

Third Order No. 1000 Regional Compliance Filing
of
ISO New England Inc.
and the
Participating Transmission Owners
Administrative Committee

Docket No. ER13-193-____

May 18, 2015

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May 18, 2015

The Hon. Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street NE
Washington, DC 20426

Re: Amendments to the ISO New England Inc. Transmission, Markets and Services Tariff and Transmission Operating Agreement in Compliance with May 17, 2013 Order, Docket No. ER13-193-____

Dear Secretary Bose:

Pursuant to Rule 1907 of the Federal Energy Regulatory Commission's ("FERC or the "Commission")¹ Rules of Practice and Procedure, 18 C.F.R. § 385.1907 (2013), and Section 206 of the Federal Power Act ("FPA"), ISO New England Inc. ("ISO-NE" or "ISO") and the Participating Transmission Owners Administrative Committee ("PTO AC")² (collectively, the "Filing Parties") hereby jointly submit this transmittal letter regarding the proposed revisions to Sections I and II of the ISO-NE Tariff and to the TOA (the "Compliance Revisions") to comply with the Commission's March 19, 2015 order³ regarding the Filing Parties' November 15, 2013 filing (the "November 15 Filing") in compliance with *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order Nos. 1000 and 1000-A.⁴

The Compliance Revisions span – and are submitted contemporaneously in – two dockets: ER13-193 (for the revisions made to the ISO-NE Tariff sheets) and ER13-196 (for the revisions made to the TOA sheets). This dual submission is necessitated by the same eTariff limitation that required the establishment of these two dockets in the initial October 25, 2012 compliance filing: the TOA is stored in a separate database from the ISO-NE Tariff. The same transmittal letter (differing only in the referenced docket

¹ Capitalized terms not otherwise defined in this transmittal letter having the meanings ascribed thereto in the ISO New England Inc. Transmission, Markets and Services Tariff (the "ISO-NE Tariff") or the Transmission Operating Agreement between ISO New England Inc. and the Participating Transmission Owners (the "TOA"). The Open Access Transmission Tariff (the "OATT") is Section II of the ISO-NE Tariff.

² The PTO AC joins this filing on behalf of the Participating Transmission Owners ("PTOs") in New England based on votes of the PTO AC (with some abstentions) in support of the amendments to the TOA and OATT Attachment K Appendix 1 that are included as part of this filing.

³ *ISO New England Inc.*, 150 FERC ¶ 61,209 ("March 19 Order").

⁴ *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 76 Fed. Reg. 49,842 (Aug. 11, 2011), FERC Stats. & Regs. ¶ 31,323 (2011) ("Order No. 1000"), Order No. 1000-A, 77 Fed. Reg. 32,184 (May 31, 2012), 139 FERC ¶ 61,132 (2012) ("Order No. 1000-A"), Order No. 1000-B, 141 FERC ¶ 61,044 (2012).

number) is being filed in each of the two dockets, and the Commission should treat the submissions as a single compliance filing.

On April 20, 2015, the ISO sought clarification, or in the alternative rehearing, on two discrete elements of the March 19 Order (“Motion for Clarification”): (1) to ensure comparable treatment regarding a hold harmless provision by having PTOs execute the Non-Incumbent Transmission Developer Operating Agreement (“NTDOA”),⁵ which contains the language; and (2) to remove language from Schedule 15 regarding treatment of cost impacts external to the New England region but caused by an upgrade within the New England region. On the first, the ISO agreed with the Commission but explained that there were several complications and unintended consequences of having the PTOs sign the NTDOA, which was intended as a transitional contract setting out the relationship between the ISO and an entity until, and only until, the entity could meet the prerequisites necessary to execute a TOA, at which point the NTDOA would terminate. The ISO explained that the comparable treatment could instead be achieved by placing in the hold harmless language in the TOA as well. Thus, the issue raised by the ISO was not *whether* the language would apply to all types of entities, but simply *where* the language was located. On the issue of costs outside the region, the ISO noted that the Commission had accepted the same type of provisions in the NYISO compliance filing and sought the same treatment for the ISO’s language.

On May 15, 2015, the Commission issued a tolling order in Docket Nos. ER13-193-004 and ER13-1963-003, granting rehearing for further consideration.

Because the substance of the Motion for Clarification has not yet been addressed, the Filing Parties are including compliance provisions in the instant filing that track what the Commission directed in the March 19 Order. For the reasons stated in the motion for clarification, the ISO believes that issues remain with the two items identified in the motion and notes that its compliance filing in these dockets does not indicate that the motion is withdrawn.

I. INTRODUCTION

A. The March 19 Order and Its Requirements

The March 19 Order accepted the Filing Parties’ November 15 Filing, subject to conditions, and directed the Filing Parties to submit further revisions to the OATT in a further compliance filing, to address the following topic areas:⁶

⁵ The NTDOA is Attachment O to the OATT.

⁶ In addition, the list below includes the restoration of language permitted by the Commission’s grant of a rehearing request of the PTO AC (see March 19 Order at PP 227-228).

Enrollment process

- Set forth the enrollment process that defines how transmission providers enroll in the transmission planning region (March 19 Order at P 62)
- Include in the tariff a list of enrolled transmission providers (P 63)

Public policy transmission planning (local planning process)

- Include in Appendix 1 to Attachment K (Local System Planning Process) (“Attachment K – Local”) a process through which each PTO will identify, out of the larger set of potential transmission needs driven by federal public policy requirements that may be proposed, those transmission needs for which transmission solutions will be evaluated in the local transmission planning process (P 153)
- Include in Attachment K – Local: (1) procedures to evaluate at the local level potential transmission solutions to identified transmission needs driven by public policy requirements, including those proposed by stakeholders; and (2) a description of how PTOs will provide stakeholders other than local and state authorities with an opportunity to offer input during the evaluation of those potential transmission solutions in the local transmission planning process. (P 154)

Rights of way

- Per the rehearing request granted by the Commission, restore in the TOA and OATT language recognizing the transmission owners’ rights to retain use and control of their existing rights of way (PP 227-228, 237)

Preliminary solicitation of alternatives

- Remove proposed process for solicitation of confidential alternative conceptual solutions, and make conforming changes (P 236)

NTDOA/hold harmless

- Revise the OATT definition of Non-Incumbent Transmission Developer (“NTD”) to require that a PTO that proposes to develop a transmission facility not located within or connected to its existing electric system enter into an NTDOA (P 255)
- Modify the hold harmless provision in the NTDOA and the TOA to exempt a PTO’s own ordinary negligence and remove the reference to FERC penalties (P 256)

Deposits for Phase One and Stage One proposals

- Add language requiring provision to each Qualified Sponsor a description of the costs to which the deposit will be applied, how those costs will be calculated, and an accounting of the actual costs (P 271)
- Add clarity that any disputes regarding the accounting for specific deposits should be addressed under ISO-NE's dispute resolution process (P 271)

Timing for submission of Phase Two and Stage Two Solutions

- Add a provision clarifying when a Qualified Sponsor's Phase Two or Stage Two Solution must be submitted (P 273)

Delay of competitively selected reliability or market efficiency project

- Add a definition of "Backstop Transmission Solution" for use in both the OATT and the TOA (P 305)
- Remove OATT language requiring a PTO to continue developing a Backstop Transmission Solution after the Qualified Sponsor has accepted responsibility for the competitively selected project (P 308)

Costs of external impacts

- Add language ensuring that the costs of new transmission projects are not imposed involuntarily on parties outside the transmission planning region, including removal of the language stating that the costs of any external impacts of New England regional projects will not be borne by New England customers (P 325)
- Demonstrate that a process exists through which impacts on neighboring regions and their associated costs will be resolved, or add language explicitly describing how external impacts and costs will be addressed (P 325)

B. Structure of the Transmittal Letter

The transmittal letter is structured as follows:

- Section I provides an introduction.
- Section II describes the elements of the Compliance Revisions.
- Section III describes the stakeholder process used to develop the Compliance Revisions.

- Section IV addresses the requested effective date.
- Section V is the conclusion.

II. THE ELEMENTS OF THE COMPLIANCE REVISIONS

A. Enrollment Process

1. Process for Enrollment of Transmission Providers in the Planning Region

Paragraph 62 of the March 19 Order requires the Filing Parties to set forth the enrollment process that defines how transmission providers enroll in the New England transmission planning region.

In response, Section 1.1 of Attachment K to the OATT has been modified to provide that an entity chooses to enroll (*i.e.*, participate as a transmission provider) in the New England transmission planning region by executing (or having already executed) a: (i) transmission operating agreement with the ISO, or (ii) a Market Participant Service Agreement (“MPSA”) coupled with a written notification to the ISO that the entity desires to be a transmission provider in the New England region. Subsection (i) encompasses the PTOs (as they have already executed the TOA) and signatories to any other type of transmission operating agreement (such as the Phase I/II Transmission Operating Agreement). Subsection (ii) responds to the March 19 Order’s suggestion that the ISO use the “existing process to become a member of ISO-NE,” which, for non-transmission owning entities that cannot sign the TOA, equates to becoming a Market Participant through execution of the MPSA, but adds the requirement for a notification of the entity’s desire to be a transmission provider. That section also clarifies that 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 Attachment K.

2. Listing of Enrolled Transmission Providers

Paragraph 63 of the March 19 Order requires the ISO to include in the tariff a list of enrolled transmission providers. The Commission further stated its expectation in Paragraph 63 that such a list would include, on day one, all of the public utility transmission providers in the region. In response, that list is included as Appendix 2 to Attachment K to the OATT, and will be updated in the future as required.

B. Public Policy Transmission Planning (Local Planning Process)

In Paragraph 153 of the March 19 Order, the Commission directed the Filing Parties to submit a further compliance filing that describes the process through which each PTO will identify, out of the larger set of potential transmission needs driven by federal public policy requirements that may be proposed, those transmission needs for which transmission solutions will be evaluated in the local transmission planning process. In

paragraph 154 of the March 19 Order, the Commission directed the Filing Parties to submit a further compliance filing that describes: (1) procedures to evaluate at the local level potential transmission solutions to identified transmission needs driven by public policy requirements, including those proposed by stakeholders; and (2) how PTOs will provide stakeholders other than local and state authorities with an opportunity to offer input during the evaluation of those potential transmission solutions in the local transmission planning process.

A new Section 1.6A has been added to Attachment K – Local which provides the process to identify public policy requirements driving Non-PTF transmission needs. In the proposed process, each PTO reviews NESCOE’s – or if NESCOE does not provide such, ISO-NE’s – explanation of which transmission needs driven by state, federal or local public policy requirements will or will not be evaluated by ISO-NE. 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 transmission planning process. Each PTO then lists the identified needs on its Non-PTF transmission system that will be evaluated and provides an explanation of why any identified needs will not be evaluated as part of its annual Local System Plan (“LSP”). The list is then posted in the PTO’s LSP and presented at the annual Planning Advisory Committee (“PAC”) meeting for stakeholder input. After receiving stakeholder input, if any, each PTO then confirms or modifies, as appropriate, its determination of which identified transmission needs on its Non-PTF system driven by state, federal, or local public policy requirements will be evaluated or not and revises its annual LSP accordingly.

Furthermore, a new Section 1.6B has been added to Attachment K – Local that contains the procedure for evaluating potential public policy solutions on the Non-PTF and includes multiple opportunities for stakeholder input. In this new section, once it is determined that a Non-PTF transmission need driven by state, federal or local public policy requirements will be evaluated, each PTO prepares a scope and associated assumptions as part of a Public Policy Local Transmission Study. Where a scope is available, a PTO may present the proposed scope for the Public Policy Local Transmission Study within its LSP as part of its annual 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 then schedules a follow-up PAC meeting presentation within four months of the PTO’s LSP presentation if the proposed scope was not included in its annual LSP presentation. Stakeholders are afforded the opportunity in this new proposed Section 1.6B to provide written input within 30 days after the follow up meeting. Next, the PTO determines the study scope for the Public Policy Local Transmission Study and revises its annual LSP accordingly. In preparation for a Public Policy Local Transmission Study that will be presented to the PAC, the PTO will: 1) perform the initial phase of the Public Policy Local Transmission Study to develop an estimate of cost and benefits and post preliminary results on a website; and 2) use good faith efforts to contact stakeholders and appropriate state and/or local authorities informing them of the posting and 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 study

of a Local Public Policy Transmission Upgrade. Each PTO then makes a determination of whether further study is warranted or will select its final solution and revise its LSP accordingly. PTOs will coordinate with other affected PTOs as necessary. The results of a Public Policy Local Transmission Study will be provided to the PAC as part of the LSP for the following year.

C. Rights of Way

Paragraphs 227, 228 and 237 of the March 19 Order require restoration of right-of-way language deleted from the OATT and TOA in response to the initial compliance order in these proceedings.⁷ In the March 19 Order, the Commission granted rehearing regarding those deletions. In response, these provisions have been restored as Section 4.3(b) of Attachment K to the OATT, and as Section 1.1(f) of the TOA.

D. Preliminary Solicitation of Alternatives

In paragraph 236 of the March 19 Order, the Commission ordered the removal of the proposed process (in Section 4.3(a) of Attachment K to the OATT) for solicitation of confidential alternative conceptual solutions before soliciting Stage One Proposals for those projects where it appeared that it was unlikely that any solution other than an upgrade to existing facilities would be cost-effective. The Compliance Revisions remove this streamlined vetting alternative to the RFP process for certain needs, renumber Section 4.3 accordingly, and make a conforming change in Section 4.1(i) of Attachment K.

E. NTDOA/Hold Harmless

1. NTDOA Signature by PTO NTD

Paragraph 255 of the March 19 Order requires the ISO to revise the OATT definition of Non-Incumbent Transmission Developer (“NTD”) to require that a PTO that proposes to develop a transmission facility not located within or connected to its existing electric system enter into an NTDOA. In response, the NTD definition in Section I.2.2 of the ISO-NE Tariff has been modified to remove the phrase: “; 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”. In addition, a conforming change has been made in Section 4B.3 of OATT Attachment K, to provide that a PTO meeting the specified criteria becomes a Qualified Transmission Project Sponsor “upon its execution of the [NTDOA].”

The ISO has sought clarification or rehearing of the requirement that PTO NTDs enter into the NTDOA, given that the agreement is intended and structured solely as a transitional document for use only until the signatory is qualified to execute the TOA (to which the PTOs are already parties). The ISO does not (by the making of this compliance filing) waive its request for clarification/rehearing to modify this compliance requirement.

⁷ *ISO New England Inc.*, 143 FERC ¶ 61,150 at P 231 (2013) (the “Initial Compliance Order”).

2. Exemption of PTO Ordinary Negligence

Paragraph 256 of the March 19 Order requires the modification of the hold harmless provision in Section 9.01 of the NTDOA, and the reference in TOA Section 1.1(g) to the NTDOA hold harmless provision, to exempt a PTO's own ordinary negligence and remove the reference to FERC penalties. These provisions have been modified accordingly.

F. Deposits for Phase One and Stage One Proposals

1. Description and Accounting

Section 4.3(c) of Attachment K to the OATT requires Qualified Sponsors to include payment of a study deposit to support the ISO's costs of studying Phase One and Phase Two (reliability and market efficiency) proposals, and Sections 4A.5(a) and 4A.6 contain parallel deposit provisions for Stage One and Stage Two (public policy) proposals. Sections 4.3(i) and 4A.6 address collection and refund of ISO study costs.

Paragraph 271 of the March 19 Order requires the addition of language requiring the ISO to: "(1) provide to each Qualified Sponsor a description of the costs to which the deposit will be applied, how those costs will be calculated, and an accounting of the actual costs, and (2) provide a provision that any disputes arising from this process be addressed under ISO-NE's dispute resolution process." In setting out this requirement for further compliance, the Commission references Order No. 2003.⁸ To comply with the directive, the ISO has utilized the language from its Large Generator Interconnection Procedures ("LGIP") that the Commission approved for this purpose in the Order No. 2003 proceeding. The relevant portions of the Commission-approved LGIP are: (i) "The deposit of \$50,000 shall be applied toward the costs incurred by the System Operator associated with the Interconnection Request and Long Lead Facility treatment, as well as, the costs of the Interconnection Feasibility Study and/or the Interconnection System Impact Study, including the cost of developing the study agreements and their attachments, and the cost of developing the LGIA;"⁹ and (ii) "Any invoices for Interconnection Studies shall include a detailed and itemized accounting of the cost of each Interconnection Study."¹⁰

Accordingly, the Compliance Revisions:

- Modify Section 4.3(c) of Attachment K to the OATT to state explicitly that the deposit "shall be applied toward the costs incurred by the ISO associated with the study of the Phase One and Phase Two proposal." Section 4A.5(a) is modified, similarly, to state that the deposit "shall be

⁸ See March 19 Order at n. 516.

⁹ OATT Schedule 22 at § 3.3.1.

¹⁰ *Id.* at § 13.3.

applied towards the costs incurred by the ISO associated with the study of the Stage One and Stage Two proposal.”

- Modify Sections 4.3(i) and 4A.6 of Attachment K to the OATT to provide that “[a]ny 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.”

2. Dispute Resolution

Paragraph 271 of the March 19 Order requires addition of a provision that any disputes arising from the study/deposit process be addressed under ISO-NE’s dispute resolution process. In response, Sections 4.3(i) and 4A.6 of Attachment K have been modified accordingly and direct that disputes be addressed pursuant to the ISO’s Commission-approved dispute resolution procedures.

G. Timing for Submission of Phase Two and Stage Two Solutions

Paragraph 273 of the March 19 Order requires the ISO to clarify when a Qualified Sponsor’s Phase Two or Stage Two proposal must be submitted. In discussing the need for further compliance, the Commission notes with approval in Paragraph 273 the language set out in Section 4.3(c) of Attachment K for the timing of Phase One and Stage One proposals. That language states: “Phase One Proposals must be submitted by the deadline specified in the posting by the ISO of the public notice described in Section 4.3(a) of this Attachment, which shall not be less than 60 days from the posting date of the notice.”

The ISO has adapted that Stage One/Phase One language to address the timing of Stage Two/Phase Two submittals. Therefore, the Compliance Revisions:

- Modify Section 4.3(h) of Attachment K to the OATT to specify that “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.”
- Modify Section 4A.7 of Attachment K to the OATT to specify that “Stage 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 4A.5(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.”

H. Delay of Competitively Selected Reliability or Market Efficiency Project

1. Definition of “Backstop Transmission Solution”

Paragraph 305 of the March 19 Order requires the creation of a defined term for “backstop transmission solution,” to be used consistently in the OATT and TOA in reference to a PTO(s)’ proposal. In response, a definition of Backstop Transmission Solution has been included in Section I.2.2 of the ISO-NE Tariff, and in Schedule 1.01 of the TOA, and the defined term has been substituted in the OATT and TOA for the formerly undefined phrases.

2. Continued Development of Backstop Transmission Solution

Paragraph 308 of the March 19 Order requires the removal of OATT language requiring a PTO to continue developing a Backstop Transmission Solution after the Qualified Sponsor has accepted responsibility for the competitively selected project. In response, the Compliance Revisions include the removal of language in Section 4.3(k) of Attachment K to the OATT removing the phrase “unless the year of need or other factors, as applicable, associated with the project are such that the ISO determines that the PTO should continue the development of the backstop regulated transmission solution. A determination by the ISO for the PTO to continue work on the backstop project shall be communicated by the ISO to the PTO in writing and shall also be communicated to the Planning Advisory Committee.”

I. Costs of External Impacts

Paragraph 325 of the March 19 Order requires adding language ensuring that the costs of new transmission projects are not imposed involuntarily on parties outside the transmission planning region, and the removal of the language in OATT Schedule 15 stating that the costs of any external impacts of New England regional projects will not be borne by New England customers. That paragraph also requires the ISO to demonstrate that a process exists through which impacts on neighboring regions and their associated costs will be resolved, or add language explicitly describing how external impacts and costs will be addressed.

In response, Section 5 of OATT Schedule 15 has been modified to strike the phrase “regional or” and language showing that imposition is not involuntary and demonstrating that a process exists for resolution of impacts (and associated costs) on neighboring regions is already present in documents filed with the Commission. Specifically, Attachment K to the ISO-NE OATT already includes a process for coordination with neighboring regions that can be used to resolve impacts of projects located in New England on neighboring regions and their associated costs. Sections 4.2(d) (for reliability and market efficiency projects) and 4A.8(a) (for public policy projects) both refer to coordination with neighboring entities as the means of identifying external impacts, and states that the impacts will be identified in the RSP. Further, the Amended and Restated Northeastern

ISO/RTO Planning Coordination Protocol (the “Protocol”)¹¹ provides processes that could be used to resolve external impacts and costs. For example, Section 3.5 of the Protocol calls for “analyses to accurately identify cross border impacts,” and Section 2.1 states that the Joint ISO/RTO Planning Committee will establish “ad hoc committees to resolve specific interregional planning coordination issues.” Precedent supports the sufficiency of these measures regarding external impacts: NYISO was found to have provided “sufficient explanation regarding how agreements with neighboring transmission planning regions will allow for the identification of impacts on Required Transmission Enhancements on other transmission planning regions.”¹² The NYISO explanation relied on Protocol provisions and their incorporation into the NYISO tariff, as the ISO has done here. Indeed, in the NYISO Second Compliance Order, the Commission found acceptable a statement that NYISO shall not bear the costs of required upgrades in another region.¹³

The ISO has sought clarification or rehearing of the requirement that the language of OATT Schedule 15 be struck and of the finding of insufficiency, and the ISO does not (by the making of this compliance filing) waive its request for modification of this compliance requirement.

III. THE STAKEHOLDER PROCESS USED TO DEVELOP THE COMPLIANCE REVISIONS

The overall time period for compliance meant that the revisions were considered at two meetings of the NEPOOL Transmission Committee (held on April 13 and 23, 2015). The revisions were modified in several respects in response to the input of stakeholders at those meetings.

IV. REQUESTED EFFECTIVE DATE

The Filing Parties request a May 18, 2015 effective date for the Compliance Revisions, consistent with the date identified in the March 19 Order.

¹¹ The Protocol is included with the ISO-NE interregional coordination filing in Docket Nos. ER13-1957-000 and ER13-1960-000.

¹² *New York Independent System Operator, Inc.* 148 FERC ¶ 61,044 at P 296 (2014) (the “NYISO Second Compliance Order”).

¹³ *See id.* at PP 296-297.

The Hon. Kimberly D. Bose
May 18, 2015
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V. CONCLUSION

The Filing Parties request the Commission to accept the Compliance Revisions without hearing, modification or condition.

Respectfully submitted,

/s/ Theodore J. Paradise

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for the PTO AC

CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Holyoke, MA this 18th day of May, 2015.

/s/ Julie A. Horgan

Julie A. Horgan
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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:

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.

Adjusted Audited Demand Reduction is the Audited Demand Reduction of a Demand Response Resource adjusted in accordance with Section III.13.7.1.5.10.1.1.

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 Capacity Price Rule is a rule potentially affecting Capacity Clearing Prices in a Forward Capacity Auction, as described in Section III.13.2.7.8 of Market Rule 1.

Alternative Dispute Resolution (ADR) is the procedure set forth in Appendix D to Market Rule 1.

Alternative Technology Regulation Resource is any Resource eligible to provide Regulation that is not registered as a different Resource type.

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.

Annualized FCA Payment is used to determine a resource's availability penalties and is calculated in accordance with Section III.13.7.2.7.1.2(b) of Market Rule 1.

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.

APR-1 means the first of three Alternative Capacity Price Rule mechanisms described in Section III.13.2.7.8.

APR-2 means the second of three Alternative Capacity Price Rule mechanisms described in Section III.13.2.7.8.

APR-3 means the third of three Alternative Capacity Price Rule mechanisms described in Section III.13.2.7.8.

Asset is a generating unit, interruptible load, a component of a demand response resource or load asset.

Asset Registration Process is the ISO business process for registering a physical load, generator, or tie-line for settlement purposes. The Asset Registration Process is posted on the ISO's website.

Asset Related Demand is a physical load that has been discretely modeled within the ISO's dispatch and settlement systems, settles at a Node and, except for pumped storage load, is made up of 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.

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 risk-adjusted going forward costs of an asset that is part of an Existing Generating Capacity Resource, calculated for the asset in the same manner as the net-risk adjusted going forward costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.2.

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.

Audited Demand Reduction is the seasonal claimed capability of a Demand Response Resource as established pursuant to Section III.13.6.1.5.4.

Audited Full Reduction Time is the Offered Full Reduction Time associated with the Demand Response Resource's most recent audit.

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 generating unit change its output while providing Regulation between the Regulation High Limit and Regulation Low Limit.

Average Hourly Load Reduction is either: (i) the sum of the 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; (ii) the sum of the 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; or (iii) in each Real-Time Demand Response Event Hour, the sum of the baseline electrical energy consumption less the sum of the actual electrical energy consumption of all of the Real-Time Demand Response Assets associated with the Real-Time Demand Response Resource as registered with the ISO as of the first day of the month; or (iv) in each Real-Time Emergency Generation Event Hour, the sum of the baseline electrical energy consumption less the sum of the actual electrical energy consumption of all of the Real-Time Emergency Generation Assets associated with the Real-time Emergency Generation Resource as registered with the ISO as of the first day of the month. The Demand Resource's electrical energy reduction and Average Hourly Load Reduction shall be determined consistent with the Demand 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 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; (ii) the sum of the 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; or (iii) in each Real-Time Demand Response Event Hour or Real-Time Emergency Generation Event Hour, the sum of the electrical energy output of all of the Real-Time Demand Response Assets or Real-Time Emergency Generation Assets associated with the Real-Time Demand Response Resource or Real-Time Emergency Generation Resource as registered with the ISO as of the first day of the month. Electrical energy output and Average Hourly Output shall be determined consistent with the Demand 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.13.7.2.7.1.1.2(a) 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.

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 CIP Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 utilizing data from Table 6 of Appendix A to this Schedule 16, or as referred to in Section 5.2, of Schedule 16 to the OATT, for a Blackstart Station's costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service.

Blackstart CIP O&M Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 to the OATT, utilizing data from Table 6 of Appendix A to this Schedule 16, for a Blackstart Station's operating and maintenance costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of the provision 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 compensation, as calculated pursuant to Section 5.1 of Schedule 16 to the OATT, for a Designated Blackstart Resource's operating and maintenance costs associated with the provision of Blackstart Service (except for operating and maintenance costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

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, which also encompasses "System Restoration and Planning Service" under the predecessor version of Schedule 16.

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 under a “Signature Page for Schedule 16 of the NEPOOL OATT” that was executed and in effect prior to January 1, 2013 for Category A Designated Blackstart Resources or a commitment to provide Blackstart Service established under Operating Procedure 11 – Designated Blackstart Resource Administration (OP11) for Category B Designated Blackstart Resources.

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).

Blackstart Station-specific Rate CIP Capital Payment is a component of the Blackstart Station-specific Rate Payment that reflects a Blackstart Station’s 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 (for Capacity Commitment Periods commencing on or after June 1, 2017, 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.

Capability Year means a year's period beginning on June 1 and ending May 31.

Capacity Acquiring Resource is a resource that is seeking to acquire a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1 of Market Rule 1.

Capacity Balancing Ratio is a ratio used in calculating the Capacity Performance Payment in the Forward Capacity Market beginning on June 1, 2018 pursuant to rules filed with the Commission on July 14, 2014.

Capacity Capability Interconnection Standard has the meaning specified in Schedule 22, Schedule 23, and Schedule 25 of the OATT.

Capacity Carried Forward Due to Rationing is described in Section III.13.2.7.8.2.1(c)(b)(ii) of Market Rule 1.

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 Clearing Price Floor is described in Section III.13.2.7.

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, equal to that Market Participant's Capacity Requirement (if any) adjusted to account for any relevant Capacity Load Obligation Bilaterals, as described in Section III.13.7.3.1 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 is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Performance Payment is the performance-dependent portion of revenue received in the Forward Capacity Market beginning on June 1, 2018 pursuant to rules filed with the Commission on July 14, 2014.

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 Requirement is described in Section III.13.7.3.1 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 Right (CTR) is a financial right that entitles the holder to the difference in the Net Regional Clearing Prices between Capacity Zones for which the transfer right is defined, in the MW amount of the holder's entitlement.

Capacity Transferring Resource is a resource that has a Capacity Supply Obligation and is seeking to shed such obligation, or a portion thereof, through a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1 of Market Rule 1.

Capacity Value is the value (in kW-month) of a Demand Resource for a month determined pursuant to Section III.13.7.1.5 of Market Rule 1.

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.

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.

Carried Forward Excess Capacity is calculated as described in Section III.13.2.7.8.2.1(c) of Market Rule 1.

Category A Designated Blackstart Resource is a Designated Blackstart Resource that has committed to provide Blackstart Service under a "Signature Page for Schedule 16 of the NEPOOL OATT" that was executed and in effect prior to January 1, 2013 and has not been converted to a Category B Designated Blackstart Resource.

Category B Designated Blackstart Resource is a Designated Blackstart Resource that is not a Category A 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.

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 power year, 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 in all Load Zones. 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, for the purposes of the ISO New England Financial Assurance Policy, is defined in Section VII.A of that policy.

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 (1) the clearing of the Static De-List Bids or the Permanent De-List Bids of all the Existing Generating Capacity Resources comprising the Station; or (2) the acceptance of a Non-Price Retirement Request of 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.

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.

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, a performance or surety bond, or a combination thereof.

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)(iii) of Market Rule 1.

Day-Ahead Congestion Revenue is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Demand Reduction Obligation is a cleared Demand Reduction Offer multiplied by one plus the percent average avoided peak distribution losses. For Capacity Commitment Periods commencing on or after June 1, 2017, Day-Ahead Demand Reduction Obligation is the hourly demand reduction amounts of a Demand Response Resource scheduled by the ISO as a result of the Day-Ahead Energy Market, multiplied by one plus the percent average avoided peak distribution losses.

Day-Ahead Energy Market means the schedule of commitments for the purchase or sale of energy, 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 and purchase of demand

reductions pursuant to Appendix III.E2 of Market Rule 1 for Capacity Commitment Periods commencing on or after June 1, 2017.

Day-Ahead Energy Market Congestion Charge/Credit is defined in Section III.3.2.1(d) of Market Rule 1.

Day-Ahead Energy Market Energy Charge/Credit is defined in Section III.3.2.1(d) of Market Rule 1.

Day-Ahead Energy Market Loss Charge/Credit is defined in Section III.3.2.1(d) 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)(ii) of Market Rule 1.

Day-Ahead Load Obligation is defined in Section III.3.2.1(a)(i) of Market Rule 1.

Day-Ahead Load Response Program provides a Day-Ahead aspect to the Load Response Program. The Day-Ahead Load Response Program allows Market Participants with registered Load Response Program Assets to make energy reduction offers into the Day-Ahead Load Response Program concurrent with the Day-Ahead Energy Market.

Day-Ahead Locational Adjusted Net Interchange is defined in Section III.3.2.1(a)(iv) of Market Rule 1.

Day-Ahead Loss Charges or Credits is defined in Section III.3.2.1(h) of Market Rule 1.

Day-Ahead Loss Revenue is defined in Section III.3.2.1(g) of Market Rule 1.

Day-Ahead Prices means the Locational Marginal Prices resulting from the Day-Ahead Energy Market.

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 Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for Demand Response Resources, Real-Time Demand Response Resources and Real-Time Emergency Generation 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 Real-Time Demand Response Asset to reduce demand. For Capacity Commitment Periods commencing on or after June 1, 2017, Demand Reduction Offer is an offer by a Market Participant with a Demand Response Resource to reduce demand.

Demand Reduction Threshold Price is a minimum offer price calculated pursuant to Section III.E1.6 and Section III.E2.6.

Demand Reduction Value is the quantity of reduced demand calculated pursuant to Section III.13.7.1.5.3 of Market Rule 1.

Demand Resource is a resource defined as Demand Response Capacity Resources, On-Peak Demand Resources, Seasonal Peak Demand Resources, Real-Time Demand Response Resources, or Real-Time Emergency Generation Resources. Demand Resources are installed measures (i.e., products, equipment, systems, services, practices and/or strategies) that result in additional and verifiable reductions in end-use demand on the electricity network in the New England Control Area pursuant to Appendix III.E1 and Appendix III.E2 of Market Rule 1, or during Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, respectively. A Demand Resource may include a portfolio of measures aggregated together to meet or exceed the minimum Resource size requirements of the Forward Capacity Auction.

Demand Resource Commercial Operation Audit is an audit initiated pursuant to Section III.13.6.1.5.4.4.

Demand Resource Forecast Peak Hours are those hours, or portions thereof, in which, absent the dispatch of Real-Time Demand Response Resources, Dispatch Zone, Load Zone, or system-wide implementation of the action of ISO New England Operating Procedure No. 4 where the ISO would have begun to allow the depletion of Thirty-Minute Operating Reserve is forecasted in the ISO's most recent next-day forecast.

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 Operable Capacity Analysis means an analysis performed by the ISO estimating the expected dispatch hours of active Demand Resources given different assumed levels of Demand Resources clearing in the primary Forward Capacity Auction.

Demand Resource Performance Incentives means the additional monthly capacity payment that a Demand Resource may earn for producing a positive Monthly Capacity Variance in a period where other Demand Resources yield a negative monthly capacity variance.

Demand Resource Performance Penalties means the reduction in the monthly capacity payment to a Demand Resource for producing a negative Monthly Capacity Variance.

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 the pumping load associated with pumped storage generators) 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 that meets the registration requirements in Section III.E2.2. The demand reduction of a Demand Response Asset is the difference between the Demand Response Asset's actual demand measured at the Retail Delivery Point, which could reflect Net Supply, at the time the Demand Response Resource to which the asset is associated is dispatched by the ISO, and its adjusted Demand Response Baseline.

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 or the expected output levels of the generation of an individual end-use metered customer whose asset is comprised of Distributed Generation as determined pursuant to Section III.8A or Section III.8B.

Demand Response 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.

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 Regulation Resource is a Real-Time Demand Response Resource eligible to provide Regulation.

Demand Response Resource is an individual Demand Response Asset or aggregation of Demand Response Assets within a Dispatch Zone that meets the registration requirements and participates in the Energy Market pursuant to Appendix III.E2 of Market Rule 1 for Capacity Commitment Periods commencing on or after June 1, 2017.

Demand Response Resource Notification Time is the minimum time, from the receipt of a Dispatch Instruction, that it takes a Demand Response Resource that was not previously reducing demand to start 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 time required from the time a Demand Response Resource that was not previously reducing demand starts reducing demand in response to a Dispatch Instruction and the time the resource achieves its Minimum Reduction.

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, and may be a Category A Designated Blackstart Resource or a Category B Designated Blackstart Resource.

Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for generation 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) is the Dispatch Rate expressed in megawatts.

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 Resources, change External Transactions, or change the status 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 Rate means the control signal, expressed in dollars per MWh and/or megawatts, calculated and transmitted to direct the output, consumption or demand reduction level of each generating Resource, Dispatchable Asset Related Demand and Demand Response Resource dispatched by the ISO in accordance with the Offer Data.

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.13.1.4.6.1.

Dispatchable Asset Related Demand is any portion of an Asset Related Demand of a Market Participant that is capable of having its energy consumption modified in Real-Time in response to Dispatch Instructions has Electronic Dispatch Capability, and 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 Manuals. Pumped storage facilities may qualify as Dispatchable Asset Related Demand resources, however, such resources shall not qualify as a capacity resource for both the generating output and dispatchable pumping demand of the facility.

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 resources directly connected to end-use customer load and located behind the end-use customer's meter, which reduce the amount of energy that would otherwise have been produced by other capacity resources on the electricity network in the New England Control Area during Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, provided that the aggregate nameplate capacity of the generation resource does not exceed 5 MW, or does not exceed the most recent annual non-coincident peak demand of the end-use metered customer at the location where the generation resource is directly connected, whichever is greater. Generation resources cannot participate in the Forward Capacity Market or the Energy Markets as Demand Resources or Demand Response Resources, unless they meet the definition of Distributed Generation.

Do Not Exceed Dispatch Point is a Dispatch Instruction indicating a maximum output level that a wind resource must not exceed.

DR Auditing Period is the summer DR Auditing Period or winter DR Auditing Period as defined in Section III.13.6.1.5.4.3.1.

Dynamic De-List Bid is a bid that may be submitted by Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Forward Capacity Auction at or 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 level to which a Resource would have been dispatched, based on the Resource's Supply Offer 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 resource that a Market Participant offers to supply in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the resource's Supply Offer. This represents the highest MW output a Market Participant has offered for a resource for economic dispatch. A Market Participant must maintain an up-to-date Economic Maximum Limit for all hours in which a resource has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Economic Minimum Limit or Economic Min is (a) for Resources 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 Resources without an incremental heat rate, the lowest sustainable output level that is consistent with the physical design characteristics of the Resource and with meeting all environmental regulations and licensing limits, and

(c) for Resources undergoing Facility and Equipment Testing or auditing, the level to which the Resource 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 set of Supply Offer values that are 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.

Electronic Dispatch Capability is the ability to provide for the electronic transmission, receipt, and acknowledgment of data relative to the dispatch of generating units and Dispatchable Asset Related Demands and the ability to carry out the real-time dispatch processes from ISO issuance of Dispatch Instructions to the actual increase or decrease in output of dispatchable Resources.

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 generation amount, in MWs, that a generating unit 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 hours for which the Customer has a positive or negative Real-Time System Adjusted Net Interchange as determined by the ISO settlement process for the Energy Market.

Energy Offer Cap is \$1,000/MWh.

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 and Energy Non-Zero Spot Market Settlement Hours.

Enrolling Participant is the Market Participant that registers Customers for the Load Response Program.

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, the Capacity Requirement 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.

Estimated Net Regional Clearing Price (ENRCP) is calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

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 by 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, and, subject to ISO evaluation, for the Forward Capacity Auction to be conducted beginning February 1, 2008, any resource that is under construction and within 12 months of its expected commercial operations date.

Existing Demand Resource is a type of Demand Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1.1 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.

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; (v) is capable of receiving and acknowledging a Dispatch Instruction electronically; and (vi) has satisfied its Minimum Time Between Reductions.

Fast Start Generator means a generating unit that the ISO may dispatch within the hour 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 and manned or has automatic remote dispatch capability; (v) capable of receiving and acknowledging a start-up or shut-down dispatch instruction electronically; and (vi) has satisfied its minimum down time.

FCA Cleared Export Transaction is defined in Section III.1.10.7(f)(ii) of Market Rule 1.

FCA Payment is the monthly capacity payment for a resource whose offer has cleared in a Forward Capacity Auction as described in Section III.13.7.2.1.1(a) 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 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.

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.

Forecast Hourly Demand Reduction means the estimated maximum quantity of energy reduction (MWh), measured at the end-use customer meter that can be produced by a Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource, in each hour of an Operating Day. For a Real-Time Emergency Generation Asset that is metered at the generator and associated with a Real-Time Emergency Generation Resource, the Forecast Hourly Demand Reduction means the estimated maximum generator output (MWh) in each hour of an Operating Day.

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 descending clock auction in the Forward Capacity Market, as 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 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 \$14,000/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 Award Financial Assurance is a required amount of financial assurance that must be maintained at all times from a Designated FTR Participant for each FTR awarded to the participant in any FTR Auctions. This amount is calculated pursuant to Section VI.C of the ISO New England Financial Assurance Policy.

FTR Bid Financial Assurance is an amount of financial assurance required from a Designated FTR Participant for each bid submission into an FTR auction. This amount is calculated pursuant to Section VI.B of the ISO New England Financial Assurance Policy.

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 generator that has been registered 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 Adjusted Audited Demand Reduction is calculated in accordance with Section III.13.7.1.5.10.1.2.

Hourly Calculated Demand Resource Performance Value means the performance of a Demand Resource during Real-Time Demand Response Event Hours and Real-Time Emergency Generation Event Hours for purposes of calculating a Demand Reduction Value pursuant to Sections III.13.7.1.5.7.3 and III.13.7.1.5.8.3.

Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Hourly PER is calculated in accordance with Section III.13.7.2.7.1.1.1(a) of Market Rule 1.

Hourly Real-Time Demand Response Resource Deviation means the difference between the Average Hourly Load Reduction or Average Hourly Output of the Real-Time Demand Response Resource and the amount of load reduction or output that the Market Participant was instructed to produce pursuant to a Dispatch Instruction calculated pursuant to Section III.13.7.1.5.7.3.1.

Hourly Real-Time Emergency Generation Resource Deviation is calculated pursuant to Section III.13.7.1.5.8.3.1.

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.

Inadequate Supply is defined in Section III.13.2.8.1 of Market Rule 1.

Inadvertent Energy Revenue is defined in Section III.3.2.1(k) of Market Rule 1.

Inadvertent Energy Revenue Charges or Credits is defined in Section III.3.2.1(l) 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 generation 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.

Insufficient Competition is defined in Section III.13.2.8.2 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 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.

Intermittent Power Resource is defined in Section III.13.1.2.2.2 of Market Rule 1.

Intermittent Settlement Only Resource is a Settlement Only Resource that is also an Intermittent Power Resource.

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.

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.

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 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.

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 generating resources 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.

Load Management means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that curtail electrical usage or shift electrical usage from Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, or Real-Time Demand Response Event Hours to other hours and reduce the amount of capacity needed, 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, chilled water storage, and other forms of electricity storage.

Load Response Program means the program implemented and administered by the ISO to promote demand side response as described in Appendix E to Market Rule 1.

Load Response Program Asset means one or more individual end-use metered customers that report load reduction and consumption, or generator output as a single set of values, are assigned an identification number, that participate in the Load Response Program and which encompass assets registered in the Real-Time Price Response Program or Real-Time Demand Response Assets, and are further described in Appendix E of Market Rule 1.

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 the minimum amount of capacity that must be located within an import-constrained Load Zone, calculated as described in Section III.12.2 of Market Rule 1.

Local System Planning (LSP) is the process defined in Appendix 1 of Attachment K to the OATT.

Localized Costs are the incremental costs resulting from a RTEP02 Upgrade or a Regional Benefit Upgrade or a Public Policy Transmission Upgrade that exceeds those requirements that the ISO deems reasonable and consistent with Good Utility Practice and the current engineering design and construction practices in the area in which the Transmission Upgrade is built. In making its determination of whether Localized Costs exist, the ISO will consider, in accordance with Schedule 12C of the OATT, the reasonableness of the proposed engineering design and construction method with respect to alternate feasible Transmission Upgrades and the relative costs, operation, timing of implementation, efficiency and reliability of the proposed Transmission Upgrade. The ISO, with advisory input from the Reliability Committee, as appropriate, shall review such Transmission Upgrade, and determine whether there are any Localized Costs resulting from such Transmission Upgrade. If there are any such costs, the ISO shall identify them in the Regional System Plan.

Location is a Node, External Node, Load Zone or Hub. For Capacity Commitment Periods commencing on or after June 1, 2017, the Location also is a Dispatch Zone.

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 or Reliability Region is the Zonal Price for that Load Zone or Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub. For Capacity Commitment Periods

commencing on or after June 1, 2017, the Location Marginal Price for a Dispatch Zone is the Zonal Price for that Dispatch Zone.

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.

Lump Sum Blackstart CIP Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Major Transmission Outage is a major transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Manual Response Rate is the rate, in MW/Minute, at which the output of a Generator Asset is capable of changing.

Marginal Loss Revenue Load Obligation is defined in Section III.3.2.1(b)(v) of Market Rule 1.

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 the maximum amount of capacity that can be procured in an export-constrained Load Zone, calculated as described in Section III.12.2 of Market Rule 1, to meet the Installed Capacity Requirement.

Maximum Consumption Limit is the maximum amount, in MW, available from the Dispatchable Asset Related Demand for economic dispatch and is based on the physical characteristics as submitted as part of a Resource's Offer Data except that a Self-Scheduled Dispatchable Asset Related Demand may modify its Minimum Consumption Limit on an hourly basis, as part of its Demand Bid, in order to indicate the desired level of Self-Scheduled MW.

Maximum Facility Load is the most recent annual non-coincident peak demand or, if unavailable, an estimate of the annual non-coincident peak demand of a Real-Time Demand Response Asset or a Real-Time Emergency Generation Asset, where the demand evaluated is established by adding actual metered demand and the output of all generators located behind the asset's end-use customer meter in the same time intervals.

Maximum Generation is the maximum generation output of a Real-Time Demand Response Asset comprised of Distributed Generation or the maximum generation output of a Demand Response Asset comprised of Distributed Generation.

Maximum Interruptible Capacity is an estimate of the maximum hourly demand reduction amount that a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or a Demand Response Asset can deliver. For assets that deliver demand reduction, the Maximum Interruptible Capacity is the asset's peak load less its uninterruptible load. For assets that deliver reductions through the use of generation, the Maximum Interruptible Capacity is the difference between the generator's maximum possible output and its expected output when not providing demand reduction. For assets that deliver demand reduction and Net Supply, the Maximum Interruptible Capacity is the asset's peak load plus Maximum Net Supply as measured at the Retail Delivery Point.

Maximum Load is the most recent annual non-coincident peak demand or, if unavailable, an estimate of the annual non-coincident peak demand, of a Demand Response Asset, Real-Time Demand Response Asset or Real-Time Emergency Generation Asset.

Maximum Net Supply is an estimate of the maximum hourly Net Supply for a Demand Response Asset as measured from the Demand Response Asset's Retail Delivery Point.

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 a 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 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 Value of the Demand 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 Value for an Existing Demand Resource is not overstated in a subsequent Capacity Commitment Period. Measure Life shall be determined consistent with the Demand 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, which includes 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 a Demand Resource supplier 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 Demand Resource suppliers 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 Value of the 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 a Demand Resource supplier with the monthly settlement report for the Forward Capacity Market, which documents the total Demand Reduction Values for all Demand Resources in operation as of the end of the previous month.

MEPCO Grandfathered Transmission Service Agreement (MGTSA) 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), MGTSA 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.

Minimum Consumption Limit is the minimum amount, in MW, available from a Dispatchable Asset Related Demand that is not available for economic dispatch and is based on the physical characteristics as submitted as part of a Resource's Offer Data.

Minimum Down Time is the number of hours that must elapse after a Generator Asset has been released for shutdown at or below its Economic Minimum Limit before the Generator Asset can be brought online and be released for dispatch at its Economic Minimum Limit.

Minimum Generation Emergency means an Emergency declared by the ISO in which the ISO anticipates requesting one or more generating Resources 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.

Minimum Time Between Reductions is the minimum number of hours that a Market Participant requires between the time the Demand Response Resource receives a Dispatch Instruction from the ISO to not reduce demand and the time the Demand Response Resource receives a Dispatch Instruction from the ISO to reduce demand.

Monthly Blackstart Service Charge is the charge made to Transmission Customers pursuant to Section 6 of Schedule 16 to the OATT.

Monthly Capacity Variance means a Demand Resource's actual monthly Capacity Value established pursuant to Section III.13.7.1.5.1 of Market Rule 1, minus the Demand Resource's final Capacity Supply Obligation for the month.

Monthly Peak is defined in Section II.21.2 of the OATT.

Monthly PER is calculated in accordance with Section III.13.7.2.7.1.1.2(a) of Market Rule 1.

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.

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.

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 the first-year 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, in its first year of operation, to be economically viable given reasonable expectations of the first year energy and ancillary services revenues, and projected revenue for subsequent years.

Net Regional Clearing Price is described in Section III.13.7.3 of Market Rule 1.

Net Supply is energy injected at the Retail Delivery Point by a Demand Response Asset with Distributed Generation.

Net Supply Limit is the estimated portion of the offered Maximum Reduction of a Demand Response Resource that would be provided through Net Supply. The Net Supply Limit is calculated by multiplying the offered Maximum Reduction of the Demand Response Resource by the ratio of total Net Supply to total demand reduction performance from the prior like Seasonal DR Audit of the Demand Response Assets that are mapped to the Demand Response Resource for the month.

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 Resource, as described in Section III.13.2.3.2 of Market Rule 1.

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 Required is the amount of additional capacity required to meet the Installed Capacity Requirement or a Capacity Zone's Local Sourcing Requirement, as described in Section III.13.2.8.1.1 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 Resource Show of Interest Form, as described in Section III.13.1.10 of Market Rule 1.

New Demand Resource is a type of Demand Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1.2 of Market Rule 1.

New Demand Resource Qualification Package is the information that a Project Sponsor must submit, in accordance with Section III 13.1.4.2.3 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Demand Resource.

New Demand Resource Show of Interest Form is described in Section III.13.1.4.2 of Market Rule 1.

New Demand Response Asset is a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or Demand Response Asset that is registered with the ISO, has been mapped to a

resource, is ready to respond, and has been included in the dispatch model of the remote terminal unit but does not have a winter audit value and a summer audit value.

New Demand Response Asset Audit is an audit of a New Demand Response Asset performed pursuant to Section III.13.6.1.5.4.8.

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.

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.

Nodal Amount is node(s)-specific on-peak and off-peak proxy value to which an FTR bid or awarded FTR bid relates.

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 generating unit that must be paid to Market Participants with an Ownership Share in the unit 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 generating unit 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.13.7.3.1.3.

Non-Commercial Capacity is the capacity of a New Capacity Resource or an increment of an Existing Capacity Resource that is treated as a New Capacity Resource in the Forward Capacity Auction and that has not been declared commercial and has not had its capacity rating verified by the ISO.

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-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.

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-Intermittent Settlement Only Resource is a Settlement Only Resource that is not an Intermittent Power Resource.

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-Price Retirement Request is a binding request to retire the entire capacity of a Generating Capacity Resource as described in Section III.13.1.2.3.1.5.

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.

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 generating unit and Dispatchable Asset Related Demand, and for Capacity Commitment Periods commencing on or after June 1, 2017, Demand Response Resource operating limits based on physical characteristics, and information necessary to schedule and dispatch generating and Dispatchable Asset Related Demand Resources, and for Capacity Commitment Periods commencing on or after June 1, 2017. Demand Response Resources for the provision of energy and 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.

Offered CLAIM10 is, for a generating Resource, a Supply Offer value between 0 and the CLAIM10 of the Resource that represents the amount of TMNSR available from the Resource from an off-line state, and, for a Dispatchable Asset Related Demand or Demand Response Resource that has not been dispatched, is a Demand Bid or Demand Reduction Offer value between 0 and the CLAIM10 of the Resource that represents the amount of TMNSR or TMSR available from the Resource.

Offered CLAIM30 is a Supply Offer, Demand Bid or Demand Reduction Offer value between 0 and the CLAIM30 of a Resource that represents the amount of TMOR available from an off-line generating Resource, or Dispatchable Asset Related Demand or Demand Response Resource that has not been dispatched.

Offered Full Reduction Time is the value calculated pursuant to Section III.13.6.1.5.4.6.

On-Peak Demand Resource is a type of Demand 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 generating unit asset or Load Asset, where such unit or load 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.

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.13.7.2.7.1 of Market Rule 1.

PER Proxy Unit is described in Section III.13.7.2.7.1 of Market Rule 1.

Percent of Total Demand Reduction Value Complete means the delivery schedule as a percentage of a Demand Resource's total Demand Reduction Value that will be or has been achieved as of specific target dates, as described in Section III.13 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 Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.2 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 II Transfer Credit is 60% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

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.

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(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.

Poorly Performing Resource is described in Section III.13.7.1.1.5 of Market Rule 1.

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 Credit for Dispatchable Asset Related Demand Resources (Pumps Only) Postured for Reliability, 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 Resource participate in the Forward Capacity Market, as described in Section III.13.

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.

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.

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.

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 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)(iii) of Market Rule 1.

Real-Time Adjusted Load Obligation Deviation is defined in Section III.3.2.1(c)(iii) 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(f) of Market Rule 1.

Real-Time Demand Reduction Obligation is a Real-Time demand reduction amount determined pursuant to Section III.E1.8 for Capacity Commitment Periods commencing prior to June 1, 2017, and Section III.E2.7 for Capacity Commitment Periods commencing on or after June 1, 2017.

Real-Time Demand Resource Dispatch Hours means those hours, or portions thereof, in which ISO New England Operating Procedure No. 4 is implemented and the ISO has begun to allow the depletion of Thirty-Minute Operating Reserve on a Dispatch Zone, Load Zone, or system-wide basis, and the ISO notifies the Market Participants with Real-Time Demand Response Resources of such hours.

Real-Time Demand Response Asset means one or more individual end-use metered customers that are located at a single Node, report load reduction and consumption, or generator output as a single set of values, are assigned a unique asset identification number by the ISO, and that participate in the Forward Capacity Market as part of a Market Participant's Real-Time Demand Response Resource.

Real-Time Demand Response Event Hours means hours when the ISO dispatches Real-Time Demand Response Resources in response to Real-Time Demand Resource Dispatch Hours, which may include Dispatch Zone, Load Zone, or system-wide dispatch of such resources.

Real-Time Demand Response Resource is a type of Demand Resource that is comprised of installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer

facilities that: (i) curtail electrical usage in response to a Dispatch Instruction; and (ii) continue curtailing electrical usage until receiving Dispatch Instructions to restore electrical usage. Such measures include Load Management and Distributed Generation. The period of curtailment shall be consistent with Real-Time Demand Response Event Hours.

Real-Time Dispatch NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Emergency Generation Asset means one or more individual end-use metered customers that are located at a single Node, report load reduction and consumption, or generator output as a single set of values, are assigned a unique asset identification number by the ISO, and that participate in the Forward Capacity Market as part of a Market Participant's Real-Time Emergency Generation Resource.

Real-Time Emergency Generation Event Hours means those hours, or portions thereof, between 7 a.m. and 7 p.m. Monday through Friday, non-Demand Response Holidays in which the ISO dispatches Real-Time Emergency Generation Resources on a Dispatch Zone, Load Zone, or system-wide basis when deficient in Thirty-Minute Operating Reserve and when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement.

Real-Time Emergency Generation Resource is Distributed Generation whose federal, state and/or local air quality permits, rules or regulations limit operation in response to requests from the ISO to the times when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement. A Real-Time Emergency Generation Resource must be capable of: (i) curtailing its end-use electric consumption from the New England grid within 30 minutes of receiving a Dispatch Instruction; and (ii) continuing that curtailment until receiving a Dispatch Instruction to restore consumption.

Real-Time Energy Market means the purchase or sale of energy, purchase of demand reductions pursuant to Appendix III.E2 of Market Rule 1, 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(e) of Market Rule 1.

Real-Time Energy Market Deviation Energy Charge/Credit is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Energy Market Deviation Loss Charge/Credit is defined in Section III.3.2.1(e) 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)(ii) of Market Rule 1.

Real-Time Generation Obligation Deviation is defined in Section III.3.2.1(c)(ii) of Market Rule 1.

Real-Time High Operating Limit is the maximum output, in MW, of a resource that could be achieved, consistent with Good Utility Practice, in response to an ISO request for Energy under Section III.13.6.4 of Market Rule 1, for each hour of the Operating Day, as reflected in the resource's Offer Data. This value is based on real-time operating conditions and the physical operating characteristics and operating permits of the unit.

Real-Time Load Obligation is defined in Section III.3.2.1(b)(i) of Market Rule 1.

Real-Time Load Obligation Deviation is defined in Section III.3.2.1(c)(i) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange is defined in Section III.3.2.1(b)(iv) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange Deviation is defined in Section III.3.2.1(c)(iv) of Market Rule 1.

Real-Time Loss Revenue is defined in Section III.3.2.1(i) 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 Price Response Program is the program described in Appendix E to Market Rule 1.

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 Dispatchable Asset Related Demand Resources (Pumps Only) Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

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.2.4 of Market Rule 1.

Real-Time Reserve Credit is a Market Participant's compensation associated with that Market Participant's Resources' Real-Time Reserve Designation 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 adjusted after-the-fact utilizing revenue quality meter data as described under Section III.10 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.5.6.1 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 an 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 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, for Capacity Commitment Periods commencing on or after June 1, 2017, 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 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 generating unit, a Dispatchable Asset Related Demand, an External Resource or an External Transaction or, for Capacity Commitment Periods commencing on or after June 1, 2017, a Demand Response Resource. For purposes of providing Regulation, Resource means a generating unit, a Dispatchable Asset Related Demand, a Demand Response Regulation Resource or an Alternative Technology Regulation 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.

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 generating unit or ISO-approved combination of units, and represent the maximum dependable load carrying ability of such unit or units, excluding capacity required for station use.

Seasonal Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.3.

Seasonal DR Audit is a seasonal audit of the demand response capability of a Demand Resource initiated pursuant to Section III.13.6.1.5.4.1.

Seasonal Peak Demand Resource is a type of Demand 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.

Self-Schedule is the action of a Market Participant in committing or scheduling its Resource, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Resource would have been scheduled or dispatched by the ISO to provide the service. For a Generator Asset, Self-Schedule is the action of a Market Participant in committing or scheduling 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 scheduled or dispatched by the ISO to provide the Energy. For a Dispatchable Asset Related Demand, Self-Schedule is the action of a Market Participant in committing or scheduling a Dispatchable Asset Related Demand to consume Energy in an hour at its Minimum Consumption Limit, whether or not in the absence of that action the Dispatchable Asset Related Demand would have been scheduled or dispatched by the ISO to consume Energy. Demand Response Resources are not permitted to Self-Schedule.

Self-Scheduled MW is an amount, in megawatts, that is Self-Scheduled and is equal to: (i) a Generator Asset's Economic Minimum Limit; (ii) a Dispatchable Asset Related Demand's Minimum Consumption Limit.

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 office.

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.D of the ISO New England Financial Assurance Policy.

Settlement Only Resources are generators of less than 5 MW or otherwise eligible for Settlement Only Resource treatment as described 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.

Shortage Event is defined in Section III.13.7.1.1.1 of Market Rule 1.

Shortage Event Availability Score is the average of the hourly availability scores for each hour or portion of an hour during a Shortage Event, as described in Section III.13.7.1.1.1.A of Market Rule 1.

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.

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).

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 generating unit to Market Participants with an Ownership Share in the unit each time the unit 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 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 risk-adjusted going forward costs associated with a Station that are avoided only by (1) the clearing of the Static De-List Bids or the Permanent De-List Bids of all the Existing Generating Capacity Resources comprising the Station; or (2) the acceptance of a Non-Price Retirement Request of the Station, calculated in the same manner as the net-risk adjusted going forward costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.2.

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.

Successful FCA is a Forward Capacity Auction in which a Capacity Zone has neither Inadequate Supply nor Insufficient Competition.

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. 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.

Supplemental Availability Bilateral is described in Section III.13.5.3.2 of Market Rule 1.

Supplemental Capacity Resources are described in Section III.13.5.3.1 of Market Rule 1.

Supplemented Capacity Resource is described in Section III.13.5.3.2 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-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 the reserve capability of (1) a generating Resource that can be converted fully into energy within ten minutes from the request of the ISO (2) a Dispatchable Asset Related Demand that can be fully utilized within ten minutes from the request of the ISO to reduce consumption; or (3) a Demand Response Resource that can provide demand reduction within ten minutes from the request of the ISO.

Ten-Minute Non-Spinning Reserve Service is the form of Ancillary Service described in Schedule 6 of the OATT.

Ten-Minute Spinning Reserve (TMSR) is the reserve capability of (1) a generating Resource that is electrically synchronized to the New England Transmission System that can be converted fully into energy within ten minutes from the request of the ISO; (2) a Dispatchable Asset Related Demand pump that is electrically synchronized to the New England Transmission System that can reduce energy consumption to provide reserve capability within ten minutes from the request of the ISO; or (3) a Demand Response Resource that can provide demand reduction within ten minutes from the request of the ISO for which none of the associated Demand Response Assets have a generator whose output can be controlled located behind the Retail Delivery Point other than emergency generators that cannot operate electrically synchronized to the New England Transmission System.

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) means the reserve capability of (1) a generating Resource that can be converted fully into energy within thirty minutes from the request of the ISO (2) a Dispatchable Asset Related Demand that can be fully utilized within thirty minutes from the request of the ISO to reduce consumption; or (3) a Demand Response Resource that can provide demand reduction within thirty minutes from the request of the ISO.

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 O&M Payment is the annual compensation calculated under either Section 5.1 or 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 Negative Hourly Demand Response Resource Deviation means the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Dispatch Zone.

Total Positive Hourly Demand Response Resource Deviation means the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Dispatch Zone.

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 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.

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 Demand Resource project. The Updated Measurement and Verification Plan may include updated Demand Resource 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 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.

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. 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.

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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) = Cost (X) / (1+D)^{N(X)}
 - Present Value of Cost (Y) = PV Cost (Y) = Cost (Y) / (1+D)^{N(Y)}
 - Cost Allocation to Region A = Cost (Z) x PV Cost (X)/[PV Cost (X) + PV Cost (Y)]

- $\text{Cost Allocation to Region B} = \text{Cost (Z)} \times \text{PV Cost (Y)} / [\text{PV Cost (X)} + \text{PV Cost (Y)}]$
- 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:
 - $\text{PV Cost (X)} = 60 / (1 + 0.075)^{8.25} = 33.039$ Million
 - $\text{PV Cost (Y)} = 40 / (1 + 0.075)^{4.50} = 28.888$ 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 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.

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 Section 4.1(f) 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) or 4.3 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 during a given year. 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 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, and (iv) potential market responses to the needs identified by the ISO in a Needs Assessment or the RSP. 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

Any entity, including State regulators or agencies and NESCOE, as specified in Attachment N of the OATT, may designate a member to the Planning Advisory Committee by providing written notice to the Secretary of that Committee identifying the name of the entity represented by the member and the member's name, address, telephone number, facsimile number and electronic mail address. The entity may remove or replace such member at any time by written notice to the Secretary of the Planning Advisory Committee.

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, may meet 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. 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.

The RSP shall also include 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. Each annual assessment will model out-of-service all Non-Price Retirement Requests and Permanent De-List Bids as well as rejected for reliability Static De-List Bids and rejected for reliability Dynamic De-List Bids from the most recent Forward Capacity Auction.

Each RSP shall be built upon the previous year's 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 and 4.3 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 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) 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) Concept; (ii) Proposed; (iii) Planned; (iv) Under Construction; and (v) 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, “Concept” shall include a transmission project that is being considered by its proponent as a potential solution to meet a need identified by the ISO in a Needs Assessment or the RSP, but for which there is little or no analysis available to support the transmission project.

- (ii) 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.

(iii) “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.

(iv) “Under Construction” shall include a Transmission Upgrade that has received the approvals required under the Tariff and engineering and construction is underway.

(v) “In Service” shall include a Transmission Upgrade that has been placed in commercial operation.

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.

(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; and (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. 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 Section 4.1(f) of this Attachment and has been determined, pursuant to Section 4.1(f) 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 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 Non-Applicability of Sections 4.1 through 4.3; 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 Sections 4A.5(e) or 4A.7, respectively, 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, if:

- (i) a need for additional transfer capability is identified by the ISO in its ongoing evaluation of the PTF's adequacy and performance;
- (ii) a need for additional transfer capability is identified as a result of an ERO and/or NPCC reliability assessment or more stringent publicly available local reliability criteria, if any;
- (iii) constraints or available transfer capability limitations that are identified possibly as a result of generation additions or retirements, evaluation of load forecasts or proposals for the addition of transmission facilities in the New England Control Area;
- (iv) as requested by a stakeholder pursuant to the provisions of Section 4.1(b) of this Attachment; or
- (v) as otherwise deemed appropriate by the ISO as warranting such an assessment.

(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 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 Non-Price Retirement Requests and De-List Bids

- (i) Where a Needs Assessment is underway for an area affected by a rejected Permanent De-List Bid or Non-Price Retirement Request, the Needs Assessment will represent the resource with the rejected Permanent De-List Bid as being interconnected, but unavailable for reliability purposes, and the Non-Price Retirement Request as being retired in the base representation being used to assess the system to identify reliability needs that must be addressed.
- (ii) Where there is not a Needs Assessment underway for an area affected by a rejected Permanent De-List Bid or Non-Price Retirement Request, the ISO will initiate a Needs Assessment for that area.
- (iii) 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.

- (iv) 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 de-list bids or Non-Price Retirement Requests 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 Solutions 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. With respect to (ii) or (iii) above, the proponent of the market response shall inform the ISO, in writing, of its selection or its assumption of financially binding obligations, respectively. 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. The ISO will also present the Needs Assessments in appropriate market forums to facilitate market responses. 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 or Stage One Proposal submitted in response to a public notice issued under Sections 4.3(a) or 4A.5(a) of this Attachment, respectively, or only one proposed solution that is selected to move on to Phase Two or Stage Two, 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 competition, as described in Section 4.3 of this Attachment.

(j) Requirements for Use of Solution Studies Rather than Competitive Process for

Projects Based on Year of Need

The following requirements must be met in order for the ISO to use Solution 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 Participating Transmission Owner 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 30-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 Solution 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 either a Reliability Transmission Upgrade and/or a Market Efficiency Transmission Upgrade pursuant to the standards set forth in Attachment N of this OATT.

(d) 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.

4.3 Competitive Solution Process for Reliability Transmission Upgrades and Market Efficiency Transmission Upgrades

(a) Public Notice Initiating Competitive Solution Process

The ISO will issue a public notice 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 notice will indicate that Qualified Transmission Project Sponsors may submit Phase One Proposals offering solutions that comprehensively address the identified needs.

A PTO or PTOs shall submit an individual or joint Phase One Proposal as a Backstop Transmission Solution for any need 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 Proposal (and to develop and construct the project, if selected in the competitive 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 project sponsor. If more than one Qualified Transmission Project Sponsor expresses interest, the Planning Advisory Committee member shall select the sponsor. In either case, the designated 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 in Phase One.

(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;
- (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 lifecycle cost of the proposed solution, including a high-level itemization of the components of the cost estimate.

With each proposal, the Qualified Transmission Project Sponsor must include payment of a \$100,000 study deposit per submitted proposal to support the cost of Phase One and Phase Two

study work by the ISO. The deposit of \$100,000 shall be applied towards the costs incurred by the ISO associated with the study of the Phase One and Phase Two proposal.

Phase One Proposals must be submitted by the deadline specified in the posting by the ISO of the public notice described in Section 4.3(a) of this Attachment, which shall not be less than 60 days from the posting date of the notice. The ISO may reject submittals which are insufficient or not adequately supported.

(d) LSP Coordination

Sponsors of Phase One Proposals shall also identify any LSP plans that require coordination with their proposals.

(e) Preliminary Review by ISO

If the sole Phase One Proposal in response to a given Needs Assessment has been submitted by PTO(s), proposing a project that would be located within or connected to its/their existing electric system, the ISO shall proceed under Section 4.2(a)-(d) 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 public notice 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(a) in the information provided in connection with a proposed Phase One Proposal, the ISO will notify the Phase One Proposal sponsor and provide an opportunity for the sponsor to cure the deficiencies within the timeframe specified by the ISO. Upon request, sponsors of Phase 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 Phase One Proposals. In providing information under this subsection (f), or in Phase Two, the sponsor may not modify its project materially or submit a new project, but instead may clarify its project. Phase Two Proposals 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(c). 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, based on a determination that the project 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 Phase Two.

(h) Information Required for Phase Two Solutions; Identification and Reporting of Preliminary Preferred Phase Two Solution

Qualified Transmission Project Sponsors of projects 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 costs;
- (vi) design standards to be used;
- (vii) description of the authority the sponsor has to acquire necessary rights of way;
- (viii) experience of the 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 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 project 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 solution.

(i) Reimbursement of Phase Two Solution Costs; Collection and Refund of ISO Study Costs

Qualified Transmission Project Sponsors whose projects 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 project 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 and Phase Two studies for a project 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) Inclusion of Preferred Phase Two Solution in RSP and/or RSP Project List

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 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) Milestone Schedules

Within 30 Business Days of its receiving notification pursuant to Section 4.3(j) of this Attachment, the Qualified Transmission Project Sponsor shall submit to the ISO (and shall update periodically) a schedule that indicates the dates by which applications for siting and other approvals necessary to develop and construct the project by the required in-service date shall be submitted. Within 30 Business Days of its receiving all necessary siting and other approvals, the Qualified Transmission Project Sponsor shall submit to the ISO its acceptance of responsibility to proceed with the project, and a schedule acceptable to the ISO of dates by which typical project construction phases will be completed. The Qualified Transmission Project Sponsor shall submit to the ISO on a monthly basis thereafter, until the project is placed into service, a report that provides updated information, as specified by the ISO, showing the progress of the project. The ISO shall provide notification to any PTO providing a Backstop Transmission Solution to cease developing its project as of the date of the selected sponsor's acceptance of responsibility.

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 implement the Backstop Transmission Solution, and 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 ISO shall 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. 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.

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: (i) provide NESCOE 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. By no later than April 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 has 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. 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 June 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. With respect to (ii) or (iii) above, the proponent of the market response shall inform the ISO, in writing, of its selection or its assumption of financially binding obligations, respectively. 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 Stage One Proposals

(a) Information Required for Stage One Proposals

The ISO will post on its website a notice 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 public notice, which shall be not less than 60 days from the date of posting the public notice) 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;
- (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 lifecycle cost of the proposed solution, including a high-level itemization of the components of the cost estimate.

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 “un-sponsored”) must identify a Qualified Transmission Project Sponsor willing to submit a corresponding Stage One Proposal and Stage Two Proposal (and to develop and construct the project, if selected in the competitive process) in order for the un-sponsored project to be submitted in response to an ISO solicitation in Stage One. 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 un-sponsored project. If only one Qualified Transmission Project Sponsor expresses interest, the ISO shall designate it as the project sponsor. If more than one Qualified Transmission Project Sponsor expresses interest, the Planning Advisory Committee member shall select the sponsor. In either case, the designated 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 un-sponsored project may not be submitted in Stage One.

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 and Stage Two study work by the ISO. The deposit of \$100,000 shall be applied towards the costs incurred by the ISO associated with the study of the Stage One and Stage Two proposal.

(b) LSP Coordination

Sponsors of Stage One Proposals shall also identify any LSP plans that require coordination with their 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.5(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.5(a)) in the information provided in connection with a proposed Stage One Proposal, the ISO will notify the Stage One Proposal sponsor and provide an opportunity for the sponsor to cure the deficiencies within the timeframe specified by the ISO. Upon request, 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, the sponsor may not modify its project materially or submit a new project, but instead may clarify its project. Stage Two Proposals 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.5(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 projects may also satisfy identified reliability needs of the system. The ISO with input from the Planning Advisory Committee may exclude projects from the list, and from consideration in Stage Two, based on a determination that the project is not competitive with other projects 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.6 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.5(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 project 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 and Stage Two studies for a project 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.7 Information Required for Stage Two Solutions; Identification and Reporting of Preliminary Preferred Stage Two Solution

Qualified Transmission Project Sponsors of projects listed pursuant to Section 4A.5(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 costs;
- (vi) design standards to be used;
- (vii) description of the authority the sponsor has to acquire necessary rights of way;

- (viii) experience of the 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 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 Phase One Proposals described in Section 4A.5(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 report the preliminary preferred Stage Two Solution(s), along with its views as to whether the preferred solution(s) also satisfies identified reliability needs of the system, to the Planning Advisory Committee and seek stakeholder input on the preliminary preferred solutions.

4A.8 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 project 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. 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) Milestone Schedules

Within 30 Business Days of its receiving notification pursuant to Section 4A.8(a) of this Attachment, the Qualified Transmission Project Sponsor shall submit to the ISO (and shall update periodically) a schedule that indicates the dates by which applications for siting and other approvals necessary to develop and construct the project by the required in-service date shall be submitted. Within 30 Business Days of its receiving all necessary siting and other approvals, the Qualified Transmission Project Sponsor shall submit to the ISO its acceptance of responsibility to proceed with the project, and a schedule acceptable to the ISO of dates by which typical project construction phases will be completed. The Qualified Transmission Project Sponsor shall submit to the ISO on a monthly basis thereafter, until the project is placed into service, a report that provides updated information (as specified by the ISO) showing the progress of the project.

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.

(c) Removal from RSP Project List

If a Public Policy Transmission Upgrade is removed from the RSP Project List by the ISO pursuant to Section 3.6(c), the entity responsible for the construction of the Public Policy 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 that Public Policy Transmission Upgrade.

4A.9 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.8 shall be allocated in accordance with Schedule 21 of the ISO OATT.

4B. Qualified Transmission Project Sponsors

4B.1 Periodic Evaluation of Applications

The ISO will periodically 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, upon its execution of the Non-incumbent Transmission Developer Operating Agreement (in the form specified in Attachment O of the OATT), 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; Annual Certification

Qualified Transmission Project Sponsors are listed in Appendix 3 of this Attachment K. 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 Inter-Area 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 annual 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 Inter-Area Coordination

The regional system planning process shall be conducted and the annual RSP shall be developed in coordination with the similar plans of the surrounding ISOs/RTOs and Control Areas pursuant to the Northeastern ISO/RTO Planning Coordination Protocol and other agreements with neighboring systems and NPCC. Inter-area planning studies shall be conducted over as broad a region as feasible, including adjacent Canadian systems who are members of NPCC, or its successor organization, and, as appropriate, MAAC and Reliability First, or their successor organizations. The ISO shall convene periodic meetings of the Planning Advisory Committee, within the scope of its respective functions of Section 2 of this Attachment, to provide input and feedback to the ISO concerning an Inter-area needs assessment and identification of potential market and regulated responses to the ISO's identification of inter-area needs.

7. Procedures for Development and Approval of the RSP

7.1 Initiation of RSP

Every year, the ISO shall initiate an effort to develop its annual 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.

7.2 Draft RSP; Public Meeting

On or about August of each year, 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.

On or about September of each year, 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 no later than September 30 of each year 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 No. 3 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.

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.

1.3 Role of the PTOs

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.

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 solution 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

Town of Braintree Electric Light Department
Central Maine Power Company
Chicopee Municipal Lighting Department
Connecticut Transmission Municipal Electric Energy Cooperative
The City of Holyoke Gas and Electric Department
Emera Maine
Green Mountain Power Corporation
The City of Holyoke Gas and Electric Department
Massachusetts Municipal Wholesale Electric Company
Maine Electric Power Company
Middleborough Gas and Electric Department
New England Power Company
New Hampshire Electric Cooperative, Inc.
New Hampshire Transmission, LLC
Northeast Utilities Service Company dba 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
Town of Reading Municipal Light Department
Shrewsbury Electric and Cable Operations
Taunton Municipal Lighting Plant
The United Illuminating Company
Unitil Energy Systems, Inc. and Fitchburg Gas and Electric Light Company
Vermont Electric Cooperative, Inc.
Vermont Electric Power Company, Inc.
Vermont Public Power Supply Authority

Vermont Transco LLC

Town of Wallingford – Electric Division

New England Hydro-Transmission Electric Company Inc.

New England Hydro-Transmission Corporation

ATTACHMENT K APPENDIX 3

LIST OF QUALIFIED TRANSMISSION PROJECT SPONSORS

APPENDIX 3

ATTACHMENT K

LIST OF QUALIFIED TRANSMISSION PROJECT SPONSORS

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

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One Sullivan Road

Holyoke, MA 01040

Telephone: (413) 535-4000

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[NTD]

[Name

Address

Phone:

Fax:]

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:

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.

Adjusted Audited Demand Reduction is the Audited Demand Reduction of a Demand Response Resource adjusted in accordance with Section III.13.7.1.5.10.1.1.

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 Capacity Price Rule is a rule potentially affecting Capacity Clearing Prices in a Forward Capacity Auction, as described in Section III.13.2.7.8 of Market Rule 1.

Alternative Dispute Resolution (ADR) is the procedure set forth in Appendix D to Market Rule 1.

Alternative Technology Regulation Resource is any Resource eligible to provide Regulation that is not registered as a different Resource type.

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.

Annualized FCA Payment is used to determine a resource's availability penalties and is calculated in accordance with Section III.13.7.2.7.1.2(b) of Market Rule 1.

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.

APR-1 means the first of three Alternative Capacity Price Rule mechanisms described in Section III.13.2.7.8.

APR-2 means the second of three Alternative Capacity Price Rule mechanisms described in Section III.13.2.7.8.

APR-3 means the third of three Alternative Capacity Price Rule mechanisms described in Section III.13.2.7.8.

Asset is a generating unit, interruptible load, a component of a demand response resource or load asset.

Asset Registration Process is the ISO business process for registering a physical load, generator, or tie-line for settlement purposes. The Asset Registration Process is posted on the ISO's website.

Asset Related Demand is a physical load that has been discretely modeled within the ISO's dispatch and settlement systems, settles at a Node and, except for pumped storage load, is made up of 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.

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 risk-adjusted going forward costs of an asset that is part of an Existing Generating Capacity Resource, calculated for the asset in the same manner as the net-risk adjusted going forward costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.2.

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.

Audited Demand Reduction is the seasonal claimed capability of a Demand Response Resource as established pursuant to Section III.13.6.1.5.4.

Audited Full Reduction Time is the Offered Full Reduction Time associated with the Demand Response Resource's most recent audit.

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 generating unit change its output while providing Regulation between the Regulation High Limit and Regulation Low Limit.

Average Hourly Load Reduction is either: (i) the sum of the 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; (ii) the sum of the 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; or (iii) in each Real-Time Demand Response Event Hour, the sum of the baseline electrical energy consumption less the sum of the actual electrical energy consumption of all of the Real-Time Demand Response Assets associated with the Real-Time Demand Response Resource as registered with the ISO as of the first day of the month; or (iv) in each Real-Time Emergency Generation Event Hour, the sum of the baseline electrical energy consumption less the sum of the actual electrical energy consumption of all of the Real-Time Emergency Generation Assets associated with the Real-time Emergency Generation Resource as registered with the ISO as of the first day of the month. The Demand Resource's electrical energy reduction and Average Hourly Load Reduction shall be determined consistent with the Demand 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 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; (ii) the sum of the 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; or (iii) in each Real-Time Demand Response Event Hour or Real-Time Emergency Generation Event Hour, the sum of the electrical energy output of all of the Real-Time Demand Response Assets or Real-Time Emergency Generation Assets associated with the Real-Time Demand Response Resource or Real-Time Emergency Generation Resource as registered with the ISO as of the first day of the month. Electrical energy output and Average Hourly Output shall be determined consistent with the Demand 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.13.7.2.7.1.1.2(a) 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.

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 CIP Capital Payment is the annual compensation level, as calculated pursuant to Section 5.1 utilizing data from Table 6 of Appendix A to this Schedule 16, or as referred to in Section 5.2, of Schedule 16 to the OATT, for a Blackstart Station's costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service.

Blackstart CIP O&M Payment is the annual compensation level, as calculated pursuant to Section 5.1 of Schedule 16 to the OATT, utilizing data from Table 6 of Appendix A to this Schedule 16, for a Blackstart Station's operating and maintenance costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of the provision 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 compensation, as calculated pursuant to Section 5.1 of Schedule 16 to the OATT, for a Designated Blackstart Resource's operating and maintenance costs associated with the provision of Blackstart Service (except for operating and maintenance costs associated with compliance with NERC Critical Infrastructure Protection Reliability Standards as part of Blackstart Service).

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, which also encompasses "System Restoration and Planning Service" under the predecessor version of Schedule 16.

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 under a “Signature Page for Schedule 16 of the NEPOOL OATT” that was executed and in effect prior to January 1, 2013 for Category A Designated Blackstart Resources or a commitment to provide Blackstart Service established under Operating Procedure 11 – Designated Blackstart Resource Administration (OP11) for Category B Designated Blackstart Resources.

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).

Blackstart Station-specific Rate CIP Capital Payment is a component of the Blackstart Station-specific Rate Payment that reflects a Blackstart Station’s 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 (for Capacity Commitment Periods commencing on or after June 1, 2017, 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.

Capability Year means a year's period beginning on June 1 and ending May 31.

Capacity Acquiring Resource is a resource that is seeking to acquire a Capacity Supply Obligation through a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1 of Market Rule 1.

Capacity Balancing Ratio is a ratio used in calculating the Capacity Performance Payment in the Forward Capacity Market beginning on June 1, 2018 pursuant to rules filed with the Commission on July 14, 2014.

Capacity Capability Interconnection Standard has the meaning specified in Schedule 22, Schedule 23, and Schedule 25 of the OATT.

Capacity Carried Forward Due to Rationing is described in Section III.13.2.7.8.2.1(c)(b)(ii) of Market Rule 1.

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 Clearing Price Floor is described in Section III.13.2.7.

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, equal to that Market Participant's Capacity Requirement (if any) adjusted to account for any relevant Capacity Load Obligation Bilaterals, as described in Section III.13.7.3.1 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 is defined in Section I of Schedule 22 and Attachment 1 to Schedule 23 of the OATT.

Capacity Performance Payment is the performance-dependent portion of revenue received in the Forward Capacity Market beginning on June 1, 2018 pursuant to rules filed with the Commission on July 14, 2014.

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 Requirement is described in Section III.13.7.3.1 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 Right (CTR) is a financial right that entitles the holder to the difference in the Net Regional Clearing Prices between Capacity Zones for which the transfer right is defined, in the MW amount of the holder's entitlement.

Capacity Transferring Resource is a resource that has a Capacity Supply Obligation and is seeking to shed such obligation, or a portion thereof, through a Capacity Supply Obligation Bilateral, as described in Section III.13.5.1 of Market Rule 1.

Capacity Value is the value (in kW-month) of a Demand Resource for a month determined pursuant to Section III.13.7.1.5 of Market Rule 1.

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.

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.

Carried Forward Excess Capacity is calculated as described in Section III.13.2.7.8.2.1(c) of Market Rule 1.

Category A Designated Blackstart Resource is a Designated Blackstart Resource that has committed to provide Blackstart Service under a "Signature Page for Schedule 16 of the NEPOOL OATT" that was executed and in effect prior to January 1, 2013 and has not been converted to a Category B Designated Blackstart Resource.

Category B Designated Blackstart Resource is a Designated Blackstart Resource that is not a Category A 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.

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 power year, 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 in all Load Zones. 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, for the purposes of the ISO New England Financial Assurance Policy, is defined in Section VII.A of that policy.

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 (1) the clearing of the Static De-List Bids or the Permanent De-List Bids of all the Existing Generating Capacity Resources comprising the Station; or (2) the acceptance of a Non-Price Retirement Request of 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.

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.

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, a performance or surety bond, or a combination thereof.

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)(iii) of Market Rule 1.

Day-Ahead Congestion Revenue is defined in Section III.3.2.1(f) of Market Rule 1.

Day-Ahead Demand Reduction Obligation is a cleared Demand Reduction Offer multiplied by one plus the percent average avoided peak distribution losses. For Capacity Commitment Periods commencing on or after June 1, 2017, Day-Ahead Demand Reduction Obligation is the hourly demand reduction amounts of a Demand Response Resource scheduled by the ISO as a result of the Day-Ahead Energy Market, multiplied by one plus the percent average avoided peak distribution losses.

Day-Ahead Energy Market means the schedule of commitments for the purchase or sale of energy, 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 and purchase of demand

reductions pursuant to Appendix III.E2 of Market Rule 1 for Capacity Commitment Periods commencing on or after June 1, 2017.

Day-Ahead Energy Market Congestion Charge/Credit is defined in Section III.3.2.1(d) of Market Rule 1.

Day-Ahead Energy Market Energy Charge/Credit is defined in Section III.3.2.1(d) of Market Rule 1.

Day-Ahead Energy Market Loss Charge/Credit is defined in Section III.3.2.1(d) 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)(ii) of Market Rule 1.

Day-Ahead Load Obligation is defined in Section III.3.2.1(a)(i) of Market Rule 1.

Day-Ahead Load Response Program provides a Day-Ahead aspect to the Load Response Program. The Day-Ahead Load Response Program allows Market Participants with registered Load Response Program Assets to make energy reduction offers into the Day-Ahead Load Response Program concurrent with the Day-Ahead Energy Market.

Day-Ahead Locational Adjusted Net Interchange is defined in Section III.3.2.1(a)(iv) of Market Rule 1.

Day-Ahead Loss Charges or Credits is defined in Section III.3.2.1(h) of Market Rule 1.

Day-Ahead Loss Revenue is defined in Section III.3.2.1(g) of Market Rule 1.

Day-Ahead Prices means the Locational Marginal Prices resulting from the Day-Ahead Energy Market.

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 Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for Demand Response Resources, Real-Time Demand Response Resources and Real-Time Emergency Generation 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 Real-Time Demand Response Asset to reduce demand. For Capacity Commitment Periods commencing on or after June 1, 2017, Demand Reduction Offer is an offer by a Market Participant with a Demand Response Resource to reduce demand.

Demand Reduction Threshold Price is a minimum offer price calculated pursuant to Section III.E1.6 and Section III.E2.6.

Demand Reduction Value is the quantity of reduced demand calculated pursuant to Section III.13.7.1.5.3 of Market Rule 1.

Demand Resource is a resource defined as Demand Response Capacity Resources, On-Peak Demand Resources, Seasonal Peak Demand Resources, Real-Time Demand Response Resources, or Real-Time Emergency Generation Resources. Demand Resources are installed measures (i.e., products, equipment, systems, services, practices and/or strategies) that result in additional and verifiable reductions in end-use demand on the electricity network in the New England Control Area pursuant to Appendix III.E1 and Appendix III.E2 of Market Rule 1, or during Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, respectively. A Demand Resource may include a portfolio of measures aggregated together to meet or exceed the minimum Resource size requirements of the Forward Capacity Auction.

Demand Resource Commercial Operation Audit is an audit initiated pursuant to Section III.13.6.1.5.4.4.

Demand Resource Forecast Peak Hours are those hours, or portions thereof, in which, absent the dispatch of Real-Time Demand Response Resources, Dispatch Zone, Load Zone, or system-wide implementation of the action of ISO New England Operating Procedure No. 4 where the ISO would have begun to allow the depletion of Thirty-Minute Operating Reserve is forecasted in the ISO's most recent next-day forecast.

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 Operable Capacity Analysis means an analysis performed by the ISO estimating the expected dispatch hours of active Demand Resources given different assumed levels of Demand Resources clearing in the primary Forward Capacity Auction.

Demand Resource Performance Incentives means the additional monthly capacity payment that a Demand Resource may earn for producing a positive Monthly Capacity Variance in a period where other Demand Resources yield a negative monthly capacity variance.

Demand Resource Performance Penalties means the reduction in the monthly capacity payment to a Demand Resource for producing a negative Monthly Capacity Variance.

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 the pumping load associated with pumped storage generators) 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 that meets the registration requirements in Section III.E2.2. The demand reduction of a Demand Response Asset is the difference between the Demand Response Asset's actual demand measured at the Retail Delivery Point, which could reflect Net Supply, at the time the Demand Response Resource to which the asset is associated is dispatched by the ISO, and its adjusted Demand Response Baseline.

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 or the expected output levels of the generation of an individual end-use metered customer whose asset is comprised of Distributed Generation as determined pursuant to Section III.8A or Section III.8B.

Demand Response 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.

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 Regulation Resource is a Real-Time Demand Response Resource eligible to provide Regulation.

Demand Response Resource is an individual Demand Response Asset or aggregation of Demand Response Assets within a Dispatch Zone that meets the registration requirements and participates in the Energy Market pursuant to Appendix III.E2 of Market Rule 1 for Capacity Commitment Periods commencing on or after June 1, 2017.

Demand Response Resource Notification Time is the minimum time, from the receipt of a Dispatch Instruction, that it takes a Demand Response Resource that was not previously reducing demand to start 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 time required from the time a Demand Response Resource that was not previously reducing demand starts reducing demand in response to a Dispatch Instruction and the time the resource achieves its Minimum Reduction.

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, and may be a Category A Designated Blackstart Resource or a Category B Designated Blackstart Resource.

Designated Entity is the entity designated by a Market Participant to receive Dispatch Instructions for generation 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) is the Dispatch Rate expressed in megawatts.

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 Resources, change External Transactions, or change the status 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 Rate means the control signal, expressed in dollars per MWh and/or megawatts, calculated and transmitted to direct the output, consumption or demand reduction level of each generating Resource, Dispatchable Asset Related Demand and Demand Response Resource dispatched by the ISO in accordance with the Offer Data.

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.13.1.4.6.1.

Dispatchable Asset Related Demand is any portion of an Asset Related Demand of a Market Participant that is capable of having its energy consumption modified in Real-Time in response to Dispatch Instructions has Electronic Dispatch Capability, and 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 Manuals. Pumped storage facilities may qualify as Dispatchable Asset Related Demand resources, however, such resources shall not qualify as a capacity resource for both the generating output and dispatchable pumping demand of the facility.

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 resources directly connected to end-use customer load and located behind the end-use customer's meter, which reduce the amount of energy that would otherwise have been produced by other capacity resources on the electricity network in the New England Control Area during Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, Real-Time Demand Response Event Hours, or Real-Time Emergency Generation Event Hours, provided that the aggregate nameplate capacity of the generation resource does not exceed 5 MW, or does not exceed the most recent annual non-coincident peak demand of the end-use metered customer at the location where the generation resource is directly connected, whichever is greater. Generation resources cannot participate in the Forward Capacity Market or the Energy Markets as Demand Resources or Demand Response Resources, unless they meet the definition of Distributed Generation.

Do Not Exceed Dispatch Point is a Dispatch Instruction indicating a maximum output level that a wind resource must not exceed.

DR Auditing Period is the summer DR Auditing Period or winter DR Auditing Period as defined in Section III.13.6.1.5.4.3.1.

Dynamic De-List Bid is a bid that may be submitted by Existing Generating Capacity Resources, Existing Import Capacity Resources, and Existing Demand Resources in the Forward Capacity Auction at or 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 level to which a Resource would have been dispatched, based on the Resource's Supply Offer 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 resource that a Market Participant offers to supply in the Day-Ahead Energy Market or Real-Time Energy Market, as reflected in the resource's Supply Offer. This represents the highest MW output a Market Participant has offered for a resource for economic dispatch. A Market Participant must maintain an up-to-date Economic Maximum Limit for all hours in which a resource has been offered into the Day-Ahead Energy Market or Real-Time Energy Market.

Economic Minimum Limit or Economic Min is (a) for Resources 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 Resources without an incremental heat rate, the lowest sustainable output level that is consistent with the physical design characteristics of the Resource and with meeting all environmental regulations and licensing limits, and

(c) for Resources undergoing Facility and Equipment Testing or auditing, the level to which the Resource 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 set of Supply Offer values that are 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.

Electronic Dispatch Capability is the ability to provide for the electronic transmission, receipt, and acknowledgment of data relative to the dispatch of generating units and Dispatchable Asset Related Demands and the ability to carry out the real-time dispatch processes from ISO issuance of Dispatch Instructions to the actual increase or decrease in output of dispatchable Resources.

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 generation amount, in MWs, that a generating unit 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 hours for which the Customer has a positive or negative Real-Time System Adjusted Net Interchange as determined by the ISO settlement process for the Energy Market.

Energy Offer Cap is \$1,000/MWh.

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 and Energy Non-Zero Spot Market Settlement Hours.

Enrolling Participant is the Market Participant that registers Customers for the Load Response Program.

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, the Capacity Requirement 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.

Estimated Net Regional Clearing Price (ENRCP) is calculated in accordance with Section VII.C of the ISO New England Financial Assurance Policy.

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 by 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, and, subject to ISO evaluation, for the Forward Capacity Auction to be conducted beginning February 1, 2008, any resource that is under construction and within 12 months of its expected commercial operations date.

Existing Demand Resource is a type of Demand Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1.1 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.

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; (v) is capable of receiving and acknowledging a Dispatch Instruction electronically; and (vi) has satisfied its Minimum Time Between Reductions.

Fast Start Generator means a generating unit that the ISO may dispatch within the hour 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 and manned or has automatic remote dispatch capability; (v) capable of receiving and acknowledging a start-up or shut-down dispatch instruction electronically; and (vi) has satisfied its minimum down time.

FCA Cleared Export Transaction is defined in Section III.1.10.7(f)(ii) of Market Rule 1.

FCA Payment is the monthly capacity payment for a resource whose offer has cleared in a Forward Capacity Auction as described in Section III.13.7.2.1.1(a) 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 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.

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.

Forecast Hourly Demand Reduction means the estimated maximum quantity of energy reduction (MWh), measured at the end-use customer meter that can be produced by a Real-Time Demand Response Resource, or Real-Time Emergency Generation Resource, in each hour of an Operating Day. For a Real-Time Emergency Generation Asset that is metered at the generator and associated with a Real-Time Emergency Generation Resource, the Forecast Hourly Demand Reduction means the estimated maximum generator output (MWh) in each hour of an Operating Day.

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 descending clock auction in the Forward Capacity Market, as 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 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 \$14,000/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 Award Financial Assurance is a required amount of financial assurance that must be maintained at all times from a Designated FTR Participant for each FTR awarded to the participant in any FTR Auctions. This amount is calculated pursuant to Section VI.C of the ISO New England Financial Assurance Policy.

FTR Bid Financial Assurance is an amount of financial assurance required from a Designated FTR Participant for each bid submission into an FTR auction. This amount is calculated pursuant to Section VI.B of the ISO New England Financial Assurance Policy.

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 generator that has been registered 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 Adjusted Audited Demand Reduction is calculated in accordance with Section III.13.7.1.5.10.1.2.

Hourly Calculated Demand Resource Performance Value means the performance of a Demand Resource during Real-Time Demand Response Event Hours and Real-Time Emergency Generation Event Hours for purposes of calculating a Demand Reduction Value pursuant to Sections III.13.7.1.5.7.3 and III.13.7.1.5.8.3.

Hourly Charges are defined in Section 1.3 of the ISO New England Billing Policy.

Hourly PER is calculated in accordance with Section III.13.7.2.7.1.1.1(a) of Market Rule 1.

Hourly Real-Time Demand Response Resource Deviation means the difference between the Average Hourly Load Reduction or Average Hourly Output of the Real-Time Demand Response Resource and the amount of load reduction or output that the Market Participant was instructed to produce pursuant to a Dispatch Instruction calculated pursuant to Section III.13.7.1.5.7.3.1.

Hourly Real-Time Emergency Generation Resource Deviation is calculated pursuant to Section III.13.7.1.5.8.3.1.

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.

Inadequate Supply is defined in Section III.13.2.8.1 of Market Rule 1.

Inadvertent Energy Revenue is defined in Section III.3.2.1(k) of Market Rule 1.

Inadvertent Energy Revenue Charges or Credits is defined in Section III.3.2.1(l) 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 generation 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.

Insufficient Competition is defined in Section III.13.2.8.2 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 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.

Intermittent Power Resource is defined in Section III.13.1.2.2.2 of Market Rule 1.

Intermittent Settlement Only Resource is a Settlement Only Resource that is also an Intermittent Power Resource.

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.

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.

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 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.

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 generating resources 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.

Load Management means installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer facilities that curtail electrical usage or shift electrical usage from Demand Resource On-Peak Hours, Demand Resource Seasonal Peak Hours, or Real-Time Demand Response Event Hours to other hours and reduce the amount of capacity needed, 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, chilled water storage, and other forms of electricity storage.

Load Response Program means the program implemented and administered by the ISO to promote demand side response as described in Appendix E to Market Rule 1.

Load Response Program Asset means one or more individual end-use metered customers that report load reduction and consumption, or generator output as a single set of values, are assigned an identification number, that participate in the Load Response Program and which encompass assets registered in the Real-Time Price Response Program or Real-Time Demand Response Assets, and are further described in Appendix E of Market Rule 1.

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 the minimum amount of capacity that must be located within an import-constrained Load Zone, calculated as described in Section III.12.2 of Market Rule 1.

Local System Planning (LSP) is the process defined in Appendix 1 of Attachment K to the OATT.

Localized Costs are the incremental costs resulting from a RTEP02 Upgrade or a Regional Benefit Upgrade or a Public Policy Transmission Upgrade that exceeds those requirements that the ISO deems reasonable and consistent with Good Utility Practice and the current engineering design and construction practices in the area in which the Transmission Upgrade is built. In making its determination of whether Localized Costs exist, the ISO will consider, in accordance with Schedule 12C of the OATT, the reasonableness of the proposed engineering design and construction method with respect to alternate feasible Transmission Upgrades and the relative costs, operation, timing of implementation, efficiency and reliability of the proposed Transmission Upgrade. The ISO, with advisory input from the Reliability Committee, as appropriate, shall review such Transmission Upgrade, and determine whether there are any Localized Costs resulting from such Transmission Upgrade. If there are any such costs, the ISO shall identify them in the Regional System Plan.

Location is a Node, External Node, Load Zone or Hub. For Capacity Commitment Periods commencing on or after June 1, 2017, the Location also is a Dispatch Zone.

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 or Reliability Region is the Zonal Price for that Load Zone or Reliability Region, respectively; and the Locational Marginal Price for a Hub is the Hub Price for that Hub. For Capacity Commitment Periods

commencing on or after June 1, 2017, the Location Marginal Price for a Dispatch Zone is the Zonal Price for that Dispatch Zone.

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.

Lump Sum Blackstart CIP Capital Payment is defined and calculated as specified in Section 5.4 of Schedule 16 to the OATT.

Major Transmission Outage is a major transmission outage scheduled in accordance with ISO New England Operating Procedure No. 3.

Manual Response Rate is the rate, in MW/Minute, at which the output of a Generator Asset is capable of changing.

Marginal Loss Revenue Load Obligation is defined in Section III.3.2.1(b)(v) of Market Rule 1.

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 the maximum amount of capacity that can be procured in an export-constrained Load Zone, calculated as described in Section III.12.2 of Market Rule 1, to meet the Installed Capacity Requirement.

Maximum Consumption Limit is the maximum amount, in MW, available from the Dispatchable Asset Related Demand for economic dispatch and is based on the physical characteristics as submitted as part of a Resource's Offer Data except that a Self-Scheduled Dispatchable Asset Related Demand may modify its Minimum Consumption Limit on an hourly basis, as part of its Demand Bid, in order to indicate the desired level of Self-Scheduled MW.

Maximum Facility Load is the most recent annual non-coincident peak demand or, if unavailable, an estimate of the annual non-coincident peak demand of a Real-Time Demand Response Asset or a Real-Time Emergency Generation Asset, where the demand evaluated is established by adding actual metered demand and the output of all generators located behind the asset's end-use customer meter in the same time intervals.

Maximum Generation is the maximum generation output of a Real-Time Demand Response Asset comprised of Distributed Generation or the maximum generation output of a Demand Response Asset comprised of Distributed Generation.

Maximum Interruptible Capacity is an estimate of the maximum hourly demand reduction amount that a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or a Demand Response Asset can deliver. For assets that deliver demand reduction, the Maximum Interruptible Capacity is the asset's peak load less its uninterruptible load. For assets that deliver reductions through the use of generation, the Maximum Interruptible Capacity is the difference between the generator's maximum possible output and its expected output when not providing demand reduction. For assets that deliver demand reduction and Net Supply, the Maximum Interruptible Capacity is the asset's peak load plus Maximum Net Supply as measured at the Retail Delivery Point.

Maximum Load is the most recent annual non-coincident peak demand or, if unavailable, an estimate of the annual non-coincident peak demand, of a Demand Response Asset, Real-Time Demand Response Asset or Real-Time Emergency Generation Asset.

Maximum Net Supply is an estimate of the maximum hourly Net Supply for a Demand Response Asset as measured from the Demand Response Asset's Retail Delivery Point.

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 a 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 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 Value of the Demand 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 Value for an Existing Demand Resource is not overstated in a subsequent Capacity Commitment Period. Measure Life shall be determined consistent with the Demand 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, which includes 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 a Demand Resource supplier 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 Demand Resource suppliers 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 Value of the 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 a Demand Resource supplier with the monthly settlement report for the Forward Capacity Market, which documents the total Demand Reduction Values for all Demand Resources in operation as of the end of the previous month.

MEPCO Grandfathered Transmission Service Agreement (MGTSA) 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), MGTSA 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.

Minimum Consumption Limit is the minimum amount, in MW, available from a Dispatchable Asset Related Demand that is not available for economic dispatch and is based on the physical characteristics as submitted as part of a Resource's Offer Data.

Minimum Down Time is the number of hours that must elapse after a Generator Asset has been released for shutdown at or below its Economic Minimum Limit before the Generator Asset can be brought online and be released for dispatch at its Economic Minimum Limit.

Minimum Generation Emergency means an Emergency declared by the ISO in which the ISO anticipates requesting one or more generating Resources 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.

Minimum Time Between Reductions is the minimum number of hours that a Market Participant requires between the time the Demand Response Resource receives a Dispatch Instruction from the ISO to not reduce demand and the time the Demand Response Resource receives a Dispatch Instruction from the ISO to reduce demand.

Monthly Blackstart Service Charge is the charge made to Transmission Customers pursuant to Section 6 of Schedule 16 to the OATT.

Monthly Capacity Variance means a Demand Resource's actual monthly Capacity Value established pursuant to Section III.13.7.1.5.1 of Market Rule 1, minus the Demand Resource's final Capacity Supply Obligation for the month.

Monthly Peak is defined in Section II.21.2 of the OATT.

Monthly PER is calculated in accordance with Section III.13.7.2.7.1.1.2(a) of Market Rule 1.

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.

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.

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 the first-year 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, in its first year of operation, to be economically viable given reasonable expectations of the first year energy and ancillary services revenues, and projected revenue for subsequent years.

Net Regional Clearing Price is described in Section III.13.7.3 of Market Rule 1.

Net Supply is energy injected at the Retail Delivery Point by a Demand Response Asset with Distributed Generation.

Net Supply Limit is the estimated portion of the offered Maximum Reduction of a Demand Response Resource that would be provided through Net Supply. The Net Supply Limit is calculated by multiplying the offered Maximum Reduction of the Demand Response Resource by the ratio of total Net Supply to total demand reduction performance from the prior like Seasonal DR Audit of the Demand Response Assets that are mapped to the Demand Response Resource for the month.

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 Resource, as described in Section III.13.2.3.2 of Market Rule 1.

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 Required is the amount of additional capacity required to meet the Installed Capacity Requirement or a Capacity Zone's Local Sourcing Requirement, as described in Section III.13.2.8.1.1 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 Resource Show of Interest Form, as described in Section III.13.1.10 of Market Rule 1.

New Demand Resource is a type of Demand Resource participating in the Forward Capacity Market, as defined in Section III.13.1.4.1.2 of Market Rule 1.

New Demand Resource Qualification Package is the information that a Project Sponsor must submit, in accordance with Section III 13.1.4.2.3 of Market Rule 1, for each resource that it seeks to offer in the Forward Capacity Auction as a New Demand Resource.

New Demand Resource Show of Interest Form is described in Section III.13.1.4.2 of Market Rule 1.

New Demand Response Asset is a Real-Time Demand Response Asset, Real-Time Emergency Generation Asset or Demand Response Asset that is registered with the ISO, has been mapped to a

resource, is ready to respond, and has been included in the dispatch model of the remote terminal unit but does not have a winter audit value and a summer audit value.

New Demand Response Asset Audit is an audit of a New Demand Response Asset performed pursuant to Section III.13.6.1.5.4.8.

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.

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.

Nodal Amount is node(s)-specific on-peak and off-peak proxy value to which an FTR bid or awarded FTR bid relates.

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 generating unit that must be paid to Market Participants with an Ownership Share in the unit 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 generating unit 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.13.7.3.1.3.

Non-Commercial Capacity is the capacity of a New Capacity Resource or an increment of an Existing Capacity Resource that is treated as a New Capacity Resource in the Forward Capacity Auction and that has not been declared commercial and has not had its capacity rating verified by the ISO.

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-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-Intermittent Settlement Only Resource is a Settlement Only Resource that is not an Intermittent Power Resource.

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-Price Retirement Request is a binding request to retire the entire capacity of a Generating Capacity Resource as described in Section III.13.1.2.3.1.5.

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.

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 generating unit and Dispatchable Asset Related Demand, and for Capacity Commitment Periods commencing on or after June 1, 2017, Demand Response Resource operating limits based on physical characteristics, and information necessary to schedule and dispatch generating and Dispatchable Asset Related Demand Resources, and for Capacity Commitment Periods commencing on or after June 1, 2017. Demand Response Resources for the provision of energy and 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.

Offered CLAIM10 is, for a generating Resource, a Supply Offer value between 0 and the CLAIM10 of the Resource that represents the amount of TMNSR available from the Resource from an off-line state, and, for a Dispatchable Asset Related Demand or Demand Response Resource that has not been dispatched, is a Demand Bid or Demand Reduction Offer value between 0 and the CLAIM10 of the Resource that represents the amount of TMNSR or TMSR available from the Resource.

Offered CLAIM30 is a Supply Offer, Demand Bid or Demand Reduction Offer value between 0 and the CLAIM30 of a Resource that represents the amount of TMOR available from an off-line generating Resource, or Dispatchable Asset Related Demand or Demand Response Resource that has not been dispatched.

Offered Full Reduction Time is the value calculated pursuant to Section III.13.6.1.5.4.6.

On-Peak Demand Resource is a type of Demand 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 generating unit asset or Load Asset, where such unit or load 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.

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.13.7.2.7.1 of Market Rule 1.

PER Proxy Unit is described in Section III.13.7.2.7.1 of Market Rule 1.

Percent of Total Demand Reduction Value Complete means the delivery schedule as a percentage of a Demand Resource's total Demand Reduction Value that will be or has been achieved as of specific target dates, as described in Section III.13 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 Resource in the Forward Capacity Auction to permanently remove itself from the capacity market, as described in Section III.13.1.2.3.1.2 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 II Transfer Credit is 60% of the HQICC, or such other fraction of the HQICC as the ISO may establish.

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.

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(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.

Poorly Performing Resource is described in Section III.13.7.1.1.5 of Market Rule 1.

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 Credit for Dispatchable Asset Related Demand Resources (Pumps Only) Postured for Reliability, 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 Resource participate in the Forward Capacity Market, as described in Section III.13.

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.

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.

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.

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 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)(iii) of Market Rule 1.

Real-Time Adjusted Load Obligation Deviation is defined in Section III.3.2.1(c)(iii) 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(f) of Market Rule 1.

Real-Time Demand Reduction Obligation is a Real-Time demand reduction amount determined pursuant to Section III.E1.8 for Capacity Commitment Periods commencing prior to June 1, 2017, and Section III.E2.7 for Capacity Commitment Periods commencing on or after June 1, 2017.

Real-Time Demand Resource Dispatch Hours means those hours, or portions thereof, in which ISO New England Operating Procedure No. 4 is implemented and the ISO has begun to allow the depletion of Thirty-Minute Operating Reserve on a Dispatch Zone, Load Zone, or system-wide basis, and the ISO notifies the Market Participants with Real-Time Demand Response Resources of such hours.

Real-Time Demand Response Asset means one or more individual end-use metered customers that are located at a single Node, report load reduction and consumption, or generator output as a single set of values, are assigned a unique asset identification number by the ISO, and that participate in the Forward Capacity Market as part of a Market Participant's Real-Time Demand Response Resource.

Real-Time Demand Response Event Hours means hours when the ISO dispatches Real-Time Demand Response Resources in response to Real-Time Demand Resource Dispatch Hours, which may include Dispatch Zone, Load Zone, or system-wide dispatch of such resources.

Real-Time Demand Response Resource is a type of Demand Resource that is comprised of installed measures (e.g., products, equipment, systems, services, practices and/or strategies) on end-use customer

facilities that: (i) curtail electrical usage in response to a Dispatch Instruction; and (ii) continue curtailing electrical usage until receiving Dispatch Instructions to restore electrical usage. Such measures include Load Management and Distributed Generation. The period of curtailment shall be consistent with Real-Time Demand Response Event Hours.

Real-Time Dispatch NCPC Credit is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

Real-Time Emergency Generation Asset means one or more individual end-use metered customers that are located at a single Node, report load reduction and consumption, or generator output as a single set of values, are assigned a unique asset identification number by the ISO, and that participate in the Forward Capacity Market as part of a Market Participant's Real-Time Emergency Generation Resource.

Real-Time Emergency Generation Event Hours means those hours, or portions thereof, between 7 a.m. and 7 p.m. Monday through Friday, non-Demand Response Holidays in which the ISO dispatches Real-Time Emergency Generation Resources on a Dispatch Zone, Load Zone, or system-wide basis when deficient in Thirty-Minute Operating Reserve and when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement.

Real-Time Emergency Generation Resource is Distributed Generation whose federal, state and/or local air quality permits, rules or regulations limit operation in response to requests from the ISO to the times when the ISO implements voltage reductions of five percent of normal operating voltage that require more than 10 minutes to implement. A Real-Time Emergency Generation Resource must be capable of: (i) curtailing its end-use electric consumption from the New England grid within 30 minutes of receiving a Dispatch Instruction; and (ii) continuing that curtailment until receiving a Dispatch Instruction to restore consumption.

Real-Time Energy Market means the purchase or sale of energy, purchase of demand reductions pursuant to Appendix III.E2 of Market Rule 1, 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(e) of Market Rule 1.

Real-Time Energy Market Deviation Energy Charge/Credit is defined in Section III.3.2.1(e) of Market Rule 1.

Real-Time Energy Market Deviation Loss Charge/Credit is defined in Section III.3.2.1(e) 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)(ii) of Market Rule 1.

Real-Time Generation Obligation Deviation is defined in Section III.3.2.1(c)(ii) of Market Rule 1.

Real-Time High Operating Limit is the maximum output, in MW, of a resource that could be achieved, consistent with Good Utility Practice, in response to an ISO request for Energy under Section III.13.6.4 of Market Rule 1, for each hour of the Operating Day, as reflected in the resource's Offer Data. This value is based on real-time operating conditions and the physical operating characteristics and operating permits of the unit.

Real-Time Load Obligation is defined in Section III.3.2.1(b)(i) of Market Rule 1.

Real-Time Load Obligation Deviation is defined in Section III.3.2.1(c)(i) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange is defined in Section III.3.2.1(b)(iv) of Market Rule 1.

Real-Time Locational Adjusted Net Interchange Deviation is defined in Section III.3.2.1(c)(iv) of Market Rule 1.

Real-Time Loss Revenue is defined in Section III.3.2.1(i) 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 Price Response Program is the program described in Appendix E to Market Rule 1.

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 Dispatchable Asset Related Demand Resources (Pumps Only) Postured for Reliability is an NCPC Credit calculated pursuant to Appendix F to Market Rule 1.

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.2.4 of Market Rule 1.

Real-Time Reserve Credit is a Market Participant's compensation associated with that Market Participant's Resources' Real-Time Reserve Designation 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 adjusted after-the-fact utilizing revenue quality meter data as described under Section III.10 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.5.6.1 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 an 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 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, for Capacity Commitment Periods commencing on or after June 1, 2017, 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 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 generating unit, a Dispatchable Asset Related Demand, an External Resource or an External Transaction or, for Capacity Commitment Periods commencing on or after June 1, 2017, a Demand Response Resource. For purposes of providing Regulation, Resource means a generating unit, a Dispatchable Asset Related Demand, a Demand Response Regulation Resource or an Alternative Technology Regulation 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.

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 generating unit or ISO-approved combination of units, and represent the maximum dependable load carrying ability of such unit or units, excluding capacity required for station use.

Seasonal Claimed Capability Audit is the audit performed pursuant to Section III.1.5.1.3.

Seasonal DR Audit is a seasonal audit of the demand response capability of a Demand Resource initiated pursuant to Section III.13.6.1.5.4.1.

Seasonal Peak Demand Resource is a type of Demand 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.

Self-Schedule is the action of a Market Participant in committing or scheduling its Resource, in accordance with applicable ISO New England Manuals, to provide service in an hour, whether or not in the absence of that action the Resource would have been scheduled or dispatched by the ISO to provide the service. For a Generator Asset, Self-Schedule is the action of a Market Participant in committing or scheduling 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 scheduled or dispatched by the ISO to provide the Energy. For a Dispatchable Asset Related Demand, Self-Schedule is the action of a Market Participant in committing or scheduling a Dispatchable Asset Related Demand to consume Energy in an hour at its Minimum Consumption Limit, whether or not in the absence of that action the Dispatchable Asset Related Demand would have been scheduled or dispatched by the ISO to consume Energy. Demand Response Resources are not permitted to Self-Schedule.

Self-Scheduled MW is an amount, in megawatts, that is Self-Scheduled and is equal to: (i) a Generator Asset's Economic Minimum Limit; (ii) a Dispatchable Asset Related Demand's Minimum Consumption Limit.

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 office.

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.D of the ISO New England Financial Assurance Policy.

Settlement Only Resources are generators of less than 5 MW or otherwise eligible for Settlement Only Resource treatment as described 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.

Shortage Event is defined in Section III.13.7.1.1.1 of Market Rule 1.

Shortage Event Availability Score is the average of the hourly availability scores for each hour or portion of an hour during a Shortage Event, as described in Section III.13.7.1.1.1.A of Market Rule 1.

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.

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).

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 generating unit to Market Participants with an Ownership Share in the unit each time the unit 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 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 risk-adjusted going forward costs associated with a Station that are avoided only by (1) the clearing of the Static De-List Bids or the Permanent De-List Bids of all the Existing Generating Capacity Resources comprising the Station; or (2) the acceptance of a Non-Price Retirement Request of the Station, calculated in the same manner as the net-risk adjusted going forward costs of Existing Generating Capacity Resources as described in Section III.13.1.2.3.2.1.2.

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.

Successful FCA is a Forward Capacity Auction in which a Capacity Zone has neither Inadequate Supply nor Insufficient Competition.

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. 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.

Supplemental Availability Bilateral is described in Section III.13.5.3.2 of Market Rule 1.

Supplemental Capacity Resources are described in Section III.13.5.3.1 of Market Rule 1.

Supplemented Capacity Resource is described in Section III.13.5.3.2 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-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 the reserve capability of (1) a generating Resource that can be converted fully into energy within ten minutes from the request of the ISO (2) a Dispatchable Asset Related Demand that can be fully utilized within ten minutes from the request of the ISO to reduce consumption; or (3) a Demand Response Resource that can provide demand reduction within ten minutes from the request of the ISO.

Ten-Minute Non-Spinning Reserve Service is the form of Ancillary Service described in Schedule 6 of the OATT.

Ten-Minute Spinning Reserve (TMSR) is the reserve capability of (1) a generating Resource that is electrically synchronized to the New England Transmission System that can be converted fully into energy within ten minutes from the request of the ISO; (2) a Dispatchable Asset Related Demand pump that is electrically synchronized to the New England Transmission System that can reduce energy consumption to provide reserve capability within ten minutes from the request of the ISO; or (3) a Demand Response Resource that can provide demand reduction within ten minutes from the request of the ISO for which none of the associated Demand Response Assets have a generator whose output can be controlled located behind the Retail Delivery Point other than emergency generators that cannot operate electrically synchronized to the New England Transmission System.

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) means the reserve capability of (1) a generating Resource that can be converted fully into energy within thirty minutes from the request of the ISO (2) a Dispatchable Asset Related Demand that can be fully utilized within thirty minutes from the request of the ISO to reduce consumption; or (3) a Demand Response Resource that can provide demand reduction within thirty minutes from the request of the ISO.

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 O&M Payment is the annual compensation calculated under either Section 5.1 or 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 Negative Hourly Demand Response Resource Deviation means the absolute value of the sum of the negative Hourly Real-Time Demand Response Resource Deviations and negative Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Dispatch Zone.

Total Positive Hourly Demand Response Resource Deviation means the sum of the positive Hourly Real-Time Demand Response Resource Deviations and positive Hourly Real-Time Emergency Generation Deviations from all Real-Time Demand Response Resources and Real-Time Emergency Generation Resources receiving Dispatch Instructions in the same hour in the same Dispatch Zone.

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 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.

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 Demand Resource project. The Updated Measurement and Verification Plan may include updated Demand Resource 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 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.

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. 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.

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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) = Cost (X) / (1+D)^{N(X)}
 - Present Value of Cost (Y) = PV Cost (Y) = Cost (Y) / (1+D)^{N(Y)}
 - Cost Allocation to Region A = Cost (Z) x PV Cost (X)/[PV Cost (X) + PV Cost (Y)]

- $\text{Cost Allocation to Region B} = \text{Cost (Z)} \times \text{PV Cost (Y)} / [\text{PV Cost (X)} + \text{PV Cost (Y)}]$
- 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:
 - $\text{PV Cost (X)} = 60 / (1 + 0.075)^{8.25} = 33.039$ Million
 - $\text{PV Cost (Y)} = 40 / (1 + 0.075)^{4.50} = 28.888$ 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.

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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 Section 4.1(f) 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) or 4.3 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 during a given year. 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 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 ~~become a part of the New England planning region~~ enroll by ~~becoming a PTO Qualified Transmission Project Sponsor~~ 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

~~or a non PTO Qualified Transmission Project Sponsor.~~ A list of PTO Qualified Transmission Project Sponsors and non PTO Qualified Transmission Project Sponsors 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, and (iv) potential market responses to the needs identified by the ISO in a Needs Assessment or the RSP. 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

Any entity, including State regulators or agencies and NESCOE, as specified in Attachment N of the OATT, may designate a member to the Planning Advisory Committee by providing written notice to the Secretary of that Committee identifying the name of the entity represented by the member and the member's name, address, telephone number, facsimile number and electronic mail address. The entity

may remove or replace such member at any time by written notice to the Secretary of the Planning Advisory Committee.

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, may meet 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. 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.

The RSP shall also include 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. Each annual assessment will model out-of-service all Non-Price Retirement Requests and Permanent De-List Bids as well as rejected for reliability Static De-List Bids and rejected for reliability Dynamic De-List Bids from the most recent Forward Capacity Auction.

Each RSP shall be built upon the previous year's 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 and 4.3 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 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) 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) Concept; (ii) Proposed; (iii) Planned; (iv) Under Construction; and (v) 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, “Concept” shall include a transmission project that is being considered by its proponent as a potential solution to meet a need identified by the ISO in a Needs Assessment or the RSP, but for which there is little or no analysis available to support the transmission project.

(ii) 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.

(iii) “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.

(iv) “Under Construction” shall include a Transmission Upgrade that has received the approvals required under the Tariff and engineering and construction is underway.

(v) “In Service” shall include a Transmission Upgrade that has been placed in commercial operation.

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.

(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; and (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. 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 Section 4.1(f) of this Attachment and has been determined, pursuant to Section 4.1(f) 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 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 Non-Applicability of Sections 4.1 through 4.3; 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 Sections 4A.5(e) or 4A.7, respectively, 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, if:

- (i) a need for additional transfer capability is identified by the ISO in its ongoing evaluation of the PTF's adequacy and performance;
- (ii) a need for additional transfer capability is identified as a result of an ERO and/or NPCC reliability assessment or more stringent publicly available local reliability criteria, if any;
- (iii) constraints or available transfer capability limitations that are identified possibly as a result of generation additions or retirements, evaluation of load forecasts or proposals for the addition of transmission facilities in the New England Control Area;
- (iv) as requested by a stakeholder pursuant to the provisions of Section 4.1(b) of this Attachment; or
- (v) as otherwise deemed appropriate by the ISO as warranting such an assessment.

(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 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 Non-Price Retirement Requests and De-List Bids**

- (i) Where a Needs Assessment is underway for an area affected by a rejected Permanent De-List Bid or Non-Price Retirement Request, the Needs Assessment will represent the resource with the rejected Permanent De-List Bid as being interconnected, but unavailable for reliability purposes, and the Non-Price Retirement Request as being retired in the base representation being used to assess the system to identify reliability needs that must be addressed.

- (ii) Where there is not a Needs Assessment underway for an area affected by a rejected Permanent De-List Bid or Non-Price Retirement Request, the ISO will initiate a Needs Assessment for that area.
- (iii) 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.
- (iv) 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 de-list bids or Non-Price Retirement Requests 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 Solutions 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. With respect to (ii) or (iii) above, the proponent of the market response shall inform the ISO, in writing, of its selection or its assumption of financially binding obligations, respectively. 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. The ISO will also present the Needs Assessments in appropriate market forums to facilitate market responses. 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 the ISO finds that there is no feasible and credible alternative conceptual solution pursuant to Section 4.3(a) of this Attachment,~~ or where there is only one Phase One Proposal or Stage One Proposal submitted in response to a public notice issued under Sections 4.3(ab) or 4A.5(a) of this Attachment, respectively, or only one proposed solution that is selected to move on to Phase Two or Stage

Two, 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 competition, as described in Section 4.3 of this Attachment.

(j) Requirements for Use of Solution Studies Rather than Competitive Process for Projects Based on Year of Need

The following requirements must be met in order for the ISO to use Solution 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 Participating Transmission Owner 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 30-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 Solution 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 either a Reliability Transmission Upgrade and/or a Market Efficiency Transmission Upgrade pursuant to the standards set forth in Attachment N of this OATT.

(d) 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.

4.3 **Competitive Solution Process for Reliability Transmission Upgrades and Market Efficiency Transmission Upgrades**

~~**(a) Preliminary Solicitation of Alternatives**~~

~~If, in the ISO's judgment, it appears that the only efficient and cost-effective solution to a need identified in a Needs Assessment is an upgrade to existing PTO facilities, the ISO will solicit confidential alternative conceptual solutions from the Planning Advisory Committee. If the ISO finds preliminarily that there are credible and feasible conceptual transmission solutions that may be more efficient and cost-effective alternatives to an upgrade of existing PTO facilities, it will proceed to issue the public notice specified in Section 4.3(b) of this Attachment K and undertake the competitive solution process of Section 4.3 of this Attachment K. If not, the ISO will proceed under Section 4.2(a)-(d) of this Attachment K.~~

(ab) Public Notice Initiating Competitive Solution Process

The ISO will issue a public notice 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 notice will indicate that Qualified Transmission Project Sponsors may submit Phase One Proposals offering solutions that comprehensively address the identified needs.

A PTO or PTOs shall submit an individual or joint Phase One Proposal as a Backstop Transmission Solution for any need 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 Proposal (and to develop and construct the project, if selected in the competitive 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 project sponsor. If more than one Qualified Transmission Project Sponsor expresses interest, the Planning Advisory Committee member shall select the sponsor. In either case, the designated 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 in Phase One.

(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;

- (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 lifecycle cost of the proposed solution, including a high-level itemization of the components of the cost estimate.

With each proposal, the Qualified Transmission Project Sponsor must include payment of a \$100,000 study deposit per submitted proposal to support the cost of Phase One and Phase Two study work by the ISO. The deposit of \$100,000 shall be applied towards the costs incurred by the ISO associated with the study of the Phase One and Phase Two proposal.

Phase One Proposals must be submitted by the deadline specified in the posting by the ISO of the public notice described in Section 4.3(~~ab~~) of this Attachment, which shall not be less than 60 days from the posting date of the notice. The ISO may reject submittals which are insufficient or not adequately supported.

(d) LSP Coordination

Sponsors of Phase One Proposals shall also identify any LSP plans that require coordination with their proposals.

(e) Preliminary Review by ISO

If the sole Phase One Proposal in response to a given Needs Assessment has been submitted by PTO(s), proposing a project that would be located within or connected to its/their existing electric

system, the ISO shall proceed under Section 4.2(a)-(d) 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 public notice described in Section 4.3(ab) 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(ab) in the information provided in connection with a proposed Phase One Proposal, the ISO will notify the Phase One Proposal sponsor and provide an opportunity for the sponsor to cure the deficiencies within the timeframe specified by the ISO. Upon request, sponsors of Phase 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 Phase One Proposals. In providing information under this subsection (f), or in Phase Two, the sponsor may not modify its project materially or submit a new project, but instead may clarify its project. Phase Two Proposals 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(c). 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, based on a determination that the project 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 Phase Two.

(h) Information Required for Phase Two Solutions; Identification and Reporting of Preliminary Preferred Phase Two Solution

Qualified Transmission Project Sponsors of projects 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 costs;

- (vi) design standards to be used;
- (vii) description of the authority the sponsor has to acquire necessary rights of way;
- (viii) experience of the 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 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 project 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 solution.

(i) Reimbursement of Phase Two Solution Costs; Collection and Refund of ISO Study Costs
Qualified Transmission Project Sponsors whose projects 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 project 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 and Phase Two studies for a project 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) Inclusion of Preferred Phase Two Solution in RSP and/or RSP Project List

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 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) Milestone Schedules

Within 30 Business Days of its receiving notification pursuant to Section 4.3(j) of this Attachment, the Qualified Transmission Project Sponsor shall submit to the ISO (and shall update periodically) a schedule that indicates the dates by which applications for siting and other

approvals necessary to develop and construct the project by the required in-service date shall be submitted. Within 30 Business Days of its receiving all necessary siting and other approvals, the Qualified Transmission Project Sponsor shall submit to the ISO its acceptance of responsibility to proceed with the project, and a schedule acceptable to the ISO of dates by which typical project construction phases will be completed. The Qualified Transmission Project Sponsor shall submit to the ISO on a monthly basis thereafter, until the project is placed into service, a report that provides updated information, as specified by the ISO, showing the progress of the project. The ISO shall provide notification to any PTO providing a ~~backstop-regulated transmission solution~~ Backstop Transmission Solution to cease developing its project as of the date of the selected sponsor's acceptance of responsibility ~~unless the year of need or other factors, as applicable, associated with the project are such that the ISO determines that the PTO should continue the development of the backstop-regulated transmission solution. A determination by the ISO for the PTO to continue work on the backstop project shall be communicated by the ISO to the PTO in writing and shall also be communicated to the Planning Advisory Committee.~~

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 implement the ~~backstop-regulated transmission solution~~ Backstop Transmission Solution, and 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 ISO shall 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. 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.

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: (i) provide NESCOE 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. By no later than April 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 has 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. –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 June 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. With respect to (ii) or (iii) above, the proponent of the market response shall inform the ISO, in writing, of its selection or its assumption of financially binding obligations, respectively. 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 Stage One Proposals

(a) Information Required for Stage One Proposals

The ISO will post on its website a notice 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 public notice, which shall be not less than 60 days from the date of posting the public notice) 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;
- (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 lifecycle cost of the proposed solution, including a high-level itemization of the components of the cost estimate.

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 Proposal (and to develop and construct the project, if selected in the competitive process) in order for the unsponsored project to be submitted in response to an ISO solicitation in Stage One. 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 project sponsor. If more than one Qualified Transmission Project Sponsor expresses interest, the Planning Advisory Committee member shall select the sponsor. In either case, the designated 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 in Stage One.

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 and Stage Two study work by the ISO. The deposit of \$100,000 shall be applied towards the costs incurred by the ISO associated with the study of the Stage One and Stage Two proposal.

(b) LSP Coordination

Sponsors of Stage One Proposals shall also identify any LSP plans that require coordination with their 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.5(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.5(a)) in the information provided in connection with a proposed Stage One Proposal, the ISO will notify the Stage One Proposal sponsor and provide an opportunity for the sponsor to cure the deficiencies within the timeframe specified by the ISO. Upon request, 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, the sponsor may not modify its project materially or submit a new project, but instead may clarify its project. Stage Two Proposals 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.5(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 projects may also satisfy identified reliability needs of the system. The ISO with input from the Planning Advisory Committee may exclude projects from the list, and from consideration in Stage Two, based on a determination that the project is not competitive with other projects 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.6 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.5(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 project 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 and Stage Two studies for a project 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.7 Information Required for Stage Two Solutions; Identification and Reporting of Preliminary Preferred Stage Two Solution

Qualified Transmission Project Sponsors of projects listed pursuant to Section 4A.5(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 costs;
- (vi) design standards to be used;
- (vii) description of the authority the sponsor has to acquire necessary rights of way;
- (viii) experience of the 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 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 Phase One Proposals described in Section 4A.5(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 report the preliminary preferred Stage Two Solution(s), along with its views as to whether the preferred solution(s) also satisfies identified reliability needs of the system, to the Planning Advisory Committee and seek stakeholder input on the preliminary preferred solutions.

4A.8 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 project 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. 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) Milestone Schedules

Within 30 Business Days of its receiving notification pursuant to Section 4A.8(a) of this Attachment, the Qualified Transmission Project Sponsor shall submit to the ISO (and shall update periodically) a schedule that indicates the dates by which applications for siting and other approvals necessary to develop and construct the project by the required in-service date shall be submitted. Within 30 Business Days of its receiving all necessary siting and other approvals, the Qualified Transmission Project Sponsor shall submit to the ISO its acceptance of responsibility to proceed with the project, and a schedule acceptable to the ISO of dates by which typical project construction phases will be completed. The Qualified Transmission Project Sponsor shall submit to the ISO on a monthly basis thereafter, until the project is placed into service, a report that provides updated information (as specified by the ISO) showing the progress of the project.

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.

(c) Removal from RSP Project List

If a Public Policy Transmission Upgrade is removed from the RSP Project List by the ISO pursuant to Section 3.6(c), the entity responsible for the construction of the Public

Policy 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 that Public Policy Transmission Upgrade.

4A.9 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.8 shall be allocated in accordance with Schedule 21 of the ISO OATT.

4B. Qualified Transmission Project Sponsors

4B.1 Periodic Evaluation of Applications

The ISO will periodically 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, upon its execution of the Non-incumbent Transmission Developer Operating Agreement (in the form specified in Attachment O of the OATT), 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; Annual Certification

Qualified Transmission Project Sponsors are listed in Appendix ~~32~~ of this Attachment K. 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 Inter-Area 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 annual 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 Inter-Area Coordination

The regional system planning process shall be conducted and the annual RSP shall be developed in coordination with the similar plans of the surrounding ISOs/RTOs and Control Areas pursuant to the Northeastern ISO/RTO Planning Coordination Protocol and other agreements with neighboring systems and NPCC. Inter-area planning studies shall be conducted over as broad a region as feasible, including adjacent Canadian systems who are members of NPCC, or its successor organization, and, as appropriate, MAAC and Reliability First, or their successor organizations. The ISO shall convene periodic meetings of the Planning Advisory Committee, within the scope of its respective functions of Section 2 of this Attachment, to provide input and feedback to the ISO concerning an Inter-area needs assessment and identification of potential market and regulated responses to the ISO's identification of inter-area needs.

7. Procedures for Development and Approval of the RSP

7.1 Initiation of RSP

Every year, the ISO shall initiate an effort to develop its annual 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.

7.2 Draft RSP; Public Meeting

On or about August of each year, 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.

On or about September of each year, 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 no later than September 30 of each year 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 No. 3 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.

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 ~~and~~, 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. ~~If the potential Non-PTF transmission needs identified are driven by state or local Public Policy Requirements, each PTO will use good faith efforts to contact the appropriate state and/or local authorities to determine whether such authorities agree that~~ 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. ~~Each PTO will use good faith efforts to share the results of studies conducted with the appropriate state and local authorities and seek recommendations about whether to proceed with further planning and construction of a Local Public Policy Transmission Upgrade. 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 solution 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
~~LISTS OF ENTITIES ENROLLED PTO-QUALIFIED TRANSMISSION PROJECT SPONSORS~~
~~AND ENROLLED NON-PTO-QUALIFIED TRANSMISSION PROJECT SPONSORS~~

APPENDIX 2

ATTACHMENT K

~~LIST OF ENTITIES ENROLLED IN THE TRANSMISSION PLANNING REGION S-OF
ENROLLED PTO QUALIFIED TRANSMISSION PROJECT SPONSORS AND ENROLLED
NON-PTO QUALIFIED TRANSMISSION PROJECT SPONSORS~~

~~ENROLLED PTO QUALIFIED TRANSMISSION PROJECT SPONSORS~~

Town of Braintree Electric Light Department

Central Maine Power Company

Chicopee Municipal Lighting Department

Connecticut Transmission Municipal Electric Energy Cooperative

The City of Holyoke Gas and Electric Department

Emera Maine

Green Mountain Power Corporation

The City of Holyoke Gas and Electric Department

Massachusetts Municipal Wholesale Electric Company

Maine Electric Power Company

Middleborough Gas and Electric Department

New England Power Company

New Hampshire Electric Cooperative, Inc.

New Hampshire Transmission, LLC

Northeast Utilities Service Company dba 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

Town of Reading Municipal Light Department

Shrewsbury Electric and Cable Operations

Taunton Municipal Lighting Plant

The United Illuminating Company

Unitil Energy Systems, Inc. and Fitchburg Gas and Electric Light Company

Vermont Electric Cooperative, Inc.

Vermont Electric Power Company, Inc.

Vermont Public Power Supply Authority

Vermont Transco LLC

Town of Wallingford – Electric Division

New England Hydro-Transmission Electric Company Inc.

New England Hydro-Transmission Corporation

~~**ENROLLED NON-PTO QUALIFIED TRANSMISSION PROJECT SPONSORS**~~

ATTACHMENT K APPENDIX 3

LIST OF QUALIFIED TRANSMISSION PROJECT SPONSORS

APPENDIX 3

ATTACHMENT K

LIST OF QUALIFIED TRANSMISSION PROJECT SPONSORS

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), ~~including but not limited to liability for penalties assessed by NERC or FERC~~, 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

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