customer. Any entity taking Transmission Service under the ISO OATT.

Transmission Facilities. “Transmission Facilities” shall have the meaning ascribed thereto in Sections 2.01 and 2.02 of this Agreement.

Transmission Owner. “Transmission Owner” shall have the meaning ascribed thereto in the ISO OATT.

Transmission Provider. The ISO, in its capacity as the provider of transmission services over the Transmission Facilities of the PTOs in accordance with FERC’s Order No. 2000 and FERC’s RTO regulations.

Transmission Service. The non-discriminatory, open access, wholesale transmission services provided to customers by the ISO in accordance with the ISO OATT.

Transmission Upgrade. Any upgrade to an existing Transmission Facility owned by NTD that goes into commercial operation after the Effective Date.

VAR. Volt-Amps Reactive.

Schedule 2.01(a)

Schedule 2.01(b)

Schedule 11.01

NOTICES

ISO New England Inc.

President and Chief Executive Officer

ISO New England Inc.

One Sullivan Road

Holyoke, MA 01040

Telephone: (413) 535-4000

Facsimile: 413-535-4379

General Counsel

ISO New England Inc.

One Sullivan Road

Holyoke, MA 01040

Telephone: (413) 535-4000

Facsimile: (413) 535-4379

[NTD]

[Name

Address

Phone:

Fax:]

ATTACHMENT P
SELECTED QUALIFIED TRANSMISSION PROJECT SPONSOR AGREEMENT

Between
ISO NEW ENGLAND, INC.

And

This Selected Qualified Transmission Project Sponsor Agreement, including the Schedules attached hereto and incorporated herein (collectively, “Agreement”) is made and entered into as of the Effective Date between ISO New England, Inc. (“ISO-NE” or “the ISO”), and _____ (“Selected QTPS”), referred to herein individually as “Party” and collectively as “the Parties.”

RECITALS

WHEREAS, in accordance with FERC Order No. 1000 and Attachment K of the ISO-NE Open Access Transmission Tariff (“OATT”), ISO-NE selects the preferred Phase or Stage Two Solution for inclusion in the in the Regional System Plan (“RSP”) and/or its Project List;

WHEREAS, the Selected QTPS is a Qualified Transmission Project Sponsor pursuant to Section 4B of Attachment K of the OATT;

WHEREAS, the Selected QTPS has executed the [Transmission Operating Agreement] [Non-Incumbent Developer Transmission Operating Agreement];

WHEREAS, pursuant to Section 4.3(j) or 4A.9(a) of Attachment K of the OATT, ISO-NE notified the Selected QTPS that its project has been selected for development;

WHEREAS, pursuant to Section 4.3(k) or 4A.9(b) of Attachment K of the OATT, by executing this Agreement the Selected QTPS accepts responsibility to proceed with the Project, and therefore has the obligation to construct the Project; and

NOW, THEREFORE, in consideration of the promises, and the mutual representations, warranties, covenants and agreements hereinafter set forth, and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, and intending to be legally bound, Selected QTPS and the ISO-NE agree as follows:

1.0 Defined Terms

All capitalized terms used in this Agreement shall have the meanings ascribed to them in the Tariff or in definitions either in the body of this Agreement or its attached Schedules. In the event of any conflict between defined terms set forth in Section I of the Tariff or defined terms in this Agreement, including the Schedules, such conflict will be resolved in favor of the terms as defined in this Agreement.

Applicable Laws and Regulations shall mean all duly promulgated applicable federal, state and local laws, regulations, rules, ordinances, codes, decrees, judgments, directives, or judicial or administrative orders, permits and other duly authorized actions of any Governmental Authority.

Breach shall mean the failure of a Party to perform or observe any material term or condition of the Selected Qualified Transmission Project Sponsor Agreement.

Breaching Party shall mean a Party that is in Breach of the Selected Qualified Transmission Project Sponsor Agreement.

Commercially Reasonable Efforts shall mean a level of effort which, in the exercise of prudent judgment in the light of facts or circumstances known or which should reasonably be known at the time a decision is made, can be expected by a reasonable person to accomplish the desired result in a manner consistent with Good Utility Practice and which takes the performing party's interests into consideration.

Component In-Service shall mean that a portion (component) of the Project has been placed in commercial operation.

Component In-Service Date shall mean the date that a portion (component) of the Project is placed In-Service.

Default shall mean the failure of a Breaching Party to cure its Breach in accordance with Article 8 of the Selected Qualified Transmission Project Sponsor Agreement.

Governmental Authority shall mean the government of any nation, state or other political subdivision thereof, including any entity exercising executive, military, legislative, judicial, regulatory, or administrative functions of or pertaining to a government.

In-Service shall mean that the Project has been placed in commercial operation.

In-Service Date shall mean the date the Project is placed In-Service.

Project shall mean the Market Efficiency Transmission Upgrade, Reliability Transmission, or Public Policy Upgrade included in the Regional System Plan and/or the ISO-NE Project List described in Schedule A of this Agreement.

Required Project In-Service Date is the date the Project is required to: (i) be completed in accordance with the Scope of Work in Schedule A of this Agreement, (ii) is placed In-Service; and; (iii) be under ISO-NE operational dispatch.

Tariff consists of the ISO New England, Inc. Transmission, Markets, and Services Tariff.

Article 2 - Effective Date and Term

2.0 Effective Date

This Agreement shall become effective on the date the Agreement has been executed by all Parties, or if this Agreement is required to be filed with FERC for acceptance, upon the date specified by FERC.

2.1 Term

This Agreement shall continue in full force and effect from the Effective Date until: (i) the Selected QTPS has executed the TOA; and (ii) the Project (a) has been completed in accordance with the terms and conditions of this Agreement and (b) meets all relevant required planning criteria, or (iii) the Agreement is terminated pursuant to Article 6 of this Agreement.

Article 3 - Project Construction

3.0 Construction of Project by Selected QTPS

Selected QTPS shall design, engineer, procure, install and construct the Project, including any modifications thereto, in accordance with: (i) the terms of this Agreement, including but not limited to the Scope of Work in Schedule A and the Development Schedule in Schedule B; (ii) applicable reliability principles, guidelines, and standards of the Northeast Power Coordinating Council and the North American Electric Reliability Corporation; (iii) the ISO New England Operating Documents; and (iv) Good Utility Practice. Nothing contained herein shall modify PTOs' rights under the TOA to construct and own upgrades to its existing and affected substation or facilities.

3.1 Milestones

3.1.0 Milestone Dates

Selected QTPS shall meet the milestone dates set forth in the Development Schedule in Schedule B of this Agreement. Milestone dates set forth in Schedule B only may be extended by ISO-NE in writing. ISO-NE reasonably may extend any such milestone date, in the event of delays not caused by the Selected QTPS that could not be remedied by the Selected QTPS through the exercise of due diligence if a corporate officer of the Selected QTPS submits a revised Development Schedule containing revised milestones and showing the Project in full operation no later than the Required Project In-Service Date specified in Schedule B of this Agreement.

3.2 Applicable Technical Requirements and Standards

At the point of interconnection, the applicable technical requirements and standards of the Participating Transmission Owner(s) ("PTO") to whose facilities the Project will interconnect shall apply to the design, engineering, procurement, construction and installation of the Project. The remaining portion of the Project shall meet applicable industry standards and Good Utility Practice. At a minimum, all new facilities should comply with the current National Electric Safety Code.

3.3 Project Modification

3.3.0 Project Modification

The Scope of Work and Development Schedules (Schedules A and B, respectively), including the milestones therein, may be revised, as required through written consent by the parties. Such modifications may include alterations as necessary and directed by ISO-NE such as modifications resulting from the I.3.9 process or to meet the system condition for which the Project was included in the Regional System Plan.

3.3.1 Consent of ISO-NE to Project Modifications

Selected QTPS may not modify the Project without prior written consent of ISO-NE.

3.4 Project Status Reports

Selected QTPS shall submit to ISO-NE quarterly construction status reports in writing. The reports shall contain, but not be limited to, updates and information related to: (i) current engineering and construction status of the Project; (ii) Project completion percentage, including milestone completion; (iii) current target Project or phase completion date(s); (iv) applicable outage information; and (v) cost expenditures to date and revised projected cost estimates for completion of the Project.

3.5 Exclusive Responsibility of Selected QTPS

Selected QTPS shall be solely responsible for all planning, design, engineering, procurement, construction, installation, management, operations, safety, and compliance with Applicable Laws and Regulations associated with the Project. ISO-NE shall have no responsibility to manage, supervise, or ensure compliance or adequacy of same.

Article 4 – Subcontractor Insurance

4.0 Subcontractor Insurance

In accordance with Good Utility Practice, Selected QTPS shall require each of its subcontractors to maintain and, upon request, provide Selected QTPS evidence of insurance coverage of types, and in amounts, commensurate with the risks associated with the services provided by the subcontractor. Bonding and

hiring of contractors or subcontractors shall be the Selected QTPS's discretion, but regardless of bonding or the existence or non-existence of insurance, the Selected QTPS shall be responsible for the performance or non-performance of any contractor or subcontractor it hires.

Article 5 – Default and Force Majeure

5.0 Events of Default

(a) Subject to the terms and conditions of this Section 5.0, the occurrence of any of the following events shall constitute an event of default of a Party under this Agreement:

- (i) Failure by a Party to perform any material obligation set forth in this Agreement, and continuation of such failure for longer than thirty (30) days after the receipt by the non-breaching Party of written notice of such failure; provided, however, that if the breaching Party is diligently pursuing a remedy during such thirty (30) day period, said cure period shall be extended for an additional thirty (30) days or as otherwise agreed by the Parties, provided that such extension ensures that the Project meets the Required Project In-Service Date.
- (ii) Failure to perform a material obligation set forth in this Agreement shall include but not be limited to:
 - a. Any breach of a representation, warranty, or covenant made in this Agreement;
 - b. Failure to meet a milestone or milestone date set forth in the Development Schedule in Schedule B of this Agreement, or as extended in writing as described in Sections 3.1.0 and 3.3.0 of this Agreement;
 - c. Assignment of this Agreement in a manner inconsistent with the terms of this Agreement;
or
 - d. Failure of any Party to provide information or data required to be provided to another Party under this Agreement for such other Party to satisfy its obligations under this Agreement.
 - e. If there is a dispute between the Parties as to whether a Party has failed to perform a material obligation, the cure period(s) provided in Section 5.0(a)(i) above shall run from the point at which a finding of failure to perform has been made by a Governmental Authority.

- f. With respect to either Party, (A) the filing of any petition in bankruptcy or insolvency, or for reorganization or arrangement under any bankruptcy or insolvency laws, or voluntarily taking advantage of any such laws by answer or otherwise or the commencement of involuntary proceedings under any such laws, (B) assignment by either Party for the benefit of creditors; or (C) allowance by either Party of the appointment of a receiver or trustee of all or a material part of its property if such receiver or trustee is not discharged within thirty (30) days after such appointment.

5.1 Remedies

Upon the occurrence of an event of Default, the non-Defaulting Party shall be entitled to: (i) commence an action to require the Defaulting Party to remedy such Default and specifically perform its duties and obligations hereunder in accordance with the terms and conditions hereof; (ii) suspend performance hereunder; and (iii) exercise such other rights and remedies as it may have in equity or at law. Nothing in this Section 5.1 is intended in any way to affect the rights of a third-party to seek any remedy it may have in equity or at law from the Selected QTPS resulting from Selected QTPS's Default of this Agreement.

5.2 Waiver

The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement, or to exercise its rights with respect to a Breach or Default under this Agreement or with regard to any other matters arising in connection with this Agreement will not be deemed a waiver or continuing waiver with respect to any other failure to comply with any other obligation, right, or duty of this Agreement. Any waiver of any obligation, right, or duty under this Agreement must be in writing.

5.3 Force Majeure

A Party shall not be considered to be in Default or Breach under this Agreement, and shall be excused from performance or liability for damages to any other party, if and to the extent it shall be delayed in or prevented from performing or carrying out any of the provisions of this Agreement, except the obligation to pay any amount when due, in consequence of any act of God, labor disturbance, failure of contractors or suppliers of materials (not including as a result of non-payment), act of the public enemy or terrorists, war, invasion, insurrection, riot, fire, storm, flood, ice, explosion, breakage or accident to machinery or equipment or by any other cause or causes (not including a lack of funds or other financial causes) beyond such Party's

reasonable control, including any order, regulation, or restriction imposed by governmental, military or lawfully established civilian authorities. A Party claiming a force majeure event shall use reasonable diligence to remove the condition that prevents performance, except that the settlement of any labor disturbance shall be in the sole judgment of the affected Party.

Article 6 - Termination

6.0 Termination by ISO-NE

In the event that: (i) ISO-NE determines to remove the Project from the RSP; (ii) ISO-NE otherwise determines that the identified need has changed or been eliminated therefore the Project is no longer required to address the specific need for which the Project was included in the RSP; or (iii) a force majeure or other event outside of the Selected QTPS's control that, with the exercise of reasonable efforts, Selected QTPS cannot alleviate and which prevents the Selected QTPS from satisfying its obligations under this Agreement; or (iv) the Parties fail to agree to modifications under Section 3.3.0, ISO-NE may terminate this Agreement by providing written notice of termination to Selected QTPS. The termination shall become effective upon the date the Selected QTPS receives such notice, except as otherwise provided in Section 6.2.

6.1 Termination by Default

This Agreement shall terminate in the event a Party is in Default of this Agreement in accordance with Section 5.0 of this Agreement and the ISO shall take action in accordance with Section 4.3(l) or 4A.9(c) of Attachment K.

6.2 Filing at FERC

If, pursuant to FERC regulations, the termination of this agreement is required to be filed with FERC, such termination shall be effective upon the date established by FERC. ISO-NE shall report any termination of this Agreement in its Electric Quarterly Report.

Article 7 – Indemnity and Limitation of Liability

7.0 Hold Harmless

Selected QTPS will indemnify and hold harmless all affected PTOs and ISO-NE and its directors, managers, members, shareholders, officers and employees from any and all liability (except for that stemming from the ISO-NE or an affected PTO's negligence, gross negligence or willful misconduct), resulting from the Selected QTPS's failure to timely complete the Project. As used herein, an "affected PTO" is one that would be subject to penalties assessed by NERC or FERC or adverse regulatory orders or monetary claims or damages due to the Selected QTPS's failure to timely complete the Project.

7.1 Liability

- (a) Neither Party shall be liable to the other Party for any incidental, indirect, special, exemplary, punitive or consequential damages, including lost revenues or profits, even if such damages are foreseeable or the damaged Party has advised such Party of the possibility of such damages and regardless of whether any such damages are deemed to result from the failure or inadequacy of any exclusive or other remedy.
- (b) Nothing in this Agreement shall be deemed to affect the right of ISO-NE to recover its costs due to liability under this Article 7 through the NEPOOL Participants Agreement or ISO-NE Tariff.

Article 8 – Assignment

8.0 Assignment

A Party may assign all of its rights, duties, and obligations under this Agreement in accordance with this Section 8.0. No Party may assign any of its rights or delegate any of its duties or obligations under this Agreement without prior written consent of the other Party, which consent shall not be unreasonably withheld, conditioned, or delayed. Any such assignment or delegation made without such written consent shall be null and void. Assignment by the Selected QTPS shall be contingent upon, prior to the effective date of the assignment: (i) the Selected QTPS or the assignee demonstrating to the satisfaction of ISO-NE that the assignee has the technical competence and financial ability: (a) to comply with the requirements of this Agreement, (b) to construct the Project consistent with the assignor's cost estimates for the Project and in accordance with any cost cap or cost containment commitments, and (c) to operate and maintain the

Project once constructed; and (ii) the assignee is a Qualified Transmission Project Sponsor pursuant to Section 4B of Attachment K of the OATT. For all assignments by any Party, the assignee must assume in writing, to be provided to the other Party, all rights, duties, and obligations of the assignor arising under this Agreement. Any assignment described herein shall not relieve or discharge the assignor from any of its obligations hereunder absent the written consent of the other Party. In no circumstance, shall an assignment of this Agreement or any of the rights, duties, and obligations under this Agreement diminish the rights of the ISO-NE under this Agreement or the ISO New England Operating Documents. Any assignees that will construct, maintain, or operate the Project shall be subject to, and comply with the terms of this Agreement, and the ISO New England Operating Documents.

Article 9 - Information Exchange

9.0 Information Access

Subject to the ISO Information Policy, each Party shall make available to the other Party information necessary to carry out each Party's obligations and responsibilities under this Agreement and the ISO New England Operating Documents. Such information shall include but not be limited to, information reasonably requested by ISO-NE to prepare the Regional System Plan. The Parties shall not use such information for purposes other than to carry out their obligations or enforce their rights under this Agreement and the ISO New England Operating Documents.

Article 10 - Confidentiality

10.0 Confidential Information and CEII

Confidential Information and CEII shall be treated in accordance with the ISO Information Policy.

Article 11 – Dispute Resolution

11.0 Dispute Resolution Procedures

The Parties agree that any dispute arising under this Agreement shall be the subject of good-faith negotiations among the Parties. Each Party shall designate one or more representatives with the authority to negotiate the matter in dispute to participate in such negotiations. The Parties shall engage in such good-faith negotiations for a period of not less than sixty (60) calendar days. Notwithstanding the foregoing, any dispute arising under this Agreement may be submitted to arbitration or any other form of alternative dispute resolution upon the agreement of the Parties to participate in such an alternative dispute resolution process. Nothing in this Agreement shall, however, restrict a Party's right to file a complaint with FERC under the relevant provisions of the Federal Power Act.

Article 12 - Regulatory Requirements

12.0 Regulatory Approvals

Selected QTPS shall seek and obtain all required authorizations or approvals as soon as reasonably practicable, and by the milestone dates set forth in the Development Schedule of Schedule B of this Agreement, as applicable.

Article 13 - Representations and Warranties

13.0 General

Selected QTPS hereby represents, warrants and covenants as follows, with these representations, warranties, and covenants effective as to the Selected QTPS during the full time this Agreement is effective:

13.0.1 Organization

Selected QTPS is duly organized, validly existing and in good standing under the laws of the state of its organization.

13.0.2 Authority

Selected QTPS has all requisite power and authority to execute, deliver and perform this Agreement; the execution, delivery and performance by Selected QTPS of this Agreement have been duly authorized by

all necessary and appropriate action on the part of Selected QTPS; and this Agreement has been duly and validly executed and delivered by Selected QTPS and constitutes the legal, valid and binding obligations of Selected QTPS, enforceable against Selected QTPS in accordance with the terms of this Agreement.

13.0.3 No Breach

The execution, delivery and performance by Selected QTPS of this Agreement will not result in a breach of any terms, provisions or conditions of any agreement to which Selected QTPS is a party which breach has a reasonable likelihood of materially and adversely affecting Selected QTPS's performance under this Agreement.

Article 14 - Operation of Project

14.0 In-Service

The following requirements shall be satisfied prior to the date the Project goes In-Service:

14.0.1 Execution of the Transmission Operating Agreement

Selected QTPS is able to meet all requirements of the Transmission Operating Agreement and has authority to execute that agreement.

14.0.2 Operational Requirements

The Project must meet all applicable operational requirements described in the ISO New England Operating Documents.

14.0.3 Synchronization

Selected QTPS shall have received any necessary authorizations or permissions from ISO-NE and the owners of the facilities to which the Project will interconnect to synchronize with the New England Transmission System or to energize, as applicable, the Project.

14.1 Partial Operation

If the Project is to be completed in phases, the completed part of the Project may operate prior to completion and Required Project In-Service Date set forth in Schedule B of this Agreement, provided that: (i) Selected QTPS has notified ISO-NE in writing of the successful completion of the Project phase; (ii) ISO-NE has determined that partial operation of the Project will not negatively impact the reliability of the New England Transmission System; (iii) Selected QTPS has demonstrated that the requirements for going In-Service set forth in Section 14.0 of this Agreement have been met for partial operation of the Project; and (iv) partial operation of the Project is consistent with Applicable Laws and Regulations, applicable reliability standards, and Good Utility Practice.

Article 15 - Survival

15.0 Survival of Rights

The rights and obligations of the Parties in this Agreement shall survive the termination, expiration, or cancellation of this Agreement to the extent necessary to provide for the determination and enforcement of said obligations arising from acts or events that occurred while this Agreement was in effect. The Indemnity and Limitation of Liability provisions in Article 7 and the Binding Cost Cap or Cost Containment Measures referenced in Article 16 and set forth in Schedule C of this Agreement also shall survive termination, expiration, or cancellation of this Agreement.

Article 16 - Binding Cost Cap or Cost Containment Measures

16.0 Binding Cost Cap or Cost Containment Measures

Any binding cost cap or cost containment measures, or commitment to forego any kind of rate incentives or rate recovery submitted by the Selected QTPS as part of its Project shall be detailed in Schedule C of this Agreement.

Article 17 - Non-Standard Terms and Conditions

17.0 Schedule D - Non-Standard Terms and Conditions

Subject to FERC acceptance or approval, the Parties agree that the terms and conditions set forth in the attached Schedule D are hereby incorporated by reference, and made a part of, this Agreement. In the event of any conflict between a provision of Schedule D that FERC has accepted and any provision of the standard terms and conditions set forth in this Agreement that relates to the same subject matter, the pertinent provision of Schedule D shall control.

Article 18 - Miscellaneous

18.0 Notices

Unless otherwise expressly specified or permitted by the terms hereof, all communications and notices provided for herein shall be in writing and any such communication or notice shall become effective (a) upon personal delivery thereof, including by overnight mail or courier service, (b) in the case of notice by United States mail, certified or registered, postage prepaid, return receipt requested, upon receipt thereof, or (c) in the case of notice by e-mail, upon receipt thereof; provided that such transmission is promptly confirmed by either of the methods set forth in clauses (a) or (b) above, in each case addressed to the relevant party and copy party hereto at its address set forth below in this section 18.0 or at such other address as such party or copy party may from time to time designate by written notice to the other party hereto; further provided that a notice given in connection with this Section 18.0 but received on a day other than a Business Day, or after business hours in the situs of receipt, will be deemed to be received on the next Business Day.

Addresses:

ISO-NE:
ISO New England, Inc.
1 Sullivan Road
Holyoke, MA 01040
Attention:
e-mail: sqtspa@iso-ne.com

Selected QTPS:

Attention:
e-mail address _____

18.1 No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon any Party. No Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Parties.

18.2 Incorporation of Other Documents

The ISO New England Operating Documents, as they may be amended from time to time, are incorporated by reference herein and made a part hereof and Selected QTPS is subject to, and must comply with the terms and conditions of those documents.

18.3 Headings

The headings of the sections of this Agreement are inserted for purposes of convenience only and shall not be construed to affect the meaning or construction of any of the provisions hereof.

18.4 Interpretation

Wherever the context may require, any noun or pronoun used herein shall include the corresponding masculine, feminine or neuter forms. The singular form of nouns, pronouns and verbs shall include the plural and vice versa.

18.5 Amendment; Limitations on Modifications of Agreement

- (a) This Agreement shall only be subject to modification or amendment by agreement of the Parties in writing and the acceptance of any such amendment by FERC, if required to be filed at FERC.
- (b) In light of the foregoing, the Parties agree that they shall not rely to their detriment on any purported amendment, waiver or other modification of any rights under this Agreement unless the requirements of this Section 18.5 are satisfied and further agree not to assert equitable estoppel or any other equitable theory to prevent enforcement of this provision in any court of law or equity, arbitration or other proceeding.

18.6 Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

18.7 Further Assurances

Each Party agrees, upon the other Party's request, to make Commercially Reasonable Efforts to execute and deliver such additional documents and instruments, provide information, and to perform such additional

acts as may be necessary or appropriate to effectuate, carry out and perform all of the terms, provisions, and conditions of this Agreement.

18.8 Counterparts

This Agreement may be executed in any number of counterparts, each of which shall be deemed an original, but all of which together shall constitute but one and the same instrument. The parties hereto agree that any document or signature delivered by facsimile transmission shall be deemed an original executed document for all purposes hereof.

18.9 Governing Law

This Agreement shall be governed by and construed in accordance with the laws of the State of Delaware including all matters of construction, validity and performance without regard to the conflicts-of-laws provisions thereof and the Federal Power Act, as applicable.

18.10 Entire Agreement

Except for the ISO New England Operating Documents, applicable reliability standards, or successor documents, this Agreement, including all Schedules, constitutes the entire agreement between the Parties with reference to the subject matter hereof, and supersedes all prior and contemporaneous understandings or agreements, oral or written, between the Parties with respect to the subject matter of this Agreement. Except for the ISO New England Operating Documents, applicable reliability standards, or successor documents, there are no other agreements, representations, warranties, or covenants which constitute any part of the consideration for, or any condition to, either Party's compliance with its obligations under this Agreement.

18.11 No Third Party Beneficiaries

It is not the intention of this Agreement or of the Parties to confer a third party beneficiary status or rights of action upon any person or entity whatsoever other than the Parties and nothing contained herein, either express or implied, shall be construed to confer upon any person or entity other than the Parties any rights of action or remedies either under this Agreement or in any manner whatsoever.

[Signature Page Follows]

IN WITNESS WHEREOF, this Agreement has been duly executed and delivered by the duly authorized officer of each Party as of the date written below.

For ISO New England Inc.

Name: _____

Title: _____

Date: _____

For Selected QTPS

Name: _____

Title: _____

Date: _____

SCHEDULE A

Description of Project and Scope of Work

SCHEDULE B

Development Schedule

Selected QTPS shall ensure and demonstrate to the ISO-NE that it timely has met the following milestones and milestone dates and that the milestones remain in good standing:

[As appropriate include the following standard Milestones, with any revisions, and additional milestones necessary for the Project]:

Milestones and Milestone Dates
Demonstrate adequate Project financing. On or before _____, Selected QTPS must demonstrate that adequate project financing has been secured. Project financing must be maintained for the term of this Agreement [add detail if necessary].
Acquisition of all necessary federal, state, county, and local site permits. On or before _____, Selected QTPS must demonstrate that all required federal, state, county and local site permits have been acquired. [add detail if necessary]. Provide separate dates for each permit]
Substantial Site Work Completed: On or before _____, Selected QTPS must demonstrate that at least 20% of Project site construction is completed. Additionally, the Selected QTPS must submit updated ratings and the final project drawings to the ISO-NE.
Delivery of major electrical equipment. On or before _____, Selected QTPS must demonstrate that all major electrical equipment has been delivered to the project site. [add detail if necessary].
Demonstrate required ratings. On or before _____, Selected QTPS must demonstrate that the project meets all required electrical ratings. [add detail if necessary].
Required Project In-Service Date. On or before _____, Selected QTPS must: (i) demonstrate that the Project is completed in accordance with the Scope of Work in Schedules A of this Agreement; (ii) meets the criteria outlined in Schedule B of this Agreement; (iii) is placed In-Service; and (iv) is under ISO-NE operational dispatch.
[Add additional Milestones]

SCHEDULE C

Binding Cost Cap or Cost Containment Measures

[Insert binding cost cap or cost containment terms and conditions, if any contained in the Selected QTPS selected proposal. If no such binding cost cap or cost containment measures state “None”.]

SCHEDULE D

Non-Standard Terms and Conditions

[Insert non-standard terms and conditions, if any. If no such non-standard terms and conditions, state "None".]

PPL CORPORATION, PPL RHODE ISLAND HOLDINGS, LLC,
NATIONAL GRID USA, and THE NARRAGANSETT ELECTRIC COMPANY

Docket No. D-21-09

PPL Corporation and PPL Rhode Island Holdings, LLC's
Responses to Division's First Set of Data Requests
Issued on June 8, 2021

Division 1-38

Request:

Witness Gregory N. Dudkin states (at 11:20-12:1) that "PPL Electric Utilities' operation and maintenance costs in 2020 are substantially the same level they were in 2011." Please provide the basis for this statement and all supporting data, including annual Operation & Maintenance expense for PPL Electric Utilities for the years 2011 through 2020.

Response:

Overall, on a comparative percentage basis, PPL Electric Utilities Corporation's ("PPL Electric Utilities") operation and maintenance costs have not fluctuated significantly for the years 2011 through 2020. The table below reflects PPL Electric Utilities' operation and maintenance costs (in millions of dollars and for the full fiscal year) as set forth in its SEC Form 10-K filings, as well as PPL Electric Utilities' internal view, which adjusts for costs recovered through rate recovery mechanisms and one-time special items.

	<u>2011</u>	<u>2012</u>	<u>2013</u>	<u>2014</u>	<u>2015</u>	<u>2016</u>	<u>2017</u>	<u>2018</u>	<u>2019</u>	<u>2020</u>
O&M per 10-K	530	576	531	543	607	602	572	578	566	513
Less: Rate recovery mechanisms	108	104	82	103	114	108	120	121	125	91
Less: O&M special items	-	-	-	<u>3</u>	-	-	-	<u>7</u>	-	<u>1</u>
Internal O&M	422	472	449	437	493	494	452	450	441	421

Please see Attachment DIV 1-38-1 for PPL Electric Utilities' Consolidated Statement of Income from its Form 10-K, which includes additional support for the rate recovery mechanisms and special items.

CONSOLIDATED STATEMENTS OF INCOME FOR THE YEARS ENDED DECEMBER 31,
PPL Electric Utilities Corporation and Subsidiaries
(Millions of Dollars)

	2012	2011
Operating Revenues		
Retail electric	\$ 1,760	\$ 1,881
Electric revenue from affiliate	3	11
Total Operating Revenues	1,763	1,892
Operating Expenses		
Operation		
Energy purchases	550	738
Energy purchases from affiliate	78	26
Other operation and maintenance	576	530
Depreciation	160	146
Taxes, other than income	105	104
Total Operating Expenses	1,469	1,544
Operating Income	294	348
Other Income (Expense) - net	9	7
Interest Expense	99	98
Income Before Income Taxes	204	257
Income Taxes	68	68
Net Income (a)	136	189
Distributions on Preferred Securities	4	16
Net Income Available to PPL	\$ 132	\$ 173

(a) Net income approximates comprehensive income.

The accompanying Notes to Financial Statements are an integral part of the financial statements.

Reconciliation of Non-GAAP Financial Measures

The following tables reconcile "Operating Income" to PPL's three non-GAAP financial measures.

	2012				2011					
	Kentucky Gross Margins	PA Gross Delivery Margins	Unregulated Gross Energy Margins	Other (a)	Operating Income (b)	Kentucky Gross Margins	PA Gross Delivery Margins	Unregulated Gross Energy Margins	Other (a)	Operating Income (b)
Operating Revenues										
Utility	\$ 2,759	\$ 1,760		\$ 2,289 (d)	\$ 6,808	\$ 2,791	\$ 1,881		\$ 1,620 (d)	\$ 6,292
PLR intersegment utility revenue (expense) (e)		(78)	78				(26)	26		
Unregulated retail electric and gas			865	(21) (g)	844			696	30 (g)	726
Wholesale energy marketing Realized			4,412	21 (f)	4,433			3,745	62 (f)	3,807
Unrealized economic activities				(311) (g)	(311)				1,407 (g)	1,407
Net energy trading margins			4		4			(2)		(2)
Energy-related businesses				508	508				507	507
Total Operating Revenues	2,759	1,682	3,359	2,486	12,285	2,791	1,855	4,465	3,626	12,737
Operating Expenses										
Fuel	872		991	34 (h)	1,837	866		1,151	(71) (h)	1,946
Energy purchases Realized	195	550	2,204	48 (f)	2,997	238	738	912	242 (f)	2,130
Unrealized economic activities				(442) (g)	(442)				1,123 (g)	1,123
Other operation and maintenance	101	104	19	2,611	2,835	90	108	16	2,453	2,667
Depreciation	51			1,049	1,100	49			911	960
Taxes, other than income		91	34	241	366		99		30	326
Energy-related businesses				484	484				484	484
Intercompany eliminations							(11)			8
Total Operating Expenses	1,219	742	3,191	4,025	9,177	1,243	934	2,112	5,347	9,636
Discontinued operations								12	(12) (i)	
Total	\$ 1,540	\$ 940	\$ 2,168	\$ (1,539)	\$ 3,109	\$ 1,548	\$ 921	\$ 2,365	\$ (1,733)	\$ 3,101

CONSOLIDATED STATEMENTS OF INCOME FOR THE YEARS ENDED DECEMBER 31,
PPL Electric Utilities Corporation and Subsidiaries
(Millions of Dollars)

	2015	2014	2013
Operating Revenues	\$ 2,124	\$ 2,044	\$ 1,870
Operating Expenses			
Operation			
Energy purchases	657	587	588
Energy purchases from affiliate	14	84	51
Other operation and maintenance	607	543	531
Depreciation	214	185	178
Taxes, other than income	94	107	103
Total Operating Expenses	1,586	1,506	1,451
Operating Income	538	538	419
Other Income (Expense) - net	8	7	6
Interest Expense	130	122	108
Income Before Income Taxes	416	423	317
Income Taxes	164	160	108
Net Income (a)	\$ 252	\$ 263	\$ 209

(a) Net income approximates comprehensive income.

The accompanying Notes to Financial Statements are an integral part of the financial statements.

Reconciliation of Margins

The following tables contain the components from the Statement of Income that are included in the non-GAAP financial measures and a reconciliation to PPL's "Operating Income" for the years ended December 31.

	2015					2014				
	U.K. Gross Margins	Kentucky Gross Margins	PA Gross Delivery Margins	Other (a)	Operating Income (b)	U.K. Gross Margins	Kentucky Gross Margins	PA Gross Delivery Margins	Other (a)	Operating Income (b)
Operating Revenues	\$ 2,364 (c)	\$ 3,115	\$ 2,124	\$ 66	\$ 7,669	\$ 2,638 (c)	\$ 3,168	\$ 2,044	\$ 2	\$ 7,852
Operating Expenses:										
Fuel		863	657	14	855		965			965
Energy purchases		184	14	(14)	855		255	587	84	924
Energy purchases from affiliate								84	(84)	
Other operation and maintenance	121	100	114	1,603	1,938	111	99	103	1,543	1,816
Depreciation		38	845	11	883		11	883	912	923
Taxes, other than income		4	102	193	299		24	98	217	317
Total Operating Expenses	121	1,189	887	2,641	4,838	111	1,330	872	2,672	4,985
Total	\$ 2,243	\$ 1,926	\$ 1,237	\$ (2,575)	\$ 2,831	\$ 2,527	\$ 1,838	\$ 1,172	\$ (2,670)	\$ 2,867

	2013				
	U.K. Gross Margins	Kentucky Gross Margins	PA Gross Delivery Margins	Other (a)	Operating Income (b)
Operating Revenues	\$ 2,404 (c)	\$ 2,976	\$ 1,870	\$ 13	\$ 7,263
Operating Expenses:					
Fuel		896		(1)	895
Energy purchases		217	588	51	856
Energy purchases from affiliate				(51)	
Other operation and maintenance	107	97	82	1,524	1,810
Depreciation		5	838	1	843
Taxes, other than income		1	202	298	4,702
Total Operating Expenses	107	1,216	816	2,563	4,702
Total	\$ 2,297	\$ 1,760	\$ 1,054	\$ (2,550)	\$ 2,561

(a) Represents amounts excluded from Margins.

(b) As reported on the Statements of Income.

(c) 2015, 2014 and 2013 exclude \$46 million, \$48 million and \$44 million of ancillary activity revenues. 2014 and 2013 also exclude \$65 million and \$45 million of revenue reductions related to adjustments to WPD's line loss accrual related to DPCR4 which are considered special items.

The following after-tax loss, which management considers a special item, impacted the Pennsylvania Regulated segment's results and is excluded from Earnings from Ongoing Operations.

	Income Statement Line Item	2015	2014	2013
Separation benefits, net of tax of \$0, \$1, \$0 (a)	Other operation and maintenance		\$ (2)	

(a) In June 2014, PPL Electric's largest IBEW local ratified a new three-year labor agreement. In connection with the new agreement, bargaining unit one-time voluntary retirement benefits were recorded.

CONSOLIDATED STATEMENTS OF INCOME FOR THE YEARS ENDED DECEMBER 31,
PPL Electric Utilities Corporation and Subsidiaries
(Millions of Dollars)

	2018	2017	2016
Operating Revenues	\$ 2,277	\$ 2,195	\$ 2,156
Operating Expenses			
Operation			
Energy purchases	544	507	535
Other operation and maintenance	578	572	602
Depreciation	352	309	253
Taxes, other than income	109	107	105
Total Operating Expenses	1,583	1,495	1,495
Operating Income	694	700	661
Other Income (Expense) - net	23	12	20
Interest Income from Affiliate	8	5	—
Interest Expense	159	142	129
Income Before Income Taxes	566	575	552
Income Taxes	136	213	212
Net Income (a)	\$ 430	\$ 362	\$ 340

(a) Net income equals comprehensive income.

The accompanying Notes to Financial Statements are an integral part of the financial statements.

Reconciliation of Adjusted Gross Margins

The following tables contain the components from the Statement of Income that are included in the non-GAAP financial measures and a reconciliation to PPL's "Operating Income" for the years ended December 31.

	2018				
	U.K. Adjusted Gross Margins	Kentucky Adjusted Gross Margins	Pennsylvania Adjusted Gross Margins	Other (a)	Operating Income (b)
Operating Revenues	\$ 2,230 (c)	\$ 3,214	\$ 2,277	\$ 64	\$ 7,785
Operating Expenses					
Fuel	—	799	—	—	799
Energy purchases	—	201	544	—	745
Other operation and maintenance	141	98	121	1,623	1,983
Depreciation	—	70	35	989	1,094
Taxes, other than income	—	5	104	203	312
Total Operating Expenses	141	1,173	804	2,815	4,933
Total	\$ 2,089	\$ 2,041	\$ 1,473	\$ (2,751)	\$ 2,852

	2017				
	U.K. Adjusted Gross Margins	Kentucky Adjusted Gross Margins	Pennsylvania Adjusted Gross Margins	Other (a)	Operating Income (b)
Operating Revenues	\$ 2,050 (c)	\$ 3,156	\$ 2,195	\$ 46	\$ 7,447
Operating Expenses					
Fuel	—	759	—	—	759
Energy purchases	—	178	507	—	685
Other operation and maintenance	98	111	120	1,473	1,802
Depreciation	—	64	21	923	1,008
Taxes, other than income	—	6	102	184	292
Total Operating Expenses	98	1,118	750	2,580	4,546
Total	\$ 1,952	\$ 2,038	\$ 1,445	\$ (2,534)	\$ 2,901

	2016				
	U.K. Adjusted Gross Margins	Kentucky Adjusted Gross Margins	Pennsylvania Adjusted Gross Margins	Other (a)	Operating Income (b)
Operating Revenues	\$ 2,165 (c)	\$ 3,141	\$ 2,156	\$ 55	\$ 7,517
Operating Expenses					
Fuel	—	791	—	—	791
Energy purchases	—	171	535	—	706
Other operation and maintenance	98	109	108	1,542	1,857
Depreciation	—	56	—	870	926

Taxes, other than income	—	5	99	197	301
Total Operating Expenses	98	1,132	742	2,609	4,581
Total	\$ 2,067	\$ 2,009	\$ 1,414	\$ (2,554)	\$ 2,936

- (a) Represents amounts excluded from Adjusted Gross Margins.
 (b) As reported on the Statements of Income.
 (c) 2018, 2017 and 2016 exclude \$38 million, \$41 million and \$42 million of ancillary revenues.

The following after-tax gains (losses), which management considers special items, impacted the Pennsylvania Regulated segment's results and are excluded from Earnings from Ongoing Operations.

	Income Statement Line Item	2018	2017	2016
IT transformation, net of tax of \$2, \$0, \$0 (a)	Other operation and maintenance	\$ (5)	\$ —	\$ —
U.S. tax reform (b)	Income Taxes	—	10	—
Total		\$ (5)	\$ 10	\$ —

- (a) In June 2018, PPL EU Services' IT department announced an internal reorganization. As a result, \$5 million of after-tax costs, which includes separation benefits as well as outside services for strategic consulting to establish the new IT organization, were incurred. See Note 13 to the Financial Statements for additional information.
 (b) During 2017, PPL recorded a deferred income tax benefit for the enactment of the TCJA. See Note 6 to the Financial Statements for additional information.

**CONSOLIDATED STATEMENTS OF INCOME FOR THE YEARS ENDED DECEMBER 31,
 PPL Electric Utilities Corporation and Subsidiaries**

(Millions of Dollars)

	2020	2019	2018
Operating Revenues	\$ 2,331	\$ 2,358	\$ 2,277
Operating Expenses			
Operation			
Energy purchases	491	549	544
Other operation and maintenance	513	566	578
Depreciation	403	386	352
Taxes, other than income	107	112	109
Total Operating Expenses	1,514	1,613	1,583
Operating Income	817	745	694
Other Income (Expense) - net	18	25	23
Interest Income from Affiliate	2	6	8
Interest Expense	173	170	159
Income Before Income Taxes	664	606	566
Income Taxes	167	149	136
Net Income (a)	\$ 497	\$ 457	\$ 430

(a) Net income equals comprehensive income.

The accompanying Notes to Financial Statements are an integral part of the financial statements.

Reconciliation of Adjusted Gross Margins

The following tables contain the components from the Statement of Income that are included in the non-GAAP financial measures and a reconciliation to PPL's "Operating Income" for the years ended December 31:

	2020					Operating Income (b)
	U.K. Adjusted Gross Margins	Kentucky Adjusted Gross Margins	Pennsylvania Adjusted Gross Margins	Other (a)	Total	
Operating Revenues	\$ 2,095 (c)	\$ 3,106	\$ 2,331	\$ 75	\$ 7,607	
Operating Expenses						
Fuel	—	632	—	—	632	
Energy purchases	—	143	491	—	634	
Other operation and maintenance	141	91	91	1,621	1,944	
Depreciation	—	154	53	1,080	1,287	
Taxes, other than income	—	5	107	195	307	
Total Operating Expenses	141	1,025	742	2,896	4,804	
Total	\$ 1,954	\$ 2,081	\$ 1,589	\$ (2,821)	\$ 2,803	
	2019					Operating Income (b)
	U.K. Adjusted Gross Margins	Kentucky Adjusted Gross Margins	Pennsylvania Adjusted Gross Margins	Other (a)	Total	
Operating Revenues	\$ 2,129 (c)	\$ 3,206	\$ 2,358	\$ 76	\$ 7,769	
Operating Expenses						
Fuel	—	709	—	—	709	
Energy purchases	—	174	549	—	723	
Other operation and maintenance	131	92	125	1,637	1,985	
Depreciation	—	116	50	1,033	1,199	
Taxes, other than income	—	4	107	202	313	
Total Operating Expenses	131	1,095	831	2,872	4,929	
Total	\$ 1,998	\$ 2,111	\$ 1,527	\$ (2,796)	\$ 2,840	

(a) Represents amounts excluded from Adjusted Gross Margins.

(b) As reported on the Statements of Income.

(c) 2020 and 2019 exclude \$38 million of ancillary revenues.

The following after-tax gains (losses), which management considers special items, impacted the Pennsylvania Regulated segment's results and are excluded from Earnings from Ongoing Operations:

	Income Statement Line Item		2020	2019
			\$	\$
COVID-19 impact, net of tax of \$0, \$0 (a)	Other operation and maintenance		(1)	—
Total			(1)	—

(a) Incremental costs for outside services, personal protective equipment and other safety related actions associated with the COVID-19 pandemic.

Division 1-39

Request:

Please provide any plans developed by PPL or PPL RI “to modernize and harden the Rhode Island electric grid and facilitate the transition to more renewable energy resources, greater energy efficiency, better demand and load control, and electrification of the transportation sector,” as referenced in the testimony of Gregory N. Dudkin (at 31:7-11).

Response:

PPL and PPL RI have not yet developed specific plans to modernize and harden the Rhode Island electric grid to help facilitate the transition to more renewable energy resources, greater energy efficiency, better demand and load control, and electrification of the transportation sector. The basis for Mr. Dudkin's statement is the experience of PPL Electric Utilities Corporation (“PPL Electric”). For the past ten years, PPL Electric has worked to both innovate and implement a new concept of the electrical grid. This grid of the future will be able to better manage traditional power and renewable energy resources, better positioning the grid to provide customers with safe, reliable and cost-efficient electricity when and where they need it.

PPL Electric's grid modernization efforts focused on developing telemetered systems that are leveraged by centralized operations systems to provide industry-leading safety, reliability, power quality, and customer satisfaction for its employees and customers. For details of PPL Electric's grid modernization efforts, please refer to Response to Division 1-35.

PPL CORPORATION, PPL RHODE ISLAND HOLDINGS, LLC,
NATIONAL GRID USA, and THE NARRAGANSETT ELECTRIC COMPANY

Docket No. D-21-09

PPL Corporation and PPL Rhode Island Holdings, LLC's
Responses to Division's First Set of Data Requests

Issued on June 8, 2021

Division 1-40

Request:

Referencing the Testimony of Lonnie Bellar at 7:4-7, identify the “nearly 20 gas operations functions” and provide all Documents related to the plans for which PPL and Narragansett are currently “crafting [integration and transition] plans.”

Response:

The gas operations functions for which PPL, PPL RI and Narragansett are currently crafting specific plans at this time are: Gas Engineering; Gas Asset Management Services; Resource Management, Investment Planning and Dispatching; Gas Complex Capital Construction Services; Pipeline Safety and Compliance; Mandated Programs including Leak Survey Support; Gas Control Center Operations; LNG Operations; Gas Meter Operations/Meter Shop; Customer Meter Support; Technical Training; Emergency Planning; Gas and Electric Loading Forecasting; Gas Procurement Services – General; Energy Transactions (Physical Transactions); Energy Transactions (Financial); Retail Choice Programs. In addition to these gas specific functions, the transition and integration process includes the development of plans for numerous additional functions that will support both gas and electric operations. The parties are continuing to negotiate the terms and conditions of the Transition Service Agreement. Accordingly, PPL and PPL RI will supplement this response as appropriate as new milestones are met.

Additionally, PPL and PPL RI refer to Attachments NG-DIV 1-28-2-3 through 1-28-2-4 for the draft version of the TSA schedules related to gas operation functions as of June 25, 2021.

Division 1-41

Request:

Referencing Mr. Bellar's testimony at 10:12-14, please identify whether PPL intends to continue the Gas Business Enablement Program as it currently exists after the close of the Transaction, or whether it will discontinue that program (whether partially or entirely).

Response:

PPL and PPL RI are in the process of negotiating the services that will be provided pursuant to the Transition Services Agreement (the "TSA"). Currently, PPL and PPL RI anticipate that National Grid USA Service Company, Inc. will provide at least a portion of the Gas Business Enablement Program ("GBE") under the TSA starting on day one after closing of PPL RI's purchase of The Narragansett Electric Company, and, initially, PPL and PPL RI will use some of the GBE functionality. PPL continues to evaluate whether it will continue to use, in whole or in part, GBE after the expiration of the TSA, or if PPL will transfer this functionality to its own systems.

PPL and PPL RI will base their decision whether to continue to use GBE components on whether PPL and PPL RI can feasibly, effectively, and efficiently maintain and integrate each such component into PPL and PPL RI's systems and operations at a reasonable cost and without impacting the provision of safe and reliable service to Narragansett ratepayers. Throughout the transition and integration process, during the pendency of this proceeding and afterward, PPL and PPL RI will work to ensure they provide Information Technology systems and services that deliver excellent service without increases in costs to customers.

Division 1-42

Request:

Referencing Mr. Bellar's testimony at 11:4-6, please:

- a. Provide the date by which the PPL expects to have established the "Rhode Island-dedicated gas control center";
- b. Provide the most recent cost estimate for the PPL gas control center; and
- c. Please confirm that none of those costs will be charged to ratepayers. If that is not the case, please identify the cost components that PPL plans to recover from ratepayers, and state the basis for such recovery.

Response:

- a. PPL and PPL RI continue to develop schedules to establish the Rhode Island dedicated gas control center ("GCC"). The current estimate to establish the GCC no later than two years after closing. National Grid USA Service Company, Inc. will provide gas control center support under the Transition Service Agreement ("TSA") until the GCC is operational.
- b. PPL and PPL RI do not currently have cost estimates for the GCC. Once PPL and PPL RI have prepared such cost estimates, they will provide a supplemental response to this data request.
- c. PPL and PPL RI do not plan to seek recovery from ratepayers for the costs associated with the GCC that do not relate to new or improved technology capabilities to Narragansett, or for costs related to capital investments that would not have been made in the normal course of business for reasons including but not limited to obsolescence. These costs would be recoverable in the ordinary course of business in the absence of PPL RI's purchase of Narragansett, subject to ordinary regulatory and prudence review. PPL and PPL RI will seek recovery for any such costs pursuant to the appropriate cost recovery mechanisms Narragansett already has in place with the Rhode Island Public Utilities Commission and the Rhode Island Division of Public Utilities and Carriers, under existing statutes, rules, and tariffs.

PPL CORPORATION, PPL RHODE ISLAND HOLDINGS, LLC,
NATIONAL GRID USA, and THE NARRAGANSETT ELECTRIC COMPANY

Docket No. D-21-09

PPL Corporation and PPL Rhode Island Holdings, LLC's
Responses to Division's First Set of Data Requests

Issued on June 8, 2021

Division 1-43

Request:

Referencing Mr. Dudkin's statement in his testimony (at 30:12-14) that "PPL will work to integrate Narragansett into its existing operations and make infrastructure investments that will enhance reliability and resiliency," please provide any plans or Documents related to such integration.

Response:

Counsel for PPL, PPL RI, National Grid USA ("National Grid"), The Narragansett Electric Company ("Narragansett"), and The Rhode Island Division of Public Utilities and Carriers Advocacy Section (the "Division Advocacy Section") met and conferred regarding the breadth and scope of certain data requests. After that meet and confer, the Division Advocacy Section sent a letter, dated June 22, 2021, advising that PPL, PPL RI, National Grid, and Narragansett can "use sound judgment and the rule of reason in crafting responses and providing responsive documents." The Division Advocacy Section also advised in the June 22, 2021 letter PPL, PPL RI, National Grid, and Narragansett to "consider the Advocacy Section's goal of protecting ratepayers when determining scope and relevancy." Based on the scope and breadth of this request, PPL and PPL RI have applied the rule of reason and used sound judgment in limiting the breadth and scope of documents produced in response to this request, and have considered the Division Advocacy Section's goal of protecting ratepayers in determining which documents it will produce.

PPL and PPL RI at this time have not prepared formal plans or Documents related to integrating Narragansett into their operations and making infrastructure investments that will enhance reliability and resiliency. Mr. Dudkin's statement is based upon the experience of PPL Electric Utilities Corporation ("PPL Electric") in making infrastructure investments that have enhanced the reliability and resiliency of PPL Electric's transmission and distribution systems. Please refer to Response to Division 1-35.

Division 1-44

Request:

Please state whether PPL has identified any compatibility issues with integrating the existing Narragansett/National Grid and PPL information systems. Please provide any analyses, assessments, or studies of compatibility issues, including any plans that have been developed to address identified or perceived incompatibilities. In addition, please (a) provide any cost estimates associated with resolving any incompatibilities; and (b) confirm that PPL does not intend to recover the costs of addressing any such incompatibilities from Narragansett ratepayers.

Response:

PPL and PPL RI are in the process of evaluating the technologies and associated systems currently utilized for the operation of The Narragansett Electric Company ("Narragansett"). Currently, PPL and PPL RI are working with National Grid USA to better understand the current technology ecosystem. Based on the current status of the evaluation and information learned to date, PPL and PPL RI expect that there will be few incompatibility issues in the near term transition. During the transition and integration, PPL, PPL RI and National Grid USA and its affiliate National Grid USA Service Company, Inc. will have Transition Service Agreements ("TSAs") in place to ensure the continued safe and reliable operation of Narragansett, including the information systems necessary for Narragansett's operations. PPL and PPL RI anticipate that, at the start of the transition period, Narragansett will continue to use the majority of the National Grid USA Information Technology platforms, and, throughout the transition period, PPL and PPL RI will gradually transition Narragansett's information systems and information technology operations on to PPL systems.

PPL and PPL RI do not currently have cost estimates for the transition of Narragansett's information systems and information technology operations over to PPL's systems. Once PPL and PPL RI have prepared such cost estimates, they will provide a supplemental response to this data request.

PPL and PPL RI do not plan to seek recovery for technology transition activities that do not provide new or improved technology capabilities to Narragansett, or for capital investments that would not have been made in the normal course of business for reasons including but not limited to obsolescence.

PPL CORPORATION, PPL RHODE ISLAND HOLDINGS, LLC,
NATIONAL GRID USA, and THE NARRAGANSETT ELECTRIC COMPANY

Docket No. D-21-09

PPL Corporation and PPL Rhode Island Holdings, LLC's
Responses to Division's First Set of Data Requests

Issued on June 8, 2021

Division 1-45

Request:

Following the close of the Transaction, will Narragansett be included in any mutual assistance agreements among the PPL family of companies? If so, please provide copies of any such agreements.

Response:

It is anticipated that The Narragansett Electric Company ("Narragansett") will be included in a mutual assistance agreement with PPL's existing utilities, PPL Electric Utilities, Louisville Gas & Electric, and Kentucky Utilities. PPL and PPL RI also expect to enter into a mutual assistance agreement between the relevant operating entities of PPL and National Grid USA. To date, there are not yet any written agreements for either of the above-identified mutual assistance agreements. PPL and PPL RI will supplement this response as appropriate when such written agreements are finalized.

Additionally, Narragansett will remain a party to mutual assistance agreements with Edison Electric Institute, attached hereto as PPL-DIV-1-45-1 and with Northeast Gas Association and Southern Gas Association, attached hereto as PPL-DIV-1-45-2.



Edison Electric Institute Mutual Assistance Agreement

Edison Electric Institute (“EEI”) member companies have established and implemented an effective system whereby member companies may receive and provide assistance in the form of personnel and equipment to aid in restoring and/or maintaining electric utility service when such service has been disrupted by acts of the elements, equipment malfunctions, accidents, sabotage, or any other occurrence for which emergency assistance is deemed to be necessary or advisable (“Emergency Assistance”). This Mutual Assistance Agreement sets forth the terms and conditions to which the undersigned EEI member company (“Participating Company”) agrees to be bound on all occasions that it requests and receives (“Requesting Company”) or provides (“Responding Company”) Emergency Assistance from or to another Participating Company who has also signed the EEI Mutual Assistance Agreement; provided, however, that if a Requesting Company and one or more Responding Companies are parties to another mutual assistance agreement at the time of the Emergency Assistance is requested, such other mutual assistance agreement shall govern the Emergency Assistance among those Participating Companies.

In consideration of the foregoing, the Participating Company hereby agrees as follows:

1. When providing Emergency Assistance to or receiving Emergency Assistance from another Participating Company, the Participating Company will adhere to the written principles developed by EEI members to govern Emergency Assistance arrangements among member companies (“EEI Principles”), that are in effect as of the date of a specific request for Emergency Assistance, unless otherwise agreed to in writing by each Participating Company.
2. With respect to each Emergency Assistance event, Requesting Companies agree that they will reimburse Responding Companies for all costs and expenses incurred by Responding Companies in providing Emergency Assistance as provided under the EEI Principles, unless otherwise agreed to in writing by each Participating Company; provided, however, that Responding Companies must maintain auditable records in a manner consistent with the EEI Principles.
3. During each Emergency Assistance event, the conduct of the Requesting Companies and the Responding Companies shall be subject to the liability and indemnification provisions set forth in the EEI Principles.
4. A Participating Company may withdraw from this Agreement at any time. In such an event, the company should provide written notice to EEI’s Vice President of Security and Preparedness or his/her designee.

5. EEI's Senior Director of Preparedness and Recovery Policy or his/her designee who shall maintain a list of each Mutual Assistance Agreement Participating Company Signatory which shall be posted in the RestorePower Workroom as <https://eei-restorepower.groupsie.com/page/mutual-assistance-agreement> .

Company Name

Signature

Officer Name:

Title:

Date:



SUGGESTED GOVERNING PRINCIPLES COVERING EMERGENCY ASSISTANCE ARRANGEMENTS BETWEEN EDISON ELECTRIC INSTITUTE MEMBER COMPANIES

Electric companies have occasion to call upon other companies for emergency assistance in the form of personnel or equipment to aid in maintaining or restoring electric utility service when such service has been disrupted by acts of the elements, equipment malfunctions, accidents, sabotage or any other occurrences where the parties deem emergency assistance to be necessary or advisable. While it is acknowledged that a company is not under any obligation to furnish such emergency assistance, experience indicates that companies are willing to furnish such assistance when personnel or equipment are available.

In the absence of a continuing formal contract between a company requesting emergency assistance ("Requesting Company") and a company willing to furnish such assistance ("Responding Company"), the following principles are suggested as the basis for a contract governing emergency assistance to be established at the time such assistance is requested:

1. The emergency assistance period shall commence when personnel and/or equipment expenses are initially incurred by the Responding Company in response to the Requesting Company's needs. (This would include any request for the Responding Company to prepare its employees and/or equipment for transport to the Requesting Company's location but to await further instructions before departing). The emergency assistance period shall terminate when such employees and/or equipment have returned to the Responding Company, and shall include any mandated DOT rest time resulting from the assistance provided and reasonable time required to prepare the equipment for return to normal activities (e.g. cleaning off trucks, restocking minor materials, etc.).
2. To the extent possible, the companies should reach a mutual understanding and agreement in advance on the anticipated length – in general – of the emergency assistance period. For extended assistance periods, the companies should agree on the process for replacing or providing extra rest for the Responding Company's employees. It is understood and agreed that if, in the Responding Company's judgment such action becomes necessary the decision to terminate the assistance and recall employees, contractors, and equipment lies solely with the Responding Company. The Requesting Company will take the necessary action to return such employees, contractors, and equipment promptly.
3. Employees of Responding Company shall at all times during the emergency assistance period continue to be employees of Responding Company and shall not be deemed employees of Requesting Company for any purpose. Responding Company shall be an independent Contractor of Requesting Company and wages, hours and other terms and conditions of employment of Responding Company shall remain applicable to its employees during the emergency assistance period.
4. Responding Company shall make available upon request supervision in addition to crew leads. All instructions for work to be done by Responding Company's crews shall be given by

Requesting Company to Responding Company's supervision; or, when Responding Company's crews are to work in widely separate areas, to such of Responding Company's crew lead as may be designated for the purpose by Responding Company's supervision.

5. Unless otherwise agreed by the companies, Requesting Company shall be responsible for supplying and/or coordinating support functions such as lodging, meals, materials, etc. As an exception to this, the Responding Company shall normally be responsible for arranging lodging and meals en route to the Requesting Company and for the return trip home. The cost for these in transit expenses will be covered by the Requesting Company.
6. Responding Company's safety rules shall apply to all work done by their employees. Unless mutually agreed otherwise, the Requesting Company's switching and tagging rules should be followed to ensure consistent and safe operation. Any questions or concerns arising about any safety rules and/or procedures should be brought to the proper level of management for prompt resolution between management of the Requesting and Responding Companies.
7. All time sheets and work records pertaining to Responding Company's employees furnishing emergency assistance shall be kept by Responding Company.
8. Requesting Company shall indicate to Responding Company the type and size of trucks and other equipment desired as well as the number of job function of employees requested but the extent to which Responding Company makes available such equipment and employees shall be at Responding Company's sole discretion.
9. Requesting Company shall reimburse Responding Company for all costs and expenses incurred by Responding Company as a result of furnishing emergency assistance. Responding Company shall furnish documentation of expenses to Requesting Company. Such costs and expenses shall include, but not be limited to, the following:
 - a. Employees' wages and salaries for paid time spent in Requesting Company's service area and paid time during travel to and from such service area, plus Responding Company's standard payable additives to cover all employee benefits and allowances for vacation, sick leave and holiday pay and social and retirement benefits, all payroll taxes, workmen's compensation, employer's liability insurance and other contingencies and benefits imposed by applicable law or regulation.
 - b. Employee travel and living expenses (meals, lodging and reasonable incidentals).
 - c. Replacement cost of materials and supplies expended or furnished.
 - d. Repair or replacement cost of equipment damaged or lost.
 - e. Charges, at rates internally used by Responding Company, for the use of transportation equipment and other equipment requested.
 - f. Administrative and general costs, which are properly allocable to the emergency assistance to the extent such costs, are not chargeable pursuant to the foregoing subsections.
10. Requesting Company shall pay all costs and expenses of Responding Company within sixty days after receiving a final invoice therefor.

11. Requesting Company shall indemnify, hold harmless and defend the Responding Company from and against any and all liability for loss, damage, cost or expense which Responding Company may incur by reason of bodily injury, including death, to any person or persons or by reason of damage to or destruction of any property, including the loss of use thereof, which result from furnishing emergency assistance and whether or not due in whole or in part to any act, omission, or negligence of Responding Company except to the extent that such death or injury to person, or damage to property, is caused by the willful or wanton misconduct and / or gross negligence of the Responding Company. Where payments are made by the Responding Company under a workmen's compensation or disability benefits law or any similar law for bodily injury or death resulting from furnishing emergency assistance, Requesting Company shall reimburse the Responding Company for such payments, except to the extent that such bodily injury or death is caused by the willful or wanton misconduct and / or gross negligence of the Responding Company.
12. In the event any claim or demand is made or suit or action is filed against Responding Company alleging liability for which Requesting Company shall indemnify and hold harmless Responding Company under paragraph (11) above, Responding Company shall promptly notify Requesting Company thereof, and Requesting Company, at its sole cost and expense, shall settle, compromise or defend the same in such manner as it in its sole discretion deems necessary or prudent. Responding Company shall cooperate with Requesting Company's reasonable efforts to investigate, defend and settle the claim or lawsuit.
13. Non-affected companies should consider the release of contractors during restoration activities. The non-affected company shall supply the requesting companies with contact information of the contactors (this may be simply supplying the contractors name). The contractors will negotiate directly with requesting companies.

Date	Description
October 2014	Sections 4, 5, and 10
September 2005	Sections 11 and 12

(5) EEI's Director of Security of Transmission and Distribution Operations shall maintain a list of each Participating Company which shall be posted on the RestorePower web site at www.restorepower.com. However, a Participating Company may request a copy of the signed Mutual Assistance Agreement of another Participating Company prior to providing or receiving Emergency Assistance.

National Grid
Company Name

R. Francario
Signature

Officer Name: *Richard Francario.*
Title: *Dir Emergency Planning*
Date: *10/25/07*

NGA and SGA Mutual Assistance Agreement – June 1, 2015

Northeast Gas Association and Southern Gas Association

Mutual Assistance Agreement

Approved June 1, 2015

As directed by the Board of Directors of the Northeast Gas Association (“NGA”) and Southern Gas Association (“SGA”), NGA’s Operations Managing Committee and SGA’s Distribution Operations and Engineering Section Managing Committee have developed and approved the following Mutual Assistance Agreement (“Agreement”) for Members to request and provide emergency assistance in the form of personnel, supplies and/or equipment, to aid in restoring gas service when it has been disrupted and cannot be restored in a safe and timely manner by the affected company or companies alone. Committee Members recognize the significant differences between work performed under normal circumstances and emergency restoration, as well as the fact that each Member may, at any given point, both require as well render emergency assistance. Therefore, the Members have reached an understanding and agreement to adhere to the terms and conditions contained herein.

NGA’s Operations Managing Committee and SGA’s Distribution Operations and Engineering Section Managing Committee shall have joint responsibility for the maintenance and revision of this Agreement and all associated mutual assistance documents including the Northeast Gas Association and Southern Gas Association Mutual Assistance Procedures and Guidelines (Exhibit A “MA Procedures and Guidelines”).

1. Members (“Members”) understand and agree:

- 1.1 This document, as well as any future approved modifications, amendments or revisions, shall be known as the Northeast Gas Association and Southern Gas Association Mutual Assistance Agreement (“NGA and SGA Mutual Assistance Agreement” or “Agreement”).¹
- 1.2 Members will make a good faith effort to provide assistance to aid in restoring gas service when aid is needed by another Member company. Nothing in this Agreement commits, binds or otherwise obligates a Member to respond to any particular request for assistance; Members will, however, follow the terms and conditions set forth herein if they are able and choose to respond to a Requesting Company’s need for assistance.
- 1.3 Members will work together to minimize risk to all parties. Responding Company will provide assistance (which may include personnel, equipment, and/ or materials) on a not-for-profit basis, and Requesting Company will reimburse

¹ In this Agreement the terms “Responding Company” and “Requesting Company” refer to both the company and its employees or contractors.

NGA and SGA Mutual Assistance Agreement – June 1, 2015

Responding Company for all direct and indirect costs and expenses incurred in providing the assistance.

- 1.4 To adhere to and operate in accordance with the procedures contained in this Agreement.
- 1.5 Should there be a conflict in procedures and guidelines contained in this Agreement and any other regional or national mutual assistance agreements, guidelines, principles, or procedures, Members shall adhere to the provisions of this Agreement when assisting or requesting assistance from fellow Members.
- 1.6 Members reserve the right to respond or not respond to a request for assistance on a case-by-case basis in their sole and absolute discretion.
- 1.7 At all times, employees of a Responding Company continue to be employees of that Responding Company and are not ever deemed to be employees of a Requesting Company.
- 1.8 Wages, hours and other terms and conditions of employment of Responding Company shall apply to its employees at all times.
- 1.9 Other than as noted below, a Member company may withdraw from participation under this Agreement at any time by providing written notice to the President of NGA or SGA. Such notice shall not affect any obligations which may arise out of the events occurring prior to the date of such notice. No Requesting Company may withdraw from participation under this Agreement while it is receiving assistance pursuant to the terms of this Agreement.

2. Personnel Safety

- 2.1 Whether providing or receiving assistance, the safety of all personnel and the general public will be the preeminent objective and responsibility of all participant Members. The Responding Company and the Requesting Company will make all reasonable efforts under the circumstances to provide for adequate safety measures, including necessary involvement of police or governmental agencies, to ensure and otherwise protect the safety of all personnel and the general public.
- 2.2 In the event the Responding Company or its employees are party to any incident involving damage to persons or property, Responding Company will report and document the specifics of such incident to Requesting Company as soon as practicable after any such incident.
- 2.3 Responding Company will follow its own safety rules, except as may otherwise be agreed to in this Section 2.3. Where the Responding Company and Requesting Company's safety procedures differ, prior to mobilization the companies shall agree which procedures the Responding Company will follow. If

NGA and SGA Mutual Assistance Agreement – June 1, 2015

any of the Requesting Company's procedures are used, the Requesting Company will provide the necessary training and orientation for the Responding Company's employees. Any questions or concerns arising from any safety rules and/or procedures should be promptly resolved by the appropriate level of management of each of the Requesting Company and Responding Company.

3. Definition of Emergency Assistance Period

- 3.1 Members agree that the "Emergency Assistance Period" shall commence when personnel and/or equipment expenses are initially incurred by the Responding Company in response to the Requesting Company's authorization to proceed. This includes any request for the Responding Company to prepare its employees and/or equipment for travel to the Requesting Company's location and to await further instructions before departing. Except as noted in Section 3.3 below, the Emergency Assistance Period shall terminate when such employees and/or equipment have returned to their point of origin, and shall include any mandated DOT reset time and reasonable time required to prepare the equipment for return to normal service activities (e.g. cleaning trucks, restocking minor materials, etc.).
- 3.2 The length of stay/response by Responding Company personnel will be mutually agreed to by both companies. This period should not exceed fourteen (14) consecutive days, including travel time to the work area and return to the point of origin. When mutual assistance assignments go beyond this timeframe, Members agree that Responding Company personnel will usually be changed out (rotated) rather than take extended reset periods (days off). The Responding Company and Requesting Company may mutually agree to exceptions to this Section 3.2.
- 3.3 It is understood and agreed that Responding Company can, in its sole independent judgment, during any time after it has mobilized to provide emergency assistance hereunder recall any or all of its employee and/or contract workforce. In these instances:
 - a. It is understood and agreed that the decision to terminate assistance and recall employees lies solely with the Responding Company.
 - b. If a recall of Responding Company's workforce becomes necessary, the Requesting Company will be responsible for all expenses incurred by Responding Company up to the time of recall, as well as return travel costs to the workforce's point of origin and any needed retrofit of equipment as described above.
 - c. If Responding Company's workforce is recalled to a location other than their point of origin, the Requesting Company will be responsible for travel costs not to exceed that which would have been incurred had the workforce returned to their original point of origin.

4. Requesting Company Responsibilities

NGA and SGA Mutual Assistance Agreement – June 1, 2015

- 4.1 The Requesting Company is expected to inform the Responding Company prior to deployment if their requirements for maintaining and furnishing receipts differs from the procedures stated in this Agreement or the MA Procedures and Guidelines document.
- 4.2 The Requesting Company will notify each Responding Company twenty four (24) hours in advance of the anticipated release off/termination of emergency assistance by their utility and contract crews.
- 4.3 Members understand and agree that the provision of emergency mutual assistance is a not-for-profit endeavor for Responding Companies. Therefore, the Requesting Company will reimburse all reasonable and actual costs and expenses incurred by the Responding Company in the provision of the emergency assistance for the entire Emergency Assistance Period as defined in Section 3. Responding Company shall furnish substantiating documentation (including receipts) of costs and expenses to Requesting Company. Such costs and expenses shall include, but not be limited to, the following:
 - a. Employees' wages and salaries including applicable overheads (employee benefits such as vacation, sick time, social security, retirement benefits, workman's compensation and other contingencies and benefits imposed by applicable laws or regulations).
 - b. Employee travel and living expenses (meals, lodging and reasonable incidentals – beer, wine or other alcoholic beverages are not considered reasonable incidentals and will not be covered).
 - c. Replacement cost of materials and supplies expended or furnished.
 - d. Repair or replacement cost of equipment damaged or lost.
 - e. Charges, at rates internally used by Responding Company, for the use of transportation equipment and other equipment requested.
 - f. Administrative and general costs, which are properly allocable to the emergency assistance to the extent such costs, are not chargeable pursuant to the foregoing subsections.
- 4.4 If Responding Company resources are released after mobilization but before being utilized, the Requesting Company will reimburse Responding Company for all incurred preparation and travel expenses (from and to the point of origin), including any mandated DOT reset time and reasonable time required to prepare the equipment for return to normal activities after returning to their point of origin.
- 4.5 During emergencies impacting more than one Member, Responding Company resources may be re-assigned either: en route to the Requesting Company; at an

NGA and SGA Mutual Assistance Agreement – June 1, 2015

initial staging area before reaching the Requesting Company; or at the Responding Company's final staging area. Additionally, resources may be assigned to assist a second Requesting Company after completing work for the initial Requesting Company. In any of these instances, unless otherwise mutually agreed or stated in this Agreement, the Requesting Company receiving the re-assigned Responding Company resources will be responsible for all Responding Company costs from the time of re-assignment.

- 4.6 "Host Companies" are those companies who may provide staging areas or other resources to a Responding Company. Requesting Company will reimburse Host Company for expenses incurred in the provision and management of interim staging areas (i.e. labor and miscellaneous expenses provided by the host company to operate the staging area, but not including any Responding Company crew costs). In emergencies involving more than one Requesting Company, staging costs will be shared by Requesting Companies on a prorated basis based on the resources committed to each Requesting Company entering (logged into) the staging site.
- 4.7 Provided proper supporting documentation is included, the Requesting Company will pay invoice(s) from Responding Company within sixty (60) calendar days after receipt of invoice(s).

5. Responding Company Responsibilities

- 5.1 Responding Company will maintain daily records of time and expenses for personnel and equipment. This documentation will be provided with its Preliminary Invoice.
- 5.2 When the Requesting Company has provided specific guidance in advance that differs from that in Section 5.3, the Responding Company will maintain and furnish the requested documentation of expenses with their Preliminary Invoice.
- 5.3 Unless otherwise agreed prior to mobilization, Members agree that Responding Companies will maintain and furnish upon request receipts for all individual expenses / purchases made during the Emergency Assistance Period in accordance with the IRS requirements in effect at the time assistance is requested.
- 5.4 Responding Company will document all work performed and installations in a manner reasonably agreeable to the Requesting Company.
- 5.5 Responding Company shall be an independent Contractor of Requesting Company and wages, hours and other terms and conditions of employment of Responding Company shall remain applicable to its employees during the emergency assistance period.

NGA and SGA Mutual Assistance Agreement – June 1, 2015

- 5.6 Unless otherwise agreed, Responding Company should submit an invoice ("Preliminary Invoice") to Requesting Company within sixty (60) calendar days from the date released by the Requesting Company. Responding Company will provide supporting documentation at the time the Preliminary Invoice is mailed. Requesting Company should receive a final invoice within ninety (90) calendar days from invoice date of Preliminary Invoice.
- 5.7 Responding Company agrees to maintain auditable records of billed expenses for emergency mutual assistance reasonably sufficient to satisfy the legal / statutory requirements and obligations incumbent upon the Requesting Company. It is Requesting Company's responsibility to make those requirements and obligations known to the Responding Company prior to mobilization.
- 5.8 The appropriate vehicle/automobile insurance coverage and workman's compensation coverage for Responding Company personnel are the sole responsibility of the Responding Company.

6. Indemnification

- 6.1 Requesting Company shall indemnify, defend and hold harmless the Responding Company, its employees, officers, directors, agents and affiliates, from and against any and all actions, claims, liability for loss, damage, cost or expense which Responding Company may incur by reason of bodily injury, including death, to any person or persons or by reason of damage to or destruction of any property, including the loss of use thereof, which results from furnishing emergency assistance under this Agreement and whether or not due in whole or in part to any act, omission, or negligence of Responding Company except to the extent that such death or injury to person, or damage to property, is caused by the willful or wanton misconduct and/or gross negligence of the Responding Company. Where payments are made to Responding Company's employees under a worker's compensation or disability benefits law or any similar law for bodily injury or death resulting from furnishing emergency assistance, Requesting Company shall reimburse the Responding Company for such payments, except to the extent that such bodily injury or death is caused by the willful or wanton misconduct and/or gross negligence of the Responding Company.
- 6.2 In the event any claim or demand is made or suit or action is filed against Responding Company alleging liability for which Requesting Company shall indemnify and hold harmless Responding Company under Section 6.1 above, Responding Company shall promptly notify Requesting Company thereof, and Requesting Company, at its sole cost and expense, shall settle, compromise or defend the same in such manner as it in its sole reasonable discretion deems necessary or prudent.
- 6.3 The provisions of this Section 6 shall remain in effect for a period of five (5) years after the last date on which the Responding Company provided assistance to the Requesting Company, and unless mutually agreed to otherwise, shall be

NGA and SGA Mutual Assistance Agreement – June 1, 2015

governed by and construed in accordance with the laws of the state of the Responding Company.

- 6.4 Each Member Company agrees to carry the minimum amount of twenty-five (25) million dollars liability insurance, including a contractual liability extension specifically covering the indemnification and hold harmless provision set forth in this Agreement and subject to retentions or deductibles, consistent with good business practice in the industry.

7. Governing Law of Agreement

- 7.1 This Agreement shall be governed in accordance with the laws of the State of [Delaware] for all members.

NGA and SGA Mutual Assistance Agreement – June 1, 2015

**Northeast Gas Association and Southern Gas Association Mutual Assistance
Agreement Signature Page**

The undersigned Member company, by signature of its duly authorized representative,
hereby agrees to the foregoing Northeast Gas Association and Southern Gas
Association Mutual Assistance Agreement.

NATIONAL GRID

Company

Robert A. DeMarinis

Date 8/3/15

Company Officer's Signature

ROBERT A. DEMARINIS

VICE PRESIDENT - GAS NY

Printed Name of Officer

Title of Officer

PPL CORPORATION, PPL RHODE ISLAND HOLDINGS, LLC,
NATIONAL GRID USA, and THE NARRAGANSETT ELECTRIC COMPANY
Docket No. D-21-09
PPL Corporation and PPL Rhode Island Holdings, LLC's
Responses to Division's First Set of Data Requests
Issued on June 8, 2021

Division 1-46

Request:

Referencing Mr. Dudkin's testimony at 28:5-6, please state when PPL expects to take over the provision of each of the following services:

- a. meter data services;
- b. mutual assistance for storm response;
- c. electricity procurement;
- d. engineering; and
- e. asset management.

Response:

PPL and PPL RI and National Grid USA Service Company, Inc. ("National Grid") have agreed to a form Transition Service Agreement ("TSA"). Under the TSA, PPL, PPL RI and The Narragansett Electric Company ("Narragansett") are identifying every service for which National Grid will provide services for a period of time after closing. Each of the services identified above in Division 1-46 (a) - (e) may be provided under the TSA, but PPL and PPL RI have not determined the specific time when they expect each of the above-referenced services will be taken over by PPL and PPL RI and no longer be provided under the TSA. PPL and PPL RI will supplement this response once they have determined the time when they expect each of the above services will be taken over by PPL and PPL RI.

PPL CORPORATION, PPL RHODE ISLAND HOLDINGS, LLC,
NATIONAL GRID USA, and THE NARRAGANSETT ELECTRIC COMPANY

Docket No. D-21-09

PPL Corporation and PPL Rhode Island Holdings, LLC's

Responses to Division's First Set of Data Requests

Issued on June 8, 2021

Division 1-47

Request:

Please provide a copy of Schedule 6.9 to the Newquay Disclosure Schedule.

Response:

Please see Attachment DIV 1-47-1 (CONFIDENTIAL) and Attachment DIV 1-47-2 (CONFIDENTIAL).

PPL CORPORATION, PPL RHODE ISLAND HOLDINGS, LLC,
NATIONAL GRID USA, and THE NARRAGANSETT ELECTRIC COMPANY

Docket No. D-21-09

PPL Corporation and PPL Rhode Island Holdings, LLC's
Responses to Division's First Set of Data Requests

Issued on June 8, 2021

Attachments PPL-DIV 1-47-1 to 1-47-2

Confidential Attachments PPL-DIV 1-47-1 to 1-47-2 contain confidential commercial and financial information. PPL and PPL RI have requested protective treatment of these confidential attachments in their entirety.

PPL CORPORATION, PPL RHODE ISLAND HOLDINGS, LLC,
NATIONAL GRID USA, and THE NARRAGANSETT ELECTRIC COMPANY
Docket No. D-21-09
PPL Corporation and PPL Rhode Island Holdings, LLC's
Responses to Division's First Set of Data Requests
Issued on June 8, 2021

Division 1-48

Request:

Please provide PPL's projections of the number of direct Narragansett employees for each of the three years following the close of the Transaction.

Response:

PPL and PPL RI do not currently have projections for the number of direct Narragansett employees for each of the three years following the close of the Transaction. PPL and National Grid continue to work out the details to ensure a smooth transition. National Grid USA Service Company, Inc. will provide certain services to Narragansett under a Transition Service Agreement ("TSA") for up to two years. During this time, services provided will migrate to PPL when the people, processes and technology that are needed are in place to ensure the transition. Organization structures and the filling of the positions are still being developed and implemented. This will continue to evolve for up to two years as PPL completes transition and integration of services and operations to PPL and PPL RI's systems. PPL and PPL RI do not expect any immediate changes to the number of direct Narragansett employees. PPL and PPL RI also refer to their response to data request Division 1-54.

PPL CORPORATION, PPL RHODE ISLAND HOLDINGS, LLC,
NATIONAL GRID USA, and THE NARRAGANSETT ELECTRIC COMPANY

Docket No. D-21-09

PPL Corporation and PPL Rhode Island Holdings, LLC's
Responses to Division's First Set of Data Requests
Issued on June 8, 2021

Division 1-49

Request:

Assuming PPL will need to pay comparatively higher salaries (or offer improved benefit packages) to retain employees of National Grid or its affiliates, including the Service Company, who currently provide services to Narragansett, please explain whether PPL will treat any such wage increases (or the costs of improved benefits) as part of acquisition premiums or transaction costs for which PPL has agreed in its petition not to seek to recover in customer rates.

Response:

PPL and PPL RI do not agree with the assumption that they will need to pay comparatively higher salaries or offer improved benefits packages to retain any employees of National Grid USA or its affiliates, including National Grid USA Service Company, Inc., who currently provide services to The Narragansett Electric Company (the "Potential Retained Employees"). The Share Purchase Agreement does not require PPL or PPL RI to pay higher salaries or offer improved benefits packages. Accordingly, PPL has not evaluated how it would treat any such wage increases or costs of improved benefits.

To the extent that PPL and/or PPL RI agrees to pay any increased salaries or to offer benefits that exceed those currently provided to any of the Potential Retained Employees, PPL and PPL RI will evaluate on a case-by-case basis: (1) the reason for the increased salary or benefit costs, (2) the overall impact on the labor and benefit costs to be incurred by The Narragansett Electric Company ("Narragansett"), and (3) whether PPL RI's purchase of Narragansett was the cause of such costs, and, on the basis of these and any other relevant factors, PPL and PPL RI will determine whether it will seek to recover such costs in customer rates, or whether it will treat them as part of acquisition premium or transaction costs and exclude them from any request for recovery in customer rates.

Division 1-50

Request:

Provide any projections for Narragansett's annual Administrative and General ("A&G") costs, including costs allocated to Narragansett through cost sharing arrangements with National Grid, PPL, or either of their affiliates, through the transition period of the Transaction. In addition:

- a. If the projections show an increase over Narragansett's current annual A&G costs, to what extent are these costs considered acquisition premiums or transaction costs for which PPL has agreed not to seek to recover in customer rates.

Response:

PPL and PPL RI do not currently have projections for Narragansett's annual A&G costs through the transition period. Once PPL and PPL RI have prepared such cost projections, they will provide a supplemental response to this data request.

PPL and PPL RI do not plan to seek recovery of either acquisition premiums or transaction costs in customer rates.

PPL CORPORATION, PPL RHODE ISLAND HOLDINGS, LLC,
NATIONAL GRID USA, and THE NARRAGANSETT ELECTRIC COMPANY

Docket No. D-21-09

PPL Corporation and PPL Rhode Island Holdings, LLC's
Responses to Division's First Set of Data Requests

Issued on June 8, 2021

Division 1-51

Request:

Provide all Documents, including estimates or data, studies, workpapers, reports, and information, related to the permanent headcount reduction that would be attributable to PPL's proposed implementation of smart grid technology. Please delineate the portion of this permanent headcount reduction that is estimated to be direct Narragansett employees.

Response:

PPL has not prepared any Documents, including but not limited to estimates, studies, workpapers, reports, information or other data, related to any potential headcount reduction that would be attributable to PPL's proposed implementation of smart grid technology. PPL does not expect headcount reductions from smart grid investments.

PPL CORPORATION, PPL RHODE ISLAND HOLDINGS, LLC,
NATIONAL GRID USA, and THE NARRAGANSETT ELECTRIC COMPANY

Docket No. D-21-09

PPL Corporation and PPL Rhode Island Holdings, LLC's
Responses to Division's First Set of Data Requests

Issued on June 8, 2021

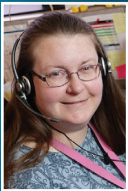
Division 1-52

Request:

Please provide the two most recent reports assessing employee satisfaction and workplace climate for LG&E and KU.

Response:

PPL and PPL RI refer to Attachment PPL-DIV 1-52-1 and Attachment PPL-DIV 1-52-2, which are the two most recent reports assessing employee satisfaction and workplace climate for LG&E and KU.



2019

Employee Opinion Survey

Results



PPL companies

Dear employees,

I am pleased to provide the results from the 2019 Employee Opinion Survey.

With an outstanding 96% participation rate, the 2019 survey demonstrates your active engagement in providing honest feedback and a desire to help improve our workplace. Thank you for letting your voice be heard.

This booklet contains LG&E and KU's overall results for 2019, along with comparative results, where available, from the 2014 and 2017 all-employee surveys to measure our progress since then.

Overall, your 2019 responses reflect excellent results across all survey areas, especially for our safety and wellness culture and customer focus. Your feedback also demonstrates high levels of pride in our company and awareness of LG&E and KU's mission and values. At the same time, we saw significant improvement in the area of growth and development and improvement in our taking action as a result of your feedback, but these are still areas where we scored low relative to other items. Additionally, you indicated a need for us to further focus on cooperation across departments.

We also had 843 individuals respond to the open-ended question: "What other suggestions or comments do you have?" Common themes from those comments will be evaluated over the next several months for action.

Because company leadership is firmly committed to act on the survey results, a series of follow-up activities will occur within work groups and companywide.

Your manager or supervisor will conduct team meetings during the fall to discuss companywide results, as well as specific results for your work group. During these meetings, your team will develop action plans, as needed, to address areas of concern within your work group.

Additionally, the officers determined that they will continue to focus on growth and development along with a focus on cooperation across departments in the upcoming months.

Once again, thank you for participating in the 2019 LG&E and KU Employee Opinion Survey. Your input and active participation in follow-up actions contributes to our future success, and we are committed to listening and responding to your feedback.

Sincerely,



Paul W. Thompson

Chairman, CEO and President



Results for LG&E and KU

Employees were asked to choose one of five responses — “strongly agree,” “agree,” “neutral,” “disagree,” “strongly disagree” — for each statement on the questionnaire. In the results that follow, these five responses have been combined into three broader response categories.

- Favorable (green) = the percentage of employees who responded “strongly agree” and “agree”
- Neutral (yellow) = the percentage of employees who responded “neutral”
- Unfavorable (red) = the percentage of employees who responded “strongly disagree” or “disagree”

Year-to-Year Comparisons

The LG&E and KU results presented in this booklet show comparative data between the 2019 and 2017 all-employee surveys. Where applicable, 2014 results also are provided.

Interpreting the Results

It is recommended that you look first at the percentage of “favorable” responses, which is typically a good indicator of key trends (strengths and weaknesses).

Please note that in some groups, the percentages will not total 100% due to rounding.

Clarity of Direction

<i>I am aware of the company's mission and values.</i>	2019		94%	4%	2%
	2017		95%	4%	1%
<i>I can see a clear link between my work and the company's objectives.</i>	2019		89%	8%	3%
	2017		90%	8%	2%
<i>Leadership keeps employees informed of company matters.</i>	2019		75%	15%	10%
	2017		77%	15%	8%
<i>I have a clear understanding of the goals and objectives of LG&E and KU Energy.</i>	2019		87%	10%	3%
	2017		88%	9%	2%
	2014		69%	24%	7%
<i>I trust our officers to take the necessary actions to move LG&E and KU Energy in the right direction.</i>	2019		81%	15%	4%
	2017		85%	12%	3%
	2014		77%	19%	5%

Continuous Improvement

<i>The company is committed to exceeding our customers' expectations.</i>	2019		92%	7%	2%
	2017		94%	5%	1%
	2014		86%	12%	2%
<i>I am encouraged to share my ideas about improving the company.</i>	2019		72%	18%	10%
	2017		73%	18%	10%
	2014		70%	17%	12%
<i>I believe feedback from this survey will be used to make improvements.</i>	2019		61%	24%	16%
	2017		60%	27%	13%

In my team, we regularly discuss what we can improve.



Process improvement is encouraged in my work group.



My immediate supervisor encourages understanding and readiness for change.



Employee Empowerment

I am appropriately involved in decisions that affect my work.



My job makes good use of my skills and abilities.



I am able to balance my work and personal life.



Growth and Development

Growth and development opportunities are awarded fairly.



I am satisfied with the training I receive for my present job.



My immediate supervisor supports my skill and career development.



I am given the opportunity to grow professionally at the company.



There are growth and development opportunities for me at the company.



Performance Management

In my work group, people are held accountable for results.



My immediate supervisor gives me valuable feedback on my performance.



My immediate supervisor clearly communicates what is expected of me at work.



My immediate supervisor values me for the talent and perspectives I bring.



Pride in Company

Other than retirement, I intend to stay with the company for at least the next 12 months.



My contributions are helping the company reach its goals and objectives.



I am proud to work for LG&E and KU Energy.



I enjoy my day-to-day work.



I would recommend LG&E and KU Energy as a good place to work.



Recognition and Reward

I am paid fairly for my contribution to the company.



My overall benefits package meets my needs.



My work gives me a feeling of personal accomplishment.



My accomplishments are recognized.



Resources and Support

My work environment enables me to be effective in my role.



I have the information I need to do my job.



I have the tools and equipment that I need to be productive.



My department has the personnel resources necessary to do a good job.



I am satisfied with the internal communication (e.g., company announcements, safety/benefits/wellness information, etc.) I receive from the company.



Safety and Wellness

Company wellness initiatives support the health and well-being of employees.



In my work environment, necessary precautions are taken to avoid accidents.



Our company has a continuous focus on safety.



Supervisor Relationship

I am comfortable discussing concerns with my immediate supervisor.



My immediate supervisor cares about me as a person.



My immediate supervisor keeps commitments.



My immediate supervisor treats employees with respect.



My immediate supervisor values my input.



Teamwork and Collaboration

My team is committed to doing high quality work.



My team members work well together.



People at our company trust and respect each other.



There is effective cooperation across departments.



In my work environment, everyone is treated equally, regardless of age, race, gender, nationality, religion, physical ability, sexual orientation, etc.



Ethics and Compliance

Leadership is committed to acting ethically and in compliance with the PPL Standards of Integrity.



Appropriate action will be taken, regardless of position or rank of those involved, if I report an actual or suspected violation of the PPL Standards of Integrity.



I would feel comfortable reporting an actual or suspected violation of the PPL Standards of Integrity using one or more of the channels available (e.g., supervisor, manager, human resources, Ethics Helpline, company attorney, or Global Chief Compliance Officer) without fear of retaliation.





PPL companies

LG&E and KU Energy LLC
220 West Main Street
P.O. Box 32020
Louisville, KY 40232

lge-ku.com



2017

Employee Opinion Survey

Results



PPL companies



Dear employees,

I am pleased to provide the results from the 2017 Employee Opinion Survey.

With an outstanding 93 percent participation rate, the 2017 survey demonstrates your active engagement in providing honest feedback and a desire to help improve our workplace.

This booklet contains LG&E and KU's overall results for 2017, along with comparative results from the 2014 all-employee survey to measure our progress since then.

Your 2017 responses indicated excellent results for our safety and wellness culture and customer focus. Your feedback also demonstrates high levels of pride in our company and awareness of LG&E and KU's mission and values. However, you expressed continued concerns about growth and development opportunities.

Because company leadership is firmly committed to take action on the survey, a series of follow-up activities will occur within work groups and companywide.

By July 30, your manager or supervisor will conduct team meetings to discuss companywide results, as well as specific results for your work group. During these meetings, your team will develop action plans, as needed, to address areas of concern within your work group.

From a company-wide perspective, we will focus on the topic of growth and development through additional manager/supervisor training; continued open and honest dialogue between supervisors and their employees in feedback sessions; and a series of communications about processes related to job postings, union progression, staffing policy and succession planning.

I encourage your active participation in these follow-up processes. By working together, we will make LG&E and KU an even better place to work on behalf of our customers, who count on us to power their lives.

Once again, thank you for participating in the 2017 LG&E and KU Employee Opinion Survey. Your input contributes to our future success, and we are committed to listening and responding to your feedback.

Sincerely,

Handwritten signature of Paul W. Thompson.

Paul W. Thompson

President and Chief Operating Officer

Results for LG&E and KU

Employees were asked to choose one of five responses — “strongly agree,” “agree,” “neutral,” “disagree,” “strongly disagree” — for each statement on the questionnaire. In the results that follow, these five responses have been combined into three broader response categories.

- Favorable (green) = the percentage of employees who responded “strongly agree” and “agree”
- Neutral (yellow) = the percentage of employees who responded “neutral”
- Unfavorable (red) = the percentage of employees who responded “strongly disagree” or “disagree”

Year-to-Year Comparisons

The LG&E and KU results presented in this booklet show comparisons, where applicable, between the 2017 and 2014 surveys. Questions that were new to the 2017 survey will have only one set of response results.

Interpreting the Results

It is recommended that you look first at the percentage of “favorable” responses, which is typically a good indicator of key trends (strengths and weaknesses).

Please note that in some groups, the percentages will not total 100 percent due to rounding.

Clarity of Direction

I am aware of the company's mission and values.



I can see a clear link between my work and the company's objectives.



Senior management keeps employees informed of company matters.



I have a clear understanding of the goals and objectives of the company.



I trust our officers to take the necessary actions to move LG&E and KU Energy in the right direction.



Continuous Improvement

We are committed to exceeding our customers' expectations.



I am encouraged to share my ideas about improving the company.



I believe issues identified through this survey will be acted upon.



In my team, we regularly discuss what we can improve.



Process improvement is encouraged in my work group.



My immediate supervisor encourages understanding and readiness for change.



Employee Empowerment

I am appropriately involved in decisions that affect my work.



My job makes good use of my skills and abilities.



I am able to balance my work and personal life.



Growth and Development

Advancement opportunities are awarded fairly.



I am satisfied with the training I receive for my present job.



My immediate supervisor supports my skill and career development.



I am given the opportunity to grow professionally at the company.



There are career opportunities for me at the company.



Performance Management

In my work group, people are held accountable for results.



My immediate supervisor gives me regular feedback on my performance.



My immediate supervisor clearly communicates what is expected of me at work.



My immediate supervisor values me for the talent and perspectives I bring.



Pride in Company

I intend to stay with the company for at least the next 12 months.



My contributions are helping the company reach its goals and objectives.



I am proud to work for the company.



I enjoy my day-to-day work.



I would recommend the company as a good place to work.



Recognition and Reward

I am paid fairly for my contribution to the company.



My overall benefits package meets my needs.



My work gives me a feeling of personal accomplishment.



When I do an excellent job, my accomplishments are recognized.



Resources and Support

My work environment enables me to be effective in my role.



I have the information I need to do my job.



I have the tools and technology that I need to be productive.



My department has the personnel resources necessary to do a good job.



I am satisfied with the internal communication I receive from the company.



Safety and Wellness

Company wellness initiatives support the health and well-being of employees.



In my work environment, every precaution is taken to avoid accidents.



Our company has a continuous focus on safety.



Supervisor Relationship

I am comfortable discussing concerns with my immediate supervisor.



My immediate supervisor cares about me as a person.



My immediate supervisor keeps commitments.



My immediate supervisor treats employees with respect.



My immediate supervisor values my input.



Teamwork and Collaboration

My team is committed to doing high quality work.



My team members work well together.



People at our company trust and respect each other.



There is effective cooperation across departments.



In my work environment, everyone is treated equally, regardless of age, race, gender, nationality, religion, physical ability, sexual orientation, etc.



Ethics and Compliance

Leadership is committed to acting ethically and in compliance with the PPL Standards of Integrity.



Appropriate action will be taken, regardless of position or rank of those involved, if I report an actual or suspected violation of the PPL Standards of Integrity.



I would feel comfortable reporting an actual or suspected violation of the PPL Standards of Integrity without fear of retaliation.



I would feel comfortable reporting an actual or suspected violation of the PPL Standards of Integrity using one or more of the channels available (e.g., supervisor, manager, human resources, Ethics Helpline, company attorney, or Global Chief Compliance Officer).





PPL companies

LG&E and KU Energy LLC
220 West Main Street
P.O. Box 32020
Louisville, KY 40232

lge-ku.com

PPL CORPORATION, PPL RHODE ISLAND HOLDINGS, LLC,
NATIONAL GRID USA, and THE NARRAGANSETT ELECTRIC COMPANY

Docket No. D-21-09

PPL Corporation and PPL Rhode Island Holdings, LLC's
Responses to Division's First Set of Data Requests

Issued on June 8, 2021

Division 1-53

Request:

Please provide the two most recent reports assessing employee safety for LG&E and KU.

Response:

PPL and PPL RI refer to Attachment PPL-DIV 1-53-1 and Attachment PPL-DIV 1-53-2, which are the two most recent reports assessing employee safety for LG&E and KU.



June 9, 2021

To: Officer Team

Re: May 2021 LG&E and KU Summary of Injury and Illness Rates

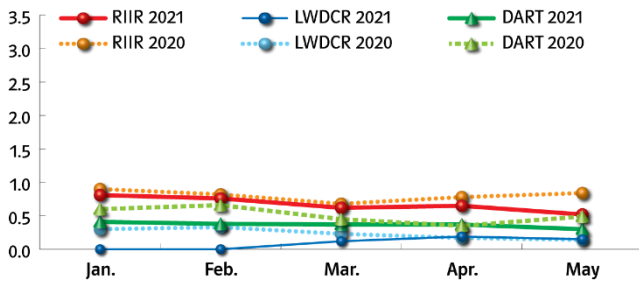
There were seven employee recordable incidents through May for an OSHA recordable rate of 0.52, compared to 12 and a rate of 0.84 in 2020. There were two lost-time incidents for a rate of 0.15 through May, compared to two in 2020 for a rate of 0.14. There were four DART cases through May for a rate of 0.30, compared to seven and a rate of 0.49 in 2020. There were two hearing-loss cases through May.

LG&E and KU Energy LLC

Safety and Technical Training
 10300 Ballardsville Road
 Louisville, Kentucky 40241

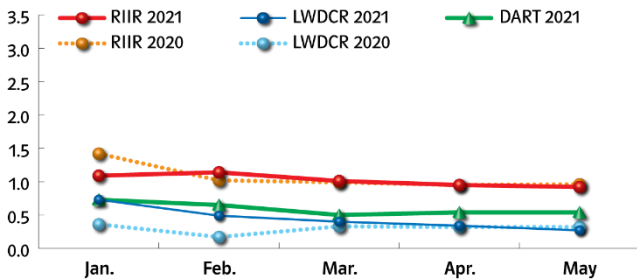
Amanda Chambers
 Director,
 Safety and Technical Training
 T 502-333-1824
Amanda.Chambers@lge-ku.com

Employee Safety Performance — 2021 vs. 2020



Contractors reported 17 incidents through May for an OSHA recordable rate of 0.92, compared to 15 incidents and a rate of 0.96 in 2020. There were five contractor lost-time incidents through May 2020 for a rate of 0.27, compared to five and a rate of 0.32. Through May, there were 10 contractor DART injuries for a rate of 0.54.

Contractor Safety Performance — 2021 vs. 2020



Sincerely,

Amanda Chambers

Attachments

Employee Data

LG&E and KU Employee Corporate Summary Comparison

Year-To-Date 05/2021

	2021 YTD LG&E and KU	2020 Year End	2019 EEI ¹ Group D Top Quartile	2019 EEI ¹ Group D Top Performer	2019 BLS Utility Average ²
YTD OSHA Incidence Rate Excluding	0.52	1.00	0.87	0.58	1.80
OSHA Incidence Rate Target Excluding Hearing	0.94	0.95			
Lost Work Day Case Rate	0.15	0.29	0.21	0.18	0.50
Dart Rate	0.30	0.66	0.44	0.18	0.90
Dart Rate Target	0.45	0.46			

¹Edison Electric Institute ²Bureau of Labor Statistics
 Group D: Combination (Gas/Electric with no Nuclear Plants) - Organizations with Electric Generation, Transmission & Distribution and Gas with no nuclear plants.

	Corporate 2021 YTD MVIR	Corporate 2020 Year End MVIR	2021 YTD Miles Driven	EEI Group 2 Top Performer	EEI Group 2 Average MVIR
Corporate Motor Vehicle Incident (MVIR)	1.54	2.53	5,849,939	1.06	2.54

EEI groups for MVIR are based on total miles driven

LG&E and KU Employee Detailed Summary of Injury and Illness Rates Comparison

Year-To-Date 05/2021

	Customer Service	Electric	Energy Supply, R&D & Proj Eng	Environmental Affairs	Gas	Power Production & Gen. Services	Safety	Transmission	Operations YTD	Operations MTD
2021 YTD Hours Worked	453,508.00	591,303.75	91,902.25	15,609.00	229,358.00	669,260.75	31,286.00	123,068.50	2,205,296.25	442,520.75
2021 YTD OSHA Recordables Excluding Hearing	1	3	0	0	3	0	0	0	7	0
2021 YTD Incidence Rate Excluding Hearing	0.44	1.01	0.00	0.00	2.62	0.00	0.00	0.00	0.63	0.00
2021 Incidence Rate Target Excluding Hearing	0.68	1.65	0.00	0.00	1.56	1.10	0.00	0.13	1.08	1.08
2021 YTD OSHA Recordables Including Hearing	1	3	0	0	4	1	0	0	9	0
2021 BLS Average Incidence Rate	0.60	2.30	0.60	0.60	2.30	1.10	0.60	2.30	1.80	1.80
2021 YTD Lost Work Day Cases	0	1	0	0	1	0	0	0	2	0
2021 YTD Lost Work Day Case Rate	0.00	0.34	0.00	0.00	0.87	0.00	0.00	0.00	0.18	0.00
2021 BLS Average Lost Work Day Case Rate	0.10	0.60	0.10	0.10	0.60	0.30	0.10	0.60	0.50	0.50
2021 Restricted/Transferred Cases	0	0	0	0	2	0	0	0	2	0
2021 Days Away/Restricted/Transferred Case Rate (DART)	0.00	0.34	0.00	0.00	2.62	0.00	0.00	0.00	0.36	0.00
2021 DART Target	0.22	0.75	0.00	0.00	0.78	0.63	0.00	0.00	0.51	0.51
2021 BLS Average DART Case Rate	0.30	1.10	0.30	0.30	1.40	0.60	0.30	1.10	0.90	0.90
2021 Serious Injury Cases	0	0	0	0	0	0	0	0	0	0
2021 Serious Injury Incident Rate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

	Admin	Supply Chain	Corporate Total
2021 YTD Hours Worked	436,792.25	41,677.00	2,683,608.50
2021 YTD OSHA Recordables Excluding Hearing	0	0	7
2021 YTD Incidence Rate Excluding Hearing	0.00	0.00	0.52
2021 Incidence Rate Target Excluding Hearing	0.23	0.41	0.94
2021 YTD OSHA Recordables Including Hearing	0	0	9
2021 BLS Average Incidence Rate	0.60	4.80	1.80
2021 YTD Lost Work Day Cases	0	0	2
2021 YTD Lost Work Day Case Rate	0.00	0.00	0.15
2021 BLS Average Lost Work Day Case Rate	0.10	1.90	0.50
2021 Restricted/Transferred Cases	0	0	2
2021 Days Away/Restricted/Transferred Case Rate (DART)	0.00	0.00	0.30
2021 DART Target	0.15	0.00	0.45
2021 BLS Average DART Case Rate	0.30	3.70	0.90
2021 Serious Injury Cases	0	0	0
2021 Serious Injury Incident Rate	0.00	0.00	0.00

Contractor Data

LG&E and KU Contractor Corporate Summary Comparison Year-To-Date 05/2021

	2021 YTD	Targets	2020 Year End	BLS General Industrial Average
Number of OSHA Incidents	17	N/A	48	N/A
OSHA Incident Rate	0.98	1.42	1.19	3.3
Lost Work Day Case Rate	0.27	N/A	0.30	0.9
Dart Rate	0.54	N/A	0.55	2

LG&E and KU Contractor Detailed Summary of Injury and Illness Rates Year-To-Date 05/2021

		Customer Services	Electric Distribution	Gas Operations	Generation Operations	Project Engineering	Transmission	Corporate Total	Operations YTD	Operations MTD
2021	YTD Hours Worked	434,911	981,836	555,754	947,132	270,169	511,124	3,700,925	3,700,925	614,381
2021	YTD OSHA Recordables	3	5	2	6	0	1	17	17	3
2021	YTD Incidence Rate	1.38	1.02	0.72	1.27	0.00	0.39	0.92	0.92	0.98
2021	Incidence Rate Target	1.66	1.66	1.66	1.66	1	1.66	1.42	1.42	1.42
2020	Incidence Rate	1.40	1.26	1.54	1.07	0.00	1.38	1.19	1.19	1.19
2021	YTD Lost Work Day Cases	2	1	0	2	0	0	5	5	0
2021	YTD Lost Work Day Case Rate	0.92	0.20	0.00	0.42	0.00	0.00	0.27	0.27	0.00
2020	Lost Work Day Case Rate	0.40	0.29	0.31	0.32	0.00	0.34	0.30	0.30	0.30
2021	YTD DART Case	2	3	0	5	0	0	10	10	2
2021	YTD DART Case Rate	0.92	0.61	0.00	1.06	0.00	0.00	0.54	0.54	0.65



May 12, 2021

To: Officer Team

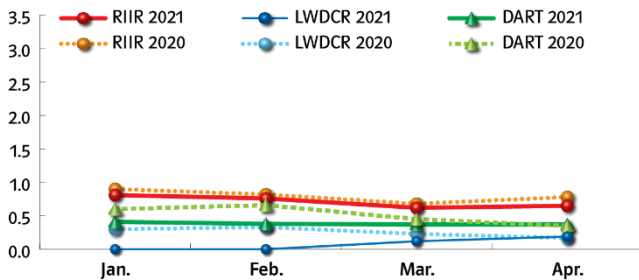
LG&E and KU Energy LLC
 Safety and Technical Training
 10300 Ballardsville Road
 Louisville, Kentucky 40241

Re: April 2021 LG&E and KU Summary of Injury and Illness Rates

Amanda Chambers
 Director,
 Safety and Technical Training
 T 502-333-1824
Amanda.Chambers@lge-ku.com

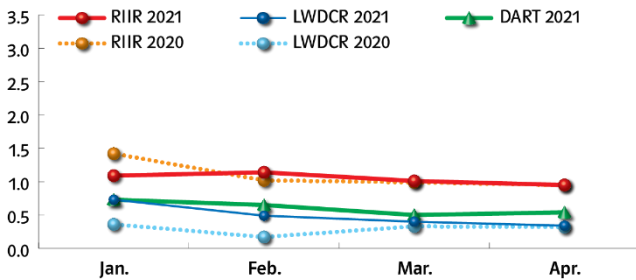
There were seven employee recordable incidents through April for an OSHA recordable rate of 0.65, compared to nine and a rate of 0.78 in 2020. There were two lost-time incidents for a rate of 0.19 through April, compared to two in 2020 for a rate of 0.17. There were four DART cases through April for a rate of 0.37, compared to four and a rate of 0.35 in 2020. There were two hearing-loss cases through April.

Employee Safety Performance — 2021 vs. 2020



Contractors reported 14 incidents through April for an OSHA recordable rate of 0.95, compared to 12 incidents and a rate of 0.95 in 2020. There were five contractor lost-time incidents through April with a rate of 0.34, compared to four in 2020 for a rate of 0.32 for the same period last year. Through April, there were eight contractor DART injuries for a rate of 0.54.

Contractor Safety Performance — 2021 vs. 2020



Sincerely,

Amanda Chambers

Attachments

Employee Data

LG&E and KU Employee Corporate Summary Comparison Year-To-Date 04/2021

	2021 YTD LG&E and KU	2020 Year End	2019 EEI1 Group D Top Quartile	2019 EEI1 ¹ Group D Top Performer	2019 BLS Utility Average ²
YTD OSHA Incidence Rate Excluding Hearing	0.65	1.00	0.87	0.58	1.80
OSHA Incidence Rate Target Excluding Hearing	0.94	0.95			
Lost Work Day Case Rate	0.19	0.29	0.21	0.18	0.50
Dart Rate	0.37	0.66	0.44	0.18	0.90
Dart Rate Target	0.45	0.46			

¹Edison Electric Institute ²Bureau of Labor Statistics
 Group D: Combination (Gas/Electric with no Nuclear Plants) - Organizations with Electric Generation, Transmission & Distribution and Gas with no nuclear plants.

	Corporate 2021 YTD MVIR	Corporate 2020 Year End MVIR	2021 YTD Miles Driven	EEI Group 2 Top Performer	EEI Group 2 Average MVIR
Corporate Motor Vehicle Incident (MVIR)	1.49	2.53	4,707,527	1.06	2.54

EEI groups for MVIR are based on total miles driven

LG&E and KU Employee Detailed Summary of Injury and Illness Rates Comparison Year-To-Date 04/2021

		Customer Service	Electric	Energy Supply, R&D & Proj Eng	Environmental Affairs	Gas	Power Production & Gen. Services	Safety	Transmission	Operations YTD	Operations MTD
2021	YTD Hours Worked	366,326.75	471,215.25	72,532.25	12,414.00	183,385.50	535,069.25	24,169.50	97,663.00	1,762,775.50	439,780.00
2021	YTD OSHA Recordables Excluding Hearing	1	3	0	0	3	0	0	0	7	2
2021	YTD Incidence Rate Excluding Hearing	0.55	1.27	0.00	0.00	3.27	0.00	0.00	0.00	0.79	0.91
2021	Incidence Rate Target Excluding Hearing	0.68	1.65	0.00	0.00	1.56	1.10	0.00	0.13	1.08	1.08
2021	YTD OSHA Recordables Including Hearing	1	3	0	0	4	1	0	0	9	2
2021	BLS Average Incidence Rate	0.60	2.30	0.60	0.60	2.30	1.10	0.60	2.30	1.80	1.80
2021	YTD Lost Work Day Cases	0	1	0	0	1	0	0	0	2	1
2021	YTD Lost Work Day Case Rate	0.00	0.42	0.00	0.00	1.09	0.00	0.00	0.00	0.23	0.45
2021	BLS Average Lost Work Day Case Rate	0.10	0.60	0.10	0.10	0.60	0.30	0.10	0.60	0.50	0.50
2021	Restricted/Transferred Cases	0	0	0	0	2	0	0	0	2	0
2021	Days Away/Restricted/Transferred Case Rate (DART)	0.00	0.42	0.00	0.00	3.27	0.00	0.00	0.00	0.45	0.45
2021	DART Target	0.22	0.75	0.00	0.00	0.78	0.63	0.00	0.00	0.51	0.51
2021	BLS Average DART Case Rate	0.30	1.10	0.30	0.30	1.40	0.60	0.30	1.10	0.90	0.90
2021	Serious Injury Cases	0	0	0	0	0	0	0	0	0	0
2021	Serious Injury Incident Rate	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
		Admin	Supply Chain	Corporate Total							
2021	YTD Hours Worked	349,243.50	33,289.00	2,145,308.00							
2021	YTD OSHA Recordables Excluding Hearing	0	0	7							
2021	YTD Incidence Rate Excluding Hearing	0.00	0.00	0.65							
2021	Incidence Rate Target Excluding Hearing	0.23	0.41	0.94							
2021	YTD OSHA Recordables Including Hearing	0	0	9							
2021	BLS Average Incidence Rate	0.60	4.80	1.80							
2021	YTD Lost Work Day Cases	0	0	2							
2021	YTD Lost Work Day Case Rate	0.00	0.00	0.19							
2021	BLS Average Lost Work Day Case Rate	0.10	1.90	0.50							
2021	Restricted/Transferred Cases	0	0	2							
2021	Days Away/Restricted/Transferred Case Rate (DART)	0.00	0.00	0.37							
2021	DART Target	0.15	0.00	0.45							
2021	BLS Average DART Case Rate	0.30	3.70	0.90							
2021	Serious Injury Cases	0	0	0							
2021	Serious Injury Incident Rate	0.00	0.00	0.00							



Contractor Data

LG&E and KU Contractor Corporate Summary Comparison Year-To-Date 04/2021

	2021 YTD	Targets	2020 Year End	BLS General Industrial Average
Number of OSHA Incidents	14	N/A	48	N/A
OSHA Incident Rate	0.95	1.42	1.19	3.3
Lost Work Day Case Rate	0.34	N/A	0.30	0.9
Dart Rate	0.54	N/A	0.55	2

LG&E and KU Contractor Detailed Summary of Injury and Illness Rates Year-To-Date 04/2021

	Customer Services	Electric Distribution	Gas Operations	Generation Operations	Project Engineering	Transmission	Corporate Total	Operations YTD	Operations MTD
2021 YTD Hours Worked	347,477	818,344	426,661	761,846	200,447	401,167	2,955,941	2,955,941	685,319
2021 YTD OSHA Recordables	3	5	2	3	0	1	14	14	4
2021 YTD Incidence Rate	1.73	1.22	0.94	0.79	0.00	0.50	0.95	0.95	1.17
2021 Incidence Rate Target	1.66	1.66	1.66	1.66	1	1.66	1.42	1.42	1.42
2020 Incidence Rate	1.40	1.26	1.54	1.07	0.00	1.38	1.19	1.19	1.19
2021 YTD Lost Work Day Cases	2	1	0	2	0	0	5	5	1
2021 YTD Lost Work Day Case Rate	1.15	0.24	0.00	0.53	0.00	0.00	0.34	0.34	0.29
2020 Lost Work Day Case Rate	0.40	0.29	0.31	0.32	0.00	0.34	0.30	0.30	0.30
2021 YTD DART Case	2	3	0	3	0	0	8	8	3
2021 YTD DART Case Rate	1.15	0.73	0.00	0.79	0.00	0.00	0.54	0.54	0.88

EMPLOYEE DART CASES 2012 THRU MARCH 2021 YTD

2012 THRU MARCH 2021 YTD EMPLOYEE DART CASES										
TYPES OF INJURIES										
YEAR	STRAINS/SPRAINS	CONTUSIONS	HEAT EXHAUSTION	BURN	LACERATION	FRACTURE	ABRASION	AMPUTATION	IRRITATION	TOTAL DART CASES
2012	9	3	1	0	0	0	0	0	0	13
2013	5	2	0	1	2	0	0	0	0	10
2014	9	1	0	1	1	2	1	0	0	15
2015	7	0	0	1	2	4	0	0	0	14
2016	7	0	0	0	0	5	0	0	0	12
2017	13	0	0	1	0	1	1	1	1	18
2018	7	3	0	1	0	4	1	0	0	16
2019	5	2	0	0	5	4	0	0	2	18
2020	12	1	0	2	4	4	0	0	0	23
2021	2	1	0	0	0	0	0	0	0	3
TOTAL	76	13	1	7	14	24	3	1	3	142

2012 THRU MARCH 2021 YTD EMPLOYEE DART CASES												
SOURCE OF INJURIES												
YEAR	SLIP/TRIPS/FALL	STRUCK BY OBJECT/STRUCK AGAINST OBJECT	MOTOR VEHICLE	AWKWARD MOTION	OVER-EXERTION	HEAT	HOT OBJECT	CAUGHT BETWEEN OBJECT	SHARP OBJECT	REPETITIVE MOTION	FOREIGN BODY	TOTAL DART CASES
2012	3	3	1	4	1	1	0	0	0	0	0	13
2013	3	0	0	2	2	0	1	1	1	0	0	10
2014	6	1	0	5	1	0	1	1	0	0	0	15
2015	6	1	0	4	0	0	0	1	2	0	0	14
2016	6	0	2	1	3	0	0	0	0	0	0	12
2017	3	0	1	5	3	0	2	2	0	1	1	18
2018	5	3	2	2	0	0	1	2	0	1	0	16
2019	10	2	0	1	1	0	1	1	1	0	1	18
2020	5	2	1	5	5	0	2	2	0	1	0	23
2021	1	0	1	0	1	0	0	0	0	0	0	3
TOTAL	48	12	8	29	17	1	8	10	4	3	2	142

2012 THRU MARCH 2021 EMPLOYEE DART CASES											
TOP 3 INJURY TYPES BY SOURCE											
TYPES OF INJURIES	SOURCE OF INJURIES										
	SLIP/TRIPS/FALL	STRUCK BY OBJECT/STRUCK AGAINST OBJECT	MOTOR VEHICLE	AWKWARD MOTION	OVER-EXERTION	HEAT	HOT OBJECT	CAUGHT BETWEEN OBJECT	SHARP OBJECT	REPETITIVE MOTION	FOREIGN BODY
SPRAINS/STRAINS	22	3	5	26	14	0	0	1	0	2	0
FRACTURES	17	2	1	1	0	0	0	3	0	0	0
CONTUSIONS	6	3	2	0	1	0	0	1	0	0	0

Division 1-54

Request:

Referencing the testimony of Mr. Sorgi's testimony at 9:10-12, in which he states: "We also believe that infrastructure investments and a more localized operating model under PPL's ownership will create jobs and support economic development in Rhode Island," please:

- a. Explain PPL's "localized operating model,"
- b. Provide any analyses or comparisons performed assessing the PPL model against how Narragansett is currently managed;
- c. Quantify the number of jobs PPL expects that will be created, including any supporting data, studies, workpapers, reports, and information; and
- d. Please provide any data, studies, workpapers, reports, and information to support PPL's claim that the Transaction will result in economic development.

Response:

- a. PPL's localized operating model can best be described as the people who are responsible to ensure the safe and reliable electric and gas service to customers will be present locally in Rhode Island and will have the appropriate decision making authority commensurate with those responsibilities. In addition, the President will work directly with the EVP and COO and other members of PPL's Executive team, as necessary, to ensure that Narragansett has the resources and support necessary to provide this service to Rhode Island customers as having the appropriate resources necessary to carry out that mission. Also see PPL and PPL RI's response to data request Division 1-19.
- b. No such analyses or comparisons have been performed or documented. PPL and National Grid continue to work out the details to ensure a smooth transition.
- c. As stated in b. above, PPL and National Grid continue to develop the organization structure and number of employees needed as we transition off the TSA over the two-year transition period. Certain functions that are currently provided by National Grid that are planned to be created in Rhode Island are Customer Contact and back office functions, Electric dispatch and control room operations, gas control and dispatch functions, gas and electric training operations and miscellaneous service company functions. Total number of employees in these areas has not been determined at this time.

PPL CORPORATION, PPL RHODE ISLAND HOLDINGS, LLC,
NATIONAL GRID USA, and THE NARRAGANSETT ELECTRIC COMPANY

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- d. We did not perform any studies or reports on the resulting economic impact of this transaction. A key component of utility operations is investments in infrastructure. If the Transaction is approved, PPL expect to submit plans for approval that increases the amount of infrastructure investments in Rhode Island, which will have a direct impact on the Rhode Island economy through direct and indirect purchases, use of contractors and service providers. In addition, PPL plans to create certain functions in Rhode Island that will require investments in facilities, construction, professional services and purchases (see item c. above) Also, PPL has a long history of investing in the communities they serve. In Pennsylvania & Kentucky for 2020 PPL provided more than \$12M in charitable giving, had 60-80K hours of volunteer work, supported over 300 nonprofits, had \$275M spend on diverse suppliers, had 60% of the corporate spend on locally based suppliers, provided over \$2M to support COVID relief, donated 20k N95 masks to health care workers and donated \$100K to support racial injustice initiatives.

Division 1-55

Request:

Referencing the discussion in Mr. Sorgi's testimony (at 16:18-17:2) regarding remaining "effects bargaining" needed to resolve issues with bargaining units prior to the close of the Transaction, please:

- a. Identify with specificity the "effects bargaining issues" that need to be resolved prior to the close of the Transaction;
- b. Provide current status of negotiations to resolve the "effects bargaining issues";
- c. State whether the Transaction is contingent upon successful resolution of the "effects bargaining issues"; and
- d. If the Transaction is not contingent upon successful resolution of the "effects bargaining issues," explain what impact, if any, would the failure to resolve the "effects bargaining issues" have on the Transaction.

Response:

- a. As explained in greater detail in response to subpart d below, no effects bargaining issues "must" be resolved prior to the close of the transaction. The National Grid USA Labor Relations Team, with support from the PPL Labor Relations Team, will proactively engage in effects bargaining prior to the close of PPL RI purchase of The Narragansett Electric Company ("Narragansett") (the "Transaction") for the following unions: 1) United Steelworkers, AFL-CIO Local 12431; 2) Utility Workers Union of America, AFL-CIO Local 310; and 3) Utility Workers Union of America, AFL-CIO Local 310B. Effects bargaining generally requires good faith bargaining by National Grid on request of a union in regard to the effects of the Transaction on represented employees. In addition, PPL will engage in bargaining with the unions as a prospective successor employer with respect to any proposed modifications in the terms of the collective bargaining agreements it would assume upon the Transaction's closing.
- b. The Human Resources and Labor Relations Teams of both National Grid and PPL have had numerous and ongoing joint sessions in preparation for National Grid's effects bargaining, as well as PPL's successor bargaining, which is expected to commence in mid-August.
- c. The Transaction is not contingent upon successful resolution of effects bargaining issues.

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- d. Although the parties fully expect that any effects bargaining issues will be resolved between National Grid and the unions, any failure to resolve effects bargaining issues would not impact the Transaction. Prior to the closing date, National Grid USA has an obligation to engage in effects bargaining with affected labor union locals on request and to the extent required by law. PPL will support National Grid USA throughout this process. As seller, National Grid USA is not obligated to reach agreement with a union on any particular issue discussed during effects bargaining. As a successor employer, PPL will bargain with the unions with respect to any modifications in the terms of the collective bargaining agreements it would assume. After the Transaction closes, PPL RI, as the purchaser, will adopt and assume the collective bargaining agreements with the following unions: 1) United Steelworkers, AFL-CIO Local 12431; 2) Utility Workers Union of America, AFL-CIO Local 310; and 3) Utility Workers Union of America, AFL-CIO Local 310B.