September 10, 2015

BY ELECTRONIC FILING

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

RE: **ISO New England Inc. and New England Power Pool, Coordination Agreement, Market Rule 1, OATT Conforming Revisions Relating to Coordinated Transaction Scheduling; Docket No. ER15-___-000**

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("Section 205"),[1] ISO New England Inc. (the "ISO" or "ISO-NE"), joined by the New England Power Pool ("NEPOOL") Participants Committee,[2] and the Participating Transmission Owners Administrative Committee ("PTO AC") on behalf of the Participating Transmission Owners ("PTO") (collectively, the "Filing Parties"),[3] hereby submit this transmittal letter and revisions to the ISO-NE Tariff and the ISO-NE/New York Independent System Operator, Inc. Coordination Agreement (the "CTS Conforming Revisions"), which support the implementation of Coordinated Transaction Scheduling between New

[1] 16 U.S.C. § 824d (2006 and Supp. II 2009).

[2] Capitalized terms used but not defined in this filing are intended to have the meaning given to such terms in the ISO New England Inc. Transmission, Markets and Services Tariff (the "ISO-NE Tariff"), the Second Restated New England Power Pool Agreement, and the Participants Agreement. The Open Access Transmission Tariff ("OATT") is Section II of the Tariff. Market Rule 1 is Section III of the Tariff.

[3] Under New England's RTO arrangements, the rights under Section 205 of the Federal Power Act to modify terms, conditions and rates in the ISO-NE Tariff are held and exercised by the ISO, with the limited exception of, *inter alia*, Attachment G-3 to the OATT over which the PTOs jointly share the Section 205 rights and for which reason they join in this filing. The PTO AC is joining this filing specifically and solely for the purpose of submitting the revisions to Attachment G-3. NEPOOL, which pursuant to the Participants Agreement provides the sole Market Participant stakeholder process for advisory voting on ISO matters, supported the changes reflected in this filing and accordingly, joins in this Section 205 filing.

England and New York over the New York Northern AC interface ("Coordinated Transaction Scheduling" or "CTS").

Coordinated Transaction Scheduling was jointly developed by ISO-NE and the New York Independent System Operator, Inc. ("NYISO") to enhance the market efficiency of external transactions (*i.e.*, energy imports and exports) between the two regions. Tariff revisions addressing Coordinated Transaction Scheduling were filed by both ISO-NE and NYISO and were accepted by the Commission in April 2012.[4] At the time the CTS rules were filed, the ISOs explained to the Commission that a significant undertaking would be required to develop the systems and processes to allow New England and New York to implement CTS. That effort, which has been underway for the last three years, will be completed in late 2015, at which time Coordinated Transaction Scheduling will go into effect.

In anticipation of CTS's implementation, ISO-NE is now filing conforming revisions to a number of ISO-NE Tariff provisions, as well as to the ISO-NE/NYISO Coordination Agreement. The CTS Conforming Revisions include the following:

- Revisions to the ISO-NE/NYISO Coordination Agreement (the "Coordination Agreement"), including the addition of a new Schedule D that addresses the two ISOs' coordination on the administration of CTS and the operation of the two transmission systems under CTS.

- Revisions to Market Rule 1. The majority of these changes are not substantive, but are necessary to ensure the intent of the original Coordinated Transaction Scheduling rules are carried into the current market rules.

- Revisions to the OATT that are necessary to distinguish the different scheduling and curtailment rules for External Transactions on the CTS and non-CTS interfaces.

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[4] *See ISO New England Inc. and New England Power Pool*, Market Rule 1 Revisions Relating to Coordinated Transaction Scheduling, Docket No. ER12-1155-000 (filed February 24, 2012) ("ISO-NE CTS Filing"); Order Accepting Tariff Revisions, Subject to a Compliance Filing, 139 FERC ¶ 61,047 (2012) (accepting ISO-NE's CTS proposal subject to the condition that the ISO file a notice at least two weeks' prior to the implementation of CTS to inform the Commission of the actual effective date, which as of the filing of CTS was to be on or after August 1, 2013). *See also New York Independent System Operator, Inc.*, Proposed Tariff Amendments to Add External Coordinated Transaction Scheduling Market Rules and Request for Waiver, Docket No. ER12-701-000 (filed December 28, 2011), *amended by* Errata to Filing re: Tariff Amendments to Add External Coordinated Transaction Scheduling Market Rules and Request for Waiver, Docket No. ER12-701-000 (filed January 13, 2012) ("NYISO CTS Filing"); Order Accepting Tariff Revisions, 139 FERC ¶ 61,048 (2012).

- Revisions to ISO-NE's Self-Funding Tariff to carry through the elimination of cross-border transaction costs for Coordinated External Transactions, addressing one of the three root causes of inefficiency in the current scheduling system that is remedied by Coordinated Transaction Scheduling.

This transmittal letter explains each of these changes and their connection to Coordinated Transaction Scheduling.

I. REQUESTED EFFECTIVE DATE; COMMISSION ORDER; PLANNED IMPLEMENTATION OF COORDINATED TRANSACTION SCHEDULING

The Filing Parties are requesting that the Commission accept the revisions herein as filed, without suspension or hearing, to be effective on or after December 1, 2015, with notice of the actual effective date to be filed with the Commission at least two weeks prior thereto. At this time, ISO-NE and NYISO anticipate that CTS will be implemented sometime during the month of December 2015. The ISOs are not able to establish a specific effective date until the software changes needed to implement CTS are ready for deployment and testing is complete. ISO-NE will coordinate with NYISO to agree on an implementation date and time.

Because the ISOs have not yet established the effective date for the implementation of CTS, the version of the Coordination Agreement submitted in this filing is not executed or dated. The ISOs have agreed that they will include with the notice of effective date a copy of the Coordination Agreement updated to reflect the effective date and the ISOs' execution of the agreement.

Given the significant coordination between the two ISOs that is required to implement Coordinated Transaction Scheduling, ISO-NE respectfully requests that the Commission issue an order within 60 days of the date of this filing. This will provide the ISOs and their respective market participants with certainty as to the market construct and system operating procedures that will be in effect for CTS, and will permit all such entities to take the final steps necessary in advance thereof to ensure a smooth transition.

Up to the date and time of CTS implementation, market participants will continue to utilize the current transaction submittal process for transactions taking place through the day prior to the effective date for CTS. To promote a smooth transition to CTS, the software enhancement for the ISO-NE Enhanced Energy Scheduler ("EES") and the NYISO Joint Energy Scheduling System ("JESS") will allow the submittal of CTS transactions (for transactions that will flow in real-time starting with the effective date for CTS) approximately 10 days prior to the effective date.

II. DESCRIPTION OF THE FILING PARTIES; COMMUNICATIONS.

ISO-NE is the private, non-profit entity that serves as the regional transmission organization ("RTO") for New England. The ISO operates the New England bulk power

system and administers New England's organized wholesale electricity market pursuant to the Tariff and the Transmission Operating Agreement with the New England Participating Transmission Owners. In its capacity as an RTO, the ISO has the responsibility to protect the short-term reliability of the New England Control Area and to operate the system according to reliability standards established by the Northeast Power Coordinating Council ("NPCC") and the North American Electric Reliability Corporation ("NERC").

The PTOs[5] are Transmission Providers providing Local Service over Non-Pool Transmission Facilities on an open-access basis under Schedule 21 of the OATT. Pursuant to the terms of the TOA among the PTOs and the ISO, the PTOs own, physically operate and maintain Transmission Facilities in New England and the ISO has Operating Authority (as defined in Schedule 3.02 of the TOA) over all of the Transmission Facilities of the PTOs, including those used to provide service under Schedule 21. Section 3.04 of the TOA also grants the PTOs authority under Section 205 of the FPA to submit filings to the Commission in matters affecting the rates, terms and conditions of Local Service under Schedule 21 and rates and charges, including cost allocation, for Regional Transmission Service under the OATT.

NEPOOL is a voluntary association organized in 1971 pursuant to the New England Power Pool Agreement, and it has grown to include more than 440 members. The Participants include all of the electric utilities rendering or receiving service under the Tariff, as well as independent power generators, marketers, load aggregators, brokers, consumer-owned utility systems, end users, demand resource providers, developers and a merchant transmission provider. Pursuant to revised governance provisions accepted by the Commission,[6] the Participants act through the NEPOOL Participants Committee. The Participants Committee is authorized by Section 6.1 of the Second Restated

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[5] The PTOs include: Town of Braintree Electric Light Department; Central Maine Power Company; Maine Electric Power Company; Chicopee Electric Lighting Department; Connecticut Municipal Electric Energy Cooperative; Connecticut Transmission Municipal Electric Energy Cooperative; Emera Maine (Bangor Hydro Division); The City of Holyoke Gas and Electric Department; Green Mountain Power Corporation; Hudson Light and Power Department; Massachusetts Municipal Wholesale Electric Company; Middleborough Gas and Electric Department; New England Power Company d/b/a National Grid; New Hampshire Electric Cooperative, Inc.; New Hampshire Transmission, LLC; Eversource Energy Service Company on behalf of certain of its affiliates: The Connecticut Light and Power Company, Western Massachusetts Electric Company, and Public Service Company of New Hampshire; NSTAR Electric Company; Taunton Municipal Lighting Plant; Town of Norwood Municipal Light Department; Town of Reading Municipal Light Department; The United Illuminating Company; Unitil Energy Systems, Inc.; Fitchburg Gas and Electric Light Company; Vermont Electric Power Company, Inc.; Vermont Electric Cooperative, Inc.; Vermont Transco, LLC; Vermont Public Power Supply Authority; Town of Wallingford (CT) Department of Public Utilities, Electric Division; and Shrewsbury Electric and Cable Operations.

[6] *ISO New England Inc., et al.*, 109 FERC ¶ 61,147 (2004).

NEPOOL Agreement and Section 8.1.3(c) of the Participants Agreement to represent NEPOOL in proceedings before the Commission. Pursuant to Section 2.2 of the Participants Agreement, "NEPOOL provide[s] the sole Participant Processes for advisory voting on ISO matters and the selection of ISO Board members, except for input from state regulatory authorities and as otherwise may be provided in the Tariff, TOA and the Market Participant Services Agreement included in the Tariff."

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III. STANDARD OF REVIEW.

These changes are being submitted pursuant to Section 205, which "gives a utility the right to file rates and terms for services rendered with its assets."[8] Under Section 205, the Commission "plays 'an essentially passive and reactive role'"[9] whereby it "can reject [a filing] only if it finds that the changes proposed by the public utility are not 'just and reasonable.'"[10] The Commission limits this inquiry "into whether the rates proposed by a utility are reasonable - and [this inquiry does not] extend to determining whether a proposed rate schedule is more or less reasonable than alternative rate designs."[11] The changes proposed herein "need not be the only reasonable methodology, or even the most accurate."[12] As a result, even if an intervenor or the Commission develops an alternative proposal, the Commission must accept this Section 205 filing if it is just and reasonable.[13]

IV. BACKGROUND – COORDINATED TRANSACTION SCHEDULING

Under the current inter-regional trading system, market participants in New England and New York submit separate external transaction requests to each ISO. An

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[7] Due to the joint nature of this filing, the Filing Parties respectfully request a waiver of Section 385.203(b)(3) of the Commission's regulations to allow the inclusion of more than two persons on the service list in this proceeding.

[8] *Atlantic City Elec. Co. v. FERC*, 295 F. 3d 1, 9 (D.C. Cir. 2002).

[9] *Id.* at 10 (*quoting City of Winnfield v. FERC*, 744 F.2d 871, 876 (D.C. Cir. 1984)).

[10] *Id.* at 9.

[11] *City of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984).

[12] *Oxy USA, Inc. v. FERC*, 64 F.3d 679, 692 (D.C. Cir. 1995).

[13] *Cf. Southern California Edison Co., et al*, 73 FERC ¶ 61,219 at 61,608 n.73 (1995) ("Having found the Plan to be just and reasonable, there is no need to consider in any detail the alternative plans proposed by the Joint Protesters." (*citing Bethany*)).

offer to buy, or export, from New England is submitted only to ISO-NE, and the matching offer to sell, or import, into New York is submitted only to the NYISO. There is no economic coordination between the ISOs when they evaluate these offers and use them to determine the net interface schedule.

As ISO-NE explained in the ISO-NE CTS Filing, the current External Transaction scheduling process between New England and New York is inefficient.[14] There is significant under-utilized transmission capacity between New York and New England, which takes place during times when there is sufficient transmission capacity to move additional power from the region with the lower Locational Marginal Price ("LMP") to the region with the higher LMP. Further, current scheduling procedures often result in net interchange schedules from the *higher* price region to the *lower* price region, known as *counter-intuitive flow*.

The ISOs identified three root causes of these inefficiencies:[15]

- *Latency delay* occurs because each ISO determines whether or not a "real-time" external transaction offer clears about an hour before the corresponding delivery hour, and this quantity remains fixed for the full delivery hour, meaning the latency delay is nearly two hours for both NYISO and ISO-NE. This latency delay produces transmission under-utilization, counter-intuitive flow, and unnecessary economic risk when the price difference between regions changes after a market participant's external transaction is scheduled.

- *Non-economic clearing* occurs because the ISOs make decisions about which import and export schedule requests to accept without economic coordination.

- *Cross-border transaction costs* in the form of various fees and charges on external transactions can be highly variable from day-to-day, are difficult to predict and, as a result, difficult to hedge against. These costs serve as an economic impediment to trade between the two regions.

Coordinated Transaction Scheduling was developed with the objective of addressing the identified inefficiencies and their root causes.[16] CTS is an external transaction scheduling process implemented by the ISOs at designated CTS Enabled Interfaces that allow real-time energy transactions to be scheduled based on a market participant's willingness to purchase energy at a source External Proxy Bus (in the New England Control Area, or in the New York Control Area) and sell it at a sink External Proxy Bus in the other Control Area if the forecasted price at the sink minus the

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[14] *See* the ISO-NE CTS Filing transmittal letter, at pp. 5-10, and the supporting testimony of Drs. White and Dombrowski filed therewith.

[15] *Id.*

[16] ISO-NE CTS Filing transmittal letter, at pp. 10-12.

forecasted price at the corresponding source is greater than or equal to the bid price. To minimize latency delay, CTS uses more frequent interface scheduling. To reduce non-economic clearing, CTS uses a simplified bid format and a clearing rule that coordinates economic clearing of external transactions between the two ISOs. To reduce cross-border transaction costs, CTS eliminates the transaction fees from external transactions at interfaces subject to Coordinated Transaction Scheduling.

The ISOs intend to implement CTS at the New York Northern AC interface. The External Proxy Buses used for scheduling CTS transactions in the two control areas are the Sandy Pond proxy bus (used in the New York markets) and the Roseton proxy bus (used in the New England markets).

CTS Interface Bids ordinarily will be evaluated on a 15-minute basis utilizing forecasted real-time prices and forecasted system information from each ISO. The evaluation will be performed by the NYISO's Real-Time Commitment ("RTC") optimization consistent with the rules specified in the NYISO Services Tariff and the new Schedule D to the Coordination Agreement, which is being filed herewith.

As part of the iterative CTS process, NYISO will share forward looking RTC interchange schedules with ISO-NE and these schedules will be used by ISO-NE as an input to develop a new set of forecasted prices and system information, which ISO-NE will then provide to NYISO for use in the next RTC optimization.

The RTC optimization will determine the External Interface Congestion component of the RTC LMP at a CTS Enabled Interface, which will subsequently be incorporated into the Parties' real-time settlement LMPs. Wheel-through transactions across a CTS Enabled Interface will continue to be scheduled on an hourly basis.

V. CONFORMING REVISIONS TO GOVERNING DOCUMENTS

Following the Commission's acceptance of the ISO-NE and NYISO CTS filings, the ISOs began meeting regularly to work through the requirements for implementing and administering CTS. It was established that NYISO would host the platform used by both New York and New England market participants to submit CTS bids, and would also incorporate into its real-time clearing engine the clearing of CTS bids. The ISOs also worked out the extensive details for how information and data would be communicated between the two ISOs and to their respective market participants.

The ISOs have largely completed the systems and procedures required to implement and administer CTS. As part of these efforts, the ISOs have made modifications to a number of governing documents that are included with their respective tariffs filed with the Commission under Section 205 of the FPA. The revisions to the ISO-NE governing documents filed herewith are explained in the following sections of this transmittal letter. These revisions largely memorialize the agreements between ISO-NE and NYISO on how the two parties will administer CTS. The revisions also conform sections of the ISO-NE Tariff to ensure they meet the underlying objectives of CTS and

also make certain adjustments to the way in which CTS will function. Finally, the revisions re-incorporate certain concepts that were included in the initial ISO-NE CTS Filing to account for modifications to the ISO-NE Tariff that have been made since the ISO-NE CTS Filing was submitted in 2012.

A. A New Schedule D to the Coordination Agreement

The ISO-NE/NYISO Coordination Agreement memorializes the arrangements between the ISOs to coordinate interconnected operation of the two Control Areas' transmission systems.[17] The CTS Conforming Revisions add to the Coordination Agreement a new Schedule D to address the joint administration of Coordinated Transaction Scheduling, including the respective responsibilities of the two ISOs in administering CTS.

Schedule D contains ten sections that address a range of matters including the parties' responsibilities with respect to the administration of the CTS bid submittal system, the parties' responsibilities with respect to the clearing of CTS bids, ramp and transfer limit calculations, allocation of external interface congestion costs, settlement of CTS transactions, non-standard CTS operation, change management for the various CTS-related software and processes, and auditing requirements. The following explains each of these sections.

Article I – Overview

Article I of Schedule D provides an overview of Coordinated Transaction Scheduling and highlights several features of the CTS implementation that are addressed in greater detail in Schedule D. In particular, it explains that the evaluation of CTS bids (referred to in Schedule D as "CTS Interface Bids" and in the remainder of the ISO Tariff as "Interface Bids") will use forecasted real-time prices and system information from each ISO and will be performed by NYISO's Real-Time Commitment, or "RTC" optimization software. For this to occur, NYISO will share forward-looking RTC interchange schedules with ISO-NE. These schedules will be used by ISO-NE to develop a new set of forecasted New England prices at CTS Enabled Interfaces[18] and system information, which in turn will be provided to NYISO to use in the next RTC optimization, or clearing. It explains also that wheel-through transactions across CTS Enabled Interfaces will continue to be scheduled hourly, which is required because the scheduling frequency of the other interface associated with the wheel-through transaction will not necessarily match the 15-minute scheduling frequency that will normally be used

[17] Coordination Agreement recitals.

[18] A "CTS Enabled Interface" is defined in the Coordination Agreement as "an Interconnection at which the Parties accept CTS Interface Bids for all import offers, for all export bids, and for wheels through the NECA. The CTS Enabled Interfaces are specified in Section 4.4.4 of the NYISO's Market Administration and Control Area Services Tariff and in Section III.1.10.7.A of the ISO-NE Tariff." *See* the revised ISO Tariff sections filed herewith.

for evaluation of CTS Interface Bids at a CTS Enabled Interface. Article I concludes with the affirmation by both parties that CTS and its components will operate in accordance with Schedule D and the terms of the parties' respective tariffs.

Article II – Submittal of CTS Interface Bids

Article II of Schedule D details several processes related to the submittal of CTS Interface Bids in the "Joint Energy Scheduling System," which is the bid-submission software system that will be used by market participants and hosted by the NYISO. It explains the responsibilities of each ISO to ensure market participants have appropriate access to the scheduling system and to minimize the financial impact should a market participant that uses the system be suspended or terminated in one of the Control Areas. It also addresses the need for a market participant submitting a bid in one Control Area to have that bid confirmed by a counter-part in the other Control Area, and it explains the requirements that each ISO must follow to ensure market participants are able to confirm bids.

Articles III and IV – Calculating ISO-NE Supply Price Points and Scheduling External Transactions at CTS Enabled Interfaces

Articles III and IV explain several significant features of how CTS Interface Bids will be cleared.

1. Background

A fundamental objective of Coordinated Transaction Scheduling is to increase the likelihood that energy will flow from the lower-priced region to the higher-priced region for any given 15-minute interval.[19] CTS achieves this objective through the clearing of CTS Interface Bids submitted from both New England and New York market participants at a CTS Enabled Interface. A CTS Interface Bid is a real-time bid to simultaneously purchase and sell energy on each side of a CTS Enabled Interface.[20] The bid consists of four components: A price, a direction, a quantity, and the time period to which the bid applies. The price indicates the minimum expected price difference between the two regions that the market participant is willing to accept. The direction indicates in which region the market participant wants to buy, and in which it wants to sell. The quantity indicates how many megawatts the market participant is willing to transact. A CTS Interface Bid will clear if the offered price is less than the expected LMP difference across the interface in the requested direction, as of the time the interface is scheduled.

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[19] *See* the ISO-NE CTS Filing transmittal letter at p. 11.

[20] *See* the ISO-NE CTS Filing transmittal letter at pp. 13-16 for an explanation of CTS Interface Bid clearing. In the ISO-NE Tariff, a CTS Interface Bid is referred to as an "Interface Bid." In the Coordination Agreement, the parties have agreed to use the term "CTS Interface Bid."

2. ISO-NE Supply Price Points

NYISO will manage the clearing and scheduling of CTS Interface Bids using its Real-Time Commitment ("RTC") optimization system in accordance with the rules specified in the NYISO Services Tariff and the additional details provided in Schedule D for CTS Interface Bid clearing and scheduling. Because a CTS Interface Bid is a spread bid – indicating the minimum price difference between the two regions the market participant is willing to accept – to clear CTS Interface Bids ISO-NE must provide NYISO with the underlying price points, representing the forecast prices for energy at varying interchange levels at the CTS Enabled Interface. Article III addresses how this price data – referred to ISO-NE Supply Price Points – will be calculated and provided to the NYISO.

ISO-NE Supply Price Points will be calculated as a set of increasing forecast energy prices at the relevant External Proxy Bus for the CTS Enabled Interface, with each price point corresponding to a net interchange level. The resulting MW-price pairs, where the MW value represents a net interchange level on the CTS Enabled Interface and the price value represents ISO-NE's forecast of its real-time LMP for its External Proxy Bus at that net interchange MW level, will be provided to NYISO each quarter hour, with 10 consecutive quarter-hour sets of price points provided each quarter hour. Article III requires that ISO-NE calculate the price points using a forward-looking version of the security-constrained economic dispatch that ISO-NE uses for dispatching its system, using current unit commitment information and current production data. These requirements help ensure that the price points are an accurate representation of prices on the New England side of the interface.

3. Scheduling CTS Interface Bids

As Article IV explains, the RTC will use the CTS Interface Bids and the ISO-NE Supply Price Points (as well as real-time pricing data from the corresponding New York External Proxy Bus) to establish (1) which CTS Interface Bids clear (or are "economically scheduled"), (2) the LMP for each CTS Enabled External Proxy Bus, and (3) the congestion for the CTS Enabled Interface. The RTC will clear CTS Interface Bids up to the Transfer Limits, and within the Ramp Limits, established in accordance with Article V of Schedule D.

Article IV also addresses several unique scheduling conditions for CTS Enabled Interfaces. If the RTC optimization is scheduling CTS Interface Bids hourly, rather than on a 15-minute basis (which can occur pursuant to Section 7.3 when necessary to ensure or preserve system reliability or when not able to implement schedules as expected due to software or communication issues), the RTC will use the ISO-NE Supply Price Points for each 15-minute interval in that hour to complete the scheduling. Similarly, since some transactions will continue to be scheduled hourly at CTS Enabled Interfaces (Emergency Energy and wheel-through transactions), Article IV explains that the RTC optimization for scheduling CTS Interface Bids at 15-minute intervals will take account of the hourly RTC external transaction schedules through an adjustment to the ISO-NE Supply Price

Points. Finally, Article IV explains that when there are multiple CTS Interface Bids at the same bid price but not all of them can be economically cleared, bids with the same price will be scheduled pro-rata.

4. External Interface Congestion Price Assignment

Under the current inter-regional trading system, ISO-NE and NYISO do not exchange the information necessary to calculate an economically correct congestion price associated with a binding external interface limit.[21] Under Coordinated Transaction Scheduling, each ISO will set a congestion component for the CTS Enabled Interface LMP when there is a binding external interface limit. When the external interface is binding at the time it is scheduled, the difference between one ISO's incremental cost of sending power and the other ISO's decremental cost of receiving power comprises the total congestion price across the interface. The ISOs will incorporate this difference, less the net amount paid to the marginal (*i.e.*, last accepted) CTS Interface Bid, into the congestion component of their real-time LMPs associated with the CTS Enabled Interface.[22]

As ISO-NE explained in the ISO-NE CTS Filing, to avoid both ISO-NE and the NYISO charging the total congestion price to market participants (which would result in the double-counting of congestion charges), the total of the two regions' congestion components of the real-time LMPs associated with an external interface will add up to the desired total congestion price determined at the time the interface is scheduled.[23] Section 4.2 of Schedule D addresses how congestion will be allocated between the two regions, with the allocation being based on the cause of the congestion. As described in Section 5.2 of Schedule D, transfer limits will be submitted by ISO-NE to NYISO to help ensure that the economic objective of the RTC solution for clearing CTS Interface Bids does not create or worsen a reliability condition in ISO-NE. When congestion is caused by any of these transfer limits, the congestion will be allocated to ISO-NE and incorporated into the ISO-NE LMP at the External Proxy Bus associated with the CTS Enabled Interface. When the congestion is caused by a NYISO ramping limit, then the congestion will be

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[21] Congestion is a condition in which transmission system operating limits prevent unconstrained economic dispatch of the power system. Congestion is captured in the Congestion Component of the LMP. The Congestion Component of the LMP differs across locations within the New England transmission system whenever one (or more) internal transmission limits are binding.

[22] *See* the ISO-NE CTS Filing transmittal letter at pp. 17-18 and Section III.2.5(a) of the CTS market rules, which states in relevant part, "For an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented, the Real-Time Price at the External Node shall be further adjusted to include the effect on Congestion Costs (whether positive or negative) associated with a binding constraint limiting the external interface schedule, as determined when the interface is scheduled."

[23] ISO-NE CTS Filing transmittal letter at pp. 17-18. NYISO addresses this in its filing materials on page 13 of the transmittal letter for the NYISO CTS Filing.

allocated to NYISO and incorporated into its NYISO LMP at the relevant External Proxy Bus. When the congestion is caused by any other factor, or when it is the result of an operator override,[24] then the congestion will be split equally between the two ISOs.

If there are insufficient CTS Interface Bids to produce a Transfer Limit for the interface, congestion pricing is used to represent the value of energy given the supply shortage. Section 4.2 indicates that under such circumstances the RTC will schedule the available MW and determine a congestion price based on the price that NYISO uses for establishing such a congestion price under other similar circumstances (referred to in the NYISO Tariff as "Transmission Shortage Costs," which is set at $4,000/MWh).[25]

Article V – Operating Rules for CTS Enabled Interfaces

Currently, ramp limits and transfer limits are managed independently by each ISO. Under CTS, ramp limits on CTS Enabled Interfaces will be coordinated between the two ISOs. Transfer limits, while set independently, will take into consideration a number of additional factors as addressed in Sections 5.2 and 5.3 of Schedule D.

1. Ramp Limits

Prior to CTS implementation the ISOs will agree to the default quarter-hour Ramp Limit[26] for the NY/NE Northern AC Interconnection, and will also agree to a default top-of-the-hour Ramp Limit for use when quarter-hour scheduling is unavailable. Under Section 5.1, when necessary to protect reliability, the ISOs may agree to temporarily change the Ramp Limits at a CTS Enabled Interface and will restore the modified limit to the default limit as soon as reliable system operations permit and it is practicable to do so.

2. Transfer Limits

The Transfer Limits on a CTS Enabled Interface establish the minimum and maximum net interchange that can be scheduled on the interface, and therefore are

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[24] Section 5.2.5 of Schedule D states, "Real-time system conditions may require that a NYISO or ISO-NE operator override the Transfer Limit to establish the flow that can be transferred over a CTS Enabled Interface in a reliable manner. Except when necessary to protect reliability, an operator override shall not be used to submit limits that can be submitted via the electronic data exchange."

[25] *See* NYISO Services Tariff Attachment B, Section 17.1.4 and NYISO Services Tariff Definitions, Section 2.20.

[26] The CTS Conforming Revisions add to Article 2.0 of the Coordination Agreement the defined term Ramp Limit, which is defined as "(1) the maximum allowable amount of change in net interchange at a CTS Enabled Interface over a defined period of time, established in accordance with Section 5.1 of Schedule D; or (2) the maximum allowable amount of change in net interchange across all NYISO Proxy Generator Buses over a defined period of time, established in accordance with the NYISO Tariffs."

important inputs in the RTC solution. The parties have therefore memorialized several inputs that impact the Transfer Limit on a CTS Enabled Interface (in Section 5.2) and how those inputs are used in calculating the Transfer Limit used in the RTC solution (in Section 5.3).

a. Reliability Inputs that Impact the Transfer Limit

Inputs that impact the Transfer Limit calculation include the normal scheduling limit for the interface, Operating Reserve limitations, minimum generation limitations, capacity transfer limits, and transfer limits set by operator override. For NYISO, these limits are currently included, as necessary, in the existing RTC optimization. Section 5.2 addresses ISO-NE's obligation to provide these limits, when necessary, to NYISO. Normal scheduling limits are established individually by each ISO. ISO-NE will communicate scheduling limits (and any adjustments thereto) in 15-minute intervals covering the same ten consecutive quarter-hour intervals as the ISO-NE Supply Price Points.

In the event the Transfer Limit must be modified so that New England is able to meet its 10-minute and 30-minute reserve requirements, Section 5.2 allows ISO-NE to provide NYISO with Transfer Limit values reflecting the net interchange required to meet these reserve requirements.

When New England approaches minimum generation conditions, ISO-NE may provide Transfer Limit values that reflect these conditions – *i.e.*, reflecting the net interchange level beyond which ISO-NE cannot further dispatch down internal generation while maintaining reliable operations. NYISO, however, is not obligated to enforce a minimum generation limit that would require it to accept energy from New England.

Section 5.2 also recognizes that the Transfer Limit on a CTS Enabled Interface can be impacted by capacity requests between Control Areas. It therefore establishes the "Capacity Available to NYISO" and the "Capacity Available to ISO-NE," with the critical determinants in each case being whether the supplier has taken the steps necessary in its native Control Area to have the energy from its resource scheduled and available for delivery in the native Control Area.

Finally, Section 5.2 recognizes that "real-time system conditions may require that a NYISO or ISO-NE operator override the Transfer Limit to establish the flow that can be transferred over a CTS Enabled Interface in a reliable manner."

c. Calculating the Transfer Limits for use in RTC

Section 5.3 provides a series of rules for determining the Transfer Limits (high or low) under various conditions, using the inputs established in Section 5.2.

A Minimum Generation Transfer Limit provided by ISO-NE will set the low Transfer Limit value at a CTS Enabled Interface so long as it adheres to the requirements in Section 5.2.

When ISO-NE wants to limit flows into New York to address a 30-minute Operating Reserve limitation in New England, the Transfer Limit at a CTS Enabled Interface will respect ISO-NE's request so long as doing so will not cause NYISO to have a deficiency in 10-minute Operating Reserve, and otherwise the Transfer Limit will be set at the lowest possible value that is not projected to result in such a deficiency. Similar conditions are established for when ISO-NE wants the Transfer Limit to reflect a positive flow from New York into New England in order to support a 30-minute Operating Reserve limitation in New England.

Transfer Limits are also impacted by requests for capacity, which generally trump requests for more restrictive limitations on the Transfer Limit (such as restrictions related to Operating Reserve limits). This priority is reflected in the provisions in Section 5.3 addressing Transfer Limits on a CTS Enabled Interface when ISO-NE has requested capacity from NYISO. These provisions call for the Transfer Limit to be set under such circumstances as the higher of an ISO-NE 30-minute Operating Reserve Transfer Limit and a limit that accounts for capacity requests between the two regions.

Finally, under Section 5.3, a low or high Transfer Limit established by operator override to protect reliability will trump all other proposed Transfer Limits.

Article VI – Settlement

Article VI memorializes how CTS transactions will be settled, and addresses the handling of errors and disputes regarding settlement. Pursuant to the parties' respective tariffs, bids and offers scheduled at CTS Enabled Interfaces from each ISO's market participants will be settled in accordance with the rules set forth in that ISO's tariff.[27] Accordingly, Article VI provides that settlement-related corrections and disputes regarding an ISO's settlement of a CTS transaction will be addressed in accordance with the settlement correction and dispute resolution provisions in that ISO's tariff. Given the potential for any such dispute to involve information and data held by the other ISO, Article VI requires that each party provide support, including information and data, when necessary to assist the other party in addressing a settlement correction or a CTS settlement-related dispute. For price correction issues, which are distinct from settlement-related issues, each ISO agrees to follow the price correction processes set forth in their respective tariffs.

Article VII – Non-Standard CTS Operation

[27] *See* the ISO-NE CTS Filing transmittal letter at pp. 16-17 for a discussion of the ISO-NE settlement rules for CTS transactions.

Article VII addresses the ISOs' agreement on the handling of three circumstances in which normal CTS operation will be suspended or modified: circumstances in which ISO-NE Supply Price Points are modified outside the normal course, circumstances in which ISO-NE Transfer Limits are modified outside the normal course, and the disabling of 15-minute CTS scheduling.

As explained above, the RTC clearing of CTS Interface Bids is dependent on ISO-NE providing NYISO a set of ISO-NE Supply Price Points that represent the forecasted price of energy at a CTS Enabled Interface at various MW levels. Section 7.1 addresses what will occur if ISO-NE faces problems in providing NYISO with a set of ISO-NE Supply Price Points for one or more intervals. If NYISO does not receive a set of points before commencing the RTC optimization for an interval, or if the set of points provided by ISO-NE fails NYISO's validation checks, then the last set of points provided by ISO-NE will be used for that interval. If the ISO-NE Supply Price Points for an interval do not fully cover the CTS Interface Bid MWs that are to be evaluated by RTC, NYISO will extend the point curve in either direction to cover all the bids.

Similar rules apply in the event NYISO does not receive valid ISO-NE Transfer Limit values. If ISO-NE does not provide Transfer Limits for an interval before the RTC optimization commences for that interval, NYISO will use the last set of Transfer Limits received to perform the optimization. If Transfer Limits fail input checks that are intended to ensure the Transfer Limit rules specified in Article V are honored, then again the last set of Transfer Limits received from ISO-NE will be used in the RTC optimization.

Finally, the parties may agree to temporarily employ hourly scheduling in RTC on a CTS Enabled Interface when necessary to ensure or preserve system reliability or when not able to implement schedules as expected due to software or communication issues.

Article VIII – Customer Service; Maintenance; Suspension of CTS; Cooperation

Article VIII addresses a number of administrative aspects of CTS related to the need for regular communication, cooperation and support between the two ISOs to ensure that CTS functions efficiently.

Under Section 8.1, the parties agree that each ISO will serve as the primary customer service contact for their respective market participants and that ISO-NE will have read-only access to its market participants' bids so that it can assist with customer service requests.

Given the need for continuous, timely transfer of data between the two ISOs for the administration of CTS, the parties agree in Section 8.2 to terms of maintenance. The ISOs agree to the goal, subject to reasonable expectations, that data links, software and other systems necessary to implement CTS will be available continuously, and to that end agree to employ regular maintenance. In the event of a problem with a data link,

software, computational or data system, the parties agree that they will use reasonable efforts to promptly address the problem, work together, and keep each other informed regarding the progress on a resolution. In the event testing or maintenance outages are scheduled, the parties will inform each other in advance, with sufficient notice to allow each ISO to inform its market participants of any impacts on CTS operation.

Section 8.3 addresses the circumstances under which the scheduling of CTS transactions will be suspended, and the actions to be taken in the event of a suspension. CTS operations may need to be suspended for any of the following reasons:

(1) the inability of the NYISO to receive bids for a CTS Enabled Interface;

(2) a failure or outage of the data link between the parties that prevents the timely exchange of information necessary to implement CTS transactions;

(3) the actual or suspected failure of any software, computational, or data system that is necessary to implement CTS transactions;

(4) the need to verify the functionality of the tools that are necessary to implement CTS; or

(5) when necessary to ensure or preserve NYISO or ISO-NE system reliability.

In the event CTS is suspended, the parties agree to use reasonable efforts to promptly address the issue, work together and keep each other informed of progress in resolving the issue. CTS will resume after successful testing.

During a suspension, the two ISOs will mutually agree to interchange schedules at CTS Enabled Interfaces.

Finally, under Section 8.4, in the event either ISO identifies an issue for self-report to the Commission's Office of Enforcement, that party agrees to inform and provide a copy of the self-report to the other party, which shall be held by the receiving party confidentially.

Article IX – Change Management

Article IX explains the process the parties agree to follow when materially changing any tariff language, software or process that is directly involved in implementing CTS. Article IX ensures timely notification of a proposed change and details a procedure for addressing disagreements over a change.

The provision requires prior notice of a proposed change, in writing, with an explanation of the reason for and impact of the change on CTS implementation. The receiving party may then request additional information or documentation, including a request to be involved with testing the change. Within 10 days of receiving notice of a change, the receiving party may notify the party proposing the change of a disagreement

with the change, identifying specifically its concern. If the parties cannot agree on implementation of the change, the change cannot be implemented until the completion of the dispute resolution processes addressed in Article 19 of the Coordination Agreement. These processes include the right of either party to request mediation through the Commission's dispute resolution services.

Article X – Audits, Certification and Testing

Article X addresses the parties' agreement with respect to CTS software and process certification and testing, and with respect to CTS auditing.

The parties agree that all CTS processes and software components will be tested prior to initial implementation and prior to implementing any material change thereto. While the parties are not making an affirmative obligation to certify or audit CTS-related software, they do each agree to undertake an annual Service Organization Controls ("SOC") report that covers CTS process-related controls, and NYISO agrees that the report will include controls related to the Joint Energy Scheduling System. Each party also agrees to provide the other party with the CTS-related results of the SOC report, which must be held confidentially. Further, in the event either party undertakes a separate certification or audit of CTS-related software, it agrees to provide the results thereof to the other party, again with the agreement that the results be held in confidence.

Finally, the parties agree that if there is a break of cyber security related to CTS, each party will take actions to address the issue, at its own expense, and will promptly notify the other party of the incident. While the parties anticipate that cooperation and information sharing will be necessary in the event of such a breach, the agreement is intended to ensure that any cyber security issue is addressed quickly and efficiently using each party's respective procedures for handling other cyber security-related issues, rather than through a joint process that could unnecessarily delay corrective action.

B. Revisions to the ISO-NE/NYISO Coordination Agreement

A small number of revisions are being made to the main body of the Coordination Agreement. These include revisions to add new definitions or modifications to existing definitions to recognize CTS transactions, revisions to introduce the concept of CTS transactions within the context of the agreement, updates to the confidentiality provisions, and a number of more ministerial or housekeeping revisions.

The revisions add a number of new defined terms to Article 1.0 of the Coordination Agreement, which are used almost exclusively in the new Schedule D. The large majority of these defined terms are versions of terms from the parties' respective tariffs on CTS. To the extent necessary, these terms are explained above in Section V.B on Schedule D.

The revisions add to Section 2.2 two additional functions that the agreement addresses: administering Coordinated Transaction Scheduling and implementing other arrangements between the ISOs for the coordination of their systems.

The revisions make a number of clarifications to Section 6 of the agreement on information exchange and treatment of confidential information. These clarifications are as follows:

- Currently, Section 6 conditions the sharing of confidential information on compliance with all other confidentiality agreements and related tariff provisions of the respective parties. The revisions remove this general obligation and instead address confidentiality in greater detail in Section 6 of the agreement.

- Section 6.1 is being revised to expressly authorize the sharing of a large range of information that is necessary for the parties to implement and administer CTS.

- Ministerial changes are being made to Section 6.2 to ensure that a contact from each ISO is available at all times to facilitate the exchange of data and respond to inquiries regarding data.

- Section 6.4 is revised to remove the vague reference to sharing additional information by "mutual agreement" and replace it with a specific reference permitting such additional sharing so long as it is subject to the protections detailed in Section 6.5 on treatment of confidential information.

- Section 6.5, which addresses the treatment of confidential information and Critical Energy Infrastructure Information, is being revised to ensure that the protection afforded to confidential information and CEII is the same as the protection required under the parties' respective tariff provisions that address treatment of confidential information generally. Thus, for ISO-NE, the revisions conform the confidentiality protections to the ISO New England Information Policy, which is Attachment D to the ISO-NE Tariff. These revisions ensure that information is protected at least to the same standard of protection that is required under the ISO New England Information Policy.

- A new Section 6.6 is being added to help prevent and minimize claims or losses in the event of an unauthorized transfer of a third-party's intellectual property. The provision prohibits such transfers and requires prompt notice and reasonable steps to avoid claims and mitigate losses in the event of such a transfer.

The revisions add a new Article 11 to address scheduling checkout protocols. This provision identifies four types of checkouts for transaction schedules between the two Control Areas and obligates the two ISOs to perform these checkouts. These protocols are utilized today between the ISOs and are being memorialized in the Coordination Agreement at this time given that they address coordination, generally, between the two ISOs on external transaction scheduling for all interfaces. They include:

(1) daily day-ahead checkout on the day before a transaction is to flow to verify net interchange totals and individual transaction schedules; (2) daily real-time checkout performed during the period before the transaction is to flow, to verify net interchange totals and individual transaction schedules; (3) after-the-fact checkout of real-time transactions performed the business day following the transaction day, to ensure that changes made by one ISO or the other in real-time are reflected in the checkout data that is used for settlement purposes; and (4) after-the-fact reporting of scheduled and actual energy interchanges will be provided by each ISO each day, and data for a month will be reconciled within 10 days of the end of the month.

Article 19 on dispute resolution is being modified to add the use of the Commission's Dispute Resolution Service to mediate a dispute under the agreement should the parties otherwise be unable to agree to submit the dispute to arbitration.

Section 22.3 is being modified to address obligations in the event a party is required to self-report a potential violation of the agreement (including the administration of CTS) to the Commission. Under Section 22.3, a party that self-reports such a violation must provide a copy of the self-report to the other party, and the parties must make reasonable efforts to cooperate and assist in addressing the violation.

The billing and payment provisions in Schedule C, which addresses the purchase of emergency energy from one Control Area by the other, are being updated to require payment of an invoice for emergency energy within five business days of issuance. This language replaces the current requirement that invoices be paid by the latter of the twentieth day of each month or the first common banking day after the nineteenth day of the month, whichever is later.

The remaining changes to the Coordination Agreement are ministerial in nature.

In preparing the materials for this submittal, the ISOs discovered that two provisions in Section 6.5 of the Coordination Agreement that they had intended to strike – specifically, Sections 6.5 (d) and (h) – were inadvertently removed altogether before the proposed changes were presented to stakeholders. Because stakeholders did not have the opportunity to review these proposed strike-outs, the ISOs have agreed not to remove the two provisions from Section 6.5 at this time. The ISOs have also agreed that they will address the removal of these two provisions with stakeholders and file the proposed changes with the Commission as quickly as possible.

C. Revisions to Market Rule 1

The ISO is proposing a limited number of changes to the market rules, necessitated primarily because of changes to the market rules that have been made since the CTS rules were originally developed in 2012. The majority of these changes are non-substantive.

1. Implementing CTS at a Single CTS Enabled Interface

The ISO is removing language in Section III.1.10.7A of Market Rule 1 indicating that CTS will be implemented at the Northport-Norwalk external location. In the ISO-NE CTS Filing, the ISO indicated that CTS would be implemented at two locations – the Northport-Norwalk external location and the New York Northern AC external location – but noted that further evaluation with NYISO was necessary before reaching certainty on whether CTS could be implemented at the Northport-Norwalk external location.[28] ISO-NE and NYISO have determined that it is not possible to implement CTS at the Northport-Norwalk location at this time, due to the complexity involved with clearing two interfaces under the ISO-NE Supply Price Points CTS model.

The challenges presented by implementing CTS at two interfaces are primarily the result of limitations with the existing production software and algorithms. Under the planned implementation, as discussed above, ISO-NE will compute the marginal cost for the New England system to deliver power to a CTS Enabled Interface for a variety of interchange levels for each 15 minute interval and will pass this supply curve information to the NYISO. NYISO will combine the supply curve information with the CTS Interface Bids and New York production cost information to determine the interface schedule. To account for the interdependencies between interfaces and provide interface schedules for two CTS Enabled Interfaces would require repeated iterations of passing information between the ISOs, which is not feasible under the existing production software and algorithms.

2. Moving the CTS Interface Bid Submittal Deadline

In the initial CTS filing, ISO-NE proposed that the deadline for submitting CTS Interface Bids would be 75 minutes before the start of the 15 minute interval for which the bid was being submitted.[29] NYISO is hosting the CTS bidding platform, which must be integrated into their existing bidding platform. NYISO's existing bidding platform requires that all bids be submitted no later than 75 minutes prior to the start of the clock hour, and NYISO is not proposing to modify the submittal deadline for CTS implementation. Accordingly, CTS Interface Bids will also need to be submitted under this timetable. ISO-NE is therefore updating the relevant market rule language to reflect a 75 minute before the "clock hour" deadline.

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[28] ISO-NE CTS Filing, transmittal letter at p. 3. ISO-NE stated in the transmittal letter: "As the NYISO indicates in its filing materials for Coordinated Transaction Scheduling, at this time only the New York Northern AC external Location has been evaluated for Coordinated Transaction Scheduling implementation. In the event further evaluation reveals that implementation for the Northport-Norwalk external Location is not feasible, the ISO will file a Tariff amendment to remove reference to this latter location before Coordinated Transaction Scheduling becomes effective." (citations omitted).

[29] ISO-NE CTS Filing, transmittal letter at pp. 13-14, 15.

3. Inadvertent Energy Settlement

The ISO-NE CTS Filing provided that, as with other credits and charges for CTS transactions, Inadvertent Energy for CTS transactions would be settled every 15 minutes.[30] Under the current market rules, Inadvertent Energy for External Transactions is settled hourly. The ISO is proposing to retain the hourly settlement for Inadvertent Energy for the initial CTS implementation and to re-evaluate sub-hourly settlement for Inadvertent Energy as part of a larger project on sub-hourly settlement, when a comprehensive assessment of acquiring or estimating sub-hourly data that is not currently available will occur.

4. Non-Substantive Conforming Changes

The remainder of the market rule changes are necessary to maintain the CTS market rule treatment proposed by ISO-NE in its ISO-NE CTS filing. These changes are needed because subsequent market rule changes have changed the structure of the rules, and therefore it is not possible to overlay the original CTS rule changes onto the existing tariff; modifications are necessary to ensure the original intent is preserved. These changes include:

- Revisions to Appendix F on Net Commitment Period Compensation are necessary to exclude Coordinated External Transactions from the Day-Ahead and Real-Time NCPC charge calculations and make Coordinated External Transactions ineligible for NCPC, all of which were features of the original ISO-NE CTS filing.[31]

- Modifications to the provisions in Section III.2 on the calculation of LMPs made since the ISO-NE CTS Filing was submitted combined some provisions with others. The last sentence in Section III.2.5(a) addresses the calculation of Congestion Costs for real-time LMPs at CTS Enabled Interfaces, and therefore a qualifier is being added to the language above in that paragraph to explain that the congestion calculation addressed in that sentence applies only to External Transaction purchases submitted under Section III.1.10.7, which include all External Transactions other than CTS transactions.

- The ISO-NE CTS filing exempted Coordinated External Transactions from regulation charges in Section 3.2.2.[32] The regulation charge language has since been moved (with the rest of the Regulation Market

[30] ISO-NE CTS Filing, transmittal letter at pp. 16-17. Inadvertent Energy is the difference between the scheduled and actual energy flow into or out of the New England Control Area.

[31] ISO-NE CTS Filing, transmittal letter at pp. 11-12.

[32] *Id.*

rules) to Section III.14, and it is therefore necessary to relocate the exemption language to Section III.14.8(c) to preserve the design intent.

- Finally, the CTS Conforming Revisions include changes to Section I.2.2 (Definitions) of the ISO Tariff to include a supporting definition for the term "Coordination Transaction Scheduling," which had been included as a capitalized term in the ISO-NE CTS Filing, but omitted as a defined term in Section I.2.2. To address this, ISO-NE has revised Section I.2.2 to include the following definition: "Coordinated Transaction Scheduling means the enhanced scheduling procedures set forth in Section III.1.10.7.A."

D. Revisions to the OATT

The CTS Conforming Revisions include changes to the ISO-NE Open Access Transmission Tariff, which is Section II of the ISO-NE Tariff. The revisions to the OATT are necessary to distinguish the different scheduling and curtailment rules for External Transactions on the CTS (*i.e.*, the New York Northern AC interface) and non-CTS interfaces, and reflect other conforming, non-substantive clean-up changes. Specifically, the revisions modify Section II.44 (Scheduling and Curtailment Rules) to recognize the treatment applicable to the CTS Enabled Interface. To improve readability and avoid confusion, the revisions also separate Section II.44 into three subsections such that the scheduling and curtailment rules that are applicable to External Transactions on non- CTS Enabled Interfaces are set out in subsection II.44(1), the rules applicable to External Transactions on CTS Enabled Interfaces are provided in subsection II.44(2), and the terms and conditions that are equally applicable to both CTS and non-CTS external interfaces are reflected in subsection II.44(3). Although restructured, for the most part, the existing provisions in Section II.44 remain intact. The CTS Conforming Revisions introduce new language in subsection II.44(2) to provide for External Transactions on the CTS external interface to be scheduled and curtailed on the basis of economic merit order, and ties within economics are to be reduced on a *pro-rata* basis. The revisions also include the following non-substantive, clean-up changes in subsections II.44(1) and II.44(3):

- Add reference to MEPCO Grandfathered Transactions in subsection II.44(1)(a) to improve transparency in the treatment of those transactions;

- Delete the examples provided in subsections II.44(1)(b)-(d) as unnecessary since transmission provisions elsewhere in the OATT define which external interfaces require advance physical reservations;

- Replace "ISO System Rules and this OATT" terminology in subsection II.44(1)(f) with "ISO New England Operating Documents", as the more appropriate defined term;

- Reflect appropriate cross-reference of the subsections consistent with the reorganization of Section II.44; and

- Conforming changes to Schedule 2 (Reactive Supply and Voltage Control Service) of the OATT, to conform to the CTS design element of eliminating transaction fees by removing CTS reserved capacity from the current Through or Out and Regional Network Service allocation of the VAR charges.

In addition, the CTS Conforming Revisions modify Section II.11 (Nature of Regional Network Service) to and Attachment C (Available Transfer Capability Methodology), and Attachment G-3 (Complete List of Excepted Transaction (Transmission) Agreements Over External Ties) to reflect certain conforming changes. As provided in Section II.44, a Real-Time External Transaction that is submitted and scheduled in the Real-Time Energy Market is treated as a request for Regional Network Service for which ISO-NE generates a reservation for the transmission service over the Pool Transmission Facilities on the system. Currently, Section II.11 provides for the reservation to be equal to the transaction's "schedule set at the beginning of the scheduling period." The CTS Conforming Revisions modify this reserve capacity language with the "maximum scheduled flow during the operating hour" to align with the current Through or Out Service reserve capacity language. The revisions also include certain conforming changes in Appendix C to recognize hourly and sub-hourly scheduling intervals. Finally, the revisions modify Attachment G-3 to replace the cross-reference to "Section II.44(a)" with "Section II.44(1)(a)", consistent with the restructuring of Section II.44 described above.

E. Revisions to the Self-Funding Tariff

The CTS Conforming Revisions include changes to the ISO-NE Self-Funding Tariff, which is Section IV of the ISO Tariff. These revisions support the effort to reduce cross-border transaction costs, one of the underlying objectives of CTS that helps ensure more efficient trade between the regions. The majority of transaction fees were eliminated as part of the ISO-NE CTS Filing. The CTS Conforming Revisions carry this objective through to charges for External Transactions at CTS-Enabled Interfaces contained in the ISO-NE Self-Funding Tariff.

The revisions remove charges allocated to CTS transactions under the ISO-NE Self-Funding Tariff as follows:

- Charges to Transmission Customers for Through or Out Service

- Energy transaction unit-based charges to market participants

- Volumetric measure-based energy charges to market participants

- Per-transaction charges for exports.

VI. STAKEHOLDER PROCESS.

The CTS Conforming Revisions were vetted through the complete NEPOOL Participant Processes and received the unanimous support of the NEPOOL Participants Committee. Prior to the Participants Committee approval, portions of the CTS Conforming Revisions were considered and voted separately by NEPOOL's three Technical Committees.[33] The Technical Committee votes were as follows:

- At its May 5-6, 2015 meeting, the NEPOOL Markets Committee voted to recommend Participants Committee support for the revisions to Market Rule 1, with three abstentions and none opposed.

- At its May 26, 2015 meeting, the NEPOOL Transmission Committee voted to recommend Participants Committee support for the revisions to the OATT, with 40 abstentions and none opposed.

- At a joint Markets/Reliability Committee meeting on June 3, 2015, the NEPOOL Markets Committee voted to recommend Participants Committee support for the addition of Schedule D to the Coordination Agreement, along with the supporting revisions to defined terms, with 24 abstentions and none opposed, and the NEPOOL Reliability Committee voted to recommend Participants Committee support for the revisions to the Coordination Agreement, including the addition of Schedule D, with 38 abstentions and none opposed.

- Subsequent to the Markets/Reliability Committee votes on Schedule D to the Coordination Agreement, the two committees each voted to support additional minor revisions to Schedule D. The Markets Committee voted to recommend Participants Committee support for these additional changes at its July 9, 2015 meeting, with three abstentions and none opposed. The Reliability Committee voted unanimously to recommend Participants Committee support for the additional changes at its July 14-15, 2015 meeting.

At its August 7, 2015 meeting, the NEPOOL Participants Committee voted unanimously to support the CTS Conforming Revisions. With the exception of the revisions to the ISO-NE Self-Funding Tariff,[34] the package of revisions was included on the Consent Agenda for the meeting, which the Participants Committee unanimously

[33] Per the Second Restated NEPOOL Agreement and the Participants Agreement, the three standing Technical Committees of the NEPOOL Participants Committee are the Markets Committee, the Reliability Committee and the Transmission Committee.

[34] Prior to the Participants Committee's consideration, the changes to the ISO-NE Self-Funding Tariff were discussed by the NEPOOL Budget and Finance Subcommittee at its May 13, 2015 teleconference meeting.

voted to support.[35] The Committee also voted unanimously to support the revisions to the ISO-NE Self-Funding Tariff.

The PTO AC voted 100% in support of the revisions to Attachment G-3 of the OATT at its June 10, 2015 meeting.

VII. ADDITIONAL SUPPORTING INFORMATION.

Section 35.13 of the Commission's regulations generally requires public utilities to file certain cost and other information related to an examination of traditional cost-of-service rates. However, the revisions filed herewith do not modify a traditional "rate" and the ISO is not a traditional investor-owned utility. Therefore, to the extent necessary, the Filing Parties request waiver of Section 35.13 of the Commission's regulations.[36] Notwithstanding its request for waiver, the Filing Parties submit the following additional information in substantial compliance with relevant provisions of Section 35.13 of the Commission's regulations:

35.13(b)(1) – Materials included herewith are as follows:

- This transmittal letter;
- Blacklined ISO-NE Tariff sections reflecting the revisions to Market Rule 1, the ISO-NE Self-Funding Tariff, the OATT, and the ISO-NE/NYISO Coordination Agreement submitted in this filing;
- Clean ISO-NE Tariff sections reflecting the revisions to Market Rule 1, the ISO-NE Self-Funding Tariff, the OATT, and the ISO-NE/NYISO Coordination Agreement submitted in this filing;
- List of governors and utility regulatory agencies in Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont to which a copy of this filing has been sent.

[35] The Consent Agenda for a Participants Committee meeting, similar to the Consent Agenda for a Commission open meeting, is a group of actions (each recommended by a Technical Committee or subgroup established by the Participants Committee) to be taken by the Participants Committee through approval of a single motion at a meeting. Although voted as a single motion, all recommendations voted on as part of the Consent Agenda are deemed to have been voted on individually and independently. The Participants Committee's unanimous approval of the August 7, 2015 Consent Agenda included its support for the CTS Conforming Revisions, other than the revisions to the ISO-NE Self-Funding Tariff, which were separately supported unanimously.

[36] 18 C.F.R. § 35.13 (2011).

35.13(b)(2) – As set forth in Section I above, the Filing Parties request that the revisions become effective on or after December 1, 2015, with two weeks prior notice to be filed identifying the actual effective date.

35.13(b)(3) – Pursuant to Section 17.11(e) of the Participants Agreement, Governance Participants are being served electronically rather than by paper copy. The names and addresses of the Governance Participants are posted on the ISO's website at http://www.iso-ne.com/regulatory/ferc/nepool/gov_prtcpnts_eserved.pdf. A copy of this transmittal letter and the accompanying materials have also been sent to the governors and electric utility regulatory agencies for the six New England states that comprise the New England Control Area, the New England Conference of Public Utility Commissioners, Inc., and to the New England States Committee on Electricity. Their names and addresses are shown in the attached listing. In accordance with Commission rules and practice, there is no need for the Governance Participants or the entities identified in the listing to be included on the Commission's official service list in the captioned proceeding unless such entities become intervenors in this proceeding.

35.13(b)(4) – A description of the materials submitted pursuant to this filing is contained in Section VII of this transmittal letter.

35.13(b)(5) – The reasons for this filing are discussed in Sections IV and V of this transmittal letter.

35.13(b)(6) – The ISO's approval of these changes is evidenced by this filing. These changes reflect the results of the Participant Processes required by the Participants Agreement and reflect the support of the Participants Committee.

35.13(b)(7) – Neither the ISO nor NEPOOL has knowledge of any relevant expenses or costs of service that have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices.

35.13(b)(8) – A form of notice and electronic media are no longer required for filings in light of the Commission's Combined Notice of Filings notice methodology.

35.13(c)(1) – The CTS Conforming Revisions herein do not modify a traditional "rate," and the statement required under this Commission regulation is not applicable to the instant filing.

35.13(c)(2) – The ISO does not provide services under other rate schedules that are similar to the wholesale, resale and transmission services it provides under the Tariff.

35.13(c)(3) - No specifically assignable facilities have been or will be installed or modified in connection with the revisions filed herein.

VIII. CONCLUSION.

For the reasons identified in this transmittal letter, the ISO, NEPOOL and the PTO AC request that the Commission accept this filing with the revisions to become effective on or after December 1, 2015, with two weeks prior notice to be filed identifying the actual effective date.

Respectfully submitted,

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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 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.

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 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.

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.

Coordinated External Transaction is an External Transaction at an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented. A transaction to wheel energy into, out of or through the New England Control Area is not a Coordinated External Transaction.

Coordinated Transaction Scheduling means the enhanced scheduling procedures set forth in Section III.1.10.7.A.

Correction Limit means the date that is one hundred and one (101) calendar days from the last Operating Day of the month to which the data applied. As described in Section III.3.6.1 of Market Rule 1, this will be the period during which meter data corrections must be submitted unless they qualify for submission as a Requested Billing Adjustment under Section III.3.7 of Market Rule 1.

Cost of Energy Consumed (CEC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Cost of Energy Produced (CEP) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Cost of New Entry (CONE) is the estimated cost of new entry ($/kW-month) for a capacity resource that is determined by the ISO for each Forward Capacity Auction pursuant to Section III.13.2.4.

Counterparty means the status in which the ISO acts as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Customer (including assignments involving Customers) involving sale to the ISO, and/or purchase from the ISO, of Regional Transmission Service and market and other products and services, and other transactions and assignments involving Customers, all as described in the Tariff.

Covered Entity is defined in the ISO New England Billing Policy.

Credit Coverage is third-party credit protection obtained by the ISO, in the form of credit insurance coverage, 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.

Curtailment 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 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.

Interface Bid is a unified real-time bid to simultaneously purchase and sell energy on each side of an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented.

Intermittent Power Resource is 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 over-stated 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.

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.

New Resource Offer Floor Price is defined in Section III.A.21.2.

NMPTC means Non-Market Participant Transmission Customer.

NMPTC Credit Threshold is described in Section V.A.2 of the ISO New England Financial Assurance Policy.

NMPTC Financial Assurance Requirement is an amount of additional financial assurance for Non-Market Participant Transmission Customers described in Section V.D of the ISO New England Financial Assurance Policy.

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.5.7 of Appendix A of Market Rule 1.

Regional Benefit Upgrade(s) (RBU) means a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in the OATT; and (iii) is included in the Regional System Plan as either a Reliability Transmission Upgrade or 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.

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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.

Zonal Price is calculated in accordance with Section III.2.7 of Market Rule 1

II.11 Nature of Regional Network Service

Regional Network Service is the service over the PTF pursuant to Part II.B of this OATT which is provided by the ISO to Network Customers to serve their loads. It includes transmission service over the PTF for the delivery to a Network Customer of its energy and capacity in Network Resources and delivery to or by Network Customers of energy and capacity in Market transactions.

When a Real-Time External Transaction purchase is submitted by the Transmission Customer and is scheduled in the Real-Time Energy Market, the submission shall be deemed a request for Regional Network Service and the ISO shall generate a reservation for the transmission service over the PTF equal to the transaction's maximum scheduled flow during the operating hour~~schedule set at the beginning of the scheduling period~~. This reservation amount shall be the basis for the Reserved Capacity. Each Transmission Customer which has a Regional Network Load within or outside of the New England Control Area shall pay for Regional Network Service under the terms of Section II.B of this OATT.

II.44 Scheduling and Curtailment Rules

For purposes of scheduling and Curtailment of Real-Time External Transactions over interconnections between the New England Control Area and neighboring Control Areas, the following rules shall apply:

(1) For External Interfaces that are not subject to Coordinated Transaction Scheduling

(a) Real-Time External Transaction sales and purchases that (i) are supported by those service agreements referenced in Attachment G-3 to this OATT that have not opted for Auction Revenue Rights consideration under applicable ISO System Rules or (ii) are supported by those service agreements referenced in Attachment H to this OATT, and (iii) have been submitted into the Real-Time Energy Market prior to noon the day before the Operating Day as a Self-Scheduled Real-Time External Transaction ("real-time without price") at an External Node referenced in Attachment G-3 or Attachment H to this OATT shall be assigned the highest transmission priority when compared to other Real-Time External Transaction purchases or sales at that node having the same offer price or bid price. In the event that the transfer limit for a given external interface does not allow all Excepted Transactions or MEPCO Grandfathered Transactions submitted over that interface to flow, they shall be scheduled or curtailed on a pro-rata basis. For Real-Time External Transactions referenced in Attachment G-3 or Attachment H to this OATT that also require an advance physical reservation associated with a MTF or OTF external interface, the MTF or OTF transmission priority shall take precedence over the above language for the purposes of scheduling and curtailment under Sections II.44(1)(c) and II.44(1)(d) of this OATT, respectively. For Excepted Transactions or MEPCO Grandfathered Transactions that are tied within economic merit, and tied within transmission priority, such ~~External T~~transactions cleared in the Day-Ahead Energy Market that have a corresponding Real-Time Energy Market External Transaction will have scheduling and curtailment priority in the Real-Time Energy Market before Excepted Transactions or MEPCO Grandfathered Transactions not cleared in the Day-Ahead Energy Market;

(b) For external interfaces where advance physical reservations are not required ~~(e.g., external interfaces solely made up of PTF, such as the AC facilities that make up the New York/ New England interface or the New Brunswick/New England interface)~~, in the event that the transfer limit for a given external interface does not allow all such Real-Time External Transactions submitted over that interface to flow, the scheduling and Curtailment of Real-Time External Transactions shall be based on economic merit order

in accordance with the ISO System Rules. In the case of a tie within economic merit, transmission priority will be used as the next tiebreaker. In the case of a tie within economic merit and within transmission priority, those External Transactions that cleared in the Day-Ahead Energy Market that have a corresponding Real-Time Energy Market External Transaction will have scheduling and curtailment priority in the Real-Time Energy Market before those that did not clear in the Day-Ahead Energy Market. In the case of a tie within economic merit, transmission priority, and Day-Ahead Energy Market status, Real-Time External Transactions sales that were submitted pursuant to Section III.1.10.7(f) of the Tariff will have scheduling and curtailment priority over those that were not submitted pursuant to Section III.1.10.7(f). After economic merit, transmission priority, Day-Ahead Energy Market status, and supported in Real-Time status pursuant to Section III.1.10.7(f) of the Tariff have been considered, (i) the Real-Time Energy Market timestamp shall be used as the final tiebreaker for External Transactions not submitted pursuant to Section II.44(a) and (ii) pro-rata scheduling and curtailment shall be used as the final tiebreaker for External Transactions submitted pursuant to Section II.44(a). With the exception of Section II.44(a) of this OATT, all transactions crossing external interfaces not requiring advance physical reservations shall have equal transmission priority;

(c) For external interfaces where advance physical reservations are required ~~(e.g., external interfaces made up of MTF or OTF)~~, in the event that the transfer limit for a given external interface does not allow all such Real-Time External Transactions submitted over that interface to flow, the scheduling of Real-Time External Transactions which satisfy the reservation requirements for service shall be based on economic merit order in accordance with the ISO System Rules. In the case of a tie within economic merit, transmission priority shall be used as a tiebreaker. Relative to a given interface, transmission priority is based on the priority rights of the associated MTF or OTF advance physical reservation. In the case of a tie within economic merit and within a category of transmission service, those External Transactions that cleared in the Day-Ahead Energy Market that have a corresponding Real-Time Energy Market External Transaction shall be scheduled in the Real-Time Energy Market before those that did not clear in the Day-Ahead Energy Market. In the case of a tie within economic merit, transmission priority, and Day-Ahead Energy Market status, Real-Time External Transactions sales that were submitted pursuant to Section III.1.10.7(f) of the Tariff will

have scheduling and curtailment priority over those that were not submitted pursuant to Section III.1.10.7(f). After economic merit, transmission priority, Day-Ahead Energy Market status, and supported in Real-Time status pursuant to Section III.1.10.7(f) of the Tariff have been considered, (i) the associated Real-Time Energy Market timestamp shall be used as the final tiebreaker for scheduling within a given subcategory of non-firm transmission service and (ii) pro-rata scheduling shall be used as the final tiebreaker for ties within firm transmission service;

(d) For external interfaces where advance physical reservations are required ~~(e.g., external interfaces made up of MTF or OTF)~~, Curtailments resulting from a reduction in total transfer capability shall be based on transmission priority of the associated MTF or OTF advance physical reservation to the extent possible. In the case of a tie within a category of transmission service, those External Transactions that cleared in the Day-Ahead Energy Market that have a corresponding Real-Time Energy Market External Transaction shall be curtailed in the Real-Time Energy Market after those that did not clear in the Day-Ahead Energy Market. In the case of a tie within transmission priority associated with External Transaction sales that cleared in the Day-Ahead Energy Market that have a corresponding Real-Time Energy Market External Transaction, those Real-Time Energy Market External Transactions that were submitted pursuant to Section III.1.10.7(f) of the Tariff will be curtailed after those that were not submitted pursuant to Section III.1.10.7(f). After transmission priority, Day-Ahead Energy Market status, and supported in Real-Time status pursuant to Section III.1.10.7(f) of the Tariff have been considered, (i) the associated Real-Time Energy Market timestamp shall be used as the final tiebreaker for curtailments within a given sub-category of non-firm transmission service and (ii) pro-rata curtailment shall be used as the final tiebreaker for ties within firm transmission service;

(e) ~~(e)~~ In instances of a Real-Time External Transaction scheduled against multiple advance physical reservations on a MTF or OTF external interface, the lowest transmission priority of the associated advance physical reservations shall apply; and

(f) Scheduling and Curtailment of Real-Time External Transactions shall be conducted in accordance with the specifications of the ISO New England Operating Documents. Real-Time External Transactions not satisfying Section III.1.10.7(i) criteria shall be scheduled and curtailed under the following protocol as may be necessary to respond to and prevent system-

wide Emergencies: (1) initial scheduling and curtailment priority shall be based upon whether the transaction cleared the Day-Ahead Energy Market; in the case of a tie within Day-Ahead Energy Market cleared transactions, priority will next be given to transactions based on the priority of the transmission service; and a tie within any specific transmission service shall be resolved based on the timestamp of the Real-Time Energy Market submission; and (2) secondary scheduling and curtailment priority shall be provided to External Transactions that were only submitted or scheduled in the Real-Time Energy Market and did not clear the Day-Ahead Energy Market; in the case of an economic tie among Real-Time Energy Market cleared transactions, priority will next be given to transactions based on the priority of the transmission service; and a tie within any specific transmission service shall be resolved based on the timestamp of the Real-Time Energy Market submission. Real-Time External Transactions satisfying Section III.1.10.7(i) criteria shall be treated in accordance with that section.

(2) For External Interfaces that are subject to Coordinated Transaction Scheduling, the transmission priority for all Real Time External Transactions is equal. As such, the associated Real Time External Transactions shall be scheduled and curtailed on the basis of economic merit order in accordance with Section III.1.10.7A of the Tariff and the Coordination Agreement between ISO-NE and the NYISO; In the event of a tie within economics, all affected Real-Time External Transactions will be reduced on a pro-rata basis.

(3) Terms and Conditions applied to all External Interfaces

(a~~f~~) The transmission priority for wheel-through transactions will be based on the transmission service utilized at the restricted external interface as indicated by the transmission reservation;

(g~~b~~) Transmission Customers wishing to schedule Real-Time External Transactions shall comply with applicable ISO System Rules;

~~(h) Scheduling and Curtailment of Real-Time External Transactions shall be conducted in accordance with the specifications of the ISO System Rules and this OATT. Real-Time External Transactions not satisfying Section III.1.10.7(i) criteria shall be scheduled and curtailed under the following protocol as may be necessary to respond to and prevent system-wide Emergencies: (1) initial scheduling and curtailment priority shall be based upon whether the transaction cleared the Day-Ahead Energy Market; in the case of a tie~~

~~within Day-Ahead Energy Market cleared transactions, priority will next be given to transactions based on the priority of the transmission service; and a tie within any specific transmission service shall be resolved based on the timestamp of the Real-Time Energy Market submission; and (2) secondary scheduling and curtailment priority shall be provided to External Transactions that were only submitted or scheduled in the Real-Time Energy Market and did not clear the Day-Ahead Energy Market; in the case of an economic tie among Real-Time Energy Market cleared transactions, priority will next be given to transactions based on the priority of the transmission service; and a tie within any specific transmission service shall be resolved based on the timestamp of the Real-Time Energy Market submission. Real-Time External Transactions satisfying Section III.1.10.7(i) criteria shall be treated in accordance with that section.~~

(c~~i~~) Real-Time External Transactions scheduled in the Real-Time Energy Market shall continue to be scheduled and curtailed according to Section II.44(1) and (2) ~~(a) (d) of this OATT~~ , as applicable, when there are transmission limitations on an external interface, except as may be necessary to respond to emergencies;

(d~~j~~) The ISO will redispatch all Resources subject to its control, pursuant to Market Rule 1, in order to meet load and to accommodate Real-Time External Transactions. Transmission Customers will be charged for the Congestion Cost and any other costs associated with such redispatch in accordance with Market Rule 1. Pursuant to such redispatch, in the event the ISO exercises its right to effect a Curtailment, in whole or part, of Through or Out Service, MTF Service or OTF Service, no credit or other adjustment shall be provided as a result of the Curtailment with respect to the charge payable by the customer;

(~~k~~e) The ISO will furnish to the Delivering Party's system operator schedules from each applicable scheduling interval equal to those furnished by the Receiving Party (unless reduced for losses) and will deliver the capacity and energy provided by such schedules;

(~~l~~f) Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the ISO, and the ISO will have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered;

(~~m~~g) The ISO shall apply the above-listed rules consistent with maintaining the reliability of the New England Transmission System; and

(~~n~~h) The ISO shall develop and post procedures on its Internet website reflecting the above-listed External Transaction rules.

SCHEDULE 2

REACTIVE SUPPLY AND VOLTAGE CONTROL SERVICE

In order to maintain transmission voltages on the New England Transmission System (for voltage constraints that are reflected in the ISO's systems for operating the New England Transmission System or in the ISO New England Operating Procedures) within acceptable limits, Qualified Reactive Resources are operated to produce (or absorb) reactive power. Thus, VAR Service must be provided to support Regional Network Service and Through or Out Service on the New England Transmission System (both of which services have a direct impact on voltage constraints that are reflected in the ISO's systems for operating the New England Transmission System or in the ISO New England Operating Procedures). The amount of VAR Service that must be supplied with respect to a Transmission Customer's Regional Network Service and Through or Out Service will be determined based on the degree of dynamic reactive power support necessary to maintain transmission voltages within limits that are consistently adhered to in the operation of the New England Transmission System. Additional information regarding the processes used to collect data and calculate amounts due or payable under this Schedule 2 can be found in the Ancillary Service Schedule 2 Business Procedure posted on the ISO website. Transmission Customers taking Local Service, MTF Service or OTF Service may also need to acquire voltage support services not otherwise provided under this Schedule 2 pursuant to Schedules 18, 20A or 21 to this OATT, as appropriate.

I. DEFINITIONS

Whenever used in this Schedule, in either the singular or plural number, capitalized terms shall have the meanings specified in Section I.2.2. of the Tariff.

II. ELIGIBILITY FOR PAYMENT UNDER SCHEDULE 2

A. Qualified Generator Reactive Resources

Qualified Generator Reactive Resources shall be eligible for VAR Payments under this Schedule 2. A Qualified Generator Reactive Resource shall be offered into the Real-Time Energy Market at a MW level of at least its Economic Minimum Limit in all hours of the month whenever the resource is physically available, and be eligible for commitment by the ISO for the purpose of providing reactive power voltage

support to the New England Transmission System. Qualified Generator Reactive Resources are subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures for the purpose of providing reactive power voltage support to the New England Transmission System. In addition, any generator that is dispatched by ISO for the purpose of providing voltage support to the New England Transmission System shall be eligible to recover its Lost Opportunity Costs ("LOC"), Cost of Energy Consumed ("CEC"), and Cost of Energy Produced ("CEP") pursuant to Sections IV.B-D of this Schedule 2.

A generator shall be deemed a Qualified Generator Reactive Resource if it meets the following criteria:

1. the entity owning or controlling the reactive power capability of the generator reactive resource is a Market Participant;

2. the generator is: (a) interconnected to the New England Transmission System or (b) interconnected to the distribution system but participating in the New England Markets and (c) is metered and dispatchable by the ISO or otherwise subject to operational control by the ISO;

3. the generator provides measurable reactive power voltage support to the New England Transmission System, as determined from time-to-time by the ISO, and has its automatic voltage regulator status and control mode (including power factor, reactive power output and voltage control) telemetered to the ISO and the applicable Local Control Center; provided that the generator shall have until January 1, 2009 to have the necessary telemetering equipment installed and operating;

4. the generator meets the reactive power testing requirements applicable to generators, as determined from time-to-time by the ISO and specified in the ISO New England Operating Documents; and

5. the installation of the generator shall have been approved in accordance with the requirements of Section I.3.9 of the Tariff or its predecessor or successor provisions under the New England regional transmission arrangements.

Any generator that has been receiving VAR Payments under Schedule 2 prior to June 1, 2007 shall be deemed to be a Qualified Generator Reactive Resource as of that date, provided that it continues to meet the criteria specified in Section II, A. (1), (3) and (4) above. Additionally, each generator seeking to be newly designated as a Qualified Generator Reactive Resource shall submit information to the ISO regarding its capability to provide leading VAR Service prior to receiving any leading VAR Payments under Schedule 2. Such information shall be submitted in the form and within the timeframe prescribed in the Ancillary Service Schedule 2 Business Procedure and/or the Schedule 2 VAR Payment Implementation Rule.

B. Qualified Non-Generator Reactive Resources

Qualified Non-Generator Reactive Resources shall be eligible for VAR Payments under this Schedule 2. However, to the extent that cost recovery for the dynamic reactive power capability of a non-generator resource could occur under the PTF cost recovery mechanism, it shall occur only under such cost recovery mechanism and not under this Schedule 2.

A non-generator shall be deemed a Qualified Non-Generator Reactive Resource if it meets the following criteria:

1. the entity owning or controlling the reactive power capability of the non-generator reactive power resource is a Market Participant;

2. the non-generator reactive power equipment provides measurable dynamic reactive power voltage support to the New England Transmission System, as determined from time-to-time by the ISO;

3. the type of dynamic reactive power equipment is within a category of equipment that has been approved by the ISO, with advisory input from the Reliability Committee;

4. the dynamic reactive power equipment is subject to the Operating Authority of the ISO and all necessary operating protocols for provision of reactive power voltage support from such equipment have been agreed to, in writing, between the ISO and the non-generator reactive power resource;

5. such equipment is interconnected to the New England Transmission System and metered and dispatchable by the ISO or otherwise subject to operational control by the ISO, and has its automatic voltage regulator status and control mode (including power factor, reactive power output and voltage control) telemetered to the ISO and the applicable Local Control Center; provided that the non-generator shall have until January 1, 2009 to have the necessary telemetering equipment installed and operating;

6. the non-generator reactive resource meets the reactive power testing requirements applicable to such non-generators, as determined from time-to-time by the ISO and specified in the ISO New England Operating Documents; and

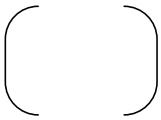
7. the installation of such equipment shall have been approved in accordance with the requirements of Section I.3.9 of the Tariff or its predecessor provisions under the New England regional transmission arrangements.

C. Non-Dynamic Reactive Resources

Nothing in this Schedule 2 is intended to preclude, or provide support for, the cost recovery under a separate schedule to the Tariff, filed with the Commission pursuant to the requirements of Sections 205 or 206 of the Federal Power Act, for non-generator, non-dynamic reactive resources that are interconnected to and provide VAR Service to the New England Transmission System but do not meet the criteria to be deemed either Qualified Non-Generator Reactive Resources or PTF.

III. DETERMINATION AND ALLOCATION OF VAR SERVICE CHARGES

Transmission Customers must purchase VAR Service from the ISO for the support of transmission voltages on the New England Transmission System. With the exception of VAR Service charges related to high voltage conditions, the hourly charge for VAR Service shall be paid by each Transmission Customer that receives either Regional Network Service or Through or Out Service. In the event that VAR Service charges for an hour are exclusively related to service provided to meet reliability criteria that address high voltage conditions in one or more Reliability Regions, then the VAR Service charges associated with high voltage conditions for that hour are allocated to each Transmission Customer within the affected Reliability Regions that receives Regional Network Service based on its pro rata share of Regional Network Load within the affected Reliability Regions. VAR Service charges are determined pursuant to the following formula:



$$CH = (CC + LOC_O + CEC_O + CEP_O)\ )\ \frac{HL_1 + RC_1}{HL + RC}$$

$$+ (LOC_{HV} + CEC_{HV} + CEP_{HV})\ \left(\frac{HLR_1}{HLR}\right)$$

in which the inputs to the formula have the following meaning:

CH = the amount to be paid by the Transmission Customer for the hour;

CC = the Capacity Costs for the hour shall be the VAR Revenue Requirement determined as set forth herein divided by the number of hours in the month;

LOC_{HV} = the Lost Opportunity Costs for the hour to be paid for a dynamic reactive power resource that supplies VAR Service to meet reliability criteria in the Transmission Customer's Reliability Region, provided the VAR Service is supplied exclusively to address high voltage conditions within one or more Reliability Regions;

LOC_O = the Lost Opportunity Costs for the hour to be paid for a dynamic reactive power resource that provides VAR Service to meet reliability criteria within one or more Reliability Regions excluding the costs for VAR Service that is supplied exclusively to address high voltage conditions;

CEP_{HV} = the Cost of Energy Produced which is the portion of the amount paid for the hour for Energy produced by a dynamic reactive power resource for VAR Service to meet reliability criteria in the Transmission Customer's Reliability Region, provided the VAR Service is supplied exclusively to address high voltage conditions within one or more Reliability Regions;

CEP_O = the Cost of Energy Produced which is the portion of the amount paid for the hour for Energy produced by a dynamic reactive power resource for VAR Service to meet reliability criteria within one or more Reliability Regions excluding the costs for VAR Service supplied exclusively to address high voltage conditions;

CEC_{HV} = the Cost of Energy Consumed which is the cost of energy used in the hour by a dynamic reactive power resource in order to supply VAR Service to meet reliability criteria in the Transmission Customer's Reliability Region, provided the VAR Service is supplied exclusively to address high voltage conditions within one or more Reliability Regions;

CEC_O = the Cost of Energy Consumed which is the cost of Energy used in the hour by a dynamic reactive power resource in order to provide VAR Service to meet reliability criteria within one or more Reliability Regions excluding the costs for VAR Service supplied exclusively to address high voltage conditions;

HL_I = the Regional Network Load of the Transmission Customer for the hour;

HL = the aggregate of the Regional Network Loads of all Transmission Customer for the hour;

HLR_1 = that portion of the Regional Network Load of the Transmission Customer that is within a Reliability Region where VAR Service charges in the hour were a result of VAR Service provided exclusively to meet reliability criteria that address high voltage conditions;

HLR = the aggregate of all the Regional Network Loads of all Transmission Customers within Reliability Regions where VAR Service charges in the hour were a result of VAR Service provided exclusively to meet reliability criteria that address high voltage conditions;

RC_I = the Reserved Capacity for Through or Out Service of the Transmission Customers for the hour, excluding any Coordinated External Transaction Reserved Capacity for Through or Out Service; and

RC = the aggregate Reserved Capacity for Through or Out Service of all Transmission Customers for the hour, excluding all Coordinated External Transaction Reserved Capacity for Through or Out Service.

IV. DETERMINING A QUALIFIED REACTIVE RESOURCE'S PAYMENT UNDER THIS SCHEDULE

The compensation to be paid to resources providing VAR Service shall be as set forth below.

A. Capacity Cost (CC)

1. A Qualified Reactive Resource shall be eligible to receive VAR Payments under the Capacity Cost component of this Schedule 2 for the capability to provide VAR Service.

2. Payment for VAR Service associated with lagging capability is not intended to compensate a Qualified Generator Reactive Resource for reactive power absorbed by the generator step-up transformer. Payment for VAR Service associated with leading capability is intended to compensate a Qualified Generator Reactive Resource for reactive power absorbed by the generator step-up transformer.

3. The "VAR CC Rate" will be established each year as of January 1 on a prospective basis for that calendar year and shall be the Adjusted CC Rate * Min (1, (1.2*Forecast Peak Adjusted Reference Load for the year/(SUM of all Qualified Reactive Resources' Summer Seasonal Claimed Capability))).

4. The "Base CC Rate" shall be $2.19/kVAR-yr effective January 1, 2012.

5. The Adjusted CC Rate shall be a single rate applied over the full range of leading and lagging capability of a Qualified Reactive Resource and shall be determined as described below. The Base CC Rate shall be converted into an Adjusted CC Rate, expressed in the form of $/kVARyr, representing the amount to be paid for leading and lagging capability. The Adjusted CC Rate shall be calculated in accordance with the following formula: Adjusted CC Rate (CCRateadjusted) shall equal: (the Base CC Rate (CCRatebase) * Current Total Aggregate lagging VARs) / (Current Total Aggregate Lagging VARs + Current Total Aggregate Leading VARs). The basis of each such formula element and methodology for calculation is set forth in the Schedule 2 VAR Payment Implementation Rule. The details of the Schedule 2 VAR Payment Implementation Rule may be modified by the ISO without a filing under the Federal Power Act, provided that: (i) the modifications are consistent with the requirements of this Schedule 2; and (ii) the modifications receive the support of at least two-thirds of the voting percentage of the Transmission Committee members.

6. The "Forecast Peak Adjustment Reference Load" shall be the value published in the then-most recently published Forecast Report of Capacity, Energy, Loads and Transmission (the "CELT Report") at the time the VAR CC Rate is established for a year.

7. "Seasonal Claimed Capability" for Qualified Reactive Resources shall be determined as follows:

a. A "Qualified Generator Reactive Resource's Seasonal Claimed Capability" shall be the Seasonal Claimed Capability of each Qualified Generator applicable for the season in which the ISO Forecast Peak Adjusted Load is forecast to occur. The Seasonal Claimed Capability (SCC) represents the Summer (SCC-S) and Winter (SCC-W) Claimed Capability of a generating unit (or ISO approved combination of units in accordance with ISO New England Operating Procedures). Claimed Capability Ratings are the maximum dependable load carrying ability, in megawatts to three decimal places, of such unit or units, excluding capacity required for station use. SCC-S and SCC-W are the MW values of the Resource that will be used as billing determinants under this Tariff.

b. A "Qualified Non-Generator Reactive Resource's Seasonal Claimed Capability" shall be 2.5 times the maximum dynamic reactive power capability on a lagging basis demonstrated by the Qualified Non-Generator Reactive Resource during the testing of its VAR Service capability consistent with ISO Procedures for measurement of such capability in megawatts to three decimal places.

8. The "VAR Revenue Requirement" shall be the sum over a month of all Qualified Reactive Resources' VAR Payments.

9. A Qualified Reactive Resource's VAR Payment shall equal (1/12) * (VAR CC Rate*Qualified VARs).

10. Qualified Reactive Resources will be paid their VAR Payment under this Section for each month of a calendar year starting with the month in which the resource is approved as a Qualified Reactive Resource.

11. "Qualified VARs" shall be determined as follows:

(a) In accordance with the ISO New England Operating Procedures, the Qualified VARs of a Qualified Reactive Resource initially Section II – Schedule 2 -Reactive Supply and Voltage Control from Qualified Reactive Resources Service shall be determined through an actual testing in accordance with the then-applicable VAR testing procedures set forth in the ISO New England Operating Procedures. At least every five (5) years after that initial test, an ongoing test of the capability of a Qualified Reactive Resource to supply VAR Service in both leading and lagging capability shall be conducted. The Qualified VARs of a Qualified Reactive Resource shall equal the sum total of the absolute values of the leading and lagging VAR capability of the resource determined pursuant to this section.

(b) Qualified VARs of a Qualified Generator Reactive Resource:

- The Qualified VARs of an untested Qualified Generator Reactive Resource shall be equal to the sum of the absolute values of the lagging VAR capability at the Summer Seasonal Claimed Capability and the leading VAR capability at the EcoMin point as indicated on the Qualified Generator Reactive Resource's NX-12D form that is then in effect adjusted (downward for lagging capability and upward for leading capability) for reactive power absorbed by the generator step-up transformer.

- The Qualified VARs of an untested Qualified Non-Generator Reactive Resource shall be equal to the sum of the absolute values of the lagging VAR capability at the corresponding Summer Seasonal Claimed Capability or an equivalent point and the leading VAR capability at the corresponding EcoMin point or an equivalent point as indicated on the Qualified Non-Generator Reactive Resource's NX-12D form that is then in effect adjusted for reactive power absorbed by its step-up transformer.

B. Lost Opportunity Cost (LOC)

1. The LOC for generators that are dispatched down by, or at the request of, the ISO, or a Local Control Center for the purpose of providing VAR Service will be calculated pursuant to Market Rule 1.

2. Qualified Non-Generator Reactive Resources shall be eligible for payment of the LOC for Qualified Non-Generator Reactive Resources that are dispatched down (pursuant to the authority established within written operating protocols developed under Section II.B.4) at the request of the ISO or a Local Control Center for the purpose of providing VAR Service. The LOC of such Qualified Non-Generator Reactive Resources will be calculated pursuant to procedures established at the time of approval of the equipment type pursuant to Section II.B and filed with the Commission pursuant to the requirements of Section 205 of the Federal Power Act.

C. Cost of Energy Consumed (CEC)

1. The CEC associated with hydro and pumped storage generating units that are motoring at the request of the ISO or a Local Control Center for the purpose of providing VAR Service will equal the cost of Energy to motor and will be calculated in each hour as follows: CEC = (MWhUnit * (LMP or actual Energy cost), where the MWh Unit are calculated pursuant to the Ancillary Service Schedule 2 Business Procedure. The actual Energy cost applies only if motoring Energy is purchased through a bilateral contract.

2. For the Chester SVC, the CEC will be set to zero ($0), and the cost of Energy to supply reactive supply and voltage control from the Chester SVC will be treated as losses on the New England Transmission System.

3. Qualified Non-Generator Reactive Resources shall be eligible for payment of the CEC incurred by Qualified Non-Generator Reactive Resources for the purpose of providing VAR Service (pursuant to the authority established within written operating protocols developed under Section II.B.4). The CEC of such Qualified Non-Generator Reactive Resources shall be measured pursuant to procedures established at the time of approval of the equipment type pursuant to Section II.B and filed with the Commission pursuant to the requirements of Section 205 of the Federal Power Act.

D. Cost of Energy Produced (CEP)

1. The CEP associated with thermal generating units that are brought on-line by the ISO or a Local Control Center for the purpose of providing VAR Service shall equal the portion of the total NCPC (as defined in Market Rule 1) to be paid that resource for a day that is attributed to the hour(s) during which the resource is run to provide VAR Service in accordance with Market Rule 1 and the ISO New England Operating Documents.

2. The CEP associated with hydro or pumped storage generating units that are producing real power and that have also been brought on-line by the ISO or a Local Control Center to provide VAR Service shall equal the portion of the total NCPC to be paid that resource for a day that is attributed to the hour(s) during which the resource is run to provide VAR Service in accordance with Market Rule 1 and the ISO New England Operating Documents.

3. Qualified Non-Generator Reactive Resources shall be eligible for payment of the CEP incurred by Qualified Non-Generator Reactive Resources for the purpose of providing VAR Service (pursuant to the authority established within written operating protocols developed under Section II.B.4). The CEP of such Qualified Non-Generator Reactive Resources shall be measured pursuant to procedures established at the time of approval of the equipment type pursuant to Section II.B and filed with the Commission pursuant to the requirements of Section 205 of the Federal Power Act.

VI. ALTERNATIVE PAYMENT FOR VAR SERVICE

Where a non-generator source of VAR Service (i) responds to identified needs for dynamic reactive power on the New England Transmission System, as identified in the Regional System Plan, and (ii) is confirmed by the ISO as a dynamic reactive power resource that will meet the identified need, and (iii) such non-generator source of VAR Service meets the criteria to be a Qualified Non-Generator Reactive Resource but cannot recover its costs of providing dynamic reactive power under Schedule 2, such non-generator may submit a separate schedule to the ISO OATT to be filed with the Commission pursuant to the requirements of Section 205 of the Federal Power Act for a rate to be paid to allow such resource to recover its costs related to providing VAR Service. In such case, it shall not be considered a Qualified Non-Generator Reactive Resource under this Schedule 2 and its provision of VAR Service and payment shall be governed solely by such separate schedule filed with the Commission.

SCHEDULE 2 VAR PAYMENT IMPLEMENTATION RULE

This rule describes the steps to be taken to calculate the VAR CC Rate in accordance with Section V.A. of Schedule 2. On an annual basis, the Base CC Rate shall be converted into a VAR CC Rate, expressed in the form of $/kVAR-yr, representing the amount to be paid for leading and lagging capability.

The following calculations shall be done in December of each year to calculate the VAR CC Rate for the next year of VAR Payments for leading and lagging reactive power capability in the following year. As described below, the VAR CC Rate shall be updated on an annual basis utilizing the most current leading and lagging test results, and it is expected to take three years to test all of the Qualified Reactive Resources in leading mode.

1. Calculate the "Current Total Aggregate Lagging VARs", which shall equal the "Current Net Aggregate Tested Lagging VARs" plus the "Current Net Aggregate Non-Tested Lagging VARs"; Where:

    a. the Current Net Aggregate Tested Lagging VARs shall equal the total of Lagging Qualified VAR Capability for all Schedule 2 Qualified Reactive Resources that have completed a successful lagging VAR test, as reflected in the *VAR Status Report* tab of the VAR Annual Capacity Cost Rate Report that is posted on the ISO website; this value will reflect the lagging kVARs of Schedule 2 Qualified Reactive Resources as taken from its lagging VAR test results adjusted for losses incurred for such VARs to reach the high side of the step-up transformer (i.e., gross lagging VARs test results adjusted down for losses); and

    b. the Current Net Aggregate Non-Tested lagging VARs shall equal the total of Lagging Qualified VAR Capability for all Schedule 2 Qualified Reactive Resources that have not yet completed a successful lagging VAR test, as reflected in the *VAR Status Report* tab of the VAR Annual Capacity Cost Rate Report that is posted on the ISO website; this value will reflect the lagging kVARs of Schedule 2 Qualified Reactive Resources as taken from its NX-12D (and NX-9B, where needed to calculate generator step-up transformer losses) data at EcoMin adjusted for losses incurred for such VARs to reach the high side of the step-up transformer (i.e., gross lagging VARs NX-12D data at SCC adjusted down for losses).

c. Increase and decrease limiters shall be applied to potential increases or decreases in the Current Total Aggregate Lagging VARs as follows:

i. Current Total Aggregate Lagging VARs Limiters for 2010:
• The Current Total Aggregate Lagging VARs value shall not be limited for 2010.

ii. Current Total Aggregate Lagging VARs Limiters for 2011 and beyond:
• Current Total Aggregate Lagging VARs Increase Limiter for 2011 and beyond: the calculated Current Total Aggregate Lagging VARs will be limited to no greater than 130% of the Current Total Aggregate Lagging VARs value used in the determination of $CCRate_{adjusted}$ for 2010; and

• Current Total Aggregate Lagging VARs Decrease Limiter for 2011 and beyond: the calculated Current Total Aggregate Lagging VARs will be limited to no less than 70% of the Current Total Aggregate Lagging VARs value used in the determination of $CCRate_{adjusted}$ for 2010.

2. Calculate the Current Total Aggregate Leading VARs which shall equal the Current Net Aggregate Tested Leading VARs plus the Current Net Aggregate Non-Tested Leading VARs;

Where:

a. the Current Net Aggregate Tested Leading VARs shall equal the total of Leading Qualified VAR Capability for all Schedule 2 Qualified Reactive Resources that have completed a successful Leading VAR Test, as reflected in the *VAR Status Report* tab of the VAR Annual Capacity Cost Rate Report that is posted on the ISO website; this value will reflect the Leading kVARs of Schedule 2 Qualified Reactive Resources as taken from its leading VAR test results adjusted for losses incurred for such VARs to reach the high side of the step-up transformer (i.e., gross leading VARs test results adjusted up for losses);

b. the Current Net Aggregate Non-Tested Leading VARs: shall equal the total of Leading Qualified VAR Capability for all Schedule 2 Qualified Reactive Resources that have not yet completed a successful Leading VAR Test, as reflected in the *VAR Status Report* tab

of the VAR Annual Capacity Cost Rate Report that is posted on the ISO website. This value will reflect the Leading kVARs of Schedule 2 Qualified Reactive Resources as taken from its NX-12D (and NX-9B, where needed to calculate generator step-up transformer losses) data at EcoMin adjusted for losses incurred for such VARs to reach the high side of the step-up transformer (i.e., gross leading VARs NX-12D data at EcoMin adjusted up for losses).

c. Current Total Aggregate Leading VARs Limiters

i. Current Total Aggregate Leading VARs Limiters for 2010:
• The Current Total Aggregate Leading VARs value shall not be limited for 2010.

ii. Current Total Aggregate Leading VARs Limiters for 2011 and beyond:

• Current Total Aggregate Leading VARs Increase Limiter for 2011 and beyond: the calculated Current Total Aggregate Leading VARs will be limited to no greater than 130% of the Current Total Aggregate Leading VARs value used in the determination of $CCRate_{adjusted}$ for 2010; and

• Current Total Aggregate Leading VARs Decrease Limiter for 2011 and beyond: the calculated Current Total Aggregate Leading VARs will be limited to no less than 70% of the Current Total Aggregate Leading VARs value used in the determination of $CCRate_{adjusted}$ for 2010.

3. Calculate the Adjusted CC Rate ($CCRate_{adjusted}$): shall equal (the Base CC $Rate_e$ * Current Total Aggregate Lagging VARs) / (Current Total Aggregate Lagging VARs + Current Total Aggregate Leading VARs).

4. VAR CC Rate ("VARCCRate"): shall equal (the Adjusted CC Rate) * (the lesser of 1 or (1.2 * "Forecast Peak Adjusted Reference Load" for the year / the sum of the "Qualified Reactive Resources' Seasonal Claimed Capability"));

Where:

a. the "Forecast Peak Adjusted Reference Load" for the year shall equal the amount specified as "Adjusted Reference Load" for the applicable year in *Section I.1 -Summaries – Summer* from the most current *Forecast Report of Capability, Energy, Loads and Transmission (CELT Report)*;

b. The sum of the "Qualified Reactive Resources' Seasonal Claimed Capability" shall equal the Qualified Generator Reactive Resources' Seasonal Claimed Capability plus the Qualified Non-Generator Reactive Resources' Adjusted Seasonal Claimed Capability;

Where:

i. the Qualified Generator Reactive Resources' Seasonal Claimed Capability is reflected on the *VAR CC Rate* tab of the VAR Annual Capacity Cost Rate Report; and

ii. the Qualified Non-Generator Reactive Resources' Adjusted Seasonal Claimed Capability is reflected on the *VAR CC Rate* tab of the VAR Annual Capacity Cost Rate Report.

5. Monthly VAR Payment for a Qualified Reactive Resource in a particular month shall equal the (VARCCRate / 12 * (its Monthly Net Lagging VARs for that month + its Monthly Net Leading VARs for that month)), as reflected in the applicable monthly *VAR Status Summary Report* that is posted on the ISO website.

a. Monthly Net Lagging VARs: Qualified Reactive Resource's Monthly Net Lagging VARs value shall equal its VAR value based on (a) its most recent successful Lagging VAR test or (b) if it has not yet completed such a test, its VAR value at SCC based on its submitted and ISO accepted NX-12D and NX-9B data. The Qualified VAR Resource's Monthly Net Lagging VARs value shall be reflected in the applicable monthly *VAR Status Summary Report* that is posted on the ISO website.

b. Monthly Net Leading VARs: a Qualified Reactive Resource's Monthly Net Leading VARs value shall equal its VAR value based on (a) its most recent successful Leading VAR test or (b) if it has not yet completed such a test, its VAR value at EcoMin based on its submitted and ISO accepted NX-12D and NX-9B data. The Qualified Reactive

Resource's Monthly Net Leading VARs value shall be reflected in the applicable monthly *VAR Status Summary Report* that is posted on the ISO website.

ATTACHMENT C

AVAILABLE TRANSFER CAPABILITY METHODOLOGY

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1. Introduction

ISO is the regional transmission organization (RTO) for the New England Control Area. The New England Control Area includes the transmission system located in the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont, but does not include the transmission system in northern Maine (i.e., Aroostook and parts of Penobscot and Washington Counties) that is radially connected to New Brunswick and administered by the Northern Maine Independent System Administrator. The New England Control Area is comprised of PTF, non-PTF, OTF, MTF, and is interconnected to three neighboring Balancing Authority Areas ("BAA") with various interface types as shown in the Table 1. A graphical depiction of the New England Control Area and its interfaces is provided in Figure 1.

Table 1. New England Control Area interfaces with neighboring BAAs

Neighboring BAA ("NBAA")	Interface	Interface Type
New Brunswick System Operator BAA	New England - New Brunswick	PTF – NBAA (external)
Hydro-Quebec TransEnergie BAA	New England – Hydro Quebec via the Phase I/II high voltage direct current ("HVDC") Transmission Facilities	OTF – NBAA (external)
	New England PTF - Phase I/II HVDC Transmission Facilities	PTF – OTF (internal)
Hydro-Quebec TransEnergie BAA	New England - Hydro Quebec via the Highgate Transmission Facility	PTF – NBAA (external)
New York Independent System Operator BAA	New England - New York-AC	PTF – NBAA (external)
New York Independent System Operator BAA	New England - New York via the Northport - Norwalk Harbor Cable ("NNC") Transmission Facility	PTF – NBAA (external)
New York Independent System Operator BAA	New England – New York via the Cross Sound Cable ("CSC") transmission facility	MTF – NBAA (external)
	New England PTF – CSC transmission facility	PTF – MTF (internal)

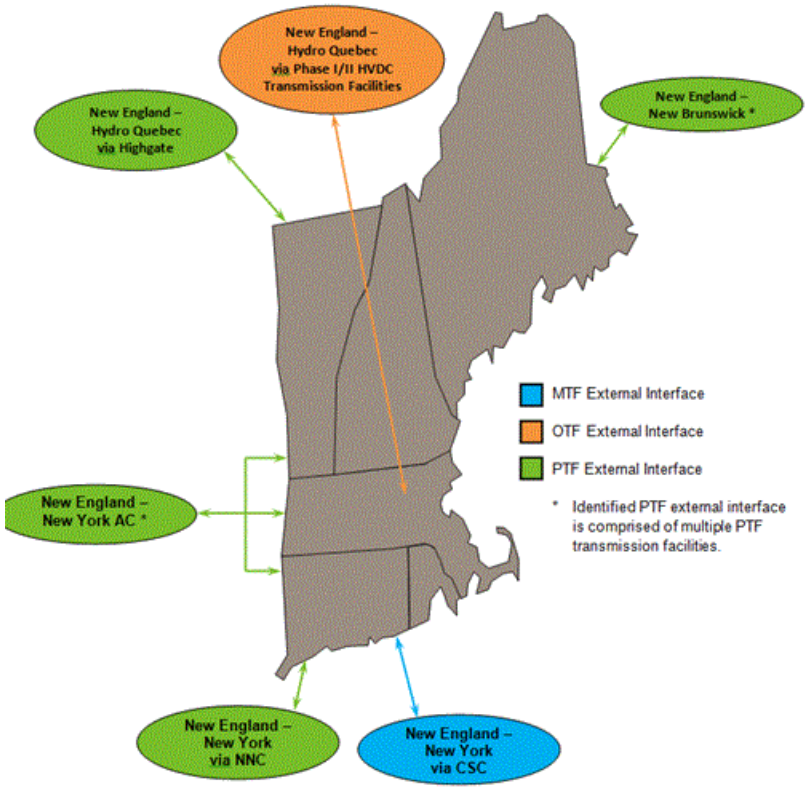

Figure 1. Graphical representation of New England Control Area external interfaces with neighboring BAAs

1.1 ISO Responsibilities

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERC Standards: MOD-001 – Available Transmission System Capability ("MOD-001"), MOD-004 – Capability Benefit Margin ("MOD-004"), and MOD-008 - Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission approved transmission operating agreements and the provisions of the ISO New England Operating Documents. Table 2 below depicts those responsibilities as they apply to the interfaces associated with the New England Control Area and its neighboring BAAs for which the ISO is the Transmission Operator ("TOP") and has varying responsibilities with respect to the calculation of ATC over those interfaces.

Table 2. New England Control Area Internal and External Interfaces

Interface	Interface Type	ATC	TTC	TRM
New England - New Brunswick	PTF – NBAA (external)	ISO as Transmission Service Provider ("TSP")	ISO as TOP	ISO as TOP
New England – Hydro Quebec via the Phase I/II HVDC Transmission Facilities	OTF – NBAA (external)	Schedule 20A Service Providers ("SSPs") as TSPs per Schedule 20A	ISO as TOP	ISO as TOP
New England PTF - Phase I/II HVDC Transmission Facilities	PTF – OTF (internal)	ISO as TSP	ISO as TOP	ISO as TOP
New England - Hydro Quebec via the Highgate Transmission Facility	PTF – NBAA (external)	ISO as TSP	ISO as TOP	ISO as TOP
New England - New York-AC	PTF – NBAA (external)	ISO as TSP	ISO as TOP	ISO as TOP
New England - New York via the Northport - NNC Transmission Facility	PTF – NBAA (external)	ISO as TSP	ISO as TOP	ISO as TOP
New England – New York via the CSC transmission facility	MTF – NBAA (external)	Cross Sound Cable Company, LLC ("CSC, LLC") as TSP per Schedule 18	ISO as TOP	ISO as TOP

New England PTF – CSC transmission facility	PTF – MTF (internal)	ISO as TSP	ISO as TOP	ISO as TOP

1.2. Applicability of this Attachment C

This Attachment C describes the ATC methodology for RNS and Through or Out Service, and also describes the methodology for certain ATC components that are calculated by the ISO for use by other TSPs as described below:

- The TTC methodology for use by CSC, LLC under Schedule 18 and the SSPs under Schedule 20A.
- The CBM methodology for use by CSC, LLC under Schedule 18 and SSPs under Schedule 20A.
- The TRM methodology for use by CSC, LLC under Schedule 18 and the SSPs under Schedule 20A.

The manner in which these ISO-calculated ATC components are used by CSC, LLC and the SSPs for purposes of calculating a Schedule-specific ATC is governed by Schedules 18 and 20A, respectively.

2. Transmission Service in the New England Markets

Since the inception of the OATT for New England, the process by which generation located inside New England supplies energy to the bulk electric system has differed from the Commission pro forma OATT. The fundamental difference is that internal generation is dispatched in an economic, security-constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point transmission service. Through this process, internal generation provides offers that are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, entities may submit External Transactions to move energy into the New England Control Area, out of the New England Control Area or through the New England Control Area. The Real-Time Energy Market clears these External Transactions based on forecast LMPs and the transfer capability of the associated external interfaces. With those External Transactions in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region.

The process for submitting External Transactions into the Real-Time Energy Market does not require an advance physical reservation for use of the PTF. In the event that the net of the economic External Transactions is greater than the transfer capability of the associated external interface, the External Transactions selected to flow are selected based on the rules specified in the Tariff. For any External Transactions that are confirmed to flow in Real-Time based on the economics of the system, a transmission reservation for RNS and Through or Out Service is created after-the-fact to satisfy the transparency needs of the market; however, entities who want to submit an External Transaction to flow energy over an MTF or OTF external interface must first obtain a confirmed transmission service reservation from the respective TSP prior to offering energy into the Real-Time Energy Market. Entities who want to submit an External Transaction to flow energy over an MTF or OTF external interface may refer to Schedule 18 or 20A for information regarding the calculation of ATC on the MTF and OTF external interfaces, respectively

The values resulting from the methodologies described in this Attachment C relate solely to the flow of energy in the Real-Time Energy Market, and shall not be construed as defining methodologies or limits for use in other New England markets.

3. Total Transfer Capability (TTC) for the New England Control Area

The TTCs on all of the New England Control Area external interfaces are calculated using the NERC Standard MOD-029 – Rated System Path Methodology ("MOD-029"). Consistent with the NERC definition, TTC is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. TTCs for the New England Control Area external interfaces are studied by the ISO based on thermal, voltage and stability limitations of the transmission lines that comprise the interface. Power flow and transient stability analysis is used to ensure that the interface's physical limits will not be violated for credible system contingencies per NPCC and ISO reliability criteria. As required by MOD-029, reports are generated that contain the study results and the corresponding TTCs.

These reports are reviewed and updated seasonally, as needed, or as new equipment is placed in-service that impacts the interface. The studies identify the transmission facilities, generators and system conditions that can have a substantial impact upon the transfer capability and, where applicable, the report

indicates the resulting impact upon the transfer capability of the external interfaces. These reports are available in a manner consistent with the ISO New England Information Policy.

The NPCC region maintains, on a confidential basis, a list of generation and transmission facilities that, if removed from service, may have a significant direct or indirect impact on a neighboring BAA, which is in accordance with *Appendix F – Procedure for Operational Planning Coordination (Appendix F) to NPCC Regional Reliability Reference Director #1 – Design and Operation of the Bulk Power System (Directory #1).* If any facilities on that list have a planned outage, those outages are communicated between the neighboring BAAs. If there is a facility on that list in the New England Control Area that is submitted for an outage by an entity, the ISO conducts a study using an energy management system powerflow model and evaluates the impact on the TTC of the affected interface. The ISO applies its load forecast and generation dispatch for the relevant time frame to determine the TTCs for the given condition. In addition, on a daily basis, ISO evaluates the expected New England Control Area system conditions (e.g., generation availability, transmission outages, submitted External Transactions, resulting expected net flow across an external interface) for the following day to determine if there is a system operating limit that has a direct impact upon an external interface that is more restrictive than the previously calculated TTC and, if so, revises the TTC. TTCs impact the maximum megawatt ("MW") amount of confirmed ~~hourly~~ net flow in the Real-Time Energy Market, and may be adjusted prior to Real-Time to reflect Real-Time system operating limits. However, the TTCs in the direction opposite to the prevailing ~~hourly~~ net flow are neither reviewed nor adjusted prior to Real-Time, since those values do not affect reliability.

4. Capacity Benefit Margin (CBM) for the New England Control Area

CBM is defined as the amount of firm transmission transfer capability set aside by a TSP for use by the Load Serving Entities. The ISO does not set aside any CBM for use by the Load Serving Entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents. Load Serving Entities operating within the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with ISO Tariff, Section III 13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of ATC calculation, CBM for the New England Control Area is set to zero (0).

5. Transmission Reliability Margin (TRM) for the New England Control Area

TRM is the amount of transmission transfer capability set aside to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.

5.1 TRM Calculation for the PTF

The ISO, acting as the TOP and TSP, does not set aside TRM on PTF external interfaces or PTF/MTF and PTF/OTF internal interfaces.

5.2 TRM Calculation for the MTF and OTF

The ISO, acting as the TOP, calculates the TRM on MTF and OTF external interfaces, which are both HVDC transmission facilities, by taking into account any operational uncertainties associated with the external facility in accordance with MOD-008.

The TSPs responsible for calculating the ATC and providing transmission service over the MTF or OTF dictate how the ISO-calculated TRM is applied in their respective Schedule-specific ATC calculations.

5.2.1 TRM Calculation for the MTF

Typically, the operational uncertainties associated with an external HVDC transmission facility are minimal and result in a TRM value of zero (0). Therefore, the TRM value for the MTF (i.e., CSC transmission facility) is zero (0).

5.2.2 TRM Calculation for the OTF

5.2.2.1 Quebec to New England TRM for the Phase I/II HVDC Transmission Facilities

There are operational uncertainties associated with the Phase I/II HVDC Transmission Facilities that arise out of neighboring and nearby BAAs such that the TRM on this facility is not zero (0). Due to the large transfer capability of the Phase I/II HVDC Transmission Facilities and the geographic location of the New England Control Area with respect to the rest of the Eastern Interconnection, the loss of this facility

may have a substantial impact on the New York and Pennsylvania, New Jersey and Maryland ("PJM") transmission systems. The inertial impact from the loss of the Phase I/II HVDC Transmission Facilities on the New York and PJM transmission systems will be dependent upon the simultaneous path interactions and the generation dispatch on those transmission systems and within the New England Control Area.

As such, pursuant to Attachment G of the ISO Tariff, the Reliability Coordinators in New York and PJM can require the ISO to limit the amount of energy transferred into the New England Control Area over the Phase I/II HVDC Transmission Facilities (or the output from other large source contingencies within the New England Control Area) in Real-Time to a value as low as 1200 MW, which is referred to as the "largest single source contingency limit". The amount of energy transferred into the New England Control Area over the Phase I/II HVDC Transmission Facilities is not always limited to 1200 MW; it is also dependent upon the dynamic state of the New York and PJM transmission systems, as well as, the additional room (or "available margin") on those systems that can reliably sustain the inertial response following the loss of the Phase I/II HVDC Transmission Facilities (or other large source contingencies within the New England Control Area) when the amount of energy transferred into the New England Control Area over the Phase I/II HVDC Transmission Facilities (or the output from other large source contingencies within the New England Control Area) in Real-Time is in amounts greater than 1200 MW. For these reasons, the TRM value for the Phase I/II HVDC Transmission Facilities for all time horizons in the importing direction (North to South) shall be between zero (0) MW and 800 MW, where 800 MW is calculated from the "Phase I/II HVDC Transmission Facilities maximum transfer capability" (which is 2000 MW) minus the "largest single source contingency limit" (which is 1200 MW).

This range of TRM values is not dependent upon any databases, but instead is driven by the magnitude of the largest single source contingency in the New England Control Area that the New York and PJM transmission systems is able to sustain following the loss of the largest contingent resource.

5.2.2.2 New England to Quebec TRM for the Phase I/II HVDC Transmission Facilities:

When energy is flowing from the New England Control Area to the Hydro-Quebec TransEnergie BAA (South to North) over the Phase I/II HVDC Transmission Facilities, Hydro-Quebec TransEnergie may restrict the energy flow due to uncertainties on their Hydro-Quebec TransEnergie transmission system. The ISO considers whatever Hydro-Quebec TransEnergie restrictions are submitted to it in the calculation of the New England to Quebec TRM for the Phase I/II HVDC Transmission Facilities.

6. Available Transfer Capability (ATC) Calculation of PTF Interfaces

This section describes the process for the ATC calculations performed by the ISO pursuant to MOD-029 for the PTF external interfaces and the PTF/MTF and PTF/OTF internal interfaces. This section does not describe the process for the ATC calculations performed by other New England TSPs.

6.1 ATC Algorithm: Process for ATC Calculation for PTF Interfaces

Consistent with the NERC definition, the equation for Available Transfer Capability is: ATC = (TTC – CBM – TRM – Existing Transmission Commitments + Postbacks + counterflows). As discussed above, the CBM and TRM for the PTF interfaces for which the ISO calculates ATC are zero (0). The purpose of the Existing Transmission Commitments ("ETC") component of the ATC equation is for the TSP to reduce the amount of ATC by the amount of existing firm transmission commitments that are not otherwise included in CBM or TRM. As described in Section 2 of this Attachment C, there is no requirement to purchase transmission service in advance of flowing energy in Real-Time, and there is no MW amount set aside by the ISO on any interface. Therefore there are no Existing Transmission Commitments to be applied in the ATC equation. For this reason, ETC equals zero (0) for the purposes of ATC calculation. Because Postbacks and counterflows are related to ETC and ETC is zero (0), both Postbacks and counterflows also are equal to zero (0).

Entities submit their bids and offers to move energy into, out of and through the Energy Market through External Transactions. As Real-Time approaches, the ISO determines which of the submitted External Transactions will be scheduled during the applicable scheduling interval ~~in the coming hour~~ in accordance with the rules set forth in the ISO New England Operating Documents. The ATC of the PTF external interfaces are equal to the TTC for all time horizons (i.e., scheduling, operating and planning). The ATC is equal to the amount of net External Transactions that the ISO will schedule on an interface for during the applicable scheduling interval~~the designated hour~~. With this simplified version of ATC, the mathematical algorithm is simply "ATC equals TTC." This mathematical algorithm can be found on the ISO New England OASIS site at: http://www.oatioasis.com/ISNE/ISNEdocs/isone_atc_algorithm.docx

The scheduling of External Transactions on a PTF interface will consider the net of all economic External Transactions and the transfer limits. For example, if the transfer limit on the interface is 1000 MW import, there could be 1300 MW of economic import External Transactions and 300 MW of economic

export External Transactions scheduled for a given scheduling interval ~~hour~~ such that the net flow on the interface is 1000 MW.

Figure 2 describes how External Transactions are processed in the Real-Time Energy Markets where the timing of the submittal of the External Transactions is governed by Section III of the ISO Tariff.

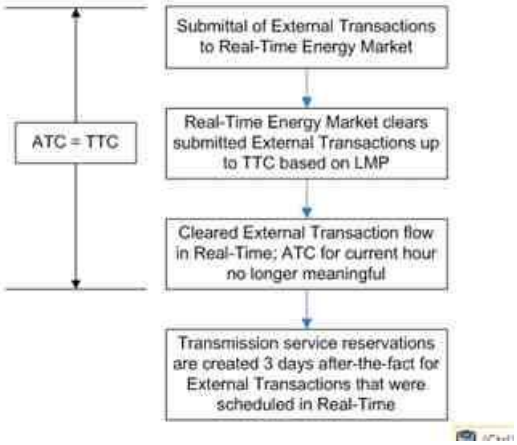

Figure 2. Processing of External Transactions in the Real-Time Energy Markets

6.2. Firm versus Non-Firm ATC on PTF Interfaces

As described in the preceding sections, the RNS and Through or Out Service provided over the PTF on an after-the-fact basis are the equivalent of firm transmission service. Therefore, the ATC calculation process described above results in a single ATC value. Where industry standards or software require the classification of ATC as Firm and non-Firm the ISO posts the single ATC value for both.

6.3. ATC Coordination for PTF Interfaces

As described in this Section 6 of this Attachment C, the ATC calculations for PTF external interfaces performed by the ISO are dependent solely on the TTC values. As such, the ISO does not coordinate ATC values with the neighboring BAAs. The ISO, however, has established procedures within the ISO New England Operating Procedures for coordinating outages with neighboring BAAs that could impact the

resulting TTC on the external interface(s) with that neighbor. These procedures also include the timely communication of the resulting TTCs between the ISO and each of its neighboring BAAs.

ATTACHMENT G-3

COMPLETE LIST OF EXCEPTED TRANSACTION (TRANSMISSION) AGREEMENTS OVER EXTERNAL TIES

Attachment G-3 is a comprehensive list of Excepted Transaction Agreements that relate to the use of ties with neighboring Control Areas ("External Ties"). The party responsible for paying the Congestion Cost associated with energy purchased under the Excepted Transactions listed in Attachment G-3 will retain their existing contract rights for physical scheduling of a transaction at the External Node associated with the Excepted Transaction until such party elects to be allocated Auction Revenue Rights pursuant to Market Rule 1. Until the party responsible for paying the Congestion Cost associated with energy purchased under an Excepted Transaction listed in Attachment G-3 elects to be allocated Auction Revenue Rights, the Excepted Transaction shall have physical scheduling and curtailment rights in accordance with Section II.44(1)(a) of this OATT. Once the party responsible for paying the Congestion Cost associated with energy purchased under the Excepted Transaction elects to be allocated Auction Revenue Rights, the party will not be able to revert back to using their contract rights for physical scheduling and curtailment.

All such agreements have terminated with respect to Attachment G-3.

STANDARD MARKET DESIGN

III.1 Market Operations

III.1.1 Introduction.

This Market Rule 1 sets forth the scheduling, other procedures, and certain general provisions applicable to the operation of the New England Markets within the New England Control Area. The ISO shall operate the New England Markets in compliance with NERC, NPCC and ISO reliability criteria. The ISO is the Counterparty for agreements and transactions with its Customers (including assignments involving Customers), including bilateral transactions described in Market Rule 1, and sales to the ISO and/or purchases from the ISO of energy, reserves, Ancillary Services, capacity, demand/load response, FTRs and other products, paying or charging (if and as applicable) its Customers the amounts produced by the pertinent market clearing process or through the other pricing mechanisms described in Market Rule 1. The bilateral transactions to which the ISO is the Counterparty (subject to compliance with the requirements of Section III.1.4) include, but are not limited to, Internal Bilaterals for Load, Internal Bilaterals for Market for Energy, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Supplemental Availability Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied FCA Resources). Notwithstanding the foregoing, the ISO will not act as Counterparty for the import into the New England Control Area, for the use of Publicly Owned Entities, of: (1) energy, capacity, and ancillary products associated therewith, to which the Publicly Owned Entities are given preference under Articles 407 and 408 of the project license for the New York Power Authority's Niagara Project; and (2) energy, capacity, and ancillary products associated therewith, to which Publicly Owned Entities are entitled under Article 419 of the project license for the New York Power Authority's Franklin D. Roosevelt – St. Lawrence Project. This Market Rule 1 addresses each of the three time frames pertinent to the daily operation of the New England Markets: "Pre-scheduling" as specified in Section III.1.9, "Scheduling" as specified in III.1.10, and "Dispatch" as specified in III.1.11. This Market Rule 1 became effective on February 1, 2005.

III.1.2 [Reserved.]

III.1.3 Definitions.

Whenever used in Market Rule 1, in either the singular or plural number, capitalized terms shall have the meanings specified in Section I of the Tariff. Terms used in Market Rule 1 that are not defined in Section

I shall have the meanings customarily attributed to such terms by the electric utility industry in New England or as defined elsewhere in the ISO New England Filed Documents. Terms used in Market Rule 1 that are defined in Section I are subject to the 60% Participant Vote threshold specified in Section 11.1.2 of the Participants Agreement.

III.1.3.1 [Reserved.]

III.1.3.2 [Reserved.]

III.1.3.3 [Reserved.]

III.1.4 Requirements for Certain Transactions.

III.1.4.1 ISO Settlement of Certain Transactions.

The ISO will settle, and act as Counterparty to, the transactions described in Section III.1.4.2 if the transactions (and their related transactions) conform to, and the transacting Market Participants comply with, the requirements specified in Section III.1.4.3.

III.1.4.2 Transactions Subject to Requirements of Section III.1.4.

Transactions that must conform to the requirements of Section III.1.4 include: Internal Bilaterals for Load, Internal Bilaterals for Market for Energy, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Supplemental Availability Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied FCA Resources). The foregoing are referred to collectively as "Section III.1.4 Transactions," and individually as a "Section III.1.4 Transaction." Transactions that conform to the standards are referred to collectively as "Section III.1.4 Conforming Transactions," and individually as a "Section III.1.4 Conforming Transaction."

III.1.4.3 Requirements for Section III.1.4 Conforming Transactions.

(a) To qualify as a Section III.1.4 Conforming Transaction, a Section III.1.4 Transaction must constitute an exchange for an off-market transaction (a "Related Transaction"), where the Related Transaction:

(i) is not cleared or settled by the ISO as Counterparty;

(ii) is a spot, forward or derivatives contract that contemplates the transfer of energy or a MW obligation to or from a Market Participant;

(iii) involves commercially appropriate obligations that impose a duty to transfer electricity or a MW obligation from the seller to the buyer, or from the buyer to the seller, with performance taking place within a reasonable time in accordance with prevailing cash market practices; and

(iv) is not contingent on either party to carry out the Section III.1.4 Transaction.

(b) In addition, to qualify as a Section III.1.4 Conforming Transaction:

(i) the Section III.1.4 Transaction must be executed between separate beneficial owners or separate parties trading for independently controlled accounts;

(ii) the Section III.1.4 Transaction and the Related Transaction must be separately identified in the records of the parties to the transactions; and

(iii) the Section III.1.4 Transaction must be separately identified in the records of the ISO.

(c) As further requirements:

(i) each party to the Section III.1.4 Transaction and Related Transaction must maintain, and produce upon request of the ISO, records demonstrating compliance with the requirements of Sections III.1.4.3(a) and (b) for the Section III.1.4 Transaction, the Related Transaction and any other transaction that is directly related to, or integrated in any way with, the Related Transaction, including the identity of the counterparties and the material economic terms of the transactions including their price, tenor, quantity and execution date; and

(ii) each party to the Section III.1.4 Transaction must be a Market Participant that meets all requirements of the ISO New England Financial Assurance Policy.

III.1.5 Resource Auditing.

III.1.5.1 Claimed Capability Audits.

III.1.5.1.1 General Audit Requirements.

(a) Three types of Claimed Capability Audits may be performed:

(i) An Establish Claimed Capability Audit establishes the Generator Asset's ability to respond to ISO dispatch instructions and to maintain performance at a specified output level for a specified duration.

(ii) A Seasonal Claimed Capability Audit determines a Generator Asset's capability to perform under specified summer and winter conditions for a specified duration.

(iii) An ISO-Initiated Claimed Capability Audit is conducted by the ISO to verify the Generator Asset's Establish Claimed Capability Audit value.

(b) The Claimed Capability Audit value of a Generator Asset shall reflect any limitations based upon the interdependence of common elements between two or more Generator Assets such as: auxiliaries, limiting operating parameters, and the deployment of operating personnel.

(c) The Claimed Capability Audit value of gas turbine, combined cycle, and pseudo-combined cycle assets shall be normalized to standard 90° (summer) and 20° (winter) temperatures.

(d) The Claimed Capability Audit value for steam turbine assets with stream exports, combined cycle, or pseudo-combined cycle assets with steam exports where steam is exported for uses external to the electric power facility, shall be normalized to the facility's Seasonal Claimed Capability steam demand.

(e) A Claimed Capability Audit may be denied or rescheduled by the ISO if its performance will jeopardize the reliable operation of the electrical system.

III.1.5.1.2 Establish Claimed Capability Audit.

(a) The time and date of an Establish Claimed Capability Audit shall be unannounced.

(b) For a newly commercial Generator Asset:

(i) An Establish Claimed Capability Audit will be scheduled by the ISO within seven Business Days of the commercial operation date for all Generator Assets except:

1. Non-intermittent daily cycle hydro;
2. Non-intermittent net-metered, or special qualifying facilities that do not elect to audit as described in Section III.1.5.1.3; and
3. Intermittent Generator Assets

(ii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.

(iii) The Establish Claimed Capability Audit values shall be effective as of the commercial operation date of the Generator Asset.

(c) For Generator Assets with an Establish Claimed Capability Audit value:

(i) An Establish Claimed Capability Audit may be performed at the request of a Market Participant in order to support a change in the summer and winter Establish Claimed Capability Audit values for a Generator Asset.

(ii) An Establish Claimed Capability Audit shall be performed within seven Business Days of the date of the request.

(iii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.

(iv) The Establish Claimed Capability Audit values become effective one Business Day following notification of the audit results to the Market Participant by the ISO.

(v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.

(d) An Establish Claimed Capability Audit value may not exceed the maximum interconnected flow specified in the Network Resource Capability for the resource associated with the Generator Asset.

(e) Establish Claimed Capability Audits shall be performed on Business Days between 0800 and 2200.

(f) To conduct an Establish Claimed Capability Audit, the ISO shall:

(i) Notify the Designated Entity immediately prior to issuing the Dispatch Instruction that an audit will be conducted.

(ii) Initiate an Establish Claimed Capability Audit by issuing a Dispatch Instruction ordering the asset's net output to increase from the current operating level to its Real-Time High Operating Limit.

(iii) Begin the audit with the first full clock hour after sufficient time has been allowed for the asset to ramp, based on its offered ramp rate from its current operating point to reach its Real-Time High Operating Limit.

(g) An Establish Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for an Establish Claimed Capability Audit	
Unit Type	**Claimed Capability Audit Duration (Hrs)**
Steam Turbine (Includes Nuclear)	4
Combined Cycle	4
Integrated Coal Gasification Combustion Cycle	4
Pressurized Fluidized Bed Combustion	4
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine – Reversible Hydraulic Turbine – Other	2

Hydro-Conventional Daily Pondage Hydro-Conventional Run of River Hydro-Conventional Weekly	2
Wind Photovoltaic Fuel Cell	2
Energy Storage (Excludes Pumped Storage)	2

(h) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for a Generator Asset of a unit type not listed in Section III.1.5.1.2(g).

III.1.5.1.3. Seasonal Claimed Capability Audits.

(a) A Seasonal Claimed Capability Audit must be conducted by all Generator Assets except:
  (i) Non-intermittent daily hydro; and
  (ii) Intermittent, net-metered, and special qualifying facilities. Non-intermittent net-metered and special qualifying facilities may elect to perform Seasonal Claimed Capability Audits pursuant to Section III.1.7.11(c)(iv).

(b) An Establish Claimed Capability Audit or ISO-Initiated Claimed Capability Audit that meets the requirements of a Seasonal Claimed Capability Audit in this Section III.1.5.1.3 may be used to fulfill a Generator Asset's Seasonal Claimed Capability Audit obligation.

(c) Except as provided in Section III.1.5.1.3(m) below, a summer Seasonal Claimed Capability Audit must be conducted:
  (i) At least once every Capability Demonstration Year;
  (ii) Either (1) at a mean ambient temperature during the audit that is greater than or equal to 80 degrees Fahrenheit at the location of the Generator Asset, or (2) during an ISO-announced summer Seasonal Claimed Capability Audit window.

(d) A winter Seasonal Claimed Capability Audit must be conducted:
  (i) At least once in the previous three Capability Demonstration Years, except that a newly commercial Generator Asset which becomes commercial on or after:
    (1) September 1 and prior to December 31 shall perform a winter Seasonal Claimed Capability Audit prior to the end of that Capability Demonstration Year.
    (2) January 1 shall perform a winter Seasonal Claimed Capability Audit prior to the end of the next Capability Demonstration Year.

(ii) Either (1) at a mean ambient temperature during the audit that is less than or equal to 32 degrees Fahrenheit at the location of the Generator Asset, or (2) during an ISO-announced winter Seasonal Claimed Capability Audit window.

(e) A Seasonal Claimed Capability Audit shall be performed by operating the Generator Asset for the audit time period and submitting to the ISO operational data that meets the following requirements:

(i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal Claimed Capability Audit requirement by 5:00 p.m. on the seventh Business Day following the day on which the audit concludes.

(ii) The notification must include the date and time period of the demonstration to be used for the Seasonal Claimed Capability Audit and other relevant operating data.

(f) The Seasonal Claimed Capability Audit value (summer or winter) will be the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.

(g) The Seasonal Claimed Capability Audit value (summer or winter) shall be the most recent audit data submitted to the ISO meeting the requirements of this Section III.1.5.1.3. In the event that a Market Participant fails to submit Seasonal Claimed Capability Audit data to meet the timing requirements in Section III.1.5.1.3(c) and (d), the Seasonal Claimed Capability Audit value for the season shall be set to zero.

(h) The Seasonal Claimed Capability Audit value shall become effective one Business Day following notification of the audit results to the Market Participant by the ISO.

(i) A Seasonal Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for a Seasonal Claimed Capability Audit	
Unit Type	**Claimed Capability Audit Duration (Hrs)**
Steam Turbine (Includes Nuclear)	2
Combined Cycle	2
Integrated Coal Gasification Combustion Cycle	2
Pressurized Fluidized Bed Combustion	2
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine-Reversible Hydraulic Turbine-Other	2

Hydro-Conventional Weekly	2
Fuel Cell	1
Energy Storage (Excludes Pumped Storage)	2

(j) A Generator Asset that is on a planned outage that was approved in the ISO's annual maintenance scheduling process during all hours that meet the temperature requirements for a Seasonal Claimed Capability Audit that is to be performed by the asset during that Capability Demonstration Year shall:

(i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these auditing requirements;

(ii) Have its Seasonal Claimed Capability Audit value for the season set to zero; and

(iii) Perform the required Seasonal Claimed Capability Audit on the next available day that meets the Seasonal Claimed Capability Audit temperature requirements.

(k) A Generator Asset that does not meet the auditing requirements of this Section III.1.5.1.3 because (1) every time the temperature requirements were met at the Generator Asset's location the ISO denied the request to operate to full capability, or (2) the temperature requirements were not met at the Generator Asset's location during the Capability Demonstration Year during which the asset was required to perform a Seasonal Claimed Capability Audit during the hours 0700 to 2300 for each weekday excluding those weekdays that are defined as NERC holidays, shall:

(i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these temperature requirements, including verifiable temperature data;

(ii) Retain the current Seasonal Claimed Capability Audit value for the season; and

(iii) Perform the required Seasonal Claimed Capability Audit during the next Capability Demonstration Year.

(l) The ISO may issue notice of a summer or winter Seasonal Claimed Capability Audit window for some or all of the New England Control Area if the ISO determines that weather forecasts indicate that temperatures during the audit window will meet the summer or winter Seasonal Claimed Capability Audit temperature requirements. A notice shall be issued at least 48 hours prior to the opening of the audit window. Any audit performed during the announced audit window shall be deemed to meet the temperature requirement for the summer or winter audit. In the event that five or more audit windows for the summer Seasonal Claimed Capability Audit temperature requirement, each of at least a four hour duration between 0700 and 2300 and occurring on a weekday excluding those weekdays that are defined as NERC holidays, are not opened for a Generator Asset prior to August 15 during a Capability Demonstration Year, a two-

week audit window shall be opened for that Generator Asset to perform a summer Seasonal Claimed Capability Audit, and any audit performed by that Generator Asset during the open audit window shall be deemed to meet the temperature requirement for the summer Seasonal Claimed Capability Audit. The open audit window shall be between 0700 and 2300 each day during August 15 through August 31.

(m) A Market Participant that is required to perform testing on a Generator Asset that is in addition to a summer Seasonal Claimed Capability Audit may notify the ISO that the summer Seasonal Claimed Capability Audit was performed in conjunction with this additional testing, provided that:

(i) The notification shall be provided at the time the Seasonal Claimed Capability Audit data is submitted under Section III.1.5.1.3(e).

(ii) The notification explains the nature of the additional testing and that the summer Seasonal Claimed Capability Audit was performed while the Generator Asset was online to perform this additional testing.

(iii) The summer Seasonal Claimed Capability Audit and additional testing are performed during the months of June, July or August between the hours of 0700 and 2300.

(iv) In the event that the summer Seasonal Claimed Capability Audit does not meet the temperature requirements of Section III.1.5.1.3(c)(ii), the summer Seasonal Claimed Capability Audit value may not exceed the summer Seasonal Claimed Capability Audit value from the prior Capability Demonstration Year.

(v) This Section III.1.5.1.3(m) may be utilized no more frequently than once every three Capability Demonstration Years for a Generator Asset.

(n) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for a Generator Asset of a unit type not listed in Section III.1.5.1.3(i).

III.1.5.1.4. ISO-Initiated Claimed Capability Audits.

(a) An ISO-Initiated Claimed Capability Audit may be performed by the ISO at any time.

(b) An ISO-Initiated Claimed Capability Audit value shall replace the winter and summer Establish Claimed Capability Audit values for a Generator Asset, normalized for temperature and steam exports, except:

(i) The Establish Claimed Capability Audit values may not exceed the maximum interconnected flow specified in the Network Resource Capability for that resource.

(ii) An ISO-Initiated Claimed Capability Audit value shall not set the winter Establish Claimed Capability Audit value unless the ISO-Initiated Claimed Capability Audit was performed at a

mean ambient temperature that is less than or equal to 32 degrees Fahrenheit at the Generator Asset location.

(c) If a Market Participant submits pressure and relative humidity data for the previous Establish Claimed Capability Audit and the current ISO-Initiated Claimed Capability Audit, the Establish Claimed Capability Audit values derived from the ISO-Initiated Claimed Capability Audit will be normalized to the pressure of the previous Establish Claimed Capability Audit and a relative humidity of 64%.

(d) Establish Claimed Capability Audit values derived from the ISO-Initiated Claimed Capability Audit shall become effective one Business Day following notification of the audit results to the Market Participant by the ISO.

(e) To conduct an ISO-Initiated Claimed Capability Audit, the ISO shall:

(i) Notify the Designated Entity, immediately prior to issuing the Dispatch Instruction, that an audit will be conducted.

(ii) Initiate an ISO-Initiated Claimed Capability Audit by issuing a Dispatch Instruction ordering the Generator Asset's net output to increase from the current operating level to its Real-Time High Operating Limit.

(iii) Begin the audit with the first full clock hour after sufficient time has been allowed for the Generator Asset to ramp, based on its offered ramp rate, from its current operating point to its Real-Time High Operating Limit.

(f) An ISO-Initiated Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for an ISO-Initiated Claimed Capability Audit	
Unit Type	**Claimed Capability Audit Duration (Hrs)**
Steam Turbine (Includes Nuclear)	4
Combined Cycle	4
Integrated Coal Gasification Combustion Cycle	4
Pressurized Fluidized Bed Combustion	4
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine – Reversible Hydraulic Turbine – Other	2

Hydro-Conventional Daily Pondage Hydro-Conventional Run of River Hydro-Conventional Weekly	2
Wind Photovoltaic Fuel Cell	2
Energy Storage (Excludes Pumped Storage)	2

(g) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for a Generator Asset of a unit type not listed in Section III.1.5.1.4(f).

III.1.5.2 ISO-Initiated Parameter Auditing.

(a) The ISO may perform an audit of any Supply Offer, Demand Reduction offer or other operating parameter that impacts the ability of a Generator Asset or Demand Response Resource to provide real-time energy or reserves.

(b) Generator audits shall be performed using the following methods for the relevant parameter:

(i) **Economic Maximum Limit**. The Generator Asset shall be evaluated based upon its ability to achieve the current offered Economic Maximum Limit value, through a review of historical dispatch data or based on a response to a current ISO-issued Dispatch Instruction.

(ii) **Manual Response Rate**. The Generator Asset shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Manual Response Rate, including hold points and changes in Manual Response Rates.

(iii) **Start-Up Time**. The Generator Asset shall be evaluated based upon its ability to achieve the offered Start-Up Time.

(iv) **Notification Time**. The Generator Asset shall be evaluated based upon its ability to close its output breaker within its offered Notification Time.

(v) **CLAIM10**. The Generator Asset shall be evaluated based upon its ability to reach its CLAIM10 value in accordance with Section III.9.5.

(vi) **CLAIM30**. The Generator Asset shall be evaluated based upon its ability to reach its CLAIM30 value in accordance with Section III.9.5.

(vii) **Automatic Response Rate**. The Generator Asset shall be analyzed, based upon a review of historical performance data, for its ability to respond to four-second electronic Dispatch Instructions.

(viii) **Dual Fuel Capability**. A Generator Asset that is capable of operating on multiple fuels may be required to audit on a specific fuel, as set out in Section III.1.5.2(e).

(c) Demand Response Resource audits shall be performed using the following methods:

(i) **Maximum Reduction**. The Demand Response Resource shall be evaluated based upon its ability to achieve the current offered Maximum Reduction value, through a review of historical dispatch data or based on a response to a current Dispatch Instruction.

(ii) **Demand Response Resource Ramp Rate**. The Demand Response Resource shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Demand Response Resource Ramp Rate.

(iii) **Demand Response Resource Start-Up Time**. The Demand Response Resource shall be evaluated based upon its ability to achieve its Minimum Reduction within the offered Demand Response Resource Start-Up Time, in response to a Dispatch Instruction and after completing its Demand Response Resource Notification Time.

(iv) **Demand Response Resource Notification Time**. The Demand Response Resource shall be evaluated based upon its ability to start reducing demand within its offered Demand Response Resource Notification Time, from the receipt of a Dispatch Instruction when the Demand Response Resource was not previously reducing demand.

(v) **CLAIM10**. The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM10 value in accordance with Section III.9.5.

(vi) **CLAIM30**. The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM30 value in accordance with Section III.9.5.

(d) To conduct an audit based upon historical data, the ISO shall:

(i) Obtain data through random sampling of generator or Demand Response Resource performance in response to Dispatch Instructions; or

(ii) Obtain data through continual monitoring of generator or Demand Response Resource performance in response to Dispatch Instructions.

(e) To conduct an unannounced audit, the ISO shall initiate the audit by issuing a Dispatch Instruction ordering the Generator Asset or Demand Response Resource to change from the current operating level to a level that permits the ISO to evaluate the performance of the Generator Asset or Demand Response Resource for the parameters being audited.

(f) To conduct an audit of the capability of a Generator Asset described in Section III.1.5.2(b)(viii) to run on a specific fuel:

(i) The ISO shall notify the Lead Market Participant if a Generator Asset is required to undergo an audit on a specific fuel. The ISO, in consultation with the Lead Market Participant, shall develop a plan for the audit.

(ii) The Lead Market Participant will have the ability to propose the time and date of the audit within the ISO's prescribed time frame and must notify the ISO at least five business days in advance of the audit, unless otherwise agreed to by the ISO and the Lead Market Participant.

(g) To the extent that the audit results indicate a Market Participant is providing Supply Offer, Demand Reduction Offer or other operating parameter values that are not representative of the actual capability of the Generator Asset or Demand Response Resource, the values for the Generator Asset or Demand Response Resource shall be restricted to those values that are supported by the audit.

(h) In the event that a Generator Asset or Demand Response Resource has had a parameter value restricted:

(i) The Market Participant may submit a restoration plan to the ISO to restore that parameter. The restoration plan shall:

1. Provide an explanation of the discrepancy;
2. Indicate the steps that the Market Participant will take to re-establish the parameter's value;
3. Indicate the timeline for completing the restoration; and
4. Explain the testing that the Market Participant will undertake to verify restoration of the parameter value upon completion.

(ii) The ISO shall:

1. Accept the restoration plan if implementation of the plan, including the testing plan, is reasonably likely to support the proposed change in the parameter value restriction;
2. Coordinate with the Market Participant to perform required testing upon completion of the restoration; and
3. Modify the parameter value restriction following completion of the restoration plan, based upon tested values.

(i) III.1.5.3 Reactive Capability Audits.

(j) (a) Two types of Reactive Capability Audits may be performed:

(k) (i) A Lagging Reactive Capability Audit measures the Generator Asset's ability to provide reactive power to the transmission system at a specified real power output.

(l) (ii) A Leading Reactive Capability Audit measures the Generator Asset's ability to absorb reactive power from the transmission system at a specified real power output.

(m) (b) The ISO shall develop a list of Generator Assets that must conduct Reactive Capability Audits.

(n) (c) Unless otherwise directed by the ISO, Generator Assets that are required to perform Reactive Capability Audits must perform both a Lagging Reactive Capability Audit and a Leading Reactive Capability Audit.

(o) (d) All Reactive Capability Audits shall meet the testing conditions specified in the ISO New England Operating Documents.

(p) (e) The Reactive Capability Audit value of a Generator Asset shall reflect any limitations based upon the interdependence of common elements between two or more Generator Assets such as: auxiliaries, limiting operating parameters, and the deployment of operating personnel.

(q) (f) A Reactive Capability Audit may be denied or rescheduled by the ISO if conducting the Reactive Capability Audit could jeopardize the reliable operation of the electrical system.

(r) (g) Reactive Capability Audits must be conducted at least every five years, unless otherwise required by the ISO. The ISO may require a Generator Asset to conduct Reactive Capability Audits more often than every five years if:

(s) (i) there is a change in the Generator Asset that may affect the reactive power capability of the Generator Asset;

(t) (ii) there is a change in electrical system conditions that may affect the achievable reactive power output or absorption of the Generator Asset; or

(u) (iii) historical data shows that the amount of reactive power that the Generator Asset can provide to or absorb from the transmission system is higher or lower than the latest audit data.

(v) (h) The Lead Market Participant may request a waiver of the requirement to conduct a Reactive Capability Audit. The ISO, at its sole discretion, will determine whether and for how long a waiver can be granted.

III.1.6 [Reserved.]

III.1.6.1 [Reserved.]

III.1.6.2 [Reserved.]

III.1.6.3 [Reserved.]

III.1.6.4 ISO New England Manuals and ISO New England Administrative Procedures.

The ISO shall prepare, maintain and update the ISO New England Manuals and ISO New England Administrative Procedures consistent with the ISO New England Filed Documents. The ISO New England Manuals and ISO New England Administrative Procedures shall be available for inspection by the Market Participants, regulatory authorities with jurisdiction over the ISO or any Market Participant, and the public.

III.1.7 General.

III.1.7.1 Provision of Market Data to the Commission.

The ISO will electronically deliver to the Commission, on an ongoing basis and in a form and manner consistent with its collection of data and in a form and manner acceptable to the Commission, data related to the markets that it administers, in accordance with the Commission's regulations.

III.1.7.2 [Reserved.]

III.1.7.3 Agents.

A Market Participant may participate in the New England Markets through an agent, provided that such Market Participant informs the ISO in advance in writing of the appointment of such agent. A Market Participant using an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the New England Markets, and shall ensure that any such agent complies with the requirements of the ISO New England Manuals and ISO New England Administrative Procedures and the ISO New England Filed Documents.

III.1.7.4 [Reserved.]

III.1.7.5 [Reserved.]

III.1.7.6 Scheduling and Dispatching.

(a) The ISO shall schedule Day-Ahead and schedule and dispatch in Real-Time Resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Participants. The ISO shall schedule and dispatch sufficient Resources of the Market Participants to serve the New England Markets energy purchase requirements under normal system conditions of the Market Participants and meet the requirements of the New England Control Area for ancillary services provided by such Resources. The ISO shall use a joint optimization process to serve Real-Time Energy Market energy requirements and meet Real-Time Operating Reserve requirements based on a least-cost, security-constrained economic dispatch.

(b) In the event that one or more Resources cannot be scheduled in the Day-Ahead Energy Market on the basis of a least-cost, security-constrained dispatch as a result of one or more Self-Schedule offers contributing to a transmission limit violation, the following scheduling protocols will apply:

(i) When a single Self-Schedule offer contributes to a transmission limit violation, the Self-Schedule offer will not be scheduled for the entire Self-Schedule period in development of Day-Ahead schedules.

(ii) When two Self-Schedule offers contribute to a transmission limit violation, parallel clearing solutions will be executed such that, for each solution, one of the Self-Schedule offers will be omitted for its entire Self-Schedule period. The least cost solution will be used for purposes of determining which Resources are scheduled in the Day-Ahead Energy Market.

(iii) When three or more Self-Schedule offers contribute to a transmission limit violation, the ISO will determine the total daily MWh for each Self-Schedule offer and will omit Self-Schedule offers in their entirety, in sequence from the offer with the least total daily MWh to the offer with the greatest total MWh, stopping when the transmission limit violation is resolved.

(c) Scheduling and dispatch shall be conducted in accordance with the ISO New England Filed Documents.

(d) The ISO shall undertake, together with Market Participants, to identify any conflict or incompatibility between the scheduling or other deadlines or specifications applicable to the New England Markets, and any relevant procedures of another Control Area, or any tariff (including the Transmission, Markets and Services Tariff). Upon determining that any such conflict or incompatibility exists, the ISO shall propose tariff or procedural changes, or undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

III.1.7.7 Energy Pricing.

The price paid for energy, including demand reductions, bought and sold by the ISO in the New England Markets will reflect the hourly Locational Marginal Price at each Location, determined by the ISO in accordance with the ISO New England Filed Documents. Congestion Costs, which shall be determined by differences in the Congestion Component of Locational Marginal Prices in an hour caused by constraints,

shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1. Loss costs associated with Pool Transmission Facilities, which shall be determined by the differences in Loss Components of the Locational Marginal Prices in an hour, shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1.

III.1.7.8 Market Participant Resources.

A Market Participant may elect to Self-Schedule its Resources in accordance with and subject to the limitations and procedures specified in this Market Rule 1 and the ISO New England Manuals.

III.1.7.9 Real-Time Reserve Prices.

The price paid by the ISO for the provision of Real-Time Operating Reserve in the New England Markets will reflect the integrated hourly Real-Time Reserve Clearing Prices determined by the ISO in accordance with the ISO New England Filed Documents for the system and each Reserve Zone.

III.1.7.10 Other Transactions.

(a) Market Participants may enter into internal bilateral transactions and External Transactions for the purchase or sale of energy or other products to or from each other or any other entity, subject to the obligations of Market Participants to make resources with a Capacity Supply Obligation available for dispatch by the ISO. External Transactions that contemplate the physical transfer of energy or obligations to or from a Market Participant shall be reported to and coordinated with the ISO in accordance with this Market Rule 1 and the ISO New England Manuals.

(b) [Reserved.]

(c) [Reserved.]

III.1.7.11 Seasonal Claimed Capability of a Generating Capacity Resource.

(a) A Seasonal Claimed Capability value must be established and maintained for all Generating Capacity Resources. A summer Seasonal Claimed Capability is established for use from June 1 through September 30 and a winter Seasonal Claimed Capability is established for use from October 1 through May 31.

(b) The Seasonal Claimed Capability of a Generating Capacity Resource is the sum of the Seasonal Claimed Capabilities of the Generator Assets that are associated with the Generating Capacity Resource.

(c) The Seasonal Claimed Capability of a Generator Asset is:

(i) Based upon review of historical data for non-intermittent daily cycle hydro.

(ii) The median net real power output during reliability hours, as described in Section III.13.1.2.2.2, for (1) intermittent facilities, and (2) net-metered and special qualifying facilities that do not elect to audit, as reflected in hourly revenue metering data.

(iii) For non-intermittent net-metered and special qualifying facilities that elect to audit, the minimum of (1) the Generator Asset's current Seasonal Claimed Capability Audit value, as performed pursuant to Section III.1.5.1.3; (2) the Generator Asset's current Establish Claimed Capability Audit value; and (3) the median hourly availability during hours ending 2:00 p.m. through 6:00 p.m. each day of the preceding June through September for Summer and hours ending 6:00 p.m. and 7:00 p.m. each day of the preceding October through May for Winter. The hourly availability:

a. For a Generator Asset that is available for commitment and following Dispatch Instructions, shall be the asset's Economic Maximum Limit, as submitted or redeclared.

b. For a Generator Asset that is off-line and not available for commitment shall be zero.

c. For a Generator Asset that is on-line but not able to follow Dispatch Instructions, shall be the asset's metered output.

(iv) For all other Generator Assets, the minimum of: (1) the Generator Asset's current Establish Claimed Capability Audit value and (2) the Generator Asset's current Seasonal Claimed Capability Audit value, as performed pursuant to Section III.1.5.1.3.

III.1.7.12 [Reserved.]

III.1.7.13 [Reserved.]

III.1.7.14 [Reserved.]

III.1.7.15 [Reserved.]

III.1.7.16 [Reserved.]

III.1.7.17 Operating Reserve.

The ISO shall schedule the Operating Reserve and load-following requirements of the New England Control Area and the New England Markets in scheduling Resources pursuant to this Market Rule 1. Reserve requirements for the Forward Reserve Market are determined in accordance with the methodology specified in Section III.9.2 of Market Rule 1. Operating Reserve requirements for Real-Time dispatch within an Operating Day are determined in accordance with Market Rule 1 and ISO New England Operating Procedure No. 8, Operating Reserve and Regulation.

III.1.7.18 [Reserved.]

III.1.7.19 Ramping.

A generating unit or Demand Response Resource dispatched by the ISO pursuant to a control signal appropriate to increase or decrease the unit's megawatt output or demand reduction level shall be able to change output or demand reduction at the ramping rate specified in the Offer Data submitted to the ISO for that unit and shall be subject to sanctions for failure to comply as described in **Appendix B**.

III.1.7.19A Real-Time Reserve.

(a) Real-Time TMSR, TMNSR, TMOR and Real-Time Replacement Reserve, if applicable, shall be supplied from Resources located within the metered boundaries of the New England Control Area subject to the condition set forth in Section III.1.7.19A(c) below. The ISO shall designate Operating Reserve in Real-Time only to Market Participant Resources that comply with the applicable standards and requirements for provision and dispatch of Operating Reserve capability as specified in Section III.10 and the ISO New England Manuals and ISO New England Administrative Procedures.

(b) The ISO shall endeavor to procure and maintain an amount of Operating Reserve in Real-Time equal to the system and locational Operating Reserve requirements as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(c) External Resources will be permitted to participate in the Real-Time reserve market when the respective Control Areas implement the technology and processes necessary to support recognition of Operating Reserves from external Resources.

III.1.7.20 Information and Operating Requirements.

(a) [Reserved.]

(b) Market Participants selling from Resources within the New England Control Area shall: supply to the ISO all applicable Offer Data; report to the ISO units that are Self-Scheduled; report to the ISO External Transaction sales; confirm to the ISO bilateral sales to Market Participants within the New England Control Area; respond to the ISO's directives to start, shutdown or change output or demand reduction levels of generating units or Demand Response Resources, change scheduled voltages or reactive output levels; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, generating and demand reduction equipment is operated

with control equipment functioning as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(c) Market Participants selling from Resources outside the New England Control Area shall: provide to the ISO all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to ISO directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the source Control Area and any intermediary Control Areas.

(d) Market Participants, as applicable, shall: respond or ensure a response to ISO directives for load management steps; report to the ISO all bilateral purchase transactions including External Transaction purchases; and respond or ensure a response to other ISO directives such as those required during Emergency operation.

(e) Market Participant, as applicable, shall provide to the ISO requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the Day-Ahead Energy Market, along with Dispatch Rate levels above which it does not desire to purchase.

(f) Market Participants are responsible for reporting to the ISO anticipated availability and other information concerning generating Resources, Demand Response Resources and Dispatchable Asset Related Demand Resources required by the ISO New England Operating Documents, including but not limited to the Market Participant's ability to procure fuel and physical limitations that could reduce Resource output or demand reduction capability for the pertinent Operating Day.

III.1.8 **[Reserved.]**

III.1.9 **Pre-scheduling.**

III.1.9.1 **[Reserved.]**

III.1.9.2 **[Reserved.]**

III.1.9.3 **[Reserved.]**

III.1.9.4 **[Reserved.]**

III.1.9.5 **[Reserved.]**

III.1.9.6 **[Reserved.]**

III.1.9.7 **Market Participant Responsibilities.**

Market Participants authorized and intending to request market-based Start-Up Fees and No-Load Fee in their Offer Data shall submit a specification of such fees to the ISO for each generating unit as to which the Market Participant intends to request such fees. Any such specification shall identify the applicable period and be submitted on or before the applicable deadline and shall remain in effect unless otherwise modified in accordance with Section III.1.10.9. The ISO shall reject any request for Start-Up Fees and No-Load Fee in a Market Participant's Offer Data that does not conform to the Market Participant's specification on file with the ISO.

III.1.9.8 [Reserved.]

III.1.10 Scheduling.

III.1.10.1 General.

(a) The ISO shall administer scheduling processes to implement a Day-Ahead Energy Market and a Real-Time Energy Market.

(b) The Day-Ahead Energy Market shall enable Market Participants to purchase and sell energy through the New England Markets at Day-Ahead Prices and enable Market Participants to submit External Transactions conditioned upon Congestion Costs not exceeding a specified level. Market Participants whose purchases and sales and External Transactions are scheduled in the Day-Ahead Energy Market shall be obligated to purchase or sell energy or pay Congestion Costs and costs for losses, at the applicable Day-Ahead Prices for the amounts scheduled.

(c) In the Real-Time Energy Market,

(i) Market Participants that deviate from the amount of energy purchases or sales scheduled in the Day-Ahead Energy Market shall replace the energy not delivered with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price, unless otherwise specified by this Market Rule 1, and

(ii) Non-Market Participant Transmission Customers shall be obligated to pay Congestion Costs and costs for losses for the amount of the scheduled transmission uses in the Real-Time Energy Market at the applicable Real-Time Congestion Component and Loss Component price differences, unless otherwise specified by this Market Rule 1.

(d) The following scheduling procedures and principles shall govern the commitment of Resources to the Day-Ahead Energy Market and the Real-Time Energy Market over a period extending from one week to one hour prior to the Real-Time dispatch. Scheduling encompasses the Day-Ahead and hourly scheduling process, through which the ISO determines the Day-Ahead Energy Market schedule and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the New England Control Area in the least costly manner, subject to maintaining the reliability of the New England Control Area. Scheduling of External Transactions in the Real-Time Energy Market is subject to Section II.44 of the OATT.

(e) If the ISO's forecast for the next seven days projects a likelihood of Emergency Condition, the ISO may commit, for all or part of such seven day period, to the use of generating Resources with Notification Time greater than 24 hours as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Participants' binding Supply Offers for such units.

III.1.10.1A Day-Ahead Energy Market Scheduling.

The following actions shall occur not later than 10:00 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the ISO in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Market Rule 1.

(a) Each Market Participant may submit to the ISO specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-Ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the ISO New England Manuals and ISO New England Administrative Procedures. Each Market Participant shall inform the ISO of (i) the prices, if any, at which it desires not to include its load in the Day-Ahead Energy Market rather than pay the Day-Ahead Price, (ii) hourly schedules for Resource increments, including hydropower units, Self-Scheduled by the Market Participant; and (iii) the Decrement Bid at which each such Self-Scheduled Resource will disconnect or reduce output, or confirmation of the Market Participant's intent not to reduce output. Price-sensitive Demand Bids and Decrement Bids must be greater than zero MW and shall not exceed the energy Supply Offer limitation specified in this Section.

(b) [Reserved.]

(c) All Market Participants shall submit to the ISO schedules for any External Transactions involving use of generating Resources or the New England Transmission System as specified below, and shall inform the ISO whether the transaction is to be included in the Day-Ahead Energy Market. Any Market Participant that elects to include an External Transaction in the Day-Ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the ISO New England Manuals and ISO New England Administrative Procedures), if any, at which it will be curtailed rather than pay Congestion Costs. The foregoing price specification shall apply to the price difference between the Locational Marginal Prices for specified External Transaction source and sink points in the Day-Ahead scheduling process only. Any Market Participant that deviates from its Day-Ahead External Transaction schedule or elects not to include its External Transaction in the Day-Ahead Energy Market shall be subject to Congestion Costs in the Real-Time Energy Market in order to complete any such scheduled External Transaction. A priced External Transaction submitted under Section III.1.10.7 and that clears in the Day-Ahead Energy Market will be considered tied within economic merit with a Self-Scheduled External Transaction submitted to the Real-Time Energy Market, unless the Market Participant modifies the price component of its Real-Time offer during the Re-Offer Period. Scheduling of External Transactions shall be conducted in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures and the following requirements:

(i) Market Participants shall submit schedules for all External Transaction purchases for delivery within the New England Control Area from Resources outside the New England Control Area;

(ii) Market Participants shall submit schedules for External Transaction sales to entities outside the New England Control Area from Resources within the New England Control Area;

(iii) If the sum of all submitted fixed External Transaction purchases less External Transaction sales exceeds the import capability associated with the applicable External Node, the offer prices for all fixed External Transaction purchases at the applicable External Node shall be set equal to the Energy Offer Floor;

(iv) If the sum of all submitted fixed External Transaction sales less External Transaction purchases exceeds the export capability associated with the applicable External Node, the

offer prices for all fixed External Transaction sales at the applicable External Node shall be set equal to the Energy Offer Cap;

(v) The ISO shall not consider Start-Up Fees, No-Load Fees, Notification Times or any other inter-temporal parameters in scheduling or dispatching External Transactions.

(d) Market Participants selling into the New England Markets, from either internal Resources or External Resources, shall submit Supply Offers or External Transactions for the supply of energy (including energy from hydropower units), and Demand Bids for the consumption of energy, Operating Reserve or other services as applicable, for the following Operating Day. Coordinated External Transactions shall be submitted to the ISO in accordance with Section III.1.10.7.A of this Market Rule 1.

Energy offered from generating Resources without a Capacity Supply Obligation shall not be supplied from Resources that are included in or otherwise committed to supply the operating reserve requirements of another Control Area. All Supply Offers and Demand Bids:

(i) Shall specify the Resource or Load Asset and energy for each hour of the Operating Day;

(ii) Shall specify, for Supply Offers, Blocks (price and quantity of Energy) for each hour of the Operating Day for each Resource offered by the Market Participant to the ISO. The price and quantity values in a Block may each vary on an hourly basis;

(iii) If based on energy from a specific generating unit internal to the New England Control Area, may specify, for Supply Offers, Start-Up Fee and No-Load Fee for each hour of the Operating Day. Start-Up Fee and No-Load Fee values may vary on an hourly basis;

(iv) For a dual fuel Resource, shall specify, for Supply Offers, the fuel type. The fuel type value may vary on an hourly basis. A Market Participant that submits a Supply Offer using the higher cost fuel type must satisfy the consultation requirements for dual fuel Resources in Section III.A.3 of Appendix A;

(v) Shall specify, for Supply Offers, a Minimum Run Time to be used for scheduling purposes that does not exceed 24 hours for a generating Resource;

(vi) Supply Offers shall constitute an offer to submit the generating Resource increment to the ISO for scheduling and dispatch in accordance with the terms of the Supply Offer, where such Supply Offer, with regard to operating limits, shall specify changes to the Economic Maximum Limit, Economic Minimum Limit and Emergency Minimum Limit from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource, except that for a Limited Energy Resource, the Economic Maximum Limit may be revised to reflect maximum energy available for the Operating Day, which offer shall remain open through the Operating Day for which the Supply Offer is submitted;

(vii) Shall constitute, for Demand Bids, an offer to submit the Dispatchable Asset Related Demand Resource increment to the ISO for scheduling and dispatch in accordance with the terms of the Demand Bid, where such Demand Bid, with regard to operating limits, shall specify changes to the Maximum Consumption Limit and Minimum Consumption Limit from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource, except that, for a Self-Scheduled Resource, the Minimum Consumption Limit may vary on an hourly basis to reflect the Self-Scheduled consumption level of the Resource;

(viii) Shall be final as to the price or prices at which the Market Participant proposes to supply or consume energy or other services to the New England Markets, such price or prices for Resources or portions of Resources scheduled in the Day-Ahead Energy Market being guaranteed by the Market Participant for the period extending through the end of the following Operating Day; and

(ix) Shall not specify an energy offer or bid price below the Energy Offer Floor or above the Energy Offer Cap.

(e) [Reserved.]

(f) [Reserved.]

(g) Each Supply Offer or Demand Bid by a Market Participant of a Resource shall remain in effect for subsequent Operating Days until superseded or canceled except in the case of an External Resource and an External Transaction purchase, in which case, the Supply Offer shall remain in effect for the

applicable Operating Day and shall not remain in effect for subsequent Operating Days. Hourly overrides of a Supply Offer or a Demand Bid shall remain in effect only for the applicable Operating Day.

(h) The ISO shall post on the internet the total hourly loads including Decrement Bids scheduled in the Day-Ahead Energy Market, as well as the ISO's estimate of the Control Area hourly load for the next Operating Day.

(i) In determining Day-Ahead schedules, in the event of multiple marginal Supply Offers, Demand Reduction Offers, Increment Offers and/or External Transaction purchases at a pricing location, the ISO shall clear the marginal Supply Offers, Demand Reduction Offers, Increment Offers and/or External Transaction purchases proportional to the amount of energy (MW) from each marginal offer and/or External Transaction at the pricing location. The Economic Maximum Limits, Economic Minimum Limits, Minimum Reductions and Maximum Reductions are not used in determining the amount of energy (MW) in each marginal Supply Offer or Demand Reduction Offer to be cleared on a pro-rated basis. However, the Day-Ahead schedules resulting from the pro-ration process will reflect Economic Maximum Limits, Economic Minimum Limits, Minimum Reductions and Maximum Reductions.

(j) In determining Day-Ahead schedules, in the event of multiple marginal Demand Bids, Decrement Bids and/or External Transaction sales at a pricing location, the ISO shall clear the marginal Demand Bids, Decrement Bids and/or External Transaction sales proportional to the amount of energy (MW) from each marginal bid and/or External Transaction at the pricing location.

(k) All Market Participants may submit Increment Offers and/or Decrement Bids that apply to the Day-Ahead Energy Market only. Such offers and bids must comply with the requirements set forth in the ISO New England Manuals and ISO New England Administrative Procedures and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-Ahead Energy Market.

III.1.10.2 Pool-Scheduled Resources.

Pool-Scheduled Resources are those Resources for which Market Participants submitted Supply Offers or Demand Reduction Offers to sell energy in the Day-Ahead Energy Market and which the ISO scheduled in the Day-Ahead Energy Market as well as generators or Demand Response Resources committed by the ISO subsequent to the Day-Ahead Energy Market. Such Resources shall be committed to provide energy in the Real-Time dispatch unless the schedules for such Resources are revised pursuant to Sections

III.1.10.9 or III.1.11. Pool-Scheduled Resources shall be governed by the following principles and procedures.

(a) Pool-Scheduled Resources shall be selected by the ISO on the basis of the prices offered for energy and related services, Start-Up Fees, No-Load Fees, Interruption Cost and the specified operating characteristics, offered by Market Participants.

(b) The ISO shall optimize the dispatch of energy from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources in the Day-Ahead Energy Market consistent with the Supply Offers and Demand Reduction Offers of other Resources, the submitted Demand Bids and Decrement Bids and Operating Reserve and Replacement Reserve requirements.

(c) Market Participants offering energy from hydropower or other facilities with fuel or environmental limitations may submit data to the ISO that is sufficient to enable the ISO to determine the available operating hours of such facilities.

(d) The Market Participant seller whose Resource is selected as a Pool-Scheduled Resource shall receive payments or credits for energy or related services, or for Start-Up Fees, No-Load Fees or Interruption Costs, from the ISO on behalf of the Market Participant buyers in accordance with Section III.3 of this Market Rule 1.

(e) Market Participants shall make available their Pool-Scheduled Resources to the ISO for coordinated operation to supply the needs of the New England Control Area for energy and ancillary services.

III.1.10.3 Self-Scheduled Resources.

A Resource that is Self-Scheduled shall be governed by the following principles and procedures.

(a) The minimum duration of a Self-Schedule for a Generator Asset shall not result in the Generator Asset operating for less than its Minimum Run Time. A Generator Asset that is online as a result of a

Self-Schedule will be dispatched above its Economic Minimum Limit based on the economic merit of its Supply Offer.

(b) The offered prices of Resources or portions of Resources that are Self-Scheduled, or otherwise not following the dispatch orders of the ISO, shall not be considered by the ISO in determining Locational Marginal Prices.

(c) A Market Participant with a Resource that does not have a Capacity Supply Obligation shall comply with the requirements in Section III.13.6.2 when Self-Scheduling that Resource.

(d) A Market Participant Self-Scheduling a Resource in the Day-Ahead Energy Market that does not deliver the energy in the Real-Time Energy Market, shall replace the energy not delivered with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price.

III.1.10.4 [Reserved.]

III.1.10.5 External Resources.

(a) Market Participants with External Resources that have dynamic scheduling and dispatch capability may submit Supply Offers to the New England Markets in accordance with the Day-Ahead and Real-Time scheduling processes specified above. Market Participants must submit Supply Offers for External Resources on a Resource specific basis. An External Resource with dynamic scheduling and dispatch capability selected as a Pool-Scheduled Resource shall be made available for scheduling and dispatch at the direction of the ISO and shall be compensated on the same basis as other Pool-Scheduled Resources.

(b) Supply Offers for External Resources with dynamic scheduling and dispatch capability shall specify the Resource being offered, along with the information specified in the Offer Data as applicable.

(c) For Resources external to the New England Control Area that are not capable of dynamic scheduling and dispatch, Market Participants shall submit External Transactions as detailed in Section III.1.10.7 and Section III.1.10.7.A of this Market Rule 1.

(d) A Market Participant whose External Resource is capable of dynamic scheduling and dispatch capability or whose External Transaction does not deliver the energy scheduled in the Day-Ahead Energy Market shall replace such energy not delivered as scheduled in the Day-Ahead Energy Market with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price.

III.1.10.6 Dispatchable Asset Related Demand Resources.

External Transactions that are sales to an external Control Area are not eligible to be Dispatchable Asset Related Demand Resources. Except as noted below with respect to a pumped storage generator that does not have a Capacity Supply Obligation, a Dispatchable Asset Related Demand Resource in the New England Control Area must:

(a) each day, either Self-Schedule or submit a Demand Bid into the Day-Ahead Energy Market as described in Section III.1.10.1A of this Market Rule 1 that specifies the prices at which the Resource is willing to consume energy, unless and to the extent that the Dispatchable Asset Related Demand Resource is unable to do so due to an outage as defined in the ISO New England Manuals;

(b) submit Demand Bid data that specifies a Maximum Consumption Limit and Minimum Consumption Limit;

(c) submit Demand Bid data that specifies a Minimum Consumption Limit that is less than or equal to its Nominated Consumption Limit;

(d) notify the ISO of any outage (including partial outages) that may reduce the Dispatchable Asset Related Demand Resource's ability to interrupt and the expected return date from the outage;

(e) in accordance with the ISO New England Manuals and Operating Procedures, perform audit tests and submit the results to the ISO or provide to the ISO appropriate historical production data;

(f) abide by the ISO maintenance coordination procedures;

(g) provide information reasonably requested by the ISO, including the name and location of the Dispatchable Asset Related Demand Resource; and

(h) comply with the ISO New England Manuals.

To schedule the dispatchable pumping demand of a pumped storage generator that does not have a Capacity Supply Obligation, a Market Participant must comply with the requirements in (b) through (h) for the applicable Operating Day and must either Self-Schedule or submit a Demand Bid into the Day-Ahead Energy Market as described in Section III.1.10.1A of this Market Rule 1 that specifies the prices at which the Resource is willing to consume energy for the applicable Operating Day.

III.1.10.7 External Transactions.

The provisions of this Section III.1.10.7 do not apply to Coordinated External Transactions.

(a) Market Participants that submit an External Transaction in the Day-Ahead Energy Market must also submit a corresponding External Transaction in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market. Priced External Transactions for the Real-Time Energy Market must be submitted by the offer submission deadline for the Day-Ahead Energy Market.

(b) Priced External Transactions submitted in both the Day-Ahead Energy Market and the Real-Time Energy Market will be treated as Self-Scheduled External Transactions in the Real-Time Energy Market for the associated megawatt amounts that cleared the Day-Ahead Energy Market, unless the Market Participant modifies the price component of its Real-Time offer during the Re-Offer Period.

(c) Any External Transaction, or portion thereof, submitted to the Real-Time Energy Market that did not clear in the Day-Ahead Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency. External Transactions cleared in the Day-Ahead Energy Market and associated with a Real-Time Energy Market submission will continue to be scheduled in Real-Time prior to and during an Emergency, until the applicable procedures governing the Emergency, as set forth in ISO New England Manual 11, require a change in schedule.

(d) A Market Participant submitting a priced External Transaction supporting Capacity Supply Obligation to the Real-Time Energy Market on an external interface where advance transmission reservations are required must comply with the requirements in Section III.13.6.1.2.1 with respect to linking the transaction to the associated transmission reservation and NERC E-Tag. All other External Transactions submitted to the Real-Time Energy Market must contain the associated NERC E-Tag and transmission reservation, if required, at the time the transaction is submitted to the Real-Time Energy Market.

(e) [Reserved.]

(f) External Transaction sales meeting all of the criteria for any of the transaction types described in (i) through (iv) below receive priority in the scheduling and curtailment of transactions as set forth in Section II.44 of the OATT. External Transaction sales meeting all of the criteria for any of the transaction types described in (i) through (iv) below are referred to herein and in the OATT as being supported in Real-Time.

(i) Capacity Export Through Import Constrained Zone Transactions:

(1) The External Transaction is exporting across an external interface located in an import-constrained Capacity Zone that cleared in the Forward Capacity Auction with price separation, as determined in accordance with Section III.12.4 and Section III.13.2.3.4 of Market Rule 1;

(2) The External Transaction is directly associated with an Export Bid or Administrative Export De-List Bid that cleared in the Forward Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the cleared Export Bid;

(3) The External Node associated with the cleared Export Bid or Administrative Export De-List Bid is connected to the import-constrained Capacity Zone, and is not connected to a Capacity Zone that is not import-constrained;

(4) The Resource, or portion thereof, that is associated with the cleared Export Bid or Administrative Export De-List Bid is not located in the import-constrained Capacity Zone;

(5) The External Transaction has been submitted and cleared in the Day-Ahead Energy Market;

(6) A matching External Transaction has also been submitted into the Real-Time Energy Market by the end of the Re-Offer Period for Self-Scheduled External Transactions, and, in accordance with Section III.1.10.7(a), by the offer submission deadline for the Day-Ahead Energy Market for priced External Transactions.

(ii) FCA Cleared Export Transactions:

(1) The External Transaction sale is exporting to an External Node that is connected only to an import-constrained Reserve Zone;

(2) The External Transaction sale is directly associated with an Export Bid or an Administrative Export De-List Bid that cleared in the Forward Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the cleared Export Bid;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation associated with the Export Bid or Administrative Export De-List Bid is located outside the import-constrained Reserve Zone;

(4) The External Transaction sale is submitted and cleared in the Day-Ahead Energy Market;

(5) A matching External Transaction has also been submitted into the Real-Time Energy Market by the end of the Re-Offer Period for Self-Scheduled External Transactions, and, in accordance with Section III.1.10.7(a), by the offer submission deadline for the Day-Ahead Energy Market for priced External Transactions.

(iii) Same Reserve Zone Export Transactions:

(1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;

(2) The External Node of the External Transaction sale is connected only to the same Reserve Zone in which the associated Resource, or portion thereof, without a Capacity Supply Obligation is located;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation is Self-Scheduled in the Real-Time Energy Market and online at a megawatt level greater than or equal to the External Transaction sale's megawatt amount;

(4) Neither the External Transaction sale nor the portion of the Resource without a Capacity Supply Obligation is required to offer into the Day-Ahead Energy Market.

(iv) Unconstrained Export Transactions:

(1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;

(2) The External Node of the External Transaction sale is not connected only to an import-constrained Reserve Zone;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation is not separated from the External Node by a transmission interface constraint as determined in Sections III.12.2.1(b) and III.12.2.2(b) of Market Rule 1 that was binding in the Forward Capacity Auction in the direction of the export;

(4) The Resource, or portion thereof, without a Capacity Supply Obligation is Self-Scheduled in the Real-Time Energy Market and online at a megawatt level greater than or equal to the External Transaction sale's megawatt amount;

(5) Neither the External Transaction sale, nor the portion of the Resource without a Capacity Supply Obligation is required to offer into the Day-Ahead Energy Market.

(g) Treatment of External Transaction sales in ISO commitment for local second contingency protection.

(i) Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions: The transaction's export demand that clears in the Day-Ahead Energy Market will be explicitly considered as load in the exporting Reserve Zone by the ISO when committing Resources to provide local second contingency protection for the associated Operating Day.

(ii) The export demand of External Transaction sales not meeting the criteria in (i) above is not considered by the ISO when planning and committing Resources to provide local second contingency protection, and is assumed to be zero.

(iii) Same Reserve Zone Export Transactions and Unconstrained Export Transactions: If a Resource, or portion thereof, without a Capacity Supply Obligation is committed to be online during the Operating Day either through clearing in the Day-Ahead Energy Market or through Self-Scheduling subsequent to the Day-Ahead Energy Market and a Same Reserve Zone Export Transaction or Unconstrained Export Transaction is submitted before the end of the Re-Offer Period designating that Resource as supporting the transaction, the ISO will not utilize the portion of the Resource without a Capacity Supply Obligation supporting the export transaction to meet local second contingency protection requirements. The eligibility of Resources not meeting the foregoing criteria to be used to meet local second contingency protection requirements shall be in accordance with the relevant provisions of the ISO New England System Rules.

(h) Allocation of costs to Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions: Market Participants with Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions shall incur a proportional share of the charges described below, which are allocated to Market Participants based on Day-Ahead Load Obligation or Real-Time Load Obligation. The share shall be determined by including the Day-Ahead Load Obligation or Real-Time Load Obligation associated with the External Transaction, as applicable, in the total Day-Ahead Load Obligation or Real-Time Load Obligation for the appropriate Reliability Region, Reserve Zone, or Load Zone used in each cost allocation calculation:

(i) NCPC for Local Second Contingency Protection Resources allocated within the exporting Reliability Region, pursuant to Section III.F.3.3.

(ii) Forward Reserve Market charges allocated within the exporting Load Zone, pursuant to Section III.9.9.

(iii) Real-Time Reserve Charges allocated within the exporting Load Zone, pursuant to Section III.10.3.

(i) When action is taken by the ISO to reduce External Transaction sales due to a system wide capacity deficient condition or the forecast of such a condition, and an External Transaction sale designates a Resource, or portion of a Resource, without a Capacity Supply Obligation, to support the transaction, the ISO will review the status of the designated Resource. If the designated Resource is Self-Scheduled and online at a megawatt level greater than or equal to the External Transaction sale, that External Transaction sale will not be reduced until such time as Regional Network Load within the New England Control Area is also being reduced. When reductions to such transactions are required, the affected transactions shall be reduced pro-rata.

(j) Market Participants shall submit External Transactions as megawatt blocks with intervals of one hour at the relevant External Node. External Transactions will be scheduled in the Day-Ahead Energy Market as megawatt blocks for hourly durations. The ISO may dispatch External Transactions in the Real-Time Energy Market as megawatt blocks for periods of less than one hour, to the extent allowed pursuant to inter-Control Area operating protocols.

III.1.10.7.A Coordinated External Transactions.

The provisions of this Section III.1.10.7.A apply to Coordinated External Transactions, which are implemented at the New York Northern AC external Location ~~and the Northport-Norwalk external Location~~.

(a) Market Participants that submit a Coordinated External Transaction in the Day-Ahead Energy Market must also submit a corresponding Coordinated External Transaction, in the form of an Interface Bid, in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market.

(b) An Interface Bid submitted in the Real-Time Energy Market shall specify a duration consisting of one or more consecutive 15-minute increments. An Interface Bid shall include a bid price, a bid quantity, and a bid direction for each 15-minute increment. The bid price may be positive or negative. An Interface Bid may not be submitted or modified later than 75 minutes before the start of the ~~period~~ clock hour for which it is offered.

(c) Interface Bids are cleared in economic merit order for each 15minute increment, based upon the forecasted real-time price difference across the external interface. The total quantity of Interface Bids cleared shall determine the external interface schedule between New England and the adjacent Control

Area. The total quantity of Interface Bids cleared shall depend upon, among other factors, bid production costs of resources in both Control Areas, the Interface Bids of all Market Participants, transmission system conditions, and any real-time operating limits necessary to ensure reliable operation of the transmission system.

(d) All Coordinated External Transactions submitted either to the Day-Ahead Energy Market or the Real-Time Energy Market must contain the associated NERC E-Tag at the time the transaction is submitted.

(e) Any Coordinated External Transaction, or portion thereof, submitted to the Real-Time Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency, unless applicable procedures governing the Emergency permit the transaction to be scheduled.

III.1.10.7.B Coordinated Transactions Scheduling Threshold Trigger to Tie Optimization

(a) Background and Overview

This Section III.1.10.B describes the process for filing amendments to the Transmission, Markets and Services Tariff under Section 205 of the Federal Power Act in the event that the production cost savings of the ISO's interchange on the New York – New England AC Interface, including the Northport/Norwalk Line, following the implementation of an inter-regional interchange scheduling process known as Coordinated Transaction Scheduling, are not satisfactory. The determination of whether savings are satisfactory will be based on actions, thresholds and triggers described in this Section III.1.10.7.B. If pursuant to the actions, thresholds and triggers described in this Section III.1.10.7.B, the production costs savings of Coordinated Transaction Scheduling are not satisfactory, and a superior alternative has not become known, the ISO will file tariff amendments with the Commission to implement the inter-regional interchange scheduling process described to the ISO stakeholders in 2011 as Tie Optimization.

If, pursuant to the timetables presented, the ISO determines the thresholds described herein have not triggered, the process for filing amendments to the ISO tariff as described herein ceases, the provisions of this Section III.1.10.7.B become null and void and the ISO will continue to implement Coordinated

Transaction Scheduling unless and until future Section 205 filings are pursued to amend Coordinated Transaction Scheduling.

(b) The Two-Year Analysis

Within 120 days of the close of the first and second years following the date that Coordinated Transaction Scheduling as an interface scheduling tool is activated in the New England and New York wholesale electricity markets, the External Market Monitor will develop, for presentation to and comment by, New England stakeholders, an analysis, of:

(i) the Tie Optimization interchange, which will be the actual bid production cost savings of incremental interchange that would have occurred had the ISO and New York Independent System Operator received an infinite number of zero bids in the Coordinated Transaction Scheduling process, which utilizes the supply curves and forecasted prices for each market; and

(ii) an optimal interchange, which will be the actual bid production cost savings of incremental interchange that would have occurred had the two ISOs had an infinite number of zero bids in the Coordinated Transaction Scheduling process, but utilizing actual real-time prices from each market rather than the forecasted prices that were used in the Coordinated Transaction Scheduling process.

The bid production cost savings associated with the Tie Optimization interchange as developed in (i) above for the second year following the date that Coordinated Transaction Scheduling is activated in the New England and New York wholesale electricity markets will reveal the "foregone" production cost savings from implementing Coordinated Transaction Scheduling rather than Tie Optimization, represented in the Section III.1.10.7.B(b)(1) formula as the term "b." The difference in bid production cost savings between (i) and (ii) above will reveal the "foregone" bid production cost savings of the Tie Optimization interchange as developed in (i) above rather than an optimal interchange as developed in (ii) above, represented in the Section III.1.10.7.B(b)(1) formula as the term "a."

This analysis will be consistent with presentations made by the External Market Monitor to the New England stakeholders during 2011 on the issue of the benefits of Coordinated Transaction Scheduling.

(1) Using the above calculations, the External Market Monitor will compute the following ratio:

b/a

If, the ratio b/a is greater than 60% and b is greater than $3 Million, the External Market Monitor will advise whether in its opinion the threshold has triggered.

(c) Improving Coordinated Transaction Scheduling

(1) If the ratio, developed pursuant to Section III.1..10.7.B(b)(1), is greater than 60% and b is greater than $3 Million, the ISO will declare whether the threshold has triggered considering the input of the External Market Monitor and the New England stakeholders.

(2) If the ISO declares the threshold has not triggered the process further described in this Section III.1.10.7.B becomes null and void.

(3) If the ISO declares that the threshold has triggered, the External Market Monitor will provide recommendations of adjustments to the design or operation of Coordinated Transaction Scheduling to improve the production cost savings available from its implementation.

(4) The ISO, considering the input of the New England stakeholders and the recommendation of the External Market Monitor, will develop and implement adjustments to Coordinated Transaction Scheduling. To the extent tariff revisions are necessary to implement the adjustments to Coordinated Transaction Scheduling, the ISO will file such revisions with the Commission as a compliance filing in the Coordinated Transaction Scheduling docket. If no adjustments to Coordinated Transaction Scheduling have been identified, the ISO will proceed to develop and file the revisions necessary to amend the Transmission, Markets and Services Tariff to implement the inter-regional interchange scheduling practice known as Tie Optimization as a compliance filing.

(d) The Second Analysis

(1) Within 120 days of the close of the twelve months following the date that the adjustments to Coordinated Transaction Scheduling, developed under Section III.1.10.7.B(c), are activated in the New England and New York wholesale electricity markets, the External Market Monitor will present a second analysis to New England stakeholders. The analysis will be consistent with the analysis described in Section III.1.10.7.B(b) but will develop bid production cost savings for the twelve month period during which the adjustments developed in Section III.1.10.7.B(c) are in place.

(2) The bid production cost savings associated with the Tie Optimization interchange as developed in Section III.1.10.7.B(d)(1) will reveal the "foregone" bid production cost savings from implementing Coordinated Transaction Scheduling rather than Tie Optimization, represented in the Section III.1.10.7.B(d)(3) formula as the term "b." The different in bid production cost savings between the Tie Optimization interchange and the optimal interchange, as developed in Section III.1.10.7.B(d)(1), will reveal the "foregone" bid production cost savings of the Tie Optimization interchange rather than the optimal interchange, represented in the Section III.1.10.7.B(d)(3) formula as the term "a."

(3) Using the above calculations, the External Market Monitor will compute the following ratio:

b/a

If the ratio b/a is greater than 60% and b is greater than $3 Million, the External Market Monitor will advise whether in its opinion the threshold has triggered.

(4) If the ratio b/a is greater than 60% and b is greater than $3 Million, the ISO will declare whether the threshold has triggered considering the input of the External Market Monitor and the New England stakeholders.

(5) If the ISO declares the threshold has not triggered the process further described in this Section III.1.10.7.B becomes null and void.

(6) If the ISO declares the threshold has triggered, considering the input of the stakeholders and the recommendation of the External Market Monitor, the ISO will determine whether a superior alternative has been proposed. If the ISO and the New York Independent System Operator both determine a superior alternative has been proposed, the ISO will prepare tariff amendments to be filed with the Commission to implement the superior alternative, and will present those amendments to the New England stakeholders in accordance with the provisions of the Participants Agreement applicable for NEPOOL review of tariff amendments and will not pursue the balance of the actions required by this Section III.1.10.7.B.

(7) If the ISO determines a superior alternative has not been proposed, the ISO will proceed to develop and file the revisions necessary to amend the Transmission, Markets and Services Tariff to implement the inter-regional interchange scheduling practice known as Tie Optimization as a compliance filing. Tie Optimization was described for stakeholders in the *Design Basis Document* for NE/NY Inter-Regional Interchange Scheduling presented at a NEPOOL Participants Committee meeting on June 10, 2011.

(e) The Compliance Filing

The ISO will develop tariff language to implement the inter-regional interchange scheduling practice known as Tie Optimization through a compliance filing with the Commission and will present those amendments to the New England stakeholders in accordance with the provisions of the Participants Agreement applicable for NEPOOL review of tariff amendments.

III.1.10.8 ISO Responsibilities.

(a) The ISO shall use its best efforts to determine (i) the least-cost means of satisfying hourly purchase requests for energy, the projected hourly requirements for Operating Reserve, Replacement Reserve and other ancillary services of the Market Participants, including the reliability requirements of the New England Control Area, of the Day-Ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve, Replacement Reserve and other ancillary service requirements for any portion of the load forecast of the ISO for the Operating Day in excess of that scheduled in the Day-Ahead Energy Market. In making these determinations, the ISO shall take into account: (i) the ISO's forecasts of New England Markets and New England Control Area energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Participants for the Day-Ahead Energy Market; (ii) the offers and bids submitted by Market Participants; (iii) the availability of Limited Energy Resources; (iv) the capacity, location, and other relevant characteristics of Self-Scheduled Resources; (v) the requirements of the New England Control Area for Operating Reserve and Replacement Reserve, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; (vi) the requirements of the New England Control Area for Regulation and other ancillary services, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; and (viii) such other factors as the ISO reasonably concludes are relevant to the foregoing

determination. The ISO shall develop a Day-Ahead Energy schedule based on the applicable portions of the foregoing determination, and shall determine the Day-Ahead Prices resulting from such schedule.

(b) Not later than 1:30 p.m. of the day before each Operating Day, or such earlier deadline as may be specified by the ISO in the ISO New England Manuals and ISO New England Administrative Procedures or such later deadline as necessary to account for software failures or other events, the ISO shall: (i) post the aggregate Day-Ahead Energy schedule; (ii) post the Day-Ahead Prices; and (iii) inform the Market Participants of their scheduled injections and withdrawals. In the event of an Emergency, the ISO will notify Market Participants as soon as practicable if the Day-Ahead Energy Market can not be operated.

(c) Following posting of the information specified in Section III.1.10.8(b), the ISO shall revise its schedule of Resources to reflect updated projections of load, conditions affecting electric system operations in the New England Control Area, the availability of and constraints on limited energy and other Resources, transmission constraints, and other relevant factors.

(d) Market Participants shall pay and be paid for the quantities of energy scheduled in the Day-Ahead Energy Market at the Day-Ahead Prices.

III.1.10.9 Hourly Scheduling.

(a) Following the initial posting by the ISO of the Locational Marginal Prices resulting from the Day-Ahead Energy Market, and subject to the right of the ISO to schedule and dispatch Pool-Scheduled Resources and to direct that schedules be changed in an Emergency, a Resource Re-Offer Period shall exist from the time of the posting specified in Section III.1.10.8(b) until 2:00 p.m. on the day before each Operating Day or such other Re-Offer Period as necessary to account for software failures or other events. During the Re-Offer Period, Market Participants may submit revisions to generation Supply Offers and revisions to Demand Bids for any Dispatchable Asset Related Demand Resource. Resources scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices.

(b) Following the completion of the initial Reserve Adequacy Analysis and throughout the Operating Day, a Market Participant may modify certain Supply Offer or Demand Bid parameters for a Generator Asset or a Dispatchable Asset Related Demand on an hour-to-hour basis, provided that the modification is

made no later than 30 minutes prior to the beginning of the hour for which the modification is to take effect:

(i) For a Generator Asset, the Start-Up Fee, the No-Load Fee, the fuel type (for dual fuel Resources), the quantity and price pairs of its Blocks, and the Supply Offer for Regulation may be modified.

(ii) For a Dispatchable Asset Related Demand, the quantity and price pairs of its Blocks may be modified.

(c) During the Re-Offer Period, Market Participants may submit revisions to priced External Transactions. External Transactions scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices. A submission during the Re-Offer Period for any portion of a transaction that was cleared in the Day-Ahead Energy Market is subject to the provisions in Section III.1.10.7. A Market Participant may at any time, consistent with the provisions in Manual 11, request to Self-Schedule an External Transaction and adjust the schedule on an hour-to-hour basis. The ISO must be notified of the request not later than 60 minutes prior to the hour in which the adjustment is to take effect. The External Transaction re-offer provisions of this Section III.1.10.9(c) shall not apply to Coordinated External Transactions, which are submitted pursuant to Section III.1.10.7.A.

(d) During the Operating Day, a Market Participant may request to Self-Schedule a Generator Asset or Dispatchable Asset Related Demand or may request to cancel a Self-Schedule for a Generator Asset or Dispatchable Asset Related Demand. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor a Self-Schedule request, a Generator Asset will be permitted to come online at its Economic Minimum Limit and a Dispatchable Asset Related Demand will be dispatched to its Minimum Consumption Limit.

(e) During the Operating Day, in the event that in a given hour a Market Participant seeks to modify a Supply Offer or Demand Bid after the deadline for modifications specified in Section III.1.10.9(b), then:

(i) the Market Participant may request that a Generator Asset be dispatched above its Economic Minimum Limit at a specified output. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor the request, the Generator Asset will

be dispatched as though it had offered the specified output for the hour in question at the Energy Offer Floor.

(ii) the Market Participant may request that a Dispatchable Asset Related Demand be dispatched above its Minimum Consumption Limit. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor the request, the Dispatchable Asset Related Demand will be dispatched as though it had offered for the hour in question at a Self-Scheduled MW.

(f) For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this Section III.1.10, the ISO shall provide Market Participants and parties to External Transactions with any revisions to their schedules for the hour.

III.1.11 Dispatch.

The following procedures and principles shall govern the dispatch of the Resources available to the ISO.

III.1.11.1 Resource Output and Demand Reduction.

The ISO shall have the authority to direct any Market Participant to adjust the output or demand reduction of any Pool-Scheduled Resource increment within the operating characteristics specified in the Market Participant's Offer Data, Supply Offer, Demand Reduction Offer or Demand Bid. The ISO may cancel its selection of, or otherwise release, Pool-Scheduled Resources. The ISO shall adjust the output or demand reduction of Pool-Scheduled Resource increments as necessary: (a) to maintain reliability, and subject to that constraint, to minimize the cost of supplying the energy, reserves, and other services required by the Market Participants and the operation of the New England Control Area; (b) to balance load and generation, maintain scheduled tie flows, and provide frequency support within the New England Control Area; and (c) to minimize unscheduled interchange that is not frequency related between the New England Control Area and other Control Areas.

III.1.11.2 Operating Basis.

In carrying out the foregoing objectives, the ISO shall conduct the operation of the New England Control Area and shall, in accordance with the ISO New England Manuals and ISO New England Administrative Procedures, (i) utilize available Operating Reserve and replace such Operating Reserve when utilized; and (ii) monitor the availability of adequate Operating Reserve.

III.1.11.3 Pool-dispatched Resources.

(a) The ISO shall optimize the dispatch of energy from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources consistent with the dynamic load-following requirements of the New England Control Area and the availability of other Resources to the ISO.

(b) The ISO shall implement the dispatch of energy from Pool-Scheduled Resource increments and the designation of Real-Time Operating Reserve to Pool-Scheduled Resource increments, including the dispatchable increments from resources which are otherwise Self-Scheduled, by sending appropriate signals and instructions to the entity controlling such Resources, in accordance with the ISO New England Manuals and ISO New England Administrative Procedures. Each Market Participant shall ensure that the entity controlling a Pool-Scheduled Resource offered or made available by that Market Participant complies with the energy dispatch signals and instructions transmitted by the ISO.

(c) The ISO shall have the authority to modify a Market Participant's operational related Offer Data if the ISO observes that the Market Participant's Resource is not operating in accordance with such Offer Data. The ISO shall modify such operational related Offer Data based on observed performance and such modified Offer Data shall remain in effect until either (i) the affected Market Participant requests a test to be performed, and coordinates the testing pursuant to the procedures specified in the ISO New England Manuals, and the results of the test justify a change to the Market Participant's Offer Data or (ii) the ISO observes, through actual performance, that modification to the Market Participant's Offer Data is justified.

(d) Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Resources in the New England Control Area as close to dispatched output or demand reduction levels as practical, consistent with Good Utility Practice.

(e) Wind resources are treated as not economically dispatchable until the ISO is technically capable of determining and telemetering a Do Not Exceed Dispatch Point to the resource.

(f) The ISO may request that dual-fueled generating Resources that normally burn natural gas voluntarily take all necessary steps (within the limitations imposed by the operating limitations of their

installed equipment and their environmental and operating permits) to prepare to switch to secondary fuel in anticipation of natural gas supply shortages. The ISO may request that Market Participants with dual-fueled units that normally burn natural gas voluntarily switch to a secondary fuel in anticipation of natural gas supply shortages. The ISO may communicate with Market Participants with dual-fueled units that normally burn natural gas to verify whether the Market Participants have switched or are planning to switch to an alternate fuel.

III.1.11.4 Emergency Condition.

If the ISO anticipates or declares an Emergency Condition, all External Transaction sales out of the New England Control Area that are not backed by a Resource may be interrupted, in accordance with the ISO New England Manuals, in order to serve load and Operating Reserve in the New England Control Area.

III.1.11.5 [Reserved.]

(a)

III.1.11.6 [Reserved]

III.1.12 Dynamic Scheduling.

Dynamic scheduling can be requested and may be implemented in accordance with the following procedures:

(a) An entity that owns or controls a generating Resource in the New England Control Area may electrically remove all or part of the generating Resource's output from the New England Control Area through dynamic scheduling of the output to load outside the New England Control Area. Such output shall not be available for economic dispatch by the ISO.

(b) An entity that owns or controls a generating Resource outside of the New England Control Area may electrically include all or part of the generating Resource's output into the New England Control Area through dynamic scheduling of the output to load inside the New England Control Area. Such output shall be available for economic dispatch by the ISO.

(c) An entity requesting dynamic scheduling shall be responsible for arranging for the provision of signal processing and communication from the generating unit and other participating Control Area and complying with any other procedures established by the ISO regarding dynamic scheduling as set forth in

the ISO New England Manuals. Allocation of costs associated with dynamic scheduling shall be determined and filed with the Commission following the first request.

(d) An entity requesting dynamic scheduling shall be responsible for reserving amounts of appropriate transmission service necessary to deliver the range of the dynamic transfer and any ancillary services.

III.2 LMPs and Real-Time Reserve Clearing Prices Calculation

III.2.1 Introduction.

The ISO shall calculate the price of energy at Nodes, Load Zones and Hubs in the New England Control Area and at External Nodes on the basis of Locational Marginal Prices and shall calculate the price of Operating Reserve in Real-Time for each Reserve Zone on the basis of Real-Time Reserve Clearing Prices as determined in accordance with this Market Rule 1. Locational Marginal Prices for energy shall be calculated on a Day-Ahead basis for each hour of the Day-Ahead Energy Market, and every five minutes during the Operating Day for the Real-Time Energy Market. Real-Time Reserve Clearing Prices shall be calculated on a Real-Time basis every five minutes as part of the joint optimization of energy and Operating Reserve during the Operating Day.

III.2.2 General.

The ISO shall determine the least cost security-constrained unit commitment and dispatch, which is the least costly means of serving load at different Locations in the New England Control Area based on scheduled or actual conditions, as applicable, existing on the power grid and on the prices at which Market Participants have offered to supply and consume energy in the New England Markets. Day-Ahead Locational Marginal Prices for energy for the applicable Locations will be calculated based on the unit commitment and economic dispatch and the prices of energy offers and bids. Real-Time Locational Marginal Prices for energy and Real-Time Reserve Clearing Prices will be calculated based on a jointly optimized economic dispatch of energy and designation of Operating Reserve utilizing the prices of energy offers and bids, and Reserve Constraint Penalty Factors when applicable.

Except as further provided in Section III.2.6, the process for the determination of Locational Marginal Prices shall be as follows:

(a) To determine operating conditions, in the Day-Ahead Energy Market or Real-Time Energy Market, on the New England Transmission System, the ISO shall use a computer model of the interconnected grid that uses scheduled quantities or available metered inputs regarding generator output, loads, and power flows to model remaining flows and conditions, producing a consistent representation of power flows on the network. The computer model employed for this purpose in the Real-Time Energy Market, referred to as the State Estimator program, is a standard industry tool and is described in Section III.2.3. It will be used to obtain information regarding the output of generation supplying energy and Operating Reserve to the New England Control Area, loads at busses in the New England Control Area,

transmission losses, penalty factors, and power flows on binding transmission and interface constraints for use in the calculation of Day-Ahead and Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices. Additional information used in the calculation of Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, including Dispatch Rates, Real-Time Operating Reserve designations and Real-Time schedules for External Transactions, will be obtained from the ISO's dispatch software and dispatchers.

(b) Using the prices at which Market Participants offer and bid energy to the New England Markets, the ISO shall determine the offers and bids of energy that will be considered in the calculation of Day-Ahead Prices, Real-Time Prices and Real-Time Reserve Clearing Prices. During the Operating Day, Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices shall be determined every five minutes and integrated hourly values of such determinations shall be the basis of the settlement of sales and purchases of energy in the Real-Time Energy Market, the settlement associated with the provision of Operating Reserve in Real-Time and the settlement of Congestion Costs and costs for losses under the Transmission, Markets and Services Tariff not covered by the Day-Ahead Energy Market. As described in Section III.2.6, every offer and bid by a Market Participant that is scheduled in the Day-Ahead Energy Market will be utilized in the calculation of Day-Ahead Locational Marginal Prices.

III.2.3 Determination of System Conditions Using the State Estimator.

Power system operations, including, but not limited to, the determination of the least costly means of serving load and system and locational Real-Time Operating Reserve requirements, depend upon the availability of a complete and consistent representation of generator outputs, loads, and power flows on the network. In calculating Day-Ahead Prices, the ISO shall base the system conditions on the expected transmission system configuration and the set of offers and bids submitted by Market Participants. In calculating Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall obtain a complete and consistent description of conditions on the electric network in the New England Control Area by using the power flow solution produced by the State Estimator for the pricing interval, which is also used by the ISO for other functions within power system operations. The State Estimator is a standard industry tool that produces a power flow model based on available Real-Time metering information, information regarding the current status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at Nodes and External Nodes for which Real-Time information is unavailable. In calculating Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall obtain a State Estimator solution every five minutes, which

shall provide the megawatt output of generators and the loads at Locations in the New England Control Area, transmission line losses, penalty factors, and actual flows or loadings on constrained transmission facilities. External Transactions between the New England Control Area and other Control Areas shall be included in the Real-Time Locational Marginal Price calculation on the basis of the Real-Time transaction schedules implemented by the ISO's dispatcher.

III.2.4 [Reserved.].

III.2.5 Calculation of Nodal Real-Time Prices.

(a) The ISO shall determine the least costly means of obtaining energy to serve the next increment of load at each Node internal to the New England Control Area represented in the State Estimator and each External Node Location between the New England Control Area and an adjacent Control Area, based on the system conditions described by the power flow solution produced by the State Estimator for the pricing interval. This calculation shall be made by applying an optimization method to minimize energy cost, given actual system conditions, a set of energy offers and bids, and any binding transmission and Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from all available generating Resources, Demand Response Resources, External Transaction purchases submitted under Section III.1.10.7 and Dispatchable Asset Related Demand Resources with an eligible energy offer as the sum of: (1) the price at which the Market Participant has offered to supply an additional increment of energy from the Resource; (2) the effect on Congestion Costs (whether positive or negative) associated with increasing the output of the Resource or reducing consumption of the Resource, based on the effect of increased generation from that Resource or reduced consumption from that Resource on transmission line loadings; and (3) the effect on Congestion Costs (whether positive or negative) associated with increasing the Operating Reserve requirement, based on the effect of Resource re-dispatch on transmission line loadings; (4) the effect on Congestion Costs (whether positive or negative) associated with a deficiency in Operating Reserve, based on the effect of the Reserve Constraint Penalty Factors described under Section III.2.8; and (5) the effect on transmission losses caused by the increment of load, generation and demand reduction. The energy offer or offers and energy bid or bids that can jointly serve an increment of load and an increment of Operating Reserve requirement at a Location at the lowest cost, calculated in this manner, shall determine the Real-Time Price at that Node or External Node. For an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented, the Real-Time Price at the External Node shall be further adjusted to include the effect on Congestion Costs (whether positive

or negative) associated with a binding constraint limiting the external interface schedule, as determined when the interface is scheduled.

(b) During the Operating Day, the calculation set forth in this Section III.2.5 shall be performed every five minutes, using the ISO's Locational Marginal Price program, producing a set of nodal Real-Time Prices based on system conditions for the pricing interval. The prices produced at five-minute intervals during an hour will be integrated to determine the nodal Real-Time Prices for that hour.

(c) For any interval during any hour in the Operating Day that the ISO has declared a Minimum Generation Emergency, the affected nodal Real-Time Prices calculated under this Section III.2.5. shall be set equal to the Energy Offer Floor for all Nodes within the New England Control Area and all External Nodes if the Minimum Generation Emergency was declared on a New England Control Area wide basis or shall be set equal to the Energy Offer Floor for all Nodes and External Nodes within a sub-region if the Minimum Generation Emergency was declared within the sub-region.

III.2.6 Calculation of Nodal Day-Ahead Prices.

(a) For the Day-Ahead Energy Market, Day-Ahead Prices shall be determined on the basis of the least-cost, security-constrained unit commitment and dispatch, model flows and system conditions resulting from the load specifications submitted by Market Participants, Supply Offers, Demand Reduction Offers and Demand Bids for Resources, Increment Offers, Decrement Bids, and External Transactions submitted to the ISO and scheduled in the Day-Ahead Energy Market.

Such prices shall be determined in accordance with the provisions of this Section applicable to the Day-Ahead Energy Market and shall be the basis for the settlement of purchases and sales of energy, costs for losses and Congestion Costs resulting from the Day-Ahead Energy Market. This calculation shall be made for each hour in the Day-Ahead Energy Market by applying an optimization method to minimize energy cost, given scheduled system conditions, scheduled transmission outages, and any transmission limitations that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from each Resource associated with an eligible energy offer or bid as the sum of: (1) the price at which the Market Participant has offered to supply an additional increment of energy from the Resource or reduce consumption from the Resource; (2) the effect on transmission Congestion Costs (whether positive or negative) associated with increasing the output of the Resource or reducing consumption of the Resource, based on the effect of increased generation from that Resource or reduced consumption from a Resource on transmission line loadings; and (3) the effect on

transmission losses caused by the increment of load and generation. The energy offer or offers and energy bid or bids that can serve an increment of load at a Node or External Node at the lowest cost, calculated in this manner, shall determine the Day-Ahead Price at that Node.

For External Nodes for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented, the clearing process specified in the previous two paragraphs shall apply. For all other External Nodes, the following process shall apply: in addition to determining the quantity cleared via the application of transmission constraints (i.e., limits on the flow over a line or set of lines), the quantity cleared is limited via the application of a nodal constraint (i.e., a limit on the total net injections at a Node) that restricts the net amount of cleared transactions to the transfer capability of the external interface. Clearing prices at all Nodes will reflect the marginal cost of serving the next increment of load at that Node while reflecting transmission constraints. A binding nodal constraint will result in interface limits being followed, but will not directly affect the congestion component of an LMP at an External Node.

(b) Energy deficient conditions. If the sum of Day-Ahead fixed Demand Bids and fixed External Transaction sales cannot be satisfied with the sum of all scheduled External Transaction purchases, cleared Increment Offers, and available generation at its Economic Maximum Limit and demand reduction at the Demand Response Resource's Maximum Reduction, the technical software issues an Emergency Condition warning message due to a shortage of economic supply in the Day-Ahead Energy Market. The following steps shall then be performed to achieve power balance:

(i) All fixed External Transaction sales are considered to be dispatchable at the Energy Offer Cap;

(ii) Reduce any remaining price-sensitive Demand Bids (including External Transaction sales) and Decrement Bids from lowest price to highest price to zero MW until power balance is achieved (there may be some price sensitive bids that are higher priced than the highest Supply Offer or Increment Offer price cleared). Set LMP values equal to the highest price-sensitive Demand Bid or Decrement Bid that was cut in this step. If no price-sensitive Demand Bid or Decrement Bid was reduced in this step, the LMP values are set equal to highest offer price of all on-line generation, dispatched Demand Response Resources, Increment Offers or External Transaction purchases; and

(iii) If power balance is not achieved after step (ii), reduce all remaining fixed Demand Bids proportionately (by ratio of load MW) until balance is achieved. Set LMP values equal to the highest offer price of all on-line generation, dispatched Demand Response Resources, Increment Offers or External Transaction purchases or the price from step (ii), whichever is higher.

(c) Excess energy conditions. If the sum of Day-Ahead cleared Demand Bids, Decrement Bids and External Transaction sales is less than the total system wide generation MW (including fixed External Transaction purchases) with all possible generation off and with all remaining generation at their Economic Minimum Limit, the technical software issues a Minimum Generation Emergency warning message due to an excess of economic generation in the Day-Ahead Energy Market. The following steps shall then be performed to achieve power balance:

(i) All fixed External Transaction purchases are considered to be dispatchable at the Energy Offer Floor and reduced pro-rata, as applicable, until power balance is reached;

(ii) If power balance is not reached in step (i), reduce all committed generation down proportionately by ratio of Economic Minimum Limits but not below Emergency Minimum Limits. If power balance is achieved prior to reaching Emergency Minimum Limits, set LMP values equal to the lowest offer price of all on-line generation; and

(iii) If power balance not achieved in step (ii), set LMP values to Energy Offer Floor and reduce all committed generation below Emergency Minimum Limits proportionately (by ratio of Emergency Minimum Limits) to achieve power balance.

III.2.7 Reliability Regions, Load Zones, Reserve Zones, Zonal Prices and External Nodes.

(a) The ISO shall calculate Zonal Prices for each Load Zone for both the Day-Ahead Energy Market and Real-Time Energy Markets for each hour using a load-weighted average of the Locational Marginal Prices for the Nodes within that Load Zone. The load weights used in calculating the Day-Ahead Zonal Prices for the Load Zone shall be determined in accordance with applicable Market Rule 1 provisions and shall be based on historical load usage patterns. The load weights do not reflect Demand Bids or Decrement Bids that settle at the Node level in the Day-Ahead Energy Market. The ISO shall determine, in accordance with applicable ISO New England Manuals, the load weights used in Real-Time based on

the actual Real-Time load distribution as calculated by the State Estimator, and shall exclude any Asset Related Demand from the load weights used to calculate the applicable Real-Time Zonal Prices.

(b) Each Load Zone shall initially be approximately coterminous with a Reliability Region.

(c) Reserve Zones shall be established by the ISO which represent areas within the New England Transmission System that require local 30 minute contingency response as part of normal system operations in order to satisfy local 2nd contingency response reliability criteria.

(d) The remaining area within the New England Transmission System that is not included within the Reserve Zones established under Section III.2.7(c) is Rest of System.

(e) Each Reserve Zone shall be completely contained within a Load Zone or shall be defined as a subset of the Nodes contained within a Load Zone.

(f) The ISO shall calculate Forward Reserve Clearing Prices and Real-Time Reserve Clearing Prices for each Reserve Zone.

(g) After consulting with the Market Participants, the ISO may reconfigure Reliability Regions, Load Zones and Reserve Zones and add or subtract Reliability Regions, Load Zones and Reserve Zones as necessary over time to reflect changes to the grid, patterns of usage, changes in local TMOR contingency response requirements and intrazonal Congestion. The ISO shall file any such changes with the Commission.

(h) In the event the ISO makes changes to a Reliability Region or Load Zone or adds or subtracts Reliability Regions and Load Zones, for settlement purposes and to the extent practicable, Load Assets that are physically located in one Reliability Region and electrically located within another Reliability Region shall be located within the Reliability Region to which they are electrically located.

(i) External Nodes are the nodes at which External Transactions settle. As appropriate and after consulting with Market Participants, the ISO will establish and re-configure External Nodes taking into consideration appropriate factors, which may include: tie line operational matters, FTR modeling and auction assumptions, market power issues associated with external contractual arrangements, impacts on Locational Marginal Prices, and inter-regional trading impacts.

(j) On or about the 20th calendar day of each month, the ISO shall publish the Real-Time nodal load weights (expressed in MW) used to calculate the load-weighted Real-Time Zonal Prices for the preceding month. Nodal load weights will be published for all nodes used in the calculations except for those nodes identified by customers as nodes for which publication would provide individual customer usage data. Any individual customer whose usage data would be revealed by publication of load weight information associated with a specific Node must submit a written request to the ISO to omit the applicable Node from the publication requirement. The request must identify the affected Node and, to the best of the customer's knowledge, the number of customers taking service at the affected Node and the estimated percentage of the total annual load (MWh) at the affected Node period that is attributable to the customer. The information contained in the request must be certified in writing by an officer of the customer's company (if applicable), by an affidavit signed by a person having knowledge of the applicable facts, or by representation of counsel for the customer. The ISO will grant a customer request if it determines based on the information provided that no more than two customers are taking service at the affected Node or that the percentage of the customer's annual load (MWh) at the affected Node. If a customer request is granted and that customer request is the only such customer request within a Load Zone, then the ISO shall randomly select one other Node and not disclose hourly load information for the randomly selected Node unless and until another customer request within the Load Zone is granted. A request to suspend publication for a month must be received by the ISO on or before the 10th calendar day of the following month in order to be effective for that month. Upon receipt of a request, the ISO will suspend publication of the load weight data for the specified Node. The ISO may, from time to time, require customer confirmation that continued omission from publication of load weight data for a particular Node is required in order to avoid disclosure of individual customer usage data. If customer confirmation is not received within a reasonable period not to exceed 30 days, the ISO may publish load weight data for the applicable Node.

III.2.7A Calculation of Real-Time Reserve Clearing Prices.

(a) The ISO shall determine the least costly means of obtaining Operating Reserve in Real-Time to serve the next increment of Operating Reserve requirement for each Reserve Zone on a jointly optimized basis with the calculation of nodal Real-Time Prices specified under Section III.2.5, based on the system conditions described by the power flow solution produced by the State Estimator program for the pricing interval. This calculation shall be made by applying an optimization method to minimize energy cost, given actual system conditions, a set of energy offers and bids, and any binding transmission constraints, including binding transmission interface constraints associated with meeting Operating Reserve

requirements, and binding Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate, on a jointly optimized basis with serving an increment of load at each Node and External Node, the cost of serving an increment of Operating Reserve requirement for the system and each Reserve Zone from all available generating Resources, Demand Response Resources and Dispatchable Asset Related Demand Resources with an eligible energy offer or bid. Real-Time Reserve Clearing Prices will be equal to zero unless system re-dispatch is required in order to create additional TMSR to meet the system TMSR requirement; or system re-dispatch is required in order to make additional TMOR available to meet a local TMOR requirement; or system re-dispatch is required to make additional TMNSR or TMOR available to meet system TMNSR or TMOR requirements; or there is a deficiency in available Operating Reserve, in which case, Real-Time Reserve Clearing Prices shall be set based upon the Reserve Constraint Penalty Factors specified in Section III.2.7A(c).

(b) If system re-dispatch is required to maintain sufficient levels of Operating Reserve or local TMOR, the applicable Real-Time Reserve Clearing Price is equal to the highest unit-specific Real-Time Reserve Opportunity Cost associated with all generating Resources, Demand Response Resources and Dispatchable Asset Related Demand Resources that were re-dispatched to meet the applicable Operating Reserve requirement. The Operating Reserve or local TMOR Real-Time Reserve Opportunity Cost of a Resource shall be determined for each Resource that the ISO re-dispatches in order to provide additional Operating Reserve or local TMOR and shall be equal to the difference between (i) the Real-Time Energy LMP at the Location for the generating Resource, Demand Response Resource or Dispatchable Asset Related Demand Resource and (ii) the offer price associated with the re-dispatch of the Resource necessary to create the additional Operating Reserve or local TMOR from the Resource's expected output, consumption, or demand reduction level if it had been dispatched in economic merit order.

(c) If there is insufficient Operating Reserve available to meet the Operating Reserve requirements for the system and/or any Reserve Zone or sufficient Operating Reserve is not available at a redispatch cost equal to or less than that specified by the Reserve Constraint Penalty Factors, the applicable Real-Time Reserve Clearing Prices shall be set based upon Reserve Constraint Penalty Factors. The Reserve Constraint Penalty Factors are inputs into the linear programming algorithm that will be utilized by the linear programming algorithm when Operating Reserve constraints are violated, requiring that the constraints be relaxed to allow the linear programming algorithm to solve. The Real-Time Reserve Clearing Prices shall be set based upon the following Reserve Constraint Penalty Factor values:

Requirement	Requirement Sub-Category	RCPF
Local TMOR		$250/MWh
System TMOR	minimum TMOR	$1000/MWh
	Replacement Reserve	$250/MWh
System TMNSR		$1500/MWh
System TMSR		$50/MWh

The RCPFs shall be applied in a manner that is consistent with the price cascading described in Section III.2.7A(d).

(d) Real-Time Reserve designations and Real-Time Reserve Clearing Prices shall be calculated in such a manner to ensure that excess Real-Time Operating Reserve capability will cascade down for use in meeting any remaining Real-Time Operating Reserve Requirements from TMSR to TMNSR to TMOR and that the pricing of Real-Time Operating Reserve shall cascade up from TMOR to TMNSR to TMSR.

(e) During the Operating Day, the calculation set forth in this Section III.2.7A shall be performed every five minutes, using the ISO's Unit Dispatch System and Locational Marginal Price program, producing a set of nodal Real-Time Reserve Clearing Prices based on system conditions for the pricing interval. The prices produced at five-minute intervals during an hour will be integrated to determine the Real-Time Reserve Clearing Prices for the system and/or each Reserve Zone for that hour to be used in settlements.

III.2.8 Hubs and Hub Prices.

(a) On behalf of the Market Participants, the ISO shall maintain and facilitate the use of a Hub or Hubs for the Day-Ahead Energy Market and Real-Time Energy Market, comprised of a set of Nodes within the New England Control Area, which Nodes shall be identified by the ISO on its internet website. The ISO has used the following criteria to establish an initial Hub and shall use the same criteria to establish any additional Hubs:

(i) Each Hub shall contain a sufficient number of Nodes to try to ensure that a Hub Price can be calculated for that Hub at all times;

(ii) Each Hub shall contain a sufficient number of Nodes to ensure that the unavailability of, or an adjacent line outage to, any one Node or set of Nodes would have only a minor impact on the Hub Price;

(iii) Each Hub shall consist of Nodes with a relatively high rate of service availability;

(iv) Each Hub shall consist of Nodes among which transmission service is relatively unconstrained; and

(v) No Hub shall consist of a set of Nodes for which directly connected load and/or generation at that set of Nodes is dominated by any one entity or its Affiliates.

(b) The ISO shall calculate and publish hourly Hub Prices for both the Day-Ahead and Real-Time Energy Markets based upon the arithmetic average of the Locational Marginal Prices of the nodes that comprise the Hub.

III.2.9A Final Real Time Prices, Real-Time Reserve Clearing and Regulation Clearing Prices.

(a) The ISO normally will post provisional Real-Time Prices, Real-Time Reserve Clearing Prices and Regulation clearing prices in Real-Time or soon thereafter. The ISO shall post the final Real-Time Prices, final Real-Time Reserve Clearing Prices and final Regulation clearing prices as soon as practicable following the Operating Day, in accordance with the timeframes specified in the ISO New England Manuals, except that the posting of such final Real-Time Prices, final Real-Time Reserve Clearing Prices and final Regulation clearing prices by the ISO shall not exceed five business days from the applicable Operating Day. If the ISO is not able to calculate Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation clearing prices normally due to human error, hardware, software, or telecommunication problems that cannot be remedied in a timely manner, the ISO will calculate Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation clearing prices as soon as practicable using the best data available; provided, however, in the event that the ISO is unable to calculate and post final Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation clearing prices due to exigent circumstances not contemplated in this market rule, the ISO shall make an emergency filing with the Commission within five business days from the applicable Operating Day detailing the exigent circumstance, which will not allow the final clearing prices to be calculated and posted, along with a proposed resolution including a timeline to post final clearing prices.

(b) The permissibility of correction of errors in Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation clearing prices for an Operating Day due to database, software or similar errors of the ISO or its systems, and the timeframes and procedures for permitted corrections, are addressed solely in this Section III.2.9A and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.2.9B Final Day-Ahead Energy Market Results

(a) Day-Ahead Energy Market results are final when published except as provided in this subsection. If the ISO determines based on reasonable belief that there may be one or more errors in the Day-Ahead Energy Market results for an Operating Day or if no Day-Ahead Energy Market results are available due to human error, database, software or similar errors of the ISO or its systems, the ISO shall post on the ISO website prior to 12:01 a.m. of the applicable Operating Day, a notice that the results are provisional and subject to correction or unavailable for initial publishing. Any Day-Ahead Energy Market results for which no notice is posted shall be final and not subject to correction or other adjustment, and shall be used for purposes of settlement. The ISO shall confirm within three business days of the close of the applicable Operating Day whether there was an error in any provisional Day-Ahead Energy Market results and shall post a notice stating its findings.

(b) The ISO will publish corrected Day-Ahead Energy Market results within three business days of the close of the applicable Operating Day or the results of the Day-Ahead Energy Market for the Operating Day will stand; provided, however, in the event that the ISO is unable to calculate and post final Day-Ahead Energy Market Results due to exigent circumstances not contemplated in this market rule, the ISO shall make an emergency filing with the Commission within five business days from the applicable Operating Day detailing the exigent circumstance, which will not allow the final prices to be calculated and posted, along with a proposed resolution including a timeline to post final prices. The ISO shall also publish a statement describing the nature of the error and the method used to correct the results.

(c) If the ISO determines in accordance with subsection (a) that there are one or more errors in the Day-Ahead Energy Market results for an Operating Day, the ISO shall calculate corrected Day-Ahead Energy Market results by determining and substituting for the initial results, final results that reasonably reflect how the results would have been calculated but for the errors. To the extent that it is necessary, reasonable and practicable to do so, the ISO may specify an allocation of any costs that are not otherwise allocable under applicable provisions of Market Rule 1. The ISO shall use the corrected results for purposes of settlement.

(d) For every change in the Day-Ahead Energy Market results made pursuant to Section III.2.9B, the ISO will prepare and submit, as soon as practicable, an informational report to the Commission describing the nature of any errors, the precise remedy administered, the method of determining corrected prices and allocating any costs, and any remedial actions that will be taken to avoid similar errors in the future.

(e) The permissibility of correction of errors in Day-Ahead Energy Market results, and the timeframes and procedures for permitted corrections, are addressed solely in this Section III.2.9B and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.3 Accounting And Billing

III.3.1 Introduction.

This Section III.3 sets forth the accounting and billing principles and procedures for the purchase and sale of services in the New England Markets and for the operation of the New England Control Area; provided that Section III.E2.9 sets forth the Day-Ahead Energy Market and Real-Time Energy Market settlement rules for Demand Response Resources.

III.3.2 Market Participants.

III.3.2.1 ISO Energy Market.

For purposes of establishing the following positions, unless otherwise expressly stated, the settlement interval for external interfaces for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented shall be 15 minutes, and the settlement interval for all other Locations shall be one hour.

(a) For each Market Participant for each hour, the ISO will determine a Day-Ahead Energy Market position representing that Market Participant's net purchases from or sales to the Day-Ahead Energy Market as follows.

(i) **Day-Ahead Load Obligation** – Each Market Participant shall have for each hour a Day-Ahead Load Obligation for energy at each Location equal to the MWhs of its Demand Bids, Decrement Bids and External Transaction sales accepted by the ISO in the Day-Ahead Energy Market at that Location and such Day-Ahead Load Obligation shall have a negative value.

(ii) **Day-Ahead Generation Obligation** – Each Market Participant shall have for each hour a Day-Ahead Generation Obligation for energy at each Location equal to the MWhs of its generation Supply Offers, Increment Offers and External Transaction purchases accepted by the ISO in the Day-Ahead Energy Market at that Location and such Day-Ahead Generation Obligation shall have a positive value.

(iii) **Day-Ahead Adjusted Load Obligation** – Each Market Participant shall have for each hour a Day-Ahead Adjusted Load Obligation at each Location equal to the Day-Ahead Load Obligation adjusted by any applicable Day-Ahead internal bilateral transactions at that Location.

(iv) **Day-Ahead Locational Adjusted Net Interchange** – Each Market Participant shall have for each hour a Day-Ahead Locational Adjusted Net Interchange at each Location equal to the Day-Ahead Adjusted Load Obligation plus the Day-Ahead Generation Obligation at that Location

(b) For each Market Participant for each settlement interval, the ISO will determine a Real-Time Energy Market position. For purposes of these calculations, if the settlement interval is less than one hour, any internal bilateral transaction shall be equally apportioned over the settlement intervals within the hour. To accomplish this, the ISO will perform calculations to determine the following:

(i) **Real-Time Load Obligation** – Each Market Participant shall have for each settlement interval a Real-Time Load Obligation for energy at each Location equal to the MWhs of load, where such MWhs of load shall include External Transaction sales and shall have a negative value, at that Location, adjusted for any applicable internal bilateral transactions which transfer Real-Time load obligations.

(ii) **Real-Time Generation Obligation** – Each Market Participant shall have for each settlement interval a Real-Time Generation Obligation for energy at each Location. The Real-Time Generation Obligation shall equal the MWhs of energy, where such MWhs of energy shall have positive value, provided by generating Resources, External Resources, and External Transaction purchases at that Location.

(iii) **Real-Time Adjusted Load Obligation** – Each Market Participant shall have for each settlement interval a Real-Time Adjusted Load Obligation at each Location equal to the Real-Time Load Obligation adjusted by any applicable energy related internal Real-Time bilateral transactions at that Location.

(iv) **Real-Time Locational Adjusted Net Interchange** – Each Market Participant shall have for each settlement interval a Real-Time Locational Adjusted Net Interchange at each Location equal to the Real-Time Adjusted Load Obligation plus the Real-Time Generation Obligation at that Location.

(v) **Marginal Loss Revenue Load Obligation** – Each Market Participant shall have for each settlement interval a Marginal Loss Revenue Load Obligation at each Location equal to the Real-Time Load Obligation adjusted by any energy related internal Real-Time bilateral transactions at that Location that the parties to those bilateral transactions have elected to include in their Marginal Loss Revenue Load Obligation for the purpose of allocating Day-Ahead Loss Revenue and Real-Time Loss Revenue. Contributions from Coordinated External Transactions shall be excluded from the Real-Time Load Obligation for purposes of determining Marginal Loss Revenue Load Obligation.

(c) For each Market Participant for eachsettlement interval, the ISO will determine the difference between the Day-Ahead Energy Market position (calculated in accordance with Section III.3.2.1(a)) and the Real-Time Energy Market position (calculated in accordance with Section III.3.2.1(b)) representing that Market Participant's net purchases from or sales to the Real-Time Energy Market. For purposes of this calculation, if the Real-Time settlement interval is less than one hour, the Day-Ahead position shall be equally apportioned over the settlement intervals within the hour. To accomplish this, the ISO will perform calculations to determine the following:

(i) **Real-Time Load Obligation Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Load Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Load Obligation and the Day-Ahead Load Obligation.

(ii) **Real-Time Generation Obligation Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Generation Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Generation Obligation and the Day-Ahead Generation Obligation.

(iii) **Real-Time Adjusted Load Obligation Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Adjusted Load Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Adjusted Load Obligation and the Day-Ahead Adjusted Load Obligation.

(iv) **Real-Time Locational Adjusted Net Interchange Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Locational Adjusted Net Interchange

Deviation at each Location equal to the difference in MWhs between the Real-Time Locational Adjusted Net Interchange and the Day-Ahead Locational Adjusted Net Interchange.

(d) For each Market Participant for each hour, the ISO will determine Day-Ahead Energy Market monetary positions representing a charge or credit for its net purchases from or sales to the ISO Day-Ahead Energy Market. The Day-Ahead Energy Market Energy Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Energy Component of the associated Day-Ahead Locational Marginal Prices. The Day-Ahead Energy Market Congestion Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Congestion Component of the associated Day-Ahead Locational Marginal Prices. The Day-Ahead Energy Market Loss Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Loss Component of the associated Day-Ahead Locational Marginal Prices.

(e) For each Market Participant for each settlement interval, the ISO will determine Real-Time Energy Market monetary positions representing a charge or credit to the Market Participant for its net purchases from or sales to the Real-Time Energy Market. The Real-Time Energy Market Deviation Energy Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Energy Component of the Real-Time Locational Marginal Prices. The Real-Time Energy Market Deviation Congestion Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Congestion Component of the associated Real-Time Locational Marginal Prices.

The Real-Time Energy Market Deviation Loss Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Loss Component of the associated Real-Time Locational Marginal Prices.

(f) For each hour, the ISO will determine the total revenues associated with transmission congestion on the New England Transmission System. To accomplish this, the ISO will perform calculations to determine the following. The Day-Ahead Congestion Revenue shall equal the sum of all Market Participants' Day-Ahead Energy Market Congestion Charge/Credits. The Real-Time Congestion

Revenue shall equal the sum of all Market Participants' Real-Time Energy Market Congestion Charge/Credits.

(g) For each hour, the ISO will determine the excess or deficiency in loss revenue associated with the Day-Ahead Energy Market. The Day-Ahead Loss Revenue shall be equal to the sum of all Market Participants' Day-Ahead Energy Market Energy Charge/Credits and Day-Ahead Energy Market Loss Charge/Credits.

(h) For each hour for each Market Participant, the ISO shall calculate a Day-Ahead payment or charge associated with the excess or deficiency in loss revenue (Section III.3.2.1(g)). The Day-Ahead Loss Charges or Credits shall be equal to the Day-Ahead Loss Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Marginal Loss Revenue Load Obligations.

(i) For each hour, the ISO will determine the excess or deficiency in loss revenue associated with the Real-Time Energy Market. The Real-Time Loss Revenue shall be equal to the sum of all Market Participants' Real-Time Energy Market Deviation Energy Charge/Credit and Real-Time Energy Market Deviation Loss Charge/Credit plus Non-Market Participant Transmission Customer loss costs. The ISO will then adjust Real-Time Loss Revenue to account for Inadvertent Energy Revenue, as calculated under Section III.3.2.1(k) and Emergency transactions as described under Section III.4.3(a).

(j) Non-Market Participant Transmission Customer loss costs shall be assessed for transmission use scheduled in the Real-Time Energy Market, calculated as the amount to be delivered in each settlement interval multiplied by the difference between the Loss Component of the Real-Time Price at the delivery point or New England Control Area boundary delivery interface and the Loss Component of the Real-Time Price at the source point or New England Control Area boundary source interface.

(k) For each ~~settlement interval~~hour, the ISO will calculate an excess or deficiency in Inadvertent Energy Revenue by multiplying the Inadvertent Interchange at each External Node by the associated Real-Time Locational Marginal Price. The resulting excess or deficiency in Inadvertent Energy Revenue at each External Node shall then be summed to determine a single hourly value for all External Nodes.

(l) For each hour for each Market Participant, the ISO shall calculate a Real-Time payment or charge associated with the excess or deficiency in Inadvertent Energy Revenue (Section III.3.2.1(k)). The

Inadvertent Energy Revenue Charges or Credits shall be equal to the Inadvertent Energy Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Real-Time Load Obligations and Real-Time Generation Obligations over all Locations, measured as absolute values, excluding contributions to Real-Time Load Obligations and Real-Time Generation Obligations from Coordinated External Transactions.

(m) For each hour for each Market Participant, the ISO shall calculate a Real-Time payment or charge associated with the excess or deficiency in Real-Time Loss Revenue (Section III.3.2.1(i)). The Real-Time Loss Revenue Charges or Credits shall be equal to the Real-Time Loss Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Marginal Loss Revenue Load Obligations.

III.3.2.2 [Reserved.]

III.3.2.3 NCPC Credits and Charges.

A Market Participant's NCPC Credits and NCPC Charges are calculated pursuant to Appendix F to Market Rule 1.

III.3.2.4 Transmission Congestion.

Market Participants shall be charged or credited for Congestion Costs as specified in Section III.3.2.1(f) of this Market Rule 1.

III.3.2.5 [Reserved.]

III.3.2.6 Emergency Energy.

(a) Hourly net costs in excess of Real-Time Prices attributable to the purchase of Emergency energy from other Control Areas shall be allocated to Market Participants based on the following hourly deviations where such deviations are negative: (i) Real-Time Adjusted Load Obligation Deviations during that Operating Day; (ii) generation deviations and demand reduction deviations for Pool-Scheduled Resources not following ISO dispatch instructions, Self-Scheduled Resources with dispatchable increments above their Self-Scheduled amounts not following ISO dispatch instructions and Self-Scheduled Resources not following their Day-Ahead Self-Scheduled amounts other than those Self-Scheduled Resources that are following ISO dispatch instructions, including External Resources, in MWhs during the Operating Day; and (iii) deviations from the Day-Ahead Energy Market for External

Transaction purchases in MWhs during the Operating Day except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency energy purchases are not included in this calculation. As provided for in the ISO New England Manuals, generating Resources and Demand Response Resources shall have a 5% or 5 MWh threshold when determining such deviations. Notwithstanding the foregoing, the allocation of costs attributable to the purchase of Emergency energy from other Control Areas shall exclude contributions to deviations from Coordinated External Transactions.

(b) Hourly net revenues in excess of Real-Time Prices attributable to the sale of Emergency energy to other Control Areas shall be credited to Market Participants based on the following deviations where such deviations are negative: (i) Real-Time Adjusted Load Obligation Deviations in MWhs during that Operating Day; (ii) generation deviations and demand reduction deviations for Pool-Scheduled Resources following ISO dispatch instructions and Self-Scheduled generating Resources with dispatchable increments above their Self-Scheduled amounts following ISO dispatch instructions, including External Resources, in MWhs during the Operating Day; and (iii) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency energy purchases are not included in this calculation. As provided for in the ISO New England Manuals, generating Resources and Demand Response Resources shall have a 5% or 5 MWh threshold when determining such deviations. Notwithstanding the foregoing, the calculation of the credit for the sale of Emergency energy to other Control Areas shall exclude contributions to deviations from Coordinated External Transactions.

III.3.2.6A New Brunswick Security Energy.

New Brunswick Security Energy is energy that is purchased from the New Brunswick System Operator by New England to preserve minimum flows on the Orrington-Keswick (396/3001) tie line and Orrington-Lepreau (390/3016) tie line in accordance with the applicable ISO / New Brunswick System Operator transmission operating guide with respect to the determination of minimum transfer limits. New Brunswick Security Energy costs are hourly costs in excess of the LMP at the applicable External Node attributable to purchases of New Brunswick Security Energy by New England. New Brunswick Security Energy costs shall be allocated among Market Participants on the basis of their pro-rata shares of Regional Network Load or in such other manner as may be described in ISO New England Manual M-28 (Market Rule 1 Accounting). Where the LMP at the applicable External Node exceeds the New Brunswick Security Energy costs, such amounts shall be accounted for in accordance with Section III.3.2.1(m).

III.3.2.7 Billing.

The ISO shall prepare a billing statement each billing cycle, in accordance with the ISO New England Billing Policy, for each Market Participant in accordance with the charges and credits specified in Sections III.3.2.1 through III.3.2.6 and Section III.E2, and showing the net amount to be paid or received by the Market Participant. Billing statements shall provide sufficient detail, as specified in the ISO New England Manuals, ISO New England Administrative Procedures and the ISO New England Billing Policy, to allow verification of the billing amounts and completion of the Market Participant's internal accounting. Billing disputes shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

III.3.3 [Reserved.]

III.3.4 Non-Market Participant Transmission Customers.

III.3.4.1 Transmission Congestion.

Non-Market Participant Transmission Customers shall be charged or credited for Congestion Costs as specified in Section III.1 of this Market Rule 1.

III.3.4.2 Transmission Losses.

Non-Market Participant Transmission Customers shall be charged or credited for transmission losses in an amount equal to the product of (i) the Transmission Customer's MWhs of deliveries in the Real-Time Energy Market, multiplied by (ii) the difference between the Loss Components of the Real-Time Locational Marginal Prices at the point-of-receipt and the point-of-delivery Locations.

III.3.4.3 Billing.

The ISO shall prepare a billing statement each billing cycle, in accordance with the ISO New England Billing Policy, for each Non-Market Participant Transmission Customer in accordance with the charges and credits specified in Sections III.3.4.1 through III.3.4.2 of this Market Rule 1, and showing the net amount to be paid or received by the Non-Market Participant Transmission Customer. Billing statements shall provide sufficient detail, as specified in the ISO New England Manuals, the ISO New England Administrative Procedures and the ISO New England Billing Policy, to allow verification of the billing amounts and completion of the Non-Market Participant Transmission Customer's internal accounting.

Billing disputes shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

III.3.5 [Reserved.]

III.3.6 Data Reconciliation.

III.3.6.1 Data Correction Billing.

The ISO will reconcile Market Participant data errors and corrections after the Correction Limit for such data has passed. The Correction Limit for meter data and for ISO errors in the processing of meter and other Market Participant data is 101 days from the last Operating Day of the month to which the data applied. Notification of Meter Data Errors applicable to Assigned Meter Reader or Host Participant Assigned Meter Reader supplied meter data must be submitted to the ISO by the Meter Data Error RBA Submission Limit.

III.3.6.2 Eligible Data.

The ISO will accept revised hourly asset meter readings from Assigned Meter Readers and Host Participant Assigned Meter Readers, daily Coincident Peak Contribution values from Assigned Meter Readers, and new or revised internal bilateral transactions from Market Participants. No other revised data will be accepted for use in settlement recalculations. The ISO will correct data handling errors associated with other Market Participant supplied data to the extent that such data did not impact unit commitment or the Real-Time dispatch. Data handling errors that impacted unit commitment or the Real-Time dispatch will not be corrected.

III.3.6.3 Data Revisions.

The ISO will accept revisions to asset specific meter data, daily Coincident Peak Contribution values, and internal bilateral transactions prior to the Correction Limit. No revisions to other Market Participant data will be accepted after the deadlines for submittal of that data have passed, except as provided in Section III.3.8 of Market Rule 1. If the ISO discovers a data error or if a Market Participant discovers and notifies the ISO of a data error prior to the Correction Limit, revised hourly data will be used to recalculate all markets and charges as appropriate, including but not limited to energy, NCPC, Regulation, Operating Reserves, Auction Revenue Rights allocations, Forward Capacity Market, cost-of-service agreements, and the ISO Tariff. No settlement recalculations or other adjustments may be made if the Correction Limit for the Operating Day to which the error applied has passed or if the correction does not qualify for treatment as a Meter Data Error correction pursuant to Section III.3.8 of Market Rule 1.

III.3.6.4 Meter Corrections Between Control Areas.

For revisions to meter data associated with assets that connect the New England Control Area to other Control Areas, the ISO will, in addition to performing settlement recalculations, adjust the actual interchange between the New England Control Area and the other Control Area to maintain an accurate record of inadvertent energy flow.

III.3.6.5 Meter Correction Data.

(a) Revised meter data and daily Coincident Peak Contribution values shall be submitted to the ISO as soon as it is available and not later than the Correction Limit, and must be submitted in accordance with the criteria specified in Section III.3.7 of Market Rule 1. Specific data submittal deadlines are detailed in the ISO New England Manuals.

(b) Errors on the part of the ISO in the administration of Market Participant supplied data shall be brought to the attention of the ISO as soon as possible and not later than the Correction Limit.

III.3.7 Eligibility for Billing Adjustments.

(a) Errors in Market Participant's statements resulting from errors in settlement software, errors in data entry by ISO personnel, and settlement production problems, that do not affect the day-ahead schedule or real-time system dispatch, will be corrected as promptly as practicable. If errors are identified prior to the issuance of final statements, the market will be resettled based on the corrected information.

(b) Calculations made by scheduling or dispatch software, operational decisions involving ISO discretion which affect scheduling or real-time operation, and the ISO's execution of mandatory dispatch directions, such as self-schedules or external contract conditions, are not subject to retroactive correction and resettlement. The ISO will settle and bill the Day-Ahead Energy Market as actually scheduled and the Real-Time Energy Market as actually dispatched. Any post-settlement issues raised concerning operating decisions related to these markets will be corrected through revision of operations procedures and guidelines on a prospective basis.

(c) While errors in reporting hourly metered data may be corrected (pursuant to Section III.3.8), Market Participants have the responsibility to ensure the correctness of all data they submit to the market settlement system.

(d) Disputes between Market Participants regarding settlement of internal bilateral transactions shall not be subject to adjustment by the ISO, but shall be resolved directly by the Market Participants unless they involve an error by the ISO that is subject to resolution under Section III.3.7(a).

(e) Billing disputes between Market Participants and the ISO or Non-Market Participants and the ISO shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

(f) Criteria for Meter Data Errors to be eligible for a Requested Billing Adjustment. In order to be eligible to submit a Requested Billing Adjustment due to a Meter Data Error on an Invoice issued by the ISO after the completion of the Data Reconciliation Process, a Market Participant must satisfy one of the following two conditions: (1) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or the Host Participant Assigned Meter Reader and communicated to the Host Participant Assigned Meter Reader no later than thirty-six (36) days prior to the Correction Limit for Directly Metered Assets and no later than two (2) days prior to the Correction Limit for Profiled Load Assets and could not be resolved prior to those deadlines; or (2) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or Host Participant Assigned Meter Reader and reported to the ISO by the Meter Data Error RBA Submission Limit, and such Meter Data Error represents an error that is equal to or greater than the 1,000 MWh per Asset over a calendar month. If the Meter Data Error affects more than one metering domain, the ISO, and affected Host Participant Assigned Meter Readers and affected Assigned Meter Readers of affected metering domains, must be notified.

III.3.8 Correction of Meter Data Errors

(a) Any Market Participant, Assigned Meter Reader or Host Participant Assigned Meter Reader may submit notification of a Meter Data Error in accordance with the procedures provided in this Section III.3.8, provided that the notification is submitted no later than the Meter Data Error RBA Submission Limit and that the notice must be submitted using the RBA form for Meter Data Errors posted on the ISO's website.

(b) Within three Business Days of the receipt by the ISO's Chief Financial Officer of an RBA form for a Meter Data Error, the ISO shall prepare and submit to all Covered Entities and to the Chair of the NEPOOL Budget and Finance Subcommittee a notice of the Meter Data Error correction ("Notice of Meter Data Error Correction"), including, subject to the provisions of the ISO New England Information Policy, the specific details of the correction and the identity of the affected metering domains and the affected Host Participant Assigned Meter Readers. The "Notice of Meter Data Error Correction" shall

identify a specific representative of the ISO to whom all communications regarding the matter are to be sent.

(c) In order for a Meter Data Error on an Invoice issued by the ISO after the completion of the Data Reconciliation Process to be eligible for correction, the Meter Data Error must satisfy one of the following conditions: (1) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or the Host Participant Assigned Meter Reader and communicated to the Host Participant Assigned Meter Reader no later than 36 days prior to the Correction Limit for Directly Metered Assets and no later than two days prior to the Correction Limit for Profiled Load Assets and could not be resolved prior to those deadlines; (2) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or Host Participant Assigned Meter Reader, and such Meter Data Error represents an error that is equal to or greater than the 1,000 MWh per asset over a calendar month; and (3) if the Meter Data Error involves only Coincident Peak Contribution values, the average of the daily Meter Data Errors involving Coincident Peak Contribution values for the affected calendar month must be greater than or equal to 5 MW for an affected asset. If the Meter Data Error affects more than one metering domain, the ISO, and affected Host Participant Assigned Meter Readers and affected Assigned Meter Readers of affected metering domains, must be notified.

(d) For a Meter Data Error, the Host Participant Assigned Meter Reader must submit to the ISO corrected meter data for Directly Metered Assets prior to the 46th calendar day after the Meter Data Error RBA Submission Limit. Corrected metered data for Profiled Load Assets and Coincident Peak Contribution values, must be submitted to the ISO by the Host Participant Assigned Meter Reader prior to the 87th calendar day after the Meter Data Error RBA Submission Limit. Corrected internal bilateral transactions data must be submitted to the ISO by a Market Participant prior to the 91st calendar day after the Meter Data Error RBA Submission Limit.

Any corrected data received after the specified deadlines is not eligible for use in the settlement process.

The Host Participant Assigned Meter Reader or Market Participant, as applicable, must confirm as part of its submission of corrected data that the eligibility criteria described in Section III.3.8(c) of Market Rule 1 have been satisfied.

To the extent that the correction of a Meter Data Error is for a Directly Metered Asset that affects multiple metering domains, all affected Host Participant Assigned Meter Readers or Assigned Meter

Readers must notify the ISO prior to the 46th calendar day after the Meter Data Error RBA Submission Limit that the corrected Directly Metered Asset data is acceptable to them in order for the ISO to use the corrected data in the final settlement calculations. The Host Participant Assigned Meter Reader for the Directly Metered Asset is responsible for initiating an e-mail to every affected Host Participant Assigned Meter Reader or Assigned Meter Reader in order to obtain such acceptance and shall coordinate delivery of such acceptance to the ISO. The Host Participant Assigned Meter Reader for the Directly Metered Asset is also responsible for submitting all corrected and agreed upon Directly Metered Asset data to the ISO prior to the 46th calendar day after the Meter Data Error RBA Submission Limit.

(e) After the submission of corrected meter and internal bilateral transactions data, the ISO will have a minimum of 30 calendar days to administer the final settlement based on that data. Revised data will be used to recalculate all charges and credits, except that revised data will not be used to recalculate the PER adjustment, including the Hourly PER and Monthly PER values. Revised data will also not be used to recalculate Demand Resource Seasonal Peak Hours. The results of the final settlement will then be included in the next Invoice containing Non-Hourly Charges and the ISO will provide to the Chair of the NEPOOL Budget and Finance Subcommittee written notification that the final settlement has been administered.

III.14 Regulation Market.

III.14.1 Regulation Market System Requirements.

The Regulation Capacity Requirement and Regulation Service Requirement are determined based on historical control performance and compliance with NERC and NPCC control standards. The Regulation Capacity Requirement and Regulation Service Requirement will be published on the ISO's website.

During abnormal system conditions, the ISO may deviate from the Regulation Capacity Requirement or Regulation Service Requirement to maintain system reliability.

III.14.2 Regulation Market Eligibility.

To be eligible to provide Regulation, a Resource must satisfy the following conditions:

(a) Physical Parameters.

(i) Automatic Response Rate.

(1) The minimum Automatic Response Rate is 1 MW/minute.

(ii) Regulation Capacity.

(1) The minimum Regulation Capacity of a generating unit will be determined based on unit size and operating characteristics and must be greater than or equal to: (a) 5 megawatts, and; (b) two times the generating unit's AGC SetPoint Deadband plus one.

(2) The minimum Regulation Capacity of a Resource that is not a generating unit is no less than one megawatt after aggregation.

(b) Regulation Technical Requirements.

A Resource providing Regulation must:

(i) be located within the New England Control Area.

(ii) meet the technical requirements specified in ISO New England Operating Procedure No. 14, Technical Requirements for Generators, Demand Resources and Asset Related Demands and ISO New England Operating Procedure No. 18, Metering and Telemetering Criteria.

(iii) be capable of receiving and following AGC SetPoints sent electronically at four-second intervals.

(iv) have a demonstrated capability to reliably follow Dispatch Instructions, consistent with normal operating characteristics and physical offer parameters, including Regulation Capacity

and Automatic Response Rate. Resources without an operational history of providing Regulation must establish and demonstrate this capability as follows:

(1) Demand Response Regulation Resources, Dispatchable Asset Related Demand, Alternative Technology Regulation Resources and any Resource with less than one-hour sustainability must participate in the Regulation test environment specified in Section III.14.9.

(2) All Resources must satisfy a minimum responsiveness test that demonstrates that a Resource can follow AGC SetPoints.

(c) Aggregation.

Non-generation sub-resources less than one megawatt in size may be aggregated into a single Resource to meet the Regulation Market eligibility requirements specified in Section III.14.2.

A single AGC SetPoint will be sent every AGC cycle to the aggregated Resource. A Market Participant with an aggregated Resource is responsible for management and control of the individual, aggregated sub-resources to ensure an accurate aggregate response to the AGC SetPoint. The sub-resources may be geographically dispersed, provided:

(i) all of the sub-resources are located within the New England Control Area

(ii) the sub-resources are metered and recorded in a manner that allows real-time performance to be measured against Dispatch Instructions and provides for the retention of the recorded information for purposes of verification, accounting for any performance offsets from other loads, generation or devices under the direct or indirect control of the aggregator as specified in ISO New England Operating Procedure No. 18, Metering and Telemetering Criteria.

(iii) communications and metering are installed and tested for each sub-resource in accordance with ISO New England Operating Procedure No, 18, Metering and Telemetering Criteria and ISO New England Operating Procedure No. 14, Technical Requirements for Generators, Demand Resources and Asset Related Demands.

III.14.3 Regulation Market Offers.

(a) A Market Participant providing Regulation must submit a Supply Offer. The Supply Offer shall remain effective until cancelled or replaced by the Market Participant. The Supply Offer must specify the following offer parameters:

(i) Regulation unit status (available/unavailable)

Regulation unit status for each hour in an Operating Day must be submitted daily prior to the close of the Re-Offer Period. After initial submission, unit status may be modified at any time.

(ii) Regulation High Limit

For generating units, the Regulation High Limit must be less than or equal to a generating unit's Economic Maximum Limit. For Dispatchable Asset Related Demand, the Regulation High Limit must be greater than or equal to a Dispatchable Asset Related Demand's Minimum Consumption Limit.

(iii) Regulation Low Limit

For generating units, the Regulation Low Limit must be greater than or equal to a generating unit's Economic Minimum Limit. For Dispatchable Asset Related Demand, the Regulation Low Limit must be less than or equal to a Dispatchable Asset Related Demand's Maximum Consumption Limit.

(iv) Automatic Response Rate (MW/minute)

(v) Regulation Capacity Offer ($/MW)

The Regulation Capacity Offer price must be greater than or equal to $0/MW and may not exceed $100/MW. A Market Participant may include estimated inter-temporal opportunity costs in its Regulation Capacity Offer price.

(vi) Regulation Service Offer ($/MW of instructed movement)

The Regulation Service Offer price must be greater than or equal to $0/MW of instructed movement and may not exceed $10/MW of instructed movement.

(b) Additional Constraints on Offer Parameters.

(i) Regulation offer parameters that exceed recent historical performance for Regulation Capacity or Automatic Response Rate will be constrained to reflect values consistent with the demonstrated performance of the Resource. The Resource of a Market Participant that submits offer parameters inconsistent with demonstrated performance will be disqualified from selection to provide Regulation until the submitted parameters are modified to be consistent with demonstrated performance.

(ii) A Resource that is dispatchable in the Real-Time Energy Market and providing Regulation shall have its energy dispatch range reduced by twice the amount of the Regulation provided as follows: the upper limit of the Resource's energy dispatch range will be reduced by the amount of Regulation Capacity, and the lower limit of the Resource's energy dispatch range will be increased by the amount of Regulation Capacity.

(c) Sustainability.

Regulation Capacity offers for Resources with less than one-hour sustainability will be evaluated in the selection process using a capacity value adjusted to reflect historical performance when dispatched at the non-adjusted value. The adjusted value will account for the Resource's demonstrated ability to follow the AGC dispatch signal over an hour at the offered Regulation Capacity level. The percentage adjustment will be reevaluated periodically to account for changes in the performance of the Resource. Resources with no historical performance record will be evaluated pursuant to the regulation resource test environment specified in Section III.14.9.

Adjusted Regulation Capacity will be used for the purpose of selecting Resources to meet the Regulation Capacity Requirement and for determining Regulation Capacity compensation.

Resources will be dispatched for Regulation in accordance with the unadjusted Regulation Capacity offer parameters.

For a storage-based resource, sustainability is measured based on full rate of charge/discharge starting from a half-full status.

III.14.4 Regulation Market Administration.

A Market Participant may modify Regulation offer parameters at any time, however the offer parameters in place at the start of a settlement interval will remain in effect through the end of the settlement interval. The most recent offer parameters will be used when new Resources are selected for a new settlement interval.

III.14.5 Regulation Market Resource Selection.

Resources are selected to provide Regulation from eligible and available Resources to meet the Regulation Capacity Requirement and Regulation Service Requirement at the least-cost based on

Regulation Capacity Offers, Regulation Service Offers, estimated energy opportunity costs, impacts on system production costs, and operational requirements related to reliability, including a minimum aggregated response rate and minimizing short-term changes in the assignment of Resources to provide Regulation. For the purposes of least-cost Resource selection, the following penalty factors are used for any violation of the Regulation requirements constraint:
(1)(a) when the Energy Component of the Real-Time Locational Marginal Price at the reference point is at least $100/MW the penalty factor is $100/MW plus the Energy Component of the Real-Time Locational Marginal Price at the reference point for each megawatt of Regulation Capacity shortfall, and
(b) when the Energy Component of the Real-Time Locational Marginal Price at the reference point is less than $100/MW the penalty factor is the maximum of either zero or $100 plus the Energy Component of the Real-Time Locational Marginal Price at the reference point for each megawatt of Regulation Capacity shortfall and:
(2) $10/MW for each megawatt of Regulation Service shortfall. In addition, selection will consider opportunity cost sensitivities associated with large changes in the estimated opportunity cost of a Resource due to the shape of the Resource's Supply Offer price curve.

An eligible Resource may be omitted from providing Regulation due to operational restrictions, including, but not limited to, binding transmission constraints, planned shutdown prior to the end of the settlement interval, or known or anticipated system operating conditions.

The ISO may deviate from the market-based Resource selections to maintain system reliability.

If one or more Resources providing Regulation become unavailable, a new selection process may be conducted to obtain the Resources needed to fulfill the Regulation Capacity Requirement and the Regulation Service Requirement and new clearing prices determined pursuant to Section III.14.8(a).

In the event one or more Resources have equivalent least-cost characteristics in the selection process, the Resource with the larger Regulation Capacity value will be selected or, if the Regulation Capacity value is also equal, the Resource with the earliest Supply Offer submission time will be selected.

III.14.6 Delivery of Regulation Market Products.
Resources selected for Regulation are dispatched to reduce the New England Control Area's area control error as needed to ensure reliability and compliance with NERC and NPCC control standards.

Resources that are generating units are dispatched based on relative response rates using multi-valued AGC SetPoints with AGC SetPoint Deadbands. Resources that are not generating units may be dispatched using one of the following methods:

(a) an energy-neutral trinary dispatch that calculates AGC SetPoints equal to one of the following three values: Regulation High Limit, Regulation Low Limit, and a midpoint between the Regulation High Limit and the Regulation Low Limit;

(b) a relative response rate dispatch using multi-valued AGC SetPoints with AGC SetPoint Deadbands, or;

(c) an energy-neutral relative response rate dispatch using multi-valued AGC SetPoints with AGC SetPoint Deadbands.

A Market Participant may change the dispatch method for a non-generating unit. Dispatch methodology may be changed to be effective at the start of every calendar quarter. Requests to change the dispatch method of a non-generating resource must be received no later than 30 Business Days before the requested effective date of the change. Dispatch will be coordinated with the objective of achieving consistent and non-discriminatory treatment of Resources providing similar offer parameters.

AGC SetPoints will be established to cost-effectively meet reliability criteria based on the current area control error, the Automatic Response Rate and offer parameters of the selected Resources, as well as the current and predicted state of the system.

III.14.7 Performance Monitoring.

The performance of a Resource providing Regulation will be monitored in Real-Time. For each settlement interval, a Resource is considered to be non-performing if, after a grace period, the Resource is not responding to AGC SetPoints at a rate at least equal to a percentage of its Automatic Response Rate or outside a tolerance band around the AGC SetPoint that is equal to a percentage of the Regulation Capacity of the Resource. The grace period will be between two and four minutes. The percentage of the Automatic Response Rate will be between 80 and 95 percent. The percentage of the Regulation Capacity of the Resource will be between 5 and 15 percent. The specific values will be published on the ISO's website.

A Resource that changes its direction of movement in a manner inconsistent with the AGC SetPoint is considered non-performing for the remainder of the settlement interval.

Compensation adjustments for non-performing Resources are addressed in Section III.14.8(b)(iv).

III.14.8 Regulation Market Settlement and Compensation.

(a) Calculation of Regulation Clearing Prices.

(i) Regulation Service clearing prices.

The Regulation Service clearing price is set equal to the highest Regulation Service Offer of the Resources selected to provide Regulation pursuant to Section III.14.5.

(ii) Regulation Capacity clearing prices.

The Regulation Capacity clearing price is set such that total compensation from the Regulation Service clearing price and the Regulation Capacity clearing price will, based on a uniform clearing price applied to all selected Resources, ensure recovery of as-bid costs for Regulation Capacity, estimated Regulation Service, estimated energy opportunity costs, and the Resource-specific incremental cost savings payment determined for each Resource for the planned duration of the settlement interval.

The incremental cost savings provided by each Resource is assessed by determining the least-cost selection of Resources as specified in Section III.14.5 both with and without the particular Resource. The incremental cost savings for the settlement interval is the estimated total cost of Regulation without the Resource minus the estimated total cost of Regulation with the Resource, including the application of penalty factors to any violation of the Regulation requirements constraint.

(b) Compensation to Regulation Providers.

(i) A Market Participant with a Resource that is selected to provide Regulation and that complies with the dispatch and performance requirements in Section III.14 shall receive:

(1) A capacity payment equal to the amount of Regulation Capacity selected times the Regulation Capacity clearing price.

(2) A service payment equal to the amount of service provided, while the Resource is considered to be performing as specified in Section III.14.7, as measured by the absolute value of the Resource's scheduled movement at the claimed rate of response without

delay, in megawatts, toward the AGC SetPoint in response to AGC dispatch signals times the Regulation Service clearing price.

(ii) Calculation of Actual Energy Opportunity Costs.

A Resource-specific Regulation energy opportunity cost for those Resources dispatchable in the Real-Time Energy Market is determined for each settlement interval that the Resource is selected to provide Regulation. The Regulation energy opportunity cost shall be equal to the product of (i) the absolute value of the deviation of the Resource's dispatch level necessary to follow the ISO's Regulation signals from the Resource's expected dispatch level if it had been dispatched in economic merit order and (ii) the absolute value of the difference between the Real-Time Price at the Node associated with the Resource and the megawatt weighted average Supply Offer or Demand Bid price for the energy associated with the deviation of the Resource's expected dispatch level if it had been dispatched in economic merit order. The Regulation energy opportunity cost for a Resource that is dispatched pursuant to Section III.1.10.9(e) shall be equal to zero for the settlement interval. Regulation energy opportunity costs are only incurred when a Resource is providing Regulation.

(iii) Make-Whole Payment

If revenues from the Regulation Capacity clearing price and the Regulation Service clearing price are insufficient to cover a Market Participant's as-bid costs for the actual Regulation Capacity and the amount of Regulation Service provided during a settlement interval plus actual energy opportunity costs as calculated in Section III.14.8(b)(ii), a make-whole payment will be provided for the period that the Resource is considered to be performing as specified in Section III.14.7.

(iv) Performance Adjustments.

A selected Resource's capacity payment will be reduced to reflect the proportion of time the Resource was determined to be non-performing pursuant to Section III.14.7.

(v) Compensation for Replacement Resources

If system conditions require the ISO to designate additional Resources in order to satisfy Regulation requirements for the remainder of a settlement interval without completing the selection process described in Section III.14.5, compensation for replacement Resources will be made according to the Resource's actual performance using the Regulation Capacity clearing

price, the Regulation Service clearing price, and any make-whole payments as specified in Section III.14.8(b)(iii).

(c) Regulation Charges.

Each Market Participant shall have a Regulation charge equal to its pro rata share of the Regulation Capacity Requirement and Regulation Service Requirement for the settlement period based on the Market Participant's total Real-Time Load Obligation. The total cost of providing Regulation for each settlement period is charged to Market Participants based on their pro rata share of Real-Time Load Obligation during the period. For the purposes of allocating Regulation charges, the Real-Time Load Obligation of a Dispatchable Asset Related Demand providing Regulation shall be limited to the Minimum Consumption Limit of the Resource. Calculation of Regulation charges shall exclude contributions to Real-Time Load Obligations from Coordinated External Transactions.

(d) Net Energy Settlement for Alternative Technology Regulation Resources.

A Market Participant with an Alternative Technology Regulation Resource that is interconnected and metered at a single location may register the resource as a combination of the following asset types for the purpose of regulation energy market settlement:

1) an Alternative Technology Regulation Resource for the settlement of regulation capacity and regulation service;

2) a Settlement-Only Generator, if not greater than or equal to 5 MW, or otherwise a non-dispatchable, non-regulation capable Generator Asset for settlement of net energy injections that result from following AGC dispatch instructions;

3) an Asset Related Demand for settlement of net energy consumption; and

4) a load asset for settlement of net energy consumption for which the Real-Time Load Obligation is separately reported to the ISO.

III.14.9 Regulation Market Testing Environment.

The ISO administers a regulation resource test environment that allows Market Participants to evaluate or demonstrate the performance of Resources without an operational history of providing Regulation prior to participation in the Regulation Market.

Resources providing Regulation under the regulation resource test environment will be compensated for the Regulation Capacity and Regulation Service provided in response to AGC SetPoints at the lowest of

the Regulation Capacity Offer prices and Regulation Service Offer prices offered for any Resource selected during each settlement interval. Resources that are also dispatchable in the Real-Time Energy Market will be compensated for Regulation energy opportunity costs incurred while operating under the regulation resource test environment.

Resources performing a minimal responsiveness test will not be compensated for Regulation.

A Resource may only provide Regulation under the regulation test environment until sufficient operational information has been collected to verify reasonable operating parameters for the Resource or to determine that the Resource does not meet the eligibility requirements necessary to participate in the Regulation Market.

SECTION III
MARKET RULE 1

APPENDIX F
NET COMMITMENT PERIOD COMPENSATION ACCOUNTING

APPENDIX F

NCPC ACCOUNTING

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NCPC ACCOUNTING

III.F.1. General.

For purposes of NCPC calculations:

a. Effective Offers. An Effective Offer for a Resource is (1) the Supply Offer used in making the decision to commit the Resource, and (2) the Supply Offer used in making the decision to dispatch the Resource at a Desired Dispatch Point above its Economic Minimum Limit, and is subject to the following conditions,

i. The Effective Offer used in making the decision to commit the Resource establishes the quantity and price pairs for output up to the Resource's Economic Minimum Limit, the Start-Up Fee, the No-Load Fee, and the operating limits used for NCPC calculations.

ii. In the event the Resource's Economic Minimum Limit is increased after the decision to commit the Resource, the energy price parameter for output at the Economic Minimum Limit used in making the decision to commit the Resource will be applied as the energy price parameter for additional output up to the increased Economic Minimum Limit.

iii. In the event a Minimum Generation Emergency is declared, the Economic Minimum Limit will be replaced with the Emergency Minimum Limit for purposes of determining the energy price parameter of the Effective Offer.

iv. The Effective Offer takes account of mitigation applied to the Supply Offer, whether performed prior to or after the commitment or dispatch decision is made.

v. The Effective Offer takes account of a reduction in the energy price parameter, the Start-Up Fee or the No-Load Fee that is made prior to the end of the Resource's Commitment Period.

vi. In the event the ISO approves the Resource's synchronization to the system as a Pool-Scheduled Resource earlier than its scheduled time, the Effective Offer takes account of the lesser of the energy price parameter, the Start-Up Fee and the No-Load Fee in place for the scheduled Commitment Period or the actual early release-for-dispatch time.

vii. A Resource that is online providing synchronous condensing is considered to be in a hot temperature state for the purpose of determining the Start-Up Fee for the Effective Offer when the Resource is requested to switch from synchronous condensing to provide energy.

b. Treatment of Self-Schedules.

i. In the Day-Ahead Energy Market, a Resource that is committed as a Self-Schedule is treated as having a Supply Offer with a Start-Up Fee equal to $0, a No-Load Fee equal to $0, and an energy price parameter for output up to the Resource's Economic Minimum Limit equal to the Energy Offer Floor. Any amounts (MW) offered above the Economic Minimum Limit are evaluated based on the energy price parameters specified in the Supply Offer.

ii. In the Real-Time Energy Market, a Resource that is committed as a Self-Schedule is treated as having a Supply Offer with a Start-Up Fee equal to $0, a No-Load Fee equal to $0, and an energy price parameter for output up to the Resource's Economic Minimum Limit equal to $0/MWh. Any amounts (MW) offered above the Economic Minimum Limit are evaluated based on the energy price parameters specified in the Supply Offer. For any hour for which a Resource is dispatched pursuant to Section III.1.10.9(e), the Start-Up Fee and No-Lead Fee are equal to $0.

iii. If the Resource's Supply Offer contains a Self-Schedule for fewer contiguous hours than its Minimum Run Time, the minimum number of additional hours required to satisfy the Resource's Minimum Run Time will be treated as a Self-Schedule in the Day-Ahead Energy Market and Real-Time Energy Market. If the Resource is committed for one or more hours immediately prior to and contiguous with the Self-Schedule, the hours of that prior Commitment Period will be counted toward satisfying the Resource's Minimum Run Time before hours subsequent to the Self-Schedule are counted. If the Resource's Supply Offer contains two Self-Schedules separated by less than the Resource's Minimum Down Time, the hours between the two Self-Schedules will be treated as a Self-Schedule in the Day-Ahead Energy Market and Real-Time Energy Market.

c. [Reserved.]

d. Supply Offers Applicable When Minimum Run Time Carries Into Second Operating Day. If a Resource that is committed in either (i) the Day-Ahead Energy Market, or (ii) the Resource Adequacy Analysis prior to the start of the Operating Day must continue to operate across an Operating Day boundary to satisfy its Minimum Run Time, the Supply Offer in place for hour ending 24 of the Operating Day is used to establish the Effective Offer for the period of the Minimum Run Time in the second Operating Day. If a Resource that is committed during the Operating Day must continue to operate across the Operating Day boundary to satisfy its Minimum Run Time, the Supply Offer in place for the second Operating Day is used to establish the Effective Offer for the period of the Minimum Run Time in the second Operating Day.

e. Supply Offers Applicable When Committed Prior to Day-Ahead Energy Market. If a Resource is committed for an Operating Day prior to the Day-Ahead Energy Market, the Supply Offer in place for the Operating Day at the time of the commitment is used to establish the Effective Offer for the period of the commitment.

f. Eligibility for NCPC Credits When Performing Audits or Facility and Equipment Testing. Market Participants are not eligible for NCPC Credits when conducting audits or Facility and Equipment Testing under the following conditions:

i. When a Market Participant requests that some hours of the commitment of a Pool-Scheduled Resource be used to satisfy an audit, and the Market Participant has changed the Resource's Economic Minimum Limit for those hours for the purpose of conducting the audit, the Market Participant is not eligible for Real-Time Dispatch NCPC Credits for the hours during which the audit is conducted.

ii. When a Market Participant Self-Schedules a Resource to perform the audit, the Market Participant is not eligible for Real-Time Commitment NCPC Credits for the duration of the Self-Schedule and is not eligible for Real-Time Dispatch NCPC Credits for the hours during which the audit is conducted.

iii. When a Market Participant requests that an audit be performed that requires the ISO to dispatch the Resource for the audit without advance notice the Market Participant is not eligible for Real-Time Commitment NCPC Credits for the duration of the commitment or Real-Time Dispatch NCPC Credits for the hours during which the audit is conducted.

iv. When an ISO-Initiated Claimed Capability Audit is performed pursuant to III.1.5.1.4, the Market Participant is not eligible for Real-Time Commitment NCPC Credits or Real-Time Dispatch NCPC Credits for the hours during which the audit is conducted if both of the following are true:

1. the Resource had a summer or winter Seasonal Claimed Capability equal to 0 MW at the beginning of the current Capability Demonstration Year, and

2. the ISO Initiated Claimed Capability Audit is the first Claimed Capability Audit that the Resource performs during that Capability Demonstration Year.

v. When a Market Participant notifies the ISO that it is conducting Facility and Equipment Testing for a Pool-Scheduled Resource, the Economic Minimum Limit in place at the time of the commitment decision is used for calculating Real-Time Commitment NCPC Credits and the Market Participant is

not eligible for Real-Time Dispatch NCPC Credits for the hours during which the Facility and Equipment Testing is conducted.

vi. When a Market Participant notifies the ISO that it is conducting Facility and Equipment Testing for a Resource that Self-Scheduled, the Market Participant is not eligible for Real-Time Commitment NCPC Credits for the duration of the commitment and is not eligible for Real-Time Dispatch NCPC Credits for the hours during which the Facility and Equipment Testing is conducted.

The Real-Time NCPC Credit calculation for a Resource performing an audit uses the Start-Up Fee, No-Lead Fee and Economic Minimum Limit in the Effective Offer applicable to the Commitment Period during which the audit is conducted, and does not take account of any increases to the Economic Minimum Limit value that take place in the course of the audit.

g. Coordinated External Transactions are Not Eligible for NCPC and are excluded from NCPC Charges. Notwithstanding anything to the contrary in this Appendix F, Market Participants are not eligible to receive NCPC Credits for Coordinated External Transactions purchases or sales and shall be excluded from all NCPC Charge calculations under this Appendix F.

h. Following Dispatch Instructions. Generation Resources with an Economic Maximum Limit less than or equal to 50 MWs are considered to be following a Dispatch Instruction if the actual output of the Resource is not greater than 5 MWs above its Desired Dispatch Point and is not less than 5 MWs below its Desired Dispatch Point for each interval in the hour. If the Resource violates this criterion in any interval during the hour, the Resource is considered to be not following Dispatch Instructions for the entire hour.

Section III.F.2. NCPC Credits

III.F.2.1 Day-Ahead Energy Market NCPC Credits

III.F.2.1.1. Eligibility for Credit. All Market Participants with an Ownership Share in a Resource with a Supply Offer that clears the Day-Ahead Energy Market in an hour are eligible for Day-Ahead Energy Market NCPC Credits for the hour.

III.F.2.1.2. Settlement Period. For purposes of calculating Day-Ahead Energy Market NCPC Credits, a settlement period is a period of one or more contiguous hours in an Operating Day for which a Resource has cleared in the Day-Ahead Energy Market. A new settlement period will begin any time a Resource's designation changes to or from a Fast Start Generator and the Resource is committed with the changed designation.

III.F.2.1.3. Eligible Quantity. The eligible quantity of energy for a Resource is the amount of energy the Resource clears in the Day-Ahead Energy Market for each hour of the settlement period.

III.F.2.1.4 Hourly Cost. The hourly cost for a Resource is equal to the energy price parameter for the eligible quantity, the Start-Up Fee and the No-Load Fee as reflected in the Effective Offer for each hour of the settlement period, subject to the following conditions.

III.F.2.1.4.1 The Start-Up Fee is apportioned equally over the hours from the time the Resource is scheduled to begin its commitment through the end of the Commitment Period during which the Minimum Run Time is scheduled to expire.

III.F.2.1.4.2 When the period of hours over which the Start-Up Fee is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Start-Up Fee.

III.F.2.1.5 Hourly Revenue. The hourly revenue for a Resource is equal to the Day-Ahead Price for each hour of the settlement period multiplied by the eligible quantity for the Resource.

III.F.2.1.6 Credit Calculation (non-Fast Start Generator). The Day-Ahead Energy Market NCPC Credit for a Resource, other than a Fast Start Generator, is equal to the greater of (i) zero, and; (ii) the total hourly cost for the Resource in all hours of the settlement period minus the total hourly revenue for the Resource in all hours of the settlement period.

III.F.2.1.7 Credit Calculation (Fast Start Generator). The Day-Ahead Energy Market NCPC Credit for a Fast Start Generator is equal to, for each hour of the settlement period, the greater of (i) zero, and; (ii) the hourly cost for the Resource in an hour minus the hourly revenue for the Resource in the hour.

III.F.2.2 Real-Time Energy Market NCPC Credits

Real-Time Energy Market NCPC Credits include a Real-Time Commitment NCPC Credit and a Real-Time Dispatch NCPC Credit.

III.F.2.2.1 Eligibility for Credit. All Market Participants with an Ownership Share in a Resource with a Supply Offer that has been submitted in the Real-Time Energy Market in an hour are eligible for Real-Time Energy Market NCPC Credits for the hour.

III.F.2.2.2 Real-Time Commitment NCPC Credits

III.F.2.2.2.1. Settlement Period. For purposes of calculating Real-Time Commitment NCPC Credits, a settlement period is a period of one or more contiguous hours in an Operating Day during which a Resource is online and operating pursuant to one or more commitments in the Day-Ahead Energy Market or Real-Time Energy Market. A new settlement period will begin any time a Resource's designation changes to or from a Fast Start Generator and the Resource is committed with the changed designation. In the event of an interruption in operation of a Resource, operation will be considered contiguous if the Resource returns to operation in accordance with the original commitment issued prior to the interruption.

III.F.2.2.2.2. Eligible Quantity.

III.F.2.2.2.2.1. For determining the hourly costs used in calculating a Real-Time Commitment NCPC Credit, the eligible quantity of energy for a Resource is the amount of energy equal to the lesser of the Resource's actual metered output or Economic Dispatch Point for the hour.

III.F.2.2.2.2.2 For determining the hourly revenues used in calculating a Real-Time Commitment NCPC Credit, the eligible quantity of energy for a Resource is the lesser of the Resource's actual metered output

or Economic Dispatch Point for the hour, except that actual metered output is used as the eligible quantity (i) when the Resource is not eligible for a Real-Time Dispatch NCPC Credit and the Real-Time Price is not below zero for the hour, (ii) when the Resource is ramping from an offline state to be released for dispatch and (iii) after the Resource has been released for shutdown.

III.F.2.2.2.3. Hourly Cost. The hourly cost for a Resource is equal to the energy price parameter for the eligible quantity as reflected in the Effective Offer, and the Start-Up Fee and No-Load Fee as reflected in the Effective Offer, for each hour of the settlement period, subject to the following conditions.

III.F.2.2.2.3.1 The energy cost for an hour excludes the cost of energy produced when the Resource is ramping from an offline state to be released for dispatch and energy produced after the Resource has been released for shutdown.

III.F.2.2.2.3.2 The Start-Up Fee is apportioned equally over the hours from the time the Resource is released for dispatch through the end of the Commitment Period during which the Minimum Run Time is scheduled to expire, subject to the following conditions:

(a) The Start-Up Fee is reduced in proportion to the number of minutes after 30 the Resource is released for dispatch, as measured from the time the Resource was scheduled to be released for dispatch, divided by the time from when the Resource was scheduled to be released for dispatch through the end of the Commitment Period during which the Minimum Run Time was scheduled to expire.

(b) The Start-Up Fee is excluded from the hourly costs calculation if the Resource is synchronized to the system prior to its scheduled synchronization time without the ISO's approval of the Resource's synchronization as a Pool-Scheduled Resource.

(c) The portion of the Start-Up Fee apportioned to any hour during which the Resource is not online because the Resource has tripped is excluded from the hourly cost calculation, except in the event the Resource is not online due to a trip that results from equipment failure involving equipment located on the electric network beyond the low voltage terminals of the Resource's step-up transformer. It is the responsibility of the Lead Market Participant for the Resource to inform the ISO at xtrip@iso-ne.com within 30 days that the trip was the result of such a transmission-related event.

(d) The Start-Up Fee is not reduced when the Resource has shutdown with the ISO's approval prior to the end of its Commitment Period.

(e) The additional Start-Up Fee for a Resource requested to re-start following a trip is apportioned equally over the remaining hours of the Commitment Period when the ISO requests a Resource to re-start to complete its Commitment Period.

(f) When the period of hours over which the Start-Up Fee is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Start-Up Fee.

III.F.2.2.2.3.3. The No-Load Fee is applied to each hour during the period when the Resource is online following its release for dispatch and prior to its release for shutdown. The No-Load Fee is pro-rated for the hour during which the Resource is released for dispatch, the hour during which the Resource is released for shutdown, and any other hour during which the Resource operates for less than 60 minutes.

III.F.2.2.2.4 Hourly Revenue. The hourly revenue for a Resource is equal to the Real-Time Price for each hour of the settlement period multiplied by the eligible quantity. The hourly revenue for an hour is increased by the amount by which the hourly revenues in the Real-Time Dispatch NCPC Credit calculation in Section III.F.2.2.3.4 exceed the hourly costs in the Real-Time Dispatch NCPC Credit calculation in Section III.F.2.2.3.3 for that hour. The revenues when the Resource is ramping from an offline state to be released for dispatch are apportioned equally to the hours of the Minimum Run Time.

III.F.2.2.2.4.1. Revenues for output up to the Resource's Economic Minimum Limit in a Self-Scheduled hour, calculated as the Real-Time Price multiplied by the output, are excluded from the hourly revenue for the Real-Time Commitment NCPC Credit calculation.

III.F.2.2.2.5 Credit Calculation (for non-Fast Start Generators). The Real-Time Commitment NCPC Credit for a Resource, other than a Fast Start Generator, is equal to:

(a) for the portion of each Commitment Period within a settlement period that contain hours of the Minimum Run Time, the greater of (i) zero, and; (ii) the total hourly cost for the Resource for the period minus the total hourly revenue for the Resource for the period,

plus,

(b) for each remaining hour of the settlement period following the completion of the Minimum Run Time, the greater of ((i) zero, and; (ii) the maximum potential net revenues for the Resource in the period) minus the actual net revenues for the Resource in the period, where

(i) The maximum potential net revenue is the maximum accumulated net hourly revenue for operating and then shutting down during the period.

(ii) The actual net revenue is the accumulated net hourly revenue over the period.

(iii) The net hourly revenue is the hourly revenues minus hourly costs in each hour of the period.

III.F.2.2.2.6. Credit Calculation (for Fast Start Generators). The Real-Time Commitment NCPC Credit for a Fast Start Generator is equal to, for each hour of the settlement period, the greater of (i) zero, and; (ii) the hourly cost for the Resource in an hour minus the hourly revenue for the Resource in the hour.

III.F.2.2.3. Real-Time Dispatch NCPC Credits

III.F.2.2.3.1 Settlement Period. For purposes of calculating Real-Time Dispatch NCPC Credits, a settlement period is an hour when the Desired Dispatch Point and the actual metered output for a Resource are each greater than its Economic Dispatch Point, excluding any period of time when the Resource is ramping from an offline state to be released for dispatch and after the Resource has been released for shutdown.

III.F.2.2.3.2. Eligible Quantity.

III.F.2.2.3.2.1. For determining the hourly costs used in calculating a Real-Time Dispatch NCPC Credit, the eligible quantity of energy for a Resource is the Resource's Economic Dispatch Point for the hour subtracted from the lesser of the Resource's actual metered output or Desired Dispatch Point for the hour.

III.F.2.2.3.2.2. For determining the hourly revenues used in calculating a Real-Time Dispatch NCPC Credit, the eligible quantity of energy for a Resource is the Resource's actual metered output for the hour minus the Resource's Economic Dispatch Point for the hour, except that the Resource's Economic Dispatch Point for the hour subtracted from the lesser of the Resource's actual metered output or Desired Dispatch Point for the hour is used as the eligible quantity when the Real-Time Price is below zero for the hour.

III.F.2.2.3.3 Hourly Cost. The hourly cost for a Resource is equal to the energy price parameter for the eligible quantity as reflected in the Effective Offer and does not include the Start-Up Fee or the No-Load Fee.

III.F.2.2.3.4 Hourly Revenue. The hourly revenue for a Resource is equal to the Real-Time Price for the hour multiplied by the eligible quantity, plus the portion of regulation opportunity costs attributed to operation in response to Regulation AGC dispatch signals at a level above the Resource's expected economic dispatch level, as specified in Section III.14.8(b)(ii).

III.F.2.2.3.5. Credit Calculation. The Real-Time Dispatch NCPC Credit for a Resource in an hour is equal to the greater of (i) zero and (ii) the hourly cost minus the hourly revenue for the Resource.

III.F.2.3. Special Case NCPC Credit Calculations

III.F.2.3.1. Day-Ahead External Transaction Import and Increment Offer NCPC Credits

III.F.2.3.1.1. Eligibility for Credit. All Market Participants with pool-scheduled External Transaction imports or Increment Offers at an External Node are eligible for Day-Ahead External Transaction Import and Increment Offer NCPC Credits, with the exception of External Transactions that are conditioned upon Congestion Costs not exceeding a specified level.

III.F.2.3.1.2. Hourly Offer. The Day-Ahead offer for a pool-scheduled External Transaction import or Increment Offer at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the offer price.

III.F.2.3.1.3. Hourly Revenue. The Day-Ahead revenue for a pool-scheduled External Transaction import or Increment Offer at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead Price.

III.F.2.3.1.4. Credit Calculation. A Day-Ahead External Transaction Import and Increment Offer NCPC Credit for an External Transaction import or Increment Offer, for an hour, is equal to any portion of the Day-Ahead offer in excess of the Day-Ahead revenue for the hour; provided, however, that if a Market Participant has a pool-scheduled External Transaction import or Increment Offer for a given External Node and hour and the Market Participant or its Affiliate also has an External Transaction export or Decrement Bid for the same External Node and hour, the Day-Ahead External Transaction Import and Increment Offer NCPC Credit for the hour is calculated only for any amount (MW) of the External Transaction import or Increment Offer at the External Node for the hour that is not offset by the amount (MW) of the External Transaction export or Decrement Bid at the External Node for the hour. If multiple External Transaction imports or Increment Offers at an External Node are eligible for a Day-Ahead External Transaction Import and Increment Offer NCPC Credit, then for purposes of the offsetting determination in the prior sentence External Transaction imports and Increment Offers will be offset in order from the highest to the lowest-priced transactions or offers.

III.F.2.3.2. Day-Ahead External Transaction Export and Decrement Bid NCPC Credits

III.F.2.3.2.1. Eligibility for Credit. All Market Participants with pool-scheduled External Transaction exports or Decrement Bids at an External Node are eligible for Day-Ahead External Transaction Export and Decrement Bid NCPC Credits, with the exception of External Transactions that are conditioned upon Congestion Costs not exceeding a specified level.

III.F.2.3.2.2. Hourly Bid. The Day-Ahead bid for a pool-scheduled External Transaction export or Decrement Bid at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the bid price.

III.F.2.3.2.3. Hourly Cost. The Day-Ahead cost for a pool-scheduled External Transaction export or Decrement Bid at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead Price at the External Node.

III.F.2.3.2.4. Credit Calculation. A Day-Ahead External Transaction Export and Decrement Bid NCPC Credit for an External Transaction export or Decrement Bid, for an hour, is equal to any portion of the Day-Ahead hourly cost in excess of its Day-Ahead hourly bid for the hour; provided, however, that if a Market Participant has a pool-scheduled External Transaction export or Decrement Bid for a given External Node and hour and the Market Participant or its Affiliate also has an External Transaction import or Increment Offer for the same External Node and hour, the Day-Ahead External Transaction Export and Decrement Bid NCPC Credit for the hour is calculated only for any amount (MW) of the External Transaction export or Decrement Bid at the External Node for the hour that is not offset by the amount (MW) of the total cleared External Transaction import or Increment Offer at the External Node for the hour. If multiple External Transaction exports or Decrement Bids at an External Node are eligible for a Day-Ahead External Transaction Export and Decrement Bid NCPC Credit, then for purposes of the offsetting determination in the prior sentence External Transaction exports and Decrement Bids will be offset in order from the lowest to the highest-priced transactions or bids.

III.F.2.3.3. Real-Time External Transaction NCPC Credits (Import and Export)

III.F.2.3.3.1. Eligibility for Credit. All Market Participants that submit pool-scheduled External Transactions (import or export) are eligible for Real-Time External Transaction NCPC Credits, with the exception of External Transactions to wheel energy through the New England Control Area.

III.F.2.3.3.2. Eligible Quantity.

(a) For each hour, the eligible quantity of energy for an External Transaction in the Real-Time Energy Market that either (i) did not clear in the Day-Ahead Energy Market, or (ii) cleared in the Day-Ahead Energy Market and the price was subsequently revised in the Re-Offer Period, is the External Transaction amount (MW) pool-scheduled in the Real-Time Energy Market.

(b) For each hour, the eligible quantity of energy for an External Transaction in the Real-Time Energy Market that cleared in the Day-Ahead Energy Market and the price was not subsequently revised in the Re-Offer Period, is the Real-Time scheduled transaction amount in excess of the cleared Day-Ahead scheduled transaction amount.

III.F.2.3.3.3. Hourly Offer. The hourly offer for a pool-scheduled External Transaction import for an hour is equal to the eligible quantity multiplied by the offer price for the hour.

III.F.2.3.3.4. Hourly Revenue. The hourly revenue for a pool-scheduled External Transaction import for an hour is equal to the eligible quantity multiplied by the Real-Time Price for the hour.

III.F.2.3.3.5. Hourly Bid. The hourly bid for a pool-scheduled External Transaction export for an hour is equal to the eligible quantity multiplied by the bid price for the hour.

III.F.2.3.3.6. Hourly Cost. The Real-Time cost for a pool-scheduled External Transaction export for an hour is equal to the eligible quantity multiplied by the Real-Time Price.

III.F.2.3.3.7. Credit Calculation. A Real-Time External Transaction NCPC Credit for an External Transaction import for an hour is equal to any portion of the hourly offer in excess of the hourly revenue. A Real-Time External Transaction NCPC Credit for an External Transaction export for an hour is equal to any portion of the hourly cost in excess of the hourly bid.

III.F.2.3.4. Real-Time Posturing NCPC Credits for Dispatchable Asset Related Demand Resources (Pumps Only) Postured for Reliability

III.F.2.3.4.1. Eligibility for Credit. All Market Participants with an Ownership Share in a Dispatchable Asset Related Demand Resource are eligible for real-time posturing NCPC credits for the pumping of a Dispatchable Asset Related Demand Resource that has been Postured to increase consumption.

III.F.2.3.4.2. Eligible Quantity. The eligible quantity for a Resource for each hour is the lesser of the Desired Dispatch Point or the Resource's actual metered consumption.

III.F.2.3.4.3. Hourly Bid. The hourly bid is the greater of, for the eligible quantity of the Resource, the Demand Bid for the hour at the time the ISO initiates the Posturing action or the Demand Bid for the hour if revised after the Posturing action is initiated.

III.F.2.3.4.4. Hourly Cost. The hourly cost is equal to the eligible quantity multiplied by the Real-Time Price.

III.F.2.3.4.5. Credit Calculation. The real-time posturing NCPC credit for an hour for the pumping of a Postured Dispatchable Asset Related Demand Resource is equal to any portion of the hourly cost in excess of the hourly bid.

III.F.2.3.5. Real-Time Synchronous Condensing NCPC Credits

III.F.2.3.5.1. Eligibility for Credit. All Market Participants with an Ownership Share in a Resource that is dispatched as a Synchronous Condenser are eligible for Real-Time Synchronous Condensing NCPC Credits.

III.F.2.3.5.2. Condensing Offer Amount. The condensing offer amount for a Resource is equal to the number of hours that the Resource is dispatched as a Synchronous Condenser in an Operating Day multiplied by the hourly price to condense as specified in the Offer Data for the Resource. For a Resource committed from an offline state to provide synchronous condensing, the condensing offer amount includes the condensing start-up fee as specified in the Offer Data for the Resource. In the event an hourly price to condense or condensing start-up fee is not included in the Offer Data for the Resource for the hours that the Resource is dispatched as a Synchronous Condenser, the value for the parameter will be zero.

III.F.2.3.5.3. Credit Calculation. The Real-Time Synchronous Condensing NCPC Credit for a Resource for an Operating Day is equal to the condensing offer amount for that Operating Day.

III.F.2.3.6. Cancelled Start NCPC Credits

III.F.2.3.6.1. Eligibility for credit. All Market Participants with an Ownership Share in a Pool-Scheduled Resource are eligible for Cancelled Start NCPC Credits if the ISO cancels its commitment of the Pool-Schedule Resource before the Resource is synchronized to the New England Transmission System, except that a Market Participant is not eligible for a credit under the following conditions:

(a) The start is cancelled before the commencement of the Notification Time;
(b) The Resource's Notification Time as reflected in the Effective Offer is equal to or greater than 24 hours;
(c) The Resource is synchronized to the New England Transmission System for a Self-Schedule within the period of time equal to the lesser of its Minimum Down Time or 10 hours after receiving the ISO cancelled start order; or
(d) The Resource fails to meet its scheduled synchronization time and the ISO cancelled start order is issued more than two hours after the Resource's scheduled synchronization time.

III.F.2.3.6.2. Credit Calculation. The Cancelled Start NCPC Credit for a Resource is equal to the Start-Up Fee reflected in the Effective Offer multiplied by the percentage of the Notification Time, as reflected in the Effective Offer, that the Resource completed prior to the ISO cancelled start order, where:

(a) The percentage of Notification Time completed is equal to the number of minutes after the start of the Notification Time the Resource was cancelled divided by the Notification Time, and cannot exceed 100%.

III.F.2.3.7. Hourly Shortfall NCPC Credits

III.F.2.3.7.1. Eligibility for Credit. All Market Participants with an Ownership Share in a generating Resource that is pool-scheduled in the Day-Ahead Energy Market are eligible for Hourly Shortfall NCPC Credits for an hour if the ISO cancels its commitment of a non-Fast Start Generator or does not dispatch a Fast Start Generator for the hour and the Resource is offline and available for operation, except that a Market Participant is not eligible for a credit under the following conditions:

(a) The Resource has been Postured for all or part of the hour;
(b) The Resource is a Limited Energy Resource that has been Postured during a prior hour in the Operating Day; or
(c) The Resource is an Intermittent Power Resource.

III.F.2.3.7.2. Settlement Period. For purposes of calculating Hourly Shortfall NCPC Credits, a settlement period is a period of one or more contiguous hours in an Operating Day during which a Resource is eligible for an Hourly Shortfall NCPC Credit. A new settlement period will begin any time a Resource's designation changes to or from a Fast Start Generator and the Resource is committed with the changed designation.

III.F.2.3.7.3. Eligible Quantity. The eligible quantity for each hour of the settlement period is:

(a) zero for a Fast Start Generator in the event the total of the energy price parameter, Start-Up Fee parameter and No-Load Fee parameter of the Supply Offer in the Real-Time Energy Market for the amount of energy cleared in the Day-Ahead Energy Market for the hour is greater than the total of the corresponding parameters of the Effective Offer in the Day-Ahead Energy Market for the hour;
    i. For purposes of this evaluation, (1) if the ISO is not able to honor a request to be Self-Scheduled for the hour under Section III.1.10.9(d), the Start-Up Fee, No-Lead Fee and energy at the Economic Minimum Limit are equal to $0, and (2) if the ISO is not able to honor a request to be dispatched for the hour under Section III.1.10.9(e), the Start-Up Fee and No-Lead Fee are equal to $0 and the energy at the requested dispatch level is the Energy Price Floor.
(b) the Day-Ahead Economic Minimum Limit for a non-Fast Start Generator in the event the total of the energy price parameter of the Supply Offer in the Real-Time Energy Market for the amount of energy cleared in the Day-Ahead Energy Market above the Day-Ahead Economic Minimum Limit for an

hour is greater than the total of the corresponding parameters of the Effective Offer in the Day-Ahead Energy Market for the hour;

and if neither (a) nor (b) applies, then

(c) the minimum of (i) the amount of energy cleared in the Day-Ahead Energy Market for an hour and (ii) the Resource's Economic Maximum Limit or a Limited Energy Resource limit imposed for the hour in the Real-Time Energy Market.

III.F.2.3.7.4. Credit Calculation (for non-Fast Start Generators). The Hourly Shortfall NCPC Credit for a Resource, other than a Fast Start Generator, is equal to:

(a) the greater of (i) zero and (ii) the total of (the Real-Time Price minus the Day-Ahead Price for an hour, multiplied by the Day-Ahead Economic Minimum Limit for the hour) for all hours of the settlement period,

plus

(b) for each hour of the settlement period, the greater of (i) zero and (ii) the Real-Time Price minus the Day-Ahead Price for an hour, multiplied by the eligible quantity minus the Day-Ahead Economic Minimum Limit for the hour.

III.F.2.3.7.5. Credit Calculation (for Fast Start Generators). The Hourly Shortfall NCPC Credit for a Fast Start Generator is equal to, for each hour of the settlement period, the greater of (i) zero, and (ii) the Real-Time Price minus the Day-Ahead Price for an hour, multiplied by the eligible quantity for the hour.

III.F.2.3.8. Real-Time Posturing NCPC Credits for Limited Energy Resources Postured for Reliability

III.F.2.3.8.1. Eligibility for Credit. All Market Participants with an Ownership Share in a Limited Energy Resource are eligible for real-time posturing NCPC credits for any Operating Day during which the Resource has been Postured, when a request to minimize the as-bid production costs of the Resource has been submitted. For purposes of calculating real-time posturing NCPC credits, the Resource is treated

as a Fast Start Generator only if it is designated as such at the time of the commitment decision for the Commitment Period during which the Resource was Postured, and if not the Resource is treated as a non-Fast Start Generator. If the Resource is offline at the time it is Postured, then its designation as a Fast Start Generator or non-Fast Start Generator is determined as of the time of the Posturing decision.

III.F.2.3.8.2. Settlement Period. For purposes of calculating real-time posturing NCPC credits for Limited Energy Resources, a settlement period is the period of one or more contiguous hours from the initiation of Posturing through the end of the Operating Day.

III.F.2.3.8.3 Resources Sharing a Single Fuel Source. When Limited Energy Resources that share a fuel source are Postured, for purposes of calculating real-time posturing NCPC credits the energy available to the Postured Resources will be allocated among the Postured Resources sharing the fuel source as indicated by estimates of available energy provided by the Lead Market Participant for each Resource prior to Posturing.

III.F.2.3.8.4. Estimated Replacement Cost of Energy. The estimated replacement cost of energy is (i) the average of the Day-Ahead Prices for hours ending 3 through 5 in the subsequent Operating Day for pumped storage generators, or (ii) the product of the oil index price multiplied by the oil-fired generator proxy heat rate for fuel oil-fired generators, or (iii) zero for Resources other than pumped storage generators and fuel oil-fired generators.

For fuel oil-fired generators, the oil index price is the ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation, and the oil-fired generator proxy heat rate is the average of the heat rate at Economic Min and the heat rate at Economic Max, where the heat rate at Economic Min is, for a Resource, the average hourly energy price parameter of the Supply Offer at the Resource's Economic Minimum Limit at the time of the Posturing decision divided by the oil index price, and the heat rate at Economic Max is, for a Resource, the average hourly energy price parameter of the Supply Offer at the Resource's Economic Maximum Limit at the time of the Posturing decision divided by the oil index price.

III.F.2.3.8.5. Estimated Revenue. The estimated revenue for a Resource is the optimized energy output multiplied by the Real-Time Price for all hours in the settlement period. The optimized energy

output is estimated for each hour by allocating the Postured energy to hours that the Resource would have operated had it not been Postured based on Real-Time Prices in the Operating Day, subject to the following conditions:

(a) the optimized energy output determination will take account of the Resource's Economic Minimum Limit, and Economic Maximum Limit.
(b) the optimized energy output determination will take account of the estimated avoided cost of replacing energy that is not allocated to any hour and remains available at the end of the Operating Day.
(c) for non-Fast Start Generators, the optimized energy output is calculated for the contiguous hours from the time the Resource is Postured until the available energy is depleted.

III.F.2.3.8.6. Estimated Avoided Replacement Cost. The estimated avoided replacement cost for an Operating Day is the remaining energy that would have been available at the end of the Operating Day had the Resource operated in accordance with the optimized energy output determination in Section III.F.2.3.8.5, plus any increase in the remaining energy resulting from pumping during the Operating Day after the Resource is Postured, multiplied by the estimated replacement cost of energy.

III.F.2.3.8.7. Actual Revenue. The actual revenue for a Resource is the actual metered output multiplied by the Real-Time Price for all hours in the settlement period.

III.F.2.3.8.8. Actual Avoided Replacement Cost. The actual avoided replacement cost for an Operating Day is the actual remaining energy at the end of the Operating Day multiplied by the estimated replacement cost of energy.

III.F.2.3.8.9. Credit Calculation. The real-time posturing NCPC credit for Limited Energy Resources is equal to the greater of (i) zero and (ii) the estimated revenue plus the estimated avoided replacement cost, minus the actual revenue plus the actual avoided replacement cost.

III.F.2.3.9. Real-Time Posturing NCPC Credits for Generators (Other Than Limited Energy Resources) Postured for Reliability

III.F.2.3.9.1. Eligibility for Credit. All Market Participants with an Ownership Share in a generating Resource, other than a Limited Energy Resource, are eligible for real-time posturing NCPC credits for the hours during which the Resource has been Postured.

III.F.2.3.9.2. Settlement Period. For purposes of calculating real-time posturing NCPC credits, a settlement period is an hour during which the generating Resource is Postured.

III.F.2.3.9.3. Offer Used for Estimated Hourly Revenue and Cost. For purposes of calculating real-time posturing NCPC credits, the offer parameters used to estimate revenue and cost for an hour are:

(a) the higher of the energy price parameter specified in (i) the Supply Offer for the hour at the time the ISO Postures the Resource, or (ii) the Supply Offer for the hour at the start of the hour.
(b) for Resources Postured offline, the Start-Up Fee and No-Load Fee specified in the Supply Offer for the hour at the time the Resource is Postured.
(c) for Resources Postured to remain online but reduce output, the Start-Up Fee and No-Load Fee are calculated pursuant to Section III.F.2.2.2.3.

III.F.2.3.9.4. Estimated Hourly Revenue. The estimated hourly revenue for a Resource is the optimized energy output multiplied by the Real-Time Price for the hour. The optimized energy output is estimated for each hour by determining where the Resource would have operated had it not been Postured based on Real-Time Prices. The optimized energy output determination will take account of the energy price parameter of the Supply Offer and the Resource's Economic Minimum Limit and Economic Maximum Limit.

III.F.2.3.9.5. Estimated Hourly Cost. The estimated hourly cost for a Resource is the energy price parameter of the Supply Offer for the optimized energy output for the hour, plus the Start-Up Fee and the No-Load Fee, subject to the following conditions:

(a) For a Fast Start Generator Postured offline, the Start-Up Fee is included in each hour's cost and is not subject to apportionment.

(b) For a non-Fast Start Generator Postured offline, the Start-Up Fee is apportioned, in accordance with Section III.F.2.2.2.3.2, as if its commitment had not been cancelled.

For purposes of determining the estimated hourly cost for a Resource, the Resource is treated as a Fast Start Generator only if it is designated as such at the time of the commitment decision for the Commitment Period during which the Resource was Postured, and if not the Resource is treated as a non-Fast Start Generator. If the Resource is offline at the time it is Postured, then its designation as a Fast Start Generator or non-Fast Start Generator is determined as of the time of the Posturing decision.

III.F.2.3.9.6. Actual Hourly Revenue. The actual hourly revenue for a Resource is the actual metered output multiplied by the Real-Time Price for the hour.

III.F.2.3.9.7. Actual Hourly Cost. The actual hourly cost for a Resource Postured to remain online but reduce output is the energy price parameter of the Supply Offer in place at the start of the hour for the actual metered output, plus the Start-Up Fee and No-Load Fee calculated pursuant to Section III.F.2.2.2.3. The actual hourly cost for a Resource Postured offline is zero.

III.F.2.3.9.8. Credit Calculation. The real-time posturing NCPC credit for a generator, other than a Limited Energy Resource, is equal to the greater of (i) zero and (ii) the estimated hourly revenue minus the estimated hourly cost, minus the actual hourly revenue minus actual hourly cost.

III.F.2.4. Apportionment of NCPC Credits

Each of the Day-Ahead Energy Market NCPC Credits for a non-Fast Start Generator are apportioned to the hours with negative net revenues in proportion to each hour's negative net revenue divided by the sum of the negative net revenue for all hours in the settlement period.

Each of the Real-Time Commitment NCPC Credits for a non-Fast Start Generator is apportioned as follows: (i) for the portion of each Commitment Period within a settlement period that contains hours of the Minimum Run Time, to the hours with negative net revenues in proportion to each hour's negative net revenue divided by the sum of the negative net revenue in the portion of the Commitment Period, and (ii)

for all remaining hours of the settlement period, to the hours with negative net revenues in proportion to each hour's negative net revenue divided by the sum of the negative net revenue in the period.

Each of the Hourly Shortfall NCPC Credits for a non-Fast Start Generator for energy cleared in the Day-Ahead Energy Market at the Resource's Economic Minimum Limit is apportioned to the hours in which the Real-Time Price exceeds the Day-Ahead Price, for all hours in the settlement period .

The following NCPC credits are assigned to the hours for which the credit was calculated:

- Day-Ahead Energy Market NCPC Credits for Fast Start Generators,
- Real-Time Commitment NCPC Credits for Fast Start Generators,
- Real-Time Dispatch NCPC Credits for all Resources,
- Day-Ahead External Transaction Import and Increment Offer NCPC Credits,
- Day-Ahead External Transaction Export and Decrement Bid NCPC Credits,
- Real-Time External Transaction NCPC Credits,
- Real-Time Posturing NCPC Credits for Dispatchable Asset Related Demand Resources (Pumps Only) Postured for Reliability,
- Hourly Shortfall NCPC Credits for Fast Start Generators, and
- Hourly Shortfall NCPC Credits for non-Fast Start Generators for energy cleared in the Day-Ahead Energy Market above the Resource's Economic Minimum Limit.

III.F.2.5. NCPC Credit Designation for Purposes of NCPC Cost Allocation. Each hourly credit for Day-Ahead Energy Market NCPC Credits, Real-Time Commitment NCPC Credits, Real-Time Dispatch NCPC Credits, Day-Ahead External Transaction Import and Increment Offer NCPC Credits, Day-Ahead External Transaction Export and Decrement Bid NCPC Credits, Real-Time External Transaction NCPC Credits, Real-Time Posturing NCPC Credits for Dispatchable Asset Related Demand Resources (Pumps Only) Postured for Reliability, Hourly Shortfall NCPC Credits, and Real-Time Posturing NCPC Credits for Generators (Other Than Limited Energy Resources) Postured For Reliability, and each daily credit for Real-Time Synchronous Condensing NCPC Credits, Cancelled Start NCPC Credits, and Real-Time Posturing NCPC Credits for Limited Energy Resources Postured for Reliability, is designated as first contingency, second contingency, voltage (VAR), distribution (SCR), ISO initiated

audits and Minimum Generation Emergency consistent with the reason provided by the ISO when issuing a Dispatch Instruction for the Resource. If there is more than one reason provided by the ISO when issuing the Dispatch Instruction, the NCPC Credits are divided equally for purposes of the above designations. With the exception of Day-Ahead External Transaction Import and Increment Offer NCPC Credits and Day-Ahead External Transaction Export and Decrement Bid NCPC Credits, the hourly credits are summed to determine the total credits for each NCPC Charge category for a day.

III.F.3. Charges for NCPC

III.F.3.1. Cost Allocation.

III.F.3.1.1 Day-Ahead Energy Market NCPC Cost Allocation. NCPC costs for the Day-Ahead Energy Market are allocated and charged as follows:

(a) The total NCPC cost for the Day-Ahead Energy Market associated with Pool-Scheduled Resources scheduled in the Day-Ahead Energy Market for the provision of voltage or VAR support (including Synchronous Condensers and Postured Resources but excluding Special Constraint Resources) are charged in accordance with the provisions of Schedule 2 of Section II of the Transmission, Markets and Services Tariff.

(b) The total NCPC cost for the Day-Ahead Energy Market for resources designated as Special Constraint Resources in the Day-Ahead Energy Market are allocated and charged in accordance with Schedule 19 of Section II of the Transmission, Markets and Services Tariff.

(c) The total NCPC cost for the Day-Ahead Energy Market for resources identified as Local Second Contingency Protection Resources for the Day-Ahead Energy Market for one or more Reliability Regions is allocated and charged in accordance with Section III.F.3.3.

(d) For each External Node, the total NCPC cost for Day-Ahead External Transaction Import and Increment Offer NCPC Credits at an External Node for an hour is allocated and charged to Market Participants based on their pro-rata share of the sum of their Day-Ahead Load Obligations at the External Node for the hour.

(e) For each External Node, the total Day-Ahead External Transaction Export and Decrement Bid NCPC Credits at an External Node for an hour is allocated and charged to Market Participants based on their pro-rata share of the sum of their Day-Ahead Generation Obligations at the External Node for the hour.

(f) All remaining NCPC costs for the Day-Ahead Energy Market are allocated and charged to Market Participants based on their pro rata daily share of the sum of of Day-Ahead Load Obligations over all Locations (including the Hub),

III.F.3.1.2. Real-Time Energy Market NCPC Cost Allocation. NCPC costs for the Real-Time Energy Market are allocated and charged as follows, subject t the conditions in Section III.F.3.1.3:

(a) The total NCPC cost for the Real-Time Energy Market associated with Pool-Scheduled Resources scheduled in the Real-Time Energy Market for the provision of voltage or VAR support (including Synchronous Condensers and Postured Resources but excluding Special Constraint Resources) are allocated and charged in accordance with the provisions of Schedule 2 of Section II of the Transmission, Markets and Services Tariff.

(b) The total NCPC cost for the Real-Time Energy Market for resources designated as Special Constraint Resources in the Real-Time Energy Market are allocated and charged in accordance with Schedule 19 of Section II of the Transmission, Markets and Services Tariff.

(c) The total ISO initiated audit NCPC cost for resources performing an ISO initiated audit is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with Dispatchable Asset Related Demand Resources (pumps only).

(d) The total NCPC cost for resources following Dispatch Instructions while being postured in the Real-Time Energy Market is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with postured Dispatchable Asset Related Demand Resources (pumps only).

(e) The total NCPC cost for the Real-Time Energy Market for resources identified as Local Second Contingency Protection Resources for the Real-Time Energy Market for one or more Reliability Regions is allocated and charged in accordance with Section III.F.3.3.

(f) Total Minimum Generation Emergency Credits within a Reliability Region are allocated and charged hourly to Market Participants based on each Market Participant's pro rata share of Real-Time Generation Obligations, excluding that portion of a Market Participant's Real-Time Generation Obligation within a Reliability Region that is eligible for a Real-Time Dispatch NCPC Credit pursuant to Section III.F.2.2.3 during a Minimum Generation Emergency.

(g) All remaining NCPC costs for the Real-Time Energy Market are allocated and charged to Market Participants based on their pro rata daily share of the sum of the absolute values of a Market Participant's (i) Real-Time Load Obligation Deviations in MWhs during that Operating Day; (ii) generation deviations for Pool-Scheduled Resources not following Dispatch Instructions, Self-Scheduled Resources with dispatchable increments above their Self-Scheduled amounts not following Dispatch Instructions, and Self-Scheduled Resources

not following their Day-Ahead Self-Scheduled amounts other than those Self-Scheduled Resources that are following Dispatch Instructions, including External Resources, in MWhs during the Operating Day; and (iii) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day. The Real-Time deviations calculation is specified in greater detail in Section III.F.3.2.

III.F.3.1.3 Additional Conditions for Real-Time Energy Market NCPC Cost Allocation.

(a) If a generation resource has been scheduled in the Day-Ahead Energy Market and the ISO determines that the unit should not be run in order to avoid a Minimum Generation Emergency, the generation owner will be responsible for all Real-Time Energy Market Deviation Energy Charges but will not incur generation related deviations for the purpose of allocating NCPC costs for the Real-Time Energy Market.

(b) Any difference between the actual consumption (Real-Time Load Obligation) of Dispatchable Asset Related Demand Resources and Dispatchable Asset Related Demand bids that clear in the Day-Ahead Energy Market that result from operation in accordance with the ISO's instructions shall be excluded from the Market Participant Real-Time Load Obligation Deviation for the purpose of allocating costs for Real-Time Energy Market NCPC Credits.

III.F.3.2 Market Participant Share of Real-Time Deviations for Real-Time Energy Market NCPC Credits.

Each Market Participant's pro-rata share of the Real-Time deviations for Real-Time Energy Market NCPC Credits is the following:

(a) If the Day-Ahead Economic Minimum Limit is equal to the Real-Time Economic Minimum Limit and the Real-Time Economic Minimum Limit is greater than or equal to the Resource's Desired Dispatch Point: Real-Time generation deviation is the greater of the absolute value of (actual metered output – cleared Day-Ahead MWh) or (actual metered output – Real-Time Economic Minimum Limit) for each generating Resource. If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

(b) If the Day-Ahead Economic Minimum Limit is not equal to Real-Time Economic Minimum Limit and the Real-Time Economic Minimum Limit is greater than or equal to the Resource's Desired Dispatch Point: Real-Time generation deviation is the greatest of the absolute value of (actual metered

output – cleared Day-Ahead MWh) or (actual metered output – Real-Time Economic Minimum Limit) or (Real-Time Economic Minimum Limit – Day-Ahead Scheduled Economic Minimum Limit) for each generating Resource.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

(c) If the Resource's Desired Dispatch Point is greater than the Resource's Real-Time Economic Minimum Limit and the Resource is not following ISO Dispatch Instructions: Real-Time generation deviation is the absolute value of (actual metered output - Desired Dispatch Point).

If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

plus
(d) for each Pool Scheduled generating Resource:

(i) If the Resource is not following Dispatch Instructions and has cleared Day-Ahead and has an actual metered output greater than zero and has not been ordered off-line by the ISO for reliability purposes: Real-Time generation deviation is the absolute value of (actual metered output − Desired Dispatch Point) for each generating Resource.
If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

(ii) If the Resource is not following Dispatch Instructions, has cleared Day-Ahead, that has an actual metered output equal to zero and has not been ordered off-line by the ISO for reliability purposes: Real-Time generation deviation is the absolute value of (actual metered output – cleared Day-Ahead MWh) for each generating Resource.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

plus,

(e) absolute values for the Operating Day of the Participant's Real-Time Load Obligation Deviation the sum of the hourly.

~~[NOTE: External Transaction sales curtailed by the ISO are omitted from this calculation],~~

where

(i) each Market Participant's Real-Time Load Obligation Deviation for each hour of the Operating Day is the sum of the difference between the Market Participant's Real-Time Load Obligation and Day-Ahead Load Obligation over all Locations (including the Hub), and.

(ii) for purposes of calculating a Participant's Real-Time Load Obligation Deviation under this sub-section (e), a Day-Ahead External Transaction that is not associated with a Real-Time External Transaction can be used to offset an External Transaction to wheel energy through the New England Control Area that is entered into the Real-Time Energy Market, and

(iii) External Transaction sales curtailed by the ISO are omitted from this calculation.

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plus,

(f) the sum of the hourly absolute values for the Operating Day of the Participant's Real-Time Generation Obligation Deviation at External Nodes except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency energy that is scheduled by the ISO to flow in the Real-Time Energy Market are not included in this calculation. .

~~[Note: External Transaction purchases curtailed by the ISO are omitted from this calculation],~~

Where

(i) each Market Participant's Real-Time Generation Obligation Deviation at External Nodes for each hour of the Operating Day is the sum of the difference between the Market Participant's Real-Time Generation Obligation and Day-Ahead Generation Obligation over all External Nodes, and

(ii) for purposes of calculating a Participant's Real-Time Generation Obligation Deviation under this sub-section (f), a Day-Ahead External Transaction that is not associated with a Real-Time External Transaction can be used to offset an External Transaction to wheel energy through the New England Control Area that is entered into the Real-Time Energy Market, and

(iii) External Transaction purchases curtailed by the ISO are omitted from this calculation.

plus,

(g) the absolute value of the total over all Locations of the Market Participant's Increment Offers.

[Please note that for purposes of this calculation an Increment Offer that clears in the Day-Ahead Energy Market always creates a Real-Time generation deviation.]

III.F.3.3 Local Second Contingency Protection Resource NCPC Charges.

Each Market Participant's pro-rata share of the cost for Day-Ahead Energy Market NCPC Credits and Real-Time Energy Market NCPC Credits for resources designated to provide Local Second Contingency Protection is based on its daily pro-rata share of the daily sum of the hourly Real-Time Load Obligations for each affected Reliability Region, subject to the following conditions:

(a) The External Node associated with an External Transaction sale that is, in accordance with Market Rule 1 Section III.1.10.7(h), a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction shall be considered to be within the Reliability Region from which the External Transaction is exporting for the purpose of calculating a Market Participant's pro-rata share of the cost for Real-Time Energy Market NCPC Credits for resources designated to provide Local Second Contingency Protection. The External Node of a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction is the External Node defined by the Forward Capacity Auction cleared Export Bid or Administrative Export De-List Bid associated with the External Transaction sale.

(b) For hours in which there is an NCPC cost for a resource providing Local Second Contingency Protection and ISO is selling Emergency energy to an adjacent Control Area, the scheduled amount of Emergency energy at the applicable External Node will be included in the calculation of a Market Participant's pro rata share of the cost for Real-Time Energy Market NCPC Credits for resources designated to provide Local Second Contingency Protection as if the Emergency energy sale were a Real-Time Load Obligation within each affected Reliability Region. The pro rata share calculated for the Emergency Energy Transaction shall be included in the charges under an agreement for purchase and sale of Emergency energy with the applicable adjacent Control Area.

For purposes of the calculation of Local Second Contingency Protection Resource NCPC Charges, Emergency energy sales by the New England Control Area to an adjacent Control Area at the External Nodes (see ISO New England Manual 11 for further discussion of the External Nodes) listed below shall be associated with the Reliability Region(s) indicated in the table:

External Node Common Name	Associated Transmission Facilities	Reliability Region(s)	Allocator
NB-NE External Node	Keene Road-Keswick (3001) Lepreau-Orrington (390/3016) tie line	Maine	100% to Maine
HQ Phase I/II External Node	HQ-Sandy Pond 3512 & 3521 Lines	West Central Massachusetts	100% to West Central Massachusetts
Highgate External Node	Bedford-Highgate (1429 Line)	Vermont	100% to Vermont
NY Northern AC External Node	Plattsburg – Sandbar Line (PV-20 Line) Whitehall – Blissville Line (K-7 Line) Hoosick- Bennington Line (K-6 Line) Rotterdam – Bearswamp Line (E205W Line) Alps – Berkshire Line (393Line) Pleasant Valley – Long Mountain Line (398 Line)	Vermont, Vermont Vermont West Central Massachusetts West Central Massachusetts Connecticut	Allocated proportionally to the Vermont, West Central Massachusetts and Connecticut Reliability Regions based on the Normal Limits as described in Appendix A to OP-16 of the transmission facilities connecting these Reliability Regions to the New York Control Area.
NY NNC External Node	Northport-Norwalk Harbor (601,602 and 603 Lines)	Connecticut	100% to Connecticut
NY CSC External Node	Shoreham-Halvarsson Converter (481 Line)	Connecticut	100% to Connecticut

(c) For each month, the ISO performs an evaluation of total Local Second Contingency Protection Resource NCPC charges for each Reliability Region. If, for any Reliability Region, the magnitude of such charges is sufficient to satisfy two conditions, a partial reallocation of the charges, from Market Participants with a Real-Time Load Obligation in that Reliability Region to Transmission Customers with Regional Network Load in that Reliability Region, is triggered. For all calculations performed under the provisions of this sub-paragraph c, the term Market Participant will include an adjacent Control Area and the term Real-Time Load Obligation will include MWh of Emergency energy sold in the circumstances described in subparagraph a above and will exclude Real-Time Load Obligations associated with the operation of a Dispatchable Asset Related Demand Resource (pumps only).

(i) Evaluation of Conditions –

Condition 1 – is the Local Second Contingency Protection Resource Charge $_{(Reliability\ Region,\ month)}$ > .06 X Load Weighted Real-Time LMP $_{(Reliability\ Region,\ month)}$

Condition 2 – is the Local Second Contingency Protection Resource Charge % $_{(Reliability\ Region,\ month)}$ > 2 X Twelve Month Rolling Average Local Second Contingency Protection Resource Charge $_{\%\ (Reliability\ Region)}$

Where:

Real-Time Load Obligation $_{(Reliability\ Region,\ month)}$ equals the sum of the hourly values of total Real-Time Load Obligation for each hour of the month in the Reliability Region.

Local Second Contingency Protection Resource Charge $_{(Reliability\ Region,\ month)}$ equals the sum of hourly Local Second Contingency Protection Resource charges for each hour of the month in the Reliability Region divided by the Real-Time Load Obligation $_{(Reliability\ Region,\ month)}$.

Load Weighted Real-Time LMP $_{(Reliability\ Region,\ month)}$ equals the sum of the hourly values of Real-Time LMP times the associated Real-Time Load Obligation for each hour of the month in the Reliability Region, divided by the Real-Time Load Obligation $_{(Reliability\ Region,\ month)}$.

Local Second Contingency Protection Resource Charge % $_{(Reliability\ Region,\ month)}$ equals the Local Second Contingency Protection Resource Charge (Reliability Region, month) divided by the Load Weighted Real-Time LMP $_{(Reliability\ Region,\ month)}$.

Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % $_{(Reliability\ Region)}$ equals the sum of the prior 12 months' values, not including the current month, of Local Second Contingency Protection Resource Charge % $_{(Reliability\ Region,\ month)}$ divided by 12. (For the purposes of other calculations which include the Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % $_{(Reliability\ Region)}$, a value of .001 will be substituted for any Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % $_{(Reliability\ Region)}$ value of 0.)

If both conditions are met, a reallocation of a portion of Local Second Contingency Protection Resource Charge $_{(Reliability\ Region,\ month)}$ is triggered.

(ii) Determination of the portion of Local Second Contingency Protection Resource Charge $_{(Reliability\ Region,\ month)}$ to be reallocated –

Local Second Contingency Protection Resource Charge $_{(Reliability\ Region,\ month)}$ to be reallocated = Real-Time Load Obligation $_{(Reliability\ Region,\ month)}$ X Min (Condition 1 Rate $_{(Reliability\ Region,\ month)}$, Condition 2 Rate $_{(Reliability\ Region,\ month)}$)

Where:

Condition 1 Rate $_{(Reliability\ Region,\ month)}$ equals the Local Second Contingency Protection Resource Charge $_{(Reliability\ Region,\ month)}$ minus .06 times the Load Weighted Real-Time LMP $_{(Reliability\ Region,\ month)}$.

Condition 2 Rate $_{(Reliability\ Region,\ month)}$ equals the Local Second Contingency Protection Resource Charge $_{(Reliability\ Region,\ month)}$ minus 2 times the Twelve Month Rolling Average Local Second Contingency Protection Resource Charge $_{\%\ (Reliability\ Region)}$ times the Load Weighted Real-Time LMP $_{(Reliability\ Region,\ month)}$.

(iii) Determination of Local Second Contingency Protection Resource Charge $_{(Reliability\ Region,\ month)}$ reallocation credits to Market Participants and reallocation charges to Transmission Customers –

Market Participant reallocation credit =

(Real-Time Load Obligation $_{(Participant,\ Reliability\ Region,\ month)}$ / Real-Time Load Obligation $_{(Reliability\ Region,\ month)}$) * Local Second Contingency Protection Resource Charges $_{(Reliability\ Region,\ month)}$ to be reallocated

Where:

Real-Time Load Obligation $_{(Participant, Reliability Region, month)}$ equals the sum of the Market Participant's hourly values of total Real-Time Load Obligation in the Reliability Region for each hour of the month.

Transmission Customer reallocation charge =

(Regional Network Load $_{(Transmission Customer, Reliability Region, month)}$ / Regional Network Load $_{(Reliability Region, month)}$) * Local Second Contingency Protection Resource Charges $_{(Reliability Region, month)}$ to be reallocated

Where:

Regional Network Load $_{(Reliability Region, month)}$ equals:

The monthly MWh of Regional Network Load of all Transmission Customers in the Reliability Region

Regional Network Load $_{(Customer, Reliability Region, month)}$ equals:
The Transmission Customer's monthly MWh of Regional Network Load in the Reliability Region.

SECTION IV.A

RECOVERY OF ISO ADMINISTRATIVE EXPENSES

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IV.A.1 Definitions:

Whenever used in this Section IV.A, in either the singular or plural number, capitalized terms shall have the meanings specified in Section I.

IV.A.2 Purpose of Section IV.A; Adjustments to Rates

IV.A.2.1 Purpose of Section IV.A

Section IV.A of the Tariff is the means by which the ISO collects the revenues necessary to carry out its administrative functions in each calendar year, and contains rates, charges, terms and conditions for the following Services, which together encompass the functions carried out by the ISO:

(1) Scheduling, System Control and Dispatch Service (Schedule 1 hereto);

(2) Energy Administration Service (Schedule 2 hereto); and

(3) Reliability Administration Service (Schedule 3 hereto).

The rates and charges for each Service during a calendar year are based on the allocated portion of that year's Revenue Requirement. "Revenue Requirement" refers to the budgeted total expense for the year as adjusted by true-ups described herein.

IV.A.2.2 True-Ups

(1) Schedule 2 True-Up

(i) Each year (Year X), in determining the ISO's Revenue Requirement for the subsequent year (Year X+1), the ISO will make a true-up of the Schedule 2 portion of the Revenue Requirement for the prior year (Year X-1). Any difference between the actual Year X-1 Schedule 2 revenues and amounts budgeted for Schedule 2 revenues in the Year X-1 Revenue Requirement will be reflected in the projected Schedule 2 rates for Year X+1 as stated in paragraph (ii) below.

(ii) In implementing the true-up adjustment for revenue differences in the volumetric portion of Schedule 2, the differences will be added to (in the case of a revenue shortfall) or subtracted from (in the case of a revenue over-recovery) the ISO's total estimated budgeted amounts for

Schedule 2 for Year X+1. For revenue over-recoveries attributable to the TUs in Schedule 2, the ISO will treat them in the same manner as revenue adjustments for the volumetric portion of Schedule 2. For revenue shortfalls attributable to the TUs in Schedule 2, the ISO will allocate them according to the following method:

(a) 50% of the shortfall will be added to the ISO's projected Revenue Requirement for the Schedule 2 volumetric component (85% of the projected Schedule 2 Revenue Requirement prior to true-ups).

(b) An additional percentage of the shortfall will be added to the ISO's projected Revenue Requirement for the Schedule 2 volumetric component for each percentage decrease which was deemed to have occurred between the number of TUs used in the true-up and the number of TUs that the ISO had used in the original projection of the rates for that year.

(c) The maximum percentage of the shortfall to be added to the Schedule 2 volumetric component is 100%, which would result if the percentage difference between the actual and forecasted TUs were 50% or greater.

(d) Any remaining shortfall revenues after allocation of the shortfall to the Schedule 2 volumetric component will be added to the ISO's projected Revenue Requirement for the Schedule 2 TU component (15% of the projected Schedule 2 Revenue Requirements prior to true-ups).

(iii) True-Ups Collected in Future Rates. To the extent the ISO proposes to change its rate design for Section IV.A, the ISO will continue to implement the true-up procedures stated in this section to recover under- or over-collections of TUs for then-current and prior years. For example, when, on a going-forward basis effective January 1, 2012, the ISO eliminated the inclusion of an estimated true-up for the current year (Year X) in the Revenue Requirement for the subsequent year (Year X+1), the ISO was still required to include in the Revenue Requirement for 2013 the difference between the estimated 2011 true-up filed with the 2012 Revenue Requirement and the final 2011 true-up calculated based on historical data.

(2) General True-Up

Each year (Year X), in determining its Revenue Requirement for Year X+1, the ISO will include in such Revenue Requirement a true-up of Year X-1's Revenue Requirement for Schedules 1, 3 and 5. Specifically, the Revenue Requirement for Year X+1 will include deviations between collections under this Section IV.A and the ISO's actual expenses for Year X-1. For example, when filing the Revenue Requirement for 2014, the ISO will compute the total actual expenses for Schedules 1, 3 and 5 in 2012 and will compare these totals with the total charges actually collected under the Tariff for each of these Schedules during calendar year 2012. Based on these comparisons, the ISO will adjust the otherwise-projected Revenue Requirement for calendar year 2014 for one or more of Schedules 1, 3 and 5, as needed, downward or upward to reflect the actual calendar year 2012 surplus or deficit, respectively. From these figures the ISO will calculate rates for calendar year 2014, and make a rate change filing for calendar year 2014 and succeeding years, as required, to reflect the budget amount for the applicable calendar year and the true-up calculated by means of the foregoing analysis and adjustments.

(3) Indemnification

The Revenue Requirement does not reflect any amounts received by the ISO due to indemnification payments.

IV.A.3 Billing and Payment

IV.A.3.1 Billing Procedure:

With respect to charges under this Section IV.A., the ISO will apply the ISO Billing Policy as set forth in Exhibit ID to Section I of the Tariff.

IV.A.3.2 Working Capital Advances:

In the event that working capital financing arranged by the ISO is terminated early or repayment is accelerated (and no replacement funding has been obtained by the ISO) and Early Amortization Working Capital Charges have been assessed to Market Participants by the ISO, each month, each Market Participant shall be required to advance to the ISO an amount (each, an "Advance") equal to the ISO's reasonable projection of such Market Participant's charges under the Tariff for three succeeding months. The Advances shall be held in an interest bearing account. In each succeeding month, the ISO shall adjust each Market Participant's Advance so that, in each calendar month, each Market Participant's

Advance is equal to the ISO's reasonable projection of such Market Participant's charges under Section IV.A of the Tariff for such month and the next two succeeding months. If, in the reasonable judgment of the ISO, a cash deficiency is likely to occur at any time as a result of a depletion of the Advances (but not as a result of the failure of any Market Participant to pay its Advance), the ISO shall, at its option, have the right to require each Market Participant to pay the ISO its pro rata share (based on such Market Participant's projected charges under Section IV.A of the Tariff for the instant month and the next two succeeding months compared to projected charges to all Market Participants under Section IV.A of the Tariff for the instant month and the next two succeeding months) of any additional Advances required for the ISO's operations. If any Market Participant withdraws from the ISO or has its membership terminated, its Advance will be returned to it at the end of the month in which its withdrawal or termination is effective, provided that all of the departing Market Participant's liabilities under the Tariff have been satisfied, and all of the other Market Participants will have their Advances adjusted accordingly.

IV.A.4 Regulatory Filings

Nothing contained in the Tariff or any Service Agreement thereunder shall be construed as affecting in any way the right of the ISO to file with the Commission under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation. Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the ability of any Customer receiving a Service under the Tariff to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

IV.A.5 Creditworthiness

For purposes of Section IV.A of the Tariff, the ISO will apply the ISO New England Financial Assurance Policy attached to Section I of the Tariff. Each Customer shall comply with the requirements of this policy, as applicable.

IV.A.6 Direct Billing; Sanctions

IV.A.6.1 Transmission Studies:

The ISO will conduct and coordinate certain System Impact Studies and Facilities Studies pursuant to, and in accordance with, the Tariff. The costs of System Impact Studies and Facilities Studies will be charged directly to the pertinent Eligible Customers or interconnection applicants. The ISO will also

conduct studies as part of the Forward Capacity Market qualification process and will charge those costs directly through Qualification Process Cost Reimbursement Deposits.

IV.A.6.2 Information Requests:
In fulfilling information requests of a significant and non-routine nature, the ISO will charge its associated direct and indirect costs to the requestor. Revenue from these charges will be credited to Revenue Requirements for the Service to which the information request is most closely related.

IV.A.6.3 Non-Standard Provisions:
If there is a significant direct or indirect cost associated with the ISO's implementation of non-standard provisions for energy or other products in a bilateral contract, the ISO will charge those costs to the contract submitter. Revenue from these charges will be credited to Revenue Requirements for the Service to which the submitted contract is most closely related.

IV.A.6.4 Non-Standard Billing Service:
Market Participants and other Customers who require non-standard billing payment arrangements, pursuant to the terms of the ISO New England Financial Assurance Policy shall be charged the ISO's associated direct and indirect costs for these arrangements. Fees collected will be credited to Revenue Requirements for all three Services, in proportion to the relative Revenue Requirements for those Services.

IV.A.6.5 Imposition of Monetary Sanctions by the ISO:
Amounts collected by the ISO during a month from Market Participants pursuant to Section III.B of the Tariff shall be disbursed or credited by the ISO in accordance with the provisions of the Section III.B.5.5.

IV.A.6.6 Re-billing Requests:
In fulfilling re-billing requests of a significant and non-routine nature as a result of data revisions not being received in a timely fashion from a Customer, the ISO will charge its associated direct and indirect costs to that Customer. Revenue from these charges will be credited to Revenue Requirements for the Service to which the information request is most closely related.

IV.A.7 Metering

IV.A.7.1 Customer Obligations:
The Customer shall be responsible for compliance with metering requirements under the Tariff and the ISO New England Operating Documents and to communicate the metering information to the ISO.

IV.A.7.2 RTO Access to Metering Data:
The ISO will have access to such metering data as may reasonably be required to facilitate measurements and billing under the ISO New England Operating Documents, the Tariff or any Service Agreement thereunder.

IV.A.8 Collection of Commission Annual Charges:
The ISO's collection of amounts necessary to pay annual charges to the Commission is addressed in Schedule 4 hereof.

Schedule 1

Scheduling, System Control and Dispatch Service

Scheduling, System Control and Dispatch Service ("Scheduling Service") is the service required to schedule at the regional level the movement of power through, out of, within, or into the New England Control Area. For regional transmission service under the Tariff, Scheduling Service is an Ancillary Service that can be provided only by the ISO. All Transmission Customers must be Customers for Scheduling Service under this Tariff and purchase this Service from the ISO. The ISO's charges stated herein for Scheduling Service are based on the expenses incurred by the ISO in providing this Service. In addition, the ISO acts as a billing agent for the operators of the Local Control Centers and certain Market Participants in order to collect expenses incurred in providing this Service pursuant to this Schedule 1.

The ISO's expenses are based on the functions and activities required to provide this Service and include, but are not limited to:

- Processing and implementation of requests for regional transmission service, including support of the OASIS node;
- Coordination of transmission system operation (including administration of reactive power requirements under Schedule 2 of Section II of the Tariff) and implementation of necessary control actions by the ISO and support for these functions;
- Billing associated with regional transmission services provided under the Tariff;
- Transmission system planning which supports this Service; and
- Administrative costs associated with the aforementioned functions.

For the ISO's expenses in providing transmission-related Scheduling Service:

(A) each Customer that is obligated to pay the Regional Network Service rate shall pay each month, in arrears, an amount equal to the product of $0.15570 per kilowatt month times its Monthly Regional Network Load for that month.

(B) each Customer that is a Transmission Customer receiving Through or Out Service shall pay each month, in arrears, an amount equal to the product of the Transmission Customer's highest amount of Reserved Capacity (expressed in kilowatts) for an hour for each transaction, other than a Coordinated

External Transaction, that is scheduled to occur during the month as Through or Out Service multiplied by $0.00021 per kilowatt for each hour of service.

Schedule 1 revenues collected from Through or Out Service customers shall be credited to each Network Customer receiving Regional Network Service that month in proportion to each Network Customer's Monthly Regional Network Load in that month.

Non-Market Participant FTR fees and any portions of Long Lead Facility deposits collected by the ISO under Schedule 22 and Schedule 25 of Section II of the Tariff that become non-refundable will be credited to Schedule 1 Revenue Requirements and will be included in the Schedule 1 true-up calculations.

All general terms and conditions of the Tariff apply to this Service.

Schedule 2

Energy Administration Service

Energy Administration Service ("EAS") is the Service provided by the ISO to administer the Energy Market.

The ISO's expenses are based on the functions required to provide EAS and include, but are not limited to:

- Core operation of the Energy Market;
- Generation and demand dispatch related to the Energy Market;
- Energy accounting;
- Loss determination and allocation;
- Billing preparation;
- Market power monitoring and mitigation for the Energy Market;
- Sanctions activities;
- Operation of FTR auctions;
- Market assessment and reports; and
- Formulation of additional market rules and proposals to modify existing rules.

Each Market Participant that has an account for Energy that is settled by the ISO for the current month shall pay each month an amount based on Energy Transaction Units (Energy TUs), Increment Offers, Decrement Bids, Volumetric Measures, submitted FTR auction bids, and cleared FTR auction bids.

Energy TU Based Charges: For purposes of this Schedule 2, Energy TUs shall be calculated without reference to contributions from Coordinated External Transactions. Each Customer that has, during a month, incurred Energy TUs exceeding zero shall pay an amount, in arrears, equal to the sum of the products of:

(1) $0.65101 times the Customer's first 12,500 Energy TUs for that month; plus

(2) $0.59182 times the amount of Energy TUs that exceed 12,500 but are less than or equal to 39,500; plus

(3) $0.53264 times the amount of Energy TUs that exceed 39,500.

Charges Based on Increment Offers and Decrement Bids: Each Customer submitting Increment Offers and/or Decrement Bids shall pay, in arrears, amounts equal to:

(1) $0.00500 times the number of Increment Offers and Decrement Bids submitted by the Customer for that month; plus

(2) $0.06000 times the number of Increment Offers and Decrement Bids submitted by the Customer for that month that clear in the Day-Ahead Energy Market.

Volumetric Measure Based Charges: A Customer shall be considered an EAS VM Customer if the sum of Monthly Real-Time Load Obligation and Monthly Real-Time Generation Obligation (measured in megawatthours, MWh and excluding Coordinated External Transactions) assessed to that Customer during the month exceeds zero (0), in which case, the total EAS VM charges for that Customer shall be equal to the sum of:

(1) Monthly Real-Time Load Obligation (MWh), excluding Monthly Real-Time Load Obligation associated with Coordinated External Transactions; and

(2) Monthly Real-Time Generation Obligation (MWh); provided, however, that Monthly Real-Time Generation Obligation associated with energy imported into the New England Control Area by Bangor Hydro-Electric Company across the New Brunswick ties shall be excluded (up to 300 MW) for billing and rate calculation purposes from EAS VMs, and provided further that Monthly Real-Time Generation Obligation associated with Coordinated External Transactions shall be excluded.

Subject to the foregoing, each Market Participant that is identified as an EAS VM Customer for that month shall pay an amount, in arrears, based on total EAS VM, equal to:

(a) $0.25517 per MWh for the first 250,000 MWh of EAS VM for that month; plus

(b) $0.23197 per MWh for each VM that exceeds 250,000 EAS VM but is less than or equal to 1,500,000 MWh for that month; plus

(c) $0.20877 per MWh for each EAS VM in excess of 1,500,000 MWh for that month.

Charges Based on Submitted and Cleared FTR Bids: Each Customer submitting FTR auction bids shall pay, in arrears, amounts equal to:

(1) $.85853 times the number of bids submitted by the Customer into any FTR auctions held for that month; plus

(2) $.85853 times the number of bids submitted by the Customer into any annual or multi-month FTR auctions (billed with the invoice for the first month of the annual or multi-month FTR auction); plus

(3) $1.21377 times the number of bids submitted by the Customer during that month that clear any FTR auctions held for that month; plus

(4) $1.21377 times the number of bids submitted by the Customer that clear any annual or multi-month FTR auctions (billed with the invoice for the first month of the annual or multi-month FTR auction).

Schedule 3

Reliability Administration Service

Reliability Administration Service ("RAS") is the Service provided by the ISO to administer the Reliability Markets (and facilitate reliability-associated transactions and arrangements) in accordance with the Tariff and the corresponding rules promulgated thereunder, and to provide other reliability and informational services. The Reliability Markets are also a means by which certain Ancillary Services are obtained under Section II of the Tariff. Each Customer must enter into a Service Agreement.

The ISO's administrative expenses are based on the functions required to provide this Service and include, but are not limited to:

- Generation and demand dispatch associated with Reliability Markets;
- Reliability Markets accounting;
- Billing preparation;
- The ISO generation emissions analysis;
- Risk profile updates;
- Triennial review of resource adequacy;
- Studies and qualification of resources under Forward Capacity Market;
- Preparation of regional reports and load forecasts and profiles (Capacity, Energy, Load and Transmission reports; reports to the Energy Information Administration (EIA) of the United States Department of Energy; reports to the North American Electric Reliability Corporation; Regional System Plan);
- Support of power supply, environmental and market reliability planning activities;
- Market power monitoring, mitigation and assessment for the Reliability Markets;
- Formulation of additional market rules and proposals to modify existing rules.

(A) Each Transmission Customer taking Through or Out Service that is not a Market Participant shall be considered a RAS Customer and shall pay each month, in arrears, a RAS fee equal to the product of $3.02 times the number of hourly Through or Out reservations made for that month.

(B) Each Customer that is a Market Participant shall be considered a RAS Customer and shall pay each month, in arrears, an amount equal to the product of $0.18763 per kilowatt month times the Market Participant's Real-Time NCP Load Obligation (measured in kilowatts) for that month.

(C) For Exports other than Coordinated External Transactions, each RAS Customer shall pay each month, in arrears, an amount equal to $0.37 per MWh per Export, where MWh represents the hourly scheduled MWs of associated Export.

In order to preserve the settlement approved in Docket No. ER01-316, Market Participants engaging in "through" transactions using Through or Out Service will not be deemed to have a Real-Time Load Obligation on account of those transactions.

Charges collected under Schedule 3 for RAS do not include any amounts paid by the ISO on behalf of the Market Participants to purchase emergency power.

Charges collected under Schedule 3 for RAS do not include the recovery of costs associated with disclosure or tracking obligations. If one or more states require Market Participants to undertake such activity the ISO will separately charge the expenses associated with such obligations.

All general terms and conditions of the Tariff apply to this Service.

Schedule 4

Collection of Commission Annual Charges

Each Transmission Owner that is jurisdictional to the Commission shall provide to the ISO under oath, sixty days in advance of the due date for the Commission's Reporting Requirement No. 582 ("FERC-582"), data for the pertinent period concerning the Transmission Owner's megawatt-hours of all unbundled transmission (including MWh delivered in wheeling transactions and MWh delivered in exchange transactions) and the Transmission Owner's megawatt-hours of all bundled wholesale power sales (to the extent these latter MWh were not separately reported as unbundled transmission) for the pertinent period, in the level of detail required by Commission regulations and necessary for the ISO to make and support a FERC-582 report by the ISO for the New England Control Area. These amounts are reported on the Commission's Form 1 in connection with accounts 447, 456, and 555.

Upon the ISO's receipt of the Commission's bill for the annual charges for the New England Control Area, the ISO will promptly calculate the allocable portion of that annual charge payable by each Transmission Owner. To determine the amount payable by each Transmission Owner for the annual charge for the then-current Commission fiscal year, the ISO will divide each Transmission Owner's total reported megawatt-hours of transmission of electric energy in interstate commerce by the total megawatt-hours of transmission of electric energy in interstate commerce reported for the prior calendar year by the ISO in FERC-582 for the New England Control Area, and multiply the resulting figure by the Commission's annual charge to the New England Control Area for the then-current Commission fiscal year. The allocation among Transmission Owners of any adjustments for the prior Commission fiscal year reflected in the current-year Commission bill will be calculated by multiplying (x) each Transmission Owner's adjusted sales (i.e., megawatt-hours of transmission of electric energy in interstate commerce) for the calendar year on which that prior Commission fiscal year's annual charges were based by (y) the final Commission charge factor for that prior fiscal year, as indicated in the Commission bill. This amount will be compared with the amount originally paid by the corresponding Transmission Owner for the prior fiscal year and any difference (positive or negative) will be an adjustment to the payment required from that Transmission Owner for current-year Commission annual charges. The ISO will promptly notify each Transmission Owner of the required payment, and each Transmission Owner shall pay to the ISO, within fifteen (15) days of the Transmission Owner's receipt of the notice, the amount specified in the notice.

Each Transmission Owner will provide the ISO with assistance reasonably required in responding to information requests and audits by the Commission in connection with the Form 582 Reporting Requirement and payment of annual charges.

Schedule 5

Collection of NESCOE Budget

The ISO acts as the billing and collection agent for the New England States Committee on Electricity (NESCOE) for recovery of amounts reflected in the annual NESCOE budget through the rates set forth below. Each year, NESCOE will develop an annual budget, including supporting documentation and justification and a collection schedule, and present it to the ISO in final form no later than October 20 for the following calendar year, following the budget review process set forth in understandings among NESCOE, the ISO, and NEPOOL, which process is anticipated to begin in June each year. NESCOE shall not exceed its budget in any given calendar year. The "General True-Up Provision" in Section IV.A.2.2.(2) of this Tariff shall apply to this Schedule 5.

The ISO will calculate the Schedule 5 rate based on the rate design specified below. The ISO will submit the NESCOE-provided materials and any revised tariff sheets to the Commission separately but contemporaneously with the ISO's annual filing of rates to recover ISO's other administrative expenses.

For the calendar year 2015, the six New England states shall bear NESCOE's budgeted costs as follows. Each Customer that is obligated to pay the Regional Network Service rate shall pay each month, in arrears, an amount equal to the product of $0.00000 per kilowatt times its Monthly Regional Network Load for that month.

NEW YORK INDEPENDENT SYSTEM OPERATOR COORDINATION AGREEMENT

Coordination Agreement

Between

ISO New England Inc.

And

The New York Independent System Operator, Inc.

~~**Effective Date:**~~

~~**November 15, 2008**~~

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THIS AGREEMENT was made the 1st day of January, 2006, and is hereby restated on the ~~15th~~ ___ day of ~~November~~ _____, ~~2008~~2015,

BETWEEN:

NEW YORK INDEPENDENT SYSTEM OPERATOR, INC., a not-for-profit corporation established under the laws of New York State, hereinafter called the "NYISO".

And

ISO NEW ENGLAND INC., a not-for-profit, private corporation established under the laws of the State of Delaware, hereinafter called "ISO-NE".

WHEREAS, capitalized terms not otherwise defined herein shall have the meanings ascribed to them in Section 1.0 hereof;

WHEREAS, ISO-NE and the NYISO are sometimes hereinafter referred to, collectively, as the "Parties" and, individually, as a "Party";

WHEREAS, the NYISO is an independent, not-for-profit corporation established pursuant to the ISO Agreement, responsible for providing transmission service, maintaining the Reliability of the electric power system and facilitating efficient markets for capacity, energy and ancillary services in the New York Balancing Authority Area in accordance with its filed NYISO Tariffs;

WHEREAS, ISO-NE is a not-for-profit, independent corporation that serves as the RTO for New England, in which capacity it operates New England's wholesale electricity markets, manages a comprehensive regional bulk power system planning process and is responsible for the day-to-day reliable operation of New England's bulk power system;

WHEREAS, ISO-NE, as RTO for the New England Transmission System and administrator of the New England markets, and the NYISO as the ISO for the New York Transmission System, enter into coordination agreements and operating arrangements with the operators of neighboring Reliability

Coordinator Areas and Balancing Authority Areas, and coordinate system operation and Emergency procedures with neighboring Reliability Coordinator Areas and Balancing Authority Areas;

WHEREAS, the NYISO and ISO-NE desire to coordinate interconnected operation to maintain Reliability for both of the power systems of New York State and the New England States, recognizing the Parties' desire to maximize interconnected capability under the terms and conditions contained in this Agreement; and

WHEREAS, related to the Interconnection Facilities:

A. ISO-NE is the Reliability Coordinator, Balancing Authority, Transmission Operator, market operator, and Planning Authority for the six New England States and operates and is responsible for the secure operation of the New England Transmission System in accordance with its Transmission Operating Agreements with New England Transmission Owners and in compliance with the FERC-accepted ISO-NE Tariff, and the requirements and criteria set forth by NERC or NPCC and, as such, has the power and authority to enter into this Agreement and perform its obligations under it;

B. NYISO is the Reliability Coordinator, Balancing Authority, Transmission Operator, market operator, and Planning Authority for New York State and operates and is responsible for the secure operation of the New York Transmission System in accordance with its Transmission Operating Agreements with New York Transmission Owners and in compliance with the FERC-accepted New York Independent System Operator Agreement ("ISO Agreement"), the Agreement Between New York Independent System Operator and Transmission Owners ("ISO/TO Agreement"), the Agreement between New York Independent System Operator and the New York State Reliability Council ("ISO/NYSRC Agreement"), NYISO Tariffs, and the requirements and criteria set forth by NERC, NPCC and the NYSRC and, as such, has the power and authority to enter into this Agreement and perform its obligations under it; and

C. The New England Transmission System and the New York Transmission System interconnect by way of the Interconnection Facilities, which are described in Schedule A of this Agreement; and

D. The Parties wish to record their agreement as to the operational and other matters addressed herein and pertaining to the Interconnection Facilities; and

WHEREAS the Parties desire to manage the operational aspects of their interconnected operations by developing, administering and implementing practices, procedures and sharing information relating to Reliability coordination and power system operation that will be managed and approved by a committee formed under this Agreement;

NOW, THEREFORE, THIS AGREEMENT WITNESSES THAT in consideration of the mutual agreements and obligations between the Parties and for other good and valuable consideration ISO-NE and the NYISO agree as follows:

ARTICLE 1.0: DEFINITIONS

In this Agreement, the following words and terms shall have the meanings (such meanings to be equally applicable to both the singular and the plural forms) ascribed to them in this Article 1.0.

"Adequacy" means the ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

"Agreement" means this Agreement and the Schedule(s) attached hereto and incorporated herein.
"Balancing Authority" means the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

"Balancing Authority Area" means the collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.

"Confidential Information" has the meaning stated in Section 6.5 of this Agreement.

"Confirmed Trust Relationship" means that one Responsible Settlement Party has granted another Responsible Settlement Party permission to confirm, modify or withdraw its CTS Interface Bids.

"Control Area" means an electric 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 capacity to maintain Operating Reserves in accordance with Good Utility Practice.

"Coordination Committee" means the jointly constituted ISO-NE and NYISO committee established to administer the terms and provisions of this Agreement pursuant to Article 7.0 of this Agreement.

"Coordinated Transaction Scheduling" or "CTS" means an external transaction scheduling process between the NYCA and NECA in which Market Participants' bid, to buy energy in one region and sell in another region, is economically and simultaneously cleared by ISO-NE and NYISO. This process takes place pursuant to market rules in the Parties' respective tariffs that allow transactions to be scheduled over a CTS Enabled Interface based on a bidder's willingness to purchase energy from the NYCA or NECA (the source) and sell it to the other Control Area (the sink) if the bid price is less than or equal to the expected LMP difference across the interface in the requested direction, as of the time the interface is scheduled.

"CTS Enabled External Proxy Bus" shall mean an External Proxy Bus at which the Parties accept CTS Interface Bids to schedule external transactions in the real-time energy market.

"CTS Enabled Interface" means an Interconnection at which the Parties accept CTS Interface Bids for all import offers, for all export bids, and for wheels through the NECA. The CTS Enabled Interfaces are specified in Section 4.4.4 of the NYISO's Market Administration and Control Area Services Tariff and in Section III.1.10.7.A of the ISO-NE Tariff.

"CTS Interface Bid" means: (1) in ISO-NE, an Interface Bid as defined in the ISO-NE Tariff, and an hourly spread bid associated with the wheeling of energy through the NECA, and (2) in NYISO, a CTS Interface Bid as defined in the NYISO Tariff.

"Delivery Point" means a point on each of the three Interconnections between the New England Balancing Authority Area and the NYISO Balancing Authority Area and such other points of Interconnection as may be established. Such Delivery Point(s) shall include the Interconnection Facilities between ISO-NE and the NYISO.

"Dispute" has the meaning attributed thereto in Article ~~17~~19.0 of this Agreement.

"Effective Date" means the reference date of this Agreement as shown on the first page of this Agreement.

"Emergency" means any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the Reliability of the Bulk Electric System (as defined by NERC).

"Emergency Energy" means energy supplied from Operating Reserve or electrical generation available for sale in New York or New England or available from another Balancing Authority Area. Emergency Energy may be provided in cases of sudden and unforeseen outages of generating units, transmission lines or other equipment, or to meet other sudden and unforeseen circumstances such as forecast errors, or to provide sufficient Operating Reserve. Emergency Energy is provided pursuant to this Agreement and priced according to Attachment A of Schedule C of this Agreement.

"External Interface Congestion" means the portion of the congestion component of the LMP at an External Proxy Bus that is associated with an External Proxy Bus Constraint.

"External Proxy Bus" means a location that is selected to represent an Interconnection with a Party's Control Area for which LMPs are calculated. In NYISO, this is a Proxy Generator Bus as defined in the NYISO Services Tariff. In ISO-NE, this is an External Node as defined in the ISO-NE Tariff.

"External Proxy Bus Constraint" has the meaning set forth in Section 4.2 of Schedule D to this Agreement.

"FERC" means the Federal Energy Regulatory Commission.

"Force Majeure" means an event of force majeure as described in Section 11.1 of this Agreement.

"Good Utility Practice" means any of the practices, methods and acts engaged in or approved by a significant portion of the North American 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 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 to be acceptable practices, methods, or acts generally accepted by NERC and the FERC.

"Intentional Wrongdoing" means an act or omission taken or omitted by a Party with knowledge or intent that injury or damage could reasonably be expected to result.

"Interconnection" means a connection(s) between two or more individual Transmission Systems that have interconnecting Intertie(s).

"Interconnection Facilities" means the Interconnections described in Schedule A.

"Interconnection Reliability Operating Limit" or "IROL" means a System Operating Limit that, if violated, could lead to instability, uncontrolled separation or Cascading Outages (as defined by NERC) that adversely impact the reliability of the Bulk Electric System.

"Intertie" means a transmission line that forms part of an Interconnection.

"ISO" means independent system operator, as designated by FERC.

"ISO Agreement" means the agreement that establishes the NYISO.

"ISO-NE Supply Price Points" means a set of increasing MW and price pairs, as described in Section 3.0 of Schedule D.

"ISO-NE Tariff" means the ISO New England Inc. Transmission, Markets and Services Tariff, which includes the ISO-NE Open Access Transmission Tariff and ISO-NE market rules.

"Locational Marginal Price" or "LMP" shall mean the market price for energy at a given location in a Party's Control Area, calculated in accordance with the requirements of the Party's tariff, and "Locational Marginal Pricing" shall mean the processes related to the determination of the LMP.

"Market Participant" means ~~an entity that, for its own account, produces, transmits, sells, and/or purchases for its own consumption or resale capacity, energy, energy derivatives and ancillary services in the~~ a participant in either the ISO-NE- or NYISO-administered wholesale power markets. Market Participants include transmission service customers, power exchanges, Transmission Owners, load serving entities, loads, holders of energy derivatives, generators and other power suppliers and their designated agents.

"Metered Quantity" means apparent power, reactive power, active power, with associated time tagging and any other quantity that may be measured by a Party's Metering Equipment and that is reasonably required by either Party for Security reasons or revenue requirements.

"Metering Equipment" means the potential transformers, current transformers, meters, interconnecting wiring and recorders used to meter any Metered Quantity.

"Mutual Benefits" as described in Article 3.0 of this Agreement, means the transient and steady-state support that the integrated generation and transmission facilities in the New England and New York Transmission Systems provide to each other inherently by virtue of being interconnected.

"NERC" means the North American Electric Reliability Corporation or the successor organization.

"New England Control Area" or "NECA" is the Control Area for New England as defined in the ISO-NE Tariff.

"New England Transmission System" for the purpose of this Agreement means the entire system of transmission facilities, within the New England Reliability Coordinator Area and Balancing Authority Area that are under ISO-NE's operational jurisdiction, as defined in Transmission Operating Agreements and the ISO-NE Tariff.

"New York Control Area" or "NYCA" means the Control Area that is under the operational control of the NYISO, as defined in the NYISO Tariffs.

“New York State Reliability Council” or “NYSRC” means the organization that promotes and preserves the Reliability of electric service on the New York Transmission System by developing and maintaining NYSRC Reliability Rules which are complied with by the NYISO, and for monitoring and assuring compliance with such rules.

“New York Transmission System” for the purpose of this Agreement means the “NYS Transmission System” as that term is defined in the NYISO OATT.

"NPCC" means the Northeast Power Coordinating Council Inc. or its successor organization.

“NPCC Criteria, Guides and Procedures” are documents, or the successor of these documents, that contain the Reliability Standards of the NPCC and which detail the principles of interconnected planning and operations that define and direct the efforts of the NPCC and its members. These documents are essential to maintaining the Security, Adequacy, Reliability and efficient operation of the interconnected bulk power supply system of NPCC members.

“NYISO Open Access Transmission Tariff” or “NYISO OATT” means the NYISO Open Access Transmission Tariff accepted by FERC.

“NYISO Services Tariff” means the NYISO Market Administration and Control Area Services Tariff accepted by FERC.

“NYISO Tariffs” means the NYISO OATT and the NYISO Services Tariff, collectively.

“NYSRC Reliability Rules” means the rules applicable to the operation of the New York Transmission System by the NYISO. These rules are based on Reliability Standards adopted by NERC and NPCC, but also include more specific and more stringent rules to reflect the particular requirements of the New York Transmission System.

“Operating Instructions” means the joint operating procedures, steps, and instructions that are to be utilized by both Parties for the operation of the Interconnection Facilities established and modified from time to time by the Coordination Committee in accordance with (a) the ISO-NE Tariff and the NYISO Tariffs, (b) Schedule B of this Agreement and (c) the ISO-NE and NYISO individual procedures and

processes. Operating Instructions are separate from the ISO-NE and NYISO individual procedures and processes.

"Operating Reserve" means ~~that capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve~~: (1) in ISO-NE, an Operating Reserve as defined in Section I.2.2 of the ISO-NE Tariff, and (2) in NYISO, an Operating Reserve as defined in Section 2.2 of the NYISO Services Tariff. For purposes of Schedule D to this Agreement, 10-minute Operating Reserve is considered a higher quality product than 30-minute Operating Reserve.

"Operational Control" for the purpose of this Agreement, means Security monitoring, adjustment of generation and transmission resources, coordinating and approval of changes in transmission status for maintenance, determination of changes in transmission status for Reliability, coordination with other Balancing Authority Areas and Reliability Coordinators, voltage reductions and load shedding, except that each legal owner of generation and transmission resources continues to physically operate and maintain its own facilities.

"Parties" means ISO-NE and NYISO, and "Party" means either one of them.

"Planning Authority" means the responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.

"Ramp Limit" means, for purposes of Schedule D to this Agreement, either: (1) the maximum allowable amount of change in net interchange at a CTS Enabled Interface over a defined period of time, established in accordance with Section 5.1 of Schedule D; or (2) the maximum allowable amount of change in net interchange across all NYISO Proxy Generator Buses over a defined period of time, established in accordance with the NYISO Tariffs.

"Real-Time Commitment" or "RTC" means the NYISO's multi-period security constrained unit commitment and dispatch model, as defined in the NYISO Tariffs.

"Reliability" means the degree of performance of the bulk electric system that results in electricity being delivered within Reliability Standards and in the amount desired. Electric system Reliability can be

addressed by considering two basic and functional aspects of electric systems, which are Adequacy and Security.

"Reliability Coordinator" means the entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area (as defined by NERC) view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority, to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.

"Reliability Coordinator Area" means the collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.

"Reliability Standards" means the criteria, standards and requirements relating to Reliability established by a Standards Authority.

"Responsible Settlement Party" or "RSP" means a Market Participant that is responsible for the financial settlement of one or more transactions at a CTS Enabled Interface, as determined in accordance with the requirements of the Parties' respective tariffs that address the settlement of external transactions at CTS Enabled Interfaces.

"RTO" means a regional transmission organization, as designated by FERC.

"Schedule" means a schedule attached to this Agreement and all amendments, attachments, supplements, replacements and/or additions thereto.

"Security" means the ability of the electric system to withstand sudden disturbances including, without limitation, electric short circuits or unanticipated loss of system elements.

"Standards Authority" means NERC, NPCC, NYSRC or any other agency with authority over either Party regarding standards or criteria relating to the Reliability of Transmission Systems.

"System Operating Limit" means the value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable Reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to the following NERC-defined ratings or limits: Facility Ratings (applicable pre- and post-Contingency equipment or facility ratings); Transient Stability Ratings (applicable pre- and post-Contingency Stability Limits); Voltage Stability Ratings (applicable pre- and post-Contingency Voltage Stability); and System Voltage Limits (applicable pre- and post-Contingency Voltage Limits).

"Third Party" means a person or entity that is not a Party to this Agreement.

"Transfer Limit" means the maximum net interchange that can be scheduled on a CTS Enabled Interface and is established in accordance with Section 5.0 of Schedule D.

"Transmission Operating Agreement(s)" means the respective agreements that establish the terms and conditions under which the Transmission Owners transferred to the NYISO and ISO-NE Operational Control over the Interconnection Facilities. For the NYISO, these agreements are the ISO Agreement, the ISO/TO Agreement, and the ISO/NYSRC Agreement. For ISO-NE, this is the Transmission Operating Agreement, which provides operating authority over certain Interconnection Facilities (i.e., the NY/NE Northern AC Interconnection and the NNC Interconnection), and Attachment K to Section II of the ISO-NE Tariff, which provides operating authority over other Interconnection Facilities (i.e., the CSC Interconnection).

"Transmission Operator" means the entity responsible for the Reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities in accordance with applicable Transmission Operating Agreements.

"Transmission Owner" means the entity that owns and maintains transmission facilities.

"Transmission System" means a system for transmitting electricity, and includes any structures, equipment or other facilities used for that purpose.

ARTICLE 2.0: SCOPE OF AGREEMENT

2.1 Restatement of Prior Agreement

The terms of the prior agreement made between the Parties dated January 1, 2006, are hereby amended, restated and superseded by the terms of this Agreement, to be effective on the Effective Date of this Agreement.

2.2 Purpose of This Agreement

This Agreement provides for the reliable operation of the interconnected New England and New York Transmission Systems in accordance with the requirements of the Standards Authority.

This Agreement establishes a structure and framework for the following functions related to the Reliability of interconnected operations between the Parties:

(a) developing and issuing Operating Instructions and System Operating Limits;
(b) coordinating operation of their respective Transmission Systems;
(c) developing and adopting operating criteria and standards;
(d) conducting operating performance reviews of the Interconnection Facilities;
(e) considering matters related to transmission service and access;
(f) implementing each Party's respective NERC and NPCC requirements with regard to the New England Transmission System and New York Transmission System;
(g) exchanging operations information regarding the Interconnection;
(h) exchanging information and coordinating regarding system planning; ~~and~~
(i) providing mutual assistance in an Emergency and during system restoration;~~.~~
(j) administering Coordinated Transaction Scheduling; and
(k) implementing other arrangements between the Parties for the coordination of their systems.

The Parties shall, consistent with NPCC Criteria, Guides and Procedures and the Parties' respective tariffs, rules and standards, including with respect to the NYISO, the NYSRC Reliability Rules, to the maximum extent they deem consistent with the safe and proper operation of their respective Reliability Coordinator Area and Balancing Authority Area and necessary coordination with other interconnected

systems, and with the furnishing of dependable and satisfactory service to their own customers, operate their systems in accordance with the following procedures and principles.

ARTICLE 3.0: MUTUAL BENEFITS

3.1 No Charge for Mutual Benefits of Interconnection

Both the New England Transmission System and New York Transmission System, by virtue of being connected to each other and with a much larger Interconnection, share Mutual Benefits such as transient and steady-state support. NYISO and ISO-NE shall not charge one another for such Mutual Benefits.

3.2 Maintenance of Mutual Benefits

The Parties shall endeavor to operate or direct the operation of the Interconnection Facilities to realize the Mutual Benefits. The Parties recognize circumstances beyond their control, such as a result of operating configurations, contingencies, maintenance, or actions by Third Parties, may result in a reduction of Mutual Benefits.

ARTICLE 4.0: INTERCONNECTED OPERATION

4.1 Obligation to Remain Interconnected

The Parties shall at all times during the term of this Agreement operate or direct the operation of their respective Transmission Systems so that they remain interconnected except:

(a) during the occurrence of an event of Force Majeure which renders a Party unable to remain interconnected;

(b) when an Interconnection is opened in accordance with the terms of an Operating Instruction;

(c) when an Interconnection is opened in accordance with Good Utility Practice in a particular circumstance where there is an imminent risk of equipment failure, or of danger to personnel or the public, or a risk to the environment, or risk to the Reliability of a Transmission System that is not anticipated and addressed within an Operating Instruction; or

(d) during planned maintenance where notice has been given in accordance with outage procedures as implemented by the Coordination Committee.

4.2 Adherence to NPCC Criteria, Guides and Procedures

The Parties are participants in the NPCC and are required to comply with NPCC Criteria, Guides and Procedures. Such NPCC Criteria, Guides and Procedures detail the many coordinating functions carried out by the Parties and this Agreement is intended to enhance this arrangement. Such NPCC Criteria include, and the Parties agree to comply with, "Emergency Operation Criteria" (Document A-3), which describes the basic factors to be considered by a Reliability Coordinator and Balancing Authority in formulating plans and procedures to be followed in an Emergency. A principle of operation in this NPCC Criterion is that upon receiving a request for assistance to avoid or mitigate an Emergency, a Balancing Authority Area would provide "maximum reasonable assistance" to a neighboring Balancing Authority Area. Such reasonable assistance would not normally require the shedding of firm load.

4.3 Notification of Circumstances

In the event that a component of the Interconnection Facilities is opened or if the transfer capability of a component of the Interconnection Facilities is changed, or if a Party plans to initiate the opening of any component of the Interconnection Facilities, or to change the transfer capability of any component of the Interconnection Facilities, such Party shall immediately provide the other Party with notification indicating the circumstances of the opening or transfer capability change and expected restoration time, in accordance with procedures implemented by the Coordination Committee or applicable NPCC Criteria, Guides and Procedures.

4.4 Compliance with Coordination Committee Direction.

ISO-NE shall direct the operation of the New England Transmission System and the NYISO shall direct the operation of the New York Transmission System in accordance with the obligations of their respective tariffs, rules and standards and applicable directions of the Coordination Committee that conform with their respective tariffs, rules and standards, including with respect to the NYISO, the NYSRC Reliability Rules, except where prevented by Force Majeure. The Coordination Committee direction includes decisions and jointly developed and approved Operating Instructions. If decisions or Operating

Instructions of the Coordination Committee do not anticipate a particular circumstance, the Parties shall act in accordance with Good Utility Practice.

4.5 Control and Monitoring

Each Party shall provide or arrange for 24-hour control and monitoring of their portion of the Interconnection Facilities.

4.6 Reactive Transfer and Voltage Control

The Parties agree to determine reactive transfers and control voltages in accordance with the provisions of NPCC "Guidelines for Inter-Area Voltage Control" (Document B-03). Real and reactive power will be transferred over the Interconnection Facilities, which are described in Schedule A of this Agreement.

4.7 Inadvertent

Inadvertent power transfers on all Interconnection Facilities shall be controlled and accounted for in accordance with the standards and procedures developed by NERC and NPCC and implemented by the Coordination Committee and the system operators of each Party to this Agreement.

4.8 Adoption of Standards

The Parties hereby agree to adopt, enforce and comply with requirements and standards that will safeguard Reliability of the interconnected Transmission Systems. Such Reliability requirements and Reliability Standards shall be:

(a) adopted and enforced for the purpose of providing reliable service;
(b) not unduly discriminatory in substance or application;
(c) applied consistently to both Parties (with the exception of subsection (e) below);
(d) consistent with the Parties' respective obligations to applicable Standards Authorities including, without limitation, any relevant requirements or guidelines from each of NERC, NPCC or any other Standards Authority to which the Parties are required to adhere; and
(e) with respect to the NYISO, consistent with the NYSRC Reliability Rules.

4.9 New York - New England IROL Interface

The Parties share a joint Interconnection Reliability Operating Limit ("IROL") related to transfers on the interconnecting transmission lines between their respective Reliability Coordinator Areas and Balancing Authority Areas. This IROL is adhered to in order to ensure acceptable steady-state and transient performance of the New York and New England Transmission Systems. Both Parties will monitor this limit in accordance with this Agreement and independently determine the applicable import and export transfer limits. Both Parties agree to operate the interface to the most conservative limits developed in real-time and the day-ahead planning process. These operating limits shall be determined in accordance with NERC Reliability Standards and NPCC Criteria, Guides and Procedures. Both Parties will take coordinated corrective actions to avoid a violation of the IROL. If a violation occurs, coordinated corrective actions shall be taken to ensure that the violation is cleared as soon as possible, and in accordance with NERC Reliability Standards.

4.10 Coordination and Exchange of Information Regarding System Planning

Each Party shall have operating procedures, processes or plans in place for activities that require notification, exchange of information or coordination of actions with the other Party to support Interconnection reliability. Each Party shall have communications capabilities with the other Party, for both voice and data exchange as required to meet reliability needs of the Interconnection.

The Parties shall exchange information and coordinate regarding system operations and planning and inter-regional planning activities in a manner consistent with NERC and NPCC requirements, and consistent with the requirements of ~~confidentiality agreements or rules binding upon either of the Parties, including the ISO New England Information Policy set forth in Attachment D to the ISO-NE Tariff, as it may be amended from time to time, and the NYISO Code of Conduct as set forth in Attachment F to the NYISO OATT~~ Section 6 of this Coordination Agreement.

ARTICLE 5.0: EMERGENCY ASSISTANCE

5.1 Emergency Assistance

Both Parties shall exercise due diligence to avoid or mitigate an Emergency to the extent practicable as per each Party's requirements related to the mitigation of an Emergency, in applicable policies and procedures imposed by NERC, NPCC, or (for the NYISO) the NYSRC, or contained in the ISO-NE Tariff and NYISO Tariffs. In avoiding or mitigating an Emergency, both Parties shall strive to allow for commercial remedies, but if commercial remedies are not successful, the Parties agree to be the suppliers of last resort to ensure Reliability on the system. For each hour during which Emergency conditions exist in a Party's Balancing Authority Area, that Party (while still ensuring operations within applicable Reliability Standards) shall determine what commercial remedies are available and make use of those that are available and needed to avoid or mitigate the Emergency before any Emergency Energy is scheduled in that hour.

5.2 Emergency Energy Transactions

Each Party shall, to the maximum extent it deems consistent with the safe and proper operation of its respective Transmission System, provide Emergency Energy to the other Party in accordance with the provisions of Schedule C of this Agreement.

ARTICLE 6.0: EXCHANGE OF INFORMATION AND CONFIDENTIALITY

~~**6.1 Information**~~

ISO-NE and NYISO are authorized and agree to exchange and share such information as ~~may be~~ is required ~~from time to time~~ for the Coordination Committee to perform its duties and for the Parties to fulfill their obligations under this Agreement. ~~, subject to the requirements of existing confidentiality agreements or rules binding upon either of the Parties, including the ISO New England Information Policy, as it may be amended from time to time, and the NYISO Code of Conduct as set forth in Attachment F to the NYISO OATT, and subject to the Parties' policies and processes for the protection of~~ Any Party that receives Confidential Information or Critical Energy Infrastructure Information ("CEII") pursuant to this Article 6 (the "Receiving Party") shall treat such information as confidential subject to the terms and conditions set forth in Section 6.5 of this Agreement. ~~, as that term is defined by FERC). Subject to said agreements, policies and processes, the Parties may share the following information:~~

6.1 Information

Parties are authorized and agree to share the following information:

(a) Information required to develop Operating Instructions;

(b) Transmission System facility specifications and modeling data required to perform Security analysis;

(c) Functional descriptions and schematic diagrams of Transmission System protective devices and communication facilities;

(d) Ratings data and associated ratings methodologies for the Interconnection Facilities;

(e) Telemetry points, equipment alarms and status points required for real-time monitoring of Security dispatch;

(f) Data required to reconcile accounts for inadvertent energy, and for Emergency Energy transactions;

(g) Transmission System information that is consistent with the information sharing requirements imposed by the NERC and NPCC; ~~and~~

(h) Such other information as may be required for the Parties to maintain the reliable operation of their interconnected Transmission Systems and fulfill their obligations under this Agreement and to any Standards Authority of which either Party is a member, provided, however, that this other information will be exchanged only if it can be done in accordance with applicable restrictions on the disclosure of information to any Market Participant~~.~~; and

(i) Information related to the administration of CTS including:

- ISO-NE Market Participant user and organization information;
- ISO-NE Supply Price Points for each CTS Enabled Interface;
- ISO-NE Transfer Limits for each CTS Enabled Interface;
- NYISO and ISO-NE Operating Reserves and reserve requirements;
- Day-ahead schedules, and real-time actual output and limits for NYCA generators that have capacity obligations in the ISO-NE market and for NECA generators that have capacity obligations in the NYISO market;
- Real-time bids, including real-time bids to wheel energy, submitted at a CTS Enabled Interface between the NYCA and the NECA (to be provided by NYISO);
- NYISO Day Ahead Operating Plan; and

- NYISO RTC results, including cleared MWs for all bids at a CTS Enabled Interface between the NYCA and the NECA, as well as LMPs, Transfer Limits and constraint information related to the scheduling of real-time energy transactions between the NYCA and the NECA.

6.2 Data Exchange Contact

To facilitate the exchange of all such data, each Party will designate to the other Party's Vice President in charge of operations a contact(s), plus one or more alternate contacts, to be available twenty-four (24) hours each day, seven (7) days per week to respond to data inquiries. ~~The~~ An alternate contact of each Party shall be its Operations Control Room. ~~With respect to each contact and alternate, e~~Each Party shall provide the name, telephone number, e-mail address, and fax number of each contact and alternate. Each Party may change the designated contact by notifying the other Party's Vice President in charge of operations in advance of the change.

The Parties agree to exchange data in a timely manner consistent with existing defined formats or such other formats to which the Parties may agree. Each Party shall provide notification to the other Party thirty (30) days prior to modifying an established data exchange format.

6.3 Cost of Data and Information Exchange

Each Party shall bear its own cost of providing information to the other Party.

6.4 Other Data

The Parties may share ~~other data~~ Confidential Information not listed in this Article 6 ~~as mutually agreed upon by the Parties~~ that is necessary for the coordinated operation of their systems, subject to the protections set forth in Section 6.5, below.

6.5 Treatment of Confidential Information and Critical Energy Infrastructure Information

(a) Definitions. ~~The~~ For purposes of addressing information shared or exchanged pursuant to this Agreement, the term "Confidential Information" shall mean: (~~a~~i) all information, whether furnished before or after the mutual execution of this Agreement, whether oral,

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written or recorded/electronic, and regardless of the manner in which it is furnished, that is marked "confidential" or "proprietary" or which under all of the circumstances should be treated as confidential or proprietary; (~~b~~ii) information that is Confidential Information or Strategic Information under the ISO New England Information Policy or the NYISO Code of Conduct; (iii) information that is Protected Information under the NYISO Market Monitoring Plan; (iv) all reports, summaries, compilations, analyses, notes or other information of a Party hereto which are based on, contain or reflect any Confidential Information; or (~~c~~v) any information which, if disclosed by a transmission function employee of a utility regulated by the FERC to a market function employee of the same utility system, other than by public posting, would violate the FERC's Standards of Conduct set forth in 18 C.F.R. § 37 *et. seq*. and the Parties' Standards of Conduct on file with the FERC.

(b) Labeling of Confidential Information. In circumstances where it may not be clear that information that is provided or exchanged between the Parties pursuant to the authority provided in this Agreement is Confidential Information, the information being provided should be clearly marked "confidential" or "proprietary." Such labeling is not required for the regular, automated exchange of Confidential Information that occurs, for example, to permit the Parties to administer CTS.

(c~~b~~) Protection. Except ~~for disclosure to the FERC or its staff~~ as set forth herein, the Receiving Party shall not, at any time during or after the term of this Agreement, in any manner, either directly or indirectly, divulge, disclose, or communicate to any person, firm, corporation or other entity, or use for any purposes other than those set forth herein, any Confidential Information acquired from the party disclosing the information (the "Disclosing Party"), without the express prior written consent of the Disclosing Party. The Receiving Party shall not disclose any Confidential Information to anyone except to officers and employees of the Receiving Party and to its outside consultants, advisers and/or attorneys, in each case who have a need to know to further the purposes set forth herein and who have been advised of the confidential nature of the Confidential Information and who have agreed to abide by the terms of this Agreement or are bound by equally restrictive covenants (collectively, "Authorized Representatives"). The Receiving Party agrees that it shall be liable for any breach of this Agreement by its Authorized Representatives.

(~~c~~d) Notwithstanding anything in this Section to the contrary, if the FERC or its staff, during the course of an investigation or otherwise, request information from one of the Parties that is otherwise required to be maintained in confidence pursuant to the Agreement, the Party shall provide the requested information to the FERC or its staff, within the time provided for in the request for information.

(~~d~~e) Survival. The obligation of each Party and each Authorized Representative under this Article 6 continues and survives the termination of this Agreement.

(~~e~~f) Scope. This obligation of confidentiality shall not extend to data and information that, at no fault of the Receiving Party, is or becomes: (a) in the public domain or generally available or known to the public; (b) disclosed to a recipient by a non-Party who had a legal right to do so; or (c) independently developed by the Receiving Party or known to such Party prior to its disclosure hereunder.

(~~f~~g) Required Disclosure~~. Except for disclosure to the FERC or its staff, if~~ or Submission on a Confidential Basis. If a governmental authority requests or requires the Receiving Party to publicly disclose any of the Disclosing Party's Confidential Information, ~~such~~ or if a request from another person or entity is made in writing pursuant to a legal discovery process, the Receiving Party shall provide the Disclosing Party with prompt notice of such request or requirement ~~so that the Disclosing Party may seek an appropriate~~. The Disclosing Party shall in turn, to the extent required by the terms of its tariff, provide any Market Participant whose Confidential Information is the subject of possible disclosure with prompt written notice of the circumstances that may require such disclosure so that the Market Participant has a reasonable opportunity to seek a protective order or other appropriate remedy ~~or waive compliance with the provisions of this Agreement. Notwithstanding the absence of a protective order or a waiver, a Receiving Party shall disclose only such Confidential Information which it is legally required to disclose. Each Party shall use reasonable efforts to obtain reliable assurances that confidential treatment will be accorded to Confidential Information required to be disclosed~~to prevent disclosure.

If a Receiving Party is required to publicly disclose any Confidential Information under this Section, the Parties shall meet as soon as practicable in an effort to resolve any and all issues associated with the required disclosure ~~of such Confidential Information, and the likelihood of additional~~ , and the possibility of further requested or required disclosures of ~~such~~ the Disclosing Party's Confidential Information.

The process described above shall also be followed if a governmental authority requests or requires the Receiving Party to submit any of the Disclosing Party's Confidential Information on a confidential basis (with the exception of requests for Confidential Information from FERC or the Commodity Futures Trading Commission ("CFTC") to the NYISO). The Receiving Party shall notify the governmental authority that the requested or required information contains NYISO or ISO-NE Market Participant specific Confidential Information, if applicable, and shall use reasonable efforts to protect the Confidential Information from public disclosure.

If FERC or the CFTC request or require the NYISO to submit any Confidential Information it received from ISO-NE on a confidential basis, the NYISO will seek permission to inform ISO-NE of the requirement or request and, if granted, will follow the procedures outlined above. In the event FERC or the CFTC does not permit the NYISO to notify ISO-NE of the request, NYISO shall inform FERC or the CFTC in writing that the disclosed information includes Confidential Information, and shall request that FERC or the CFTC inform NYISO before releasing to a third party any of the Confidential Information.

If a governmental authority (including FERC and the CFTC) that requested or required he submission, on a confidential basis, of Confidential Information by a Receiving Party issues a notice indicating that it is considering disclosing, or intends to disclose any Confidential Information provided by the Disclosing Party, or if the governmental authority (including FERC and the CFTC) receives a public records demand or other legal discovery request seeking disclosure of any Confidential Information provided by the Disclosing Party, the Receiving Party shall notify the Disclosing Party so that the Disclosing Party may seek an appropriate protective order or other appropriate remedy. The Disclosing Party shall in turn, to the extent required by the terms of its tariff, provide any Market Participant whose Confidential Information is the subject of possible

disclosure under this provision with prompt written notice of the circumstances that may require such disclosure so that the Market Participant has a reasonable opportunity to seek a protective order or other appropriate remedy to prevent disclosure.

(~~g~~h) In providing the information to FERC or its staff, the Party may, consistent with 18 C.F.R. § 388.112, request that the information be treated as confidential and non-public by the FERC and its staff and that the information be withheld from public disclosure. The Party shall notify the other Party to the Agreement when it is notified by FERC or its staff that a request for disclosure of, or decision to disclose, confidential information has been received, at which time either of the Parties may respond before such information is made public, pursuant to 18 C.F.R.§ 388.112.

(~~h~~i) Return of Confidential Information. Information provided pursuant to this Section 6 is deemed to be on loan, and remains the property of the Disclosing Party notwithstanding the disclosure of such Confidential Information to the Receiving Party hereunder. All Confidential Information provided by the Disclosing Party shall be returned by the Receiving Party to the Disclosing Party or destroyed, erased or deleted by the Receiving Party, with written confirmation provided to the Disclosing Party, promptly upon request. Upon termination ~~or expiration~~ of this Agreement, a Party shall use reasonable efforts to destroy, erase, delete or return to the Disclosing Party any and all written or electronic Confidential Information. Unless otherwise expressly agreed in a separate license agreement, the disclosure of Confidential Information to the Receiving Party will not be deemed to constitute a grant, by implication or otherwise, of a right or license to the Confidential Information or in any patents or patent applications of the Disclosing Party.

(~~i~~j) Relief. Each Party acknowledges that remedies at law are inadequate to protect against breach of the covenants and agreements in this Article, and hereby in advance agrees, without prejudice to any rights to judicial relief that it may otherwise have, to the granting of equitable relief, including injunction, in the Disclosing Party's favor without proof of actual damages. In addition to the equitable relief referred to in this Section, a Disclosing Party shall only be entitled to recover from a Receiving Party any and all gains wrongfully acquired, directly or indirectly, from a Receiving Party's unauthorized disclosure of Confidential Information.

(~~j~~k) Existing Confidential Information Obligations. Notwithstanding anything to the contrary in this Agreement, the ~~p~~Parties shall have no obligation to disclose Confidential Information or data to the extent such disclosure of information or data would be a violation of or inconsistent with ~~the terms and conditions of any ISO-NE governing agreement or NYISO OATT or Services Tariff and any other agreement, or~~ applicable state or federal regulation or law. This Agreement requires the Parties to exchange Confidential Information that is necessary for the Coordination Committee to perform its duties, or for the Parties to fulfill their obligations under this Agreement. The Parties are not obligated to share Confidential Information for other purposes.

(~~k~~l) The term "CEII" or "Critical Energy Infrastructure Information" shall mean all information, whether furnished before or after the mutual execution of this Agreement, whether oral, written or recorded/electronic, and regardless of the manner in which it is furnished, that is marked "CEII" or "Critical Energy Infrastructure Information" or which under all of the circumstances should be treated as such in accordance with the definition of CEII in 18 C.F.R. § 388.13(c)(1). The Receiving Party shall maintain all CEII in a secure place. The Receiving Party shall treat CEII received under this agreement in accordance with its own procedures for protecting CEII and shall not disclose CEII to anyone except its Authorized Representatives.

6.6 Unauthorized Transfer of Third-Party Intellectual Property

In the performance of this Agreement, no Party shall transfer to the other Party any Intellectual Property, the use of which by the other Party would constitute an infringement of the rights of another entity (including the Parties). In the event such transfer occurs, whether or not inadvertent, the transferring Party shall, promptly upon learning of the transfer, provide Notice to the receiving Party and upon receipt of such Notice the receiving Party shall take reasonable steps to avoid claims and mitigate losses.

ARTICLE 7.0: COORDINATION COMMITTEE

7.1 Coordination Committee Inauguration and Authorization

The Parties shall form a Coordination Committee under this Agreement. Within 30 days of the Effective Date, each of the Parties shall appoint two representatives, a principal and an alternate, to serve as members of the Coordination Committee with the authority to act on their behalf with respect to actions or decisions taken by the Coordination Committee. A Party may, at any time upon providing prior notice to the other Party, designate a replacement principal member or alternate member to the Coordination Committee.

7.2 Coordination Committee Duties and Responsibilities

The Coordination Committee exists to administer or assist the Parties' implementation of the provisions of this Agreement. The Coordination Committee shall develop and adopt policies, instructions, and recommendations relating to the Parties' performance of their obligations under this Agreement, attempt to resolve Disputes between the Parties pursuant to Article 17.0 of this Agreement, and shall undertake any other actions specifically delegated to it pursuant to this Agreement.

The Coordination Committee shall undertake to assist the Parties' efforts to jointly develop ~~and authorize~~ Operating Instructions to implement the intent of this Agreement in accordance with Schedule B of this Agreement, 'Procedures for Development and Authorization of Operating Instructions'. The Coordination Committee shall authorize such Operating Instructions once developed. To the extent that the Operating Instructions require participation by local control centers and Transmission Owners in the New England or the New York Reliability Coordinator Areas, those entities will be involved in the development process.

Should the terms and conditions contained in this Agreement be found to conflict with or fail to recognize obligations of a Standards Authority of which either Party is a member or other regulatory requirements, the Parties agree to amend this Agreement accordingly.

Any recommendations on revisions to this Agreement shall be provided to each Party's appropriate corporate officers for approval.

7.3 Limitations of Coordination Committee Authority

~~With the exception of the Schedules, t~~The Coordination Committee is not authorized to modify or amend any of the terms of this Agreement. The Coordination Committee is also not authorized to excuse any obligations under this Agreement or waive any rights pertaining to this Agreement.

The Coordination Committee has no authority to commit either Party to any expenditure that is beyond those expenses described herein.

7.4 Exercise of Coordination Committee Duties

The Coordination Committee shall hold meetings no less frequently than once each calendar year. The matters to be addressed at all meetings shall be specified in an agenda, which shall contain items specified by either Party in advance of the meeting and sent to the representatives of the other Party. All decisions of the Coordination Committee must be unanimous. Special meetings may be called at any time if the Coordination Committee deems such meetings to be necessary or appropriate.
Subject to the limitations on its authority as described in Section 7.3 of this Agreement, the Coordination Committee has the responsibility and authority to take action on all aspects of this Agreement, including, but not limited to the following:

(a) amending, adding or canceling ~~Schedules, or~~ Operating Instructions and providing written notice in accordance with Article 1~~8~~6.0 of this Agreement;
(b) assessment of non-compliance with this Agreement and, subject to Article 1~~9~~7.0 of this Agreement, the taking of appropriate action in respect thereof;
(c) documentation of decisions related to the initial resolution of Disputes as set out in Article 1~~9~~7.0 of this Agreement, or in cases of unresolved Disputes, the circumstances relevant to the Dispute in question as contemplated by the requirements of Article 1~~9~~7.0 of this Agreement; and
(d) preparation, documentation, retention and distribution of Coordination Committee meeting minutes and agendas.

ARTICLE 8.0: RELIABILITY COORDINATION AND RELIABILITY ASSESSMENT OF OUTAGES

Both Parties agree to provide each other with updates on planned outage schedules and other activities in accordance with NPCC Criteria, Guides and Procedures that may impact on the Reliability or availability

of the interconnected New York Transmission System and New England Transmission System. As Reliability Coordinators and Balancing Authorities, the NYISO and ISO-NE, shall interact with each other as required, and with other Balancing Authorities and Reliability Coordinators, to establish System Operating Limits and to perform Reliability coordination and Reliability assessments of outages.

ARTICLE 9.0: OPERATIONAL INFORMATION

9.1 Obligation to Provide Operational Data and Status Points

The Parties shall ensure that appropriate monitoring facilities are installed as required to provide for electric power quantities or equipment loading to enable monitoring of System Operating Limits, meet requirements of each of NERC and NPCC, and for determining Interconnection Facilities inadvertent energy accounting.

~~**9.2 Points of Operational Data**~~

~~The points of data for operating information are those points as may be agreed in writing by the Coordination Committee from time to time.~~

ARTICLE 10.0: INTERCONNECTION REVENUE METERING

10.1 Obligation to Provide Inadvertent Energy Accounting Metering

The Parties shall ensure appropriate electric metering devices are installed as required to measure electric power quantities for determining Interconnection Facilities inadvertent energy accounting.

10.2 Standards for Metering Equipment

Any Metering Equipment used to meter Metered Quantities for inadvertent energy accounting shall be designed, verified, sealed and maintained in accordance with the Party's respective metering standards or as otherwise agreed to by the Coordination Committee.

10.3 Meter Compensation to the Point of Interconnection

The metering compensation for transmission line losses to the Interconnection Facilities Delivery Point shall be determined by the Party's respective standards or otherwise agreed to by the Coordination Committee.

10.4 Metering Readings

The Parties shall ensure that integrated meter readings are provided at least once each hour for Interconnection Facilities accounting purposes and meter registers are read at least monthly, as close as practicable to the last hour of the month. An appropriate adjustment shall be made to register readings not taken on the last hour of the month.

ARTICLE 11.0: ~~LIABILITY~~ JOINT CHECKOUT PROCEDURES

11.1 Scheduling Checkout Protocols

Both Parties shall require all real-time energy market transaction schedules over Interconnections to be tagged in accord with the NERC tagging standard. For Simultaneous Activation of Reserves ("SAR") and other emergency schedules that are not tagged, the Parties will enter manual schedules into their respective operating systems.

When there is a real-time energy market transaction scheduling conflict, the Parties will work to modify the schedule as soon as practical.

Consistent with the foregoing requirements, the Parties will perform the following types of checkouts:

(a) Day-ahead checkout shall be performed daily on the day before the transaction is to flow. Day-ahead checkout includes the verification of net interchange totals and individual transaction schedules;

(b) Real-time checkout shall be performed during the period before the transaction is to flow. Real-time checkout includes the verification of net interchange totals and individual transaction schedules;

(c) After-the-fact checkout of real-time transactions shall be performed the next business day following the day of the transactions;

(d) After-the-fact reporting of scheduled energy interchange and actual energy interchange shall be updated by each Party each day and exchanged with the other Party. Within ten (10) business days of the end of each month, the previous month's data shall be reconciled.

ARTICLE 12.0: COORDINATED TRANSACTION SCHEDULING

CTS is addressed in Schedule D to this Agreement and in the ISO-NE and NYISO Tariffs.

ARTICLE 13.0: LIABILITY

~~11.1~~13.1 Force Majeure

A Party shall not be considered to be in default or breach of this Agreement, and shall be excused from performance or liability for damages to the 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, arising out of or from any act, omission, or circumstance by or in consequence of any act of God, labor disturbance, sabotage, failure of contractors or suppliers of materials, act of the public enemy, war, invasion, insurrection, riot, fire, storm, flood, ice, earthquake, explosion, epidemic, breakage or accident to machinery or equipment or any other cause or causes beyond such Party's reasonable control, including any curtailment, order, regulation, or restriction imposed by governmental, military or lawfully established civilian authorities, or by making of repairs necessitated by an emergency circumstance not limited to those listed above upon the property or equipment of the Party or property or equipment of others which is deemed under the Operational Control of the Party. A Force Majeure event does not include an act of negligence or Intentional Wrongdoing by a Party. Any Party claiming a Force Majeure event shall use reasonable diligence to remove the condition that prevents performance and shall not be entitled to suspend performance of its obligations in any greater scope or for any longer duration than is required by the Force Majeure event. Each Party shall use its best efforts to mitigate the effects of such Force Majeure event, remedy its inability to perform, and resume full performance of its obligations hereunder.

A Party suffering a Force Majeure event ("Affected Party") shall notify the other Party ("Non-Affected Party") in writing ("Notice of Force Majeure Event") as soon as reasonably practicable specifying the cause of the event, the scope of commitments under the Agreement affected by the event, and a good faith estimate of the time required to restore full performance. Except for those commitments identified in the Notice of Force Majeure Event, the Affected Party shall not be relieved of its responsibility to fully perform as to all other commitments in the Agreement. If the Force Majeure event continues for a period of more than 90 days from the date of the Notice of Force Majeure Event, the Non-Affected Party shall be entitled, at its sole discretion, to terminate the Agreement.

~~11.2~~13.2 Liability to Third Parties

Nothing in this Agreement, whether express or implied, is intended to confer any rights or remedies under or by reason of this Agreement on any person or entity that is not a Party or a permitted successor or assign.

~~11.~~13.3 Indemnification

(a) Definitions. An "Indemnifying Party" means a Party who holds an indemnification obligation hereunder. An "Indemnitee" means a Party entitled to receive indemnification under this Agreement.

(b) Third Party Losses. Each Party will defend, indemnify, and hold the other Party harmless from all losses, damages, liabilities, obligations, claims, demands, suits, proceedings, recoveries, settlements, costs and expenses, court costs, attorney fees, causes of action, judgments and other obligations (~~"~~collectively, "Losses") brought or obtained by any ~~t~~Third ~~p~~Party against such other Party, only to the extent that such Losses arise~~s~~ directly from the:

(i) Gross negligence, recklessness, or willful misconduct of the Indemnifying Party or any of its agents or employees, in the performance of this Agreement; except to the extent such Losses arise~~s~~ (i) from gross negligence, recklessness, willful misconduct or breach of contract or law by the Indemnitee or such Indemnitee's agents or employees, or (ii) as a consequence of strict liability imposed as a matter of law upon the Indemnitee, or such Indemnitee's agents or employees; or

(ii) Breach of the ~~p~~Parties' obligations in Article 6 hereof.

(c) Process. The Indemnitee shall give Notice to the Indemnifying Party as soon as reasonably practicable after the Indemnitee becomes aware of the indemnifiable Losses or any claim, action or proceeding that may give rise to an indemnification. Such notice shall describe the nature of the Losses or proceeding in reasonable detail, explain how the Losses relate to the performance of this Agreement, and shall indicate, if practicable, the estimated amount of the Losses that has been sustained by the Indemnitee. A delay or failure of the Indemnitee to provide the required notice shall release the Indemnifying Party (i) from any indemnification obligation to the extent that such delay or failure materially and adversely affects the Indemnifying Party's ability to defend such claim or materially and adversely increases the amount of the indemnifiable Losses, and (ii) from any responsibility for any costs or expenses of the Indemnitee in the defense of the claim during such period of delay or failure.

(d) Indemnification shall be limited to the extent that the liability of the Indemnitee would be limited by any applicable law.

13.4~~11.4~~ Liability Between the Parties

The Parties' duties and standard of care with respect to each other, and the benefits and rights conferred on each other shall be no greater than as expressly stated herein. Neither Party, its directors, officers, trustees, employees or agents, shall be liable to the other Party for any Losses, whether direct, indirect, incidental, punitive, special, exemplary or consequential, arising from that Party's performance or nonperformance under this Agreement, except to the extent that the Party, is found liable for gross negligence or willful misconduct, in which case the Party responsible shall be liable only for direct and ordinary damages and not for any incidental, consequential, punitive, special, exemplary or indirect damages.

This section shall not limit amounts required to be paid for Emergency Energy under Schedule C to this Agreement. This section shall not apply to adjustments or corrections for errors in invoiced amounts due under Schedule C to this Agreement.

13.5~~11.5~~ Liability for Interruptions

Except as set forth herein, neither Party shall be liable to the other Party for any Losses or damage, whether direct, indirect, incidental, punitive, special, exemplary or consequential, resulting from an occurrence on the circuits and system that are under the Operational Control of the other Party and which results in damage to or renders inoperative such circuits and system, or the separation of the systems in an Emergency, or interrupts or diminishes service, or increases, decreases or in any way affects for whatever length of time the voltage or frequency of the energy delivered hereunder to the other Party.

ARTICLE ~~12~~14.0: APPLICABLE LAW

This Agreement shall be governed by and construed in accordance with the laws of the State of Delaware.

ARTICLE ~~13~~15.0: LICENSE AND AUTHORIZATION

The agreements and obligations expressed herein are subject to such initial and continuing governmental permission and authorization as may be required. Each Party shall be responsible for securing and paying for any approvals required by it from any regulatory agency of competent jurisdiction relating to its participation in this Agreement and will reasonably cooperate with the other Party in seeking such approvals.

ARTICLE ~~14~~16.0: ASSIGNMENT

This Agreement shall inure to the benefit of, and be binding upon and may be performed by, the successors and assigns of the Parties hereto respectively, but shall not be assignable by either Party without the written consent of the other.

ARTICLE ~~15~~17.0: AMENDMENT

~~15~~17.1 Review of Agreement

The terms of this Agreement are subject to review for potential amendment at the request of either Party. If, consequent to such review, the Parties agree that any of the provisions hereof, or the practices or conduct of either Party impose an inequity, hardship or undue burden upon the other Party, or if the Parties agree that any of the provisions of this Agreement have become obsolete or inconsistent with

changes related to the Interconnection Facilities, the Parties shall endeavor in good faith to amend or supplement this Agreement in such a manner as will remove such inequity, hardship or undue burden, or otherwise appropriately address the cause for such change.

Any amendment of this Agreement by the Parties must be done in accordance with Section ~~15~~17.2.

~~15~~17.2 Authorized Representatives

No amendment of this Agreement shall be effective unless effected by written instrument duly executed by the Parties' authorized representatives ~~(except as provided for in Section 7.3 of this Agreement)~~. For the purposes of this Section, an authorized person refers to individuals designated as such by Parties in their respective corporate by-laws.

ARTICLE ~~16~~18.0: NOTICES

Except as otherwise agreed from time to time, any notice, invoice or other communication which is required by this Agreement to be given in writing, shall be sufficiently given at the earlier of the time of actual receipt or deemed time of receipt if delivered personally to a senior official of the Party for whom it is intended or electronically transferred or sent by registered mail, addressed as follows:

In the case of the NYISO to:

New York Independent System Operator, Inc.
10 Krey Boulevard, Rensselaer, New York 12144
Attention: Vice President of Operations

In the case of ISO-NE to:

ISO New England Inc.
One Sullivan Road
Holyoke, Massachusetts 01040-2841
Attention: Vice President of System Operations

or delivered to such other person or electronically transferred or sent by registered mail to such other address as either Party may designate for itself by notice given in accordance with this Section or delivered by any other means agreed to by the Parties hereto.

Any notice, or communication so mailed shall be deemed to have been received on the third business day following the day of mailing, or if electronically transferred shall be deemed to have been received on the same business day as the date of the electronic transfer, or if delivered personally shall be deemed to have been received on the date of delivery or if delivered by some other means shall be deemed to have been received as agreed to by the Parties hereto.

The use of a signed facsimile of notices and correspondence between the Parties related to this Agreement shall be accepted as proof of the matters therein set out. Follow-up with hard copy by mail will not be required unless agreed to by the Coordination Committee.

ARTICLE ~~17~~19.0: DISPUTE RESOLUTION

In the event of a d~~D~~ispute arising out of or relating to this Agreement (a "Dispute") that is not resolved by the representatives of the Parties who have been designated under Section 7.1 of this Agreement within 7 days of the reference to such representatives of such Dispute, each Party shall, within 14 days' written notice by either Party to the other, designate a senior officer with authority and responsibility to resolve the Dispute and refer the Dispute to them. The senior officer designated by each Party shall have authority to make decisions on its behalf with respect to that Party's rights and obligations under this Agreement. The senior officers, once designated, shall promptly begin discussions in a good faith effort to agree upon a resolution of the Dispute. If the senior officers do not agree upon a resolution of the Dispute within ~~14~~ 30 days of its referral to them~~,~~ (or ~~do not~~ within ~~the same 14 day~~ such longer period as the senior officers mutually agree to ~~refer the matter to some individual or organization for alternate Dispute resolution, then either Party shall have the right to~~ in writing), or do not mutually agree to submit their Dispute for binding or non-binding arbitration by the Federal Energy Regulatory Commission's Dispute Resolution Service, then the Parties shall request that the Federal Energy Regulatory Commission's Dispute Resolution Service mediate their efforts to resolve the Dispute. At any point in the mediation process, either Party may terminate the mediation and may pursue any and all remedies available to it at law or in equity.

Neither the giving of notice of a Dispute, nor the pendency of any Dispute resolution process as described in this Section shall relieve a Party of its obligations under this Agreement, extend any notice period described in this Agreement or extend any period in which a Party must act as described in this Agreement. Notwithstanding the requirements of this Section, either Party may terminate this Agreement in accordance with its provisions, or pursuant to an order of FERC or a court at equity. The issue of whether such a termination is proper shall not be considered a Dispute hereunder.

ARTICLE ~~18~~20.0: REPRESENTATIONS

~~18.~~20.1 Good Standing

Each Party represents and warrants that it is duly organized, validly existing and in good standing under the laws of the state in which it is organized, formed, or incorporated, as applicable.

~~18~~20.2 Authority to Enter Into Agreement

Each Party represents and warrants that it has the right, power and authority to enter into this Agreement, to become a ~~p~~Party hereto and to perform its obligations hereunder. This Agreement is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms.

~~18~~20.3 Organizational Formation Documents

Each Party represents and warrants that the execution, delivery and performance of this Agreement does not violate or conflict with the organizational or formation documents, bylaws, operating agreement, or agency agreement of such Party, or any judgment, license, permit, regulatory order, or governmental authorization applicable to such Party.

~~18~~20.4 Regulatory Authorizations

Each Party represents and warrants that it has, or applied for, all regulatory authorizations necessary for it to perform its obligations under this Agreement.

ARTICLE ~~19~~21.0: EFFECTIVE DATE AND TERM

Subject to the conditions of Article 13.0- (License and Authorization) above, this Agreement shall take effect as of the date that all of the following have occurred: (i) upon the execution hereof by both Parties on the date set forth above; and (ii) acceptance or approval by the FERC. This Agreement shall continue in force until terminated in accordance with this Article.

This Agreement may be terminated at any time by mutual agreement in writing. It may also be terminated by either Party with prior written notice of at least ninety (90) days to the other Party of its intention to terminate.

ARTICLE ~~20~~22.0: MISCELLANEOUS

~~20~~22.1 Performance

The failure of a Party to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any right held by such Party. Any waiver on any specific occasion by either Party shall not be deemed a continuing waiver of such right, nor shall it be deemed a waiver of any other right under this Agreement.

~~20~~22.2 Agreement

This Agreement, including all Schedules and Attachments hereto, is the entire agreement between the Parties with respect to the subject matter hereof, and supersedes all prior or contemporaneous understandings or agreements, oral or written, with respect to the subject matter of this Agreement.

~~20~~22.3 Governmental Authorizations

This Agreement, including its future amendments is subject to the initial and continuing Federal Energy Regulatory Commission authorizations required to establish, operate and maintain the Interconnection Facilities as herein specified. Each Party shall take all actions necessary and reasonably within its control to maintain all rights and Federal Energy Regulatory Commission approvals required to perform its respective obligations under this Agreement.

If one Party determines that it is required to self-report a potential violation to the Commission's Office of Enforcement regarding its compliance with this Agreement or the administration of CTS, the reporting Party shall inform, and provide a copy of the self-report to the other Party. Any such report provided by

one Party to the other shall be Confidential Information. Each Party shall make reasonable efforts to cooperate and assist in remedying any such violation, to the extent such assistance is necessary to resolve the matter and to the extent doing so is consistent with maintaining the Party's legal privilege.

~~20~~22.4 Unenforceable Provisions

If any provision of this Agreement is deemed unenforceable, the rest of the Agreement shall remain in effect and the Parties shall negotiate in good faith and seek to agree upon a substitute provision that will achieve the original intent of the Parties.

~~20~~22.5 Execution

This Agreement may be executed in multiple counterparts, each of which shall be considered an original instrument, but all of which shall be considered one and the same Agreement, and shall become binding when all counterparts have been signed by each of the Parties and delivered to each Party hereto. Delivery of an executed signature page counterpart by telecopier shall be as effective as delivery of a manually executed counterpart.

~~20~~22.6 Regulatory Authority

If any Regulatory Authority having jurisdiction (or any successor boards or agencies), a court of competent jurisdiction or other governmental entity with the appropriate jurisdiction (collectively, the "Regulatory Bodies") issues a rule, regulation, law or order that has the effect of cancelling, changing or superseding any term or provision of this Agreement, including changes to section headings or numbering (the "Regulatory Requirement"), then this Agreement will be deemed modified to the extent necessary to comply with the Regulatory Requirement. Notwithstanding the foregoing, if the Regulatory Authority materially modifies the terms and conditions of this Agreement and such modification(s) materially affect the benefits flowing to one or both of the Parties, as determined by either of the Parties within twenty (20) business days of the receipt of the Agreement as materially modified, the Parties agree to attempt in good faith to negotiate an amendment or amendments to this Agreement or take other appropriate action(s) so as to put each Party in effectively the same position in which the Parties would have been had such modification not been made. In the event that, within sixty (60) days or some other time period mutually agreed upon by the Parties after such modification has been made, the Parties are unable to reach agreement as to what, if any, amendments are necessary and fail to take other appropriate action to put

each Party in effectively the same position in which the Parties would have been had such modification not been made, then either Party shall have the right to unilaterally terminate this Agreement forthwith.

~~20~~22.7 Headings

The headings used for the Articles and Sections of this Agreement are for convenience and reference purposes only, and shall not be construed to modify, expand, limit, or restrict the provisions of this Agreement.

IN WITNESS WHEREOF

IN WITNESS WHEREOF the Parties hereto have caused this Agreement to be executed in duplicate as of the day and year first written above.

NEW YORK INDEPENDENT SYSTEM OPERATOR

_____

By: Ricardo T. Gonzales,
Senior Vice President and Chief ~~of~~ Operating Officer~~ons~~
Date: _____

ISO NEW ENGLAND INC.

_____

By: Vamsi Chadalavada,
Senior Vice President and Chief Operating Officer
Date: _____

Schedule A: Description Of Interconnection Facilities

The Coordination Agreement between ISO-NE and the NYISO covers the New England – NYISO Interconnection Facilities under the Operational Control of the NYISO and ISO-NE.
For Operational Control purposes, the point of demarcation for each of the Interconnection Facilities listed below is the point at which each Interconnection crosses the New England-New York State boundary, except as noted below.

There are presently three (3) ISO-NE-NYISO Interconnections. The three Interconnections are comprised of eight (8) alternating current ("AC") Interties and one (1) high-voltage direct current ("HVDC") Intertie. The first Interconnection (the "NY/NE Northern AC Interconnection") is comprised of seven (7) of the eight (8) AC Interties. The second Interconnection (the "NNC Interconnection") is comprised of the remaining AC Intertie. The third and final Interconnection (the "CSC Interconnection") is comprised of a single HVDC Intertie. For each Interconnection, NYISO and ISO-NE have identified respective associated external nodes for scheduling and pricing purposes. The nodes associated with each of the Interconnections are listed in Table 1 of Attachment A of Schedule C of this Agreement.

List of Interconnections

NY/NE Northern AC Interconnection - The NY/NE Northern AC Interconnection is comprised of the following seven (7) Interties (as ordered from North to South):

1. PV-20 Intertie (115 kV AC),
2. K7 Intertie (115 kV AC),
3. K6 Intertie (115 kV AC),
4. E205W Intertie (230 kV AC),
5. 393 Intertie (345 kV AC),
6. 690/FV Intertie (69 kV AC), and
7. 398 Intertie (345 kV AC).

NNC Interconnection - The Northport-Norwalk Harbor Cable ("NNC") Interconnection is comprised of the following Intertie:

1. NNC Intertie (138 kV AC).

CSC Interconnection - The Cross Sound Cable "CSC") Interconnection is comprised of the following Intertie:

1. CSC Intertie (150 kV HVDC).

List of Interties (as ordered from North to South)

PV-20 Intertie - A 115 kV AC transmission circuit, designated PV-20, series switched reactor and phase shifting transformers, connecting the Plattsburgh transmission substation in NY to the Sandbar transmission substation in VT. The common meter point for this Intertie is located at the Plattsburg transmission substation.

K7 Intertie - A 115 kV AC transmission circuit, designated K7, and phase shifter transformer connecting the Whitehall transmission substation in NY to the Blissville transmission substation in VT. The common meter point for this Intertie is located at the Whitehall transmission substation.

K6 Intertie - A 115 kV AC transmission circuit, designated K6, connecting the Hoosick transmission substation in NY to the Bennington transmission substation in VT. The common meter point for this Intertie is located at the Hoosick transmission substation.

E205W Intertie - A 230 kV AC transmission circuit, designated E205W, connecting the ~~Rotterdam~~Eastover Road transmission substation in NY to the Bear Swamp transmission substation in MA. The common meter point for this Intertie is located at the Bear Swamp transmission substation.

393 Intertie - A 345 kV AC transmission circuit, designated 393, connecting the Alps transmission substation in NY to the Berkshire transmission substation in MA. The common meter point for this Intertie is located at the Alps transmission substation.

690/FV Intertie - A 69 kV AC transmission circuit, designated 690/FV, connecting the Smithfield transmission substation in NY to the Salisbury transmission substation in CT. The common meter point for this Intertie is located at the Salisbury transmission substation.

398 Intertie - A 345 kV AC transmission circuit, designated 398, connecting the Pleasant Valley transmission substation in NY to the Long Mountain transmission substation in CT. The common meter point for this Intertie is located at the Pleasant Valley transmission substation.

NNC Intertie - Three 138 kV AC transmission circuits (designated 601, 602 and 603), transformer and phase shifting transformer, initially designated as the 1385 Cable Intertie and now the NNC Intertie, connecting the Northport transmission substation in NY to the Norwalk Harbor transmission substation in CT.[1] The common meter point for this Intertie is located at the Norwalk Harbor transmission substation.

CSC Intertie - A 150+/- kV HVDC transmission circuit and associated converter facilities, designated CSC, connecting the Tomson converter at Shoreham, NY to the Halvarsson converter at New Haven, CT. This entire facility is under ISO-NE operating authority, pursuant to the FERC Order containing approvals regarding the HVDC Cross Sound Cable. For Operational Control purposes, the point of demarcation for the HVDC Interconnection CSC is within New York State at the point where the converter facilities interconnect with LIPA's 138 kV AC facilities at Shoreham, NY. The common meter point for this Intertie is located at the Shoreham transmission substation.

[1] The NCC Intertie may be referenced in the Parties individual operating documents as the Northport-Norwalk Harbor Cable ("NNC"), the 1385 Cable/Line or the 601, 602 and 603 Cables.

SCHEDULE B: Procedures For Development And Authorization Of Operating Instructions

Overview

Operating Instructions (a) will be developed and recorded by the Parties, with assistance from the Coordination Committee, in accordance with this Schedule B, (b) will be contained in a document separate from this Agreement, and (c) may be modified by the Parties, with assistance from the Coordination Committee, without amending this Agreement.

The Parties, with assistance from the Coordination Committee, shall jointly develop ~~and approve~~ Operating Instructions and review them at least annually. The Parties, with assistance from the Coordination Committee, shall submit draft material to one another for review and comment. The Parties, with assistance from the Coordination Committee, shall provide comment on the draft material promptly. The Parties, with assistance from the Coordination Committee, shall promptly provide such information as may reasonably be required in connection with establishing, or reviewing, the material. The Coordination Committee shall be responsible for approving final versions of Operating Instructions.

In the event that any conflicts arise or are made apparent to a Party regarding any Operating Instructions, they shall notify the other Party and engage the Coordination Committee, if necessary, to resolve such conflicts.

The Coordination Committee will periodically review applicable ISO-NE and NYISO individual procedures and processes to determine any benefits of sharing these procedures and processes. These benefits may be for the purpose of training or to satisfy Reliability Standards. The Coordination Committee will determine how best to share these individual procedures and processes.

A list of Operating Instructions and applicable ISO-NE and NYISO individual procedures will be maintained by the Coordination Committee.

Outlined below are the key principles and items of methodology to be observed while the Parties, with assistance from the Coordination Committee, ~~is~~ are engaged in developing ~~and approving~~ Operating Instructions, and issuing them to their respective operations staff.

Principles

Given that the Parties' respective operations staff benefit from following a single instruction for all aspects of their execution of interconnected operations, it is an acceptable practice to combine this content to achieve the single Operating Instructions for use by a respective Party's operations staff. The preferred methodology when appropriate is to use the NPCC Criteria, Guides and Procedures for the coordination and operation of the interconnected Transmission Systems. When the NPCC documentation is insufficient to accomplish this task separate instructions will be developed in accordance with this Schedule.

Each Party shall coordinate the issuance internally of any Operating Instructions developed and agreed to by the Parties, with assistance from the Coordination Committee, to ensure that their respective operations staff has these Operating Instructions. In addition annual review of the Operating Instructions and the Parties' internal procedures associated with the Operating Instructions shall be conducted by the Parties, with assistance from the Coordination Committee, to ensure consistency.

Operating Instructions, when approved by the ~~Coordination Committee~~Parties, shall be binding on the Parties insofar as they relate to the Interconnection Facilities until they expire, are changed, deleted, or superseded by authority of the Parties, with assistance from the Coordination Committee.

Items of Methodology

~~Each page of an approved Operating Instructions shall be identified in the header or footer with "NYISO – ISO-NE Coordination Committee", the effective date and any revision number.~~

By mutual agreement of the Coordination Committee, one of the Parties shall be designated by the Coordination Committee to control the revision process of the Operating Instruction from the initial drafting of material through to the conversion of the Operating Instruction into its final form.

SCHEDULE C: Emergency Energy Transactions Schedule

WHEREAS, ISO-NE, as the regional transmission organization for the New England Transmission System and the administrator of the New England markets, arranges for the sale and purchase of Emergency capacity and energy on behalf of Market Participants with neighboring Balancing Authority Areas, all in accordance with the ISO-NE Tariff, which includes the Open Access Transmission Tariff and ISO-NE market rules;

WHEREAS, ISO-NE is responsible for, among other matters, procuring and acting as supplier of last resort of ancillary services (including arranging for the sale and purchase of Emergency capacity and energy with neighboring Balancing Authority Areas), in accordance with the ISO-NE Tariff;

WHEREAS, the NYISO, as the independent system operator of the New York Transmission System and the administrator of the New York wholesale electricity markets, arranges for the sale and purchase of Emergency capacity and energy on behalf of Market Participants with neighboring Balancing Authority Areas, all in accordance with the NYISO Tariffs;

WHEREAS, the NYISO is the administrator of the NYISO Tariffs and is responsible for, among other matters, procuring and acting as supplier of last resort of ancillary services (including arranging for the sale and purchase of Emergency capacity and energy with neighboring Balancing Authority Areas), in accordance with the NYISO Tariffs;

WHEREAS, either of the Parties may, from time to time, have insufficient Operating Reserve available on the respective systems that they operate, or need to supplement available resources to cover sudden and unforeseen circumstances such as loss of equipment or forecast errors, and such conditions could result in the need to arrange for the purchase of Emergency Energy for Reliability reasons;

NOW, THEREFORE, in consideration of the premises and of the mutual covenants herein set forth, the Parties mutually agree as follows:

ARTICLE I

1.0 **DELIVERY POINT**

The Delivery Point for energy delivered pursuant to the terms of this Schedule shall be at one of three points of Interconnection between the NYISO Balancing Authority Area and the ISO-NE Balancing Authority Area, and at such other points of Interconnection as may be established. These three points of Interconnection are as follows: (1) the NY/NE Northern AC Interconnection[2]; (2) the NNC Interconnection; and (3) the Cross Sound Cable (CSC) Interconnection, which is a HVDC facility.

Unless otherwise agreed by the Coordination Committee, the price for energy for an hour delivered pursuant to this Schedule shall include all transmission costs of delivering such energy to the Delivery Point in that hour, and the Party taking delivery of such energy for the hour shall be responsible for all transmission costs beyond the Delivery Point for that hour.

ARTICLE II

2.0 CHARACTERISTICS OF EMERGENCY ENERGY

2.1 All Emergency Energy made available under this Schedule shall be three phase, 60 Hz alternating current at operating voltages established at the Delivery Point in accordance with system requirements and appropriate to the Interconnection Facilities or other such characteristics as may be agreed upon by the Parties.

ARTICLE III

3.0 NATURE OF SERVICE

3.1 ISO-NE and the NYISO shall, to the maximum extent each deems consistent with the safe and proper operation of its system, the furnishing of economical, dependable and satisfactory services by its participants, and the obligations of its participants to other parties, make available to the other Party when a system Emergency exists on the other Party's system, Emergency Energy from its system's available generating capability in excess of the system's load requirements (i.e., load requirements alone, not load plus reserve requirements) up to the transfer limits in use between the two Balancing Authority Areas. Emergency Energy is provided in cases of emergency outages of generating units, transmission lines or

[2] The NY/NE Northern AC Interconnection, as defined in Schedule A – Interconnection Facilities ("Schedule A") to the Coordination Agreement between ISO-NE Inc. and the NYISO Inc.

other equipment, or to meet other sudden and unforeseen circumstances such as forecast errors, or to provide sufficient Operating Reserve. Normally, a Party requests Emergency Energy from the other Party as a last resort, when market-based real-time energy transactions are not available, or not available in a timely fashion in order to maintain its ten-minute reserve requirement. At the time the Emergency Energy sale is being initiated, the Party delivering such Emergency Energy shall describe the Emergency Energy transaction as being one of the following: (1) "delivered out of ten-minute reserve"; (2) "delivered out of thirty-minute reserve" where such a delivery could reasonably be expected to be recalled if the Party delivering the Emergency Energy needed the generation for a reserve pick-up or other Emergency; or (3) "delivered above and beyond ten-minute and thirty-minute reserves" where the Party delivering such Emergency Energy is normally expected to be able to continue delivering the energy following a reserve pick-up.

3.2 The Parties are participants in the NPCC and are expected to comply with NPCC Criteria, Guides and Procedures. Such NPCC Criteria, Guides and Procedures include "Emergency Operation Criteria" (Document A-3), which describes the basic factors to be considered by a Balancing Authority Area in formulating plans and procedures to be followed in an Emergency. A principle of operation in this NPCC Criteria is that upon receiving a request for assistance to mitigate an Emergency, a Balancing Authority Area would provide "maximum reasonable assistance" to a neighboring Balancing Authority Area. Such reasonable assistance would not normally require the shedding of firm load.

3.3 Normally, the Party experiencing or anticipating an Emergency would request Emergency Energy from the other Party in accordance with this Schedule and applicable NPCC Criteria, Guides and Procedures after all market-based real-time transactions have been scheduled, unless there is an immediate need for such Emergency Energy in order to maintain system Reliability.

3.4 In the event a Party is unable to provide Emergency Energy to the other when needed, but there is energy available from a Third Party Balancing Authority Area supplier, the Party will use reasonable efforts to acquire and transmit such energy to the other Party where feasible.

ARTICLE IV

4.0 RATES AND CHARGES

4.1 The charge for Emergency Energy delivered to the NYISO or to ISO-NE shall be as set forth in Attachment A, attached hereto.

4.2 Should activations of reserve sharing be required by either of the Parties, inadvertent interchanges will intentionally be accumulated with each Balancing Authority Area providing assistance. In accordance with the NPCC "Procedures for Shared Activation of Ten Minute Reserve" (Document C-12), such inadvertent accumulations shall be treated as part of ordinary inadvertent energy.

ARTICLE V

5.0 MEASUREMENT OF ENERGY INTERCHANGED

5.1 All energy supplied at the Delivery Point shall be metered. The metered amounts shall be adjusted for actual losses to the Delivery Point on each of the Interconnection Facilities. This adjustment will be done to compensate for the difference in location between the Delivery Point and the meter.

5.2 Any properly designated representative of either of the Parties hereto shall have access, through coordination with the meter owner, during normal business hours, to all of the billing meters for the purpose of reading the same. The accuracy of the meters shall be verified by proper tests periodically and at any other time upon reasonable notice given by either of the Parties to the other, and each of the Parties shall be entitled to have a representative present at such verification, subject to coordination with the meter owner. In the event errors greater than +/-2% should be discovered, retroactive billing adjustments, if any, shall be determined by the Coordination Committee.

ARTICLE VI

6.0 BILLING AND PAYMENT

6.1 The procedure for rendering and payment of invoices for transactions pursuant to this Schedule shall be as set out hereunder unless otherwise agreed by the Coordination Committee.

6.2 ~~Promptly after the end of each calendar month, t~~The Party delivering energy pursuant to this Schedule shall promptly prepare, or cause to be prepared, and render an invoice to the other Party

covering all transactions conducted under the terms of this Schedule ~~during such calendar month~~. All transactions will be billed based on the schedule of energy agreed to by the Parties.

6.3 All invoices rendered by a Party shall be payable by the other Party in currency of the United States of America by electronic bank transfer~~, or in such other manner as is agreed to by the Coordination Committee, on the later of (1) the twentieth day of each month or the first common banking day after the nineteenth day of the month whichever is later~~ within five (5) business days after the issuance of an invoice (the "Due Date").

6.4 If the rendering of an invoice is unavoidably delayed, a Party may issue an interim invoice based on estimated charges. Each invoice shall be subject to adjustment for any errors in calculation, meter readings, estimating or otherwise. Any such billing adjustments shall be made as promptly as practical, but in no event later than six months after issuing the invoice.

6.5 Any amount not paid by the Due Date shall be subject to interest, calculated from the due date of the invoice to the date of payment, in accordance with the methodology specified for interest on refunds in the FERC's regulations at 18 C.F.R. § 35.19a (a) (2) (iii).

6.6 If any invoice remains unpaid by a Party for thirty (30) days after the Due Date, the Party rendering the invoice may, in addition to all other remedies available to it, and after giving the other Party at least five days written notice of the its intention to do so, present the issue in question to that Party's Board of Directors. The Party's Board of Directors shall contact the other Party's Board of Directors or its designee to develop a solution to a billing Dispute pursuant to Article 17 of this Agreement. The Boards of Directors may also choose to submit the billing Dispute to a form of alternative Dispute resolution to which the Boards of Directors may agree. Such action shall not be construed as a breach of contract by the Party rendering the invoice and shall not relieve the other Party of its obligations to pay for energy in accordance with the provisions of this Schedule.

6.7 The applicable provisions of this Schedule shall continue in effect after termination of this Schedule to the extent necessary to provide for final billing, billing adjustments, payments and disposition of any claims outstanding.

6.8 Each Party warrants that it has, or will have, the agreements and procedures in place to ensure the collection of payments from its participants for the delivery of Emergency Energy to it from the other Party.

ARTICLE VII

7.0 RECORDS

7.1 Each Party hereto shall keep or cause to be kept complete and accurate records and memoranda of its operations hereunder and shall maintain such data as may be necessary to determine with reasonable accuracy any item required hereunder. With respect to invoicing records, each Party shall maintain or cause to be maintained such records, memoranda and data for the current calendar year plus the previous calendar year. The Coordination Committee shall have the right to examine all such records and memoranda that are not confidential in so far as may be reasonably necessary for the purpose of ascertaining the reasonableness and accuracy of any statements of costs relating to transactions hereunder.

Attachment A

To the Emergency Energy Transactions Schedule

Emergency Energy Pricing

In accordance with the Emergency Energy Transactions Schedule between the NYISO and ISO-NE, the charge for Emergency Energy delivered to the Delivery Point by the NYISO or ISO-NE to the other shall be as defined within this Attachment A.

A.1. Direct NYISO/ISO-NE Emergency Energy Transaction

These are requests made by either the NYISO or ISO-NE to receive Emergency Energy in support of Emergency conditions and to protect Reliability in the event that there is a need for energy on its system that could not be supplied through the market.

The charge for Emergency Energy shall be calculated using the following two-part formula. The first part of the formula calculates the Energy Charge portion of the charge and the second part incorporates any Transmission Charge reasonably associated with the delivery of the Emergency Energy to the Delivery Point.

The Energy Charge portion of the Emergency Energy Charge (for an hour)

The Energy Charge portion of the Emergency Energy Charge for an hour =

(Emergency Energy supplied in the hour in megawatthour(s) ("MWh"))

* (Delivering Party's Cost of Energy in $/MWh)
* 110%

In the case of the NYISO as delivering Party, the Cost of Energy shall be the NYISO final external time-weighted/integrated real-time Locational Based Marginal Price ("LBMP") at the external node associated with the Delivery Point (as used in the NYISO market system for energy exports from the NYISO Balancing Authority Area into the New England Balancing Authority Area, as such pricing node is defined in NYISO Tariffs and as summarized in Table 1), for the hour of the Emergency Energy delivery.

In the case of ISO-NE as the delivering Party, the Cost of Energy shall be the ISO-NE final real-time integrated hourly Locational Marginal Price ("LMP") at the external node associated with the Delivery Point (as used in the New England market system for energy exports from the New England Balancing Authority Area into the NYISO Balancing Authority Area, as such pricing node is defined in the ISO-NE Tariff and as summarized in Table 1), for the hour of the Emergency Energy delivery.

Table 1

Delivery Points and Associated Pricing Nodes, as Modeled by the Delivering Party		
	External Nodes for Pricing Node for the Delivering Party (as modeled in the Delivering Party's system)	
Delivery Point	**Delivering Party: ISO-NE**	**Delivering Party: NYISO**
NY/NE Northern AC Interconnection (excludes the NNC (or 1385 Cable) Intertie)	**.I.ROSETON 345 1 (4011)**	**N.E._GEN_SANDY PD (24062)**
NNC Interconnection	**.I.NRTHPORT 1385 (4017)**	**NPX_1385_GEN (323591)**
CSC Interconnection	**.I.SHOREHAM 138 99 9(4014)**	**NPX_GEN_CSC (323557)**

The Transmission Charge portion of the Emergency Energy Charge (for an hour)

The Transmission charge portion of the Emergency Energy Charge to the Delivery Point for an hour shall equal the actual ancillary services costs and any transmission costs reasonably associated with the delivery of such Emergency Energy for an hour by the delivering Party to the Delivery Point pursuant to the applicable tariff of the delivering Party, as filed with and accepted by the governmental agency with jurisdiction over such tariff.

A.2. NYISO/ISO-NE Emergency Energy Transaction From Third Party Balancing Authority Area Supplier

These are requests made by NYISO or ISO-NE to deliver Energy to the other to address system balancing or other Reliability conditions present on the exporting system, which could not be accomplished through the market.

The charge for Emergency Energy supplied to a Party from a Third Party Balancing Authority Area supplier shall be calculated using the following two-part formula. The first part of the formula calculates the Energy Charge portion of the charge, which in this case includes the total charge (energy and transmission) that the Third Party Balancing Authority Area supplier charges for delivery of the Emergency Energy to the delivering Party's Balancing Authority Area border. The second part of the formula incorporates any Transmission Charges reasonably associated with the delivery of the Emergency Energy by the delivering Party through its system to the Delivery Point. It is expected that that all such Third Party Balancing Authority Area supplier charges will be in accordance with rates filed and accepted by the governmental body with jurisdiction over such rates.

The Energy Charge portion of the Emergency Energy Charge (for an hour)

The Energy Charge portion of the Emergency Energy Charge for an hour =

(Emergency Energy supplied in the hour in MWh)

* (Third Party Balancing Authority Area supplier's total charge for such energy in $/MWh)

(Note: 10% adder does not apply to pricing of Emergency Energy from Third Party Balancing Authority Area suppliers.)

The Transmission Charge portion of the Emergency Energy Charge (for an hour)

The Transmission Charge portion of the Emergency Energy Charge to the Delivery Point for an hour shall equal the actual ancillary services costs and any transmission costs reasonably associated with the delivery of such energy for an hour to the Delivery Point pursuant to the applicable tariff of the delivering Party, as filed with and accepted by the governmental agency with jurisdiction over such tariff. Transmission costs would include, but not be limited to, any costs for congestion and losses that are associated with the delivery of such Emergency Energy through the delivering Party's Balancing

Authority Area for an hour to the Delivery Point, as calculated by the amount of Emergency Energy supplied multiplied by: (1) when NYISO is the delivering Party, (the NYISO real-time LBMP of the external node at which the Emergency Energy exits the NYISO Balancing Authority Area minus the NYISO real-time LBMP of the external node at which the Emergency Energy enters the NYISO Balancing Authority Area); or (2) when ISO-NE is the delivering Party, (the ISO-NE real-time LMP of the external node at which the Emergency Energy exits the ISO-NE Balancing Authority Area minus the ISO-NE real-time LMP of the external node at which the Emergency Energy enters the ISO-NE Balancing Authority Area).

Schedule D: Coordinated Transaction Scheduling

WHEREAS, ISO-NE, as the regional transmission organization for the New England Transmission System and the administrator of the New England wholesale electricity markets, schedules the sale of energy by its Market Participants to, and the purchase of energy by its Market Participants from, neighboring Balancing Authority Areas, all in accordance with the ISO-NE Tariff, which includes the Open Access Transmission Tariff and ISO-NE market rules;

WHEREAS, ISO-NE is the administrator of the ISO-NE Tariff and is responsible for, among other matters, ensuring sufficient reserves are available to provide reliable service in its Balancing Authority Area, in accordance with the ISO-NE Tariff;

WHEREAS, the NYISO, as the independent system operator of the New York Transmission System and the administrator of the New York wholesale electricity markets, schedules the sale of energy by its Market Participants to, and the purchase of energy by its Market Participants from, neighboring Balancing Authority Areas, all in accordance with the NYISO Tariffs;

WHEREAS, the NYISO is the administrator of the NYISO Tariffs and is responsible for, among other matters, ensuring sufficient reserves are available to provide reliable service in its Balancing Authority Area, in accordance with the NYISO Tariffs;

WHEREAS, Coordinated Transaction Scheduling will improve interregional scheduling efficiency by taking into account relative price differences between the regions and scheduling bids and offers on a 15 minute basis at CTS Enabled Interfaces; and

WHEREAS, the Parties desire to schedule energy between their Balancing Authority Areas more efficiently, while continuing to ensure that each Party will maintain sufficient Operating Reserve available on its respective system to ensure the reliable operation thereof;

NOW, THEREFORE, in consideration of the premises and of the mutual covenants herein set forth, the Parties mutually agree as follows:

ARTICLE I

1.0 OVERVIEW OF COORDINATED TRANSACTION SCHEDULING

Coordinated Transaction Scheduling or "CTS" is an external transaction scheduling process implemented by the Parties at designated CTS Enabled Interfaces that allow real-time energy transactions to be scheduled based on a Market Participant's willingness to purchase energy at a source External Proxy Bus (in the NECA, or in the NYCA) and sell it at a sink External Proxy Bus in the other Control Area if the forecasted price at the sink minus the forecasted price at the corresponding source is greater than or equal to the bid price. The rules set forth in this Schedule D only apply at CTS Enabled Interfaces.

In accordance with the terms of this Schedule D and the Parties' respective tariffs, CTS Interface Bids are ordinarily evaluated on a 15-minute basis utilizing forecasted real-time prices and forecasted system information from NYISO and forecasted real-time prices and forecasted system information from ISO-NE. The evaluation will be performed by the NYISO's Real-Time Commitment (RTC) optimization consistent with the rules specified in the NYISO Services Tariff and this Schedule D.

As part of the iterative CTS process, NYISO will share forward looking RTC interchange schedules with ISO-NE and these schedules will be used by ISO-NE as an input to develop a new set of forecasted prices and system information, which ISO-NE will then provide to NYISO for use in the next RTC optimization.

In accordance with Section 4 below, the RTC optimization will determine the External Interface Congestion component of the RTC LMP at a CTS Enabled Interface, which will subsequently be incorporated into the Parties' real-time settlement LMPs.

Wheel-through transactions across a CTS Enabled Interface will be scheduled on an hourly basis. Wheels through the NYCA will use decremental or sink price cap bids at CTS Enabled Interfaces.

Wheels through the NECA will use hourly CTS Interface Bids at CTS Enabled Interfaces for scheduling by the NYISO.

The Parties agree that CTS and its components will operate in accordance with this Schedule D and the terms of the Parties' respective tariffs.

ARTICLE II

2.0 SUBMITTAL OF CTS INTERFACE BIDS

2.1 CTS Interface Bid Submittal by New England Responsible Settlement Parties and their Representatives

NYISO is hosting the platform used by both New York and New England Responsible Settlement Parties to submit CTS Interface Bids. New York RSPs shall submit and confirm bids at CTS Enabled Interfaces in accordance with the NYISO Tariffs.

Authorized New England RSPs shall have access to the bidding platform for purposes of submitting bids at CTS Enabled Interfaces between the NECA and the NYCA. Such access will be provided under equivalent terms and conditions to New York RSPs.

On an hourly or more frequent basis ISO-NE shall provide NYISO with: (a) a list of all New England RSPs that are authorized to submit or confirm bids at CTS Enabled Interfaces and (b) identification information for each representative (*i.e.*, an individual) that is authorized to submit or confirm bids at CTS Enabled Interfaces on behalf of a New England RSP. Only representatives designated by ISO-NE shall be permitted access to the platform that is used to submit bids at CTS Enabled Interfaces on behalf of a New England RSP. NYISO shall verify the authorization of a New England RSP and its representative at the time a bid is submitted, confirmed, modified or deleted. If it has been more than two hours since the NYISO last received from ISO-NE an updated list of all authorized New England RSPs and identification information for each representative that is authorized to submit or confirm bids at CTS Enabled Interfaces on behalf of a New England RSP, then NYISO shall not allow any New England RSP to access the platform that is used to submit bids at CTS Enabled Interfaces until an updated list is received.

In the event NYISO is not able to implement a new or changed status in a timely fashion, NYISO will inform ISO-NE of any delay it is aware of and the reason for the delay, and will implement the new or changed status as soon as possible.

2.2 Confirmation of New England Responsible Settlement Parties

A representative submitting an initial or revised CTS Interface Bid, or a bid to schedule a wheel through the NYCA at a CTS Enabled External Proxy Bus must belong to an authorized RSP in either NYISO or ISO-NE. In that submittal, the representative must identify the participating RSP in the other area. The other participating RSP must confirm the submittal of the CTS Interface Bid or bid to wheel through the NYCA, in order for the bid to be valid. A CTS Interface Bid or a bid to wheel through the NYCA can be withdrawn by either participating RSP; no confirmation is required.

An RSP may establish a Confirmed Trust Relationship with another RSP such that the required confirmation will be automatically granted for any submittal of a CTS Interface Bid or bid to wheel through the NYCA at a CTS Enabled External Proxy Bus that is submitted by the trusted RSP and includes both RSPs as parties to the transaction. Upon representative action to submit, update or revoke a Confirmed Trust Relationship, NYISO shall verify that (i) the submittal identifies two authorized RSPs, one in New York and one in New England and (ii) the representative belongs to the RSP that is granting the Confirmed Trust Relationship to the other RSP.

Upon representative action to submit or confirm an initial or revised CTS Interface Bid or bid to wheel through the NYCA, or to withdraw a CTS Interface Bid or bid to wheel through the NYCA at a CTS Enabled External Proxy Bus, the NYISO shall verify that (i) the submittal identifies two valid RSPs, one in New York and one in New England, and (ii) the representative belongs to an RSP that is identified on the submittal. If a Confirmed Trust Relationship exists between the two authorized RSPs and the action is taken by a representative that is associated with a trusted RSP to submit or confirm an initial or revised CTS Interface Bid or bid to wheel through the NYCA, the bid shall be deemed submitted and confirmed, or the revision confirmed.

Upon receiving ISO-NE's notice of suspension or termination of a New England RSP, which ISO-NE shall do consistent with its authority under the ISO-NE Tariff, NYISO will promptly:

1. cease honoring Confirmed Trust Relationships associated with the suspended or terminated New England RSP;
2. within the real-time market day on which NYISO receives the instruction from ISO-NE, remove the suspended or terminated New England RSP's bids at CTS Enabled Interfaces that are offered in the NECA to NYCA direction;
3. within the real-time market day on which NYISO receives the instruction from ISO-NE, remove bids at CTS Enabled Interfaces that are offered in the NECA to NYCA direction that include the New England RSP as a trusted RSP;
4. for all real-time market days subsequent to the real-time market day on which NYISO receives the instruction from ISO-NE, remove all of the suspended or terminated New England RSP's bids at CTS Enabled Interfaces; and
5. for all real-time market days subsequent to the real-time market day on which NYISO receives the instruction from ISO-NE, remove all bids at CTS Enabled Interfaces that include the suspended or terminated New England RSP as a trusted RSP.

The five changes enumerated above will be effectuated prospectively. The Parties will not effectuate changes one through three for a real-time market hour in which RSPs are no longer able to submit or modify bids.

ISO-NE will curtail the e-tags for the transactions associated with the bids NYISO is required to remove under the rules set forth above.

In the event NYISO is not able to implement a new or changed status that is addressed in this Section 2.2 in a timely fashion, NYISO will inform ISO-NE of any delay it is aware of and the reasons for the delay, and will implement the new or changed status as soon as possible.

If the NYISO is unable to verify that the required confirmations have been received, then the CTS Interface Bid or bid to wheel through the NYCA shall not be considered in the RTC optimization.

If the NYISO is not able to validate an RSP or a representative, then that entity or person will not be able to submit, modify, confirm or delete a CTS Interface Bid or a bid to wheel through the NYCA.

ARTICLE III

3.0 CALCULATION OF ISO-NE SUPPLY PRICE POINTS

Each quarter-hour, ISO-NE shall calculate a set of forecast energy prices at its External Proxy Buses for each CTS Enabled Interface corresponding to varying interchange levels on that interface. The results will be provided to NYISO as increasing MW-price pairs, where the MW value represents a net interchange level on the CTS Enabled Interface and the price value represents ISO-NE's forecast of its real-time LMP for its External Proxy Bus at that net interchange MW level. ISO-NE will provide no fewer than one and no more than 11 MW-price pairs for each of ten consecutive quarter-hour intervals, which are referred to as the "ISO-NE Supply Price Points."

The ISO-NE Supply Price Points are created with a forward-looking, security-constrained economic dispatch system that co-optimizes energy and reserve requirements. This forward-looking co-optimization will assume the same units are committed as are previously committed, or scheduled to be committed, in ISO-NE's real-time production system. The energy from currently uncommitted fast-start generation will also be considered for dispatch in the forward-looking co-optimization. ISO-NE Supply Price Points shall be calculated using the current production data for load forecasts, active transmission constraints, state estimator data, Market Participant energy re-offers, wind forecasts, forecasted net interchange on all Interconnections (including forward looking RTC interchange schedules provided by NYISO), and operator updates to resource limits.

ARTICLE IV

4.0 SCHEDULING EXTERNAL TRANSACTIONS AT CTS ENABLED INTERFACES

4.1 Evaluation of CTS Interface Bids

The RTC will use the CTS Interface Bids and the ISO-NE Supply Price Points to economically schedule the CTS Interface Bids and determine the net interchange schedules. The economic scheduling of the CTS Interface Bids will be performed simultaneously with the scheduling of internal NYCA resources and external transactions at other NYCA Interconnections.

For an RTC optimization that schedules hourly CTS Interface Bids, the RTC will use the ISO-NE Supply Price Points for each 15-minute interval of the hour. An hourly CTS Interface Bid will be scheduled if it is economic for the hour.

For an RTC optimization that schedules CTS Interface Bids at 15-minute intervals, the RTC optimization will use ISO-NE Supply Price Points that have been adjusted to account for the hourly RTC external transaction schedules established at CTS Enabled Interfaces, including any scheduled Emergency Energy.

When there are multiple CTS Interface Bids at the same bid price but not all of them can be economically cleared, the CTS Interface Bids with the same price will be scheduled pro-rata.

The RTC optimization incorporates Ramp Limits and Transfer Limits in the manner described in Section 5 of this Schedule D to economically schedule CTS Interface Bids and shall determine: (1) the net interchange schedule for each CTS Enabled Interface, (2) the RTC LMP for each CTS Enabled External Proxy Bus, and (3) the External Interface Congestion at each CTS Enabled Interface.

4.2 External Interface Congestion Price Assignment

The RTC optimization will determine the External Interface Congestion at an External Proxy Bus for a CTS Enabled Interface if the net interchange schedule is limited in the RTC solution due to one or more of the following four reasons: (i) there are more economic transactions offered in a common direction (import or export) than the Transfer Limit of the External Proxy Bus can accommodate, or (ii) there are fewer economic transactions offered in a common direction (import or export) than the Transfer Limit requires, or (iii) the NYCA (system-wide) Ramp Limit prevents the RTC from scheduling one or more external transactions at the External Proxy Bus consistent with the economics of the underlying bids, or (iv) a Ramp Limit prevents the RTC from scheduling one or more external transactions consistent with the economics of the underlying bids (collectively, the "External Proxy Bus Constraints").

Whenever an External Proxy Bus Constraint at a CTS Enabled Interface is limiting in the RTC optimization, the External Interface Congestion at the External Proxy Bus will be assigned, in whole or in part, as set forth below.

ISO-NE Limiting: If the RTC optimization is limited by a Transfer Limit determined by an ISO-NE Operating Reserve limitation, an ISO-NE minimum generation limitation, or an ISO-NE capacity deliverability limit, including when the Transfer Limit is adjusted in accordance with Section 5.4 of this Schedule D to accommodate the Ramp Limit while implementing one of these limitations, then the portion of the External Interface Congestion associated with the External Proxy Bus Constraint shall be assigned to ISO-NE.

NYISO Limiting: If the RTC optimization is limited by NYCA-wide Ramp Limits, then the portion of the External Interface Congestion associated with the External Proxy Bus Constraint shall be assigned to NYISO.

NYISO and ISO-NE Limiting: If the RTC optimization is limited by any Ramp Limit or Transfer Limit that is not specifically addressed in the "ISO-NE Limiting" or "NYISO Limiting" paragraphs above, or by any Transfer Limit or Ramp Limit that results from an operator override, as described in Section 5.2.5 of this Schedule D, the portion of the External Interface Congestion for a CTS Enabled Interface that is associated with an External Proxy Bus Constraint shall be assigned to both Parties equally.

The RTC solution may be limited by multiple External Proxy Bus Constraints simultaneously. If this occurs, the foregoing rules will apply to each External Proxy Bus Constraint.

If there are not sufficient CTS Interface Bid MWs offered to achieve a Transfer Limit, RTC will schedule the available MWs. In these circumstances, RTC will determine the External Interface Congestion at the External Proxy Bus based on the NYISO's Transmission Shortage Costs as defined in the NYISO Tariff.

In order to provide consistent price signals between their respective real-time energy markets, the Parties shall each incorporate the foregoing process into the real-time settlement LMP at their External Proxy Bus for each CTS Enabled Interface.

ARTICLE V

5.0 CTS ENABLED INTERFACE OPERATING RULES

5.1 CTS Enabled Interface Ramp Limits

The default quarter-hour Ramp Limit for the NY/NE Northern AC Interconnection will be mutually agreed to by the Parties and posted on the NYISO's OASIS.

The default top-of-the-hour Ramp Limit for the NY/NE Northern AC Interconnection (for use when quarter-hour scheduling is unavailable) will be mutually agreed to by the Parties and posted on the NYISO's OASIS.

In real-time operations, when necessary to protect reliability, the Parties may mutually agree to temporarily change the Ramp Limit(s) at any CTS Enabled Interface. The Parties shall restore the modified Ramp Limit to the posted default Ramp Limit as soon as reliable system operations permit and it is practicable to do so.

5.2 Transfer Limits Reflecting Reliability Conditions

A Transfer Limit sets the minimum or maximum net interchange that can be scheduled on a CTS Enabled Interface in the RTC solution. Factors that can set the Transfer Limits include the following:

1. normal scheduling limits;
2. Operating Reserve limitations;
3. minimum generation limitations;
4. capacity requests;
5. operator overrides.

5.2.1 Normal Scheduling Limits

The normal scheduling limit for a CTS Enabled Interface is the amount of electric power that can normally be transferred over a CTS Enabled Interface. The Parties may mutually agree to change the normal scheduling limits that are used at CTS Enabled Interfaces due to transmission outages, generation outages or other changes in system conditions. In the event the change to a normal scheduling limit is planned in advance, the Parties will make reasonable efforts to change the values in time to be included in the clearing of their respective day-ahead energy markets and be publicly posted prior to implementation. For the real-time operating day, ISO-NE will send its normal scheduling limits at each CTS Enabled

Interface to the NYISO via the electronic data exchange to cover the same ten consecutive quarter-hour intervals as ISO-NE's Supply Price Points.

5.2.2 Operating Reserve Limitations

If one Control Area experiences an Operating Reserve deficiency, the other Control Area is not obligated to go deficient in its reserves of the same or a higher quality product, but may go deficient in a lower-quality reserve product in order to prevent an Operating Reserve deficiency of a higher quality reserve product in the other Control Area. To ensure these mutual reliability objectives can be satisfied, the Parties may modify the Transfer Limits in certain conditions as described below.

The RTC optimization procures reserves to meet the NYISO's reserve requirements and prices shortages of reserves using the NYISO's Operating Reserve demand curves. The RTC does not have information on the amount of Operating Reserve in the NECA. Therefore, at CTS Enabled Interfaces, ISO-NE will use the electronic data exchange to provide to NYISO both the ISO-NE Supply Price Points and Transfer Limit values that reflect the net interchange required to meet ISO-NE's 10-minute and 30-minute reserve requirements. When calculated, these values will reflect the net interchange required to meet ISO-NE's 10-minute and 30-minute reserve requirements for the same ten consecutive quarter-hour intervals for which ISO-NE's Supply Price Points are provided. ISO-NE will calculate these Transfer Limit values for each interval based on the Operating Reserve surplus in the NECA when applying the forecasted RTC net interchange on the CTS Enabled Interface. For the purposes of Schedule D, the ISO-NE Transfer Limit associated with the 10-minute reserve requirement will always be less restrictive than the Transfer Limit associated with the ISO-NE 30-minute reserve requirement. When ISO-NE sends Transfer Limits that are associated with Operating Reserve requirements, the ISO-NE Supply Price Points must also reflect those expected reserve shortage prices. RTC will evaluate whether the ISO-NE Transfer Limit would preclude NYISO from meeting its reserve requirements for an equal or higher quality reserve product. If so, RTC may adjust the Transfer Limit in accordance with Section 5.3 of this Schedule D, based on the principles set forth in the preceding paragraph.

5.2.3 Minimum Generation Limitations

The RTC optimization dispatches the NYISO system's internal generation as needed when the NYCA approaches minimum generation conditions. The RTC does not have information to assess minimum generation conditions within the NECA. Therefore, at CTS Enabled Interfaces, ISO-NE will use the

electronic data exchange to provide to NYISO Transfer Limit values that reflect the net interchange level beyond which ISO-NE cannot further dispatch down internal generation while maintaining reliable operations. When ISO-NE sends Transfer Limits for this purpose, the ISO-NE Supply Price Points must also reflect these requirements.

ISO-NE shall not send, and NYISO is not required to enforce, a minimum generation Transfer Limit that would require the NYCA to accept energy from the NECA.

ISO-NE shall not send both a minimum generation Transfer Limit and Operating Reserve Transfer Limits at the same time.

5.2.4 Capacity Transfer Limits

Day-Ahead Coordination

NYISO will provide its day-ahead operating plan to ISO-NE. Once ISO-NE determines that it expects to count on capacity resources located in New York to meet its reserve requirements, ISO-NE shall inform NYISO of the expected capacity call.

Real-Time Coordination

ISO-NE Capacity Requests at CTS Enabled Interfaces:

ISO-NE may request delivery of energy from capacity resources located in the NYCA that have obligations in the ISO-NE capacity market over a CTS Enabled Interface. The ISO-NE operator will call the NYISO operator to initiate the capacity request. Upon receiving the request, the NYISO operator will confirm what amount of the capacity request is deliverable based on projected transmission constraints ("Capacity Deliverable to ISO-NE"). If the Capacity Deliverable to ISO-NE is non-zero, RTC will determine the ISO-NE capacity that is available based on offers submitted by NYCA generators that have sold their capacity to ISO-NE and are projected to be available in real-time, subject to any real-time derates ("Capacity Available to ISO-NE").

Transactions to wheel capacity through the NYCA will be excluded from the ISO-NE/NYISO capacity request process.

NYISO Capacity Requests at CTS Enabled Interfaces:

If the NYISO projects the ISO-NE real-time capacity request could cause the NYISO to become capacity deficient, the NYISO may request delivery of energy associated with capacity resources located in ISO-NE that have an obligation in the NYISO capacity market over a CTS Enabled Interface. The NYISO operator will call the ISO-NE operator to initiate the capacity request. The NYISO will require that its eligible New England-based capacity submit CTS Interface Bids to be evaluated by RTC. It will be up to the supplier of New England-based capacity to ensure that the resource(s) backing capacity transactions are available to deliver their capacity to New York when they are called on to do so. At the time of the request, the ISO-NE operator will determine whether all or any part of the generation supporting the capacity is available and deliverable ("Capacity Available to NYISO").

Section 5.3 of this Schedule D sets forth how capacity data and Operating Reserve limitations are used to establish a Transfer Limit.

5.2.5 Operator Override Transfer Limits

Real-time system conditions may require that a NYISO or ISO-NE operator override the Transfer Limit to establish the flow that can be transferred over a CTS Enabled Interface in a reliable manner. Except when necessary to protect reliability, an operator override shall not be used to submit limits that can be submitted via the electronic data exchange.

5.3 Establishing Transfer Limits for RTC

RTC determines a net interchange for each interval that must be a value between an upper bound and lower bound. In this section, the high Transfer Limit is the upper bound on that range and the low Transfer Limit is the lower bound on that range. The rules in this Section 5.3 detail how the inputs from Section 5.2, which are first tested against the criteria set forth in Section 7.2, are used to determine the high and low Transfer Limits in RTC for each quarter-hour interval. For purposes of this Section 5.3, a positive value represents flow from New England to New York, and a negative value represents flow from New York to New England. The values associated with an ISO-NE capacity request, Capacity Deliverable to ISO-NE and Capacity Available to ISO-NE are all negative.

1. When a Minimum Generation Transfer Limit is provided by ISO-NE in accordance with Section 5.2.3, that value is the low Transfer Limit at a CTS Enabled Interface.

2. When ISO-NE provides Operating Reserve Transfer Limits but has not requested capacity from NYISO, the following rules are applied to determine the high Transfer Limit at a CTS Enabled Interface:

   a) If the ISO-NE 30-minute Operating Reserve Transfer Limit is greater than or equal to zero, then:

      i. If enforcing the ISO-NE 30-minute Operating Reserve Transfer Limit is projected to cause the NYISO to have a deficiency of 10-minute Operating Reserve, the high Transfer Limit is the minimum value that is not projected to result in a NYISO 10 minute Operating Reserve deficiency;

      ii. Otherwise the high Transfer Limit is the ISO-NE 30-minute Operating Reserve Transfer Limit.

   b) If the ISO-NE 30-minute Operating Reserve Transfer Limit is less than zero, then:

      i. If enforcing the ISO-NE 30-minute Operating Reserve Transfer Limit is projected to cause the NYISO to have a deficiency of 30-minute Operating Reserve but is not projected to cause the NYISO to have a deficiency of 10-minute Operating Reserve, then the high Transfer Limit is the lesser of (a) the minimum value that is not projected to result in a NYISO 30-minute Operating Reserve deficiency, or (b) zero;

      ii. If enforcing the ISO-NE 30-minute Operating Reserve Transfer Limit is projected to cause the NYISO to have a deficiency of 10-minute Operating Reserve, then the high Transfer Limit is the minimum value that is not projected to result in a NYISO 10-minute Operating Reserve deficiency;

      iii. Otherwise the high Transfer Limit is the ISO-NE 30-minute Operating Reserve Transfer Limit.

3. When ISO-NE has requested capacity from NYISO, the high Transfer Limit at a CTS Enabled Interface shall be the greater of:

   a) the ISO-NE 30-minute Operating Reserve Transfer Limit, or

   b) [the minimum of (i) the total quantity of CTS Interface Bids backing Capacity Available to NYISO or (ii) the Capacity Available to NYISO] plus [the maximum of (iii) the ISO-NE capacity request, (iv) the Capacity Deliverable to ISO-NE or (v) the Capacity Available to ISO-NE].

4. When system conditions require that either a low or high Transfer Limit be overridden by the NYISO or ISO-NE operator to establish the flow that can be transferred over a CTS Enabled Interface in a reliable manner, the override shall establish the low or high Transfer Limit.

5. Otherwise, the NYISO shall use the normal scheduling Transfer Limit at a CTS Enabled Interface, as described in Section 5.2.1.

5.4. Interaction Between Transfer Limits and Ramp Limits

a) Except as provided in 5.4(b), when the NYISO's RTC is provided Transfer Limits that would cause it to develop net interchange schedules at a CTS Enabled Interface with ISO-NE that exceed the Ramp Limits, RTC will reset the provided Transfer Limits to ensure the agreed Ramp Limits are not exceeded.

b) If any Transfer Limit, other than a normal scheduling limit, is implemented via an operator override, then RTC shall permit the agreed Ramp Limits to be exceeded in order to enforce the Transfer Limit.

ARTICLE VI

6.0 SETTLEMENT PROVISIONS

ISO-NE shall settle CTS Interface Bids and other bids and offers scheduled at CTS Enabled Interfaces with its Market Participants in accordance with the rules set forth in the ISO-NE Tariff.

The NYISO shall settle CTS Interface Bids and other bids scheduled at CTS Enabled Interfaces, with its Market Participants in accordance with the rules set forth in the NYISO Tariffs.

Each Party shall address settlement-related corrections and disputes regarding that Party's settlement of CTS transactions in accordance with the settlement correction and dispute resolution provisions set forth in that Party's tariff(s).

Each Party agrees to provide support, including information and data that isn't otherwise available to the other Party, when the requested information is necessary to assist the requesting Party in addressing a

settlement (but not price) correction or a settlement-related dispute between the requesting Party and one or more of its Market Participants regarding the settlement of CTS transactions.

If an erroneous price is determined at a CTS Enabled External Proxy Bus, independent of any price correction process ISO-NE may utilize, the NYISO shall follow the price correction process set forth in Attachment E to its Market Administration and Control Area Services Tariff.

If an erroneous price is determined at a CTS Enabled External Proxy Bus, independent of any price correction process NYISO may utilize, ISO-NE shall follow the price correction process set forth in the ISO-NE Tariff.

ARTICLE VII

7.0 NON-STANDARD CTS OPERATION

7.1 Permitted Modifications to ISO-NE Supply Price Points

In the event NYISO does not receive the ISO-NE Supply Price Points before it commences the RTC optimization, then the last set of ISO-NE Supply Price Points used to perform an RTC optimization will be used in the RTC optimization to determine the net interchange schedule until the NYISO receives and successfully validates a new set of ISO-NE Supply Price Points.

If one or more quarter-hour intervals within the ISO-NE Supply Price Points fail the NYISO's input checks, the last set of ISO-NE Supply Price Points used to perform an RTC optimization will be used in the RTC optimization.

When ISO-NE Supply Price Points do not cover the full quantity (in MWs) of bids that are evaluated by RTC, then the last pricing point on either end of the ISO-NE Supply Price Points will be extended by NYISO to cover all the bids and offers that are evaluated by RTC.

7.2 Permitted Modifications to ISO-NE Transfer Limits

In the event NYISO does not receive ISO-NE Transfer Limits or operator override values have not been entered before an RTC optimization commences, then the last set of ISO-NE Transfer Limits used to perform an RTC optimization will be used in the current RTC optimization.

If one or more quarter-hour intervals within the ISO-NE Transfer Limits fail any of the NYISO's input checks, including the input checks listed below, the last set of ISO-NE Transfer Limits used to perform an RTC optimization will be used in the RTC optimization.

- A Minimum Generation Transfer Limit and Operating Reserve Transfer Limits will not be sent at the same time.
- The Minimum Generation Transfer Limit will be less than or equal to zero.
- If an ISO-NE 10-minute Operating Reserve Transfer Limit is provided, an ISO-NE 30-minute Operating Reserve Transfer Limit will also be provided.
- The ISO-NE 30-minute Operating Reserve Transfer Limit will be less than the ISO-NE 10-minute Operating Reserve Transfer Limit.

7.3 Hourly Scheduling Under CTS

The Parties may agree to temporarily employ hourly scheduling in RTC on a CTS Enabled Interface when necessary to ensure or preserve system reliability or when not able to implement schedules as expected due to software or communication issues.

ARTICLE VIII

8.0 JOINT ENERGY SCHEDULING SYSTEM CUSTOMER SERVICE; MAINTENANCE; SUSPENSION OF CTS; COOPERATION

8.1 Joint Energy Scheduling System Customer Service

The NYISO developed and maintains the Joint Energy Scheduling System ("JESS") platform that both New York RSPs and New England RSPs use to submit bids at CTS Enabled Interfaces.

1. Each Party is the primary customer service contact for its respective Market Participants.

2. ISO-NE will have read-only access to bids associated with New England Market Participants at CTS Enabled Interfaces on the JESS platform.

8.2 Maintenance

Subject to reasonable expectations, it is the Parties' goal that the data links, software, and other systems necessary to implement CTS are available continuously. The Parties agree to employ regular maintenance, including scheduled maintenance outages when needed, to meet that goal.

In the event of a problem with a data link, software, computational system or data system, the responsible Party will use reasonable efforts to promptly address the problem. The Parties shall work together and shall keep each other informed regarding the problem and its resolution.

The Parties shall inform each other in advance of any scheduled testing activities or maintenance outages that will affect a CTS Enabled Interface. Notice shall be provided sufficiently in advance to allow each ISO to inform its Market Participants of any impacts on the operation of CTS.

8.3 Suspension of CTS

The Parties may suspend the scheduling of CTS transactions at CTS Enabled Interfaces due to: (1) the inability of the NYISO to receive bids for a CTS Enabled Interface; (2) a failure or outage of the data link between the Parties that prevents the timely exchange of information necessary to implement CTS transactions; (3) the actual or suspected failure of any software, computational, or data system that is necessary to implement CTS transactions; (4) the need to verify the functionality of the tools that are necessary to implement CTS; or (5) when necessary to ensure or preserve NYISO or ISO-NE system reliability.

A Party that determines that any of the foregoing conditions have occurred shall, as soon as practicable, notify the other Party.

The Parties shall resolve issues causing the failure or outage of the data link, software, computational systems, or data systems as soon as possible, and will use reasonable efforts to promptly address the problem. The Parties shall work together and shall keep each other informed regarding the problem and its resolution. The Parties shall resume implementation of CTS following, as applicable, the successful

testing of the data link or relevant system(s) after the inability to receive offers or bids, failure, or condition is resolved, or after the resolution of the system reliability issue.

When CTS is suspended the Parties shall mutually agree to interchange schedules at CTS Enabled Interfaces.

8.4 Cooperation

The Parties will cooperate to review the data and mutually identify or resolve errors and anomalies. If one Party determines that it is required to self-report a potential violation to the Commission's Office of Enforcement regarding its compliance with this Schedule D, the reporting Party shall inform, and provide a copy of the self-report to the other Party. Any such report provided by one Party to the other shall be Confidential Information.

ARTICLE IX

9.0 CTS CHANGE MANAGEMENT PROCESS

9.1 Notice

Prior to materially changing any tariff language, software or process that is directly involved in implementing this Schedule D, the Party desiring the change shall notify the other Party's data exchange contact appointed under the Coordination Agreement, in writing or via email, of the proposed change. The notice shall include a complete and detailed description of the proposed change, the reason for the proposed change, and the impacts the proposed change is expected to have on the implementation of CTS.

9.2 Opportunity to Request Additional Information

Following receipt of the Notice described in Section 9.1, the receiving Party may make reasonable requests for additional information/documentation from the other Party. This may include a request by a Party to be involved in the testing of the changes. Absent mutual agreement of the Parties, the submission of a request for additional information under this Section shall not delay the obligation to timely note any objection pursuant to Section 9.3, below.

9.3 Objection to Change

Within ten business days after receipt of the Notice described in Section 9.1 (or within such longer period of time as the Parties mutually agree), the receiving Party may notify in writing or via email the other Party of its disagreement with the proposed change. Any such notice must specifically identify and describe the concern(s) that required the receiving Party to object to the described change.

9.4 Implementation of Change

The Party proposing a change to a process that is directly involved in implementing this Schedule D shall not implement such change until (a) it receives written or email notification from the other Party that the other Party concurs with the change, or (b) the receiving Party fails to notify in writing or via email the other Party of its disagreement with the proposed change within the notice period specified in Section 9.3, or (c) completion of any dispute resolution process initiated pursuant to this Agreement.

ARTICLE X

10.0 AUDITS, CERTIFICATION AND TESTING

Each Party shall provide to the other Party the results of any certification or audit it procures regarding CTS-related software functions, subject to the following conditions: (1) the disclosure may be limited to the portions of the certification or audit that addresses the CTS-related software, and need only include the portions of the certification or audit that address the CTS-related functioning of the software; (2) if the providing Party indicates that the certification or audit is Confidential Information it shall be treated as such by the receiving party; and (3) this provision does not require a Party to disclose information that is subject to a legal privilege.

Before CTS is implemented, and upon any material changes to any components thereof, the Parties shall test the processes and component software.

Each Party shall, at its sole expense, take appropriate actions to address any actual or apparent breach of cyber security related to CTS, and shall provide prompt notification to the other Party of any such incident.

Each party will undertake an annual Service Organization Controls report that covers CTS process-related controls prepared and opined by its external auditors in accordance with Statement on Standards for Attestation Engagements No. 16 or AICPA/CICA Principles and Criterion for System Reliability (SSAE 16 engagement). The NYISO report will include controls related to the Joint Energy Scheduling System bidding platform.

Each Party shall promptly provide to the other Party the results of its annual Service Organization Controls report, subject to the following conditions: (1) the disclosure may be limited to the portions of the report or audit that address CTS, and need only include the portions of the report or audit that address CTS; (2) if the providing Party indicates that the certification or audit is Confidential Information it shall be treated as such by the receiving party; and (3) this provision does not require a Party to disclose information that is subject to a legal privilege.

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 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.

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 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.

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.

Coordinated External Transaction is an External Transaction at an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented. A transaction to wheel energy into, out of or through the New England Control Area is not a Coordinated External Transaction.

Coordinated Transaction Scheduling means the enhanced scheduling procedures set forth in Section III.1.10.7.A.

Correction Limit means the date that is one hundred and one (101) calendar days from the last Operating Day of the month to which the data applied. As described in Section III.3.6.1 of Market Rule 1, this will be the period during which meter data corrections must be submitted unless they qualify for submission as a Requested Billing Adjustment under Section III.3.7 of Market Rule 1.

Cost of Energy Consumed (CEC) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Cost of Energy Produced (CEP) is one of four forms of compensation that may be paid to resources providing VAR Service under Schedule 2 of the OATT.

Cost of New Entry (CONE) is the estimated cost of new entry ($/kW-month) for a capacity resource that is determined by the ISO for each Forward Capacity Auction pursuant to Section III.13.2.4.

Counterparty means the status in which the ISO acts as the contracting party, in its name and own right and not as an agent, to an agreement or transaction with a Customer (including assignments involving Customers) involving sale to the ISO, and/or purchase from the ISO, of Regional Transmission Service and market and other products and services, and other transactions and assignments involving Customers, all as described in the Tariff.

Covered Entity is defined in the ISO New England Billing Policy.

Credit Coverage is third-party credit protection obtained by the ISO, in the form of credit insurance coverage, 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.

Curtailment 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 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.

Interface Bid is a unified real-time bid to simultaneously purchase and sell energy on each side of an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented.

Intermittent Power Resource is 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 over-stated 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.

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.

New Resource Offer Floor Price is defined in Section III.A.21.2.

NMPTC means Non-Market Participant Transmission Customer.

NMPTC Credit Threshold is described in Section V.A.2 of the ISO New England Financial Assurance Policy.

NMPTC Financial Assurance Requirement is an amount of additional financial assurance for Non-Market Participant Transmission Customers described in Section V.D of the ISO New England Financial Assurance Policy.

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.5.7 of Appendix A of Market Rule 1.

Regional Benefit Upgrade(s) (RBU) means a Transmission Upgrade that: (i) is rated 115kV or above; (ii) meets all of the non-voltage criteria for PTF classification specified in the OATT; and (iii) is included in the Regional System Plan as either a Reliability Transmission Upgrade or 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.

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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.

Zonal Price is calculated in accordance with Section III.2.7 of Market Rule 1

II.11 Nature of Regional Network Service

Regional Network Service is the service over the PTF pursuant to Part II.B of this OATT which is provided by the ISO to Network Customers to serve their loads. It includes transmission service over the PTF for the delivery to a Network Customer of its energy and capacity in Network Resources and delivery to or by Network Customers of energy and capacity in Market transactions.

When a Real-Time External Transaction purchase is submitted by the Transmission Customer and is scheduled in the Real-Time Energy Market, the submission shall be deemed a request for Regional Network Service and the ISO shall generate a reservation for the transmission service over the PTF equal to the transaction's maximum scheduled flow during the operating hour. This reservation amount shall be the basis for the Reserved Capacity. Each Transmission Customer which has a Regional Network Load within or outside of the New England Control Area shall pay for Regional Network Service under the terms of Section II.B of this OATT.

II.44 Scheduling and Curtailment Rules

For purposes of scheduling and Curtailment of Real-Time External Transactions over interconnections between the New England Control Area and neighboring Control Areas, the following rules shall apply:

(1) For External Interfaces that are not subject to Coordinated Transaction Scheduling

(a) Real-Time External Transaction sales and purchases that (i) are supported by those service agreements referenced in Attachment G-3 to this OATT that have not opted for Auction Revenue Rights consideration under applicable ISO System Rules or (ii) are supported by those service agreements referenced in Attachment H to this OATT, and (iii) have been submitted into the Real-Time Energy Market prior to noon the day before the Operating Day as a Self-Scheduled Real-Time External Transaction ("real-time without price") at an External Node referenced in Attachment G-3 or Attachment H to this OATT shall be assigned the highest transmission priority when compared to other Real-Time External Transaction purchases or sales at that node having the same offer price or bid price. In the event that the transfer limit for a given external interface does not allow all Excepted Transactions or MEPCO Grandfathered Transactions submitted over that interface to flow, they shall be scheduled or curtailed on a pro-rata basis. For Real-Time External Transactions referenced in Attachment G-3 or Attachment H to this OATT that also require an advance physical reservation associated with a MTF or OTF external interface, the MTF or OTF transmission priority shall take precedence over the above language for the purposes of scheduling and curtailment under Sections II.44(1)(c) and II.44(1)(d) of this OATT, respectively. For Excepted Transactions or MEPCO Grandfathered Transactions that are tied within economic merit, and tied within transmission priority, such transactions cleared in the Day-Ahead Energy Market that have a corresponding Real-Time Energy Market External Transaction will have scheduling and curtailment priority in the Real-Time Energy Market before Excepted Transactions or MEPCO Grandfathered Transactions not cleared in the Day-Ahead Energy Market;

(b) For external interfaces where advance physical reservations are not required, in the event that the transfer limit for a given external interface does not allow all such Real-Time External Transactions submitted over that interface to flow, the scheduling and Curtailment of Real-Time External Transactions shall be based on economic merit order in accordance with the ISO System Rules. In the case of a tie within economic merit, transmission priority will be used as the next tiebreaker. In the case of a tie within

economic merit and within transmission priority, those External Transactions that cleared in the Day-Ahead Energy Market that have a corresponding Real-Time Energy Market External Transaction will have scheduling and curtailment priority in the Real-Time Energy Market before those that did not clear in the Day-Ahead Energy Market. In the case of a tie within economic merit, transmission priority, and Day-Ahead Energy Market status, Real-Time External Transactions sales that were submitted pursuant to Section III.1.10.7(f) of the Tariff will have scheduling and curtailment priority over those that were not submitted pursuant to Section III.1.10.7(f). After economic merit, transmission priority, Day-Ahead Energy Market status, and supported in Real-Time status pursuant to Section III.1.10.7(f) of the Tariff have been considered, (i) the Real-Time Energy Market timestamp shall be used as the final tiebreaker for External Transactions not submitted pursuant to Section II.44(a) and (ii) pro-rata scheduling and curtailment shall be used as the final tiebreaker for External Transactions submitted pursuant to Section II.44(a). With the exception of Section II.44(a) of this OATT, all transactions crossing external interfaces not requiring advance physical reservations shall have equal transmission priority;

(c) For external interfaces where advance physical reservations are required, in the event that the transfer limit for a given external interface does not allow all such Real-Time External Transactions submitted over that interface to flow, the scheduling of Real-Time External Transactions which satisfy the reservation requirements for service shall be based on economic merit order in accordance with the ISO System Rules. In the case of a tie within economic merit, transmission priority shall be used as a tiebreaker. Relative to a given interface, transmission priority is based on the priority rights of the associated MTF or OTF advance physical reservation. In the case of a tie within economic merit and within a category of transmission service, those External Transactions that cleared in the Day-Ahead Energy Market that have a corresponding Real-Time Energy Market External Transaction shall be scheduled in the Real-Time Energy Market before those that did not clear in the Day-Ahead Energy Market. In the case of a tie within economic merit, transmission priority, and Day-Ahead Energy Market status, Real-Time External Transactions sales that were submitted pursuant to Section III.1.10.7(f) of the Tariff will have scheduling and curtailment priority over those that were not submitted pursuant to Section III.1.10.7(f). After economic merit, transmission priority, Day-Ahead Energy Market status, and supported in Real-Time status pursuant to Section III.1.10.7(f) of the

Tariff have been considered, (i) the associated Real-Time Energy Market timestamp shall be used as the final tiebreaker for scheduling within a given subcategory of non-firm transmission service and (ii) pro-rata scheduling shall be used as the final tiebreaker for ties within firm transmission service;

(d) For external interfaces where advance physical reservations are required, Curtailments resulting from a reduction in total transfer capability shall be based on transmission priority of the associated MTF or OTF advance physical reservation to the extent possible. In the case of a tie within a category of transmission service, those External Transactions that cleared in the Day-Ahead Energy Market that have a corresponding Real-Time Energy Market External Transaction shall be curtailed in the Real-Time Energy Market after those that did not clear in the Day-Ahead Energy Market. In the case of a tie within transmission priority associated with External Transaction sales that cleared in the Day-Ahead Energy Market that have a corresponding Real-Time Energy Market External Transaction, those Real-Time Energy Market External Transactions that were submitted pursuant to Section III.1.10.7(f) of the Tariff will be curtailed after those that were not submitted pursuant to Section III.1.10.7(f). After transmission priority, Day-Ahead Energy Market status, and supported in Real-Time status pursuant to Section III.1.10.7(f) of the Tariff have been considered, (i) the associated Real-Time Energy Market timestamp shall be used as the final tiebreaker for curtailments within a given sub-category of non-firm transmission service and (ii) pro-rata curtailment shall be used as the final tiebreaker for ties within firm transmission service;

(e) In instances of a Real-Time External Transaction scheduled against multiple advance physical reservations on a MTF or OTF external interface, the lowest transmission priority of the associated advance physical reservations shall apply; and

(f) Scheduling and Curtailment of Real-Time External Transactions shall be conducted in accordance with the specifications of the ISO New England Operating Documents. Real-Time External Transactions not satisfying Section III.1.10.7(i) criteria shall be scheduled and curtailed under the following protocol as may be necessary to respond to and prevent system-wide Emergencies: (1) initial scheduling and curtailment priority shall be based upon whether the transaction cleared the Day-Ahead Energy Market; in the case of a tie within Day-Ahead Energy Market cleared transactions, priority will next be given to transactions based on the priority of the transmission service; and a tie within any specific transmission service shall be

resolved based on the timestamp of the Real-Time Energy Market submission; and (2) secondary scheduling and curtailment priority shall be provided to External Transactions that were only submitted or scheduled in the Real-Time Energy Market and did not clear the Day-Ahead Energy Market; in the case of an economic tie among Real-Time Energy Market cleared transactions, priority will next be given to transactions based on the priority of the transmission service; and a tie within any specific transmission service shall be resolved based on the timestamp of the Real-Time Energy Market submission. Real-Time External Transactions satisfying Section III.1.10.7(i) criteria shall be treated in accordance with that section.

(2) For External Interfaces that are subject to Coordinated Transaction Scheduling, the transmission priority for all Real Time External Transactions is equal. As such, the associated Real Time External Transactions shall be scheduled and curtailed on the basis of economic merit order in accordance with Section III.1.10.7A of the Tariff and the Coordination Agreement between ISO-NE and the NYISO; In the event of a tie within economics, all affected Real-Time External Transactions will be reduced on a pro-rata basis.

(3) Terms and Conditions applied to all External Interfaces

(a) The transmission priority for wheel-through transactions will be based on the transmission service utilized at the restricted external interface as indicated by the transmission reservation;

(b) Transmission Customers wishing to schedule Real-Time External Transactions shall comply with applicable ISO System Rules;

(c) Real-Time External Transactions scheduled in the Real-Time Energy Market shall continue to be scheduled and curtailed according to Section II.44(1) and (2), as applicable, when there are transmission limitations on an external interface, except as may be necessary to respond to emergencies;

(d) The ISO will redispatch all Resources subject to its control, pursuant to Market Rule 1, in order to meet load and to accommodate Real-Time External Transactions. Transmission Customers will be charged for the Congestion Cost and any other costs associated with such redispatch in accordance with Market Rule 1. Pursuant to such redispatch, in the

event the ISO exercises its right to effect a Curtailment, in whole or part, of Through or Out Service, MTF Service or OTF Service, no credit or other adjustment shall be provided as a result of the Curtailment with respect to the charge payable by the customer;

(e) The ISO will furnish to the Delivering Party's system operator schedules from each applicable scheduling interval equal to those furnished by the Receiving Party (unless reduced for losses) and will deliver the capacity and energy provided by such schedules;

(f) Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the ISO, and the ISO will have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered;

(g) The ISO shall apply the above-listed rules consistent with maintaining the reliability of the New England Transmission System; and

(h) The ISO shall develop and post procedures on its Internet website reflecting the above-listed External Transaction rules.

SCHEDULE 2

REACTIVE SUPPLY AND VOLTAGE CONTROL SERVICE

In order to maintain transmission voltages on the New England Transmission System (for voltage constraints that are reflected in the ISO's systems for operating the New England Transmission System or in the ISO New England Operating Procedures) within acceptable limits, Qualified Reactive Resources are operated to produce (or absorb) reactive power. Thus, VAR Service must be provided to support Regional Network Service and Through or Out Service on the New England Transmission System (both of which services have a direct impact on voltage constraints that are reflected in the ISO's systems for operating the New England Transmission System or in the ISO New England Operating Procedures). The amount of VAR Service that must be supplied with respect to a Transmission Customer's Regional Network Service and Through or Out Service will be determined based on the degree of dynamic reactive power support necessary to maintain transmission voltages within limits that are consistently adhered to in the operation of the New England Transmission System. Additional information regarding the processes used to collect data and calculate amounts due or payable under this Schedule 2 can be found in the Ancillary Service Schedule 2 Business Procedure posted on the ISO website. Transmission Customers taking Local Service, MTF Service or OTF Service may also need to acquire voltage support services not otherwise provided under this Schedule 2 pursuant to Schedules 18, 20A or 21 to this OATT, as appropriate.

I. DEFINITIONS

Whenever used in this Schedule, in either the singular or plural number, capitalized terms shall have the meanings specified in Section I.2.2. of the Tariff.

II. ELIGIBILITY FOR PAYMENT UNDER SCHEDULE 2

A. Qualified Generator Reactive Resources

Qualified Generator Reactive Resources shall be eligible for VAR Payments under this Schedule 2. A Qualified Generator Reactive Resource shall be offered into the Real-Time Energy Market at a MW level of at least its Economic Minimum Limit in all hours of the month whenever the resource is physically available, and be eligible for commitment by the ISO for the purpose of providing reactive power voltage

support to the New England Transmission System. Qualified Generator Reactive Resources are subject to the forced re-scheduling provisions for outages in accordance with the ISO New England Manuals and ISO New England Operating Procedures for the purpose of providing reactive power voltage support to the New England Transmission System. In addition, any generator that is dispatched by ISO for the purpose of providing voltage support to the New England Transmission System shall be eligible to recover its Lost Opportunity Costs ("LOC"), Cost of Energy Consumed ("CEC"), and Cost of Energy Produced ("CEP") pursuant to Sections IV.B-D of this Schedule 2.

A generator shall be deemed a Qualified Generator Reactive Resource if it meets the following criteria:

1. the entity owning or controlling the reactive power capability of the generator reactive resource is a Market Participant;

2. the generator is: (a) interconnected to the New England Transmission System or (b) interconnected to the distribution system but participating in the New England Markets and (c) is metered and dispatchable by the ISO or otherwise subject to operational control by the ISO;

3. the generator provides measurable reactive power voltage support to the New England Transmission System, as determined from time-to-time by the ISO, and has its automatic voltage regulator status and control mode (including power factor, reactive power output and voltage control) telemetered to the ISO and the applicable Local Control Center; provided that the generator shall have until January 1, 2009 to have the necessary telemetering equipment installed and operating;

4. the generator meets the reactive power testing requirements applicable to generators, as determined from time-to-time by the ISO and specified in the ISO New England Operating Documents; and

5. the installation of the generator shall have been approved in accordance with the requirements of Section I.3.9 of the Tariff or its predecessor or successor provisions under the New England regional transmission arrangements.

Any generator that has been receiving VAR Payments under Schedule 2 prior to June 1, 2007 shall be deemed to be a Qualified Generator Reactive Resource as of that date, provided that it continues to meet the criteria specified in Section II, A. (1), (3) and (4) above. Additionally, each generator seeking to be newly designated as a Qualified Generator Reactive Resource shall submit information to the ISO regarding its capability to provide leading VAR Service prior to receiving any leading VAR Payments under Schedule 2. Such information shall be submitted in the form and within the timeframe prescribed in the Ancillary Service Schedule 2 Business Procedure and/or the Schedule 2 VAR Payment Implementation Rule.

B. Qualified Non-Generator Reactive Resources

Qualified Non-Generator Reactive Resources shall be eligible for VAR Payments under this Schedule 2. However, to the extent that cost recovery for the dynamic reactive power capability of a non-generator resource could occur under the PTF cost recovery mechanism, it shall occur only under such cost recovery mechanism and not under this Schedule 2.

A non-generator shall be deemed a Qualified Non-Generator Reactive Resource if it meets the following criteria:

1. the entity owning or controlling the reactive power capability of the non-generator reactive power resource is a Market Participant;

2. the non-generator reactive power equipment provides measurable dynamic reactive power voltage support to the New England Transmission System, as determined from time-to-time by the ISO;

3. the type of dynamic reactive power equipment is within a category of equipment that has been approved by the ISO, with advisory input from the Reliability Committee;

4. the dynamic reactive power equipment is subject to the Operating Authority of the ISO and all necessary operating protocols for provision of reactive power voltage support from such equipment have been agreed to, in writing, between the ISO and the non-generator reactive power resource;

5. such equipment is interconnected to the New England Transmission System and metered and dispatchable by the ISO or otherwise subject to operational control by the ISO, and has its automatic voltage regulator status and control mode (including power factor, reactive power output and voltage control) telemetered to the ISO and the applicable Local Control Center; provided that the non-generator shall have until January 1, 2009 to have the necessary telemetering equipment installed and operating;

6. the non-generator reactive resource meets the reactive power testing requirements applicable to such non-generators, as determined from time-to-time by the ISO and specified in the ISO New England Operating Documents; and

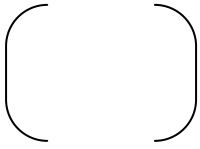
7. the installation of such equipment shall have been approved in accordance with the requirements of Section I.3.9 of the Tariff or its predecessor provisions under the New England regional transmission arrangements.

C. Non-Dynamic Reactive Resources

Nothing in this Schedule 2 is intended to preclude, or provide support for, the cost recovery under a separate schedule to the Tariff, filed with the Commission pursuant to the requirements of Sections 205 or 206 of the Federal Power Act, for non-generator, non-dynamic reactive resources that are interconnected to and provide VAR Service to the New England Transmission System but do not meet the criteria to be deemed either Qualified Non-Generator Reactive Resources or PTF.

III. DETERMINATION AND ALLOCATION OF VAR SERVICE CHARGES

Transmission Customers must purchase VAR Service from the ISO for the support of transmission voltages on the New England Transmission System. With the exception of VAR Service charges related to high voltage conditions, the hourly charge for VAR Service shall be paid by each Transmission Customer that receives either Regional Network Service or Through or Out Service. In the event that VAR Service charges for an hour are exclusively related to service provided to meet reliability criteria that address high voltage conditions in one or more Reliability Regions, then the VAR Service charges associated with high voltage conditions for that hour are allocated to each Transmission Customer within the affected Reliability Regions that receives Regional Network Service based on its pro rata share of Regional Network Load within the affected Reliability Regions. VAR Service charges are determined pursuant to the following formula:



$$CH = (CC + LOC_O + CEC_O + CEP_O)\ ) \quad \frac{HL_1 + RC_1}{HL + RC}$$

$$+ (LOC_{HV} + CEC_{HV} + CEP_{HV}) \quad \left(\frac{HLR_1}{HLR} \right)$$

in which the inputs to the formula have the following meaning:

CH = the amount to be paid by the Transmission Customer for the hour;

CC = the Capacity Costs for the hour shall be the VAR Revenue Requirement determined as set forth herein divided by the number of hours in the month;

LOC_{HV} = the Lost Opportunity Costs for the hour to be paid for a dynamic reactive power resource that supplies VAR Service to meet reliability criteria in the Transmission Customer's Reliability Region, provided the VAR Service is supplied exclusively to address high voltage conditions within one or more Reliability Regions;

LOC_O = the Lost Opportunity Costs for the hour to be paid for a dynamic reactive power resource that provides VAR Service to meet reliability criteria within one or more Reliability Regions excluding the costs for VAR Service that is supplied exclusively to address high voltage conditions;

CEP_{HV} = the Cost of Energy Produced which is the portion of the amount paid for the hour for Energy produced by a dynamic reactive power resource for VAR Service to meet reliability criteria in the Transmission Customer's Reliability Region, provided the VAR Service is supplied exclusively to address high voltage conditions within one or more Reliability Regions;

CEP_O = the Cost of Energy Produced which is the portion of the amount paid for the hour for Energy produced by a dynamic reactive power resource for VAR Service to meet reliability criteria within one or more Reliability Regions excluding the costs for VAR Service supplied exclusively to address high voltage conditions;

CEC_{HV} = the Cost of Energy Consumed which is the cost of energy used in the hour by a dynamic reactive power resource in order to supply VAR Service to meet reliability criteria in the Transmission Customer's Reliability Region, provided the VAR Service is supplied exclusively to address high voltage conditions within one or more Reliability Regions;

CEC_O = the Cost of Energy Consumed which is the cost of Energy used in the hour by a dynamic reactive power resource in order to provide VAR Service to meet reliability criteria within one or more Reliability Regions excluding the costs for VAR Service supplied exclusively to address high voltage conditions;

HL_1 = the Regional Network Load of the Transmission Customer for the hour;

HL = the aggregate of the Regional Network Loads of all Transmission Customer for the hour;

HLR_1 = that portion of the Regional Network Load of the Transmission Customer that is within a Reliability Region where VAR Service charges in the hour were a result of VAR Service provided exclusively to meet reliability criteria that address high voltage conditions;

HLR = the aggregate of all the Regional Network Loads of all Transmission Customers within Reliability Regions where VAR Service charges in the hour were a result of VAR Service provided exclusively to meet reliability criteria that address high voltage conditions;

RC_1 = the Reserved Capacity for Through or Out Service of the Transmission Customers for the hour, excluding any Coordinated External Transaction Reserved Capacity for Through or Out Service; and

RC = the aggregate Reserved Capacity for Through or Out Service of all Transmission Customers for the hour, excluding all Coordinated External Transaction Reserved Capacity for Through or Out Service.

IV. DETERMINING A QUALIFIED REACTIVE RESOURCE'S PAYMENT UNDER THIS SCHEDULE

The compensation to be paid to resources providing VAR Service shall be as set forth below.

A. Capacity Cost (CC)

1. A Qualified Reactive Resource shall be eligible to receive VAR Payments under the Capacity Cost component of this Schedule 2 for the capability to provide VAR Service.

2. Payment for VAR Service associated with lagging capability is not intended to compensate a Qualified Generator Reactive Resource for reactive power absorbed by the generator step-up transformer. Payment for VAR Service associated with leading capability is intended to compensate a Qualified Generator Reactive Resource for reactive power absorbed by the generator step-up transformer.

3. The "VAR CC Rate" will be established each year as of January 1 on a prospective basis for that calendar year and shall be the Adjusted CC Rate * Min (1, (1.2*Forecast Peak Adjusted Reference Load for the year/(SUM of all Qualified Reactive Resources' Summer Seasonal Claimed Capability))).

4. The "Base CC Rate" shall be $2.19/kVAR-yr effective January 1, 2012.

5. The Adjusted CC Rate shall be a single rate applied over the full range of leading and lagging capability of a Qualified Reactive Resource and shall be determined as described below. The Base CC Rate shall be converted into an Adjusted CC Rate, expressed in the form of $/kVARyr, representing the amount to be paid for leading and lagging capability. The Adjusted CC Rate shall be calculated in accordance with the following formula: Adjusted CC Rate (CCRateadjusted) shall equal: (the Base CC Rate (CCRatebase) * Current Total Aggregate lagging VARs) / (Current Total Aggregate Lagging VARs + Current Total Aggregate Leading VARs). The basis of each such formula element and methodology for calculation is set forth in the Schedule 2 VAR Payment Implementation Rule. The details of the Schedule 2 VAR Payment Implementation Rule may be modified by the ISO without a filing under the Federal Power Act, provided that: (i) the modifications are consistent with the requirements of this Schedule 2; and (ii) the modifications receive the support of at least two-thirds of the voting percentage of the Transmission Committee members.

6. The "Forecast Peak Adjustment Reference Load" shall be the value published in the then-most recently published Forecast Report of Capacity, Energy, Loads and Transmission (the "CELT Report") at the time the VAR CC Rate is established for a year.

7. "Seasonal Claimed Capability" for Qualified Reactive Resources shall be determined as follows:

a. A "Qualified Generator Reactive Resource's Seasonal Claimed Capability" shall be the Seasonal Claimed Capability of each Qualified Generator applicable for the season in which the ISO Forecast Peak Adjusted Load is forecast to occur. The Seasonal Claimed Capability (SCC) represents the Summer (SCC-S) and Winter (SCC-W) Claimed Capability of a generating unit (or ISO approved combination of units in accordance with ISO New England Operating Procedures). Claimed Capability Ratings are the maximum dependable load carrying ability, in megawatts to three decimal places, of such unit or units, excluding capacity required for station use. SCC-S and SCC-W are the MW values of the Resource that will be used as billing determinants under this Tariff.

b. A "Qualified Non-Generator Reactive Resource's Seasonal Claimed Capability" shall be 2.5 times the maximum dynamic reactive power capability on a lagging basis demonstrated by the Qualified Non-Generator Reactive Resource during the testing of its VAR Service capability consistent with ISO Procedures for measurement of such capability in megawatts to three decimal places.

8. The "VAR Revenue Requirement" shall be the sum over a month of all Qualified Reactive Resources' VAR Payments.

9. A Qualified Reactive Resource's VAR Payment shall equal (1/12) * (VAR CC Rate*Qualified VARs).

10. Qualified Reactive Resources will be paid their VAR Payment under this Section for each month of a calendar year starting with the month in which the resource is approved as a Qualified Reactive Resource.

11. "Qualified VARs" shall be determined as follows:

(a) In accordance with the ISO New England Operating Procedures, the Qualified VARs of a Qualified Reactive Resource initially Section II – Schedule 2 -Reactive Supply and Voltage Control from Qualified Reactive Resources Service shall be determined through an actual testing in accordance with the then-applicable VAR testing procedures set forth in the ISO New England Operating Procedures. At least every five (5) years after that initial test, an ongoing test of the capability of a Qualified Reactive Resource to supply VAR Service in both leading and lagging capability shall be conducted. The Qualified VARs of a Qualified Reactive Resource shall equal the sum total of the absolute values of the leading and lagging VAR capability of the resource determined pursuant to this section.

(b) Qualified VARs of a Qualified Generator Reactive Resource:

- The Qualified VARs of an untested Qualified Generator Reactive Resource shall be equal to the sum of the absolute values of the lagging VAR capability at the Summer Seasonal Claimed Capability and the leading VAR capability at the EcoMin point as indicated on the Qualified Generator Reactive Resource's NX-12D form that is then in effect adjusted (downward for lagging capability and upward for leading capability) for reactive power absorbed by the generator step-up transformer.

- The Qualified VARs of an untested Qualified Non-Generator Reactive Resource shall be equal to the sum of the absolute values of the lagging VAR capability at the corresponding Summer Seasonal Claimed Capability or an equivalent point and the leading VAR capability at the corresponding EcoMin point or an equivalent point as indicated on the Qualified Non-Generator Reactive Resource's NX-12D form that is then in effect adjusted for reactive power absorbed by its step-up transformer.

B. Lost Opportunity Cost (LOC)

1. The LOC for generators that are dispatched down by, or at the request of, the ISO, or a Local Control Center for the purpose of providing VAR Service will be calculated pursuant to Market Rule 1.

2. Qualified Non-Generator Reactive Resources shall be eligible for payment of the LOC for Qualified Non-Generator Reactive Resources that are dispatched down (pursuant to the authority established within written operating protocols developed under Section II.B.4) at the request of the ISO or a Local Control Center for the purpose of providing VAR Service. The LOC of such Qualified Non-Generator Reactive Resources will be calculated pursuant to procedures established at the time of approval of the equipment type pursuant to Section II.B and filed with the Commission pursuant to the requirements of Section 205 of the Federal Power Act.

C. Cost of Energy Consumed (CEC)

1. The CEC associated with hydro and pumped storage generating units that are motoring at the request of the ISO or a Local Control Center for the purpose of providing VAR Service will equal the cost of Energy to motor and will be calculated in each hour as follows: CEC = (MWhUnit * (LMP or actual Energy cost), where the MWh Unit are calculated pursuant to the Ancillary Service Schedule 2 Business Procedure. The actual Energy cost applies only if motoring Energy is purchased through a bilateral contract.

2. For the Chester SVC, the CEC will be set to zero ($0), and the cost of Energy to supply reactive supply and voltage control from the Chester SVC will be treated as losses on the New England Transmission System.

3. Qualified Non-Generator Reactive Resources shall be eligible for payment of the CEC incurred by Qualified Non-Generator Reactive Resources for the purpose of providing VAR Service (pursuant to the authority established within written operating protocols developed under Section II.B.4). The CEC of such Qualified Non-Generator Reactive Resources shall be measured pursuant to procedures established at the time of approval of the equipment type pursuant to Section II.B and filed with the Commission pursuant to the requirements of Section 205 of the Federal Power Act.

D. Cost of Energy Produced (CEP)

1. The CEP associated with thermal generating units that are brought on-line by the ISO or a Local Control Center for the purpose of providing VAR Service shall equal the portion of the total NCPC (as defined in Market Rule 1) to be paid that resource for a day that is attributed to the hour(s) during which the resource is run to provide VAR Service in accordance with Market Rule 1 and the ISO New England Operating Documents.

2. The CEP associated with hydro or pumped storage generating units that are producing real power and that have also been brought on-line by the ISO or a Local Control Center to provide VAR Service shall equal the portion of the total NCPC to be paid that resource for a day that is attributed to the hour(s) during which the resource is run to provide VAR Service in accordance with Market Rule 1 and the ISO New England Operating Documents.

3. Qualified Non-Generator Reactive Resources shall be eligible for payment of the CEP incurred by Qualified Non-Generator Reactive Resources for the purpose of providing VAR Service (pursuant to the authority established within written operating protocols developed under Section II.B.4). The CEP of such Qualified Non-Generator Reactive Resources shall be measured pursuant to procedures established at the time of approval of the equipment type pursuant to Section II.B and filed with the Commission pursuant to the requirements of Section 205 of the Federal Power Act.

VI. ALTERNATIVE PAYMENT FOR VAR SERVICE

Where a non-generator source of VAR Service (i) responds to identified needs for dynamic reactive power on the New England Transmission System, as identified in the Regional System Plan, and (ii) is confirmed by the ISO as a dynamic reactive power resource that will meet the identified need, and (iii) such non-generator source of VAR Service meets the criteria to be a Qualified Non-Generator Reactive Resource but cannot recover its costs of providing dynamic reactive power under Schedule 2, such non-generator may submit a separate schedule to the ISO OATT to be filed with the Commission pursuant to the requirements of Section 205 of the Federal Power Act for a rate to be paid to allow such resource to recover its costs related to providing VAR Service. In such case, it shall not be considered a Qualified Non-Generator Reactive Resource under this Schedule 2 and its provision of VAR Service and payment shall be governed solely by such separate schedule filed with the Commission.

SCHEDULE 2 VAR PAYMENT IMPLEMENTATION RULE

This rule describes the steps to be taken to calculate the VAR CC Rate in accordance with Section V.A. of Schedule 2. On an annual basis, the Base CC Rate shall be converted into a VAR CC Rate, expressed in the form of $/kVAR-yr, representing the amount to be paid for leading and lagging capability.

The following calculations shall be done in December of each year to calculate the VAR CC Rate for the next year of VAR Payments for leading and lagging reactive power capability in the following year. As described below, the VAR CC Rate shall be updated on an annual basis utilizing the most current leading and lagging test results, and it is expected to take three years to test all of the Qualified Reactive Resources in leading mode.

1. Calculate the "Current Total Aggregate Lagging VARs", which shall equal the "Current Net Aggregate Tested Lagging VARs" plus the "Current Net Aggregate Non-Tested Lagging VARs"; Where:

    a. the Current Net Aggregate Tested Lagging VARs shall equal the total of Lagging Qualified VAR Capability for all Schedule 2 Qualified Reactive Resources that have completed a successful lagging VAR test, as reflected in the *VAR Status Report* tab of the VAR Annual Capacity Cost Rate Report that is posted on the ISO website; this value will reflect the lagging kVARs of Schedule 2 Qualified Reactive Resources as taken from its lagging VAR test results adjusted for losses incurred for such VARs to reach the high side of the step-up transformer (i.e., gross lagging VARs test results adjusted down for losses); and

    b. the Current Net Aggregate Non-Tested lagging VARs shall equal the total of Lagging Qualified VAR Capability for all Schedule 2 Qualified Reactive Resources that have not yet completed a successful lagging VAR test, as reflected in the *VAR Status Report* tab of the VAR Annual Capacity Cost Rate Report that is posted on the ISO website; this value will reflect the lagging kVARs of Schedule 2 Qualified Reactive Resources as taken from its NX-12D (and NX-9B, where needed to calculate generator step-up transformer losses) data at EcoMin adjusted for losses incurred for such VARs to reach the high side of the step-up transformer (i.e., gross lagging VARs NX-12D data at SCC adjusted down for losses).

c. Increase and decrease limiters shall be applied to potential increases or decreases in the Current Total Aggregate Lagging VARs as follows:

i. Current Total Aggregate Lagging VARs Limiters for 2010:
• The Current Total Aggregate Lagging VARs value shall not be limited for 2010.

ii. Current Total Aggregate Lagging VARs Limiters for 2011 and beyond:
• Current Total Aggregate Lagging VARs Increase Limiter for 2011 and beyond: the calculated Current Total Aggregate Lagging VARs will be limited to no greater than 130% of the Current Total Aggregate Lagging VARs value used in the determination of $CCRate_{adjusted}$ for 2010; and

• Current Total Aggregate Lagging VARs Decrease Limiter for 2011 and beyond: the calculated Current Total Aggregate Lagging VARs will be limited to no less than 70% of the Current Total Aggregate Lagging VARs value used in the determination of $CCRate_{adjusted}$ for 2010.

2. Calculate the Current Total Aggregate Leading VARs which shall equal the Current Net Aggregate Tested Leading VARs plus the Current Net Aggregate Non-Tested Leading VARs;

Where:

a. the Current Net Aggregate Tested Leading VARs shall equal the total of Leading Qualified VAR Capability for all Schedule 2 Qualified Reactive Resources that have completed a successful Leading VAR Test, as reflected in the *VAR Status Report* tab of the VAR Annual Capacity Cost Rate Report that is posted on the ISO website; this value will reflect the Leading kVARs of Schedule 2 Qualified Reactive Resources as taken from its leading VAR test results adjusted for losses incurred for such VARs to reach the high side of the step-up transformer (i.e., gross leading VARs test results adjusted up for losses);

b. the Current Net Aggregate Non-Tested Leading VARs: shall equal the total of Leading Qualified VAR Capability for all Schedule 2 Qualified Reactive Resources that have not yet completed a successful Leading VAR Test, as reflected in the *VAR Status Report* tab

of the VAR Annual Capacity Cost Rate Report that is posted on the ISO website. This value will reflect the Leading kVARs of Schedule 2 Qualified Reactive Resources as taken from its NX-12D (and NX-9B, where needed to calculate generator step-up transformer losses) data at EcoMin adjusted for losses incurred for such VARs to reach the high side of the step-up transformer (i.e., gross leading VARs NX-12D data at EcoMin adjusted up for losses).

c. Current Total Aggregate Leading VARs Limiters

i. Current Total Aggregate Leading VARs Limiters for 2010:
• The Current Total Aggregate Leading VARs value shall not be limited for 2010.

ii. Current Total Aggregate Leading VARs Limiters for 2011 and beyond:

• Current Total Aggregate Leading VARs Increase Limiter for 2011 and beyond: the calculated Current Total Aggregate Leading VARs will be limited to no greater than 130% of the Current Total Aggregate Leading VARs value used in the determination of $CCRate_{adjusted}$ for 2010; and

• Current Total Aggregate Leading VARs Decrease Limiter for 2011 and beyond: the calculated Current Total Aggregate Leading VARs will be limited to no less than 70% of the Current Total Aggregate Leading VARs value used in the determination of $CCRate_{adjusted}$ for 2010.

3. Calculate the Adjusted CC Rate ($CCRate_{adjusted}$): shall equal (the Base CC $Rate_e$ * Current Total Aggregate Lagging VARs) / (Current Total Aggregate Lagging VARs + Current Total Aggregate Leading VARs).

4. VAR CC Rate ("VARCCRate"): shall equal (the Adjusted CC Rate) * (the lesser of 1 or (1.2 * "Forecast Peak Adjusted Reference Load" for the year / the sum of the "Qualified Reactive Resources' Seasonal Claimed Capability"));

Where:

a. the "Forecast Peak Adjusted Reference Load" for the year shall equal the amount specified as "Adjusted Reference Load" for the applicable year in *Section I.1 -Summaries – Summer* from the most current *Forecast Report of Capability, Energy, Loads and Transmission (CELT Report)*;

b. The sum of the "Qualified Reactive Resources' Seasonal Claimed Capability" shall equal the Qualified Generator Reactive Resources' Seasonal Claimed Capability plus the Qualified Non-Generator Reactive Resources' Adjusted Seasonal Claimed Capability;

Where:

i. the Qualified Generator Reactive Resources' Seasonal Claimed Capability is reflected on the *VAR CC Rate* tab of the VAR Annual Capacity Cost Rate Report; and

ii. the Qualified Non-Generator Reactive Resources' Adjusted Seasonal Claimed Capability is reflected on the *VAR CC Rate* tab of the VAR Annual Capacity Cost Rate Report.

5. Monthly VAR Payment for a Qualified Reactive Resource in a particular month shall equal the (VARCCRate / 12 * (its Monthly Net Lagging VARs for that month + its Monthly Net Leading VARs for that month)), as reflected in the applicable monthly *VAR Status Summary Report* that is posted on the ISO website.

a. Monthly Net Lagging VARs: Qualified Reactive Resource's Monthly Net Lagging VARs value shall equal its VAR value based on (a) its most recent successful Lagging VAR test or (b) if it has not yet completed such a test, its VAR value at SCC based on its submitted and ISO accepted NX-12D and NX-9B data. The Qualified VAR Resource's Monthly Net Lagging VARs value shall be reflected in the applicable monthly *VAR Status Summary Report* that is posted on the ISO website.

b. Monthly Net Leading VARs: a Qualified Reactive Resource's Monthly Net Leading VARs value shall equal its VAR value based on (a) its most recent successful Leading VAR test or (b) if it has not yet completed such a test, its VAR value at EcoMin based on its submitted and ISO accepted NX-12D and NX-9B data. The Qualified Reactive

Resource's Monthly Net Leading VARs value shall be reflected in the applicable monthly *VAR Status Summary Report* that is posted on the ISO website.

ATTACHMENT C

AVAILABLE TRANSFER CAPABILITY METHODOLOGY

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1. Introduction

ISO is the regional transmission organization (RTO) for the New England Control Area. The New England Control Area includes the transmission system located in the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont, but does not include the transmission system in northern Maine (i.e., Aroostook and parts of Penobscot and Washington Counties) that is radially connected to New Brunswick and administered by the Northern Maine Independent System Administrator. The New England Control Area is comprised of PTF, non-PTF, OTF, MTF, and is interconnected to three neighboring Balancing Authority Areas ("BAA") with various interface types as shown in the Table 1. A graphical depiction of the New England Control Area and its interfaces is provided in Figure 1.

Table 1. New England Control Area interfaces with neighboring BAAs

Neighboring BAA ("NBAA")	Interface	Interface Type
New Brunswick System Operator BAA	New England - New Brunswick	PTF – NBAA (external)
Hydro-Quebec TransEnergie BAA	New England – Hydro Quebec via the Phase I/II high voltage direct current ("HVDC") Transmission Facilities	OTF – NBAA (external)
	New England PTF - Phase I/II HVDC Transmission Facilities	PTF – OTF (internal)
Hydro-Quebec TransEnergie BAA	New England - Hydro Quebec via the Highgate Transmission Facility	PTF – NBAA (external)
New York Independent System Operator BAA	New England - New York-AC	PTF – NBAA (external)
New York Independent System Operator BAA	New England - New York via the Northport - Norwalk Harbor Cable ("NNC") Transmission Facility	PTF – NBAA (external)
New York Independent System Operator BAA	New England – New York via the Cross Sound Cable ("CSC") transmission facility	MTF – NBAA (external)
	New England PTF – CSC transmission facility	PTF – MTF (internal)

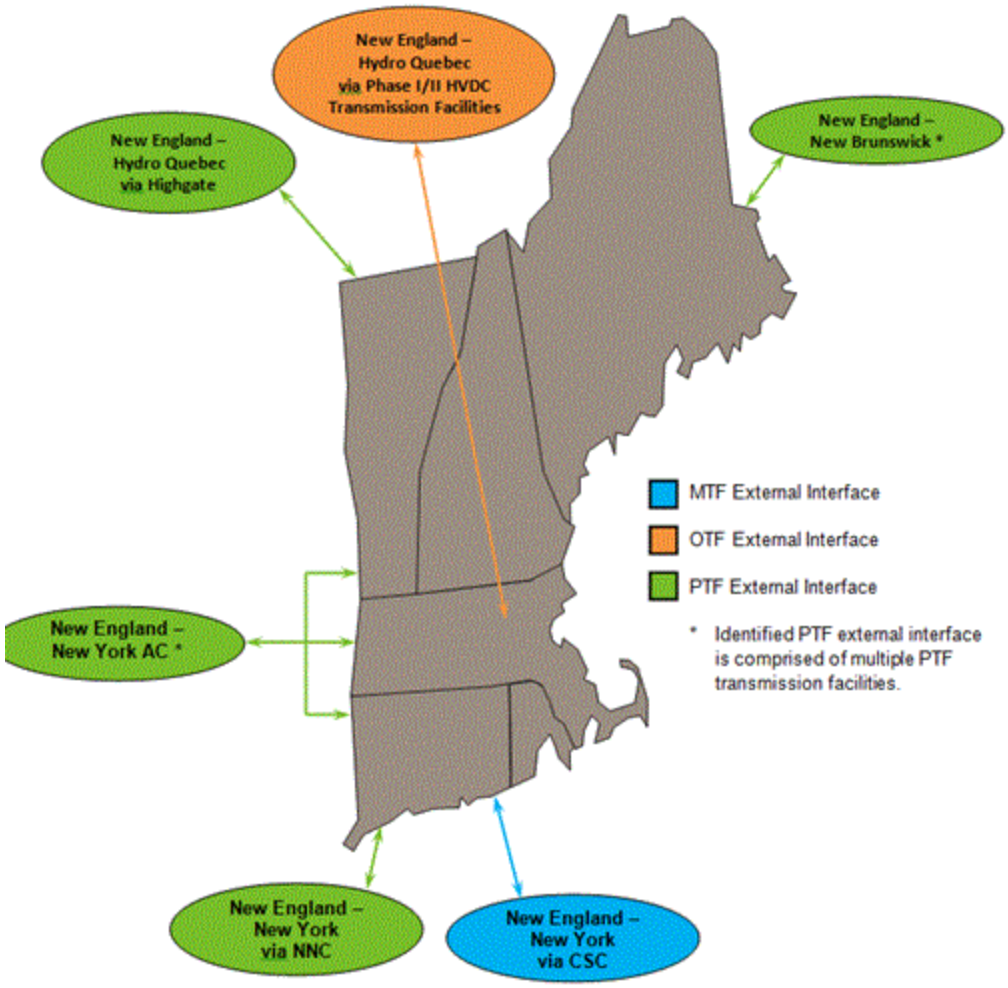

Figure 1. Graphical representation of New England Control Area external interfaces with neighboring BAAs

1.1 ISO Responsibilities

As part of its RTO responsibilities, the ISO is registered with the North American Electric Reliability Corporation ("NERC") as several functional model entities that have responsibilities related to the calculation of ATC as defined in the following NERC Standards: MOD-001 – Available Transmission System Capability ("MOD-001"), MOD-004 – Capability Benefit Margin ("MOD-004"), and MOD-008 - Transmission Reliability Margin Calculation Methodology ("MOD-008"). The extent of those responsibilities is based on various Commission approved transmission operating agreements and the provisions of the ISO New England Operating Documents. Table 2 below depicts those responsibilities as they apply to the interfaces associated with the New England Control Area and its neighboring BAAs for which the ISO is the Transmission Operator ("TOP") and has varying responsibilities with respect to the calculation of ATC over those interfaces.

Table 2. New England Control Area Internal and External Interfaces

Interface	Interface Type	ATC	TTC	TRM
New England - New Brunswick	PTF – NBAA (external)	ISO as Transmission Service Provider ("TSP")	ISO as TOP	ISO as TOP
New England – Hydro Quebec via the Phase I/II HVDC Transmission Facilities	OTF – NBAA (external)	Schedule 20A Service Providers ("SSPs") as TSPs per Schedule 20A	ISO as TOP	ISO as TOP
New England PTF - Phase I/II HVDC Transmission Facilities	PTF – OTF (internal)	ISO as TSP	ISO as TOP	ISO as TOP
New England - Hydro Quebec via the Highgate Transmission Facility	PTF – NBAA (external)	ISO as TSP	ISO as TOP	ISO as TOP
New England - New York-AC	PTF – NBAA (external)	ISO as TSP	ISO as TOP	ISO as TOP
New England - New York via the Northport - NNC Transmission Facility	PTF – NBAA (external)	ISO as TSP	ISO as TOP	ISO as TOP
New England – New York via the CSC transmission facility	MTF – NBAA (external)	Cross Sound Cable Company, LLC ("CSC, LLC") as TSP per Schedule 18	ISO as TOP	ISO as TOP

New England PTF – CSC transmission facility	PTF – MTF (internal)	ISO as TSP	ISO as TOP	ISO as TOP

1.2. Applicability of this Attachment C

This Attachment C describes the ATC methodology for RNS and Through or Out Service, and also describes the methodology for certain ATC components that are calculated by the ISO for use by other TSPs as described below:

- The TTC methodology for use by CSC, LLC under Schedule 18 and the SSPs under Schedule 20A.
- The CBM methodology for use by CSC, LLC under Schedule 18 and SSPs under Schedule 20A.
- The TRM methodology for use by CSC, LLC under Schedule 18 and the SSPs under Schedule 20A.

The manner in which these ISO-calculated ATC components are used by CSC, LLC and the SSPs for purposes of calculating a Schedule-specific ATC is governed by Schedules 18 and 20A, respectively.

2. Transmission Service in the New England Markets

Since the inception of the OATT for New England, the process by which generation located inside New England supplies energy to the bulk electric system has differed from the Commission pro forma OATT. The fundamental difference is that internal generation is dispatched in an economic, security-constrained manner by the ISO rather than utilizing a system of physical rights, advance reservations and point-to-point transmission service. Through this process, internal generation provides offers that are utilized by the ISO in the Real-Time Energy Market dispatch software. This process provides the least-cost dispatch to satisfy Real-Time load on the system.

In addition to offers from generation within New England, entities may submit External Transactions to move energy into the New England Control Area, out of the New England Control Area or through the New England Control Area. The Real-Time Energy Market clears these External Transactions based on forecast LMPs and the transfer capability of the associated external interfaces. With those External Transactions in place, the Real-Time Energy Market dispatches internal generation in an economic, security constrained manner to meet Real-Time load within the region.

The process for submitting External Transactions into the Real-Time Energy Market does not require an advance physical reservation for use of the PTF. In the event that the net of the economic External Transactions is greater than the transfer capability of the associated external interface, the External Transactions selected to flow are selected based on the rules specified in the Tariff. For any External Transactions that are confirmed to flow in Real-Time based on the economics of the system, a transmission reservation for RNS and Through or Out Service is created after-the-fact to satisfy the transparency needs of the market; however, entities who want to submit an External Transaction to flow energy over an MTF or OTF external interface must first obtain a confirmed transmission service reservation from the respective TSP prior to offering energy into the Real-Time Energy Market. Entities who want to submit an External Transaction to flow energy over an MTF or OTF external interface may refer to Schedule 18 or 20A for information regarding the calculation of ATC on the MTF and OTF external interfaces, respectively

The values resulting from the methodologies described in this Attachment C relate solely to the flow of energy in the Real-Time Energy Market, and shall not be construed as defining methodologies or limits for use in other New England markets.

3. Total Transfer Capability (TTC) for the New England Control Area

The TTCs on all of the New England Control Area external interfaces are calculated using the NERC Standard MOD-029 – Rated System Path Methodology ("MOD-029"). Consistent with the NERC definition, TTC is the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions. TTCs for the New England Control Area external interfaces are studied by the ISO based on thermal, voltage and stability limitations of the transmission lines that comprise the interface. Power flow and transient stability analysis is used to ensure that the interface's physical limits will not be violated for credible system contingencies per NPCC and ISO reliability criteria. As required by MOD-029, reports are generated that contain the study results and the corresponding TTCs.

These reports are reviewed and updated seasonally, as needed, or as new equipment is placed in-service that impacts the interface. The studies identify the transmission facilities, generators and system conditions that can have a substantial impact upon the transfer capability and, where applicable, the report

indicates the resulting impact upon the transfer capability of the external interfaces. These reports are available in a manner consistent with the ISO New England Information Policy.

The NPCC region maintains, on a confidential basis, a list of generation and transmission facilities that, if removed from service, may have a significant direct or indirect impact on a neighboring BAA, which is in accordance with *Appendix F – Procedure for Operational Planning Coordination (Appendix F) to NPCC Regional Reliability Reference Director #1 – Design and Operation of the Bulk Power System (Directory #1).* If any facilities on that list have a planned outage, those outages are communicated between the neighboring BAAs. If there is a facility on that list in the New England Control Area that is submitted for an outage by an entity, the ISO conducts a study using an energy management system powerflow model and evaluates the impact on the TTC of the affected interface. The ISO applies its load forecast and generation dispatch for the relevant time frame to determine the TTCs for the given condition. In addition, on a daily basis, ISO evaluates the expected New England Control Area system conditions (e.g., generation availability, transmission outages, submitted External Transactions, resulting expected net flow across an external interface) for the following day to determine if there is a system operating limit that has a direct impact upon an external interface that is more restrictive than the previously calculated TTC and, if so, revises the TTC. TTCs impact the maximum megawatt ("MW") amount of confirmed net flow in the Real-Time Energy Market, and may be adjusted prior to Real-Time to reflect Real-Time system operating limits. However, the TTCs in the direction opposite to the prevailing net flow are neither reviewed nor adjusted prior to Real-Time, since those values do not affect reliability.

4. Capacity Benefit Margin (CBM) for the New England Control Area

CBM is defined as the amount of firm transmission transfer capability set aside by a TSP for use by the Load Serving Entities. The ISO does not set aside any CBM for use by the Load Serving Entities, because of the New England approach to capacity planning requirements in the ISO New England Operating Documents. Load Serving Entities operating within the New England Control Area are required to arrange for their Capacity Requirements prior to the beginning of any given month in accordance with ISO Tariff, Section III 13.7.3.1 (Calculation of Capacity Requirement and Capacity Load Obligation). Load Serving Entities do not utilize CBM to ensure that their capacity needs are met; therefore, CBM is not applicable within the New England market design. Accordingly, for purposes of ATC calculation, CBM for the New England Control Area is set to zero (0).

5. Transmission Reliability Margin (TRM) for the New England Control Area

TRM is the amount of transmission transfer capability set aside to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.

5.1 TRM Calculation for the PTF

The ISO, acting as the TOP and TSP, does not set aside TRM on PTF external interfaces or PTF/MTF and PTF/OTF internal interfaces.

5.2 TRM Calculation for the MTF and OTF

The ISO, acting as the TOP, calculates the TRM on MTF and OTF external interfaces, which are both HVDC transmission facilities, by taking into account any operational uncertainties associated with the external facility in accordance with MOD-008.

The TSPs responsible for calculating the ATC and providing transmission service over the MTF or OTF dictate how the ISO-calculated TRM is applied in their respective Schedule-specific ATC calculations.

5.2.1 TRM Calculation for the MTF

Typically, the operational uncertainties associated with an external HVDC transmission facility are minimal and result in a TRM value of zero (0). Therefore, the TRM value for the MTF (i.e., CSC transmission facility) is zero (0).

5.2.2 TRM Calculation for the OTF

5.2.2.1 Quebec to New England TRM for the Phase I/II HVDC Transmission Facilities

There are operational uncertainties associated with the Phase I/II HVDC Transmission Facilities that arise out of neighboring and nearby BAAs such that the TRM on this facility is not zero (0). Due to the large transfer capability of the Phase I/II HVDC Transmission Facilities and the geographic location of the New England Control Area with respect to the rest of the Eastern Interconnection, the loss of this facility

may have a substantial impact on the New York and Pennsylvania, New Jersey and Maryland ("PJM") transmission systems. The inertial impact from the loss of the Phase I/II HVDC Transmission Facilities on the New York and PJM transmission systems will be dependent upon the simultaneous path interactions and the generation dispatch on those transmission systems and within the New England Control Area.

As such, pursuant to Attachment G of the ISO Tariff, the Reliability Coordinators in New York and PJM can require the ISO to limit the amount of energy transferred into the New England Control Area over the Phase I/II HVDC Transmission Facilities (or the output from other large source contingencies within the New England Control Area) in Real-Time to a value as low as 1200 MW, which is referred to as the "largest single source contingency limit". The amount of energy transferred into the New England Control Area over the Phase I/II HVDC Transmission Facilities is not always limited to 1200 MW; it is also dependent upon the dynamic state of the New York and PJM transmission systems, as well as, the additional room (or "available margin") on those systems that can reliably sustain the inertial response following the loss of the Phase I/II HVDC Transmission Facilities (or other large source contingencies within the New England Control Area) when the amount of energy transferred into the New England Control Area over the Phase I/II HVDC Transmission Facilities (or the output from other large source contingencies within the New England Control Area) in Real-Time is in amounts greater than 1200 MW. For these reasons, the TRM value for the Phase I/II HVDC Transmission Facilities for all time horizons in the importing direction (North to South) shall be between zero (0) MW and 800 MW, where 800 MW is calculated from the "Phase I/II HVDC Transmission Facilities maximum transfer capability" (which is 2000 MW) minus the "largest single source contingency limit" (which is 1200 MW).

This range of TRM values is not dependent upon any databases, but instead is driven by the magnitude of the largest single source contingency in the New England Control Area that the New York and PJM transmission systems is able to sustain following the loss of the largest contingent resource.

5.2.2.2 New England to Quebec TRM for the Phase I/II HVDC Transmission Facilities:

When energy is flowing from the New England Control Area to the Hydro-Quebec TransEnergie BAA (South to North) over the Phase I/II HVDC Transmission Facilities, Hydro-Quebec TransEnergie may restrict the energy flow due to uncertainties on their Hydro-Quebec TransEnergie transmission system. The ISO considers whatever Hydro-Quebec TransEnergie restrictions are submitted to it in the calculation of the New England to Quebec TRM for the Phase I/II HVDC Transmission Facilities.

6. Available Transfer Capability (ATC) Calculation of PTF Interfaces

This section describes the process for the ATC calculations performed by the ISO pursuant to MOD-029 for the PTF external interfaces and the PTF/MTF and PTF/OTF internal interfaces. This section does not describe the process for the ATC calculations performed by other New England TSPs.

6.1 ATC Algorithm: Process for ATC Calculation for PTF Interfaces

Consistent with the NERC definition, the equation for Available Transfer Capability is: ATC = (TTC – CBM – TRM – Existing Transmission Commitments + Postbacks + counterflows). As discussed above, the CBM and TRM for the PTF interfaces for which the ISO calculates ATC are zero (0). The purpose of the Existing Transmission Commitments ("ETC") component of the ATC equation is for the TSP to reduce the amount of ATC by the amount of existing firm transmission commitments that are not otherwise included in CBM or TRM. As described in Section 2 of this Attachment C, there is no requirement to purchase transmission service in advance of flowing energy in Real-Time, and there is no MW amount set aside by the ISO on any interface. Therefore there are no Existing Transmission Commitments to be applied in the ATC equation. For this reason, ETC equals zero (0) for the purposes of ATC calculation. Because Postbacks and counterflows are related to ETC and ETC is zero (0), both Postbacks and counterflows also are equal to zero (0).

Entities submit their bids and offers to move energy into, out of and through the Energy Market through External Transactions. As Real-Time approaches, the ISO determines which of the submitted External Transactions will be scheduled during the applicable scheduling interval in accordance with the rules set forth in the ISO New England Operating Documents. The ATC of the PTF external interfaces are equal to the TTC for all time horizons (i.e., scheduling, operating and planning). The ATC is equal to the amount of net External Transactions that the ISO will schedule on an interface for during the applicable scheduling interval. With this simplified version of ATC, the mathematical algorithm is simply "ATC equals TTC." This mathematical algorithm can be found on the ISO New England OASIS site at: http://www.oatioasis.com/ISNE/ISNEdocs/isone_atc_algorithm.docx

The scheduling of External Transactions on a PTF interface will consider the net of all economic External Transactions and the transfer limits. For example, if the transfer limit on the interface is 1000 MW import, there could be 1300 MW of economic import External Transactions and 300 MW of economic

export External Transactions scheduled for a given scheduling interval such that the net flow on the interface is 1000 MW.

Figure 2 describes how External Transactions are processed in the Real-Time Energy Markets where the timing of the submittal of the External Transactions is governed by Section III of the ISO Tariff.

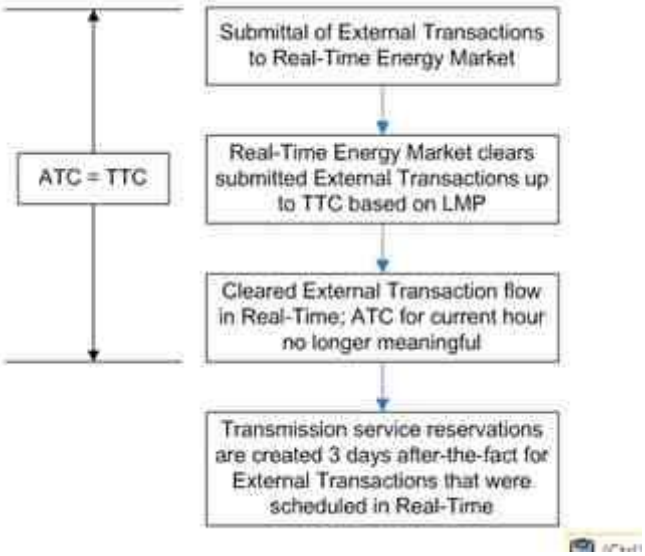

Figure 2. Processing of External Transactions in the Real-Time Energy Markets

6.2. Firm versus Non-Firm ATC on PTF Interfaces

As described in the preceding sections, the RNS and Through or Out Service provided over the PTF on an after-the-fact basis are the equivalent of firm transmission service. Therefore, the ATC calculation process described above results in a single ATC value. Where industry standards or software require the classification of ATC as Firm and non-Firm the ISO posts the single ATC value for both.

6.3. ATC Coordination for PTF Interfaces

As described in this Section 6 of this Attachment C, the ATC calculations for PTF external interfaces performed by the ISO are dependent solely on the TTC values. As such, the ISO does not coordinate ATC values with the neighboring BAAs. The ISO, however, has established procedures within the ISO New England Operating Procedures for coordinating outages with neighboring BAAs that could impact the

resulting TTC on the external interface(s) with that neighbor. These procedures also include the timely communication of the resulting TTCs between the ISO and each of its neighboring BAAs.

ATTACHMENT G-3

COMPLETE LIST OF EXCEPTED TRANSACTION (TRANSMISSION) AGREEMENTS OVER EXTERNAL TIES

Attachment G-3 is a comprehensive list of Excepted Transaction Agreements that relate to the use of ties with neighboring Control Areas ("External Ties"). The party responsible for paying the Congestion Cost associated with energy purchased under the Excepted Transactions listed in Attachment G-3 will retain their existing contract rights for physical scheduling of a transaction at the External Node associated with the Excepted Transaction until such party elects to be allocated Auction Revenue Rights pursuant to Market Rule 1. Until the party responsible for paying the Congestion Cost associated with energy purchased under an Excepted Transaction listed in Attachment G-3 elects to be allocated Auction Revenue Rights, the Excepted Transaction shall have physical scheduling and curtailment rights in accordance with Section II.44(1)(a) of this OATT. Once the party responsible for paying the Congestion Cost associated with energy purchased under the Excepted Transaction elects to be allocated Auction Revenue Rights, the party will not be able to revert back to using their contract rights for physical scheduling and curtailment.

All such agreements have terminated with respect to Attachment G-3.

STANDARD MARKET DESIGN

III.1 Market Operations

III.1.1 Introduction.

This Market Rule 1 sets forth the scheduling, other procedures, and certain general provisions applicable to the operation of the New England Markets within the New England Control Area. The ISO shall operate the New England Markets in compliance with NERC, NPCC and ISO reliability criteria. The ISO is the Counterparty for agreements and transactions with its Customers (including assignments involving Customers), including bilateral transactions described in Market Rule 1, and sales to the ISO and/or purchases from the ISO of energy, reserves, Ancillary Services, capacity, demand/load response, FTRs and other products, paying or charging (if and as applicable) its Customers the amounts produced by the pertinent market clearing process or through the other pricing mechanisms described in Market Rule 1. The bilateral transactions to which the ISO is the Counterparty (subject to compliance with the requirements of Section III.1.4) include, but are not limited to, Internal Bilaterals for Load, Internal Bilaterals for Market for Energy, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Supplemental Availability Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied FCA Resources). Notwithstanding the foregoing, the ISO will not act as Counterparty for the import into the New England Control Area, for the use of Publicly Owned Entities, of: (1) energy, capacity, and ancillary products associated therewith, to which the Publicly Owned Entities are given preference under Articles 407 and 408 of the project license for the New York Power Authority's Niagara Project; and (2) energy, capacity, and ancillary products associated therewith, to which Publicly Owned Entities are entitled under Article 419 of the project license for the New York Power Authority's Franklin D. Roosevelt – St. Lawrence Project. This Market Rule 1 addresses each of the three time frames pertinent to the daily operation of the New England Markets: "Pre-scheduling" as specified in Section III.1.9, "Scheduling" as specified in III.1.10, and "Dispatch" as specified in III.1.11. This Market Rule 1 became effective on February 1, 2005.

III.1.2 [Reserved.]

III.1.3 Definitions.

Whenever used in Market Rule 1, in either the singular or plural number, capitalized terms shall have the meanings specified in Section I of the Tariff. Terms used in Market Rule 1 that are not defined in Section

I shall have the meanings customarily attributed to such terms by the electric utility industry in New England or as defined elsewhere in the ISO New England Filed Documents. Terms used in Market Rule 1 that are defined in Section I are subject to the 60% Participant Vote threshold specified in Section 11.1.2 of the Participants Agreement.

III.1.3.1 [Reserved.]

III.1.3.2 [Reserved.]

III.1.3.3 [Reserved.]

III.1.4 Requirements for Certain Transactions.

III.1.4.1 ISO Settlement of Certain Transactions.

The ISO will settle, and act as Counterparty to, the transactions described in Section III.1.4.2 if the transactions (and their related transactions) conform to, and the transacting Market Participants comply with, the requirements specified in Section III.1.4.3.

III.1.4.2 Transactions Subject to Requirements of Section III.1.4.

Transactions that must conform to the requirements of Section III.1.4 include: Internal Bilaterals for Load, Internal Bilaterals for Market for Energy, Capacity Supply Obligation Bilaterals, Capacity Load Obligation Bilaterals, Supplemental Availability Bilaterals, and the transactions described in Sections III.9.4.1 (internal bilateral transactions that transfer Forward Reserve Obligations), and III.13.1.6 (Self-Supplied FCA Resources). The foregoing are referred to collectively as "Section III.1.4 Transactions," and individually as a "Section III.1.4 Transaction." Transactions that conform to the standards are referred to collectively as "Section III.1.4 Conforming Transactions," and individually as a "Section III.1.4 Conforming Transaction."

III.1.4.3 Requirements for Section III.1.4 Conforming Transactions.

(a) To qualify as a Section III.1.4 Conforming Transaction, a Section III.1.4 Transaction must constitute an exchange for an off-market transaction (a "Related Transaction"), where the Related Transaction:

(i) is not cleared or settled by the ISO as Counterparty;

(ii) is a spot, forward or derivatives contract that contemplates the transfer of energy or a MW obligation to or from a Market Participant;

(iii) involves commercially appropriate obligations that impose a duty to transfer electricity or a MW obligation from the seller to the buyer, or from the buyer to the seller, with performance taking place within a reasonable time in accordance with prevailing cash market practices; and

(iv) is not contingent on either party to carry out the Section III.1.4 Transaction.

(b) In addition, to qualify as a Section III.1.4 Conforming Transaction:

(i) the Section III.1.4 Transaction must be executed between separate beneficial owners or separate parties trading for independently controlled accounts;

(ii) the Section III.1.4 Transaction and the Related Transaction must be separately identified in the records of the parties to the transactions; and

(iii) the Section III.1.4 Transaction must be separately identified in the records of the ISO.

(c) As further requirements:

(i) each party to the Section III.1.4 Transaction and Related Transaction must maintain, and produce upon request of the ISO, records demonstrating compliance with the requirements of Sections III.1.4.3(a) and (b) for the Section III.1.4 Transaction, the Related Transaction and any other transaction that is directly related to, or integrated in any way with, the Related Transaction, including the identity of the counterparties and the material economic terms of the transactions including their price, tenor, quantity and execution date; and

(ii) each party to the Section III.1.4 Transaction must be a Market Participant that meets all requirements of the ISO New England Financial Assurance Policy.

III.1.5 Resource Auditing.

III.1.5.1 Claimed Capability Audits.

III.1.5.1.1 General Audit Requirements.

(a) Three types of Claimed Capability Audits may be performed:

(i) An Establish Claimed Capability Audit establishes the Generator Asset's ability to respond to ISO dispatch instructions and to maintain performance at a specified output level for a specified duration.

(ii) A Seasonal Claimed Capability Audit determines a Generator Asset's capability to perform under specified summer and winter conditions for a specified duration.

(iii) An ISO-Initiated Claimed Capability Audit is conducted by the ISO to verify the Generator Asset's Establish Claimed Capability Audit value.

(b) The Claimed Capability Audit value of a Generator Asset shall reflect any limitations based upon the interdependence of common elements between two or more Generator Assets such as: auxiliaries, limiting operating parameters, and the deployment of operating personnel.

(c) The Claimed Capability Audit value of gas turbine, combined cycle, and pseudo-combined cycle assets shall be normalized to standard 90° (summer) and 20° (winter) temperatures.

(d) The Claimed Capability Audit value for steam turbine assets with stream exports, combined cycle, or pseudo-combined cycle assets with steam exports where steam is exported for uses external to the electric power facility, shall be normalized to the facility's Seasonal Claimed Capability steam demand.

(e) A Claimed Capability Audit may be denied or rescheduled by the ISO if its performance will jeopardize the reliable operation of the electrical system.

III.1.5.1.2 Establish Claimed Capability Audit.

(a) The time and date of an Establish Claimed Capability Audit shall be unannounced.

(b) For a newly commercial Generator Asset:

(i) An Establish Claimed Capability Audit will be scheduled by the ISO within seven Business Days of the commercial operation date for all Generator Assets except:

1. Non-intermittent daily cycle hydro;
2. Non-intermittent net-metered, or special qualifying facilities that do not elect to audit as described in Section III.1.5.1.3; and
3. Intermittent Generator Assets

(ii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.

(iii) The Establish Claimed Capability Audit values shall be effective as of the commercial operation date of the Generator Asset.

(c) For Generator Assets with an Establish Claimed Capability Audit value:

(i) An Establish Claimed Capability Audit may be performed at the request of a Market Participant in order to support a change in the summer and winter Establish Claimed Capability Audit values for a Generator Asset.

(ii) An Establish Claimed Capability Audit shall be performed within seven Business Days of the date of the request.

(iii) The Establish Claimed Capability Audit values for both summer and winter shall equal the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.

(iv) The Establish Claimed Capability Audit values become effective one Business Day following notification of the audit results to the Market Participant by the ISO.

(v) A Market Participant may cancel an audit request prior to issuance of the audit Dispatch Instruction.

(d) An Establish Claimed Capability Audit value may not exceed the maximum interconnected flow specified in the Network Resource Capability for the resource associated with the Generator Asset.

(e) Establish Claimed Capability Audits shall be performed on Business Days between 0800 and 2200.

(f) To conduct an Establish Claimed Capability Audit, the ISO shall:

(i) Notify the Designated Entity immediately prior to issuing the Dispatch Instruction that an audit will be conducted.

(ii) Initiate an Establish Claimed Capability Audit by issuing a Dispatch Instruction ordering the asset's net output to increase from the current operating level to its Real-Time High Operating Limit.

(iii) Begin the audit with the first full clock hour after sufficient time has been allowed for the asset to ramp, based on its offered ramp rate from its current operating point to reach its Real-Time High Operating Limit.

(g) An Establish Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for an Establish Claimed Capability Audit	
Unit Type	**Claimed Capability Audit Duration (Hrs)**
Steam Turbine (Includes Nuclear)	4
Combined Cycle	4
Integrated Coal Gasification Combustion Cycle	4
Pressurized Fluidized Bed Combustion	4
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine – Reversible Hydraulic Turbine – Other	2

Hydro-Conventional Daily Pondage Hydro-Conventional Run of River Hydro-Conventional Weekly	2
Wind Photovoltaic Fuel Cell	2
Energy Storage (Excludes Pumped Storage)	2

(h) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for a Generator Asset of a unit type not listed in Section III.1.5.1.2(g).

III.1.5.1.3. Seasonal Claimed Capability Audits.

(a) A Seasonal Claimed Capability Audit must be conducted by all Generator Assets except:

(i) Non-intermittent daily hydro; and

(ii) Intermittent, net-metered, and special qualifying facilities. Non-intermittent net-metered and special qualifying facilities may elect to perform Seasonal Claimed Capability Audits pursuant to Section III.1.7.11(c)(iv).

(b) An Establish Claimed Capability Audit or ISO-Initiated Claimed Capability Audit that meets the requirements of a Seasonal Claimed Capability Audit in this Section III.1.5.1.3 may be used to fulfill a Generator Asset's Seasonal Claimed Capability Audit obligation.

(c) Except as provided in Section III.1.5.1.3(m) below, a summer Seasonal Claimed Capability Audit must be conducted:

(i) At least once every Capability Demonstration Year;

(ii) Either (1) at a mean ambient temperature during the audit that is greater than or equal to 80 degrees Fahrenheit at the location of the Generator Asset, or (2) during an ISO-announced summer Seasonal Claimed Capability Audit window.

(d) A winter Seasonal Claimed Capability Audit must be conducted:

(i) At least once in the previous three Capability Demonstration Years, except that a newly commercial Generator Asset which becomes commercial on or after:

(1) September 1 and prior to December 31 shall perform a winter Seasonal Claimed Capability Audit prior to the end of that Capability Demonstration Year.

(2) January 1 shall perform a winter Seasonal Claimed Capability Audit prior to the end of the next Capability Demonstration Year.

(ii) Either (1) at a mean ambient temperature during the audit that is less than or equal to 32 degrees Fahrenheit at the location of the Generator Asset, or (2) during an ISO-announced winter Seasonal Claimed Capability Audit window.

(e) A Seasonal Claimed Capability Audit shall be performed by operating the Generator Asset for the audit time period and submitting to the ISO operational data that meets the following requirements:

(i) The Market Participant must notify the ISO of its request to use the dispatch to satisfy the Seasonal Claimed Capability Audit requirement by 5:00 p.m. on the seventh Business Day following the day on which the audit concludes.

(ii) The notification must include the date and time period of the demonstration to be used for the Seasonal Claimed Capability Audit and other relevant operating data.

(f) The Seasonal Claimed Capability Audit value (summer or winter) will be the mean net real power output demonstrated over the duration of the audit, as reflected in hourly revenue metering data, normalized for temperature and steam exports.

(g) The Seasonal Claimed Capability Audit value (summer or winter) shall be the most recent audit data submitted to the ISO meeting the requirements of this Section III.1.5.1.3. In the event that a Market Participant fails to submit Seasonal Claimed Capability Audit data to meet the timing requirements in Section III.1.5.1.3(c) and (d), the Seasonal Claimed Capability Audit value for the season shall be set to zero.

(h) The Seasonal Claimed Capability Audit value shall become effective one Business Day following notification of the audit results to the Market Participant by the ISO.

(i) A Seasonal Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for a Seasonal Claimed Capability Audit	
Unit Type	**Claimed Capability Audit Duration (Hrs)**
Steam Turbine (Includes Nuclear)	2
Combined Cycle	2
Integrated Coal Gasification Combustion Cycle	2
Pressurized Fluidized Bed Combustion	2
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine-Reversible Hydraulic Turbine-Other	2

Hydro-Conventional Weekly	2
Fuel Cell	1
Energy Storage (Excludes Pumped Storage)	2

(j) A Generator Asset that is on a planned outage that was approved in the ISO's annual maintenance scheduling process during all hours that meet the temperature requirements for a Seasonal Claimed Capability Audit that is to be performed by the asset during that Capability Demonstration Year shall:

(i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these auditing requirements;

(ii) Have its Seasonal Claimed Capability Audit value for the season set to zero; and

(iii) Perform the required Seasonal Claimed Capability Audit on the next available day that meets the Seasonal Claimed Capability Audit temperature requirements.

(k) A Generator Asset that does not meet the auditing requirements of this Section III.1.5.1.3 because (1) every time the temperature requirements were met at the Generator Asset's location the ISO denied the request to operate to full capability, or (2) the temperature requirements were not met at the Generator Asset's location during the Capability Demonstration Year during which the asset was required to perform a Seasonal Claimed Capability Audit during the hours 0700 to 2300 for each weekday excluding those weekdays that are defined as NERC holidays, shall:

(i) Submit to the ISO, prior to September 10, an explanation of the circumstances rendering it incapable of meeting these temperature requirements, including verifiable temperature data;

(ii) Retain the current Seasonal Claimed Capability Audit value for the season; and

(iii) Perform the required Seasonal Claimed Capability Audit during the next Capability Demonstration Year.

(l) The ISO may issue notice of a summer or winter Seasonal Claimed Capability Audit window for some or all of the New England Control Area if the ISO determines that weather forecasts indicate that temperatures during the audit window will meet the summer or winter Seasonal Claimed Capability Audit temperature requirements. A notice shall be issued at least 48 hours prior to the opening of the audit window. Any audit performed during the announced audit window shall be deemed to meet the temperature requirement for the summer or winter audit. In the event that five or more audit windows for the summer Seasonal Claimed Capability Audit temperature requirement, each of at least a four hour duration between 0700 and 2300 and occurring on a weekday excluding those weekdays that are defined as NERC holidays, are not opened for a Generator Asset prior to August 15 during a Capability Demonstration Year, a two-

week audit window shall be opened for that Generator Asset to perform a summer Seasonal Claimed Capability Audit, and any audit performed by that Generator Asset during the open audit window shall be deemed to meet the temperature requirement for the summer Seasonal Claimed Capability Audit. The open audit window shall be between 0700 and 2300 each day during August 15 through August 31.

(m) A Market Participant that is required to perform testing on a Generator Asset that is in addition to a summer Seasonal Claimed Capability Audit may notify the ISO that the summer Seasonal Claimed Capability Audit was performed in conjunction with this additional testing, provided that:

(i) The notification shall be provided at the time the Seasonal Claimed Capability Audit data is submitted under Section III.1.5.1.3(e).

(ii) The notification explains the nature of the additional testing and that the summer Seasonal Claimed Capability Audit was performed while the Generator Asset was online to perform this additional testing.

(iii) The summer Seasonal Claimed Capability Audit and additional testing are performed during the months of June, July or August between the hours of 0700 and 2300.

(iv) In the event that the summer Seasonal Claimed Capability Audit does not meet the temperature requirements of Section III.1.5.1.3(c)(ii), the summer Seasonal Claimed Capability Audit value may not exceed the summer Seasonal Claimed Capability Audit value from the prior Capability Demonstration Year.

(v) This Section III.1.5.1.3(m) may be utilized no more frequently than once every three Capability Demonstration Years for a Generator Asset.

(n) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for a Generator Asset of a unit type not listed in Section III.1.5.1.3(i).

III.1.5.1.4. ISO-Initiated Claimed Capability Audits.

(a) An ISO-Initiated Claimed Capability Audit may be performed by the ISO at any time.

(b) An ISO-Initiated Claimed Capability Audit value shall replace the winter and summer Establish Claimed Capability Audit values for a Generator Asset, normalized for temperature and steam exports, except:

(i) The Establish Claimed Capability Audit values may not exceed the maximum interconnected flow specified in the Network Resource Capability for that resource.

(ii) An ISO-Initiated Claimed Capability Audit value shall not set the winter Establish Claimed Capability Audit value unless the ISO-Initiated Claimed Capability Audit was performed at a

mean ambient temperature that is less than or equal to 32 degrees Fahrenheit at the Generator Asset location.

(c) If a Market Participant submits pressure and relative humidity data for the previous Establish Claimed Capability Audit and the current ISO-Initiated Claimed Capability Audit, the Establish Claimed Capability Audit values derived from the ISO-Initiated Claimed Capability Audit will be normalized to the pressure of the previous Establish Claimed Capability Audit and a relative humidity of 64%.

(d) Establish Claimed Capability Audit values derived from the ISO-Initiated Claimed Capability Audit shall become effective one Business Day following notification of the audit results to the Market Participant by the ISO.

(e) To conduct an ISO-Initiated Claimed Capability Audit, the ISO shall:

(i) Notify the Designated Entity, immediately prior to issuing the Dispatch Instruction, that an audit will be conducted.

(ii) Initiate an ISO-Initiated Claimed Capability Audit by issuing a Dispatch Instruction ordering the Generator Asset's net output to increase from the current operating level to its Real-Time High Operating Limit.

(iii) Begin the audit with the first full clock hour after sufficient time has been allowed for the Generator Asset to ramp, based on its offered ramp rate, from its current operating point to its Real-Time High Operating Limit.

(f) An ISO-Initiated Claimed Capability Audit shall be performed for the following contiguous duration:

Duration Required for an ISO-Initiated Claimed Capability Audit	
Unit Type	**Claimed Capability Audit <u>Duration (Hrs)</u>**
Steam Turbine (Includes Nuclear)	4
Combined Cycle	4
Integrated Coal Gasification Combustion Cycle	4
Pressurized Fluidized Bed Combustion	4
Combustion Gas Turbine	1
Internal Combustion Engine	1
Hydraulic Turbine – Reversible Hydraulic Turbine – Other	2

Hydro-Conventional Daily Pondage Hydro-Conventional Run of River Hydro-Conventional Weekly	2
Wind Photovoltaic Fuel Cell	2
Energy Storage (Excludes Pumped Storage)	2

(g) The ISO, in consultation with the Market Participant, will determine the contiguous audit duration for a Generator Asset of a unit type not listed in Section III.1.5.1.4(f).

III.1.5.2 ISO-Initiated Parameter Auditing.

(a) The ISO may perform an audit of any Supply Offer, Demand Reduction offer or other operating parameter that impacts the ability of a Generator Asset or Demand Response Resource to provide real-time energy or reserves.

(b) Generator audits shall be performed using the following methods for the relevant parameter:

(i) **Economic Maximum Limit**. The Generator Asset shall be evaluated based upon its ability to achieve the current offered Economic Maximum Limit value, through a review of historical dispatch data or based on a response to a current ISO-issued Dispatch Instruction.

(ii) **Manual Response Rate**. The Generator Asset shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Manual Response Rate, including hold points and changes in Manual Response Rates.

(iii) **Start-Up Time**. The Generator Asset shall be evaluated based upon its ability to achieve the offered Start-Up Time.

(iv) **Notification Time**. The Generator Asset shall be evaluated based upon its ability to close its output breaker within its offered Notification Time.

(v) **CLAIM10**. The Generator Asset shall be evaluated based upon its ability to reach its CLAIM10 value in accordance with Section III.9.5.

(vi) **CLAIM30**. The Generator Asset shall be evaluated based upon its ability to reach its CLAIM30 value in accordance with Section III.9.5.

(vii) **Automatic Response Rate**. The Generator Asset shall be analyzed, based upon a review of historical performance data, for its ability to respond to four-second electronic Dispatch Instructions.

(viii) **Dual Fuel Capability**. A Generator Asset that is capable of operating on multiple fuels may be required to audit on a specific fuel, as set out in Section III.1.5.2(e).

(c) Demand Response Resource audits shall be performed using the following methods:

(i) **Maximum Reduction**. The Demand Response Resource shall be evaluated based upon its ability to achieve the current offered Maximum Reduction value, through a review of historical dispatch data or based on a response to a current Dispatch Instruction.

(ii) **Demand Response Resource Ramp Rate**. The Demand Response Resource shall be evaluated based upon its ability to respond to Dispatch Instructions at its offered Demand Response Resource Ramp Rate.

(iii) **Demand Response Resource Start-Up Time**. The Demand Response Resource shall be evaluated based upon its ability to achieve its Minimum Reduction within the offered Demand Response Resource Start-Up Time, in response to a Dispatch Instruction and after completing its Demand Response Resource Notification Time.

(iv) **Demand Response Resource Notification Time**. The Demand Response Resource shall be evaluated based upon its ability to start reducing demand within its offered Demand Response Resource Notification Time, from the receipt of a Dispatch Instruction when the Demand Response Resource was not previously reducing demand.

(v) **CLAIM10**. The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM10 value in accordance with Section III.9.5.

(vi) **CLAIM30**. The Demand Response Resource shall be evaluated based upon its ability to reach its CLAIM30 value in accordance with Section III.9.5.

(d) To conduct an audit based upon historical data, the ISO shall:

(i) Obtain data through random sampling of generator or Demand Response Resource performance in response to Dispatch Instructions; or

(ii) Obtain data through continual monitoring of generator or Demand Response Resource performance in response to Dispatch Instructions.

(e) To conduct an unannounced audit, the ISO shall initiate the audit by issuing a Dispatch Instruction ordering the Generator Asset or Demand Response Resource to change from the current operating level to a level that permits the ISO to evaluate the performance of the Generator Asset or Demand Response Resource for the parameters being audited.

(f) To conduct an audit of the capability of a Generator Asset described in Section III.1.5.2(b)(viii) to run on a specific fuel:

(i) The ISO shall notify the Lead Market Participant if a Generator Asset is required to undergo an audit on a specific fuel. The ISO, in consultation with the Lead Market Participant, shall develop a plan for the audit.

(ii) The Lead Market Participant will have the ability to propose the time and date of the audit within the ISO's prescribed time frame and must notify the ISO at least five business days in advance of the audit, unless otherwise agreed to by the ISO and the Lead Market Participant.

(g) To the extent that the audit results indicate a Market Participant is providing Supply Offer, Demand Reduction Offer or other operating parameter values that are not representative of the actual capability of the Generator Asset or Demand Response Resource, the values for the Generator Asset or Demand Response Resource shall be restricted to those values that are supported by the audit.

(h) In the event that a Generator Asset or Demand Response Resource has had a parameter value restricted:

(i) The Market Participant may submit a restoration plan to the ISO to restore that parameter. The restoration plan shall:

1. Provide an explanation of the discrepancy;
2. Indicate the steps that the Market Participant will take to re-establish the parameter's value;
3. Indicate the timeline for completing the restoration; and
4. Explain the testing that the Market Participant will undertake to verify restoration of the parameter value upon completion.

(ii) The ISO shall:

1. Accept the restoration plan if implementation of the plan, including the testing plan, is reasonably likely to support the proposed change in the parameter value restriction;
2. Coordinate with the Market Participant to perform required testing upon completion of the restoration; and
3. Modify the parameter value restriction following completion of the restoration plan, based upon tested values.

(i) III.1.5.3 Reactive Capability Audits.

(j) (a) Two types of Reactive Capability Audits may be performed:

(k) (i) A Lagging Reactive Capability Audit measures the Generator Asset's ability to provide reactive power to the transmission system at a specified real power output.

(l) (ii) A Leading Reactive Capability Audit measures the Generator Asset's ability to absorb reactive power from the transmission system at a specified real power output.

(m) (b) The ISO shall develop a list of Generator Assets that must conduct Reactive Capability Audits.

(n) (c) Unless otherwise directed by the ISO, Generator Assets that are required to perform Reactive Capability Audits must perform both a Lagging Reactive Capability Audit and a Leading Reactive Capability Audit.

(o) (d) All Reactive Capability Audits shall meet the testing conditions specified in the ISO New England Operating Documents.

(p) (e) The Reactive Capability Audit value of a Generator Asset shall reflect any limitations based upon the interdependence of common elements between two or more Generator Assets such as: auxiliaries, limiting operating parameters, and the deployment of operating personnel.

(q) (f) A Reactive Capability Audit may be denied or rescheduled by the ISO if conducting the Reactive Capability Audit could jeopardize the reliable operation of the electrical system.

(r) (g) Reactive Capability Audits must be conducted at least every five years, unless otherwise required by the ISO. The ISO may require a Generator Asset to conduct Reactive Capability Audits more often than every five years if:

(s) (i) there is a change in the Generator Asset that may affect the reactive power capability of the Generator Asset;

(t) (ii) there is a change in electrical system conditions that may affect the achievable reactive power output or absorption of the Generator Asset; or

(u) (iii) historical data shows that the amount of reactive power that the Generator Asset can provide to or absorb from the transmission system is higher or lower than the latest audit data.

(v) (h) The Lead Market Participant may request a waiver of the requirement to conduct a Reactive Capability Audit. The ISO, at its sole discretion, will determine whether and for how long a waiver can be granted.

III.1.6 [Reserved.]

III.1.6.1 [Reserved.]

III.1.6.2 [Reserved.]

III.1.6.3 [Reserved.]

III.1.6.4 ISO New England Manuals and ISO New England Administrative Procedures.

The ISO shall prepare, maintain and update the ISO New England Manuals and ISO New England Administrative Procedures consistent with the ISO New England Filed Documents. The ISO New England Manuals and ISO New England Administrative Procedures shall be available for inspection by the Market Participants, regulatory authorities with jurisdiction over the ISO or any Market Participant, and the public.

III.1.7 General.

III.1.7.1 Provision of Market Data to the Commission.

The ISO will electronically deliver to the Commission, on an ongoing basis and in a form and manner consistent with its collection of data and in a form and manner acceptable to the Commission, data related to the markets that it administers, in accordance with the Commission's regulations.

III.1.7.2 [Reserved.]

III.1.7.3 Agents.

A Market Participant may participate in the New England Markets through an agent, provided that such Market Participant informs the ISO in advance in writing of the appointment of such agent. A Market Participant using an agent shall be bound by all of the acts or representations of such agent with respect to transactions in the New England Markets, and shall ensure that any such agent complies with the requirements of the ISO New England Manuals and ISO New England Administrative Procedures and the ISO New England Filed Documents.

III.1.7.4 [Reserved.]

III.1.7.5 [Reserved.]

III.1.7.6 Scheduling and Dispatching.

(a) The ISO shall schedule Day-Ahead and schedule and dispatch in Real-Time Resources economically on the basis of least-cost, security-constrained dispatch and the prices and operating characteristics offered by Market Participants. The ISO shall schedule and dispatch sufficient Resources of the Market Participants to serve the New England Markets energy purchase requirements under normal system conditions of the Market Participants and meet the requirements of the New England Control Area for ancillary services provided by such Resources. The ISO shall use a joint optimization process to serve Real-Time Energy Market energy requirements and meet Real-Time Operating Reserve requirements based on a least-cost, security-constrained economic dispatch.

(b) In the event that one or more Resources cannot be scheduled in the Day-Ahead Energy Market on the basis of a least-cost, security-constrained dispatch as a result of one or more Self-Schedule offers contributing to a transmission limit violation, the following scheduling protocols will apply:

(i) When a single Self-Schedule offer contributes to a transmission limit violation, the Self-Schedule offer will not be scheduled for the entire Self-Schedule period in development of Day-Ahead schedules.

(ii) When two Self-Schedule offers contribute to a transmission limit violation, parallel clearing solutions will be executed such that, for each solution, one of the Self-Schedule offers will be omitted for its entire Self-Schedule period. The least cost solution will be used for purposes of determining which Resources are scheduled in the Day-Ahead Energy Market.

(iii) When three or more Self-Schedule offers contribute to a transmission limit violation, the ISO will determine the total daily MWh for each Self-Schedule offer and will omit Self-Schedule offers in their entirety, in sequence from the offer with the least total daily MWh to the offer with the greatest total MWh, stopping when the transmission limit violation is resolved.

(c) Scheduling and dispatch shall be conducted in accordance with the ISO New England Filed Documents.

(d) The ISO shall undertake, together with Market Participants, to identify any conflict or incompatibility between the scheduling or other deadlines or specifications applicable to the New England Markets, and any relevant procedures of another Control Area, or any tariff (including the Transmission, Markets and Services Tariff). Upon determining that any such conflict or incompatibility exists, the ISO shall propose tariff or procedural changes, or undertake such other efforts as may be appropriate, to resolve any such conflict or incompatibility.

III.1.7.7 Energy Pricing.

The price paid for energy, including demand reductions, bought and sold by the ISO in the New England Markets will reflect the hourly Locational Marginal Price at each Location, determined by the ISO in accordance with the ISO New England Filed Documents. Congestion Costs, which shall be determined by differences in the Congestion Component of Locational Marginal Prices in an hour caused by constraints,

shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1. Loss costs associated with Pool Transmission Facilities, which shall be determined by the differences in Loss Components of the Locational Marginal Prices in an hour, shall be calculated and collected, and the resulting revenues disbursed, by the ISO in accordance with this Market Rule 1.

III.1.7.8 Market Participant Resources.

A Market Participant may elect to Self-Schedule its Resources in accordance with and subject to the limitations and procedures specified in this Market Rule 1 and the ISO New England Manuals.

III.1.7.9 Real-Time Reserve Prices.

The price paid by the ISO for the provision of Real-Time Operating Reserve in the New England Markets will reflect the integrated hourly Real-Time Reserve Clearing Prices determined by the ISO in accordance with the ISO New England Filed Documents for the system and each Reserve Zone.

III.1.7.10 Other Transactions.

(a) Market Participants may enter into internal bilateral transactions and External Transactions for the purchase or sale of energy or other products to or from each other or any other entity, subject to the obligations of Market Participants to make resources with a Capacity Supply Obligation available for dispatch by the ISO. External Transactions that contemplate the physical transfer of energy or obligations to or from a Market Participant shall be reported to and coordinated with the ISO in accordance with this Market Rule 1 and the ISO New England Manuals.

(b) [Reserved.]

(c) [Reserved.]

III.1.7.11 Seasonal Claimed Capability of a Generating Capacity Resource.

(a) A Seasonal Claimed Capability value must be established and maintained for all Generating Capacity Resources. A summer Seasonal Claimed Capability is established for use from June 1 through September 30 and a winter Seasonal Claimed Capability is established for use from October 1 through May 31.

(b) The Seasonal Claimed Capability of a Generating Capacity Resource is the sum of the Seasonal Claimed Capabilities of the Generator Assets that are associated with the Generating Capacity Resource.

(c) The Seasonal Claimed Capability of a Generator Asset is:

(i) Based upon review of historical data for non-intermittent daily cycle hydro.

(ii) The median net real power output during reliability hours, as described in Section III.13.1.2.2.2, for (1) intermittent facilities, and (2) net-metered and special qualifying facilities that do not elect to audit, as reflected in hourly revenue metering data.

(iii) For non-intermittent net-metered and special qualifying facilities that elect to audit, the minimum of (1) the Generator Asset's current Seasonal Claimed Capability Audit value, as performed pursuant to Section III.1.5.1.3; (2) the Generator Asset's current Establish Claimed Capability Audit value; and (3) the median hourly availability during hours ending 2:00 p.m. through 6:00 p.m. each day of the preceding June through September for Summer and hours ending 6:00 p.m. and 7:00 p.m. each day of the preceding October through May for Winter. The hourly availability:

a. For a Generator Asset that is available for commitment and following Dispatch Instructions, shall be the asset's Economic Maximum Limit, as submitted or redeclared.

b. For a Generator Asset that is off-line and not available for commitment shall be zero.

c. For a Generator Asset that is on-line but not able to follow Dispatch Instructions, shall be the asset's metered output.

(iv) For all other Generator Assets, the minimum of: (1) the Generator Asset's current Establish Claimed Capability Audit value and (2) the Generator Asset's current Seasonal Claimed Capability Audit value, as performed pursuant to Section III.1.5.1.3.

III.1.7.12 [Reserved.]

III.1.7.13 [Reserved.]

III.1.7.14 [Reserved.]

III.1.7.15 [Reserved.]

III.1.7.16 [Reserved.]

III.1.7.17 Operating Reserve.

The ISO shall schedule the Operating Reserve and load-following requirements of the New England Control Area and the New England Markets in scheduling Resources pursuant to this Market Rule 1. Reserve requirements for the Forward Reserve Market are determined in accordance with the methodology specified in Section III.9.2 of Market Rule 1. Operating Reserve requirements for Real-Time dispatch within an Operating Day are determined in accordance with Market Rule 1 and ISO New England Operating Procedure No. 8, Operating Reserve and Regulation.

III.1.7.18 [Reserved.]

III.1.7.19 Ramping.

A generating unit or Demand Response Resource dispatched by the ISO pursuant to a control signal appropriate to increase or decrease the unit's megawatt output or demand reduction level shall be able to change output or demand reduction at the ramping rate specified in the Offer Data submitted to the ISO for that unit and shall be subject to sanctions for failure to comply as described in **Appendix B**.

III.1.7.19A Real-Time Reserve.

(a) Real-Time TMSR, TMNSR, TMOR and Real-Time Replacement Reserve, if applicable, shall be supplied from Resources located within the metered boundaries of the New England Control Area subject to the condition set forth in Section III.1.7.19A(c) below. The ISO shall designate Operating Reserve in Real-Time only to Market Participant Resources that comply with the applicable standards and requirements for provision and dispatch of Operating Reserve capability as specified in Section III.10 and the ISO New England Manuals and ISO New England Administrative Procedures.

(b) The ISO shall endeavor to procure and maintain an amount of Operating Reserve in Real-Time equal to the system and locational Operating Reserve requirements as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(c) External Resources will be permitted to participate in the Real-Time reserve market when the respective Control Areas implement the technology and processes necessary to support recognition of Operating Reserves from external Resources.

III.1.7.20 Information and Operating Requirements.

(a) [Reserved.]

(b) Market Participants selling from Resources within the New England Control Area shall: supply to the ISO all applicable Offer Data; report to the ISO units that are Self-Scheduled; report to the ISO External Transaction sales; confirm to the ISO bilateral sales to Market Participants within the New England Control Area; respond to the ISO's directives to start, shutdown or change output or demand reduction levels of generating units or Demand Response Resources, change scheduled voltages or reactive output levels; continuously maintain all Offer Data concurrent with on-line operating information; and ensure that, where so equipped, generating and demand reduction equipment is operated

with control equipment functioning as specified in the ISO New England Manuals and ISO New England Administrative Procedures.

(c) Market Participants selling from Resources outside the New England Control Area shall: provide to the ISO all applicable Offer Data, including offers specifying amounts of energy available, hours of availability and prices of energy and other services; respond to ISO directives to schedule delivery or change delivery schedules; and communicate delivery schedules to the source Control Area and any intermediary Control Areas.

(d) Market Participants, as applicable, shall: respond or ensure a response to ISO directives for load management steps; report to the ISO all bilateral purchase transactions including External Transaction purchases; and respond or ensure a response to other ISO directives such as those required during Emergency operation.

(e) Market Participant, as applicable, shall provide to the ISO requests to purchase specified amounts of energy for each hour of the Operating Day during which it intends to purchase from the Day-Ahead Energy Market, along with Dispatch Rate levels above which it does not desire to purchase.

(f) Market Participants are responsible for reporting to the ISO anticipated availability and other information concerning generating Resources, Demand Response Resources and Dispatchable Asset Related Demand Resources required by the ISO New England Operating Documents, including but not limited to the Market Participant's ability to procure fuel and physical limitations that could reduce Resource output or demand reduction capability for the pertinent Operating Day.

III.1.8 [Reserved.]

III.1.9 Pre-scheduling.

III.1.9.1 [Reserved.]

III.1.9.2 [Reserved.]

III.1.9.3 [Reserved.]

III.1.9.4 [Reserved.]

III.1.9.5 [Reserved.]

III.1.9.6 [Reserved.]

III.1.9.7 Market Participant Responsibilities.

Market Participants authorized and intending to request market-based Start-Up Fees and No-Load Fee in their Offer Data shall submit a specification of such fees to the ISO for each generating unit as to which the Market Participant intends to request such fees. Any such specification shall identify the applicable period and be submitted on or before the applicable deadline and shall remain in effect unless otherwise modified in accordance with Section III.1.10.9. The ISO shall reject any request for Start-Up Fees and No-Load Fee in a Market Participant's Offer Data that does not conform to the Market Participant's specification on file with the ISO.

III.1.9.8 [Reserved.]

III.1.10 Scheduling.

III.1.10.1 General.

(a) The ISO shall administer scheduling processes to implement a Day-Ahead Energy Market and a Real-Time Energy Market.

(b) The Day-Ahead Energy Market shall enable Market Participants to purchase and sell energy through the New England Markets at Day-Ahead Prices and enable Market Participants to submit External Transactions conditioned upon Congestion Costs not exceeding a specified level. Market Participants whose purchases and sales and External Transactions are scheduled in the Day-Ahead Energy Market shall be obligated to purchase or sell energy or pay Congestion Costs and costs for losses, at the applicable Day-Ahead Prices for the amounts scheduled.

(c) In the Real-Time Energy Market,

(i) Market Participants that deviate from the amount of energy purchases or sales scheduled in the Day-Ahead Energy Market shall replace the energy not delivered with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price, unless otherwise specified by this Market Rule 1, and

(ii) Non-Market Participant Transmission Customers shall be obligated to pay Congestion Costs and costs for losses for the amount of the scheduled transmission uses in the Real-Time Energy Market at the applicable Real-Time Congestion Component and Loss Component price differences, unless otherwise specified by this Market Rule 1.

(d) The following scheduling procedures and principles shall govern the commitment of Resources to the Day-Ahead Energy Market and the Real-Time Energy Market over a period extending from one week to one hour prior to the Real-Time dispatch. Scheduling encompasses the Day-Ahead and hourly scheduling process, through which the ISO determines the Day-Ahead Energy Market schedule and determines, based on changing forecasts of conditions and actions by Market Participants and system constraints, a plan to serve the hourly energy and reserve requirements of the New England Control Area in the least costly manner, subject to maintaining the reliability of the New England Control Area. Scheduling of External Transactions in the Real-Time Energy Market is subject to Section II.44 of the OATT.

(e) If the ISO's forecast for the next seven days projects a likelihood of Emergency Condition, the ISO may commit, for all or part of such seven day period, to the use of generating Resources with Notification Time greater than 24 hours as necessary in order to alleviate or mitigate such Emergency, in accordance with the Market Participants' binding Supply Offers for such units.

III.1.10.1A Day-Ahead Energy Market Scheduling.

The following actions shall occur not later than 10:00 a.m. on the day before the Operating Day for which transactions are being scheduled, or such other deadline as may be specified by the ISO in order to comply with the practical requirements and the economic and efficiency objectives of the scheduling process specified in this Market Rule 1.

(a) Each Market Participant may submit to the ISO specifications of the amount and location of its customer loads and/or energy purchases to be included in the Day-Ahead Energy Market for each hour of the next Operating Day, such specifications to comply with the requirements set forth in the ISO New England Manuals and ISO New England Administrative Procedures. Each Market Participant shall inform the ISO of (i) the prices, if any, at which it desires not to include its load in the Day-Ahead Energy Market rather than pay the Day-Ahead Price, (ii) hourly schedules for Resource increments, including hydropower units, Self-Scheduled by the Market Participant; and (iii) the Decrement Bid at which each such Self-Scheduled Resource will disconnect or reduce output, or confirmation of the Market Participant's intent not to reduce output. Price-sensitive Demand Bids and Decrement Bids must be greater than zero MW and shall not exceed the energy Supply Offer limitation specified in this Section.

(b) [Reserved.]

(c) All Market Participants shall submit to the ISO schedules for any External Transactions involving use of generating Resources or the New England Transmission System as specified below, and shall inform the ISO whether the transaction is to be included in the Day-Ahead Energy Market. Any Market Participant that elects to include an External Transaction in the Day-Ahead Energy Market may specify the price (such price not to exceed the maximum price that may be specified in the ISO New England Manuals and ISO New England Administrative Procedures), if any, at which it will be curtailed rather than pay Congestion Costs. The foregoing price specification shall apply to the price difference between the Locational Marginal Prices for specified External Transaction source and sink points in the Day-Ahead scheduling process only. Any Market Participant that deviates from its Day-Ahead External Transaction schedule or elects not to include its External Transaction in the Day-Ahead Energy Market shall be subject to Congestion Costs in the Real-Time Energy Market in order to complete any such scheduled External Transaction. A priced External Transaction submitted under Section III.1.10.7 and that clears in the Day-Ahead Energy Market will be considered tied within economic merit with a Self-Scheduled External Transaction submitted to the Real-Time Energy Market, unless the Market Participant modifies the price component of its Real-Time offer during the Re-Offer Period. Scheduling of External Transactions shall be conducted in accordance with the specifications in the ISO New England Manuals and ISO New England Administrative Procedures and the following requirements:

(i) Market Participants shall submit schedules for all External Transaction purchases for delivery within the New England Control Area from Resources outside the New England Control Area;

(ii) Market Participants shall submit schedules for External Transaction sales to entities outside the New England Control Area from Resources within the New England Control Area;

(iii) If the sum of all submitted fixed External Transaction purchases less External Transaction sales exceeds the import capability associated with the applicable External Node, the offer prices for all fixed External Transaction purchases at the applicable External Node shall be set equal to the Energy Offer Floor;

(iv) If the sum of all submitted fixed External Transaction sales less External Transaction purchases exceeds the export capability associated with the applicable External Node, the

offer prices for all fixed External Transaction sales at the applicable External Node shall be set equal to the Energy Offer Cap;

(v) The ISO shall not consider Start-Up Fees, No-Load Fees, Notification Times or any other inter-temporal parameters in scheduling or dispatching External Transactions.

(d) Market Participants selling into the New England Markets, from either internal Resources or External Resources, shall submit Supply Offers or External Transactions for the supply of energy (including energy from hydropower units), and Demand Bids for the consumption of energy, Operating Reserve or other services as applicable, for the following Operating Day. Coordinated External Transactions shall be submitted to the ISO in accordance with Section III.1.10.7.A of this Market Rule 1.

Energy offered from generating Resources without a Capacity Supply Obligation shall not be supplied from Resources that are included in or otherwise committed to supply the operating reserve requirements of another Control Area. All Supply Offers and Demand Bids:

(i) Shall specify the Resource or Load Asset and energy for each hour of the Operating Day;

(ii) Shall specify, for Supply Offers, Blocks (price and quantity of Energy) for each hour of the Operating Day for each Resource offered by the Market Participant to the ISO. The price and quantity values in a Block may each vary on an hourly basis;

(iii) If based on energy from a specific generating unit internal to the New England Control Area, may specify, for Supply Offers, Start-Up Fee and No-Load Fee for each hour of the Operating Day. Start-Up Fee and No-Load Fee values may vary on an hourly basis;

(iv) For a dual fuel Resource, shall specify, for Supply Offers, the fuel type. The fuel type value may vary on an hourly basis. A Market Participant that submits a Supply Offer using the higher cost fuel type must satisfy the consultation requirements for dual fuel Resources in Section III.A.3 of Appendix A;

(v) Shall specify, for Supply Offers, a Minimum Run Time to be used for scheduling purposes that does not exceed 24 hours for a generating Resource;

(vi) Supply Offers shall constitute an offer to submit the generating Resource increment to the ISO for scheduling and dispatch in accordance with the terms of the Supply Offer, where such Supply Offer, with regard to operating limits, shall specify changes to the Economic Maximum Limit, Economic Minimum Limit and Emergency Minimum Limit from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource, except that for a Limited Energy Resource, the Economic Maximum Limit may be revised to reflect maximum energy available for the Operating Day, which offer shall remain open through the Operating Day for which the Supply Offer is submitted;

(vii) Shall constitute, for Demand Bids, an offer to submit the Dispatchable Asset Related Demand Resource increment to the ISO for scheduling and dispatch in accordance with the terms of the Demand Bid, where such Demand Bid, with regard to operating limits, shall specify changes to the Maximum Consumption Limit and Minimum Consumption Limit from those submitted as part of the Resource's Offer Data to reflect the physical operating characteristics and/or availability of the Resource, except that, for a Self-Scheduled Resource, the Minimum Consumption Limit may vary on an hourly basis to reflect the Self-Scheduled consumption level of the Resource;

(viii) Shall be final as to the price or prices at which the Market Participant proposes to supply or consume energy or other services to the New England Markets, such price or prices for Resources or portions of Resources scheduled in the Day-Ahead Energy Market being guaranteed by the Market Participant for the period extending through the end of the following Operating Day; and

(ix) Shall not specify an energy offer or bid price below the Energy Offer Floor or above the Energy Offer Cap.

(e) [Reserved.]

(f) [Reserved.]

(g) Each Supply Offer or Demand Bid by a Market Participant of a Resource shall remain in effect for subsequent Operating Days until superseded or canceled except in the case of an External Resource and an External Transaction purchase, in which case, the Supply Offer shall remain in effect for the

applicable Operating Day and shall not remain in effect for subsequent Operating Days. Hourly overrides of a Supply Offer or a Demand Bid shall remain in effect only for the applicable Operating Day.

(h) The ISO shall post on the internet the total hourly loads including Decrement Bids scheduled in the Day-Ahead Energy Market, as well as the ISO's estimate of the Control Area hourly load for the next Operating Day.

(i) In determining Day-Ahead schedules, in the event of multiple marginal Supply Offers, Demand Reduction Offers, Increment Offers and/or External Transaction purchases at a pricing location, the ISO shall clear the marginal Supply Offers, Demand Reduction Offers, Increment Offers and/or External Transaction purchases proportional to the amount of energy (MW) from each marginal offer and/or External Transaction at the pricing location. The Economic Maximum Limits, Economic Minimum Limits, Minimum Reductions and Maximum Reductions are not used in determining the amount of energy (MW) in each marginal Supply Offer or Demand Reduction Offer to be cleared on a pro-rated basis. However, the Day-Ahead schedules resulting from the pro-ration process will reflect Economic Maximum Limits, Economic Minimum Limits, Minimum Reductions and Maximum Reductions.

(j) In determining Day-Ahead schedules, in the event of multiple marginal Demand Bids, Decrement Bids and/or External Transaction sales at a pricing location, the ISO shall clear the marginal Demand Bids, Decrement Bids and/or External Transaction sales proportional to the amount of energy (MW) from each marginal bid and/or External Transaction at the pricing location.

(k) All Market Participants may submit Increment Offers and/or Decrement Bids that apply to the Day-Ahead Energy Market only. Such offers and bids must comply with the requirements set forth in the ISO New England Manuals and ISO New England Administrative Procedures and must specify amount, location and price, if any, at which the Market Participant desires to purchase or sell energy in the Day-Ahead Energy Market.

III.1.10.2 Pool-Scheduled Resources.

Pool-Scheduled Resources are those Resources for which Market Participants submitted Supply Offers or Demand Reduction Offers to sell energy in the Day-Ahead Energy Market and which the ISO scheduled in the Day-Ahead Energy Market as well as generators or Demand Response Resources committed by the ISO subsequent to the Day-Ahead Energy Market. Such Resources shall be committed to provide energy in the Real-Time dispatch unless the schedules for such Resources are revised pursuant to Sections

III.1.10.9 or III.1.11. Pool-Scheduled Resources shall be governed by the following principles and procedures.

(a) Pool-Scheduled Resources shall be selected by the ISO on the basis of the prices offered for energy and related services, Start-Up Fees, No-Load Fees, Interruption Cost and the specified operating characteristics, offered by Market Participants.

(b) The ISO shall optimize the dispatch of energy from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources in the Day-Ahead Energy Market consistent with the Supply Offers and Demand Reduction Offers of other Resources, the submitted Demand Bids and Decrement Bids and Operating Reserve and Replacement Reserve requirements.

(c) Market Participants offering energy from hydropower or other facilities with fuel or environmental limitations may submit data to the ISO that is sufficient to enable the ISO to determine the available operating hours of such facilities.

(d) The Market Participant seller whose Resource is selected as a Pool-Scheduled Resource shall receive payments or credits for energy or related services, or for Start-Up Fees, No-Load Fees or Interruption Costs, from the ISO on behalf of the Market Participant buyers in accordance with Section III.3 of this Market Rule 1.

(e) Market Participants shall make available their Pool-Scheduled Resources to the ISO for coordinated operation to supply the needs of the New England Control Area for energy and ancillary services.

III.1.10.3 Self-Scheduled Resources.

A Resource that is Self-Scheduled shall be governed by the following principles and procedures.

(a) The minimum duration of a Self-Schedule for a Generator Asset shall not result in the Generator Asset operating for less than its Minimum Run Time. A Generator Asset that is online as a result of a

Self-Schedule will be dispatched above its Economic Minimum Limit based on the economic merit of its Supply Offer.

(b) The offered prices of Resources or portions of Resources that are Self-Scheduled, or otherwise not following the dispatch orders of the ISO, shall not be considered by the ISO in determining Locational Marginal Prices.

(c) A Market Participant with a Resource that does not have a Capacity Supply Obligation shall comply with the requirements in Section III.13.6.2 when Self-Scheduling that Resource.

(d) A Market Participant Self-Scheduling a Resource in the Day-Ahead Energy Market that does not deliver the energy in the Real-Time Energy Market, shall replace the energy not delivered with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price.

III.1.10.4 [Reserved.]

III.1.10.5 External Resources.

(a) Market Participants with External Resources that have dynamic scheduling and dispatch capability may submit Supply Offers to the New England Markets in accordance with the Day-Ahead and Real-Time scheduling processes specified above. Market Participants must submit Supply Offers for External Resources on a Resource specific basis. An External Resource with dynamic scheduling and dispatch capability selected as a Pool-Scheduled Resource shall be made available for scheduling and dispatch at the direction of the ISO and shall be compensated on the same basis as other Pool-Scheduled Resources.

(b) Supply Offers for External Resources with dynamic scheduling and dispatch capability shall specify the Resource being offered, along with the information specified in the Offer Data as applicable.

(c) For Resources external to the New England Control Area that are not capable of dynamic scheduling and dispatch, Market Participants shall submit External Transactions as detailed in Section III.1.10.7 and Section III.1.10.7.A of this Market Rule 1.

(d) A Market Participant whose External Resource is capable of dynamic scheduling and dispatch capability or whose External Transaction does not deliver the energy scheduled in the Day-Ahead Energy Market shall replace such energy not delivered as scheduled in the Day-Ahead Energy Market with energy from the Real-Time Energy Market or an internal bilateral transaction and shall pay for such energy not delivered, net of any internal bilateral transactions, at the applicable Real-Time Price.

III.1.10.6 Dispatchable Asset Related Demand Resources.

External Transactions that are sales to an external Control Area are not eligible to be Dispatchable Asset Related Demand Resources. Except as noted below with respect to a pumped storage generator that does not have a Capacity Supply Obligation, a Dispatchable Asset Related Demand Resource in the New England Control Area must:

(a) each day, either Self-Schedule or submit a Demand Bid into the Day-Ahead Energy Market as described in Section III.1.10.1A of this Market Rule 1 that specifies the prices at which the Resource is willing to consume energy, unless and to the extent that the Dispatchable Asset Related Demand Resource is unable to do so due to an outage as defined in the ISO New England Manuals;

(b) submit Demand Bid data that specifies a Maximum Consumption Limit and Minimum Consumption Limit;

(c) submit Demand Bid data that specifies a Minimum Consumption Limit that is less than or equal to its Nominated Consumption Limit;

(d) notify the ISO of any outage (including partial outages) that may reduce the Dispatchable Asset Related Demand Resource's ability to interrupt and the expected return date from the outage;

(e) in accordance with the ISO New England Manuals and Operating Procedures, perform audit tests and submit the results to the ISO or provide to the ISO appropriate historical production data;

(f) abide by the ISO maintenance coordination procedures;

(g) provide information reasonably requested by the ISO, including the name and location of the Dispatchable Asset Related Demand Resource; and

(h) comply with the ISO New England Manuals.

To schedule the dispatchable pumping demand of a pumped storage generator that does not have a Capacity Supply Obligation, a Market Participant must comply with the requirements in (b) through (h) for the applicable Operating Day and must either Self-Schedule or submit a Demand Bid into the Day-Ahead Energy Market as described in Section III.1.10.1A of this Market Rule 1 that specifies the prices at which the Resource is willing to consume energy for the applicable Operating Day.

III.1.10.7 External Transactions.

The provisions of this Section III.1.10.7 do not apply to Coordinated External Transactions.

(a) Market Participants that submit an External Transaction in the Day-Ahead Energy Market must also submit a corresponding External Transaction in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market. Priced External Transactions for the Real-Time Energy Market must be submitted by the offer submission deadline for the Day-Ahead Energy Market.

(b) Priced External Transactions submitted in both the Day-Ahead Energy Market and the Real-Time Energy Market will be treated as Self-Scheduled External Transactions in the Real-Time Energy Market for the associated megawatt amounts that cleared the Day-Ahead Energy Market, unless the Market Participant modifies the price component of its Real-Time offer during the Re-Offer Period.

(c) Any External Transaction, or portion thereof, submitted to the Real-Time Energy Market that did not clear in the Day-Ahead Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency. External Transactions cleared in the Day-Ahead Energy Market and associated with a Real-Time Energy Market submission will continue to be scheduled in Real-Time prior to and during an Emergency, until the applicable procedures governing the Emergency, as set forth in ISO New England Manual 11, require a change in schedule.

(d) A Market Participant submitting a priced External Transaction supporting Capacity Supply Obligation to the Real-Time Energy Market on an external interface where advance transmission reservations are required must comply with the requirements in Section III.13.6.1.2.1 with respect to linking the transaction to the associated transmission reservation and NERC E-Tag. All other External Transactions submitted to the Real-Time Energy Market must contain the associated NERC E-Tag and transmission reservation, if required, at the time the transaction is submitted to the Real-Time Energy Market.

(e) [Reserved.]

(f) External Transaction sales meeting all of the criteria for any of the transaction types described in (i) through (iv) below receive priority in the scheduling and curtailment of transactions as set forth in Section II.44 of the OATT. External Transaction sales meeting all of the criteria for any of the transaction types described in (i) through (iv) below are referred to herein and in the OATT as being supported in Real-Time.

(i) Capacity Export Through Import Constrained Zone Transactions:

(1) The External Transaction is exporting across an external interface located in an import-constrained Capacity Zone that cleared in the Forward Capacity Auction with price separation, as determined in accordance with Section III.12.4 and Section III.13.2.3.4 of Market Rule 1;

(2) The External Transaction is directly associated with an Export Bid or Administrative Export De-List Bid that cleared in the Forward Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the cleared Export Bid;

(3) The External Node associated with the cleared Export Bid or Administrative Export De-List Bid is connected to the import-constrained Capacity Zone, and is not connected to a Capacity Zone that is not import-constrained;

(4) The Resource, or portion thereof, that is associated with the cleared Export Bid or Administrative Export De-List Bid is not located in the import-constrained Capacity Zone;

(5) The External Transaction has been submitted and cleared in the Day-Ahead Energy Market;

(6) A matching External Transaction has also been submitted into the Real-Time Energy Market by the end of the Re-Offer Period for Self-Scheduled External Transactions, and, in accordance with Section III.1.10.7(a), by the offer submission deadline for the Day-Ahead Energy Market for priced External Transactions.

(ii) FCA Cleared Export Transactions:

(1) The External Transaction sale is exporting to an External Node that is connected only to an import-constrained Reserve Zone;

(2) The External Transaction sale is directly associated with an Export Bid or an Administrative Export De-List Bid that cleared in the Forward Capacity Auction, and the megawatt amount of the External Transaction is less than or equal to the megawatt amount of the cleared Export Bid;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation associated with the Export Bid or Administrative Export De-List Bid is located outside the import-constrained Reserve Zone;

(4) The External Transaction sale is submitted and cleared in the Day-Ahead Energy Market;

(5) A matching External Transaction has also been submitted into the Real-Time Energy Market by the end of the Re-Offer Period for Self-Scheduled External Transactions, and, in accordance with Section III.1.10.7(a), by the offer submission deadline for the Day-Ahead Energy Market for priced External Transactions.

(iii) Same Reserve Zone Export Transactions:

(1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;

(2) The External Node of the External Transaction sale is connected only to the same Reserve Zone in which the associated Resource, or portion thereof, without a Capacity Supply Obligation is located;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation is Self-Scheduled in the Real-Time Energy Market and online at a megawatt level greater than or equal to the External Transaction sale's megawatt amount;

(4) Neither the External Transaction sale nor the portion of the Resource without a Capacity Supply Obligation is required to offer into the Day-Ahead Energy Market.

(iv) Unconstrained Export Transactions:

(1) A Resource, or portion thereof, without a Capacity Supply Obligation is associated with the External Transaction sale, and the megawatt amount of the External Transaction is less than or equal to the portion of the Resource without a Capacity Supply Obligation;

(2) The External Node of the External Transaction sale is not connected only to an import-constrained Reserve Zone;

(3) The Resource, or portion thereof, without a Capacity Supply Obligation is not separated from the External Node by a transmission interface constraint as determined in Sections III.12.2.1(b) and III.12.2.2(b) of Market Rule 1 that was binding in the Forward Capacity Auction in the direction of the export;

(4) The Resource, or portion thereof, without a Capacity Supply Obligation is Self-Scheduled in the Real-Time Energy Market and online at a megawatt level greater than or equal to the External Transaction sale's megawatt amount;

(5) Neither the External Transaction sale, nor the portion of the Resource without a Capacity Supply Obligation is required to offer into the Day-Ahead Energy Market.

(g) Treatment of External Transaction sales in ISO commitment for local second contingency protection.

(i) Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions: The transaction's export demand that clears in the Day-Ahead Energy Market will be explicitly considered as load in the exporting Reserve Zone by the ISO when committing Resources to provide local second contingency protection for the associated Operating Day.

(ii) The export demand of External Transaction sales not meeting the criteria in (i) above is not considered by the ISO when planning and committing Resources to provide local second contingency protection, and is assumed to be zero.

(iii) Same Reserve Zone Export Transactions and Unconstrained Export Transactions: If a Resource, or portion thereof, without a Capacity Supply Obligation is committed to be online during the Operating Day either through clearing in the Day-Ahead Energy Market or through Self-Scheduling subsequent to the Day-Ahead Energy Market and a Same Reserve Zone Export Transaction or Unconstrained Export Transaction is submitted before the end of the Re-Offer Period designating that Resource as supporting the transaction, the ISO will not utilize the portion of the Resource without a Capacity Supply Obligation supporting the export transaction to meet local second contingency protection requirements. The eligibility of Resources not meeting the foregoing criteria to be used to meet local second contingency protection requirements shall be in accordance with the relevant provisions of the ISO New England System Rules.

(h) Allocation of costs to Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions: Market Participants with Capacity Export Through Import Constrained Zone Transactions and FCA Cleared Export Transactions shall incur a proportional share of the charges described below, which are allocated to Market Participants based on Day-Ahead Load Obligation or Real-Time Load Obligation. The share shall be determined by including the Day-Ahead Load Obligation or Real-Time Load Obligation associated with the External Transaction, as applicable, in the total Day-Ahead Load Obligation or Real-Time Load Obligation for the appropriate Reliability Region, Reserve Zone, or Load Zone used in each cost allocation calculation:

(i) NCPC for Local Second Contingency Protection Resources allocated within the exporting Reliability Region, pursuant to Section III.F.3.3.

(ii) Forward Reserve Market charges allocated within the exporting Load Zone, pursuant to Section III.9.9.

(iii) Real-Time Reserve Charges allocated within the exporting Load Zone, pursuant to Section III.10.3.

(i) When action is taken by the ISO to reduce External Transaction sales due to a system wide capacity deficient condition or the forecast of such a condition, and an External Transaction sale designates a Resource, or portion of a Resource, without a Capacity Supply Obligation, to support the transaction, the ISO will review the status of the designated Resource. If the designated Resource is Self-Scheduled and online at a megawatt level greater than or equal to the External Transaction sale, that External Transaction sale will not be reduced until such time as Regional Network Load within the New England Control Area is also being reduced. When reductions to such transactions are required, the affected transactions shall be reduced pro-rata.

(j) Market Participants shall submit External Transactions as megawatt blocks with intervals of one hour at the relevant External Node. External Transactions will be scheduled in the Day-Ahead Energy Market as megawatt blocks for hourly durations. The ISO may dispatch External Transactions in the Real-Time Energy Market as megawatt blocks for periods of less than one hour, to the extent allowed pursuant to inter-Control Area operating protocols.

III.1.10.7.A Coordinated External Transactions.

The provisions of this Section III.1.10.7.A apply to Coordinated External Transactions, which are implemented at the New York Northern AC external Location.

(a) Market Participants that submit a Coordinated External Transaction in the Day-Ahead Energy Market must also submit a corresponding Coordinated External Transaction, in the form of an Interface Bid, in the Real-Time Energy Market in order to be eligible for scheduling in the Real-Time Energy Market.

(b) An Interface Bid submitted in the Real-Time Energy Market shall specify a duration consisting of one or more consecutive 15-minute increments. An Interface Bid shall include a bid price, a bid quantity, and a bid direction for each 15-minute increment. The bid price may be positive or negative. An Interface Bid may not be submitted or modified later than 75 minutes before the start of the clock hour for which it is offered.

(c) Interface Bids are cleared in economic merit order for each 15minute increment, based upon the forecasted real-time price difference across the external interface. The total quantity of Interface Bids cleared shall determine the external interface schedule between New England and the adjacent Control Area. The total quantity of Interface Bids cleared shall depend upon, among other factors, bid production

costs of resources in both Control Areas, the Interface Bids of all Market Participants, transmission system conditions, and any real-time operating limits necessary to ensure reliable operation of the transmission system.

(d) All Coordinated External Transactions submitted either to the Day-Ahead Energy Market or the Real-Time Energy Market must contain the associated NERC E-Tag at the time the transaction is submitted.

(e) Any Coordinated External Transaction, or portion thereof, submitted to the Real-Time Energy Market will not be scheduled in Real-Time if the ISO anticipates that the External Transaction would create or worsen an Emergency, unless applicable procedures governing the Emergency permit the transaction to be scheduled.

III.1.10.7.B Coordinated Transactions Scheduling Threshold Trigger to Tie Optimization

(a) Background and Overview

This Section III.1.10.B describes the process for filing amendments to the Transmission, Markets and Services Tariff under Section 205 of the Federal Power Act in the event that the production cost savings of the ISO's interchange on the New York – New England AC Interface, including the Northport/Norwalk Line, following the implementation of an inter-regional interchange scheduling process known as Coordinated Transaction Scheduling, are not satisfactory. The determination of whether savings are satisfactory will be based on actions, thresholds and triggers described in this Section III.1.10.7.B. If pursuant to the actions, thresholds and triggers described in this Section III.1.10.7.B, the production costs savings of Coordinated Transaction Scheduling are not satisfactory, and a superior alternative has not become known, the ISO will file tariff amendments with the Commission to implement the inter-regional interchange scheduling process described to the ISO stakeholders in 2011 as Tie Optimization.

If, pursuant to the timetables presented, the ISO determines the thresholds described herein have not triggered, the process for filing amendments to the ISO tariff as described herein ceases, the provisions of this Section III.1.10.7.B become null and void and the ISO will continue to implement Coordinated

Transaction Scheduling unless and until future Section 205 filings are pursued to amend Coordinated Transaction Scheduling.

(b) The Two-Year Analysis

Within 120 days of the close of the first and second years following the date that Coordinated Transaction Scheduling as an interface scheduling tool is activated in the New England and New York wholesale electricity markets, the External Market Monitor will develop, for presentation to and comment by, New England stakeholders, an analysis, of:

(i) the Tie Optimization interchange, which will be the actual bid production cost savings of incremental interchange that would have occurred had the ISO and New York Independent System Operator received an infinite number of zero bids in the Coordinated Transaction Scheduling process, which utilizes the supply curves and forecasted prices for each market; and

(ii) an optimal interchange, which will be the actual bid production cost savings of incremental interchange that would have occurred had the two ISOs had an infinite number of zero bids in the Coordinated Transaction Scheduling process, but utilizing actual real-time prices from each market rather than the forecasted prices that were used in the Coordinated Transaction Scheduling process.

The bid production cost savings associated with the Tie Optimization interchange as developed in (i) above for the second year following the date that Coordinated Transaction Scheduling is activated in the New England and New York wholesale electricity markets will reveal the "foregone" production cost savings from implementing Coordinated Transaction Scheduling rather than Tie Optimization, represented in the Section III.1.10.7.B(b)(1) formula as the term "b." The difference in bid production cost savings between (i) and (ii) above will reveal the "foregone" bid production cost savings of the Tie Optimization interchange as developed in (i) above rather than an optimal interchange as developed in (ii) above, represented in the Section III.1.10.7.B(b)(1) formula as the term "a."

This analysis will be consistent with presentations made by the External Market Monitor to the New England stakeholders during 2011 on the issue of the benefits of Coordinated Transaction Scheduling.

(1) Using the above calculations, the External Market Monitor will compute the following ratio:

b/a

If, the ratio b/a is greater than 60% and b is greater than $3 Million, the External Market Monitor will advise whether in its opinion the threshold has triggered.

(c) Improving Coordinated Transaction Scheduling

(1) If the ratio, developed pursuant to Section III.1..10.7.B(b)(1), is greater than 60% and b is greater than $3 Million, the ISO will declare whether the threshold has triggered considering the input of the External Market Monitor and the New England stakeholders.

(2) If the ISO declares the threshold has not triggered the process further described in this Section III.1.10.7.B becomes null and void.

(3) If the ISO declares that the threshold has triggered, the External Market Monitor will provide recommendations of adjustments to the design or operation of Coordinated Transaction Scheduling to improve the production cost savings available from its implementation.

(4) The ISO, considering the input of the New England stakeholders and the recommendation of the External Market Monitor, will develop and implement adjustments to Coordinated Transaction Scheduling. To the extent tariff revisions are necessary to implement the adjustments to Coordinated Transaction Scheduling, the ISO will file such revisions with the Commission as a compliance filing in the Coordinated Transaction Scheduling docket. If no adjustments to Coordinated Transaction Scheduling have been identified, the ISO will proceed to develop and file the revisions necessary to amend the Transmission, Markets and Services Tariff to implement the inter-regional interchange scheduling practice known as Tie Optimization as a compliance filing.

(d) The Second Analysis

(1) Within 120 days of the close of the twelve months following the date that the adjustments to Coordinated Transaction Scheduling, developed under Section III.1.10.7.B(c), are activated in the New England and New York wholesale electricity markets, the External Market Monitor will present a second analysis to New England stakeholders. The analysis will be consistent with the analysis described in Section III.1.10.7.B(b) but will develop bid production cost savings for the twelve month period during which the adjustments developed in Section III.1.10.7.B(c) are in place.

(2) The bid production cost savings associated with the Tie Optimization interchange as developed in Section III.1.10.7.B(d)(1) will reveal the "foregone" bid production cost savings from implementing Coordinated Transaction Scheduling rather than Tie Optimization, represented in the Section III.1.10.7.B(d)(3) formula as the term "b." The different in bid production cost savings between the Tie Optimization interchange and the optimal interchange, as developed in Section III.1.10.7.B(d)(1), will reveal the "foregone" bid production cost savings of the Tie Optimization interchange rather than the optimal interchange, represented in the Section III.1.10.7.B(d)(3) formula as the term "a."

(3) Using the above calculations, the External Market Monitor will compute the following ratio:

b/a

If the ratio b/a is greater than 60% and b is greater than $3 Million, the External Market Monitor will advise whether in its opinion the threshold has triggered.

(4) If the ratio b/a is greater than 60% and b is greater than $3 Million, the ISO will declare whether the threshold has triggered considering the input of the External Market Monitor and the New England stakeholders.

(5) If the ISO declares the threshold has not triggered the process further described in this Section III.1.10.7.B becomes null and void.

(6) If the ISO declares the threshold has triggered, considering the input of the stakeholders and the recommendation of the External Market Monitor, the ISO will determine whether a superior alternative has been proposed. If the ISO and the New York Independent System Operator both determine a superior alternative has been proposed, the ISO will prepare tariff amendments to be filed with the Commission to implement the superior alternative, and will present those amendments to the New England stakeholders in accordance with the provisions of the Participants Agreement applicable for NEPOOL review of tariff amendments and will not pursue the balance of the actions required by this Section III.1.10.7.B.

(7) If the ISO determines a superior alternative has not been proposed, the ISO will proceed to develop and file the revisions necessary to amend the Transmission, Markets and Services Tariff to implement the inter-regional interchange scheduling practice known as Tie Optimization as a compliance filing. Tie Optimization was described for stakeholders in the *Design Basis Document* for NE/NY Inter-Regional Interchange Scheduling presented at a NEPOOL Participants Committee meeting on June 10, 2011.

(e) The Compliance Filing

The ISO will develop tariff language to implement the inter-regional interchange scheduling practice known as Tie Optimization through a compliance filing with the Commission and will present those amendments to the New England stakeholders in accordance with the provisions of the Participants Agreement applicable for NEPOOL review of tariff amendments.

III.1.10.8 ISO Responsibilities.

(a) The ISO shall use its best efforts to determine (i) the least-cost means of satisfying hourly purchase requests for energy, the projected hourly requirements for Operating Reserve, Replacement Reserve and other ancillary services of the Market Participants, including the reliability requirements of the New England Control Area, of the Day-Ahead Energy Market, and (ii) the least-cost means of satisfying the Operating Reserve, Replacement Reserve and other ancillary service requirements for any portion of the load forecast of the ISO for the Operating Day in excess of that scheduled in the Day-Ahead Energy Market. In making these determinations, the ISO shall take into account: (i) the ISO's forecasts of New England Markets and New England Control Area energy requirements, giving due consideration to the energy requirement forecasts and purchase requests submitted by Market Participants for the Day-Ahead Energy Market; (ii) the offers and bids submitted by Market Participants; (iii) the availability of Limited Energy Resources; (iv) the capacity, location, and other relevant characteristics of Self-Scheduled Resources; (v) the requirements of the New England Control Area for Operating Reserve and Replacement Reserve, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; (vi) the requirements of the New England Control Area for Regulation and other ancillary services, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; (vii) the benefits of avoiding or minimizing transmission constraint control operations, as specified in the ISO New England Manuals and ISO New England Administrative Procedures; and (viii) such other factors as the ISO reasonably concludes are relevant to the foregoing

determination. The ISO shall develop a Day-Ahead Energy schedule based on the applicable portions of the foregoing determination, and shall determine the Day-Ahead Prices resulting from such schedule.

(b) Not later than 1:30 p.m. of the day before each Operating Day, or such earlier deadline as may be specified by the ISO in the ISO New England Manuals and ISO New England Administrative Procedures or such later deadline as necessary to account for software failures or other events, the ISO shall: (i) post the aggregate Day-Ahead Energy schedule; (ii) post the Day-Ahead Prices; and (iii) inform the Market Participants of their scheduled injections and withdrawals. In the event of an Emergency, the ISO will notify Market Participants as soon as practicable if the Day-Ahead Energy Market can not be operated.

(c) Following posting of the information specified in Section III.1.10.8(b), the ISO shall revise its schedule of Resources to reflect updated projections of load, conditions affecting electric system operations in the New England Control Area, the availability of and constraints on limited energy and other Resources, transmission constraints, and other relevant factors.

(d) Market Participants shall pay and be paid for the quantities of energy scheduled in the Day-Ahead Energy Market at the Day-Ahead Prices.

III.1.10.9 Hourly Scheduling.

(a) Following the initial posting by the ISO of the Locational Marginal Prices resulting from the Day-Ahead Energy Market, and subject to the right of the ISO to schedule and dispatch Pool-Scheduled Resources and to direct that schedules be changed in an Emergency, a Resource Re-Offer Period shall exist from the time of the posting specified in Section III.1.10.8(b) until 2:00 p.m. on the day before each Operating Day or such other Re-Offer Period as necessary to account for software failures or other events. During the Re-Offer Period, Market Participants may submit revisions to generation Supply Offers and revisions to Demand Bids for any Dispatchable Asset Related Demand Resource. Resources scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices.

(b) Following the completion of the initial Reserve Adequacy Analysis and throughout the Operating Day, a Market Participant may modify certain Supply Offer or Demand Bid parameters for a Generator Asset or a Dispatchable Asset Related Demand on an hour-to-hour basis, provided that the modification is

made no later than 30 minutes prior to the beginning of the hour for which the modification is to take effect:

(i) For a Generator Asset, the Start-Up Fee, the No-Load Fee, the fuel type (for dual fuel Resources), the quantity and price pairs of its Blocks, and the Supply Offer for Regulation may be modified.

(ii) For a Dispatchable Asset Related Demand, the quantity and price pairs of its Blocks may be modified.

(c) During the Re-Offer Period, Market Participants may submit revisions to priced External Transactions. External Transactions scheduled subsequent to the closing of the Re-Offer Period shall be settled at the applicable Real-Time Prices, and shall not affect the obligation to pay or receive payment for the quantities of energy scheduled in the Day-Ahead Energy Market at the applicable Day-Ahead Prices. A submission during the Re-Offer Period for any portion of a transaction that was cleared in the Day-Ahead Energy Market is subject to the provisions in Section III.1.10.7. A Market Participant may at any time, consistent with the provisions in Manual 11, request to Self-Schedule an External Transaction and adjust the schedule on an hour-to-hour basis. The ISO must be notified of the request not later than 60 minutes prior to the hour in which the adjustment is to take effect. The External Transaction re-offer provisions of this Section III.1.10.9(c) shall not apply to Coordinated External Transactions, which are submitted pursuant to Section III.1.10.7.A.

(d) During the Operating Day, a Market Participant may request to Self-Schedule a Generator Asset or Dispatchable Asset Related Demand or may request to cancel a Self-Schedule for a Generator Asset or Dispatchable Asset Related Demand. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor a Self-Schedule request, a Generator Asset will be permitted to come online at its Economic Minimum Limit and a Dispatchable Asset Related Demand will be dispatched to its Minimum Consumption Limit.

(e) During the Operating Day, in the event that in a given hour a Market Participant seeks to modify a Supply Offer or Demand Bid after the deadline for modifications specified in Section III.1.10.9(b), then:

(i) the Market Participant may request that a Generator Asset be dispatched above its Economic Minimum Limit at a specified output. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor the request, the Generator Asset will

be dispatched as though it had offered the specified output for the hour in question at the Energy Offer Floor.

(ii) the Market Participant may request that a Dispatchable Asset Related Demand be dispatched above its Minimum Consumption Limit. The ISO will honor the request so long as it will not cause or worsen a reliability constraint. If the ISO is able to honor the request, the Dispatchable Asset Related Demand will be dispatched as though it had offered for the hour in question at a Self-Scheduled MW.

(f) For each hour in the Operating Day, as soon as practicable after the deadlines specified in the foregoing subsection of this Section III.1.10, the ISO shall provide Market Participants and parties to External Transactions with any revisions to their schedules for the hour.

III.1.11 Dispatch.

The following procedures and principles shall govern the dispatch of the Resources available to the ISO.

III.1.11.1 Resource Output and Demand Reduction.

The ISO shall have the authority to direct any Market Participant to adjust the output or demand reduction of any Pool-Scheduled Resource increment within the operating characteristics specified in the Market Participant's Offer Data, Supply Offer, Demand Reduction Offer or Demand Bid. The ISO may cancel its selection of, or otherwise release, Pool-Scheduled Resources. The ISO shall adjust the output or demand reduction of Pool-Scheduled Resource increments as necessary: (a) to maintain reliability, and subject to that constraint, to minimize the cost of supplying the energy, reserves, and other services required by the Market Participants and the operation of the New England Control Area; (b) to balance load and generation, maintain scheduled tie flows, and provide frequency support within the New England Control Area; and (c) to minimize unscheduled interchange that is not frequency related between the New England Control Area and other Control Areas.

III.1.11.2 Operating Basis.

In carrying out the foregoing objectives, the ISO shall conduct the operation of the New England Control Area and shall, in accordance with the ISO New England Manuals and ISO New England Administrative Procedures, (i) utilize available Operating Reserve and replace such Operating Reserve when utilized; and (ii) monitor the availability of adequate Operating Reserve.

III.1.11.3 Pool-dispatched Resources.

(a) The ISO shall optimize the dispatch of energy from Limited Energy Resources by request to minimize the as-bid production cost for the New England Control Area. In implementing the use of Limited Energy Resources, the ISO shall use its best efforts to select the most economic hours of operation for Limited Energy Resources, in order to make optimal use of such Resources consistent with the dynamic load-following requirements of the New England Control Area and the availability of other Resources to the ISO.

(b) The ISO shall implement the dispatch of energy from Pool-Scheduled Resource increments and the designation of Real-Time Operating Reserve to Pool-Scheduled Resource increments, including the dispatchable increments from resources which are otherwise Self-Scheduled, by sending appropriate signals and instructions to the entity controlling such Resources, in accordance with the ISO New England Manuals and ISO New England Administrative Procedures. Each Market Participant shall ensure that the entity controlling a Pool-Scheduled Resource offered or made available by that Market Participant complies with the energy dispatch signals and instructions transmitted by the ISO.

(c) The ISO shall have the authority to modify a Market Participant's operational related Offer Data if the ISO observes that the Market Participant's Resource is not operating in accordance with such Offer Data. The ISO shall modify such operational related Offer Data based on observed performance and such modified Offer Data shall remain in effect until either (i) the affected Market Participant requests a test to be performed, and coordinates the testing pursuant to the procedures specified in the ISO New England Manuals, and the results of the test justify a change to the Market Participant's Offer Data or (ii) the ISO observes, through actual performance, that modification to the Market Participant's Offer Data is justified.

(d) Market Participants shall exert all reasonable efforts to operate, or ensure the operation of, their Resources in the New England Control Area as close to dispatched output or demand reduction levels as practical, consistent with Good Utility Practice.

(e) Wind resources are treated as not economically dispatchable until the ISO is technically capable of determining and telemetering a Do Not Exceed Dispatch Point to the resource.

(f) The ISO may request that dual-fueled generating Resources that normally burn natural gas voluntarily take all necessary steps (within the limitations imposed by the operating limitations of their

installed equipment and their environmental and operating permits) to prepare to switch to secondary fuel in anticipation of natural gas supply shortages. The ISO may request that Market Participants with dual-fueled units that normally burn natural gas voluntarily switch to a secondary fuel in anticipation of natural gas supply shortages. The ISO may communicate with Market Participants with dual-fueled units that normally burn natural gas to verify whether the Market Participants have switched or are planning to switch to an alternate fuel.

III.1.11.4 Emergency Condition.

If the ISO anticipates or declares an Emergency Condition, all External Transaction sales out of the New England Control Area that are not backed by a Resource may be interrupted, in accordance with the ISO New England Manuals, in order to serve load and Operating Reserve in the New England Control Area.

III.1.11.5 [Reserved.]

(a)

III.1.11.6 [Reserved]

III.1.12 Dynamic Scheduling.

Dynamic scheduling can be requested and may be implemented in accordance with the following procedures:

(a) An entity that owns or controls a generating Resource in the New England Control Area may electrically remove all or part of the generating Resource's output from the New England Control Area through dynamic scheduling of the output to load outside the New England Control Area. Such output shall not be available for economic dispatch by the ISO.

(b) An entity that owns or controls a generating Resource outside of the New England Control Area may electrically include all or part of the generating Resource's output into the New England Control Area through dynamic scheduling of the output to load inside the New England Control Area. Such output shall be available for economic dispatch by the ISO.

(c) An entity requesting dynamic scheduling shall be responsible for arranging for the provision of signal processing and communication from the generating unit and other participating Control Area and complying with any other procedures established by the ISO regarding dynamic scheduling as set forth in

the ISO New England Manuals. Allocation of costs associated with dynamic scheduling shall be determined and filed with the Commission following the first request.

(d) An entity requesting dynamic scheduling shall be responsible for reserving amounts of appropriate transmission service necessary to deliver the range of the dynamic transfer and any ancillary services.

III.2 LMPs and Real-Time Reserve Clearing Prices Calculation

III.2.1 Introduction.

The ISO shall calculate the price of energy at Nodes, Load Zones and Hubs in the New England Control Area and at External Nodes on the basis of Locational Marginal Prices and shall calculate the price of Operating Reserve in Real-Time for each Reserve Zone on the basis of Real-Time Reserve Clearing Prices as determined in accordance with this Market Rule 1. Locational Marginal Prices for energy shall be calculated on a Day-Ahead basis for each hour of the Day-Ahead Energy Market, and every five minutes during the Operating Day for the Real-Time Energy Market. Real-Time Reserve Clearing Prices shall be calculated on a Real-Time basis every five minutes as part of the joint optimization of energy and Operating Reserve during the Operating Day.

III.2.2 General.

The ISO shall determine the least cost security-constrained unit commitment and dispatch, which is the least costly means of serving load at different Locations in the New England Control Area based on scheduled or actual conditions, as applicable, existing on the power grid and on the prices at which Market Participants have offered to supply and consume energy in the New England Markets. Day-Ahead Locational Marginal Prices for energy for the applicable Locations will be calculated based on the unit commitment and economic dispatch and the prices of energy offers and bids. Real-Time Locational Marginal Prices for energy and Real-Time Reserve Clearing Prices will be calculated based on a jointly optimized economic dispatch of energy and designation of Operating Reserve utilizing the prices of energy offers and bids, and Reserve Constraint Penalty Factors when applicable.

Except as further provided in Section III.2.6, the process for the determination of Locational Marginal Prices shall be as follows:

(a) To determine operating conditions, in the Day-Ahead Energy Market or Real-Time Energy Market, on the New England Transmission System, the ISO shall use a computer model of the interconnected grid that uses scheduled quantities or available metered inputs regarding generator output, loads, and power flows to model remaining flows and conditions, producing a consistent representation of power flows on the network. The computer model employed for this purpose in the Real-Time Energy Market, referred to as the State Estimator program, is a standard industry tool and is described in Section III.2.3. It will be used to obtain information regarding the output of generation supplying energy and Operating Reserve to the New England Control Area, loads at busses in the New England Control Area,

transmission losses, penalty factors, and power flows on binding transmission and interface constraints for use in the calculation of Day-Ahead and Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices. Additional information used in the calculation of Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, including Dispatch Rates, Real-Time Operating Reserve designations and Real-Time schedules for External Transactions, will be obtained from the ISO's dispatch software and dispatchers.

(b) Using the prices at which Market Participants offer and bid energy to the New England Markets, the ISO shall determine the offers and bids of energy that will be considered in the calculation of Day-Ahead Prices, Real-Time Prices and Real-Time Reserve Clearing Prices. During the Operating Day, Real-Time nodal Locational Marginal Prices and Real-Time Reserve Clearing Prices shall be determined every five minutes and integrated hourly values of such determinations shall be the basis of the settlement of sales and purchases of energy in the Real-Time Energy Market, the settlement associated with the provision of Operating Reserve in Real-Time and the settlement of Congestion Costs and costs for losses under the Transmission, Markets and Services Tariff not covered by the Day-Ahead Energy Market. As described in Section III.2.6, every offer and bid by a Market Participant that is scheduled in the Day-Ahead Energy Market will be utilized in the calculation of Day-Ahead Locational Marginal Prices.

III.2.3 Determination of System Conditions Using the State Estimator.

Power system operations, including, but not limited to, the determination of the least costly means of serving load and system and locational Real-Time Operating Reserve requirements, depend upon the availability of a complete and consistent representation of generator outputs, loads, and power flows on the network. In calculating Day-Ahead Prices, the ISO shall base the system conditions on the expected transmission system configuration and the set of offers and bids submitted by Market Participants. In calculating Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall obtain a complete and consistent description of conditions on the electric network in the New England Control Area by using the power flow solution produced by the State Estimator for the pricing interval, which is also used by the ISO for other functions within power system operations. The State Estimator is a standard industry tool that produces a power flow model based on available Real-Time metering information, information regarding the current status of lines, generators, transformers, and other equipment, bus load distribution factors, and a representation of the electric network, to provide a complete description of system conditions, including conditions at Nodes and External Nodes for which Real-Time information is unavailable. In calculating Real-Time Locational Marginal Prices and Real-Time Reserve Clearing Prices, the ISO shall obtain a State Estimator solution every five minutes, which

shall provide the megawatt output of generators and the loads at Locations in the New England Control Area, transmission line losses, penalty factors, and actual flows or loadings on constrained transmission facilities. External Transactions between the New England Control Area and other Control Areas shall be included in the Real-Time Locational Marginal Price calculation on the basis of the Real-Time transaction schedules implemented by the ISO's dispatcher.

III.2.4 [Reserved.].

III.2.5 Calculation of Nodal Real-Time Prices.

(a) The ISO shall determine the least costly means of obtaining energy to serve the next increment of load at each Node internal to the New England Control Area represented in the State Estimator and each External Node Location between the New England Control Area and an adjacent Control Area, based on the system conditions described by the power flow solution produced by the State Estimator for the pricing interval. This calculation shall be made by applying an optimization method to minimize energy cost, given actual system conditions, a set of energy offers and bids, and any binding transmission and Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from all available generating Resources, Demand Response Resources, External Transaction purchases submitted under Section III.1.10.7 and Dispatchable Asset Related Demand Resources with an eligible energy offer as the sum of: (1) the price at which the Market Participant has offered to supply an additional increment of energy from the Resource; (2) the effect on Congestion Costs (whether positive or negative) associated with increasing the output of the Resource or reducing consumption of the Resource, based on the effect of increased generation from that Resource or reduced consumption from that Resource on transmission line loadings; and (3) the effect on Congestion Costs (whether positive or negative) associated with increasing the Operating Reserve requirement, based on the effect of Resource re-dispatch on transmission line loadings; (4) the effect on Congestion Costs (whether positive or negative) associated with a deficiency in Operating Reserve, based on the effect of the Reserve Constraint Penalty Factors described under Section III.2.8; and (5) the effect on transmission losses caused by the increment of load, generation and demand reduction. The energy offer or offers and energy bid or bids that can jointly serve an increment of load and an increment of Operating Reserve requirement at a Location at the lowest cost, calculated in this manner, shall determine the Real-Time Price at that Node or External Node. For an external interface for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented, the Real-Time Price at the External Node shall be further adjusted to include the effect on Congestion Costs (whether positive

or negative) associated with a binding constraint limiting the external interface schedule, as determined when the interface is scheduled.

(b) During the Operating Day, the calculation set forth in this Section III.2.5 shall be performed every five minutes, using the ISO's Locational Marginal Price program, producing a set of nodal Real-Time Prices based on system conditions for the pricing interval. The prices produced at five-minute intervals during an hour will be integrated to determine the nodal Real-Time Prices for that hour.

(c) For any interval during any hour in the Operating Day that the ISO has declared a Minimum Generation Emergency, the affected nodal Real-Time Prices calculated under this Section III.2.5. shall be set equal to the Energy Offer Floor for all Nodes within the New England Control Area and all External Nodes if the Minimum Generation Emergency was declared on a New England Control Area wide basis or shall be set equal to the Energy Offer Floor for all Nodes and External Nodes within a sub-region if the Minimum Generation Emergency was declared within the sub-region.

III.2.6 Calculation of Nodal Day-Ahead Prices.

(a) For the Day-Ahead Energy Market, Day-Ahead Prices shall be determined on the basis of the least-cost, security-constrained unit commitment and dispatch, model flows and system conditions resulting from the load specifications submitted by Market Participants, Supply Offers, Demand Reduction Offers and Demand Bids for Resources, Increment Offers, Decrement Bids, and External Transactions submitted to the ISO and scheduled in the Day-Ahead Energy Market.

Such prices shall be determined in accordance with the provisions of this Section applicable to the Day-Ahead Energy Market and shall be the basis for the settlement of purchases and sales of energy, costs for losses and Congestion Costs resulting from the Day-Ahead Energy Market. This calculation shall be made for each hour in the Day-Ahead Energy Market by applying an optimization method to minimize energy cost, given scheduled system conditions, scheduled transmission outages, and any transmission limitations that may exist. In performing this calculation, the ISO shall calculate the cost of serving an increment of load at each Node and External Node from each Resource associated with an eligible energy offer or bid as the sum of: (1) the price at which the Market Participant has offered to supply an additional increment of energy from the Resource or reduce consumption from the Resource; (2) the effect on transmission Congestion Costs (whether positive or negative) associated with increasing the output of the Resource or reducing consumption of the Resource, based on the effect of increased generation from that Resource or reduced consumption from a Resource on transmission line loadings; and (3) the effect on

transmission losses caused by the increment of load and generation. The energy offer or offers and energy bid or bids that can serve an increment of load at a Node or External Node at the lowest cost, calculated in this manner, shall determine the Day-Ahead Price at that Node.

For External Nodes for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented, the clearing process specified in the previous two paragraphs shall apply. For all other External Nodes, the following process shall apply: in addition to determining the quantity cleared via the application of transmission constraints (i.e., limits on the flow over a line or set of lines), the quantity cleared is limited via the application of a nodal constraint (i.e., a limit on the total net injections at a Node) that restricts the net amount of cleared transactions to the transfer capability of the external interface. Clearing prices at all Nodes will reflect the marginal cost of serving the next increment of load at that Node while reflecting transmission constraints. A binding nodal constraint will result in interface limits being followed, but will not directly affect the congestion component of an LMP at an External Node.

(b) Energy deficient conditions. If the sum of Day-Ahead fixed Demand Bids and fixed External Transaction sales cannot be satisfied with the sum of all scheduled External Transaction purchases, cleared Increment Offers, and available generation at its Economic Maximum Limit and demand reduction at the Demand Response Resource's Maximum Reduction, the technical software issues an Emergency Condition warning message due to a shortage of economic supply in the Day-Ahead Energy Market. The following steps shall then be performed to achieve power balance:

(i) All fixed External Transaction sales are considered to be dispatchable at the Energy Offer Cap;

(ii) Reduce any remaining price-sensitive Demand Bids (including External Transaction sales) and Decrement Bids from lowest price to highest price to zero MW until power balance is achieved (there may be some price sensitive bids that are higher priced than the highest Supply Offer or Increment Offer price cleared). Set LMP values equal to the highest price-sensitive Demand Bid or Decrement Bid that was cut in this step. If no price-sensitive Demand Bid or Decrement Bid was reduced in this step, the LMP values are set equal to highest offer price of all on-line generation, dispatched Demand Response Resources, Increment Offers or External Transaction purchases; and

(iii) If power balance is not achieved after step (ii), reduce all remaining fixed Demand Bids proportionately (by ratio of load MW) until balance is achieved. Set LMP values equal to the highest offer price of all on-line generation, dispatched Demand Response Resources, Increment Offers or External Transaction purchases or the price from step (ii), whichever is higher.

(c) Excess energy conditions. If the sum of Day-Ahead cleared Demand Bids, Decrement Bids and External Transaction sales is less than the total system wide generation MW (including fixed External Transaction purchases) with all possible generation off and with all remaining generation at their Economic Minimum Limit, the technical software issues a Minimum Generation Emergency warning message due to an excess of economic generation in the Day-Ahead Energy Market. The following steps shall then be performed to achieve power balance:

(i) All fixed External Transaction purchases are considered to be dispatchable at the Energy Offer Floor and reduced pro-rata, as applicable, until power balance is reached;

(ii) If power balance is not reached in step (i), reduce all committed generation down proportionately by ratio of Economic Minimum Limits but not below Emergency Minimum Limits. If power balance is achieved prior to reaching Emergency Minimum Limits, set LMP values equal to the lowest offer price of all on-line generation; and

(iii) If power balance not achieved in step (ii), set LMP values to Energy Offer Floor and reduce all committed generation below Emergency Minimum Limits proportionately (by ratio of Emergency Minimum Limits) to achieve power balance.

III.2.7 Reliability Regions, Load Zones, Reserve Zones, Zonal Prices and External Nodes.

(a) The ISO shall calculate Zonal Prices for each Load Zone for both the Day-Ahead Energy Market and Real-Time Energy Markets for each hour using a load-weighted average of the Locational Marginal Prices for the Nodes within that Load Zone. The load weights used in calculating the Day-Ahead Zonal Prices for the Load Zone shall be determined in accordance with applicable Market Rule 1 provisions and shall be based on historical load usage patterns. The load weights do not reflect Demand Bids or Decrement Bids that settle at the Node level in the Day-Ahead Energy Market. The ISO shall determine, in accordance with applicable ISO New England Manuals, the load weights used in Real-Time based on

the actual Real-Time load distribution as calculated by the State Estimator, and shall exclude any Asset Related Demand from the load weights used to calculate the applicable Real-Time Zonal Prices.

(b) Each Load Zone shall initially be approximately coterminous with a Reliability Region.

(c) Reserve Zones shall be established by the ISO which represent areas within the New England Transmission System that require local 30 minute contingency response as part of normal system operations in order to satisfy local 2nd contingency response reliability criteria.

(d) The remaining area within the New England Transmission System that is not included within the Reserve Zones established under Section III.2.7(c) is Rest of System.

(e) Each Reserve Zone shall be completely contained within a Load Zone or shall be defined as a subset of the Nodes contained within a Load Zone.

(f) The ISO shall calculate Forward Reserve Clearing Prices and Real-Time Reserve Clearing Prices for each Reserve Zone.

(g) After consulting with the Market Participants, the ISO may reconfigure Reliability Regions, Load Zones and Reserve Zones and add or subtract Reliability Regions, Load Zones and Reserve Zones as necessary over time to reflect changes to the grid, patterns of usage, changes in local TMOR contingency response requirements and intrazonal Congestion. The ISO shall file any such changes with the Commission.

(h) In the event the ISO makes changes to a Reliability Region or Load Zone or adds or subtracts Reliability Regions and Load Zones, for settlement purposes and to the extent practicable, Load Assets that are physically located in one Reliability Region and electrically located within another Reliability Region shall be located within the Reliability Region to which they are electrically located.

(i) External Nodes are the nodes at which External Transactions settle. As appropriate and after consulting with Market Participants, the ISO will establish and re-configure External Nodes taking into consideration appropriate factors, which may include: tie line operational matters, FTR modeling and auction assumptions, market power issues associated with external contractual arrangements, impacts on Locational Marginal Prices, and inter-regional trading impacts.

(j) On or about the 20th calendar day of each month, the ISO shall publish the Real-Time nodal load weights (expressed in MW) used to calculate the load-weighted Real-Time Zonal Prices for the preceding month. Nodal load weights will be published for all nodes used in the calculations except for those nodes identified by customers as nodes for which publication would provide individual customer usage data. Any individual customer whose usage data would be revealed by publication of load weight information associated with a specific Node must submit a written request to the ISO to omit the applicable Node from the publication requirement. The request must identify the affected Node and, to the best of the customer's knowledge, the number of customers taking service at the affected Node and the estimated percentage of the total annual load (MWh) at the affected Node period that is attributable to the customer. The information contained in the request must be certified in writing by an officer of the customer's company (if applicable), by an affidavit signed by a person having knowledge of the applicable facts, or by representation of counsel for the customer. The ISO will grant a customer request if it determines based on the information provided that no more than two customers are taking service at the affected Node or that the percentage of the customer's annual load (MWh) at the affected Node. If a customer request is granted and that customer request is the only such customer request within a Load Zone, then the ISO shall randomly select one other Node and not disclose hourly load information for the randomly selected Node unless and until another customer request within the Load Zone is granted. A request to suspend publication for a month must be received by the ISO on or before the 10th calendar day of the following month in order to be effective for that month. Upon receipt of a request, the ISO will suspend publication of the load weight data for the specified Node. The ISO may, from time to time, require customer confirmation that continued omission from publication of load weight data for a particular Node is required in order to avoid disclosure of individual customer usage data. If customer confirmation is not received within a reasonable period not to exceed 30 days, the ISO may publish load weight data for the applicable Node.

III.2.7A Calculation of Real-Time Reserve Clearing Prices.

(a) The ISO shall determine the least costly means of obtaining Operating Reserve in Real-Time to serve the next increment of Operating Reserve requirement for each Reserve Zone on a jointly optimized basis with the calculation of nodal Real-Time Prices specified under Section III.2.5, based on the system conditions described by the power flow solution produced by the State Estimator program for the pricing interval. This calculation shall be made by applying an optimization method to minimize energy cost, given actual system conditions, a set of energy offers and bids, and any binding transmission constraints, including binding transmission interface constraints associated with meeting Operating Reserve

requirements, and binding Operating Reserve constraints that may exist. In performing this calculation, the ISO shall calculate, on a jointly optimized basis with serving an increment of load at each Node and External Node, the cost of serving an increment of Operating Reserve requirement for the system and each Reserve Zone from all available generating Resources, Demand Response Resources and Dispatchable Asset Related Demand Resources with an eligible energy offer or bid. Real-Time Reserve Clearing Prices will be equal to zero unless system re-dispatch is required in order to create additional TMSR to meet the system TMSR requirement; or system re-dispatch is required in order to make additional TMOR available to meet a local TMOR requirement; or system re-dispatch is required to make additional TMNSR or TMOR available to meet system TMNSR or TMOR requirements; or there is a deficiency in available Operating Reserve, in which case, Real-Time Reserve Clearing Prices shall be set based upon the Reserve Constraint Penalty Factors specified in Section III.2.7A(c).

(b) If system re-dispatch is required to maintain sufficient levels of Operating Reserve or local TMOR, the applicable Real-Time Reserve Clearing Price is equal to the highest unit-specific Real-Time Reserve Opportunity Cost associated with all generating Resources, Demand Response Resources and Dispatchable Asset Related Demand Resources that were re-dispatched to meet the applicable Operating Reserve requirement. The Operating Reserve or local TMOR Real-Time Reserve Opportunity Cost of a Resource shall be determined for each Resource that the ISO re-dispatches in order to provide additional Operating Reserve or local TMOR and shall be equal to the difference between (i) the Real-Time Energy LMP at the Location for the generating Resource, Demand Response Resource or Dispatchable Asset Related Demand Resource and (ii) the offer price associated with the re-dispatch of the Resource necessary to create the additional Operating Reserve or local TMOR from the Resource's expected output, consumption, or demand reduction level if it had been dispatched in economic merit order.

(c) If there is insufficient Operating Reserve available to meet the Operating Reserve requirements for the system and/or any Reserve Zone or sufficient Operating Reserve is not available at a redispatch cost equal to or less than that specified by the Reserve Constraint Penalty Factors, the applicable Real-Time Reserve Clearing Prices shall be set based upon Reserve Constraint Penalty Factors. The Reserve Constraint Penalty Factors are inputs into the linear programming algorithm that will be utilized by the linear programming algorithm when Operating Reserve constraints are violated, requiring that the constraints be relaxed to allow the linear programming algorithm to solve. The Real-Time Reserve Clearing Prices shall be set based upon the following Reserve Constraint Penalty Factor values:

Requirement	Requirement Sub-Category	RCPF
Local TMOR		$250/MWh
System TMOR	minimum TMOR	$1000/MWh
	Replacement Reserve	$250/MWh
System TMNSR		$1500/MWh
System TMSR		$50/MWh

The RCPFs shall be applied in a manner that is consistent with the price cascading described in Section III.2.7A(d).

(d) Real-Time Reserve designations and Real-Time Reserve Clearing Prices shall be calculated in such a manner to ensure that excess Real-Time Operating Reserve capability will cascade down for use in meeting any remaining Real-Time Operating Reserve Requirements from TMSR to TMNSR to TMOR and that the pricing of Real-Time Operating Reserve shall cascade up from TMOR to TMNSR to TMSR.

(e) During the Operating Day, the calculation set forth in this Section III.2.7A shall be performed every five minutes, using the ISO's Unit Dispatch System and Locational Marginal Price program, producing a set of nodal Real-Time Reserve Clearing Prices based on system conditions for the pricing interval. The prices produced at five-minute intervals during an hour will be integrated to determine the Real-Time Reserve Clearing Prices for the system and/or each Reserve Zone for that hour to be used in settlements.

III.2.8 Hubs and Hub Prices.

(a) On behalf of the Market Participants, the ISO shall maintain and facilitate the use of a Hub or Hubs for the Day-Ahead Energy Market and Real-Time Energy Market, comprised of a set of Nodes within the New England Control Area, which Nodes shall be identified by the ISO on its internet website. The ISO has used the following criteria to establish an initial Hub and shall use the same criteria to establish any additional Hubs:

(i) Each Hub shall contain a sufficient number of Nodes to try to ensure that a Hub Price can be calculated for that Hub at all times;

(ii) Each Hub shall contain a sufficient number of Nodes to ensure that the unavailability of, or an adjacent line outage to, any one Node or set of Nodes would have only a minor impact on the Hub Price;

(iii) Each Hub shall consist of Nodes with a relatively high rate of service availability;

(iv) Each Hub shall consist of Nodes among which transmission service is relatively unconstrained; and

(v) No Hub shall consist of a set of Nodes for which directly connected load and/or generation at that set of Nodes is dominated by any one entity or its Affiliates.

(b) The ISO shall calculate and publish hourly Hub Prices for both the Day-Ahead and Real-Time Energy Markets based upon the arithmetic average of the Locational Marginal Prices of the nodes that comprise the Hub.

III.2.9A Final Real Time Prices, Real-Time Reserve Clearing and Regulation Clearing Prices.

(a) The ISO normally will post provisional Real-Time Prices, Real-Time Reserve Clearing Prices and Regulation clearing prices in Real-Time or soon thereafter. The ISO shall post the final Real-Time Prices, final Real-Time Reserve Clearing Prices and final Regulation clearing prices as soon as practicable following the Operating Day, in accordance with the timeframes specified in the ISO New England Manuals, except that the posting of such final Real-Time Prices, final Real-Time Reserve Clearing Prices and final Regulation clearing prices by the ISO shall not exceed five business days from the applicable Operating Day. If the ISO is not able to calculate Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation clearing prices normally due to human error, hardware, software, or telecommunication problems that cannot be remedied in a timely manner, the ISO will calculate Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation clearing prices as soon as practicable using the best data available; provided, however, in the event that the ISO is unable to calculate and post final Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation clearing prices due to exigent circumstances not contemplated in this market rule, the ISO shall make an emergency filing with the Commission within five business days from the applicable Operating Day detailing the exigent circumstance, which will not allow the final clearing prices to be calculated and posted, along with a proposed resolution including a timeline to post final clearing prices.

(b) The permissibility of correction of errors in Real-Time Prices, Real-Time Reserve Clearing Prices or Regulation clearing prices for an Operating Day due to database, software or similar errors of the ISO or its systems, and the timeframes and procedures for permitted corrections, are addressed solely in this Section III.2.9A and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.2.9B Final Day-Ahead Energy Market Results

(a) Day-Ahead Energy Market results are final when published except as provided in this subsection. If the ISO determines based on reasonable belief that there may be one or more errors in the Day-Ahead Energy Market results for an Operating Day or if no Day-Ahead Energy Market results are available due to human error, database, software or similar errors of the ISO or its systems, the ISO shall post on the ISO website prior to 12:01 a.m. of the applicable Operating Day, a notice that the results are provisional and subject to correction or unavailable for initial publishing. Any Day-Ahead Energy Market results for which no notice is posted shall be final and not subject to correction or other adjustment, and shall be used for purposes of settlement. The ISO shall confirm within three business days of the close of the applicable Operating Day whether there was an error in any provisional Day-Ahead Energy Market results and shall post a notice stating its findings.

(b) The ISO will publish corrected Day-Ahead Energy Market results within three business days of the close of the applicable Operating Day or the results of the Day-Ahead Energy Market for the Operating Day will stand; provided, however, in the event that the ISO is unable to calculate and post final Day-Ahead Energy Market Results due to exigent circumstances not contemplated in this market rule, the ISO shall make an emergency filing with the Commission within five business days from the applicable Operating Day detailing the exigent circumstance, which will not allow the final prices to be calculated and posted, along with a proposed resolution including a timeline to post final prices. The ISO shall also publish a statement describing the nature of the error and the method used to correct the results.

(c) If the ISO determines in accordance with subsection (a) that there are one or more errors in the Day-Ahead Energy Market results for an Operating Day, the ISO shall calculate corrected Day-Ahead Energy Market results by determining and substituting for the initial results, final results that reasonably reflect how the results would have been calculated but for the errors. To the extent that it is necessary, reasonable and practicable to do so, the ISO may specify an allocation of any costs that are not otherwise allocable under applicable provisions of Market Rule 1. The ISO shall use the corrected results for purposes of settlement.

(d) For every change in the Day-Ahead Energy Market results made pursuant to Section III.2.9B, the ISO will prepare and submit, as soon as practicable, an informational report to the Commission describing the nature of any errors, the precise remedy administered, the method of determining corrected prices and allocating any costs, and any remedial actions that will be taken to avoid similar errors in the future.

(e) The permissibility of correction of errors in Day-Ahead Energy Market results, and the timeframes and procedures for permitted corrections, are addressed solely in this Section III.2.9B and not in those sections of Market Rule 1 relating to settlement and billing processes.

III.3 Accounting And Billing

III.3.1 Introduction.

This Section III.3 sets forth the accounting and billing principles and procedures for the purchase and sale of services in the New England Markets and for the operation of the New England Control Area; provided that Section III.E2.9 sets forth the Day-Ahead Energy Market and Real-Time Energy Market settlement rules for Demand Response Resources.

III.3.2 Market Participants.

III.3.2.1 ISO Energy Market.

For purposes of establishing the following positions, unless otherwise expressly stated, the settlement interval for external interfaces for which the enhanced scheduling procedures in Section III.1.10.7.A are implemented shall be 15 minutes, and the settlement interval for all other Locations shall be one hour.

(a) For each Market Participant for each hour, the ISO will determine a Day-Ahead Energy Market position representing that Market Participant's net purchases from or sales to the Day-Ahead Energy Market as follows.

(i) **Day-Ahead Load Obligation** – Each Market Participant shall have for each hour a Day-Ahead Load Obligation for energy at each Location equal to the MWhs of its Demand Bids, Decrement Bids and External Transaction sales accepted by the ISO in the Day-Ahead Energy Market at that Location and such Day-Ahead Load Obligation shall have a negative value.

(ii) **Day-Ahead Generation Obligation** – Each Market Participant shall have for each hour a Day-Ahead Generation Obligation for energy at each Location equal to the MWhs of its generation Supply Offers, Increment Offers and External Transaction purchases accepted by the ISO in the Day-Ahead Energy Market at that Location and such Day-Ahead Generation Obligation shall have a positive value.

(iii) **Day-Ahead Adjusted Load Obligation** – Each Market Participant shall have for each hour a Day-Ahead Adjusted Load Obligation at each Location equal to the Day-Ahead Load Obligation adjusted by any applicable Day-Ahead internal bilateral transactions at that Location.

(iv) **Day-Ahead Locational Adjusted Net Interchange** – Each Market Participant shall have for each hour a Day-Ahead Locational Adjusted Net Interchange at each Location equal to the Day-Ahead Adjusted Load Obligation plus the Day-Ahead Generation Obligation at that Location

(b) For each Market Participant for each settlement interval, the ISO will determine a Real-Time Energy Market position. For purposes of these calculations, if the settlement interval is less than one hour, any internal bilateral transaction shall be equally apportioned over the settlement intervals within the hour. To accomplish this, the ISO will perform calculations to determine the following:

(i) **Real-Time Load Obligation** – Each Market Participant shall have for each settlement interval a Real-Time Load Obligation for energy at each Location equal to the MWhs of load, where such MWhs of load shall include External Transaction sales and shall have a negative value, at that Location, adjusted for any applicable internal bilateral transactions which transfer Real-Time load obligations.

(ii) **Real-Time Generation Obligation** – Each Market Participant shall have for each settlement interval a Real-Time Generation Obligation for energy at each Location. The Real-Time Generation Obligation shall equal the MWhs of energy, where such MWhs of energy shall have positive value, provided by generating Resources, External Resources, and External Transaction purchases at that Location.

(iii) **Real-Time Adjusted Load Obligation** – Each Market Participant shall have for each settlement interval a Real-Time Adjusted Load Obligation at each Location equal to the Real-Time Load Obligation adjusted by any applicable energy related internal Real-Time bilateral transactions at that Location.

(iv) **Real-Time Locational Adjusted Net Interchange** – Each Market Participant shall have for each settlement interval a Real-Time Locational Adjusted Net Interchange at each Location equal to the Real-Time Adjusted Load Obligation plus the Real-Time Generation Obligation at that Location.

(v) **Marginal Loss Revenue Load Obligation** – Each Market Participant shall have for each settlement interval a Marginal Loss Revenue Load Obligation at each Location equal to the Real-Time Load Obligation adjusted by any energy related internal Real-Time bilateral transactions at that Location that the parties to those bilateral transactions have elected to include in their Marginal Loss Revenue Load Obligation for the purpose of allocating Day-Ahead Loss Revenue and Real-Time Loss Revenue. Contributions from Coordinated External Transactions shall be excluded from the Real-Time Load Obligation for purposes of determining Marginal Loss Revenue Load Obligation.

(c) For each Market Participant for eachsettlement interval, the ISO will determine the difference between the Day-Ahead Energy Market position (calculated in accordance with Section III.3.2.1(a)) and the Real-Time Energy Market position (calculated in accordance with Section III.3.2.1(b)) representing that Market Participant's net purchases from or sales to the Real-Time Energy Market. For purposes of this calculation, if the Real-Time settlement interval is less than one hour, the Day-Ahead position shall be equally apportioned over the settlement intervals within the hour. To accomplish this, the ISO will perform calculations to determine the following:

(i) **Real-Time Load Obligation Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Load Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Load Obligation and the Day-Ahead Load Obligation.

(ii) **Real-Time Generation Obligation Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Generation Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Generation Obligation and the Day-Ahead Generation Obligation.

(iii) **Real-Time Adjusted Load Obligation Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Adjusted Load Obligation Deviation at each Location equal to the difference in MWhs between the Real-Time Adjusted Load Obligation and the Day-Ahead Adjusted Load Obligation.

(iv) **Real-Time Locational Adjusted Net Interchange Deviation** – Each Market Participant shall have for each settlement interval a Real-Time Locational Adjusted Net Interchange

Deviation at each Location equal to the difference in MWhs between the Real-Time Locational Adjusted Net Interchange and the Day-Ahead Locational Adjusted Net Interchange.

(d) For each Market Participant for each hour, the ISO will determine Day-Ahead Energy Market monetary positions representing a charge or credit for its net purchases from or sales to the ISO Day-Ahead Energy Market. The Day-Ahead Energy Market Energy Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Energy Component of the associated Day-Ahead Locational Marginal Prices. The Day-Ahead Energy Market Congestion Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Congestion Component of the associated Day-Ahead Locational Marginal Prices. The Day-Ahead Energy Market Loss Charge/Credit shall be equal to the sum of its Location specific Day-Ahead Locational Adjusted Net Interchanges multiplied by the Loss Component of the associated Day-Ahead Locational Marginal Prices.

(e) For each Market Participant for each settlement interval, the ISO will determine Real-Time Energy Market monetary positions representing a charge or credit to the Market Participant for its net purchases from or sales to the Real-Time Energy Market. The Real-Time Energy Market Deviation Energy Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Energy Component of the Real-Time Locational Marginal Prices. The Real-Time Energy Market Deviation Congestion Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Congestion Component of the associated Real-Time Locational Marginal Prices.

The Real-Time Energy Market Deviation Loss Charge/Credit shall be equal to the sum of the Market Participant's Location specific Real-Time Locational Adjusted Net Interchange Deviations for that settlement interval multiplied by the Loss Component of the associated Real-Time Locational Marginal Prices.

(f) For each hour, the ISO will determine the total revenues associated with transmission congestion on the New England Transmission System. To accomplish this, the ISO will perform calculations to determine the following. The Day-Ahead Congestion Revenue shall equal the sum of all Market Participants' Day-Ahead Energy Market Congestion Charge/Credits. The Real-Time Congestion

Revenue shall equal the sum of all Market Participants' Real-Time Energy Market Congestion Charge/Credits.

(g) For each hour, the ISO will determine the excess or deficiency in loss revenue associated with the Day-Ahead Energy Market. The Day-Ahead Loss Revenue shall be equal to the sum of all Market Participants' Day-Ahead Energy Market Energy Charge/Credits and Day-Ahead Energy Market Loss Charge/Credits.

(h) For each hour for each Market Participant, the ISO shall calculate a Day-Ahead payment or charge associated with the excess or deficiency in loss revenue (Section III.3.2.1(g)). The Day-Ahead Loss Charges or Credits shall be equal to the Day-Ahead Loss Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Marginal Loss Revenue Load Obligations.

(i) For each hour, the ISO will determine the excess or deficiency in loss revenue associated with the Real-Time Energy Market. The Real-Time Loss Revenue shall be equal to the sum of all Market Participants' Real-Time Energy Market Deviation Energy Charge/Credit and Real-Time Energy Market Deviation Loss Charge/Credit plus Non-Market Participant Transmission Customer loss costs. The ISO will then adjust Real-Time Loss Revenue to account for Inadvertent Energy Revenue, as calculated under Section III.3.2.1(k) and Emergency transactions as described under Section III.4.3(a).

(j) Non-Market Participant Transmission Customer loss costs shall be assessed for transmission use scheduled in the Real-Time Energy Market, calculated as the amount to be delivered in each settlement interval multiplied by the difference between the Loss Component of the Real-Time Price at the delivery point or New England Control Area boundary delivery interface and the Loss Component of the Real-Time Price at the source point or New England Control Area boundary source interface.

(k) For each hour, the ISO will calculate an excess or deficiency in Inadvertent Energy Revenue by multiplying the Inadvertent Interchange at each External Node by the associated Real-Time Locational Marginal Price. The resulting excess or deficiency in Inadvertent Energy Revenue at each External Node shall then be summed to determine a single hourly value for all External Nodes.

(l) For each hour for each Market Participant, the ISO shall calculate a Real-Time payment or charge associated with the excess or deficiency in Inadvertent Energy Revenue (Section III.3.2.1(k)). The

Inadvertent Energy Revenue Charges or Credits shall be equal to the Inadvertent Energy Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Real-Time Load Obligations and Real-Time Generation Obligations over all Locations, measured as absolute values, excluding contributions to Real-Time Load Obligations and Real-Time Generation Obligations from Coordinated External Transactions.

(m) For each hour for each Market Participant, the ISO shall calculate a Real-Time payment or charge associated with the excess or deficiency in Real-Time Loss Revenue (Section III.3.2.1(i)). The Real-Time Loss Revenue Charges or Credits shall be equal to the Real-Time Loss Revenue multiplied by the Market Participant's pro rata share of the sum of all Market Participants' Marginal Loss Revenue Load Obligations.

III.3.2.2 [Reserved.]

III.3.2.3 NCPC Credits and Charges.

A Market Participant's NCPC Credits and NCPC Charges are calculated pursuant to Appendix F to Market Rule 1.

III.3.2.4 Transmission Congestion.

Market Participants shall be charged or credited for Congestion Costs as specified in Section III.3.2.1(f) of this Market Rule 1.

III.3.2.5 [Reserved.]

III.3.2.6 Emergency Energy.

(a) Hourly net costs in excess of Real-Time Prices attributable to the purchase of Emergency energy from other Control Areas shall be allocated to Market Participants based on the following hourly deviations where such deviations are negative: (i) Real-Time Adjusted Load Obligation Deviations during that Operating Day; (ii) generation deviations and demand reduction deviations for Pool-Scheduled Resources not following ISO dispatch instructions, Self-Scheduled Resources with dispatchable increments above their Self-Scheduled amounts not following ISO dispatch instructions and Self-Scheduled Resources not following their Day-Ahead Self-Scheduled amounts other than those Self-Scheduled Resources that are following ISO dispatch instructions, including External Resources, in MWhs during the Operating Day; and (iii) deviations from the Day-Ahead Energy Market for External

Transaction purchases in MWhs during the Operating Day except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency energy purchases are not included in this calculation. As provided for in the ISO New England Manuals, generating Resources and Demand Response Resources shall have a 5% or 5 MWh threshold when determining such deviations. Notwithstanding the foregoing, the allocation of costs attributable to the purchase of Emergency energy from other Control Areas shall exclude contributions to deviations from Coordinated External Transactions.

(b) Hourly net revenues in excess of Real-Time Prices attributable to the sale of Emergency energy to other Control Areas shall be credited to Market Participants based on the following deviations where such deviations are negative: (i) Real-Time Adjusted Load Obligation Deviations in MWhs during that Operating Day; (ii) generation deviations and demand reduction deviations for Pool-Scheduled Resources following ISO dispatch instructions and Self-Scheduled generating Resources with dispatchable increments above their Self-Scheduled amounts following ISO dispatch instructions, including External Resources, in MWhs during the Operating Day; and (iii) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency energy purchases are not included in this calculation. As provided for in the ISO New England Manuals, generating Resources and Demand Response Resources shall have a 5% or 5 MWh threshold when determining such deviations. Notwithstanding the foregoing, the calculation of the credit for the sale of Emergency energy to other Control Areas shall exclude contributions to deviations from Coordinated External Transactions.

III.3.2.6A New Brunswick Security Energy.

New Brunswick Security Energy is energy that is purchased from the New Brunswick System Operator by New England to preserve minimum flows on the Orrington-Keswick (396/3001) tie line and Orrington-Lepreau (390/3016) tie line in accordance with the applicable ISO / New Brunswick System Operator transmission operating guide with respect to the determination of minimum transfer limits. New Brunswick Security Energy costs are hourly costs in excess of the LMP at the applicable External Node attributable to purchases of New Brunswick Security Energy by New England. New Brunswick Security Energy costs shall be allocated among Market Participants on the basis of their pro-rata shares of Regional Network Load or in such other manner as may be described in ISO New England Manual M-28 (Market Rule 1 Accounting). Where the LMP at the applicable External Node exceeds the New Brunswick Security Energy costs, such amounts shall be accounted for in accordance with Section III.3.2.1(m).

III.3.2.7 Billing.

The ISO shall prepare a billing statement each billing cycle, in accordance with the ISO New England Billing Policy, for each Market Participant in accordance with the charges and credits specified in Sections III.3.2.1 through III.3.2.6 and Section III.E2, and showing the net amount to be paid or received by the Market Participant. Billing statements shall provide sufficient detail, as specified in the ISO New England Manuals, ISO New England Administrative Procedures and the ISO New England Billing Policy, to allow verification of the billing amounts and completion of the Market Participant's internal accounting. Billing disputes shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

III.3.3 [Reserved.]

III.3.4 Non-Market Participant Transmission Customers.

III.3.4.1 Transmission Congestion.

Non-Market Participant Transmission Customers shall be charged or credited for Congestion Costs as specified in Section III.1 of this Market Rule 1.

III.3.4.2 Transmission Losses.

Non-Market Participant Transmission Customers shall be charged or credited for transmission losses in an amount equal to the product of (i) the Transmission Customer's MWhs of deliveries in the Real-Time Energy Market, multiplied by (ii) the difference between the Loss Components of the Real-Time Locational Marginal Prices at the point-of-receipt and the point-of-delivery Locations.

III.3.4.3 Billing.

The ISO shall prepare a billing statement each billing cycle, in accordance with the ISO New England Billing Policy, for each Non-Market Participant Transmission Customer in accordance with the charges and credits specified in Sections III.3.4.1 through III.3.4.2 of this Market Rule 1, and showing the net amount to be paid or received by the Non-Market Participant Transmission Customer. Billing statements shall provide sufficient detail, as specified in the ISO New England Manuals, the ISO New England Administrative Procedures and the ISO New England Billing Policy, to allow verification of the billing amounts and completion of the Non-Market Participant Transmission Customer's internal accounting.

Billing disputes shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

III.3.5 [Reserved.]

III.3.6 Data Reconciliation.

III.3.6.1 Data Correction Billing.

The ISO will reconcile Market Participant data errors and corrections after the Correction Limit for such data has passed. The Correction Limit for meter data and for ISO errors in the processing of meter and other Market Participant data is 101 days from the last Operating Day of the month to which the data applied. Notification of Meter Data Errors applicable to Assigned Meter Reader or Host Participant Assigned Meter Reader supplied meter data must be submitted to the ISO by the Meter Data Error RBA Submission Limit.

III.3.6.2 Eligible Data.

The ISO will accept revised hourly asset meter readings from Assigned Meter Readers and Host Participant Assigned Meter Readers, daily Coincident Peak Contribution values from Assigned Meter Readers, and new or revised internal bilateral transactions from Market Participants. No other revised data will be accepted for use in settlement recalculations. The ISO will correct data handling errors associated with other Market Participant supplied data to the extent that such data did not impact unit commitment or the Real-Time dispatch. Data handling errors that impacted unit commitment or the Real-Time dispatch will not be corrected.

III.3.6.3 Data Revisions.

The ISO will accept revisions to asset specific meter data, daily Coincident Peak Contribution values, and internal bilateral transactions prior to the Correction Limit. No revisions to other Market Participant data will be accepted after the deadlines for submittal of that data have passed, except as provided in Section III.3.8 of Market Rule 1. If the ISO discovers a data error or if a Market Participant discovers and notifies the ISO of a data error prior to the Correction Limit, revised hourly data will be used to recalculate all markets and charges as appropriate, including but not limited to energy, NCPC, Regulation, Operating Reserves, Auction Revenue Rights allocations, Forward Capacity Market, cost-of-service agreements, and the ISO Tariff. No settlement recalculations or other adjustments may be made if the Correction Limit for the Operating Day to which the error applied has passed or if the correction does not qualify for treatment as a Meter Data Error correction pursuant to Section III.3.8 of Market Rule 1.

III.3.6.4 Meter Corrections Between Control Areas.

For revisions to meter data associated with assets that connect the New England Control Area to other Control Areas, the ISO will, in addition to performing settlement recalculations, adjust the actual interchange between the New England Control Area and the other Control Area to maintain an accurate record of inadvertent energy flow.

III.3.6.5 Meter Correction Data.

(a) Revised meter data and daily Coincident Peak Contribution values shall be submitted to the ISO as soon as it is available and not later than the Correction Limit, and must be submitted in accordance with the criteria specified in Section III.3.7 of Market Rule 1. Specific data submittal deadlines are detailed in the ISO New England Manuals.

(b) Errors on the part of the ISO in the administration of Market Participant supplied data shall be brought to the attention of the ISO as soon as possible and not later than the Correction Limit.

III.3.7 Eligibility for Billing Adjustments.

(a) Errors in Market Participant's statements resulting from errors in settlement software, errors in data entry by ISO personnel, and settlement production problems, that do not affect the day-ahead schedule or real-time system dispatch, will be corrected as promptly as practicable. If errors are identified prior to the issuance of final statements, the market will be resettled based on the corrected information.

(b) Calculations made by scheduling or dispatch software, operational decisions involving ISO discretion which affect scheduling or real-time operation, and the ISO's execution of mandatory dispatch directions, such as self-schedules or external contract conditions, are not subject to retroactive correction and resettlement. The ISO will settle and bill the Day-Ahead Energy Market as actually scheduled and the Real-Time Energy Market as actually dispatched. Any post-settlement issues raised concerning operating decisions related to these markets will be corrected through revision of operations procedures and guidelines on a prospective basis.

(c) While errors in reporting hourly metered data may be corrected (pursuant to Section III.3.8), Market Participants have the responsibility to ensure the correctness of all data they submit to the market settlement system.

(d) Disputes between Market Participants regarding settlement of internal bilateral transactions shall not be subject to adjustment by the ISO, but shall be resolved directly by the Market Participants unless they involve an error by the ISO that is subject to resolution under Section III.3.7(a).

(e) Billing disputes between Market Participants and the ISO or Non-Market Participants and the ISO shall be settled in accordance with procedures specified in the ISO New England Billing Policy.

(f) Criteria for Meter Data Errors to be eligible for a Requested Billing Adjustment. In order to be eligible to submit a Requested Billing Adjustment due to a Meter Data Error on an Invoice issued by the ISO after the completion of the Data Reconciliation Process, a Market Participant must satisfy one of the following two conditions: (1) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or the Host Participant Assigned Meter Reader and communicated to the Host Participant Assigned Meter Reader no later than thirty-six (36) days prior to the Correction Limit for Directly Metered Assets and no later than two (2) days prior to the Correction Limit for Profiled Load Assets and could not be resolved prior to those deadlines; or (2) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or Host Participant Assigned Meter Reader and reported to the ISO by the Meter Data Error RBA Submission Limit, and such Meter Data Error represents an error that is equal to or greater than the 1,000 MWh per Asset over a calendar month. If the Meter Data Error affects more than one metering domain, the ISO, and affected Host Participant Assigned Meter Readers and affected Assigned Meter Readers of affected metering domains, must be notified.

III.3.8 Correction of Meter Data Errors

(a) Any Market Participant, Assigned Meter Reader or Host Participant Assigned Meter Reader may submit notification of a Meter Data Error in accordance with the procedures provided in this Section III.3.8, provided that the notification is submitted no later than the Meter Data Error RBA Submission Limit and that the notice must be submitted using the RBA form for Meter Data Errors posted on the ISO's website.

(b) Within three Business Days of the receipt by the ISO's Chief Financial Officer of an RBA form for a Meter Data Error, the ISO shall prepare and submit to all Covered Entities and to the Chair of the NEPOOL Budget and Finance Subcommittee a notice of the Meter Data Error correction ("Notice of Meter Data Error Correction"), including, subject to the provisions of the ISO New England Information Policy, the specific details of the correction and the identity of the affected metering domains and the affected Host Participant Assigned Meter Readers. The "Notice of Meter Data Error Correction" shall

identify a specific representative of the ISO to whom all communications regarding the matter are to be sent.

(c) In order for a Meter Data Error on an Invoice issued by the ISO after the completion of the Data Reconciliation Process to be eligible for correction, the Meter Data Error must satisfy one of the following conditions: (1) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or the Host Participant Assigned Meter Reader and communicated to the Host Participant Assigned Meter Reader no later than 36 days prior to the Correction Limit for Directly Metered Assets and no later than two days prior to the Correction Limit for Profiled Load Assets and could not be resolved prior to those deadlines; (2) the Meter Data Error at issue was identified by the asset owner, Assigned Meter Reader or Host Participant Assigned Meter Reader, and such Meter Data Error represents an error that is equal to or greater than the 1,000 MWh per asset over a calendar month; and (3) if the Meter Data Error involves only Coincident Peak Contribution values, the average of the daily Meter Data Errors involving Coincident Peak Contribution values for the affected calendar month must be greater than or equal to 5 MW for an affected asset. If the Meter Data Error affects more than one metering domain, the ISO, and affected Host Participant Assigned Meter Readers and affected Assigned Meter Readers of affected metering domains, must be notified.

(d) For a Meter Data Error, the Host Participant Assigned Meter Reader must submit to the ISO corrected meter data for Directly Metered Assets prior to the 46th calendar day after the Meter Data Error RBA Submission Limit. Corrected metered data for Profiled Load Assets and Coincident Peak Contribution values, must be submitted to the ISO by the Host Participant Assigned Meter Reader prior to the 87th calendar day after the Meter Data Error RBA Submission Limit. Corrected internal bilateral transactions data must be submitted to the ISO by a Market Participant prior to the 91st calendar day after the Meter Data Error RBA Submission Limit.

Any corrected data received after the specified deadlines is not eligible for use in the settlement process.

The Host Participant Assigned Meter Reader or Market Participant, as applicable, must confirm as part of its submission of corrected data that the eligibility criteria described in Section III.3.8(c) of Market Rule 1 have been satisfied.

To the extent that the correction of a Meter Data Error is for a Directly Metered Asset that affects multiple metering domains, all affected Host Participant Assigned Meter Readers or Assigned Meter

Readers must notify the ISO prior to the 46th calendar day after the Meter Data Error RBA Submission Limit that the corrected Directly Metered Asset data is acceptable to them in order for the ISO to use the corrected data in the final settlement calculations. The Host Participant Assigned Meter Reader for the Directly Metered Asset is responsible for initiating an e-mail to every affected Host Participant Assigned Meter Reader or Assigned Meter Reader in order to obtain such acceptance and shall coordinate delivery of such acceptance to the ISO. The Host Participant Assigned Meter Reader for the Directly Metered Asset is also responsible for submitting all corrected and agreed upon Directly Metered Asset data to the ISO prior to the 46th calendar day after the Meter Data Error RBA Submission Limit.

(e) After the submission of corrected meter and internal bilateral transactions data, the ISO will have a minimum of 30 calendar days to administer the final settlement based on that data. Revised data will be used to recalculate all charges and credits, except that revised data will not be used to recalculate the PER adjustment, including the Hourly PER and Monthly PER values. Revised data will also not be used to recalculate Demand Resource Seasonal Peak Hours. The results of the final settlement will then be included in the next Invoice containing Non-Hourly Charges and the ISO will provide to the Chair of the NEPOOL Budget and Finance Subcommittee written notification that the final settlement has been administered.

III.14 Regulation Market.

III.14.1 Regulation Market System Requirements.

The Regulation Capacity Requirement and Regulation Service Requirement are determined based on historical control performance and compliance with NERC and NPCC control standards. The Regulation Capacity Requirement and Regulation Service Requirement will be published on the ISO's website.

During abnormal system conditions, the ISO may deviate from the Regulation Capacity Requirement or Regulation Service Requirement to maintain system reliability.

III.14.2 Regulation Market Eligibility.

To be eligible to provide Regulation, a Resource must satisfy the following conditions:

(a) Physical Parameters.

(i) Automatic Response Rate.

(1) The minimum Automatic Response Rate is 1 MW/minute.

(ii) Regulation Capacity.

(1) The minimum Regulation Capacity of a generating unit will be determined based on unit size and operating characteristics and must be greater than or equal to: (a) 5 megawatts, and; (b) two times the generating unit's AGC SetPoint Deadband plus one.

(2) The minimum Regulation Capacity of a Resource that is not a generating unit is no less than one megawatt after aggregation.

(b) Regulation Technical Requirements.

A Resource providing Regulation must:

(i) be located within the New England Control Area.

(ii) meet the technical requirements specified in ISO New England Operating Procedure No. 14, Technical Requirements for Generators, Demand Resources and Asset Related Demands and ISO New England Operating Procedure No. 18, Metering and Telemetering Criteria.

(iii) be capable of receiving and following AGC SetPoints sent electronically at four-second intervals.

(iv) have a demonstrated capability to reliably follow Dispatch Instructions, consistent with normal operating characteristics and physical offer parameters, including Regulation Capacity

and Automatic Response Rate. Resources without an operational history of providing Regulation must establish and demonstrate this capability as follows:

(1) Demand Response Regulation Resources, Dispatchable Asset Related Demand, Alternative Technology Regulation Resources and any Resource with less than one-hour sustainability must participate in the Regulation test environment specified in Section III.14.9.

(2) All Resources must satisfy a minimum responsiveness test that demonstrates that a Resource can follow AGC SetPoints.

(c) Aggregation.

Non-generation sub-resources less than one megawatt in size may be aggregated into a single Resource to meet the Regulation Market eligibility requirements specified in Section III.14.2.

A single AGC SetPoint will be sent every AGC cycle to the aggregated Resource. A Market Participant with an aggregated Resource is responsible for management and control of the individual, aggregated sub-resources to ensure an accurate aggregate response to the AGC SetPoint. The sub-resources may be geographically dispersed, provided:

(i) all of the sub-resources are located within the New England Control Area

(ii) the sub-resources are metered and recorded in a manner that allows real-time performance to be measured against Dispatch Instructions and provides for the retention of the recorded information for purposes of verification, accounting for any performance offsets from other loads, generation or devices under the direct or indirect control of the aggregator as specified in ISO New England Operating Procedure No. 18, Metering and Telemetering Criteria.

(iii) communications and metering are installed and tested for each sub-resource in accordance with ISO New England Operating Procedure No, 18, Metering and Telemetering Criteria and ISO New England Operating Procedure No. 14, Technical Requirements for Generators, Demand Resources and Asset Related Demands.

III.14.3 Regulation Market Offers.

(a) A Market Participant providing Regulation must submit a Supply Offer. The Supply Offer shall remain effective until cancelled or replaced by the Market Participant. The Supply Offer must specify the following offer parameters:

(i) Regulation unit status (available/unavailable)

Regulation unit status for each hour in an Operating Day must be submitted daily prior to the close of the Re-Offer Period. After initial submission, unit status may be modified at any time.

(ii) Regulation High Limit

For generating units, the Regulation High Limit must be less than or equal to a generating unit's Economic Maximum Limit. For Dispatchable Asset Related Demand, the Regulation High Limit must be greater than or equal to a Dispatchable Asset Related Demand's Minimum Consumption Limit.

(iii) Regulation Low Limit

For generating units, the Regulation Low Limit must be greater than or equal to a generating unit's Economic Minimum Limit. For Dispatchable Asset Related Demand, the Regulation Low Limit must be less than or equal to a Dispatchable Asset Related Demand's Maximum Consumption Limit.

(iv) Automatic Response Rate (MW/minute)

(v) Regulation Capacity Offer ($/MW)

The Regulation Capacity Offer price must be greater than or equal to $0/MW and may not exceed $100/MW. A Market Participant may include estimated inter-temporal opportunity costs in its Regulation Capacity Offer price.

(vi) Regulation Service Offer ($/MW of instructed movement)

The Regulation Service Offer price must be greater than or equal to $0/MW of instructed movement and may not exceed $10/MW of instructed movement.

(b) Additional Constraints on Offer Parameters.

(i) Regulation offer parameters that exceed recent historical performance for Regulation Capacity or Automatic Response Rate will be constrained to reflect values consistent with the demonstrated performance of the Resource. The Resource of a Market Participant that submits offer parameters inconsistent with demonstrated performance will be disqualified from selection to provide Regulation until the submitted parameters are modified to be consistent with demonstrated performance.

(ii) A Resource that is dispatchable in the Real-Time Energy Market and providing Regulation shall have its energy dispatch range reduced by twice the amount of the Regulation provided as follows: the upper limit of the Resource's energy dispatch range will be reduced by the amount of Regulation Capacity, and the lower limit of the Resource's energy dispatch range will be increased by the amount of Regulation Capacity.

(c) Sustainability.

Regulation Capacity offers for Resources with less than one-hour sustainability will be evaluated in the selection process using a capacity value adjusted to reflect historical performance when dispatched at the non-adjusted value. The adjusted value will account for the Resource's demonstrated ability to follow the AGC dispatch signal over an hour at the offered Regulation Capacity level. The percentage adjustment will be reevaluated periodically to account for changes in the performance of the Resource. Resources with no historical performance record will be evaluated pursuant to the regulation resource test environment specified in Section III.14.9.

Adjusted Regulation Capacity will be used for the purpose of selecting Resources to meet the Regulation Capacity Requirement and for determining Regulation Capacity compensation.

Resources will be dispatched for Regulation in accordance with the unadjusted Regulation Capacity offer parameters.

For a storage-based resource, sustainability is measured based on full rate of charge/discharge starting from a half-full status.

III.14.4 Regulation Market Administration.

A Market Participant may modify Regulation offer parameters at any time, however the offer parameters in place at the start of a settlement interval will remain in effect through the end of the settlement interval. The most recent offer parameters will be used when new Resources are selected for a new settlement interval.

III.14.5 Regulation Market Resource Selection.

Resources are selected to provide Regulation from eligible and available Resources to meet the Regulation Capacity Requirement and Regulation Service Requirement at the least-cost based on

Regulation Capacity Offers, Regulation Service Offers, estimated energy opportunity costs, impacts on system production costs, and operational requirements related to reliability, including a minimum aggregated response rate and minimizing short-term changes in the assignment of Resources to provide Regulation. For the purposes of least-cost Resource selection, the following penalty factors are used for any violation of the Regulation requirements constraint:
(1)(a) when the Energy Component of the Real-Time Locational Marginal Price at the reference point is at least $100/MW the penalty factor is $100/MW plus the Energy Component of the Real-Time Locational Marginal Price at the reference point for each megawatt of Regulation Capacity shortfall, and
(b) when the Energy Component of the Real-Time Locational Marginal Price at the reference point is less than $100/MW the penalty factor is the maximum of either zero or $100 plus the Energy Component of the Real-Time Locational Marginal Price at the reference point for each megawatt of Regulation Capacity shortfall and:
(2) $10/MW for each megawatt of Regulation Service shortfall. In addition, selection will consider opportunity cost sensitivities associated with large changes in the estimated opportunity cost of a Resource due to the shape of the Resource's Supply Offer price curve.

An eligible Resource may be omitted from providing Regulation due to operational restrictions, including, but not limited to, binding transmission constraints, planned shutdown prior to the end of the settlement interval, or known or anticipated system operating conditions.

The ISO may deviate from the market-based Resource selections to maintain system reliability.

If one or more Resources providing Regulation become unavailable, a new selection process may be conducted to obtain the Resources needed to fulfill the Regulation Capacity Requirement and the Regulation Service Requirement and new clearing prices determined pursuant to Section III.14.8(a).

In the event one or more Resources have equivalent least-cost characteristics in the selection process, the Resource with the larger Regulation Capacity value will be selected or, if the Regulation Capacity value is also equal, the Resource with the earliest Supply Offer submission time will be selected.

III.14.6 Delivery of Regulation Market Products.

Resources selected for Regulation are dispatched to reduce the New England Control Area's area control error as needed to ensure reliability and compliance with NERC and NPCC control standards.

Resources that are generating units are dispatched based on relative response rates using multi-valued AGC SetPoints with AGC SetPoint Deadbands. Resources that are not generating units may be dispatched using one of the following methods:

(a) an energy-neutral trinary dispatch that calculates AGC SetPoints equal to one of the following three values: Regulation High Limit, Regulation Low Limit, and a midpoint between the Regulation High Limit and the Regulation Low Limit;

(b) a relative response rate dispatch using multi-valued AGC SetPoints with AGC SetPoint Deadbands, or;

(c) an energy-neutral relative response rate dispatch using multi-valued AGC SetPoints with AGC SetPoint Deadbands.

A Market Participant may change the dispatch method for a non-generating unit. Dispatch methodology may be changed to be effective at the start of every calendar quarter. Requests to change the dispatch method of a non-generating resource must be received no later than 30 Business Days before the requested effective date of the change. Dispatch will be coordinated with the objective of achieving consistent and non-discriminatory treatment of Resources providing similar offer parameters.

AGC SetPoints will be established to cost-effectively meet reliability criteria based on the current area control error, the Automatic Response Rate and offer parameters of the selected Resources, as well as the current and predicted state of the system.

III.14.7 Performance Monitoring.

The performance of a Resource providing Regulation will be monitored in Real-Time. For each settlement interval, a Resource is considered to be non-performing if, after a grace period, the Resource is not responding to AGC SetPoints at a rate at least equal to a percentage of its Automatic Response Rate or outside a tolerance band around the AGC SetPoint that is equal to a percentage of the Regulation Capacity of the Resource. The grace period will be between two and four minutes. The percentage of the Automatic Response Rate will be between 80 and 95 percent. The percentage of the Regulation Capacity of the Resource will be between 5 and 15 percent. The specific values will be published on the ISO's website.

A Resource that changes its direction of movement in a manner inconsistent with the AGC SetPoint is considered non-performing for the remainder of the settlement interval.

Compensation adjustments for non-performing Resources are addressed in Section III.14.8(b)(iv).

III.14.8 Regulation Market Settlement and Compensation.

(a) Calculation of Regulation Clearing Prices.

(i) Regulation Service clearing prices.

The Regulation Service clearing price is set equal to the highest Regulation Service Offer of the Resources selected to provide Regulation pursuant to Section III.14.5.

(ii) Regulation Capacity clearing prices.

The Regulation Capacity clearing price is set such that total compensation from the Regulation Service clearing price and the Regulation Capacity clearing price will, based on a uniform clearing price applied to all selected Resources, ensure recovery of as-bid costs for Regulation Capacity, estimated Regulation Service, estimated energy opportunity costs, and the Resource-specific incremental cost savings payment determined for each Resource for the planned duration of the settlement interval.

The incremental cost savings provided by each Resource is assessed by determining the least-cost selection of Resources as specified in Section III.14.5 both with and without the particular Resource. The incremental cost savings for the settlement interval is the estimated total cost of Regulation without the Resource minus the estimated total cost of Regulation with the Resource, including the application of penalty factors to any violation of the Regulation requirements constraint.

(b) Compensation to Regulation Providers.

(i) A Market Participant with a Resource that is selected to provide Regulation and that complies with the dispatch and performance requirements in Section III.14 shall receive:

(1) A capacity payment equal to the amount of Regulation Capacity selected times the Regulation Capacity clearing price.

(2) A service payment equal to the amount of service provided, while the Resource is considered to be performing as specified in Section III.14.7, as measured by the absolute value of the Resource's scheduled movement at the claimed rate of response without

delay, in megawatts, toward the AGC SetPoint in response to AGC dispatch signals times the Regulation Service clearing price.

(ii) Calculation of Actual Energy Opportunity Costs.

A Resource-specific Regulation energy opportunity cost for those Resources dispatchable in the Real-Time Energy Market is determined for each settlement interval that the Resource is selected to provide Regulation. The Regulation energy opportunity cost shall be equal to the product of (i) the absolute value of the deviation of the Resource's dispatch level necessary to follow the ISO's Regulation signals from the Resource's expected dispatch level if it had been dispatched in economic merit order and (ii) the absolute value of the difference between the Real-Time Price at the Node associated with the Resource and the megawatt weighted average Supply Offer or Demand Bid price for the energy associated with the deviation of the Resource's expected dispatch level if it had been dispatched in economic merit order. The Regulation energy opportunity cost for a Resource that is dispatched pursuant to Section III.1.10.9(e) shall be equal to zero for the settlement interval. Regulation energy opportunity costs are only incurred when a Resource is providing Regulation.

(iii) Make-Whole Payment

If revenues from the Regulation Capacity clearing price and the Regulation Service clearing price are insufficient to cover a Market Participant's as-bid costs for the actual Regulation Capacity and the amount of Regulation Service provided during a settlement interval plus actual energy opportunity costs as calculated in Section III.14.8(b)(ii), a make-whole payment will be provided for the period that the Resource is considered to be performing as specified in Section III.14.7.

(iv) Performance Adjustments.

A selected Resource's capacity payment will be reduced to reflect the proportion of time the Resource was determined to be non-performing pursuant to Section III.14.7.

(v) Compensation for Replacement Resources

If system conditions require the ISO to designate additional Resources in order to satisfy Regulation requirements for the remainder of a settlement interval without completing the selection process described in Section III.14.5, compensation for replacement Resources will be made according to the Resource's actual performance using the Regulation Capacity clearing

price, the Regulation Service clearing price, and any make-whole payments as specified in Section III.14.8(b)(iii).

(c) Regulation Charges.

Each Market Participant shall have a Regulation charge equal to its pro rata share of the Regulation Capacity Requirement and Regulation Service Requirement for the settlement period based on the Market Participant's total Real-Time Load Obligation. The total cost of providing Regulation for each settlement period is charged to Market Participants based on their pro rata share of Real-Time Load Obligation during the period. For the purposes of allocating Regulation charges, the Real-Time Load Obligation of a Dispatchable Asset Related Demand providing Regulation shall be limited to the Minimum Consumption Limit of the Resource. Calculation of Regulation charges shall exclude contributions to Real-Time Load Obligations from Coordinated External Transactions.

(d) Net Energy Settlement for Alternative Technology Regulation Resources.

A Market Participant with an Alternative Technology Regulation Resource that is interconnected and metered at a single location may register the resource as a combination of the following asset types for the purpose of regulation energy market settlement:

1) an Alternative Technology Regulation Resource for the settlement of regulation capacity and regulation service;

2) a Settlement-Only Generator, if not greater than or equal to 5 MW, or otherwise a non-dispatchable, non-regulation capable Generator Asset for settlement of net energy injections that result from following AGC dispatch instructions;

3) an Asset Related Demand for settlement of net energy consumption; and

4) a load asset for settlement of net energy consumption for which the Real-Time Load Obligation is separately reported to the ISO.

III.14.9 Regulation Market Testing Environment.

The ISO administers a regulation resource test environment that allows Market Participants to evaluate or demonstrate the performance of Resources without an operational history of providing Regulation prior to participation in the Regulation Market.

Resources providing Regulation under the regulation resource test environment will be compensated for the Regulation Capacity and Regulation Service provided in response to AGC SetPoints at the lowest of

the Regulation Capacity Offer prices and Regulation Service Offer prices offered for any Resource selected during each settlement interval. Resources that are also dispatchable in the Real-Time Energy Market will be compensated for Regulation energy opportunity costs incurred while operating under the regulation resource test environment.

Resources performing a minimal responsiveness test will not be compensated for Regulation.

A Resource may only provide Regulation under the regulation test environment until sufficient operational information has been collected to verify reasonable operating parameters for the Resource or to determine that the Resource does not meet the eligibility requirements necessary to participate in the Regulation Market.

SECTION III

MARKET RULE 1

APPENDIX F

NET COMMITMENT PERIOD COMPENSATION ACCOUNTING

APPENDIX F

NCPC ACCOUNTING

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NCPC ACCOUNTING

III.F.1. General.

For purposes of NCPC calculations:

a. Effective Offers. An Effective Offer for a Resource is (1) the Supply Offer used in making the decision to commit the Resource, and (2) the Supply Offer used in making the decision to dispatch the Resource at a Desired Dispatch Point above its Economic Minimum Limit, and is subject to the following conditions,

i. The Effective Offer used in making the decision to commit the Resource establishes the quantity and price pairs for output up to the Resource's Economic Minimum Limit, the Start-Up Fee, the No-Load Fee, and the operating limits used for NCPC calculations.

ii. In the event the Resource's Economic Minimum Limit is increased after the decision to commit the Resource, the energy price parameter for output at the Economic Minimum Limit used in making the decision to commit the Resource will be applied as the energy price parameter for additional output up to the increased Economic Minimum Limit.

iii. In the event a Minimum Generation Emergency is declared, the Economic Minimum Limit will be replaced with the Emergency Minimum Limit for purposes of determining the energy price parameter of the Effective Offer.

iv. The Effective Offer takes account of mitigation applied to the Supply Offer, whether performed prior to or after the commitment or dispatch decision is made.

v. The Effective Offer takes account of a reduction in the energy price parameter, the Start-Up Fee or the No-Load Fee that is made prior to the end of the Resource's Commitment Period.

vi. In the event the ISO approves the Resource's synchronization to the system as a Pool-Scheduled Resource earlier than its scheduled time, the Effective Offer takes account of the lesser of the energy price parameter, the Start-Up Fee and the No-Load Fee in place for the scheduled Commitment Period or the actual early release-for-dispatch time.

vii. A Resource that is online providing synchronous condensing is considered to be in a hot temperature state for the purpose of determining the Start-Up Fee for the Effective Offer when the Resource is requested to switch from synchronous condensing to provide energy.

b. Treatment of Self-Schedules.

i. In the Day-Ahead Energy Market, a Resource that is committed as a Self-Schedule is treated as having a Supply Offer with a Start-Up Fee equal to $0, a No-Load Fee equal to $0, and an

energy price parameter for output up to the Resource's Economic Minimum Limit equal to the Energy Offer Floor. Any amounts (MW) offered above the Economic Minimum Limit are evaluated based on the energy price parameters specified in the Supply Offer.

ii. In the Real-Time Energy Market, a Resource that is committed as a Self-Schedule is treated as having a Supply Offer with a Start-Up Fee equal to $0, a No-Load Fee equal to $0, and an energy price parameter for output up to the Resource's Economic Minimum Limit equal to $0/MWh. Any amounts (MW) offered above the Economic Minimum Limit are evaluated based on the energy price parameters specified in the Supply Offer. For any hour for which a Resource is dispatched pursuant to Section III.1.10.9(e), the Start-Up Fee and No-Lead Fee are equal to $0.

iii. If the Resource's Supply Offer contains a Self-Schedule for fewer contiguous hours than its Minimum Run Time, the minimum number of additional hours required to satisfy the Resource's Minimum Run Time will be treated as a Self-Schedule in the Day-Ahead Energy Market and Real-Time Energy Market. If the Resource is committed for one or more hours immediately prior to and contiguous with the Self-Schedule, the hours of that prior Commitment Period will be counted toward satisfying the Resource's Minimum Run Time before hours subsequent to the Self-Schedule are counted. If the Resource's Supply Offer contains two Self-Schedules separated by less than the Resource's Minimum Down Time, the hours between the two Self-Schedules will be treated as a Self-Schedule in the Day-Ahead Energy Market and Real-Time Energy Market.

c. [Reserved.]

d. Supply Offers Applicable When Minimum Run Time Carries Into Second Operating Day. If a Resource that is committed in either (i) the Day-Ahead Energy Market, or (ii) the Resource Adequacy Analysis prior to the start of the Operating Day must continue to operate across an Operating Day boundary to satisfy its Minimum Run Time, the Supply Offer in place for hour ending 24 of the Operating Day is used to establish the Effective Offer for the period of the Minimum Run Time in the second Operating Day. If a Resource that is committed during the Operating Day must continue to operate across the Operating Day boundary to satisfy its Minimum Run Time, the Supply Offer in place for the second Operating Day is used to establish the Effective Offer for the period of the Minimum Run Time in the second Operating Day.

e. Supply Offers Applicable When Committed Prior to Day-Ahead Energy Market. If a Resource is committed for an Operating Day prior to the Day-Ahead Energy Market, the Supply Offer in place

for the Operating Day at the time of the commitment is used to establish the Effective Offer for the period of the commitment.

f. Eligibility for NCPC Credits When Performing Audits or Facility and Equipment Testing.

Market Participants are not eligible for NCPC Credits when conducting audits or Facility and Equipment Testing under the following conditions:

i. When a Market Participant requests that some hours of the commitment of a Pool-Scheduled Resource be used to satisfy an audit, and the Market Participant has changed the Resource's Economic Minimum Limit for those hours for the purpose of conducting the audit, the Market Participant is not eligible for Real-Time Dispatch NCPC Credits for the hours during which the audit is conducted.

ii. When a Market Participant Self-Schedules a Resource to perform the audit, the Market Participant is not eligible for Real-Time Commitment NCPC Credits for the duration of the Self-Schedule and is not eligible for Real-Time Dispatch NCPC Credits for the hours during which the audit is conducted.

iii. When a Market Participant requests that an audit be performed that requires the ISO to dispatch the Resource for the audit without advance notice the Market Participant is not eligible for Real-Time Commitment NCPC Credits for the duration of the commitment or Real-Time Dispatch NCPC Credits for the hours during which the audit is conducted.

iv. When an ISO-Initiated Claimed Capability Audit is performed pursuant to III.1.5.1.4, the Market Participant is not eligible for Real-Time Commitment NCPC Credits or Real-Time Dispatch NCPC Credits for the hours during which the audit is conducted if both of the following are true:

1. the Resource had a summer or winter Seasonal Claimed Capability equal to 0 MW at the beginning of the current Capability Demonstration Year, and

2. the ISO Initiated Claimed Capability Audit is the first Claimed Capability Audit that the Resource performs during that Capability Demonstration Year.

v. When a Market Participant notifies the ISO that it is conducting Facility and Equipment Testing for a Pool-Scheduled Resource, the Economic Minimum Limit in place at the time of the commitment decision is used for calculating Real-Time Commitment NCPC Credits and the Market Participant is not eligible for Real-Time Dispatch NCPC Credits for the hours during which the Facility and Equipment Testing is conducted.

vi. When a Market Participant notifies the ISO that it is conducting Facility and Equipment Testing for a Resource that Self-Scheduled, the Market Participant is not eligible for Real-Time Commitment NCPC Credits for the duration of the commitment and is not eligible for Real-Time Dispatch NCPC Credits for the hours during which the Facility and Equipment Testing is conducted.

The Real-Time NCPC Credit calculation for a Resource performing an audit uses the Start-Up Fee, No-Lead Fee and Economic Minimum Limit in the Effective Offer applicable to the Commitment Period during which the audit is conducted, and does not take account of any increases to the Economic Minimum Limit value that take place in the course of the audit.

g. Coordinated External Transactions are Not Eligible for NCPC and are excluded from NCPC Charges. Notwithstanding anything to the contrary in this Appendix F, Market Participants are not eligible to receive NCPC Credits for Coordinated External Transactions purchases or sales and shall be excluded from all NCPC Charge calculations under this Appendix F.

h. Following Dispatch Instructions. Generation Resources with an Economic Maximum Limit less than or equal to 50 MWs are considered to be following a Dispatch Instruction if the actual output of the Resource is not greater than 5 MWs above its Desired Dispatch Point and is not less than 5 MWs below its Desired Dispatch Point for each interval in the hour. If the Resource violates this criterion in any interval during the hour, the Resource is considered to be not following Dispatch Instructions for the entire hour.

Section III.F.2. NCPC Credits

III.F.2.1 Day-Ahead Energy Market NCPC Credits

III.F.2.1.1. Eligibility for Credit. All Market Participants with an Ownership Share in a Resource with a Supply Offer that clears the Day-Ahead Energy Market in an hour are eligible for Day-Ahead Energy Market NCPC Credits for the hour.

III.F.2.1.2. Settlement Period. For purposes of calculating Day-Ahead Energy Market NCPC Credits, a settlement period is a period of one or more contiguous hours in an Operating Day for which a Resource has cleared in the Day-Ahead Energy Market. A new settlement period

will begin any time a Resource's designation changes to or from a Fast Start Generator and the Resource is committed with the changed designation.

III.F.2.1.3. Eligible Quantity. The eligible quantity of energy for a Resource is the amount of energy the Resource clears in the Day-Ahead Energy Market for each hour of the settlement period.

III.F.2.1.4 Hourly Cost. The hourly cost for a Resource is equal to the energy price parameter for the eligible quantity, the Start-Up Fee and the No-Load Fee as reflected in the Effective Offer for each hour of the settlement period, subject to the following conditions.

III.F.2.1.4.1 The Start-Up Fee is apportioned equally over the hours from the time the Resource is scheduled to begin its commitment through the end of the Commitment Period during which the Minimum Run Time is scheduled to expire.

III.F.2.1.4.2 When the period of hours over which the Start-Up Fee is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Start-Up Fee.

III.F.2.1.5 Hourly Revenue. The hourly revenue for a Resource is equal to the Day-Ahead Price for each hour of the settlement period multiplied by the eligible quantity for the Resource.

III.F.2.1.6 Credit Calculation (non-Fast Start Generator). The Day-Ahead Energy Market NCPC Credit for a Resource, other than a Fast Start Generator, is equal to the greater of (i) zero, and; (ii) the total hourly cost for the Resource in all hours of the settlement period minus the total hourly revenue for the Resource in all hours of the settlement period.

III.F.2.1.7 Credit Calculation (Fast Start Generator). The Day-Ahead Energy Market NCPC Credit for a Fast Start Generator is equal to, for each hour of the settlement period, the greater of (i) zero,

and; (ii) the hourly cost for the Resource in an hour minus the hourly revenue for the Resource in the hour.

III.F.2.2 Real-Time Energy Market NCPC Credits

Real-Time Energy Market NCPC Credits include a Real-Time Commitment NCPC Credit and a Real-Time Dispatch NCPC Credit.

III.F.2.2.1 Eligibility for Credit. All Market Participants with an Ownership Share in a Resource with a Supply Offer that has been submitted in the Real-Time Energy Market in an hour are eligible for Real-Time Energy Market NCPC Credits for the hour.

III.F.2.2.2 Real-Time Commitment NCPC Credits

III.F.2.2.2.1. Settlement Period. For purposes of calculating Real-Time Commitment NCPC Credits, a settlement period is a period of one or more contiguous hours in an Operating Day during which a Resource is online and operating pursuant to one or more commitments in the Day-Ahead Energy Market or Real-Time Energy Market. A new settlement period will begin any time a Resource's designation changes to or from a Fast Start Generator and the Resource is committed with the changed designation. In the event of an interruption in operation of a Resource, operation will be considered contiguous if the Resource returns to operation in accordance with the original commitment issued prior to the interruption.

III.F.2.2.2.2. Eligible Quantity.

III.F.2.2.2.2.1. For determining the hourly costs used in calculating a Real-Time Commitment NCPC Credit, the eligible quantity of energy for a Resource is the amount of energy equal to the lesser of the Resource's actual metered output or Economic Dispatch Point for the hour.

III.F.2.2.2.2.2 For determining the hourly revenues used in calculating a Real-Time Commitment NCPC Credit, the eligible quantity of energy for a Resource is the lesser of the Resource's actual metered output or Economic Dispatch Point for the hour, except that actual metered output is used as the eligible quantity (i) when the Resource is not eligible for a Real-Time Dispatch NCPC Credit and the Real-Time Price is

not below zero for the hour, (ii) when the Resource is ramping from an offline state to be released for dispatch and (iii) after the Resource has been released for shutdown.

III.F.2.2.2.3. Hourly Cost. The hourly cost for a Resource is equal to the energy price parameter for the eligible quantity as reflected in the Effective Offer, and the Start-Up Fee and No-Load Fee as reflected in the Effective Offer, for each hour of the settlement period, subject to the following conditions.

III.F.2.2.2.3.1 The energy cost for an hour excludes the cost of energy produced when the Resource is ramping from an offline state to be released for dispatch and energy produced after the Resource has been released for shutdown.

III.F.2.2.2.3.2 The Start-Up Fee is apportioned equally over the hours from the time the Resource is released for dispatch through the end of the Commitment Period during which the Minimum Run Time is scheduled to expire, subject to the following conditions:

(a) The Start-Up Fee is reduced in proportion to the number of minutes after 30 the Resource is released for dispatch, as measured from the time the Resource was scheduled to be released for dispatch, divided by the time from when the Resource was scheduled to be released for dispatch through the end of the Commitment Period during which the Minimum Run Time was scheduled to expire.

(b) The Start-Up Fee is excluded from the hourly costs calculation if the Resource is synchronized to the system prior to its scheduled synchronization time without the ISO's approval of the Resource's synchronization as a Pool-Scheduled Resource.

(c) The portion of the Start-Up Fee apportioned to any hour during which the Resource is not online because the Resource has tripped is excluded from the hourly cost calculation, except in the event the Resource is not online due to a trip that results from equipment failure involving equipment located on the electric network beyond the low voltage terminals of the Resource's step-up transformer. It is the responsibility of the Lead Market Participant for the Resource to inform the ISO at xtrip@iso-ne.com within 30 days that the trip was the result of such a transmission-related event.

(d) The Start-Up Fee is not reduced when the Resource has shutdown with the ISO's approval prior to the end of its Commitment Period.

(e) The additional Start-Up Fee for a Resource requested to re-start following a trip is apportioned equally over the remaining hours of the Commitment Period when the ISO requests a Resource to re-start to complete its Commitment Period.

(f) When the period of hours over which the Start-Up Fee is apportioned carries over into a subsequent Operating Day, the corresponding settlement period for the beginning of the subsequent Operating Day includes the remaining portion of the Start-Up Fee.

III.F.2.2.2.3.3. The No-Load Fee is applied to each hour during the period when the Resource is online following its release for dispatch and prior to its release for shutdown. The No-Load Fee is pro-rated for the hour during which the Resource is released for dispatch, the hour during which the Resource is released for shutdown, and any other hour during which the Resource operates for less than 60 minutes.

III.F.2.2.2.4 Hourly Revenue. The hourly revenue for a Resource is equal to the Real-Time Price for each hour of the settlement period multiplied by the eligible quantity. The hourly revenue for an hour is increased by the amount by which the hourly revenues in the Real-Time Dispatch NCPC Credit calculation in Section III.F.2.2.3.4 exceed the hourly costs in the Real-Time Dispatch NCPC Credit calculation in Section III.F.2.2.3.3 for that hour. The revenues when the Resource is ramping from an offline state to be released for dispatch are apportioned equally to the hours of the Minimum Run Time.

III.F.2.2.2.4.1. Revenues for output up to the Resource's Economic Minimum Limit in a Self-Scheduled hour, calculated as the Real-Time Price multiplied by the output, are excluded from the hourly revenue for the Real-Time Commitment NCPC Credit calculation.

III.F.2.2.2.5 Credit Calculation (for non-Fast Start Generators). The Real-Time Commitment NCPC Credit for a Resource, other than a Fast Start Generator, is equal to:

(a) for the portion of each Commitment Period within a settlement period that contain hours of the Minimum Run Time, the greater of (i) zero, and; (ii) the total hourly cost for the Resource for the period minus the total hourly revenue for the Resource for the period,

plus,

(b) for each remaining hour of the settlement period following the completion of the Minimum Run Time, the greater of ((i) zero, and; (ii) the maximum potential net revenues for the Resource in the period) minus the actual net revenues for the Resource in the period, where

(i) The maximum potential net revenue is the maximum accumulated net hourly revenue for operating and then shutting down during the period.

(ii) The actual net revenue is the accumulated net hourly revenue over the period.

(iii) The net hourly revenue is the hourly revenues minus hourly costs in each hour of the period.

III.F.2.2.2.6. Credit Calculation (for Fast Start Generators). The Real-Time Commitment NCPC Credit for a Fast Start Generator is equal to, for each hour of the settlement period, the greater of (i) zero, and; (ii) the hourly cost for the Resource in an hour minus the hourly revenue for the Resource in the hour.

III.F.2.2.3. Real-Time Dispatch NCPC Credits

III.F.2.2.3.1 Settlement Period. For purposes of calculating Real-Time Dispatch NCPC Credits, a settlement period is an hour when the Desired Dispatch Point and the actual metered output for a Resource are each greater than its Economic Dispatch Point, excluding any period of time when the Resource is ramping from an offline state to be released for dispatch and after the Resource has been released for shutdown.

III.F.2.2.3.2. Eligible Quantity.

III.F.2.2.3.2.1. For determining the hourly costs used in calculating a Real-Time Dispatch NCPC Credit, the eligible quantity of energy for a Resource is the Resource's Economic Dispatch Point for the hour subtracted from the lesser of the Resource's actual metered output or Desired Dispatch Point for the hour.

III.F.2.2.3.2.2. For determining the hourly revenues used in calculating a Real-Time Dispatch NCPC Credit, the eligible quantity of energy for a Resource is the Resource's actual metered output for the hour minus the Resource's Economic Dispatch Point for the hour, except that the Resource's Economic Dispatch Point for the hour subtracted from the lesser of the Resource's actual metered output or Desired Dispatch Point for the hour is used as the eligible quantity when the Real-Time Price is below zero for the hour.

III.F.2.2.3.3 Hourly Cost. The hourly cost for a Resource is equal to the energy price parameter for the eligible quantity as reflected in the Effective Offer and does not include the Start-Up Fee or the No-Load Fee.

III.F.2.2.3.4 Hourly Revenue. The hourly revenue for a Resource is equal to the Real-Time Price for the hour multiplied by the eligible quantity, plus the portion of regulation opportunity costs attributed to operation in response to Regulation AGC dispatch signals at a level above the Resource's expected economic dispatch level, as specified in Section III.14.8(b)(ii).

III.F.2.2.3.5. Credit Calculation. The Real-Time Dispatch NCPC Credit for a Resource in an hour is equal to the greater of (i) zero and (ii) the hourly cost minus the hourly revenue for the Resource.

III.F.2.3. Special Case NCPC Credit Calculations

III.F.2.3.1. Day-Ahead External Transaction Import and Increment Offer NCPC Credits

III.F.2.3.1.1. Eligibility for Credit. All Market Participants with pool-scheduled External Transaction imports or Increment Offers at an External Node are eligible for Day-Ahead External Transaction Import and Increment Offer NCPC Credits, with the exception of External Transactions that are conditioned upon Congestion Costs not exceeding a specified level.

III.F.2.3.1.2. Hourly Offer. The Day-Ahead offer for a pool-scheduled External Transaction import or Increment Offer at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the offer price.

III.F.2.3.1.3. Hourly Revenue. The Day-Ahead revenue for a pool-scheduled External Transaction import or Increment Offer at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead Price.

III.F.2.3.1.4. Credit Calculation. A Day-Ahead External Transaction Import and Increment Offer NCPC Credit for an External Transaction import or Increment Offer, for an hour, is equal to any portion of the Day-Ahead offer in excess of the Day-Ahead revenue for the hour; provided, however, that if a Market Participant has a pool-scheduled External Transaction import or Increment Offer for a given External Node and hour and the Market Participant or its Affiliate also has an External Transaction export or Decrement Bid for the same External Node and hour, the Day-Ahead External Transaction Import and Increment Offer NCPC Credit for the hour is calculated only for any amount (MW) of the External Transaction import or Increment Offer at the External Node for the hour that is not offset by the amount (MW) of the External Transaction export or Decrement Bid at the External Node for the hour. If multiple External Transaction imports or Increment Offers at an External Node are eligible for a Day-Ahead External Transaction Import and Increment Offer NCPC Credit, then for purposes of the offsetting determination in the prior sentence External Transaction imports and Increment Offers will be offset in order from the highest to the lowest-priced transactions or offers.

III.F.2.3.2. Day-Ahead External Transaction Export and Decrement Bid NCPC Credits

III.F.2.3.2.1. Eligibility for Credit. All Market Participants with pool-scheduled External Transaction exports or Decrement Bids at an External Node are eligible for Day-Ahead External Transaction Export and Decrement Bid NCPC Credits, with the exception of External Transactions that are conditioned upon Congestion Costs not exceeding a specified level.

III.F.2.3.2.2. Hourly Bid. The Day-Ahead bid for a pool-scheduled External Transaction export or Decrement Bid at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the bid price.

III.F.2.3.2.3. Hourly Cost. The Day-Ahead cost for a pool-scheduled External Transaction export or Decrement Bid at an External Node for an hour is equal to the cleared Day-Ahead transaction amount (MW) for the hour multiplied by the Day-Ahead Price at the External Node.

III.F.2.3.2.4. Credit Calculation. A Day-Ahead External Transaction Export and Decrement Bid NCPC Credit for an External Transaction export or Decrement Bid, for an hour, is equal to any portion of the Day-Ahead hourly cost in excess of its Day-Ahead hourly bid for the hour; provided, however, that if a Market Participant has a pool-scheduled External Transaction export or Decrement Bid for a given External Node and hour and the Market Participant or its Affiliate also has an External Transaction import or Increment Offer for the same External Node and hour, the Day-Ahead External Transaction Export and Decrement Bid NCPC Credit for the hour is calculated only for any amount (MW) of the External Transaction export or Decrement Bid at the External Node for the hour that is not offset by the amount (MW) of the total cleared External Transaction import or Increment Offer at the External Node for the hour. If multiple External Transaction exports or Decrement Bids at an External Node are eligible for a Day-Ahead External Transaction Export and Decrement Bid NCPC Credit, then for purposes of the offsetting determination in the prior sentence External Transaction exports and Decrement Bids will be offset in order from the lowest to the highest-priced transactions or bids.

III.F.2.3.3. Real-Time External Transaction NCPC Credits (Import and Export)

III.F.2.3.3.1. Eligibility for Credit. All Market Participants that submit pool-scheduled External Transactions (import or export) are eligible for Real-Time External Transaction NCPC Credits, with the exception of External Transactions to wheel energy through the New England Control Area.

III.F.2.3.3.2. Eligible Quantity.

(a) For each hour, the eligible quantity of energy for an External Transaction in the Real-Time Energy Market that either (i) did not clear in the Day-Ahead Energy Market, or (ii) cleared in the Day-Ahead Energy Market and the price was subsequently revised in the Re-Offer Period, is the External Transaction amount (MW) pool-scheduled in the Real-Time Energy Market.

(b) For each hour, the eligible quantity of energy for an External Transaction in the Real-Time Energy Market that cleared in the Day-Ahead Energy Market and the price was not subsequently revised in the Re-Offer Period, is the Real-Time scheduled transaction amount in excess of the cleared Day-Ahead scheduled transaction amount.

III.F.2.3.3.3. Hourly Offer. The hourly offer for a pool-scheduled External Transaction import for an hour is equal to the eligible quantity multiplied by the offer price for the hour.

III.F.2.3.3.4. Hourly Revenue. The hourly revenue for a pool-scheduled External Transaction import for an hour is equal to the eligible quantity multiplied by the Real-Time Price for the hour.

III.F.2.3.3.5. Hourly Bid. The hourly bid for a pool-scheduled External Transaction export for an hour is equal to the eligible quantity multiplied by the bid price for the hour.

III.F.2.3.3.6. Hourly Cost. The Real-Time cost for a pool-scheduled External Transaction export for an hour is equal to the eligible quantity multiplied by the Real-Time Price.

III.F.2.3.3.7. Credit Calculation. A Real-Time External Transaction NCPC Credit for an External Transaction import for an hour is equal to any portion of the hourly offer in excess of the hourly revenue. A Real-Time External Transaction NCPC Credit for an External Transaction export for an hour is equal to any portion of the hourly cost in excess of the hourly bid.

III.F.2.3.4. Real-Time Posturing NCPC Credits for Dispatchable Asset Related Demand Resources (Pumps Only) Postured for Reliability

III.F.2.3.4.1. Eligibility for Credit. All Market Participants with an Ownership Share in a Dispatchable Asset Related Demand Resource are eligible for real-time posturing NCPC credits for the pumping of a Dispatchable Asset Related Demand Resource that has been Postured to increase consumption.

III.F.2.3.4.2. Eligible Quantity. The eligible quantity for a Resource for each hour is the lesser of the Desired Dispatch Point or the Resource's actual metered consumption.

III.F.2.3.4.3. Hourly Bid. The hourly bid is the greater of, for the eligible quantity of the Resource, the Demand Bid for the hour at the time the ISO initiates the Posturing action or the Demand Bid for the hour if revised after the Posturing action is initiated.

III.F.2.3.4.4. Hourly Cost. The hourly cost is equal to the eligible quantity multiplied by the Real-Time Price.

III.F.2.3.4.5. Credit Calculation. The real-time posturing NCPC credit for an hour for the pumping of a Postured Dispatchable Asset Related Demand Resource is equal to any portion of the hourly cost in excess of the hourly bid.

III.F.2.3.5. Real-Time Synchronous Condensing NCPC Credits

III.F.2.3.5.1. Eligibility for Credit. All Market Participants with an Ownership Share in a Resource that is dispatched as a Synchronous Condenser are eligible for Real-Time Synchronous Condensing NCPC Credits.

III.F.2.3.5.2. Condensing Offer Amount. The condensing offer amount for a Resource is equal to the number of hours that the Resource is dispatched as a Synchronous Condenser in an Operating Day multiplied by the hourly price to condense as specified in the Offer Data for the Resource. For a Resource committed from an offline state to provide synchronous condensing, the condensing offer amount includes the condensing start-up fee as specified in the Offer Data for the Resource. In the event an hourly price to condense or condensing start-up fee is not included in the Offer Data for the Resource for the hours that the Resource is dispatched as a Synchronous Condenser, the value for the parameter will be zero.

III.F.2.3.5.3. Credit Calculation. The Real-Time Synchronous Condensing NCPC Credit for a Resource for an Operating Day is equal to the condensing offer amount for that Operating Day.

III.F.2.3.6. Cancelled Start NCPC Credits

III.F.2.3.6.1. Eligibility for credit. All Market Participants with an Ownership Share in a Pool-Scheduled Resource are eligible for Cancelled Start NCPC Credits if the ISO cancels its commitment of the Pool-Schedule Resource before the Resource is synchronized to the New England Transmission System, except that a Market Participant is not eligible for a credit under the following conditions:

(a) The start is cancelled before the commencement of the Notification Time;
(b) The Resource's Notification Time as reflected in the Effective Offer is equal to or greater than 24 hours;
(c) The Resource is synchronized to the New England Transmission System for a Self-Schedule within the period of time equal to the lesser of its Minimum Down Time or 10 hours after receiving the ISO cancelled start order; or
(d) The Resource fails to meet its scheduled synchronization time and the ISO cancelled start order is issued more than two hours after the Resource's scheduled synchronization time.

III.F.2.3.6.2. Credit Calculation. The Cancelled Start NCPC Credit for a Resource is equal to the Start-Up Fee reflected in the Effective Offer multiplied by the percentage of the Notification Time, as reflected in the Effective Offer, that the Resource completed prior to the ISO cancelled start order, where:

(a) The percentage of Notification Time completed is equal to the number of minutes after the start of the Notification Time the Resource was cancelled divided by the Notification Time, and cannot exceed 100%.

III.F.2.3.7. Hourly Shortfall NCPC Credits

III.F.2.3.7.1. Eligibility for Credit. All Market Participants with an Ownership Share in a generating Resource that is pool-scheduled in the Day-Ahead Energy Market are eligible for Hourly Shortfall NCPC Credits for an hour if the ISO cancels its commitment of a non-Fast Start Generator or does not dispatch a Fast Start Generator for the hour and the Resource is offline and available for operation, except that a Market Participant is not eligible for a credit under the following conditions:

(a) The Resource has been Postured for all or part of the hour;
(b) The Resource is a Limited Energy Resource that has been Postured during a prior hour in the Operating Day; or
(c) The Resource is an Intermittent Power Resource.

III.F.2.3.7.2. Settlement Period. For purposes of calculating Hourly Shortfall NCPC Credits, a settlement period is a period of one or more contiguous hours in an Operating Day during which a Resource is eligible for an Hourly Shortfall NCPC Credit. A new settlement period will begin any time a Resource's designation changes to or from a Fast Start Generator and the Resource is committed with the changed designation.

III.F.2.3.7.3. Eligible Quantity. The eligible quantity for each hour of the settlement period is:

(a) zero for a Fast Start Generator in the event the total of the energy price parameter, Start-Up Fee parameter and No-Load Fee parameter of the Supply Offer in the Real-Time Energy Market for the amount of energy cleared in the Day-Ahead Energy Market for the hour is greater than the total of the corresponding parameters of the Effective Offer in the Day-Ahead Energy Market for the hour;
    i. For purposes of this evaluation, (1) if the ISO is not able to honor a request to be Self-Scheduled for the hour under Section III.1.10.9(d), the Start-Up Fee, No-Lead Fee and energy at the Economic Minimum Limit are equal to $0, and (2) if the ISO is not able to honor a request to be dispatched for the hour under Section III.1.10.9(e), the Start-Up Fee and No-Lead Fee are equal to $0 and the energy at the requested dispatch level is the Energy Price Floor.
(b) the Day-Ahead Economic Minimum Limit for a non-Fast Start Generator in the event the total of the energy price parameter of the Supply Offer in the Real-Time Energy Market for the amount of energy cleared in the Day-Ahead Energy Market above the Day-Ahead Economic Minimum Limit for an

hour is greater than the total of the corresponding parameters of the Effective Offer in the Day-Ahead Energy Market for the hour;

and if neither (a) nor (b) applies, then

(c) the minimum of (i) the amount of energy cleared in the Day-Ahead Energy Market for an hour and (ii) the Resource's Economic Maximum Limit or a Limited Energy Resource limit imposed for the hour in the Real-Time Energy Market.

III.F.2.3.7.4. Credit Calculation (for non-Fast Start Generators). The Hourly Shortfall NCPC Credit for a Resource, other than a Fast Start Generator, is equal to:

(a) the greater of (i) zero and (ii) the total of (the Real-Time Price minus the Day-Ahead Price for an hour, multiplied by the Day-Ahead Economic Minimum Limit for the hour) for all hours of the settlement period,

plus

(b) for each hour of the settlement period, the greater of (i) zero and (ii) the Real-Time Price minus the Day-Ahead Price for an hour, multiplied by the eligible quantity minus the Day-Ahead Economic Minimum Limit for the hour.

III.F.2.3.7.5. Credit Calculation (for Fast Start Generators). The Hourly Shortfall NCPC Credit for a Fast Start Generator is equal to, for each hour of the settlement period, the greater of (i) zero, and (ii) the Real-Time Price minus the Day-Ahead Price for an hour, multiplied by the eligible quantity for the hour.

III.F.2.3.8. Real-Time Posturing NCPC Credits for Limited Energy Resources Postured for Reliability

III.F.2.3.8.1. Eligibility for Credit. All Market Participants with an Ownership Share in a Limited Energy Resource are eligible for real-time posturing NCPC credits for any Operating Day during which the Resource has been Postured, when a request to minimize the as-bid production costs of the Resource has been submitted. For purposes of calculating real-time posturing NCPC credits, the Resource is treated

as a Fast Start Generator only if it is designated as such at the time of the commitment decision for the Commitment Period during which the Resource was Postured, and if not the Resource is treated as a non-Fast Start Generator. If the Resource is offline at the time it is Postured, then its designation as a Fast Start Generator or non-Fast Start Generator is determined as of the time of the Posturing decision.

III.F.2.3.8.2. Settlement Period. For purposes of calculating real-time posturing NCPC credits for Limited Energy Resources, a settlement period is the period of one or more contiguous hours from the initiation of Posturing through the end of the Operating Day.

III.F.2.3.8.3 Resources Sharing a Single Fuel Source. When Limited Energy Resources that share a fuel source are Postured, for purposes of calculating real-time posturing NCPC credits the energy available to the Postured Resources will be allocated among the Postured Resources sharing the fuel source as indicated by estimates of available energy provided by the Lead Market Participant for each Resource prior to Posturing.

III.F.2.3.8.4. Estimated Replacement Cost of Energy. The estimated replacement cost of energy is (i) the average of the Day-Ahead Prices for hours ending 3 through 5 in the subsequent Operating Day for pumped storage generators, or (ii) the product of the oil index price multiplied by the oil-fired generator proxy heat rate for fuel oil-fired generators, or (iii) zero for Resources other than pumped storage generators and fuel oil-fired generators.

For fuel oil-fired generators, the oil index price is the ultra low-sulfur No. 2 oil measured at New York Harbor plus a seven percent markup for transportation, and the oil-fired generator proxy heat rate is the average of the heat rate at Economic Min and the heat rate at Economic Max, where the heat rate at Economic Min is, for a Resource, the average hourly energy price parameter of the Supply Offer at the Resource's Economic Minimum Limit at the time of the Posturing decision divided by the oil index price, and the heat rate at Economic Max is, for a Resource, the average hourly energy price parameter of the Supply Offer at the Resource's Economic Maximum Limit at the time of the Posturing decision divided by the oil index price.

III.F.2.3.8.5. Estimated Revenue. The estimated revenue for a Resource is the optimized energy output multiplied by the Real-Time Price for all hours in the settlement period. The optimized energy

output is estimated for each hour by allocating the Postured energy to hours that the Resource would have operated had it not been Postured based on Real-Time Prices in the Operating Day, subject to the following conditions:

(a) the optimized energy output determination will take account of the Resource's Economic Minimum Limit, and Economic Maximum Limit.
(b) the optimized energy output determination will take account of the estimated avoided cost of replacing energy that is not allocated to any hour and remains available at the end of the Operating Day.
(c) for non-Fast Start Generators, the optimized energy output is calculated for the contiguous hours from the time the Resource is Postured until the available energy is depleted.

III.F.2.3.8.6. Estimated Avoided Replacement Cost. The estimated avoided replacement cost for an Operating Day is the remaining energy that would have been available at the end of the Operating Day had the Resource operated in accordance with the optimized energy output determination in Section III.F.2.3.8.5, plus any increase in the remaining energy resulting from pumping during the Operating Day after the Resource is Postured, multiplied by the estimated replacement cost of energy.

III.F.2.3.8.7. Actual Revenue. The actual revenue for a Resource is the actual metered output multiplied by the Real-Time Price for all hours in the settlement period.

III.F.2.3.8.8. Actual Avoided Replacement Cost. The actual avoided replacement cost for an Operating Day is the actual remaining energy at the end of the Operating Day multiplied by the estimated replacement cost of energy.

III.F.2.3.8.9. Credit Calculation. The real-time posturing NCPC credit for Limited Energy Resources is equal to the greater of (i) zero and (ii) the estimated revenue plus the estimated avoided replacement cost, minus the actual revenue plus the actual avoided replacement cost.

III.F.2.3.9. Real-Time Posturing NCPC Credits for Generators (Other Than Limited Energy Resources) Postured for Reliability

III.F.2.3.9.1. Eligibility for Credit. All Market Participants with an Ownership Share in a generating Resource, other than a Limited Energy Resource, are eligible for real-time posturing NCPC credits for the hours during which the Resource has been Postured.

III.F.2.3.9.2. Settlement Period. For purposes of calculating real-time posturing NCPC credits, a settlement period is an hour during which the generating Resource is Postured.

III.F.2.3.9.3. Offer Used for Estimated Hourly Revenue and Cost. For purposes of calculating real-time posturing NCPC credits, the offer parameters used to estimate revenue and cost for an hour are:

(a) the higher of the energy price parameter specified in (i) the Supply Offer for the hour at the time the ISO Postures the Resource, or (ii) the Supply Offer for the hour at the start of the hour.
(b) for Resources Postured offline, the Start-Up Fee and No-Load Fee specified in the Supply Offer for the hour at the time the Resource is Postured.
(c) for Resources Postured to remain online but reduce output, the Start-Up Fee and No-Load Fee are calculated pursuant to Section III.F.2.2.2.3.

III.F.2.3.9.4. Estimated Hourly Revenue. The estimated hourly revenue for a Resource is the optimized energy output multiplied by the Real-Time Price for the hour. The optimized energy output is estimated for each hour by determining where the Resource would have operated had it not been Postured based on Real-Time Prices. The optimized energy output determination will take account of the energy price parameter of the Supply Offer and the Resource's Economic Minimum Limit and Economic Maximum Limit.

III.F.2.3.9.5. Estimated Hourly Cost. The estimated hourly cost for a Resource is the energy price parameter of the Supply Offer for the optimized energy output for the hour, plus the Start-Up Fee and the No-Load Fee, subject to the following conditions:

(a) For a Fast Start Generator Postured offline, the Start-Up Fee is included in each hour's cost and is not subject to apportionment.

(b) For a non-Fast Start Generator Postured offline, the Start-Up Fee is apportioned, in accordance with Section III.F.2.2.2.3.2, as if its commitment had not been cancelled.

For purposes of determining the estimated hourly cost for a Resource, the Resource is treated as a Fast Start Generator only if it is designated as such at the time of the commitment decision for the Commitment Period during which the Resource was Postured, and if not the Resource is treated as a non-Fast Start Generator. If the Resource is offline at the time it is Postured, then its designation as a Fast Start Generator or non-Fast Start Generator is determined as of the time of the Posturing decision.

III.F.2.3.9.6. Actual Hourly Revenue. The actual hourly revenue for a Resource is the actual metered output multiplied by the Real-Time Price for the hour.

III.F.2.3.9.7. Actual Hourly Cost. The actual hourly cost for a Resource Postured to remain online but reduce output is the energy price parameter of the Supply Offer in place at the start of the hour for the actual metered output, plus the Start-Up Fee and No-Load Fee calculated pursuant to Section III.F.2.2.2.3. The actual hourly cost for a Resource Postured offline is zero.

III.F.2.3.9.8. Credit Calculation. The real-time posturing NCPC credit for a generator, other than a Limited Energy Resource, is equal to the greater of (i) zero and (ii) the estimated hourly revenue minus the estimated hourly cost, minus the actual hourly revenue minus actual hourly cost.

III.F.2.4. Apportionment of NCPC Credits

Each of the Day-Ahead Energy Market NCPC Credits for a non-Fast Start Generator are apportioned to the hours with negative net revenues in proportion to each hour's negative net revenue divided by the sum of the negative net revenue for all hours in the settlement period.

Each of the Real-Time Commitment NCPC Credits for a non-Fast Start Generator is apportioned as follows: (i) for the portion of each Commitment Period within a settlement period that contains hours of the Minimum Run Time, to the hours with negative net revenues in proportion to each hour's negative net revenue divided by the sum of the negative net revenue in the portion of the Commitment Period, and (ii)

for all remaining hours of the settlement period, to the hours with negative net revenues in proportion to each hour's negative net revenue divided by the sum of the negative net revenue in the period.

Each of the Hourly Shortfall NCPC Credits for a non-Fast Start Generator for energy cleared in the Day-Ahead Energy Market at the Resource's Economic Minimum Limit is apportioned to the hours in which the Real-Time Price exceeds the Day-Ahead Price, for all hours in the settlement period .

The following NCPC credits are assigned to the hours for which the credit was calculated:

- Day-Ahead Energy Market NCPC Credits for Fast Start Generators,
- Real-Time Commitment NCPC Credits for Fast Start Generators,
- Real-Time Dispatch NCPC Credits for all Resources,
- Day-Ahead External Transaction Import and Increment Offer NCPC Credits,
- Day-Ahead External Transaction Export and Decrement Bid NCPC Credits,
- Real-Time External Transaction NCPC Credits,
- Real-Time Posturing NCPC Credits for Dispatchable Asset Related Demand Resources (Pumps Only) Postured for Reliability,
- Hourly Shortfall NCPC Credits for Fast Start Generators, and
- Hourly Shortfall NCPC Credits for non-Fast Start Generators for energy cleared in the Day-Ahead Energy Market above the Resource's Economic Minimum Limit.

III.F.2.5. NCPC Credit Designation for Purposes of NCPC Cost Allocation. Each hourly credit for Day-Ahead Energy Market NCPC Credits, Real-Time Commitment NCPC Credits, Real-Time Dispatch NCPC Credits, Day-Ahead External Transaction Import and Increment Offer NCPC Credits, Day-Ahead External Transaction Export and Decrement Bid NCPC Credits, Real-Time External Transaction NCPC Credits, Real-Time Posturing NCPC Credits for Dispatchable Asset Related Demand Resources (Pumps Only) Postured for Reliability, Hourly Shortfall NCPC Credits, and Real-Time Posturing NCPC Credits for Generators (Other Than Limited Energy Resources) Postured For Reliability, and each daily credit for Real-Time Synchronous Condensing NCPC Credits, Cancelled Start NCPC Credits, and Real-Time Posturing NCPC Credits for Limited Energy Resources Postured for Reliability, is designated as first contingency, second contingency, voltage (VAR), distribution (SCR), ISO initiated

audits and Minimum Generation Emergency consistent with the reason provided by the ISO when issuing a Dispatch Instruction for the Resource. If there is more than one reason provided by the ISO when issuing the Dispatch Instruction, the NCPC Credits are divided equally for purposes of the above designations. With the exception of Day-Ahead External Transaction Import and Increment Offer NCPC Credits and Day-Ahead External Transaction Export and Decrement Bid NCPC Credits, the hourly credits are summed to determine the total credits for each NCPC Charge category for a day.

III.F.3. Charges for NCPC

III.F.3.1. Cost Allocation.

III.F.3.1.1 Day-Ahead Energy Market NCPC Cost Allocation. NCPC costs for the Day-Ahead Energy Market are allocated and charged as follows:

(a) The total NCPC cost for the Day-Ahead Energy Market associated with Pool-Scheduled Resources scheduled in the Day-Ahead Energy Market for the provision of voltage or VAR support (including Synchronous Condensers and Postured Resources but excluding Special Constraint Resources) are charged in accordance with the provisions of Schedule 2 of Section II of the Transmission, Markets and Services Tariff.

(b) The total NCPC cost for the Day-Ahead Energy Market for resources designated as Special Constraint Resources in the Day-Ahead Energy Market are allocated and charged in accordance with Schedule 19 of Section II of the Transmission, Markets and Services Tariff.

(c) The total NCPC cost for the Day-Ahead Energy Market for resources identified as Local Second Contingency Protection Resources for the Day-Ahead Energy Market for one or more Reliability Regions is allocated and charged in accordance with Section III.F.3.3.

(d) For each External Node, the total NCPC cost for Day-Ahead External Transaction Import and Increment Offer NCPC Credits at an External Node for an hour is allocated and charged to Market Participants based on their pro-rata share of the sum of their Day-Ahead Load Obligations at the External Node for the hour.

(e) For each External Node, the total Day-Ahead External Transaction Export and Decrement Bid NCPC Credits at an External Node for an hour is allocated and charged to Market Participants based on their pro-rata share of the sum of their Day-Ahead Generation Obligations at the External Node for the hour.

(f) All remaining NCPC costs for the Day-Ahead Energy Market are allocated and charged to Market Participants based on their pro rata daily share of the sum of of Day-Ahead Load Obligations over all Locations (including the Hub),

III.F.3.1.2. Real-Time Energy Market NCPC Cost Allocation. NCPC costs for the Real-Time Energy Market are allocated and charged as follows, subject t the conditions in Section III.F.3.1.3:

(a) The total NCPC cost for the Real-Time Energy Market associated with Pool-Scheduled Resources scheduled in the Real-Time Energy Market for the provision of voltage or VAR support (including Synchronous Condensers and Postured Resources but excluding Special Constraint Resources) are allocated and charged in accordance with the provisions of Schedule 2 of Section II of the Transmission, Markets and Services Tariff.

(b) The total NCPC cost for the Real-Time Energy Market for resources designated as Special Constraint Resources in the Real-Time Energy Market are allocated and charged in accordance with Schedule 19 of Section II of the Transmission, Markets and Services Tariff.

(c) The total ISO initiated audit NCPC cost for resources performing an ISO initiated audit is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with Dispatchable Asset Related Demand Resources (pumps only).

(d) The total NCPC cost for resources following Dispatch Instructions while being postured in the Real-Time Energy Market is allocated and charged to Market Participants based on their pro rata daily share of the sum of their Real-Time Load Obligations, excluding Real-Time Load Obligations associated with postured Dispatchable Asset Related Demand Resources (pumps only).

(e) The total NCPC cost for the Real-Time Energy Market for resources identified as Local Second Contingency Protection Resources for the Real-Time Energy Market for one or more Reliability Regions is allocated and charged in accordance with Section III.F.3.3.

(f) Total Minimum Generation Emergency Credits within a Reliability Region are allocated and charged hourly to Market Participants based on each Market Participant's pro rata share of Real-Time Generation Obligations, excluding that portion of a Market Participant's Real-Time Generation Obligation within a Reliability Region that is eligible for a Real-Time Dispatch NCPC Credit pursuant to Section III.F.2.2.3 during a Minimum Generation Emergency.

(g) All remaining NCPC costs for the Real-Time Energy Market are allocated and charged to Market Participants based on their pro rata daily share of the sum of the absolute values of a Market Participant's (i) Real-Time Load Obligation Deviations in MWhs during that Operating Day; (ii) generation deviations for Pool-Scheduled Resources not following Dispatch Instructions, Self-Scheduled Resources with dispatchable increments above their Self-Scheduled amounts not following Dispatch Instructions, and Self-Scheduled Resources

not following their Day-Ahead Self-Scheduled amounts other than those Self-Scheduled Resources that are following Dispatch Instructions, including External Resources, in MWhs during the Operating Day; and (iii) deviations from the Day-Ahead Energy Market for External Transaction purchases in MWhs during the Operating Day. The Real-Time deviations calculation is specified in greater detail in Section III.F.3.2.

III.F.3.1.3 Additional Conditions for Real-Time Energy Market NCPC Cost Allocation.

(a) If a generation resource has been scheduled in the Day-Ahead Energy Market and the ISO determines that the unit should not be run in order to avoid a Minimum Generation Emergency, the generation owner will be responsible for all Real-Time Energy Market Deviation Energy Charges but will not incur generation related deviations for the purpose of allocating NCPC costs for the Real-Time Energy Market.

(b) Any difference between the actual consumption (Real-Time Load Obligation) of Dispatchable Asset Related Demand Resources and Dispatchable Asset Related Demand bids that clear in the Day-Ahead Energy Market that result from operation in accordance with the ISO's instructions shall be excluded from the Market Participant Real-Time Load Obligation Deviation for the purpose of allocating costs for Real-Time Energy Market NCPC Credits.

III.F.3.2 Market Participant Share of Real-Time Deviations for Real-Time Energy Market NCPC Credits.

Each Market Participant's pro-rata share of the Real-Time deviations for Real-Time Energy Market NCPC Credits is the following:

(a) If the Day-Ahead Economic Minimum Limit is equal to the Real-Time Economic Minimum Limit and the Real-Time Economic Minimum Limit is greater than or equal to the Resource's Desired Dispatch Point: Real-Time generation deviation is the greater of the absolute value of (actual metered output – cleared Day-Ahead MWh) or (actual metered output – Real-Time Economic Minimum Limit) for each generating Resource. If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

(b) If the Day-Ahead Economic Minimum Limit is not equal to Real-Time Economic Minimum Limit and the Real-Time Economic Minimum Limit is greater than or equal to the Resource's Desired Dispatch Point: Real-Time generation deviation is the greatest of the absolute value of (actual metered

output – cleared Day-Ahead MWh) or (actual metered output – Real-Time Economic Minimum Limit) or (Real-Time Economic Minimum Limit – Day-Ahead Scheduled Economic Minimum Limit) for each generating Resource.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

(c) If the Resource's Desired Dispatch Point is greater than the Resource's Real-Time Economic Minimum Limit and the Resource is not following ISO Dispatch Instructions: Real-Time generation deviation is the absolute value of (actual metered output - Desired Dispatch Point).

If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

plus

(d) for each Pool Scheduled generating Resource:

(i) If the Resource is not following Dispatch Instructions and has cleared Day-Ahead and has an actual metered output greater than zero and has not been ordered off-line by the ISO for reliability purposes: Real-Time generation deviation is the absolute value of (actual metered output − Desired Dispatch Point) for each generating Resource.

If the deviation calculated above is less than or equal to 5% of Desired Dispatch Point or less than or equal to 5 MWh, then deviation = 0.

(ii) If the Resource is not following Dispatch Instructions, has cleared Day-Ahead, that has an actual metered output equal to zero and has not been ordered off-line by the ISO for reliability purposes: Real-Time generation deviation is the absolute value of (actual metered output – cleared Day-Ahead MWh) for each generating Resource.

If the deviation calculated above is less than or equal to 5% of cleared Day-Ahead MWh or less than or equal to 5 MWh, then deviation = 0.

plus,

(e) absolute values for the Operating Day of the Participant's Real-Time Load Obligation Deviation the sum of the hourly,

where

(i) each Market Participant's Real-Time Load Obligation Deviation for each hour of the Operating Day is the sum of the difference between the Market Participant's Real-Time Load Obligation and Day-Ahead Load Obligation over all Locations (including the Hub), and

(ii) for purposes of calculating a Participant's Real-Time Load Obligation Deviation under this sub-section (e), a Day-Ahead External Transaction that is not associated with a Real-Time External Transaction can be used to offset an External Transaction to wheel energy through the New England Control Area that is entered into the Real-Time Energy Market, and

(iii) External Transaction sales curtailed by the ISO are omitted from this calculation.

plus,

(f) the sum of the hourly absolute values for the Operating Day of the Participant's Real-Time Generation Obligation Deviation at External Nodes except that positive Real-Time Generation Obligation Deviation at External Nodes associated with Emergency energy that is scheduled by the ISO to flow in the Real-Time Energy Market are not included in this calculation,

Where

(i) each Market Participant's Real-Time Generation Obligation Deviation at External Nodes for each hour of the Operating Day is the sum of the difference between the Market Participant's Real-Time Generation Obligation and Day-Ahead Generation Obligation over all External Nodes, and

(ii) for purposes of calculating a Participant's Real-Time Generation Obligation Deviation under this sub-section (f), a Day-Ahead External Transaction that is not associated with a Real-Time External Transaction can be used to offset an External Transaction to wheel energy through the New England Control Area that is entered into the Real-Time Energy Market, and

(iii) External Transaction purchases curtailed by the ISO are omitted from this calculation.

plus,

(g) the absolute value of the total over all Locations of the Market Participant's Increment Offers.

[Please note that for purposes of this calculation an Increment Offer that clears in the Day-Ahead Energy Market always creates a Real-Time generation deviation.]

III.F.3.3 Local Second Contingency Protection Resource NCPC Charges.

Each Market Participant's pro-rata share of the cost for Day-Ahead Energy Market NCPC Credits and Real-Time Energy Market NCPC Credits for resources designated to provide Local Second Contingency Protection is based on its daily pro-rata share of the daily sum of the hourly Real-Time Load Obligations for each affected Reliability Region, subject to the following conditions:

(a) The External Node associated with an External Transaction sale that is, in accordance with Market Rule 1 Section III.1.10.7(h), a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction shall be considered to be within the Reliability Region from which the External Transaction is exporting for the purpose of calculating a Market Participant's pro-rata share of the cost for Real-Time Energy Market NCPC Credits for resources designated to provide Local Second Contingency Protection. The External Node of a Capacity Export Through Import Constrained Zone Transaction or an FCA Cleared Export Transaction is the External Node defined by the Forward Capacity Auction cleared Export Bid or Administrative Export De-List Bid associated with the External Transaction sale.

(b) For hours in which there is an NCPC cost for a resource providing Local Second Contingency Protection and ISO is selling Emergency energy to an adjacent Control Area, the scheduled amount of Emergency energy at the applicable External Node will be included in the calculation of a Market Participant's pro rata share of the cost for Real-Time Energy Market NCPC Credits for resources designated to provide Local Second Contingency Protection as if the Emergency energy sale were a Real-Time Load Obligation within each affected Reliability Region. The pro rata share calculated for the Emergency Energy Transaction shall be included in the charges under an agreement for purchase and sale of Emergency energy with the applicable adjacent Control Area.

For purposes of the calculation of Local Second Contingency Protection Resource NCPC Charges, Emergency energy sales by the New England Control Area to an adjacent Control Area at the External Nodes (see ISO New England Manual 11 for further discussion of the External Nodes) listed below shall be associated with the Reliability Region(s) indicated in the table:

External Node Common Name	Associated Transmission Facilities	Reliability Region(s)	Allocator
NB-NE External Node	Keene Road-Keswick (3001) Lepreau-Orrington (390/3016) tie line	Maine	100% to Maine
HQ Phase I/II External Node	HQ-Sandy Pond 3512 & 3521 Lines	West Central Massachusetts	100% to West Central Massachusetts
Highgate External Node	Bedford-Highgate (1429 Line)	Vermont	100% to Vermont
NY Northern AC External Node	Plattsburg – Sandbar Line (PV-20 Line) Whitehall – Blissville Line (K-7 Line) Hoosick- Bennington Line (K-6 Line) Rotterdam – Bearswamp Line (E205W Line) Alps – Berkshire Line (393Line) Pleasant Valley – Long Mountain Line (398 Line)	Vermont, Vermont Vermont West Central Massachusetts West Central Massachusetts Connecticut	Allocated proportionally to the Vermont, West Central Massachusetts and Connecticut Reliability Regions based on the Normal Limits as described in Appendix A to OP-16 of the transmission facilities connecting these Reliability Regions to the New York Control Area.
NY NNC External Node	Northport-Norwalk Harbor (601,602 and 603 Lines)	Connecticut	100% to Connecticut
NY CSC External Node	Shoreham-Halvarsson Converter (481 Line)	Connecticut	100% to Connecticut

(c) For each month, the ISO performs an evaluation of total Local Second Contingency Protection Resource NCPC charges for each Reliability Region. If, for any Reliability Region, the magnitude of such charges is sufficient to satisfy two conditions, a partial reallocation of the charges, from Market Participants with a Real-Time Load Obligation in that Reliability Region to Transmission Customers with Regional Network Load in that Reliability Region, is triggered. For all calculations performed under the provisions of this sub-paragraph c, the term Market Participant will include an adjacent Control Area and the term Real-Time Load Obligation will include MWh of Emergency energy sold in the circumstances described in subparagraph a above and will exclude Real-Time Load Obligations associated with the operation of a Dispatchable Asset Related Demand Resource (pumps only).

(i) Evaluation of Conditions –

Condition 1 – is the Local Second Contingency Protection Resource Charge $_{(Reliability\ Region,\ month)}$ > .06 X Load Weighted Real-Time LMP $_{(Reliability\ Region,\ month)}$

Condition 2 – is the Local Second Contingency Protection Resource Charge % $_{(Reliability\ Region,\ month)}$ > 2 X Twelve Month Rolling Average Local Second Contingency Protection Resource Charge $_{\%}$ $_{(Reliability\ Region)}$

Where:

Real-Time Load Obligation $_{(Reliability\ Region,\ month)}$ equals the sum of the hourly values of total Real-Time Load Obligation for each hour of the month in the Reliability Region.

Local Second Contingency Protection Resource Charge $_{(Reliability\ Region,\ month)}$ equals the sum of hourly Local Second Contingency Protection Resource charges for each hour of the month in the Reliability Region divided by the Real-Time Load Obligation $_{(Reliability\ Region,\ month)}$.

Load Weighted Real-Time LMP $_{(Reliability\ Region,\ month)}$ equals the sum of the hourly values of Real-Time LMP times the associated Real-Time Load Obligation for each hour of the month in the Reliability Region, divided by the Real-Time Load Obligation $_{(Reliability\ Region,\ month)}$.

Local Second Contingency Protection Resource Charge % $_{(Reliability\ Region,\ month)}$ equals the Local Second Contingency Protection Resource Charge (Reliability Region, month) divided by the Load Weighted Real-Time LMP $_{(Reliability\ Region,\ month)}$.

Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % $_{(Reliability\ Region)}$ equals the sum of the prior 12 months' values, not including the current month, of Local Second Contingency Protection Resource Charge % $_{(Reliability\ Region,\ month)}$ divided by 12. (For the purposes of other calculations which include the Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % $_{(Reliability\ Region)}$, a value of .001 will be substituted for any Twelve Month Rolling Average Local Second Contingency Protection Resource Charge % $_{(Reliability\ Region)}$ value of 0.)

If both conditions are met, a reallocation of a portion of Local Second Contingency Protection Resource Charge $_{(Reliability\ Region,\ month)}$ is triggered.

(ii) Determination of the portion of Local Second Contingency Protection Resource Charge $_{(Reliability\ Region,\ month)}$ to be reallocated –

Local Second Contingency Protection Resource Charge $_{(Reliability\ Region,\ month)}$ to be reallocated = Real-Time Load Obligation $_{(Reliability\ Region,\ month)}$ X Min (Condition 1 Rate $_{(Reliability\ Region,\ month)}$, Condition 2 Rate $_{(Reliability\ Region,\ month)}$)

Where:

Condition 1 Rate $_{(Reliability\ Region,\ month)}$ equals the Local Second Contingency Protection Resource Charge $_{(Reliability\ Region,\ month)}$ minus .06 times the Load Weighted Real-Time LMP $_{(Reliability\ Region,\ month)}$.

Condition 2 Rate $_{(Reliability\ Region,\ month)}$ equals the Local Second Contingency Protection Resource Charge $_{(Reliability\ Region,\ month)}$ minus 2 times the Twelve Month Rolling Average Local Second Contingency Protection Resource Charge $_{\%\ (Reliability\ Region)}$ times the Load Weighted Real-Time LMP $_{(Reliability\ Region,\ month)}$.

(iii) Determination of Local Second Contingency Protection Resource Charge $_{(Reliability\ Region,\ month)}$ reallocation credits to Market Participants and reallocation charges to Transmission Customers –

Market Participant reallocation credit =

(Real-Time Load Obligation $_{(Participant,\ Reliability\ Region,\ month)}$ / Real-Time Load Obligation $_{(Reliability\ Region,\ month)}$) * Local Second Contingency Protection Resource Charges $_{(Reliability\ Region,\ month)}$ to be reallocated

Where:

Real-Time Load Obligation $_{(Participant, Reliability Region, month)}$ equals the sum of the Market Participant's hourly values of total Real-Time Load Obligation in the Reliability Region for each hour of the month.

Transmission Customer reallocation charge =

(Regional Network Load $_{(Transmission Customer, Reliability Region, month)}$ / Regional Network Load $_{(Reliability Region, month)}$) * Local Second Contingency Protection Resource Charges $_{(Reliability Region, month)}$ to be reallocated

Where:

Regional Network Load $_{(Reliability Region, month)}$ equals:

The monthly MWh of Regional Network Load of all Transmission Customers in the Reliability Region

Regional Network Load $_{(Customer, Reliability Region, month)}$ equals:
The Transmission Customer's monthly MWh of Regional Network Load in the Reliability Region.

SECTION IV.A

RECOVERY OF ISO ADMINISTRATIVE EXPENSES

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IV.A.1 Definitions:

Whenever used in this Section IV.A, in either the singular or plural number, capitalized terms shall have the meanings specified in Section I.

IV.A.2 Purpose of Section IV.A; Adjustments to Rates

IV.A.2.1 Purpose of Section IV.A

Section IV.A of the Tariff is the means by which the ISO collects the revenues necessary to carry out its administrative functions in each calendar year, and contains rates, charges, terms and conditions for the following Services, which together encompass the functions carried out by the ISO:

(1) Scheduling, System Control and Dispatch Service (Schedule 1 hereto);

(2) Energy Administration Service (Schedule 2 hereto); and

(3) Reliability Administration Service (Schedule 3 hereto).

The rates and charges for each Service during a calendar year are based on the allocated portion of that year's Revenue Requirement. "Revenue Requirement" refers to the budgeted total expense for the year as adjusted by true-ups described herein.

IV.A.2.2 True-Ups

(1) Schedule 2 True-Up

(i) Each year (Year X), in determining the ISO's Revenue Requirement for the subsequent year (Year X+1), the ISO will make a true-up of the Schedule 2 portion of the Revenue Requirement for the prior year (Year X-1). Any difference between the actual Year X-1 Schedule 2 revenues and amounts budgeted for Schedule 2 revenues in the Year X-1 Revenue Requirement will be reflected in the projected Schedule 2 rates for Year X+1 as stated in paragraph (ii) below.

(ii) In implementing the true-up adjustment for revenue differences in the volumetric portion of Schedule 2, the differences will be added to (in the case of a revenue shortfall) or subtracted from (in the case of a revenue over-recovery) the ISO's total estimated budgeted amounts for

Schedule 2 for Year X+1. For revenue over-recoveries attributable to the TUs in Schedule 2, the ISO will treat them in the same manner as revenue adjustments for the volumetric portion of Schedule 2. For revenue shortfalls attributable to the TUs in Schedule 2, the ISO will allocate them according to the following method:

(a) 50% of the shortfall will be added to the ISO's projected Revenue Requirement for the Schedule 2 volumetric component (85% of the projected Schedule 2 Revenue Requirement prior to true-ups).

(b) An additional percentage of the shortfall will be added to the ISO's projected Revenue Requirement for the Schedule 2 volumetric component for each percentage decrease which was deemed to have occurred between the number of TUs used in the true-up and the number of TUs that the ISO had used in the original projection of the rates for that year.

(c) The maximum percentage of the shortfall to be added to the Schedule 2 volumetric component is 100%, which would result if the percentage difference between the actual and forecasted TUs were 50% or greater.

(d) Any remaining shortfall revenues after allocation of the shortfall to the Schedule 2 volumetric component will be added to the ISO's projected Revenue Requirement for the Schedule 2 TU component (15% of the projected Schedule 2 Revenue Requirements prior to true-ups).

(iii) True-Ups Collected in Future Rates. To the extent the ISO proposes to change its rate design for Section IV.A, the ISO will continue to implement the true-up procedures stated in this section to recover under- or over-collections of TUs for then-current and prior years. For example, when, on a going-forward basis effective January 1, 2012, the ISO eliminated the inclusion of an estimated true-up for the current year (Year X) in the Revenue Requirement for the subsequent year (Year X+1), the ISO was still required to include in the Revenue Requirement for 2013 the difference between the estimated 2011 true-up filed with the 2012 Revenue Requirement and the final 2011 true-up calculated based on historical data.

(2) General True-Up

Each year (Year X), in determining its Revenue Requirement for Year X+1, the ISO will include in such Revenue Requirement a true-up of Year X-1's Revenue Requirement for Schedules 1, 3 and 5. Specifically, the Revenue Requirement for Year X+1 will include deviations between collections under this Section IV.A and the ISO's actual expenses for Year X-1. For example, when filing the Revenue Requirement for 2014, the ISO will compute the total actual expenses for Schedules 1, 3 and 5 in 2012 and will compare these totals with the total charges actually collected under the Tariff for each of these Schedules during calendar year 2012. Based on these comparisons, the ISO will adjust the otherwise-projected Revenue Requirement for calendar year 2014 for one or more of Schedules 1, 3 and 5, as needed, downward or upward to reflect the actual calendar year 2012 surplus or deficit, respectively. From these figures the ISO will calculate rates for calendar year 2014, and make a rate change filing for calendar year 2014 and succeeding years, as required, to reflect the budget amount for the applicable calendar year and the true-up calculated by means of the foregoing analysis and adjustments.

(3) Indemnification

The Revenue Requirement does not reflect any amounts received by the ISO due to indemnification payments.

IV.A.3 Billing and Payment

IV.A.3.1 Billing Procedure:

With respect to charges under this Section IV.A., the ISO will apply the ISO Billing Policy as set forth in Exhibit ID to Section I of the Tariff.

IV.A.3.2 Working Capital Advances:

In the event that working capital financing arranged by the ISO is terminated early or repayment is accelerated (and no replacement funding has been obtained by the ISO) and Early Amortization Working Capital Charges have been assessed to Market Participants by the ISO, each month, each Market Participant shall be required to advance to the ISO an amount (each, an "Advance") equal to the ISO's reasonable projection of such Market Participant's charges under the Tariff for three succeeding months. The Advances shall be held in an interest bearing account. In each succeeding month, the ISO shall adjust each Market Participant's Advance so that, in each calendar month, each Market Participant's Advance is equal to the ISO's reasonable projection of such Market Participant's charges under Section

IV.A of the Tariff for such month and the next two succeeding months. If, in the reasonable judgment of the ISO, a cash deficiency is likely to occur at any time as a result of a depletion of the Advances (but not as a result of the failure of any Market Participant to pay its Advance), the ISO shall, at its option, have the right to require each Market Participant to pay the ISO its pro rata share (based on such Market Participant's projected charges under Section IV.A of the Tariff for the instant month and the next two succeeding months compared to projected charges to all Market Participants under Section IV.A of the Tariff for the instant month and the next two succeeding months) of any additional Advances required for the ISO's operations. If any Market Participant withdraws from the ISO or has its membership terminated, its Advance will be returned to it at the end of the month in which its withdrawal or termination is effective, provided that all of the departing Market Participant's liabilities under the Tariff have been satisfied, and all of the other Market Participants will have their Advances adjusted accordingly.

IV.A.4 Regulatory Filings

Nothing contained in the Tariff or any Service Agreement thereunder shall be construed as affecting in any way the right of the ISO to file with the Commission under Section 205 of the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder for a change in any rates, terms and conditions, charges, classification of service, Service Agreement, rule or regulation. Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the ability of any Customer receiving a Service under the Tariff to exercise its rights under the Federal Power Act and pursuant to the Commission's rules and regulations promulgated thereunder.

IV.A.5 Creditworthiness

For purposes of Section IV.A of the Tariff, the ISO will apply the ISO New England Financial Assurance Policy attached to Section I of the Tariff. Each Customer shall comply with the requirements of this policy, as applicable.

IV.A.6 Direct Billing; Sanctions

IV.A.6.1 Transmission Studies:

The ISO will conduct and coordinate certain System Impact Studies and Facilities Studies pursuant to, and in accordance with, the Tariff. The costs of System Impact Studies and Facilities Studies will be charged directly to the pertinent Eligible Customers or interconnection applicants. The ISO will also

conduct studies as part of the Forward Capacity Market qualification process and will charge those costs directly through Qualification Process Cost Reimbursement Deposits.

IV.A.6.2 Information Requests:

In fulfilling information requests of a significant and non-routine nature, the ISO will charge its associated direct and indirect costs to the requestor. Revenue from these charges will be credited to Revenue Requirements for the Service to which the information request is most closely related.

IV.A.6.3 Non-Standard Provisions:

If there is a significant direct or indirect cost associated with the ISO's implementation of non-standard provisions for energy or other products in a bilateral contract, the ISO will charge those costs to the contract submitter. Revenue from these charges will be credited to Revenue Requirements for the Service to which the submitted contract is most closely related.

IV.A.6.4 Non-Standard Billing Service:

Market Participants and other Customers who require non-standard billing payment arrangements, pursuant to the terms of the ISO New England Financial Assurance Policy shall be charged the ISO's associated direct and indirect costs for these arrangements. Fees collected will be credited to Revenue Requirements for all three Services, in proportion to the relative Revenue Requirements for those Services.

IV.A.6.5 Imposition of Monetary Sanctions by the ISO:

Amounts collected by the ISO during a month from Market Participants pursuant to Section III.B of the Tariff shall be disbursed or credited by the ISO in accordance with the provisions of the Section III.B.5.5.

IV.A.6.6 Re-billing Requests:

In fulfilling re-billing requests of a significant and non-routine nature as a result of data revisions not being received in a timely fashion from a Customer, the ISO will charge its associated direct and indirect costs to that Customer. Revenue from these charges will be credited to Revenue Requirements for the Service to which the information request is most closely related.

IV.A.7 Metering

IV.A.7.1 Customer Obligations:

The Customer shall be responsible for compliance with metering requirements under the Tariff and the ISO New England Operating Documents and to communicate the metering information to the ISO.

IV.A.7.2 RTO Access to Metering Data:

The ISO will have access to such metering data as may reasonably be required to facilitate measurements and billing under the ISO New England Operating Documents, the Tariff or any Service Agreement thereunder.

IV.A.8 Collection of Commission Annual Charges:

The ISO's collection of amounts necessary to pay annual charges to the Commission is addressed in Schedule 4 hereof.

Schedule 1

Scheduling, System Control and Dispatch Service

Scheduling, System Control and Dispatch Service ("Scheduling Service") is the service required to schedule at the regional level the movement of power through, out of, within, or into the New England Control Area. For regional transmission service under the Tariff, Scheduling Service is an Ancillary Service that can be provided only by the ISO. All Transmission Customers must be Customers for Scheduling Service under this Tariff and purchase this Service from the ISO. The ISO's charges stated herein for Scheduling Service are based on the expenses incurred by the ISO in providing this Service. In addition, the ISO acts as a billing agent for the operators of the Local Control Centers and certain Market Participants in order to collect expenses incurred in providing this Service pursuant to this Schedule 1.

The ISO's expenses are based on the functions and activities required to provide this Service and include, but are not limited to:

- Processing and implementation of requests for regional transmission service, including support of the OASIS node;
- Coordination of transmission system operation (including administration of reactive power requirements under Schedule 2 of Section II of the Tariff) and implementation of necessary control actions by the ISO and support for these functions;
- Billing associated with regional transmission services provided under the Tariff;
- Transmission system planning which supports this Service; and
- Administrative costs associated with the aforementioned functions.

For the ISO's expenses in providing transmission-related Scheduling Service:

(A) each Customer that is obligated to pay the Regional Network Service rate shall pay each month, in arrears, an amount equal to the product of $0.15570 per kilowatt month times its Monthly Regional Network Load for that month.

(B) each Customer that is a Transmission Customer receiving Through or Out Service shall pay each month, in arrears, an amount equal to the product of the Transmission Customer's highest amount of Reserved Capacity (expressed in kilowatts) for an hour for each transaction, other than a Coordinated

External Transaction, that is scheduled to occur during the month as Through or Out Service multiplied by $0.00021 per kilowatt for each hour of service.

Schedule 1 revenues collected from Through or Out Service customers shall be credited to each Network Customer receiving Regional Network Service that month in proportion to each Network Customer's Monthly Regional Network Load in that month.

Non-Market Participant FTR fees and any portions of Long Lead Facility deposits collected by the ISO under Schedule 22 and Schedule 25 of Section II of the Tariff that become non-refundable will be credited to Schedule 1 Revenue Requirements and will be included in the Schedule 1 true-up calculations.

All general terms and conditions of the Tariff apply to this Service.

Schedule 2

Energy Administration Service

Energy Administration Service ("EAS") is the Service provided by the ISO to administer the Energy Market.

The ISO's expenses are based on the functions required to provide EAS and include, but are not limited to:

- Core operation of the Energy Market;
- Generation and demand dispatch related to the Energy Market;
- Energy accounting;
- Loss determination and allocation;
- Billing preparation;
- Market power monitoring and mitigation for the Energy Market;
- Sanctions activities;
- Operation of FTR auctions;
- Market assessment and reports; and
- Formulation of additional market rules and proposals to modify existing rules.

Each Market Participant that has an account for Energy that is settled by the ISO for the current month shall pay each month an amount based on Energy Transaction Units (Energy TUs), Increment Offers, Decrement Bids, Volumetric Measures, submitted FTR auction bids, and cleared FTR auction bids.

Energy TU Based Charges: For purposes of this Schedule 2, Energy TUs shall be calculated without reference to contributions from Coordinated External Transactions. Each Customer that has, during a month, incurred Energy TUs exceeding zero shall pay an amount, in arrears, equal to the sum of the products of:

(1) $0.65101 times the Customer's first 12,500 Energy TUs for that month; plus

(2) $0.59182 times the amount of Energy TUs that exceed 12,500 but are less than or equal to 39,500; plus

(3) $0.53264 times the amount of Energy TUs that exceed 39,500.

Charges Based on Increment Offers and Decrement Bids: Each Customer submitting Increment Offers and/or Decrement Bids shall pay, in arrears, amounts equal to:

(1) $0.00500 times the number of Increment Offers and Decrement Bids submitted by the Customer for that month; plus

(2) $0.06000 times the number of Increment Offers and Decrement Bids submitted by the Customer for that month that clear in the Day-Ahead Energy Market.

Volumetric Measure Based Charges: A Customer shall be considered an EAS VM Customer if the sum of Monthly Real-Time Load Obligation and Monthly Real-Time Generation Obligation (measured in megawatthours, MWh and excluding Coordinated External Transactions) assessed to that Customer during the month exceeds zero (0), in which case, the total EAS VM charges for that Customer shall be equal to the sum of:

(1) Monthly Real-Time Load Obligation (MWh), excluding Monthly Real-Time Load Obligation associated with Coordinated External Transactions; and

(2) Monthly Real-Time Generation Obligation (MWh); provided, however, that Monthly Real-Time Generation Obligation associated with energy imported into the New England Control Area by Bangor Hydro-Electric Company across the New Brunswick ties shall be excluded (up to 300 MW) for billing and rate calculation purposes from EAS VMs, and provided further that Monthly Real-Time Generation Obligation associated with Coordinated External Transactions shall be excluded.

Subject to the foregoing, each Market Participant that is identified as an EAS VM Customer for that month shall pay an amount, in arrears, based on total EAS VM, equal to:

(a) $0.25517 per MWh for the first 250,000 MWh of EAS VM for that month; plus

(b) $0.23197 per MWh for each VM that exceeds 250,000 EAS VM but is less than or equal to 1,500,000 MWh for that month; plus

(c) $0.20877 per MWh for each EAS VM in excess of 1,500,000 MWh for that month.

Charges Based on Submitted and Cleared FTR Bids: Each Customer submitting FTR auction bids shall pay, in arrears, amounts equal to:

(1) $.85853 times the number of bids submitted by the Customer into any FTR auctions held for that month; plus

(2) $.85853 times the number of bids submitted by the Customer into any annual or multi-month FTR auctions (billed with the invoice for the first month of the annual or multi-month FTR auction); plus

(3) $1.21377 times the number of bids submitted by the Customer during that month that clear any FTR auctions held for that month; plus

(4) $1.21377 times the number of bids submitted by the Customer that clear any annual or multi-month FTR auctions (billed with the invoice for the first month of the annual or multi-month FTR auction).

Schedule 3

Reliability Administration Service

Reliability Administration Service ("RAS") is the Service provided by the ISO to administer the Reliability Markets (and facilitate reliability-associated transactions and arrangements) in accordance with the Tariff and the corresponding rules promulgated thereunder, and to provide other reliability and informational services. The Reliability Markets are also a means by which certain Ancillary Services are obtained under Section II of the Tariff. Each Customer must enter into a Service Agreement.

The ISO's administrative expenses are based on the functions required to provide this Service and include, but are not limited to:

- Generation and demand dispatch associated with Reliability Markets;
- Reliability Markets accounting;
- Billing preparation;
- The ISO generation emissions analysis;
- Risk profile updates;
- Triennial review of resource adequacy;
- Studies and qualification of resources under Forward Capacity Market;
- Preparation of regional reports and load forecasts and profiles (Capacity, Energy, Load and Transmission reports; reports to the Energy Information Administration (EIA) of the United States Department of Energy; reports to the North American Electric Reliability Corporation; Regional System Plan);
- Support of power supply, environmental and market reliability planning activities;
- Market power monitoring, mitigation and assessment for the Reliability Markets;
- Formulation of additional market rules and proposals to modify existing rules.

(A) Each Transmission Customer taking Through or Out Service that is not a Market Participant shall be considered a RAS Customer and shall pay each month, in arrears, a RAS fee equal to the product of $3.02 times the number of hourly Through or Out reservations made for that month.

(B) Each Customer that is a Market Participant shall be considered a RAS Customer and shall pay each month, in arrears, an amount equal to the product of $0.18763 per kilowatt month times the Market Participant's Real-Time NCP Load Obligation (measured in kilowatts) for that month.

(C) For Exports other than Coordinated External Transactions, each RAS Customer shall pay each month, in arrears, an amount equal to $0.37 per MWh per Export, where MWh represents the hourly scheduled MWs of associated Export.

In order to preserve the settlement approved in Docket No. ER01-316, Market Participants engaging in "through" transactions using Through or Out Service will not be deemed to have a Real-Time Load Obligation on account of those transactions.

Charges collected under Schedule 3 for RAS do not include any amounts paid by the ISO on behalf of the Market Participants to purchase emergency power.

Charges collected under Schedule 3 for RAS do not include the recovery of costs associated with disclosure or tracking obligations. If one or more states require Market Participants to undertake such activity the ISO will separately charge the expenses associated with such obligations.

All general terms and conditions of the Tariff apply to this Service.

Schedule 4

Collection of Commission Annual Charges

Each Transmission Owner that is jurisdictional to the Commission shall provide to the ISO under oath, sixty days in advance of the due date for the Commission's Reporting Requirement No. 582 ("FERC-582"), data for the pertinent period concerning the Transmission Owner's megawatt-hours of all unbundled transmission (including MWh delivered in wheeling transactions and MWh delivered in exchange transactions) and the Transmission Owner's megawatt-hours of all bundled wholesale power sales (to the extent these latter MWh were not separately reported as unbundled transmission) for the pertinent period, in the level of detail required by Commission regulations and necessary for the ISO to make and support a FERC-582 report by the ISO for the New England Control Area. These amounts are reported on the Commission's Form 1 in connection with accounts 447, 456, and 555.

Upon the ISO's receipt of the Commission's bill for the annual charges for the New England Control Area, the ISO will promptly calculate the allocable portion of that annual charge payable by each Transmission Owner. To determine the amount payable by each Transmission Owner for the annual charge for the then-current Commission fiscal year, the ISO will divide each Transmission Owner's total reported megawatt-hours of transmission of electric energy in interstate commerce by the total megawatt-hours of transmission of electric energy in interstate commerce reported for the prior calendar year by the ISO in FERC-582 for the New England Control Area, and multiply the resulting figure by the Commission's annual charge to the New England Control Area for the then-current Commission fiscal year. The allocation among Transmission Owners of any adjustments for the prior Commission fiscal year reflected in the current-year Commission bill will be calculated by multiplying (x) each Transmission Owner's adjusted sales (i.e., megawatt-hours of transmission of electric energy in interstate commerce) for the calendar year on which that prior Commission fiscal year's annual charges were based by (y) the final Commission charge factor for that prior fiscal year, as indicated in the Commission bill. This amount will be compared with the amount originally paid by the corresponding Transmission Owner for the prior fiscal year and any difference (positive or negative) will be an adjustment to the payment required from that Transmission Owner for current-year Commission annual charges. The ISO will promptly notify each Transmission Owner of the required payment, and each Transmission Owner shall pay to the ISO, within fifteen (15) days of the Transmission Owner's receipt of the notice, the amount specified in the notice.

Each Transmission Owner will provide the ISO with assistance reasonably required in responding to information requests and audits by the Commission in connection with the Form 582 Reporting Requirement and payment of annual charges.

Schedule 5

Collection of NESCOE Budget

The ISO acts as the billing and collection agent for the New England States Committee on Electricity (NESCOE) for recovery of amounts reflected in the annual NESCOE budget through the rates set forth below. Each year, NESCOE will develop an annual budget, including supporting documentation and justification and a collection schedule, and present it to the ISO in final form no later than October 20 for the following calendar year, following the budget review process set forth in understandings among NESCOE, the ISO, and NEPOOL, which process is anticipated to begin in June each year. NESCOE shall not exceed its budget in any given calendar year. The "General True-Up Provision" in Section IV.A.2.2.(2) of this Tariff shall apply to this Schedule 5.

The ISO will calculate the Schedule 5 rate based on the rate design specified below. The ISO will submit the NESCOE-provided materials and any revised tariff sheets to the Commission separately but contemporaneously with the ISO's annual filing of rates to recover ISO's other administrative expenses.

For the calendar year 2015, the six New England states shall bear NESCOE's budgeted costs as follows. Each Customer that is obligated to pay the Regional Network Service rate shall pay each month, in arrears, an amount equal to the product of $0.00000 per kilowatt times its Monthly Regional Network Load for that month.

NEW YORK INDEPENDENT SYSTEM OPERATOR COORDINATION AGREEMENT

Coordination Agreement

Between

ISO New England Inc.

And

The New York Independent System Operator, Inc.

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THIS AGREEMENT was made the 1st day of January, 2006, and is hereby restated on the ____ day of ___ _____, 2015,

BETWEEN:

NEW YORK INDEPENDENT SYSTEM OPERATOR, INC., a not-for-profit corporation established under the laws of New York State, hereinafter called the "NYISO".

And

ISO NEW ENGLAND INC., a not-for-profit, private corporation established under the laws of the State of Delaware, hereinafter called "ISO-NE".

WHEREAS, capitalized terms not otherwise defined herein shall have the meanings ascribed to them in Section 1.0 hereof;

WHEREAS, ISO-NE and the NYISO are sometimes hereinafter referred to, collectively, as the "Parties" and, individually, as a "Party";

WHEREAS, the NYISO is an independent, not-for-profit corporation established pursuant to the ISO Agreement, responsible for providing transmission service, maintaining the Reliability of the electric power system and facilitating efficient markets for capacity, energy and ancillary services in the New York Balancing Authority Area in accordance with its filed NYISO Tariffs;

WHEREAS, ISO-NE is a not-for-profit, independent corporation that serves as the RTO for New England, in which capacity it operates New England's wholesale electricity markets, manages a comprehensive regional bulk power system planning process and is responsible for the day-to-day reliable operation of New England's bulk power system;

WHEREAS, ISO-NE, as RTO for the New England Transmission System and administrator of the New England markets, and the NYISO as the ISO for the New York Transmission System, enter into coordination agreements and operating arrangements with the operators of neighboring Reliability Coordinator Areas and Balancing Authority Areas, and coordinate system operation and Emergency procedures with neighboring Reliability Coordinator Areas and Balancing Authority Areas;

WHEREAS, the NYISO and ISO-NE desire to coordinate interconnected operation to maintain Reliability for both of the power systems of New York State and the New England States, recognizing the Parties' desire to maximize interconnected capability under the terms and conditions contained in this Agreement; and

WHEREAS, related to the Interconnection Facilities:

A. ISO-NE is the Reliability Coordinator, Balancing Authority, Transmission Operator, market operator, and Planning Authority for the six New England States and operates and is responsible for the secure operation of the New England Transmission System in accordance with its Transmission Operating Agreements with New England Transmission Owners and in compliance with the FERC-accepted ISO-NE Tariff, and the requirements and criteria set forth by NERC or NPCC and, as such, has the power and authority to enter into this Agreement and perform its obligations under it;

B. NYISO is the Reliability Coordinator, Balancing Authority, Transmission Operator, market operator, and Planning Authority for New York State and operates and is responsible for the secure operation of the New York Transmission System in accordance with its Transmission Operating Agreements with New York Transmission Owners and in compliance with the FERC-accepted New York Independent System Operator Agreement ("ISO Agreement"), the Agreement Between New York Independent System Operator and Transmission Owners ("ISO/TO Agreement"), the Agreement between New York Independent System Operator and the New York State Reliability Council ("ISO/NYSRC Agreement"), NYISO Tariffs, and the requirements and criteria set forth by NERC, NPCC and the NYSRC and, as such, has the power and authority to enter into this Agreement and perform its obligations under it; and

C. The New England Transmission System and the New York Transmission System interconnect by way of the Interconnection Facilities, which are described in Schedule A of this Agreement; and

D. The Parties wish to record their agreement as to the operational and other matters addressed herein and pertaining to the Interconnection Facilities; and

WHEREAS the Parties desire to manage the operational aspects of their interconnected operations by developing, administering and implementing practices, procedures and sharing information relating to Reliability coordination and power system operation that will be managed and approved by a committee formed under this Agreement;

NOW, THEREFORE, THIS AGREEMENT WITNESSES THAT in consideration of the mutual agreements and obligations between the Parties and for other good and valuable consideration ISO-NE and the NYISO agree as follows:

ARTICLE 1.0: DEFINITIONS

In this Agreement, the following words and terms shall have the meanings (such meanings to be equally applicable to both the singular and the plural forms) ascribed to them in this Article 1.0.

"Adequacy" means the ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

"Agreement" means this Agreement and the Schedule(s) attached hereto and incorporated herein.
"Balancing Authority" means the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

"Balancing Authority Area" means the collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.

"Confidential Information" has the meaning stated in Section 6.5 of this Agreement.

"Confirmed Trust Relationship" means that one Responsible Settlement Party has granted another Responsible Settlement Party permission to confirm, modify or withdraw its CTS Interface Bids.

"Control Area" means an electric 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 capacity to maintain Operating Reserves in accordance with Good Utility Practice.

"Coordination Committee" means the jointly constituted ISO-NE and NYISO committee established to administer the terms and provisions of this Agreement pursuant to Article 7.0 of this Agreement.

"Coordinated Transaction Scheduling" or "CTS" means an external transaction scheduling process between the NYCA and NECA in which Market Participants' bid, to buy energy in one region and sell in another region, is economically and simultaneously cleared by ISO-NE and NYISO. This process takes place pursuant to market rules in the Parties' respective tariffs that allow transactions to be scheduled over a CTS Enabled Interface based on a bidder's willingness to purchase energy from the NYCA or NECA (the source) and sell it to the other Control Area (the sink) if the bid price is less than or equal to the expected LMP difference across the interface in the requested direction, as of the time the interface is scheduled.

"CTS Enabled External Proxy Bus" shall mean an External Proxy Bus at which the Parties accept CTS Interface Bids to schedule external transactions in the real-time energy market.

"CTS Enabled Interface" means an Interconnection at which the Parties accept CTS Interface Bids for all import offers, for all export bids, and for wheels through the NECA. The CTS Enabled Interfaces are specified in Section 4.4.4 of the NYISO's Market Administration and Control Area Services Tariff and in Section III.1.10.7.A of the ISO-NE Tariff.

"CTS Interface Bid" means: (1) in ISO-NE, an Interface Bid as defined in the ISO-NE Tariff, and an hourly spread bid associated with the wheeling of energy through the NECA, and (2) in NYISO, a CTS Interface Bid as defined in the NYISO Tariff.

"Delivery Point" means a point on each of the three Interconnections between the New England Balancing Authority Area and the NYISO Balancing Authority Area and such other points of

Interconnection as may be established. Such Delivery Point(s) shall include the Interconnection Facilities between ISO-NE and the NYISO.

"Dispute" has the meaning attributed thereto in Article 19.0 of this Agreement.

"Effective Date" means the reference date of this Agreement as shown on the first page of this Agreement.

"Emergency" means any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the Reliability of the Bulk Electric System (as defined by NERC).

"Emergency Energy" means energy supplied from Operating Reserve or electrical generation available for sale in New York or New England or available from another Balancing Authority Area. Emergency Energy may be provided in cases of sudden and unforeseen outages of generating units, transmission lines or other equipment, or to meet other sudden and unforeseen circumstances such as forecast errors, or to provide sufficient Operating Reserve. Emergency Energy is provided pursuant to this Agreement and priced according to Attachment A of Schedule C of this Agreement.

"External Interface Congestion" means the portion of the congestion component of the LMP at an External Proxy Bus that is associated with an External Proxy Bus Constraint.

"External Proxy Bus" means a location that is selected to represent an Interconnection with a Party's Control Area for which LMPs are calculated. In NYISO, this is a Proxy Generator Bus as defined in the NYISO Services Tariff. In ISO-NE, this is an External Node as defined in the ISO-NE Tariff.

"External Proxy Bus Constraint" has the meaning set forth in Section 4.2 of Schedule D to this Agreement.

"FERC" means the Federal Energy Regulatory Commission.

"Force Majeure" means an event of force majeure as described in Section 11.1 of this Agreement.

"Good Utility Practice" means any of the practices, methods and acts engaged in or approved by a significant portion of the North American 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 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 to be acceptable practices, methods, or acts generally accepted by NERC and the FERC.

"Intentional Wrongdoing" means an act or omission taken or omitted by a Party with knowledge or intent that injury or damage could reasonably be expected to result.

"Interconnection" means a connection(s) between two or more individual Transmission Systems that have interconnecting Intertie(s).

"Interconnection Facilities" means the Interconnections described in Schedule A.

"Interconnection Reliability Operating Limit" or "IROL" means a System Operating Limit that, if violated, could lead to instability, uncontrolled separation or Cascading Outages (as defined by NERC) that adversely impact the reliability of the Bulk Electric System.

"Intertie" means a transmission line that forms part of an Interconnection.

"ISO" means independent system operator, as designated by FERC.

"ISO Agreement" means the agreement that establishes the NYISO.

"ISO-NE Supply Price Points" means a set of increasing MW and price pairs, as described in Section 3.0 of Schedule D.

"ISO-NE Tariff" means the ISO New England Inc. Transmission, Markets and Services Tariff, which includes the ISO-NE Open Access Transmission Tariff and ISO-NE market rules.

"Locational Marginal Price" or "LMP" shall mean the market price for energy at a given location in a Party's Control Area, calculated in accordance with the requirements of the Party's tariff, and "Locational Marginal Pricing" shall mean the processes related to the determination of the LMP.

"Market Participant" means a participant in either the ISO-NE- or NYISO-administered wholesale power markets. Market Participants include transmission service customers, power exchanges, Transmission Owners, load serving entities, loads, holders of energy derivatives, generators and other power suppliers and their designated agents.

"Metered Quantity" means apparent power, reactive power, active power, with associated time tagging and any other quantity that may be measured by a Party's Metering Equipment and that is reasonably required by either Party for Security reasons or revenue requirements.

"Metering Equipment" means the potential transformers, current transformers, meters, interconnecting wiring and recorders used to meter any Metered Quantity.

"Mutual Benefits" as described in Article 3.0 of this Agreement, means the transient and steady-state support that the integrated generation and transmission facilities in the New England and New York Transmission Systems provide to each other inherently by virtue of being interconnected.

"NERC" means the North American Electric Reliability Corporation or the successor organization.

"New England Control Area" or "NECA" is the Control Area for New England as defined in the ISO-NE Tariff.

"New England Transmission System" for the purpose of this Agreement means the entire system of transmission facilities, within the New England Reliability Coordinator Area and Balancing Authority Area that are under ISO-NE's operational jurisdiction, as defined in Transmission Operating Agreements and the ISO-NE Tariff.

"New York Control Area" or "NYCA" means the Control Area that is under the operational control of the NYISO, as defined in the NYISO Tariffs.

"New York State Reliability Council" or "NYSRC" means the organization that promotes and preserves the Reliability of electric service on the New York Transmission System by developing and maintaining NYSRC Reliability Rules which are complied with by the NYISO, and for monitoring and assuring compliance with such rules.

“New York Transmission System” for the purpose of this Agreement means the “NYS Transmission System” as that term is defined in the NYISO OATT.

"NPCC" means the Northeast Power Coordinating Council Inc. or its successor organization.

“NPCC Criteria, Guides and Procedures” are documents, or the successor of these documents, that contain the Reliability Standards of the NPCC and which detail the principles of interconnected planning and operations that define and direct the efforts of the NPCC and its members. These documents are essential to maintaining the Security, Adequacy, Reliability and efficient operation of the interconnected bulk power supply system of NPCC members.

“NYISO Open Access Transmission Tariff” or “NYISO OATT” means the NYISO Open Access Transmission Tariff accepted by FERC.

“NYISO Services Tariff” means the NYISO Market Administration and Control Area Services Tariff accepted by FERC.

“NYISO Tariffs” means the NYISO OATT and the NYISO Services Tariff, collectively.

“NYSRC Reliability Rules” means the rules applicable to the operation of the New York Transmission System by the NYISO. These rules are based on Reliability Standards adopted by NERC and NPCC, but also include more specific and more stringent rules to reflect the particular requirements of the New York Transmission System.

“Operating Instructions” means the joint operating procedures, steps, and instructions that are to be utilized by both Parties for the operation of the Interconnection Facilities established and modified from time to time by the Coordination Committee in accordance with (a) the ISO-NE Tariff and the NYISO Tariffs, (b) Schedule B of this Agreement and (c) the ISO-NE and NYISO individual procedures and processes. Operating Instructions are separate from the ISO-NE and NYISO individual procedures and processes.

“Operating Reserve” means: (1) in ISO-NE, an Operating Reserve as defined in Section I.2.2 of the ISO-NE Tariff, and (2) in NYISO, an Operating Reserve as defined in Section 2.2 of the NYISO Services

Tariff. For purposes of Schedule D to this Agreement, 10-minute Operating Reserve is considered a higher quality product than 30-minute Operating Reserve.

"Operational Control" for the purpose of this Agreement, means Security monitoring, adjustment of generation and transmission resources, coordinating and approval of changes in transmission status for maintenance, determination of changes in transmission status for Reliability, coordination with other Balancing Authority Areas and Reliability Coordinators, voltage reductions and load shedding, except that each legal owner of generation and transmission resources continues to physically operate and maintain its own facilities.

"Parties" means ISO-NE and NYISO, and "Party" means either one of them.

"Planning Authority" means the responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.

"Ramp Limit" means, for purposes of Schedule D to this Agreement, either: (1) the maximum allowable amount of change in net interchange at a CTS Enabled Interface over a defined period of time, established in accordance with Section 5.1 of Schedule D; or (2) the maximum allowable amount of change in net interchange across all NYISO Proxy Generator Buses over a defined period of time, established in accordance with the NYISO Tariffs.

"Real-Time Commitment" or "RTC" means the NYISO's multi-period security constrained unit commitment and dispatch model, as defined in the NYISO Tariffs.

"Reliability" means the degree of performance of the bulk electric system that results in electricity being delivered within Reliability Standards and in the amount desired. Electric system Reliability can be addressed by considering two basic and functional aspects of electric systems, which are Adequacy and Security.

"Reliability Coordinator" means the entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area (as defined by NERC) view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority, to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection

Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
"Reliability Coordinator Area" means the collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.

"Reliability Standards" means the criteria, standards and requirements relating to Reliability established by a Standards Authority.

"Responsible Settlement Party" or "RSP" means a Market Participant that is responsible for the financial settlement of one or more transactions at a CTS Enabled Interface, as determined in accordance with the requirements of the Parties' respective tariffs that address the settlement of external transactions at CTS Enabled Interfaces.

"RTO" means a regional transmission organization, as designated by FERC.

"Schedule" means a schedule attached to this Agreement and all amendments, attachments, supplements, replacements and/or additions thereto.

"Security" means the ability of the electric system to withstand sudden disturbances including, without limitation, electric short circuits or unanticipated loss of system elements.

"Standards Authority" means NERC, NPCC, NYSRC or any other agency with authority over either Party regarding standards or criteria relating to the Reliability of Transmission Systems.

"System Operating Limit" means the value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable Reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to the following NERC-defined ratings or limits: Facility Ratings (applicable pre- and post-Contingency equipment or facility ratings); Transient Stability Ratings (applicable pre- and post-Contingency Stability Limits); Voltage Stability Ratings (applicable pre- and post-Contingency Voltage Stability); and System Voltage Limits (applicable pre- and post-Contingency Voltage Limits).

"Third Party" means a person or entity that is not a Party to this Agreement.

"Transfer Limit" means the maximum net interchange that can be scheduled on a CTS Enabled Interface and is established in accordance with Section 5.0 of Schedule D.

"Transmission Operating Agreement(s)" means the respective agreements that establish the terms and conditions under which the Transmission Owners transferred to the NYISO and ISO-NE Operational Control over the Interconnection Facilities. For the NYISO, these agreements are the ISO Agreement, the ISO/TO Agreement, and the ISO/NYSRC Agreement. For ISO-NE, this is the Transmission Operating Agreement, which provides operating authority over certain Interconnection Facilities (i.e., the NY/NE Northern AC Interconnection and the NNC Interconnection), and Attachment K to Section II of the ISO-NE Tariff, which provides operating authority over other Interconnection Facilities (i.e., the CSC Interconnection).

"Transmission Operator" means the entity responsible for the Reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities in accordance with applicable Transmission Operating Agreements.

"Transmission Owner" means the entity that owns and maintains transmission facilities.

"Transmission System" means a system for transmitting electricity, and includes any structures, equipment or other facilities used for that purpose.

ARTICLE 2.0: SCOPE OF AGREEMENT

2.1 Restatement of Prior Agreement

The terms of the prior agreement made between the Parties dated January 1, 2006, are hereby amended, restated and superseded by the terms of this Agreement, to be effective on the Effective Date of this Agreement.

2.2 Purpose of This Agreement

This Agreement provides for the reliable operation of the interconnected New England and New York Transmission Systems in accordance with the requirements of the Standards Authority.

This Agreement establishes a structure and framework for the following functions related to the Reliability of interconnected operations between the Parties:

(a) developing and issuing Operating Instructions and System Operating Limits;
(b) coordinating operation of their respective Transmission Systems;
(c) developing and adopting operating criteria and standards;
(d) conducting operating performance reviews of the Interconnection Facilities;
(e) considering matters related to transmission service and access;
(f) implementing each Party's respective NERC and NPCC requirements with regard to the New England Transmission System and New York Transmission System;
(g) exchanging operations information regarding the Interconnection;
(h) exchanging information and coordinating regarding system planning;
(i) providing mutual assistance in an Emergency and during system restoration;
(j) administering Coordinated Transaction Scheduling; and
(k) implementing other arrangements between the Parties for the coordination of their systems.

The Parties shall, consistent with NPCC Criteria, Guides and Procedures and the Parties' respective tariffs, rules and standards, including with respect to the NYISO, the NYSRC Reliability Rules, to the maximum extent they deem consistent with the safe and proper operation of their respective Reliability Coordinator Area and Balancing Authority Area and necessary coordination with other interconnected systems, and with the furnishing of dependable and satisfactory service to their own customers, operate their systems in accordance with the following procedures and principles.

ARTICLE 3.0: MUTUAL BENEFITS

3.1 No Charge for Mutual Benefits of Interconnection

Both the New England Transmission System and New York Transmission System, by virtue of being connected to each other and with a much larger Interconnection, share Mutual Benefits such as transient and steady-state support. NYISO and ISO-NE shall not charge one another for such Mutual Benefits.

3.2 Maintenance of Mutual Benefits

The Parties shall endeavor to operate or direct the operation of the Interconnection Facilities to realize the Mutual Benefits. The Parties recognize circumstances beyond their control, such as a result of operating configurations, contingencies, maintenance, or actions by Third Parties, may result in a reduction of Mutual Benefits.

ARTICLE 4.0: INTERCONNECTED OPERATION

4.1 Obligation to Remain Interconnected

The Parties shall at all times during the term of this Agreement operate or direct the operation of their respective Transmission Systems so that they remain interconnected except:

(a) during the occurrence of an event of Force Majeure which renders a Party unable to remain interconnected;

(b) when an Interconnection is opened in accordance with the terms of an Operating Instruction;

(c) when an Interconnection is opened in accordance with Good Utility Practice in a particular circumstance where there is an imminent risk of equipment failure, or of danger to personnel or the public, or a risk to the environment, or risk to the Reliability of a Transmission System that is not anticipated and addressed within an Operating Instruction; or

(d) during planned maintenance where notice has been given in accordance with outage procedures as implemented by the Coordination Committee.

4.2 Adherence to NPCC Criteria, Guides and Procedures

The Parties are participants in the NPCC and are required to comply with NPCC Criteria, Guides and Procedures. Such NPCC Criteria, Guides and Procedures detail the many coordinating functions carried out by the Parties and this Agreement is intended to enhance this arrangement. Such NPCC Criteria

include, and the Parties agree to comply with, "Emergency Operation Criteria" (Document A-3), which describes the basic factors to be considered by a Reliability Coordinator and Balancing Authority in formulating plans and procedures to be followed in an Emergency. A principle of operation in this NPCC Criterion is that upon receiving a request for assistance to avoid or mitigate an Emergency, a Balancing Authority Area would provide "maximum reasonable assistance" to a neighboring Balancing Authority Area. Such reasonable assistance would not normally require the shedding of firm load.

4.3 Notification of Circumstances

In the event that a component of the Interconnection Facilities is opened or if the transfer capability of a component of the Interconnection Facilities is changed, or if a Party plans to initiate the opening of any component of the Interconnection Facilities, or to change the transfer capability of any component of the Interconnection Facilities, such Party shall immediately provide the other Party with notification indicating the circumstances of the opening or transfer capability change and expected restoration time, in accordance with procedures implemented by the Coordination Committee or applicable NPCC Criteria, Guides and Procedures.

4.4 Compliance with Coordination Committee Direction.

ISO-NE shall direct the operation of the New England Transmission System and the NYISO shall direct the operation of the New York Transmission System in accordance with the obligations of their respective tariffs, rules and standards and applicable directions of the Coordination Committee that conform with their respective tariffs, rules and standards, including with respect to the NYISO, the NYSRC Reliability Rules, except where prevented by Force Majeure. The Coordination Committee direction includes decisions and jointly developed and approved Operating Instructions. If decisions or Operating Instructions of the Coordination Committee do not anticipate a particular circumstance, the Parties shall act in accordance with Good Utility Practice.

4.5 Control and Monitoring

Each Party shall provide or arrange for 24-hour control and monitoring of their portion of the Interconnection Facilities.

4.6 Reactive Transfer and Voltage Control

The Parties agree to determine reactive transfers and control voltages in accordance with the provisions of NPCC "Guidelines for Inter-Area Voltage Control" (Document B-03). Real and reactive power will be transferred over the Interconnection Facilities, which are described in Schedule A of this Agreement.

4.7 Inadvertent

Inadvertent power transfers on all Interconnection Facilities shall be controlled and accounted for in accordance with the standards and procedures developed by NERC and NPCC and implemented by the Coordination Committee and the system operators of each Party to this Agreement.

4.8 Adoption of Standards

The Parties hereby agree to adopt, enforce and comply with requirements and standards that will safeguard Reliability of the interconnected Transmission Systems. Such Reliability requirements and Reliability Standards shall be:

(a) adopted and enforced for the purpose of providing reliable service;
(b) not unduly discriminatory in substance or application;
(c) applied consistently to both Parties (with the exception of subsection (e) below);
(d) consistent with the Parties' respective obligations to applicable Standards Authorities including, without limitation, any relevant requirements or guidelines from each of NERC, NPCC or any other Standards Authority to which the Parties are required to adhere; and
(e) with respect to the NYISO, consistent with the NYSRC Reliability Rules.

4.9 New York - New England IROL Interface

The Parties share a joint Interconnection Reliability Operating Limit ("IROL") related to transfers on the interconnecting transmission lines between their respective Reliability Coordinator Areas and Balancing Authority Areas. This IROL is adhered to in order to ensure acceptable steady-state and transient performance of the New York and New England Transmission Systems. Both Parties will monitor this limit in accordance with this Agreement and independently determine the applicable import and export transfer limits. Both Parties agree to operate the interface to the most conservative limits developed in

real-time and the day-ahead planning process. These operating limits shall be determined in accordance with NERC Reliability Standards and NPCC Criteria, Guides and Procedures. Both Parties will take coordinated corrective actions to avoid a violation of the IROL. If a violation occurs, coordinated corrective actions shall be taken to ensure that the violation is cleared as soon as possible, and in accordance with NERC Reliability Standards.

4.10 Coordination and Exchange of Information Regarding System Planning

Each Party shall have operating procedures, processes or plans in place for activities that require notification, exchange of information or coordination of actions with the other Party to support Interconnection reliability. Each Party shall have communications capabilities with the other Party, for both voice and data exchange as required to meet reliability needs of the Interconnection.

The Parties shall exchange information and coordinate regarding system operations and planning and inter-regional planning activities in a manner consistent with NERC and NPCC requirements, and consistent with the requirements of Section 6 of this Coordination Agreement.

ARTICLE 5.0: EMERGENCY ASSISTANCE

5.1 Emergency Assistance

Both Parties shall exercise due diligence to avoid or mitigate an Emergency to the extent practicable as per each Party's requirements related to the mitigation of an Emergency, in applicable policies and procedures imposed by NERC, NPCC, or (for the NYISO) the NYSRC, or contained in the ISO-NE Tariff and NYISO Tariffs. In avoiding or mitigating an Emergency, both Parties shall strive to allow for commercial remedies, but if commercial remedies are not successful, the Parties agree to be the suppliers of last resort to ensure Reliability on the system. For each hour during which Emergency conditions exist in a Party's Balancing Authority Area, that Party (while still ensuring operations within applicable Reliability Standards) shall determine what commercial remedies are available and make use of those that are available and needed to avoid or mitigate the Emergency before any Emergency Energy is scheduled in that hour.

5.2 Emergency Energy Transactions

Each Party shall, to the maximum extent it deems consistent with the safe and proper operation of its respective Transmission System, provide Emergency Energy to the other Party in accordance with the provisions of Schedule C of this Agreement.

ARTICLE 6.0: EXCHANGE OF INFORMATION AND CONFIDENTIALITY

ISO-NE and NYISO are authorized and agree to exchange and share such information as is required for the Coordination Committee to perform its duties and for the Parties to fulfill their obligations under this Agreement. Any Party that receives Confidential Information or Critical Energy Infrastructure Information ("CEII") pursuant to this Article 6 (the "Receiving Party") shall treat such information as confidential subject to the terms and conditions set forth in Section 6.5 of this Agreement.

6.1 Information

Parties are authorized and agree to share the following information:

(a) Information required to develop Operating Instructions;

(b) Transmission System facility specifications and modeling data required to perform Security analysis;

(c) Functional descriptions and schematic diagrams of Transmission System protective devices and communication facilities;

(d) Ratings data and associated ratings methodologies for the Interconnection Facilities;

(e) Telemetry points, equipment alarms and status points required for real-time monitoring of Security dispatch;

(f) Data required to reconcile accounts for inadvertent energy, and for Emergency Energy transactions;

(g) Transmission System information that is consistent with the information sharing requirements imposed by the NERC and NPCC;

(h) Such other information as may be required for the Parties to maintain the reliable operation of their interconnected Transmission Systems and fulfill their obligations under this Agreement and to any Standards Authority of which either Party is a member, provided, however, that this other information will be exchanged only if it can be done in accordance with applicable restrictions on the disclosure of information to any Market Participant; and

(i) Information related to the administration of CTS including:

- ISO-NE Market Participant user and organization information;
- ISO-NE Supply Price Points for each CTS Enabled Interface;
- ISO-NE Transfer Limits for each CTS Enabled Interface;
- NYISO and ISO-NE Operating Reserves and reserve requirements;
- Day-ahead schedules, and real-time actual output and limits for NYCA generators that have capacity obligations in the ISO-NE market and for NECA generators that have capacity obligations in the NYISO market;
- Real-time bids, including real-time bids to wheel energy, submitted at a CTS Enabled Interface between the NYCA and the NECA (to be provided by NYISO);
- NYISO Day Ahead Operating Plan; and
- NYISO RTC results, including cleared MWs for all bids at a CTS Enabled Interface between the NYCA and the NECA, as well as LMPs, Transfer Limits and constraint information related to the scheduling of real-time energy transactions between the NYCA and the NECA.

6.2 Data Exchange Contact

To facilitate the exchange of all such data, each Party will designate to the other Party's Vice President in charge of operations a contact(s), plus one or more alternate contacts, to be available twenty-four (24) hours each day, seven (7) days per week to respond to data inquiries. An alternate contact of each Party shall be its Operations Control Room. Each Party shall provide the name, telephone number, e-mail address, and fax number of each contact and alternate. Each Party may change the designated contact by notifying the other Party's Vice President in charge of operations in advance of the change.

The Parties agree to exchange data in a timely manner consistent with existing defined formats or such other formats to which the Parties may agree. Each Party shall provide notification to the other Party thirty (30) days prior to modifying an established data exchange format.

6.3 Cost of Data and Information Exchange

Each Party shall bear its own cost of providing information to the other Party.

6.4 Other Data

The Parties may share Confidential Information not listed in this Article 6 that is necessary for the coordinated operation of their systems, subject to the protections set forth in Section 6.5, below.

6.5 Treatment of Confidential Information and Critical Energy Infrastructure Information

(a) Definitions. For purposes of addressing information shared or exchanged pursuant to this Agreement, the term "Confidential Information" shall mean: (i) all information, whether furnished before or after the mutual execution of this Agreement, whether oral, written or recorded/electronic, and regardless of the manner in which it is furnished, that is marked "confidential" or "proprietary" or which under all of the circumstances should be treated as confidential or proprietary; (ii) information that is Confidential Information or Strategic Information under the ISO New England Information Policy or the NYISO Code of Conduct; (iii) information that is Protected Information under the NYISO Market Monitoring Plan; (iv) all reports, summaries, compilations, analyses, notes or other information of a Party hereto which are based on, contain or reflect any Confidential Information; or (v) any information which, if disclosed by a transmission function employee of a utility regulated by the FERC to a market function employee of the same utility system, other than by public posting, would violate the FERC's Standards of Conduct set forth in 18 C.F.R. § 37 *et. seq*. and the Parties' Standards of Conduct on file with the FERC.

(b) Labeling of Confidential Information. In circumstances where it may not be clear that information that is provided or exchanged between the Parties pursuant to the authority provided in this Agreement is Confidential Information, the information being provided should be clearly marked "confidential" or "proprietary." Such labeling is not required for the regular, automated exchange of Confidential Information that occurs, for example, to permit the Parties to administer CTS.

(c) Protection. Except as set forth herein, the Receiving Party shall not, at any time during or after the term of this Agreement, in any manner, either directly or indirectly, divulge,

disclose, or communicate to any person, firm, corporation or other entity, or use for any purposes other than those set forth herein, any Confidential Information acquired from the party disclosing the information (the "Disclosing Party"), without the express prior written consent of the Disclosing Party. The Receiving Party shall not disclose any Confidential Information to anyone except to officers and employees of the Receiving Party and to its outside consultants, advisers and/or attorneys, in each case who have a need to know to further the purposes set forth herein and who have been advised of the confidential nature of the Confidential Information and who have agreed to abide by the terms of this Agreement or are bound by equally restrictive covenants (collectively, "Authorized Representatives"). The Receiving Party agrees that it shall be liable for any breach of this Agreement by its Authorized Representatives.

(d) Notwithstanding anything in this Section to the contrary, if the FERC or its staff, during the course of an investigation or otherwise, request information from one of the Parties that is otherwise required to be maintained in confidence pursuant to the Agreement, the Party shall provide the requested information to the FERC or its staff, within the time provided for in the request for information.

(e) Survival. The obligation of each Party and each Authorized Representative under this Article 6 continues and survives the termination of this Agreement.

(f) Scope. This obligation of confidentiality shall not extend to data and information that, at no fault of the Receiving Party, is or becomes: (a) in the public domain or generally available or known to the public; (b) disclosed to a recipient by a non-Party who had a legal right to do so; or (c) independently developed by the Receiving Party or known to such Party prior to its disclosure hereunder.

(g) Required Disclosure or Submission on a Confidential Basis. If a governmental authority requests or requires the Receiving Party to publicly disclose any of the Disclosing Party's Confidential Information, or if a request from another person or entity is made in writing pursuant to a legal discovery process, the Receiving Party shall provide the Disclosing Party with prompt notice of such request or requirement. The Disclosing Party shall in turn, to the extent required by the terms of its tariff, provide any Market Participant whose Confidential Information is the subject of possible disclosure with prompt written

notice of the circumstances that may require such disclosure so that the Market Participant has a reasonable opportunity to seek a protective order or other appropriate remedy to prevent disclosure.

If a Receiving Party is required to publicly disclose any Confidential Information under this Section, the Parties shall meet as soon as practicable in an effort to resolve any and all issues associated with the required disclosure , and the possibility of further requested or required disclosures of the Disclosing Party's Confidential Information.

The process described above shall also be followed if a governmental authority requests or requires the Receiving Party to submit any of the Disclosing Party's Confidential Information on a confidential basis (with the exception of requests for Confidential Information from FERC or the Commodity Futures Trading Commission ("CFTC") to the NYISO). The Receiving Party shall notify the governmental authority that the requested or required information contains NYISO or ISO-NE Market Participant specific Confidential Information, if applicable, and shall use reasonable efforts to protect the Confidential Information from public disclosure.

If FERC or the CFTC request or require the NYISO to submit any Confidential Information it received from ISO-NE on a confidential basis, the NYISO will seek permission to inform ISO-NE of the requirement or request and, if granted, will follow the procedures outlined above. In the event FERC or the CFTC does not permit the NYISO to notify ISO-NE of the request, NYISO shall inform FERC or the CFTC in writing that the disclosed information includes Confidential Information, and shall request that FERC or the CFTC inform NYISO before releasing to a third party any of the Confidential Information.

If a governmental authority (including FERC and the CFTC) that requested or required he submission, on a confidential basis, of Confidential Information by a Receiving Party issues a notice indicating that it is considering disclosing, or intends to disclose any Confidential Information provided by the Disclosing Party, or if the governmental authority (including FERC and the CFTC) receives a public records demand or other legal discovery request seeking disclosure of any Confidential Information provided by the Disclosing Party, the Receiving Party shall notify the Disclosing Party so that the

Disclosing Party may seek an appropriate protective order or other appropriate remedy. The Disclosing Party shall in turn, to the extent required by the terms of its tariff, provide any Market Participant whose Confidential Information is the subject of possible disclosure under this provision with prompt written notice of the circumstances that may require such disclosure so that the Market Participant has a reasonable opportunity to seek a protective order or other appropriate remedy to prevent disclosure.

(h) In providing the information to FERC or its staff, the Party may, consistent with 18 C.F.R. § 388.112, request that the information be treated as confidential and non-public by the FERC and its staff and that the information be withheld from public disclosure. The Party shall notify the other Party to the Agreement when it is notified by FERC or its staff that a request for disclosure of, or decision to disclose, confidential information has been received, at which time either of the Parties may respond before such information is made public, pursuant to 18 C.F.R.§ 388.112.

(i) Return of Confidential Information. Information provided pursuant to this Section 6 is deemed to be on loan, and remains the property of the Disclosing Party notwithstanding the disclosure of such Confidential Information to the Receiving Party hereunder. All Confidential Information provided by the Disclosing Party shall be returned by the Receiving Party to the Disclosing Party or destroyed, erased or deleted by the Receiving Party, with written confirmation provided to the Disclosing Party, promptly upon request. Upon termination of this Agreement, a Party shall use reasonable efforts to destroy, erase, delete or return to the Disclosing Party any and all written or electronic Confidential Information. Unless otherwise expressly agreed in a separate license agreement, the disclosure of Confidential Information to the Receiving Party will not be deemed to constitute a grant, by implication or otherwise, of a right or license to the Confidential Information or in any patents or patent applications of the Disclosing Party.

(j) Relief. Each Party acknowledges that remedies at law are inadequate to protect against breach of the covenants and agreements in this Article, and hereby in advance agrees, without prejudice to any rights to judicial relief that it may otherwise have, to the granting of equitable relief, including injunction, in the Disclosing Party's favor without proof of actual damages. In addition to the equitable relief referred to in this Section, a

Disclosing Party shall only be entitled to recover from a Receiving Party any and all gains wrongfully acquired, directly or indirectly, from a Receiving Party's unauthorized disclosure of Confidential Information.

(k) Existing Confidential Information Obligations. Notwithstanding anything to the contrary in this Agreement, the Parties shall have no obligation to disclose Confidential Information or data to the extent such disclosure of information or data would be a violation of or inconsistent with applicable state or federal regulation or law. This Agreement requires the Parties to exchange Confidential Information that is necessary for the Coordination Committee to perform its duties, or for the Parties to fulfill their obligations under this Agreement. The Parties are not obligated to share Confidential Information for other purposes.

(l) The term "CEII" or "Critical Energy Infrastructure Information" shall mean all information, whether furnished before or after the mutual execution of this Agreement, whether oral, written or recorded/electronic, and regardless of the manner in which it is furnished, that is marked "CEII" or "Critical Energy Infrastructure Information" or which under all of the circumstances should be treated as such in accordance with the definition of CEII in 18 C.F.R. § 388.13(c)(1). The Receiving Party shall maintain all CEII in a secure place. The Receiving Party shall treat CEII received under this agreement in accordance with its own procedures for protecting CEII and shall not disclose CEII to anyone except its Authorized Representatives.

6.6 Unauthorized Transfer of Third-Party Intellectual Property

In the performance of this Agreement, no Party shall transfer to the other Party any Intellectual Property, the use of which by the other Party would constitute an infringement of the rights of another entity (including the Parties). In the event such transfer occurs, whether or not inadvertent, the transferring Party shall, promptly upon learning of the transfer, provide Notice to the receiving Party and upon receipt of such Notice the receiving Party shall take reasonable steps to avoid claims and mitigate losses.

ARTICLE 7.0: COORDINATION COMMITTEE

7.1 Coordination Committee Inauguration and Authorization

The Parties shall form a Coordination Committee under this Agreement. Within 30 days of the Effective Date, each of the Parties shall appoint two representatives, a principal and an alternate, to serve as members of the Coordination Committee with the authority to act on their behalf with respect to actions or decisions taken by the Coordination Committee. A Party may, at any time upon providing prior notice to the other Party, designate a replacement principal member or alternate member to the Coordination Committee.

7.2 Coordination Committee Duties and Responsibilities

The Coordination Committee exists to administer or assist the Parties' implementation of the provisions of this Agreement. The Coordination Committee shall develop and adopt policies, instructions, and recommendations relating to the Parties' performance of their obligations under this Agreement, attempt to resolve Disputes between the Parties pursuant to Article 17.0 of this Agreement, and shall undertake any other actions specifically delegated to it pursuant to this Agreement.

The Coordination Committee shall undertake to assist the Parties' efforts to jointly develop Operating Instructions to implement the intent of this Agreement in accordance with Schedule B of this Agreement, 'Procedures for Development and Authorization of Operating Instructions'. The Coordination Committee shall authorize such Operating Instructions once developed. To the extent that the Operating Instructions require participation by local control centers and Transmission Owners in the New England or the New York Reliability Coordinator Areas, those entities will be involved in the development process.

Should the terms and conditions contained in this Agreement be found to conflict with or fail to recognize obligations of a Standards Authority of which either Party is a member or other regulatory requirements, the Parties agree to amend this Agreement accordingly.

Any recommendations on revisions to this Agreement shall be provided to each Party's appropriate corporate officers for approval.

7.3 Limitations of Coordination Committee Authority

The Coordination Committee is not authorized to modify or amend any of the terms of this Agreement. The Coordination Committee is also not authorized to excuse any obligations under this Agreement or waive any rights pertaining to this Agreement.

The Coordination Committee has no authority to commit either Party to any expenditure that is beyond those expenses described herein.

7.4 Exercise of Coordination Committee Duties

The Coordination Committee shall hold meetings no less frequently than once each calendar year. The matters to be addressed at all meetings shall be specified in an agenda, which shall contain items specified by either Party in advance of the meeting and sent to the representatives of the other Party. All decisions of the Coordination Committee must be unanimous. Special meetings may be called at any time if the Coordination Committee deems such meetings to be necessary or appropriate.
Subject to the limitations on its authority as described in Section 7.3 of this Agreement, the Coordination Committee has the responsibility and authority to take action on all aspects of this Agreement, including, but not limited to the following:

(a) amending, adding or canceling Operating Instructions and providing written notice in accordance with Article 18.0 of this Agreement;
(b) assessment of non-compliance with this Agreement and, subject to Article 19.0 of this Agreement, the taking of appropriate action in respect thereof;
(c) documentation of decisions related to the initial resolution of Disputes as set out in Article 19.0 of this Agreement, or in cases of unresolved Disputes, the circumstances relevant to the Dispute in question as contemplated by the requirements of Article 19.0 of this Agreement; and
(d) preparation, documentation, retention and distribution of Coordination Committee meeting minutes and agendas.

ARTICLE 8.0: RELIABILITY COORDINATION AND RELIABILITY ASSESSMENT OF OUTAGES

Both Parties agree to provide each other with updates on planned outage schedules and other activities in accordance with NPCC Criteria, Guides and Procedures that may impact on the Reliability or availability

of the interconnected New York Transmission System and New England Transmission System. As Reliability Coordinators and Balancing Authorities, the NYISO and ISO-NE, shall interact with each other as required, and with other Balancing Authorities and Reliability Coordinators, to establish System Operating Limits and to perform Reliability coordination and Reliability assessments of outages.

ARTICLE 9.0: OPERATIONAL INFORMATION

9.1 Obligation to Provide Operational Data and Status Points

The Parties shall ensure that appropriate monitoring facilities are installed as required to provide for electric power quantities or equipment loading to enable monitoring of System Operating Limits, meet requirements of each of NERC and NPCC, and for determining Interconnection Facilities inadvertent energy accounting.

ARTICLE 10.0: INTERCONNECTION REVENUE METERING

10.1 Obligation to Provide Inadvertent Energy Accounting Metering

The Parties shall ensure appropriate electric metering devices are installed as required to measure electric power quantities for determining Interconnection Facilities inadvertent energy accounting.

10.2 Standards for Metering Equipment

Any Metering Equipment used to meter Metered Quantities for inadvertent energy accounting shall be designed, verified, sealed and maintained in accordance with the Party's respective metering standards or as otherwise agreed to by the Coordination Committee.

10.3 Meter Compensation to the Point of Interconnection

The metering compensation for transmission line losses to the Interconnection Facilities Delivery Point shall be determined by the Party's respective standards or otherwise agreed to by the Coordination Committee.

10.4 Metering Readings

The Parties shall ensure that integrated meter readings are provided at least once each hour for Interconnection Facilities accounting purposes and meter registers are read at least monthly, as close as practicable to the last hour of the month. An appropriate adjustment shall be made to register readings not taken on the last hour of the month.

ARTICLE 11.0: JOINT CHECKOUT PROCEDURES

11.1 Scheduling Checkout Protocols

Both Parties shall require all real-time energy market transaction schedules over Interconnections to be tagged in accord with the NERC tagging standard. For Simultaneous Activation of Reserves ("SAR") and other emergency schedules that are not tagged, the Parties will enter manual schedules into their respective operating systems.

When there is a real-time energy market transaction scheduling conflict, the Parties will work to modify the schedule as soon as practical.

Consistent with the foregoing requirements, the Parties will perform the following types of checkouts:

(a) Day-ahead checkout shall be performed daily on the day before the transaction is to flow. Day-ahead checkout includes the verification of net interchange totals and individual transaction schedules;

(b) Real-time checkout shall be performed during the period before the transaction is to flow. Real-time checkout includes the verification of net interchange totals and individual transaction schedules;

(c) After-the-fact checkout of real-time transactions shall be performed the next business day following the day of the transactions;

(d) After-the-fact reporting of scheduled energy interchange and actual energy interchange shall be updated by each Party each day and exchanged with the other Party. Within ten (10) business days of the end of each month, the previous month's data shall be reconciled.

ARTICLE 12.0: COORDINATED TRANSACTION SCHEDULING

CTS is addressed in Schedule D to this Agreement and in the ISO-NE and NYISO Tariffs.

ARTICLE 13.0: LIABILITY

13.1 Force Majeure

A Party shall not be considered to be in default or breach of this Agreement, and shall be excused from performance or liability for damages to the 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, arising out of or from any act, omission, or circumstance by or in consequence of any act of God, labor disturbance, sabotage, failure of contractors or suppliers of materials, act of the public enemy, war, invasion, insurrection, riot, fire, storm, flood, ice, earthquake, explosion, epidemic, breakage or accident to machinery or equipment or any other cause or causes beyond such Party's reasonable control, including any curtailment, order, regulation, or restriction imposed by governmental, military or lawfully established civilian authorities, or by making of repairs necessitated by an emergency circumstance not limited to those listed above upon the property or equipment of the Party or property or equipment of others which is deemed under the Operational Control of the Party. A Force Majeure event does not include an act of negligence or Intentional Wrongdoing by a Party. Any Party claiming a Force Majeure event shall use reasonable diligence to remove the condition that prevents performance and shall not be entitled to suspend performance of its obligations in any greater scope or for any longer duration than is required by the Force Majeure event. Each Party shall use its best efforts to mitigate the effects of such Force Majeure event, remedy its inability to perform, and resume full performance of its obligations hereunder.

A Party suffering a Force Majeure event ("Affected Party") shall notify the other Party ("Non-Affected Party") in writing ("Notice of Force Majeure Event") as soon as reasonably practicable specifying the cause of the event, the scope of commitments under the Agreement affected by the event, and a good faith estimate of the time required to restore full performance. Except for those commitments identified in the Notice of Force Majeure Event, the Affected Party shall not be relieved of its responsibility to fully perform as to all other commitments in the Agreement. If the Force Majeure event continues for a period

of more than 90 days from the date of the Notice of Force Majeure Event, the Non-Affected Party shall be entitled, at its sole discretion, to terminate the Agreement.

13.2 Liability to Third Parties

Nothing in this Agreement, whether express or implied, is intended to confer any rights or remedies under or by reason of this Agreement on any person or entity that is not a Party or a permitted successor or assign.

13.3 Indemnification

(a) Definitions. An "Indemnifying Party" means a Party who holds an indemnification obligation hereunder. An "Indemnitee" means a Party entitled to receive indemnification under this Agreement.

(b) Third Party Losses. Each Party will defend, indemnify, and hold the other Party harmless from all losses, damages, liabilities, obligations, claims, demands, suits, proceedings, recoveries, settlements, costs and expenses, court costs, attorney fees, causes of action, judgments and other obligations (collectively, "Losses") brought or obtained by any Third Party against such other Party, only to the extent that such Losses arise directly from the:

(i) Gross negligence, recklessness, or willful misconduct of the Indemnifying Party or any of its agents or employees, in the performance of this Agreement; except to the extent such Losses arise (i) from gross negligence, recklessness, willful misconduct or breach of contract or law by the Indemnitee or such Indemnitee's agents or employees, or (ii) as a consequence of strict liability imposed as a matter of law upon the Indemnitee, or such Indemnitee's agents or employees; or

(ii) Breach of the Parties' obligations in Article 6 hereof.

(c) Process. The Indemnitee shall give Notice to the Indemnifying Party as soon as reasonably practicable after the Indemnitee becomes aware of the indemnifiable Losses or any claim, action or proceeding that may give rise to an indemnification. Such notice shall describe the nature of the Losses or proceeding in reasonable detail, explain how the

Losses relate to the performance of this Agreement, and shall indicate, if practicable, the estimated amount of the Losses that has been sustained by the Indemnitee. A delay or failure of the Indemnitee to provide the required notice shall release the Indemnifying Party (i) from any indemnification obligation to the extent that such delay or failure materially and adversely affects the Indemnifying Party's ability to defend such claim or materially and adversely increases the amount of the indemnifiable Losses, and (ii) from any responsibility for any costs or expenses of the Indemnitee in the defense of the claim during such period of delay or failure.

(d) Indemnification shall be limited to the extent that the liability of the Indemnitee would be limited by any applicable law.

13.4 Liability Between the Parties

The Parties' duties and standard of care with respect to each other, and the benefits and rights conferred on each other shall be no greater than as expressly stated herein. Neither Party, its directors, officers, trustees, employees or agents, shall be liable to the other Party for any Losses, whether direct, indirect, incidental, punitive, special, exemplary or consequential, arising from that Party's performance or nonperformance under this Agreement, except to the extent that the Party, is found liable for gross negligence or willful misconduct, in which case the Party responsible shall be liable only for direct and ordinary damages and not for any incidental, consequential, punitive, special, exemplary or indirect damages.

This section shall not limit amounts required to be paid for Emergency Energy under Schedule C to this Agreement. This section shall not apply to adjustments or corrections for errors in invoiced amounts due under Schedule C to this Agreement.

13.5 Liability for Interruptions

Except as set forth herein, neither Party shall be liable to the other Party for any Losses or damage, whether direct, indirect, incidental, punitive, special, exemplary or consequential, resulting from an occurrence on the circuits and system that are under the Operational Control of the other Party and which results in damage to or renders inoperative such circuits and system, or the separation of the systems in an

Emergency, or interrupts or diminishes service, or increases, decreases or in any way affects for whatever length of time the voltage or frequency of the energy delivered hereunder to the other Party.

ARTICLE 14.0: APPLICABLE LAW

This Agreement shall be governed by and construed in accordance with the laws of the State of Delaware.

ARTICLE 15.0: LICENSE AND AUTHORIZATION

The agreements and obligations expressed herein are subject to such initial and continuing governmental permission and authorization as may be required. Each Party shall be responsible for securing and paying for any approvals required by it from any regulatory agency of competent jurisdiction relating to its participation in this Agreement and will reasonably cooperate with the other Party in seeking such approvals.

ARTICLE 16.0: ASSIGNMENT

This Agreement shall inure to the benefit of, and be binding upon and may be performed by, the successors and assigns of the Parties hereto respectively, but shall not be assignable by either Party without the written consent of the other.

ARTICLE 17.0: AMENDMENT

17.1 Review of Agreement

The terms of this Agreement are subject to review for potential amendment at the request of either Party. If, consequent to such review, the Parties agree that any of the provisions hereof, or the practices or conduct of either Party impose an inequity, hardship or undue burden upon the other Party, or if the Parties agree that any of the provisions of this Agreement have become obsolete or inconsistent with changes related to the Interconnection Facilities, the Parties shall endeavor in good faith to amend or supplement this Agreement in such a manner as will remove such inequity, hardship or undue burden, or otherwise appropriately address the cause for such change.

Any amendment of this Agreement by the Parties must be done in accordance with Section 17.2.

17.2 Authorized Representatives

No amendment of this Agreement shall be effective unless effected by written instrument duly executed by the Parties' authorized representatives. For the purposes of this Section, an authorized person refers to individuals designated as such by Parties in their respective corporate by-laws.

ARTICLE 18.0: NOTICES

Except as otherwise agreed from time to time, any notice, invoice or other communication which is required by this Agreement to be given in writing, shall be sufficiently given at the earlier of the time of actual receipt or deemed time of receipt if delivered personally to a senior official of the Party for whom it is intended or electronically transferred or sent by registered mail, addressed as follows:

In the case of the NYISO to:

New York Independent System Operator, Inc.
10 Krey Boulevard, Rensselaer, New York 12144
Attention: Vice President of Operations

In the case of ISO-NE to:

ISO New England Inc.
One Sullivan Road
Holyoke, Massachusetts 01040-2841
Attention: Vice President of System Operations

or delivered to such other person or electronically transferred or sent by registered mail to such other address as either Party may designate for itself by notice given in accordance with this Section or delivered by any other means agreed to by the Parties hereto.

Any notice, or communication so mailed shall be deemed to have been received on the third business day following the day of mailing, or if electronically transferred shall be deemed to have been received on the same business day as the date of the electronic transfer, or if delivered personally shall be deemed to have

been received on the date of delivery or if delivered by some other means shall be deemed to have been received as agreed to by the Parties hereto.

The use of a signed facsimile of notices and correspondence between the Parties related to this Agreement shall be accepted as proof of the matters therein set out. Follow-up with hard copy by mail will not be required unless agreed to by the Coordination Committee.

ARTICLE 19.0: DISPUTE RESOLUTION

In the event of a dispute arising out of or relating to this Agreement (a "Dispute") that is not resolved by the representatives of the Parties who have been designated under Section 7.1 of this Agreement within 7 days of the reference to such representatives of such Dispute, each Party shall, within 14 days' written notice by either Party to the other, designate a senior officer with authority and responsibility to resolve the Dispute and refer the Dispute to them. The senior officer designated by each Party shall have authority to make decisions on its behalf with respect to that Party's rights and obligations under this Agreement. The senior officers, once designated, shall promptly begin discussions in a good faith effort to agree upon a resolution of the Dispute. If the senior officers do not agree upon a resolution of the Dispute within 30 days of its referral to them (or within such longer period as the senior officers mutually agree to in writing), or do not mutually agree to submit their Dispute for binding or non-binding arbitration by the Federal Energy Regulatory Commission's Dispute Resolution Service, then the Parties shall request that the Federal Energy Regulatory Commission's Dispute Resolution Service mediate their efforts to resolve the Dispute. At any point in the mediation process, either Party may terminate the mediation and may pursue any and all remedies available to it at law or in equity.

Neither the giving of notice of a Dispute, nor the pendency of any Dispute resolution process as described in this Section shall relieve a Party of its obligations under this Agreement, extend any notice period described in this Agreement or extend any period in which a Party must act as described in this Agreement. Notwithstanding the requirements of this Section, either Party may terminate this Agreement in accordance with its provisions, or pursuant to an order of FERC or a court at equity. The issue of whether such a termination is proper shall not be considered a Dispute hereunder.

ARTICLE 20.0: REPRESENTATIONS

20.1 Good Standing

Each Party represents and warrants that it is duly organized, validly existing and in good standing under the laws of the state in which it is organized, formed, or incorporated, as applicable.

20.2 Authority to Enter Into Agreement

Each Party represents and warrants that it has the right, power and authority to enter into this Agreement, to become a Party hereto and to perform its obligations hereunder. This Agreement is a legal, valid and binding obligation of such Party, enforceable against such Party in accordance with its terms.

20.3 Organizational Formation Documents

Each Party represents and warrants that the execution, delivery and performance of this Agreement does not violate or conflict with the organizational or formation documents, bylaws, operating agreement, or agency agreement of such Party, or any judgment, license, permit, regulatory order, or governmental authorization applicable to such Party.

20.4 Regulatory Authorizations

Each Party represents and warrants that it has, or applied for, all regulatory authorizations necessary for it to perform its obligations under this Agreement.

ARTICLE 21.0: EFFECTIVE DATE AND TERM

Subject to the conditions of Article 13.0 (License and Authorization) above, this Agreement shall take effect as of the date that all of the following have occurred: (i) upon the execution hereof by both Parties on the date set forth above; and (ii) acceptance or approval by the FERC. This Agreement shall continue in force until terminated in accordance with this Article.

This Agreement may be terminated at any time by mutual agreement in writing. It may also be terminated by either Party with prior written notice of at least ninety (90) days to the other Party of its intention to terminate.

ARTICLE 22.0: MISCELLANEOUS

22.1 Performance

The failure of a Party to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any right held by such Party. Any waiver on any specific occasion by either Party shall not be deemed a continuing waiver of such right, nor shall it be deemed a waiver of any other right under this Agreement.

22.2 Agreement

This Agreement, including all Schedules and Attachments hereto, is the entire agreement between the Parties with respect to the subject matter hereof, and supersedes all prior or contemporaneous understandings or agreements, oral or written, with respect to the subject matter of this Agreement.

22.3 Governmental Authorizations

This Agreement, including its future amendments is subject to the initial and continuing Federal Energy Regulatory Commission authorizations required to establish, operate and maintain the Interconnection Facilities as herein specified. Each Party shall take all actions necessary and reasonably within its control to maintain all rights and Federal Energy Regulatory Commission approvals required to perform its respective obligations under this Agreement.

If one Party determines that it is required to self-report a potential violation to the Commission's Office of Enforcement regarding its compliance with this Agreement or the administration of CTS, the reporting Party shall inform, and provide a copy of the self-report to the other Party. Any such report provided by one Party to the other shall be Confidential Information. Each Party shall make reasonable efforts to cooperate and assist in remedying any such violation, to the extent such assistance is necessary to resolve the matter and to the extent doing so is consistent with maintaining the Party's legal privilege.

22.4 Unenforceable Provisions

If any provision of this Agreement is deemed unenforceable, the rest of the Agreement shall remain in effect and the Parties shall negotiate in good faith and seek to agree upon a substitute provision that will achieve the original intent of the Parties.

22.5 Execution

This Agreement may be executed in multiple counterparts, each of which shall be considered an original instrument, but all of which shall be considered one and the same Agreement, and shall become binding when all counterparts have been signed by each of the Parties and delivered to each Party hereto. Delivery of an executed signature page counterpart by telecopier shall be as effective as delivery of a manually executed counterpart.

22.6 Regulatory Authority

If any Regulatory Authority having jurisdiction (or any successor boards or agencies), a court of competent jurisdiction or other governmental entity with the appropriate jurisdiction (collectively, the "Regulatory Bodies") issues a rule, regulation, law or order that has the effect of cancelling, changing or superseding any term or provision of this Agreement, including changes to section headings or numbering (the "Regulatory Requirement"), then this Agreement will be deemed modified to the extent necessary to comply with the Regulatory Requirement. Notwithstanding the foregoing, if the Regulatory Authority materially modifies the terms and conditions of this Agreement and such modification(s) materially affect the benefits flowing to one or both of the Parties, as determined by either of the Parties within twenty (20) business days of the receipt of the Agreement as materially modified, the Parties agree to attempt in good faith to negotiate an amendment or amendments to this Agreement or take other appropriate action(s) so as to put each Party in effectively the same position in which the Parties would have been had such modification not been made. In the event that, within sixty (60) days or some other time period mutually agreed upon by the Parties after such modification has been made, the Parties are unable to reach agreement as to what, if any, amendments are necessary and fail to take other appropriate action to put each Party in effectively the same position in which the Parties would have been had such modification not been made, then either Party shall have the right to unilaterally terminate this Agreement forthwith.

22.7 Headings

The headings used for the Articles and Sections of this Agreement are for convenience and reference purposes only, and shall not be construed to modify, expand, limit, or restrict the provisions of this Agreement.

IN WITNESS WHEREOF

IN WITNESS WHEREOF the Parties hereto have caused this Agreement to be executed in duplicate as of the day and year first written above.

NEW YORK INDEPENDENT SYSTEM OPERATOR

_____

By: Ricardo T. Gonzales,
Senior Vice President and Chief Operating Officer
Date: _____

ISO NEW ENGLAND INC.

_____

By: Vamsi Chadalavada,
Senior Vice President and Chief Operating Officer
Date: _____

Schedule A: Description Of Interconnection Facilities

The Coordination Agreement between ISO-NE and the NYISO covers the New England – NYISO Interconnection Facilities under the Operational Control of the NYISO and ISO-NE.
For Operational Control purposes, the point of demarcation for each of the Interconnection Facilities listed below is the point at which each Interconnection crosses the New England-New York State boundary, except as noted below.

There are presently three (3) ISO-NE-NYISO Interconnections. The three Interconnections are comprised of eight (8) alternating current ("AC") Interties and one (1) high-voltage direct current ("HVDC") Intertie. The first Interconnection (the "NY/NE Northern AC Interconnection") is comprised of seven (7) of the eight (8) AC Interties. The second Interconnection (the "NNC Interconnection") is comprised of the remaining AC Intertie. The third and final Interconnection (the "CSC Interconnection") is comprised of a single HVDC Intertie. For each Interconnection, NYISO and ISO-NE have identified respective associated external nodes for scheduling and pricing purposes. The nodes associated with each of the Interconnections are listed in Table 1 of Attachment A of Schedule C of this Agreement.

List of Interconnections

NY/NE Northern AC Interconnection - The NY/NE Northern AC Interconnection is comprised of the following seven (7) Interties (as ordered from North to South):

1. PV-20 Intertie (115 kV AC),
2. K7 Intertie (115 kV AC),
3. K6 Intertie (115 kV AC),
4. E205W Intertie (230 kV AC),
5. 393 Intertie (345 kV AC),
6. 690/FV Intertie (69 kV AC), and
7. 398 Intertie (345 kV AC).

NNC Interconnection - The Northport-Norwalk Harbor Cable ("NNC") Interconnection is comprised of the following Intertie:

1. NNC Intertie (138 kV AC).

CSC Interconnection - The Cross Sound Cable "CSC") Interconnection is comprised of the following Intertie:

1. CSC Intertie (150 kV HVDC).

List of Interties (as ordered from North to South)

PV-20 Intertie - A 115 kV AC transmission circuit, designated PV-20, series switched reactor and phase shifting transformers, connecting the Plattsburgh transmission substation in NY to the Sandbar transmission substation in VT. The common meter point for this Intertie is located at the Plattsburg transmission substation.

K7 Intertie - A 115 kV AC transmission circuit, designated K7, and phase shifter transformer connecting the Whitehall transmission substation in NY to the Blissville transmission substation in VT. The common meter point for this Intertie is located at the Whitehall transmission substation.

K6 Intertie - A 115 kV AC transmission circuit, designated K6, connecting the Hoosick transmission substation in NY to the Bennington transmission substation in VT. The common meter point for this Intertie is located at the Hoosick transmission substation.

E205W Intertie - A 230 kV AC transmission circuit, designated E205W, connecting the Eastover Road transmission substation in NY to the Bear Swamp transmission substation in MA. The common meter point for this Intertie is located at the Bear Swamp transmission substation.

393 Intertie - A 345 kV AC transmission circuit, designated 393, connecting the Alps transmission substation in NY to the Berkshire transmission substation in MA. The common meter point for this Intertie is located at the Alps transmission substation.

690/FV Intertie - A 69 kV AC transmission circuit, designated 690/FV, connecting the Smithfield transmission substation in NY to the Salisbury transmission substation in CT. The common meter point for this Intertie is located at the Salisbury transmission substation.

398 Intertie - A 345 kV AC transmission circuit, designated 398, connecting the Pleasant Valley transmission substation in NY to the Long Mountain transmission substation in CT. The common meter point for this Intertie is located at the Pleasant Valley transmission substation.

NNC Intertie - Three 138 kV AC transmission circuits (designated 601, 602 and 603), transformer and phase shifting transformer, initially designated as the 1385 Cable Intertie and now the NNC Intertie, connecting the Northport transmission substation in NY to the Norwalk Harbor transmission substation in CT.[1] The common meter point for this Intertie is located at the Norwalk Harbor transmission substation.

CSC Intertie - A 150+/- kV HVDC transmission circuit and associated converter facilities, designated CSC, connecting the Tomson converter at Shoreham, NY to the Halvarsson converter at New Haven, CT. This entire facility is under ISO-NE operating authority, pursuant to the FERC Order containing approvals regarding the HVDC Cross Sound Cable. For Operational Control purposes, the point of demarcation for the HVDC Interconnection CSC is within New York State at the point where the converter facilities interconnect with LIPA's 138 kV AC facilities at Shoreham, NY. The common meter point for this Intertie is located at the Shoreham transmission substation.

[1] The NCC Intertie may be referenced in the Parties individual operating documents as the Northport-Norwalk Harbor Cable ("NNC"), the 1385 Cable/Line or the 601, 602 and 603 Cables.

SCHEDULE B: Procedures For Development And Authorization Of Operating Instructions

Overview

Operating Instructions (a) will be developed and recorded by the Parties, with assistance from the Coordination Committee, in accordance with this Schedule B, (b) will be contained in a document separate from this Agreement, and (c) may be modified by the Parties, with assistance from the Coordination Committee, without amending this Agreement.

The Parties, with assistance from the Coordination Committee, shall jointly develop Operating Instructions and review them at least annually. The Parties, with assistance from the Coordination Committee, shall submit draft material to one another for review and comment. The Parties, with assistance from the Coordination Committee, shall provide comment on the draft material promptly. The Parties, with assistance from the Coordination Committee, shall promptly provide such information as may reasonably be required in connection with establishing, or reviewing, the material. The Coordination Committee shall be responsible for approving final versions of Operating Instructions.

In the event that any conflicts arise or are made apparent to a Party regarding any Operating Instructions, they shall notify the other Party and engage the Coordination Committee, if necessary, to resolve such conflicts.

The Coordination Committee will periodically review applicable ISO-NE and NYISO individual procedures and processes to determine any benefits of sharing these procedures and processes. These benefits may be for the purpose of training or to satisfy Reliability Standards. The Coordination Committee will determine how best to share these individual procedures and processes.

A list of Operating Instructions and applicable ISO-NE and NYISO individual procedures will be maintained by the Coordination Committee.

Outlined below are the key principles and items of methodology to be observed while the Parties, with assistance from the Coordination Committee, are engaged in developing Operating Instructions, and issuing them to their respective operations staff.

Principles

Given that the Parties' respective operations staff benefit from following a single instruction for all aspects of their execution of interconnected operations, it is an acceptable practice to combine this content to achieve the single Operating Instructions for use by a respective Party's operations staff. The preferred methodology when appropriate is to use the NPCC Criteria, Guides and Procedures for the coordination and operation of the interconnected Transmission Systems. When the NPCC documentation is insufficient to accomplish this task separate instructions will be developed in accordance with this Schedule.

Each Party shall coordinate the issuance internally of any Operating Instructions developed and agreed to by the Parties, with assistance from the Coordination Committee, to ensure that their respective operations staff has these Operating Instructions. In addition annual review of the Operating Instructions and the Parties' internal procedures associated with the Operating Instructions shall be conducted by the Parties, with assistance from the Coordination Committee, to ensure consistency.

Operating Instructions, when approved by the Parties, shall be binding on the Parties insofar as they relate to the Interconnection Facilities until they expire, are changed, deleted, or superseded by authority of the Parties, with assistance from the Coordination Committee.

Items of Methodology

By mutual agreement of the Coordination Committee, one of the Parties shall be designated by the Coordination Committee to control the revision process of the Operating Instruction from the initial drafting of material through to the conversion of the Operating Instruction into its final form.

SCHEDULE C: Emergency Energy Transactions Schedule

WHEREAS, ISO-NE, as the regional transmission organization for the New England Transmission System and the administrator of the New England markets, arranges for the sale and purchase of Emergency capacity and energy on behalf of Market Participants with neighboring Balancing Authority Areas, all in accordance with the ISO-NE Tariff, which includes the Open Access Transmission Tariff and ISO-NE market rules;

WHEREAS, ISO-NE is responsible for, among other matters, procuring and acting as supplier of last resort of ancillary services (including arranging for the sale and purchase of Emergency capacity and energy with neighboring Balancing Authority Areas), in accordance with the ISO-NE Tariff;

WHEREAS, the NYISO, as the independent system operator of the New York Transmission System and the administrator of the New York wholesale electricity markets, arranges for the sale and purchase of Emergency capacity and energy on behalf of Market Participants with neighboring Balancing Authority Areas, all in accordance with the NYISO Tariffs;

WHEREAS, the NYISO is the administrator of the NYISO Tariffs and is responsible for, among other matters, procuring and acting as supplier of last resort of ancillary services (including arranging for the sale and purchase of Emergency capacity and energy with neighboring Balancing Authority Areas), in accordance with the NYISO Tariffs;

WHEREAS, either of the Parties may, from time to time, have insufficient Operating Reserve available on the respective systems that they operate, or need to supplement available resources to cover sudden and unforeseen circumstances such as loss of equipment or forecast errors, and such conditions could result in the need to arrange for the purchase of Emergency Energy for Reliability reasons;

NOW, THEREFORE, in consideration of the premises and of the mutual covenants herein set forth, the Parties mutually agree as follows:

ARTICLE I

1.0 **DELIVERY POINT**

The Delivery Point for energy delivered pursuant to the terms of this Schedule shall be at one of three points of Interconnection between the NYISO Balancing Authority Area and the ISO-NE Balancing Authority Area, and at such other points of Interconnection as may be established. These three points of Interconnection are as follows: (1) the NY/NE Northern AC Interconnection[2]; (2) the NNC Interconnection; and (3) the Cross Sound Cable (CSC) Interconnection, which is a HVDC facility.

Unless otherwise agreed by the Coordination Committee, the price for energy for an hour delivered pursuant to this Schedule shall include all transmission costs of delivering such energy to the Delivery Point in that hour, and the Party taking delivery of such energy for the hour shall be responsible for all transmission costs beyond the Delivery Point for that hour.

ARTICLE II

2.0 CHARACTERISTICS OF EMERGENCY ENERGY

2.1 All Emergency Energy made available under this Schedule shall be three phase, 60 Hz alternating current at operating voltages established at the Delivery Point in accordance with system requirements and appropriate to the Interconnection Facilities or other such characteristics as may be agreed upon by the Parties.

ARTICLE III

3.0 NATURE OF SERVICE

3.1 ISO-NE and the NYISO shall, to the maximum extent each deems consistent with the safe and proper operation of its system, the furnishing of economical, dependable and satisfactory services by its participants, and the obligations of its participants to other parties, make available to the other Party when a system Emergency exists on the other Party's system, Emergency Energy from its system's available generating capability in excess of the system's load requirements (i.e., load requirements alone, not load plus reserve requirements) up to the transfer limits in use between the two Balancing Authority Areas. Emergency Energy is provided in cases of emergency outages of generating units, transmission lines or other equipment, or to meet other sudden and unforeseen circumstances such as forecast errors, or to

[2] The NY/NE Northern AC Interconnection, as defined in Schedule A – Interconnection Facilities ("Schedule A") to the Coordination Agreement between ISO-NE Inc. and the NYISO Inc.

provide sufficient Operating Reserve. Normally, a Party requests Emergency Energy from the other Party as a last resort, when market-based real-time energy transactions are not available, or not available in a timely fashion in order to maintain its ten-minute reserve requirement. At the time the Emergency Energy sale is being initiated, the Party delivering such Emergency Energy shall describe the Emergency Energy transaction as being one of the following: (1) "delivered out of ten-minute reserve"; (2) "delivered out of thirty-minute reserve" where such a delivery could reasonably be expected to be recalled if the Party delivering the Emergency Energy needed the generation for a reserve pick-up or other Emergency; or (3) "delivered above and beyond ten-minute and thirty-minute reserves" where the Party delivering such Emergency Energy is normally expected to be able to continue delivering the energy following a reserve pick-up.

3.2 The Parties are participants in the NPCC and are expected to comply with NPCC Criteria, Guides and Procedures. Such NPCC Criteria, Guides and Procedures include "Emergency Operation Criteria" (Document A-3), which describes the basic factors to be considered by a Balancing Authority Area in formulating plans and procedures to be followed in an Emergency. A principle of operation in this NPCC Criteria is that upon receiving a request for assistance to mitigate an Emergency, a Balancing Authority Area would provide "maximum reasonable assistance" to a neighboring Balancing Authority Area. Such reasonable assistance would not normally require the shedding of firm load.

3.3 Normally, the Party experiencing or anticipating an Emergency would request Emergency Energy from the other Party in accordance with this Schedule and applicable NPCC Criteria, Guides and Procedures after all market-based real-time transactions have been scheduled, unless there is an immediate need for such Emergency Energy in order to maintain system Reliability.

3.4 In the event a Party is unable to provide Emergency Energy to the other when needed, but there is energy available from a Third Party Balancing Authority Area supplier, the Party will use reasonable efforts to acquire and transmit such energy to the other Party where feasible.

ARTICLE IV

4.0 RATES AND CHARGES

4.1 The charge for Emergency Energy delivered to the NYISO or to ISO-NE shall be as set forth in Attachment A, attached hereto.

4.2 Should activations of reserve sharing be required by either of the Parties, inadvertent interchanges will intentionally be accumulated with each Balancing Authority Area providing assistance. In accordance with the NPCC "Procedures for Shared Activation of Ten Minute Reserve" (Document C-12), such inadvertent accumulations shall be treated as part of ordinary inadvertent energy.

ARTICLE V

5.0 MEASUREMENT OF ENERGY INTERCHANGED

5.1 All energy supplied at the Delivery Point shall be metered. The metered amounts shall be adjusted for actual losses to the Delivery Point on each of the Interconnection Facilities. This adjustment will be done to compensate for the difference in location between the Delivery Point and the meter.

5.2 Any properly designated representative of either of the Parties hereto shall have access, through coordination with the meter owner, during normal business hours, to all of the billing meters for the purpose of reading the same. The accuracy of the meters shall be verified by proper tests periodically and at any other time upon reasonable notice given by either of the Parties to the other, and each of the Parties shall be entitled to have a representative present at such verification, subject to coordination with the meter owner. In the event errors greater than +/-2% should be discovered, retroactive billing adjustments, if any, shall be determined by the Coordination Committee.

ARTICLE VI

6.0 BILLING AND PAYMENT

6.1 The procedure for rendering and payment of invoices for transactions pursuant to this Schedule shall be as set out hereunder unless otherwise agreed by the Coordination Committee.

6.2 The Party delivering energy pursuant to this Schedule shall promptly prepare, or cause to be prepared, and render an invoice to the other Party covering all transactions conducted under the terms of this Schedule. All transactions will be billed based on the schedule of energy agreed to by the Parties.

6.3 All invoices rendered by a Party shall be payable by the other Party in currency of the United States of America by electronic bank transfer within five (5) business days after the issuance of an invoice (the "Due Date").

6.4 If the rendering of an invoice is unavoidably delayed, a Party may issue an interim invoice based on estimated charges. Each invoice shall be subject to adjustment for any errors in calculation, meter readings, estimating or otherwise. Any such billing adjustments shall be made as promptly as practical, but in no event later than six months after issuing the invoice.

6.5 Any amount not paid by the Due Date shall be subject to interest, calculated from the due date of the invoice to the date of payment, in accordance with the methodology specified for interest on refunds in the FERC's regulations at 18 C.F.R. § 35.19a (a) (2) (iii).

6.6 If any invoice remains unpaid by a Party for thirty (30) days after the Due Date, the Party rendering the invoice may, in addition to all other remedies available to it, and after giving the other Party at least five days written notice of the its intention to do so, present the issue in question to that Party's Board of Directors. The Party's Board of Directors shall contact the other Party's Board of Directors or its designee to develop a solution to a billing Dispute pursuant to Article 17 of this Agreement. The Boards of Directors may also choose to submit the billing Dispute to a form of alternative Dispute resolution to which the Boards of Directors may agree. Such action shall not be construed as a breach of contract by the Party rendering the invoice and shall not relieve the other Party of its obligations to pay for energy in accordance with the provisions of this Schedule.

6.7 The applicable provisions of this Schedule shall continue in effect after termination of this Schedule to the extent necessary to provide for final billing, billing adjustments, payments and disposition of any claims outstanding.

6.8 Each Party warrants that it has, or will have, the agreements and procedures in place to ensure the collection of payments from its participants for the delivery of Emergency Energy to it from the other Party.

ARTICLE VII

7.0 RECORDS

7.1 Each Party hereto shall keep or cause to be kept complete and accurate records and memoranda of its operations hereunder and shall maintain such data as may be necessary to determine with reasonable accuracy any item required hereunder. With respect to invoicing records, each Party shall maintain or cause to be maintained such records, memoranda and data for the current calendar year plus the previous calendar year. The Coordination Committee shall have the right to examine all such records and memoranda that are not confidential in so far as may be reasonably necessary for the purpose of ascertaining the reasonableness and accuracy of any statements of costs relating to transactions hereunder.

Attachment A

To the Emergency Energy Transactions Schedule

Emergency Energy Pricing

In accordance with the Emergency Energy Transactions Schedule between the NYISO and ISO-NE, the charge for Emergency Energy delivered to the Delivery Point by the NYISO or ISO-NE to the other shall be as defined within this Attachment A.

A.1. Direct NYISO/ISO-NE Emergency Energy Transaction

These are requests made by either the NYISO or ISO-NE to receive Emergency Energy in support of Emergency conditions and to protect Reliability in the event that there is a need for energy on its system that could not be supplied through the market.

The charge for Emergency Energy shall be calculated using the following two-part formula. The first part of the formula calculates the Energy Charge portion of the charge and the second part incorporates any Transmission Charge reasonably associated with the delivery of the Emergency Energy to the Delivery Point.

The Energy Charge portion of the Emergency Energy Charge (for an hour)

The Energy Charge portion of the Emergency Energy Charge for an hour =

(Emergency Energy supplied in the hour in megawatthour(s) ("MWh"))

* (Delivering Party's Cost of Energy in $/MWh)

* 110%

In the case of the NYISO as delivering Party, the Cost of Energy shall be the NYISO final external time-weighted/integrated real-time Locational Based Marginal Price ("LBMP") at the external node associated with the Delivery Point (as used in the NYISO market system for energy exports from the NYISO Balancing Authority Area into the New England Balancing Authority Area, as such pricing node is defined in NYISO Tariffs and as summarized in Table 1), for the hour of the Emergency Energy delivery.

In the case of ISO-NE as the delivering Party, the Cost of Energy shall be the ISO-NE final real-time integrated hourly Locational Marginal Price ("LMP") at the external node associated with the Delivery Point (as used in the New England market system for energy exports from the New England Balancing Authority Area into the NYISO Balancing Authority Area, as such pricing node is defined in the ISO-NE Tariff and as summarized in Table 1), for the hour of the Emergency Energy delivery.

Table 1

Delivery Points and Associated Pricing Nodes, as Modeled by the Delivering Party		
	External Nodes for Pricing Node for the Delivering Party (as modeled in the Delivering Party's system)	
Delivery Point	**Delivering Party: ISO-NE**	**Delivering Party: NYISO**
NY/NE Northern AC Interconnection **(excludes the NNC (or 1385 Cable) Intertie)**	**.I.ROSETON 345 1 (4011)**	**N.E._GEN_SANDY PD (24062)**
NNC Interconnection	**.I.NRTHPORT 1385 (4017)**	**NPX_1385_GEN (323591)**
CSC Interconnection	**.I.SHOREHAM 138 99 9(4014)**	**NPX_GEN_CSC (323557)**

The Transmission Charge portion of the Emergency Energy Charge (for an hour)

The Transmission charge portion of the Emergency Energy Charge to the Delivery Point for an hour shall equal the actual ancillary services costs and any transmission costs reasonably associated with the delivery of such Emergency Energy for an hour by the delivering Party to the Delivery Point pursuant to the applicable tariff of the delivering Party, as filed with and accepted by the governmental agency with jurisdiction over such tariff.

A.2. NYISO/ISO-NE Emergency Energy Transaction From Third Party Balancing Authority Area Supplier

These are requests made by NYISO or ISO-NE to deliver Energy to the other to address system balancing or other Reliability conditions present on the exporting system, which could not be accomplished through the market.

The charge for Emergency Energy supplied to a Party from a Third Party Balancing Authority Area supplier shall be calculated using the following two-part formula. The first part of the formula calculates the Energy Charge portion of the charge, which in this case includes the total charge (energy and transmission) that the Third Party Balancing Authority Area supplier charges for delivery of the Emergency Energy to the delivering Party's Balancing Authority Area border. The second part of the formula incorporates any Transmission Charges reasonably associated with the delivery of the Emergency Energy by the delivering Party through its system to the Delivery Point. It is expected that that all such Third Party Balancing Authority Area supplier charges will be in accordance with rates filed and accepted by the governmental body with jurisdiction over such rates.

The Energy Charge portion of the Emergency Energy Charge (for an hour)

The Energy Charge portion of the Emergency Energy Charge for an hour =

(Emergency Energy supplied in the hour in MWh)

* (Third Party Balancing Authority Area supplier's total charge for such energy in $/MWh)

(Note: 10% adder does not apply to pricing of Emergency Energy from Third Party Balancing Authority Area suppliers.)

The Transmission Charge portion of the Emergency Energy Charge (for an hour)

The Transmission Charge portion of the Emergency Energy Charge to the Delivery Point for an hour shall equal the actual ancillary services costs and any transmission costs reasonably associated with the delivery of such energy for an hour to the Delivery Point pursuant to the applicable tariff of the delivering Party, as filed with and accepted by the governmental agency with jurisdiction over such tariff. Transmission costs would include, but not be limited to, any costs for congestion and losses that are associated with the delivery of such Emergency Energy through the delivering Party's Balancing

Authority Area for an hour to the Delivery Point, as calculated by the amount of Emergency Energy supplied multiplied by: (1) when NYISO is the delivering Party, (the NYISO real-time LBMP of the external node at which the Emergency Energy exits the NYISO Balancing Authority Area minus the NYISO real-time LBMP of the external node at which the Emergency Energy enters the NYISO Balancing Authority Area); or (2) when ISO-NE is the delivering Party, (the ISO-NE real-time LMP of the external node at which the Emergency Energy exits the ISO-NE Balancing Authority Area minus the ISO-NE real-time LMP of the external node at which the Emergency Energy enters the ISO-NE Balancing Authority Area).

Schedule D: Coordinated Transaction Scheduling

WHEREAS, ISO-NE, as the regional transmission organization for the New England Transmission System and the administrator of the New England wholesale electricity markets, schedules the sale of energy by its Market Participants to, and the purchase of energy by its Market Participants from, neighboring Balancing Authority Areas, all in accordance with the ISO-NE Tariff, which includes the Open Access Transmission Tariff and ISO-NE market rules;

WHEREAS, ISO-NE is the administrator of the ISO-NE Tariff and is responsible for, among other matters, ensuring sufficient reserves are available to provide reliable service in its Balancing Authority Area, in accordance with the ISO-NE Tariff;

WHEREAS, the NYISO, as the independent system operator of the New York Transmission System and the administrator of the New York wholesale electricity markets, schedules the sale of energy by its Market Participants to, and the purchase of energy by its Market Participants from, neighboring Balancing Authority Areas, all in accordance with the NYISO Tariffs;

WHEREAS, the NYISO is the administrator of the NYISO Tariffs and is responsible for, among other matters, ensuring sufficient reserves are available to provide reliable service in its Balancing Authority Area, in accordance with the NYISO Tariffs;

WHEREAS, Coordinated Transaction Scheduling will improve interregional scheduling efficiency by taking into account relative price differences between the regions and scheduling bids and offers on a 15 minute basis at CTS Enabled Interfaces; and

WHEREAS, the Parties desire to schedule energy between their Balancing Authority Areas more efficiently, while continuing to ensure that each Party will maintain sufficient Operating Reserve available on its respective system to ensure the reliable operation thereof;

NOW, THEREFORE, in consideration of the premises and of the mutual covenants herein set forth, the Parties mutually agree as follows:

ARTICLE I

1.0 OVERVIEW OF COORDINATED TRANSACTION SCHEDULING

Coordinated Transaction Scheduling or "CTS" is an external transaction scheduling process implemented by the Parties at designated CTS Enabled Interfaces that allow real-time energy transactions to be scheduled based on a Market Participant's willingness to purchase energy at a source External Proxy Bus (in the NECA, or in the NYCA) and sell it at a sink External Proxy Bus in the other Control Area if the forecasted price at the sink minus the forecasted price at the corresponding source is greater than or equal to the bid price. The rules set forth in this Schedule D only apply at CTS Enabled Interfaces.

In accordance with the terms of this Schedule D and the Parties' respective tariffs, CTS Interface Bids are ordinarily evaluated on a 15-minute basis utilizing forecasted real-time prices and forecasted system information from NYISO and forecasted real-time prices and forecasted system information from ISO-NE. The evaluation will be performed by the NYISO's Real-Time Commitment (RTC) optimization consistent with the rules specified in the NYISO Services Tariff and this Schedule D.

As part of the iterative CTS process, NYISO will share forward looking RTC interchange schedules with ISO-NE and these schedules will be used by ISO-NE as an input to develop a new set of forecasted prices and system information, which ISO-NE will then provide to NYISO for use in the next RTC optimization.

In accordance with Section 4 below, the RTC optimization will determine the External Interface Congestion component of the RTC LMP at a CTS Enabled Interface, which will subsequently be incorporated into the Parties' real-time settlement LMPs.

Wheel-through transactions across a CTS Enabled Interface will be scheduled on an hourly basis. Wheels through the NYCA will use decremental or sink price cap bids at CTS Enabled Interfaces.

Wheels through the NECA will use hourly CTS Interface Bids at CTS Enabled Interfaces for scheduling by the NYISO.

The Parties agree that CTS and its components will operate in accordance with this Schedule D and the terms of the Parties' respective tariffs.

ARTICLE II

2.0 SUBMITTAL OF CTS INTERFACE BIDS

2.1 CTS Interface Bid Submittal by New England Responsible Settlement Parties and their Representatives

NYISO is hosting the platform used by both New York and New England Responsible Settlement Parties to submit CTS Interface Bids. New York RSPs shall submit and confirm bids at CTS Enabled Interfaces in accordance with the NYISO Tariffs.

Authorized New England RSPs shall have access to the bidding platform for purposes of submitting bids at CTS Enabled Interfaces between the NECA and the NYCA. Such access will be provided under equivalent terms and conditions to New York RSPs.

On an hourly or more frequent basis ISO-NE shall provide NYISO with: (a) a list of all New England RSPs that are authorized to submit or confirm bids at CTS Enabled Interfaces and (b) identification information for each representative (*i.e.*, an individual) that is authorized to submit or confirm bids at CTS Enabled Interfaces on behalf of a New England RSP. Only representatives designated by ISO-NE shall be permitted access to the platform that is used to submit bids at CTS Enabled Interfaces on behalf of a New England RSP. NYISO shall verify the authorization of a New England RSP and its representative at the time a bid is submitted, confirmed, modified or deleted. If it has been more than two hours since the NYISO last received from ISO-NE an updated list of all authorized New England RSPs and identification information for each representative that is authorized to submit or confirm bids at CTS Enabled Interfaces on behalf of a New England RSP, then NYISO shall not allow any New England RSP to access the platform that is used to submit bids at CTS Enabled Interfaces until an updated list is received.

In the event NYISO is not able to implement a new or changed status in a timely fashion, NYISO will inform ISO-NE of any delay it is aware of and the reason for the delay, and will implement the new or changed status as soon as possible.

2.2 Confirmation of New England Responsible Settlement Parties

A representative submitting an initial or revised CTS Interface Bid, or a bid to schedule a wheel through the NYCA at a CTS Enabled External Proxy Bus must belong to an authorized RSP in either NYISO or ISO-NE. In that submittal, the representative must identify the participating RSP in the other area. The other participating RSP must confirm the submittal of the CTS Interface Bid or bid to wheel through the NYCA, in order for the bid to be valid. A CTS Interface Bid or a bid to wheel through the NYCA can be withdrawn by either participating RSP; no confirmation is required.

An RSP may establish a Confirmed Trust Relationship with another RSP such that the required confirmation will be automatically granted for any submittal of a CTS Interface Bid or bid to wheel through the NYCA at a CTS Enabled External Proxy Bus that is submitted by the trusted RSP and includes both RSPs as parties to the transaction. Upon representative action to submit, update or revoke a Confirmed Trust Relationship, NYISO shall verify that (i) the submittal identifies two authorized RSPs, one in New York and one in New England and (ii) the representative belongs to the RSP that is granting the Confirmed Trust Relationship to the other RSP.

Upon representative action to submit or confirm an initial or revised CTS Interface Bid or bid to wheel through the NYCA, or to withdraw a CTS Interface Bid or bid to wheel through the NYCA at a CTS Enabled External Proxy Bus, the NYISO shall verify that (i) the submittal identifies two valid RSPs, one in New York and one in New England, and (ii) the representative belongs to an RSP that is identified on the submittal. If a Confirmed Trust Relationship exists between the two authorized RSPs and the action is taken by a representative that is associated with a trusted RSP to submit or confirm an initial or revised CTS Interface Bid or bid to wheel through the NYCA, the bid shall be deemed submitted and confirmed, or the revision confirmed.

Upon receiving ISO-NE's notice of suspension or termination of a New England RSP, which ISO-NE shall do consistent with its authority under the ISO-NE Tariff, NYISO will promptly:

1. cease honoring Confirmed Trust Relationships associated with the suspended or terminated New England RSP;
2. within the real-time market day on which NYISO receives the instruction from ISO-NE, remove the suspended or terminated New England RSP's bids at CTS Enabled Interfaces that are offered in the NECA to NYCA direction;
3. within the real-time market day on which NYISO receives the instruction from ISO-NE, remove bids at CTS Enabled Interfaces that are offered in the NECA to NYCA direction that include the New England RSP as a trusted RSP;
4. for all real-time market days subsequent to the real-time market day on which NYISO receives the instruction from ISO-NE, remove all of the suspended or terminated New England RSP's bids at CTS Enabled Interfaces; and
5. for all real-time market days subsequent to the real-time market day on which NYISO receives the instruction from ISO-NE, remove all bids at CTS Enabled Interfaces that include the suspended or terminated New England RSP as a trusted RSP.

The five changes enumerated above will be effectuated prospectively. The Parties will not effectuate changes one through three for a real-time market hour in which RSPs are no longer able to submit or modify bids.

ISO-NE will curtail the e-tags for the transactions associated with the bids NYISO is required to remove under the rules set forth above.

In the event NYISO is not able to implement a new or changed status that is addressed in this Section 2.2 in a timely fashion, NYISO will inform ISO-NE of any delay it is aware of and the reasons for the delay, and will implement the new or changed status as soon as possible.

If the NYISO is unable to verify that the required confirmations have been received, then the CTS Interface Bid or bid to wheel through the NYCA shall not be considered in the RTC optimization.

If the NYISO is not able to validate an RSP or a representative, then that entity or person will not be able to submit, modify, confirm or delete a CTS Interface Bid or a bid to wheel through the NYCA.

ARTICLE III

3.0 CALCULATION OF ISO-NE SUPPLY PRICE POINTS

Each quarter-hour, ISO-NE shall calculate a set of forecast energy prices at its External Proxy Buses for each CTS Enabled Interface corresponding to varying interchange levels on that interface. The results will be provided to NYISO as increasing MW-price pairs, where the MW value represents a net interchange level on the CTS Enabled Interface and the price value represents ISO-NE's forecast of its real-time LMP for its External Proxy Bus at that net interchange MW level. ISO-NE will provide no fewer than one and no more than 11 MW-price pairs for each of ten consecutive quarter-hour intervals, which are referred to as the "ISO-NE Supply Price Points."

The ISO-NE Supply Price Points are created with a forward-looking, security-constrained economic dispatch system that co-optimizes energy and reserve requirements. This forward-looking co-optimization will assume the same units are committed as are previously committed, or scheduled to be committed, in ISO-NE's real-time production system. The energy from currently uncommitted fast-start generation will also be considered for dispatch in the forward-looking co-optimization. ISO-NE Supply Price Points shall be calculated using the current production data for load forecasts, active transmission constraints, state estimator data, Market Participant energy re-offers, wind forecasts, forecasted net interchange on all Interconnections (including forward looking RTC interchange schedules provided by NYISO), and operator updates to resource limits.

ARTICLE IV

4.0 SCHEDULING EXTERNAL TRANSACTIONS AT CTS ENABLED INTERFACES

4.1 Evaluation of CTS Interface Bids

The RTC will use the CTS Interface Bids and the ISO-NE Supply Price Points to economically schedule the CTS Interface Bids and determine the net interchange schedules. The economic scheduling of the CTS Interface Bids will be performed simultaneously with the scheduling of internal NYCA resources and external transactions at other NYCA Interconnections.

For an RTC optimization that schedules hourly CTS Interface Bids, the RTC will use the ISO-NE Supply Price Points for each 15-minute interval of the hour. An hourly CTS Interface Bid will be scheduled if it is economic for the hour.

For an RTC optimization that schedules CTS Interface Bids at 15-minute intervals, the RTC optimization will use ISO-NE Supply Price Points that have been adjusted to account for the hourly RTC external transaction schedules established at CTS Enabled Interfaces, including any scheduled Emergency Energy.

When there are multiple CTS Interface Bids at the same bid price but not all of them can be economically cleared, the CTS Interface Bids with the same price will be scheduled pro-rata.

The RTC optimization incorporates Ramp Limits and Transfer Limits in the manner described in Section 5 of this Schedule D to economically schedule CTS Interface Bids and shall determine: (1) the net interchange schedule for each CTS Enabled Interface, (2) the RTC LMP for each CTS Enabled External Proxy Bus, and (3) the External Interface Congestion at each CTS Enabled Interface.

4.2 External Interface Congestion Price Assignment

The RTC optimization will determine the External Interface Congestion at an External Proxy Bus for a CTS Enabled Interface if the net interchange schedule is limited in the RTC solution due to one or more of the following four reasons: (i) there are more economic transactions offered in a common direction (import or export) than the Transfer Limit of the External Proxy Bus can accommodate, or (ii) there are fewer economic transactions offered in a common direction (import or export) than the Transfer Limit requires, or (iii) the NYCA (system-wide) Ramp Limit prevents the RTC from scheduling one or more external transactions at the External Proxy Bus consistent with the economics of the underlying bids, or (iv) a Ramp Limit prevents the RTC from scheduling one or more external transactions consistent with the economics of the underlying bids (collectively, the "External Proxy Bus Constraints").

Whenever an External Proxy Bus Constraint at a CTS Enabled Interface is limiting in the RTC optimization, the External Interface Congestion at the External Proxy Bus will be assigned, in whole or in part, as set forth below.

ISO-NE Limiting: If the RTC optimization is limited by a Transfer Limit determined by an ISO-NE Operating Reserve limitation, an ISO-NE minimum generation limitation, or an ISO-NE capacity deliverability limit, including when the Transfer Limit is adjusted in accordance with Section 5.4 of this Schedule D to accommodate the Ramp Limit while implementing one of these limitations, then the portion of the External Interface Congestion associated with the External Proxy Bus Constraint shall be assigned to ISO-NE.

NYISO Limiting: If the RTC optimization is limited by NYCA-wide Ramp Limits, then the portion of the External Interface Congestion associated with the External Proxy Bus Constraint shall be assigned to NYISO.

NYISO and ISO-NE Limiting: If the RTC optimization is limited by any Ramp Limit or Transfer Limit that is not specifically addressed in the "ISO-NE Limiting" or "NYISO Limiting" paragraphs above, or by any Transfer Limit or Ramp Limit that results from an operator override, as described in Section 5.2.5 of this Schedule D, the portion of the External Interface Congestion for a CTS Enabled Interface that is associated with an External Proxy Bus Constraint shall be assigned to both Parties equally.

The RTC solution may be limited by multiple External Proxy Bus Constraints simultaneously. If this occurs, the foregoing rules will apply to each External Proxy Bus Constraint.

If there are not sufficient CTS Interface Bid MWs offered to achieve a Transfer Limit, RTC will schedule the available MWs. In these circumstances, RTC will determine the External Interface Congestion at the External Proxy Bus based on the NYISO's Transmission Shortage Costs as defined in the NYISO Tariff.

In order to provide consistent price signals between their respective real-time energy markets, the Parties shall each incorporate the foregoing process into the real-time settlement LMP at their External Proxy Bus for each CTS Enabled Interface.

ARTICLE V

5.0 CTS ENABLED INTERFACE OPERATING RULES

5.1 CTS Enabled Interface Ramp Limits

The default quarter-hour Ramp Limit for the NY/NE Northern AC Interconnection will be mutually agreed to by the Parties and posted on the NYISO's OASIS.

The default top-of-the-hour Ramp Limit for the NY/NE Northern AC Interconnection (for use when quarter-hour scheduling is unavailable) will be mutually agreed to by the Parties and posted on the NYISO's OASIS.

In real-time operations, when necessary to protect reliability, the Parties may mutually agree to temporarily change the Ramp Limit(s) at any CTS Enabled Interface. The Parties shall restore the modified Ramp Limit to the posted default Ramp Limit as soon as reliable system operations permit and it is practicable to do so.

5.2 Transfer Limits Reflecting Reliability Conditions

A Transfer Limit sets the minimum or maximum net interchange that can be scheduled on a CTS Enabled Interface in the RTC solution. Factors that can set the Transfer Limits include the following:

1. normal scheduling limits;
2. Operating Reserve limitations;
3. minimum generation limitations;
4. capacity requests;
5. operator overrides.

5.2.1 Normal Scheduling Limits

The normal scheduling limit for a CTS Enabled Interface is the amount of electric power that can normally be transferred over a CTS Enabled Interface. The Parties may mutually agree to change the normal scheduling limits that are used at CTS Enabled Interfaces due to transmission outages, generation outages or other changes in system conditions. In the event the change to a normal scheduling limit is planned in advance, the Parties will make reasonable efforts to change the values in time to be included in the clearing of their respective day-ahead energy markets and be publicly posted prior to implementation. For the real-time operating day, ISO-NE will send its normal scheduling limits at each CTS Enabled

Interface to the NYISO via the electronic data exchange to cover the same ten consecutive quarter-hour intervals as ISO-NE's Supply Price Points.

5.2.2 Operating Reserve Limitations

If one Control Area experiences an Operating Reserve deficiency, the other Control Area is not obligated to go deficient in its reserves of the same or a higher quality product, but may go deficient in a lower-quality reserve product in order to prevent an Operating Reserve deficiency of a higher quality reserve product in the other Control Area. To ensure these mutual reliability objectives can be satisfied, the Parties may modify the Transfer Limits in certain conditions as described below.

The RTC optimization procures reserves to meet the NYISO's reserve requirements and prices shortages of reserves using the NYISO's Operating Reserve demand curves. The RTC does not have information on the amount of Operating Reserve in the NECA. Therefore, at CTS Enabled Interfaces, ISO-NE will use the electronic data exchange to provide to NYISO both the ISO-NE Supply Price Points and Transfer Limit values that reflect the net interchange required to meet ISO-NE's 10-minute and 30-minute reserve requirements. When calculated, these values will reflect the net interchange required to meet ISO-NE's 10-minute and 30-minute reserve requirements for the same ten consecutive quarter-hour intervals for which ISO-NE's Supply Price Points are provided. ISO-NE will calculate these Transfer Limit values for each interval based on the Operating Reserve surplus in the NECA when applying the forecasted RTC net interchange on the CTS Enabled Interface. For the purposes of Schedule D, the ISO-NE Transfer Limit associated with the 10-minute reserve requirement will always be less restrictive than the Transfer Limit associated with the ISO-NE 30-minute reserve requirement. When ISO-NE sends Transfer Limits that are associated with Operating Reserve requirements, the ISO-NE Supply Price Points must also reflect those expected reserve shortage prices. RTC will evaluate whether the ISO-NE Transfer Limit would preclude NYISO from meeting its reserve requirements for an equal or higher quality reserve product. If so, RTC may adjust the Transfer Limit in accordance with Section 5.3 of this Schedule D, based on the principles set forth in the preceding paragraph.

5.2.3 Minimum Generation Limitations

The RTC optimization dispatches the NYISO system's internal generation as needed when the NYCA approaches minimum generation conditions. The RTC does not have information to assess minimum generation conditions within the NECA. Therefore, at CTS Enabled Interfaces, ISO-NE will use the

electronic data exchange to provide to NYISO Transfer Limit values that reflect the net interchange level beyond which ISO-NE cannot further dispatch down internal generation while maintaining reliable operations. When ISO-NE sends Transfer Limits for this purpose, the ISO-NE Supply Price Points must also reflect these requirements.

ISO-NE shall not send, and NYISO is not required to enforce, a minimum generation Transfer Limit that would require the NYCA to accept energy from the NECA.

ISO-NE shall not send both a minimum generation Transfer Limit and Operating Reserve Transfer Limits at the same time.

5.2.4 Capacity Transfer Limits

Day-Ahead Coordination

NYISO will provide its day-ahead operating plan to ISO-NE. Once ISO-NE determines that it expects to count on capacity resources located in New York to meet its reserve requirements, ISO-NE shall inform NYISO of the expected capacity call.

Real-Time Coordination

ISO-NE Capacity Requests at CTS Enabled Interfaces:

ISO-NE may request delivery of energy from capacity resources located in the NYCA that have obligations in the ISO-NE capacity market over a CTS Enabled Interface. The ISO-NE operator will call the NYISO operator to initiate the capacity request. Upon receiving the request, the NYISO operator will confirm what amount of the capacity request is deliverable based on projected transmission constraints ("Capacity Deliverable to ISO-NE"). If the Capacity Deliverable to ISO-NE is non-zero, RTC will determine the ISO-NE capacity that is available based on offers submitted by NYCA generators that have sold their capacity to ISO-NE and are projected to be available in real-time, subject to any real-time derates ("Capacity Available to ISO-NE").

Transactions to wheel capacity through the NYCA will be excluded from the ISO-NE/NYISO capacity request process.

NYISO Capacity Requests at CTS Enabled Interfaces:

If the NYISO projects the ISO-NE real-time capacity request could cause the NYISO to become capacity deficient, the NYISO may request delivery of energy associated with capacity resources located in ISO-NE that have an obligation in the NYISO capacity market over a CTS Enabled Interface. The NYISO operator will call the ISO-NE operator to initiate the capacity request. The NYISO will require that its eligible New England-based capacity submit CTS Interface Bids to be evaluated by RTC. It will be up to the supplier of New England-based capacity to ensure that the resource(s) backing capacity transactions are available to deliver their capacity to New York when they are called on to do so. At the time of the request, the ISO-NE operator will determine whether all or any part of the generation supporting the capacity is available and deliverable ("Capacity Available to NYISO").

Section 5.3 of this Schedule D sets forth how capacity data and Operating Reserve limitations are used to establish a Transfer Limit.

5.2.5 Operator Override Transfer Limits

Real-time system conditions may require that a NYISO or ISO-NE operator override the Transfer Limit to establish the flow that can be transferred over a CTS Enabled Interface in a reliable manner. Except when necessary to protect reliability, an operator override shall not be used to submit limits that can be submitted via the electronic data exchange.

5.3 Establishing Transfer Limits for RTC

RTC determines a net interchange for each interval that must be a value between an upper bound and lower bound. In this section, the high Transfer Limit is the upper bound on that range and the low Transfer Limit is the lower bound on that range. The rules in this Section 5.3 detail how the inputs from Section 5.2, which are first tested against the criteria set forth in Section 7.2, are used to determine the high and low Transfer Limits in RTC for each quarter-hour interval. For purposes of this Section 5.3, a positive value represents flow from New England to New York, and a negative value represents flow from New York to New England. The values associated with an ISO-NE capacity request, Capacity Deliverable to ISO-NE and Capacity Available to ISO-NE are all negative.

1. When a Minimum Generation Transfer Limit is provided by ISO-NE in accordance with Section 5.2.3, that value is the low Transfer Limit at a CTS Enabled Interface.

2. When ISO-NE provides Operating Reserve Transfer Limits but has not requested capacity from NYISO, the following rules are applied to determine the high Transfer Limit at a CTS Enabled Interface:

   a) If the ISO-NE 30-minute Operating Reserve Transfer Limit is greater than or equal to zero, then:

      i. If enforcing the ISO-NE 30-minute Operating Reserve Transfer Limit is projected to cause the NYISO to have a deficiency of 10-minute Operating Reserve, the high Transfer Limit is the minimum value that is not projected to result in a NYISO 10 minute Operating Reserve deficiency;

      ii. Otherwise the high Transfer Limit is the ISO-NE 30-minute Operating Reserve Transfer Limit.

   b) If the ISO-NE 30-minute Operating Reserve Transfer Limit is less than zero, then:

      i. If enforcing the ISO-NE 30-minute Operating Reserve Transfer Limit is projected to cause the NYISO to have a deficiency of 30-minute Operating Reserve but is not projected to cause the NYISO to have a deficiency of 10-minute Operating Reserve, then the high Transfer Limit is the lesser of (a) the minimum value that is not projected to result in a NYISO 30-minute Operating Reserve deficiency, or (b) zero;

      ii. If enforcing the ISO-NE 30-minute Operating Reserve Transfer Limit is projected to cause the NYISO to have a deficiency of 10-minute Operating Reserve, then the high Transfer Limit is the minimum value that is not projected to result in a NYISO 10-minute Operating Reserve deficiency;

      iii. Otherwise the high Transfer Limit is the ISO-NE 30-minute Operating Reserve Transfer Limit.

3. When ISO-NE has requested capacity from NYISO, the high Transfer Limit at a CTS Enabled Interface shall be the greater of:

   a) the ISO-NE 30-minute Operating Reserve Transfer Limit, or

   b) [the minimum of (i) the total quantity of CTS Interface Bids backing Capacity Available to NYISO or (ii) the Capacity Available to NYISO] plus [the maximum of (iii) the ISO-NE capacity request, (iv) the Capacity Deliverable to ISO-NE or (v) the Capacity Available to ISO-NE].

4. When system conditions require that either a low or high Transfer Limit be overridden by the NYISO or ISO-NE operator to establish the flow that can be transferred over a CTS Enabled Interface in a reliable manner, the override shall establish the low or high Transfer Limit.

5. Otherwise, the NYISO shall use the normal scheduling Transfer Limit at a CTS Enabled Interface, as described in Section 5.2.1.

5.4. Interaction Between Transfer Limits and Ramp Limits

a) Except as provided in 5.4(b), when the NYISO's RTC is provided Transfer Limits that would cause it to develop net interchange schedules at a CTS Enabled Interface with ISO-NE that exceed the Ramp Limits, RTC will reset the provided Transfer Limits to ensure the agreed Ramp Limits are not exceeded.

b) If any Transfer Limit, other than a normal scheduling limit, is implemented via an operator override, then RTC shall permit the agreed Ramp Limits to be exceeded in order to enforce the Transfer Limit.

ARTICLE VI

6.0 SETTLEMENT PROVISIONS

ISO-NE shall settle CTS Interface Bids and other bids and offers scheduled at CTS Enabled Interfaces with its Market Participants in accordance with the rules set forth in the ISO-NE Tariff.

The NYISO shall settle CTS Interface Bids and other bids scheduled at CTS Enabled Interfaces, with its Market Participants in accordance with the rules set forth in the NYISO Tariffs.

Each Party shall address settlement-related corrections and disputes regarding that Party's settlement of CTS transactions in accordance with the settlement correction and dispute resolution provisions set forth in that Party's tariff(s).

Each Party agrees to provide support, including information and data that isn't otherwise available to the other Party, when the requested information is necessary to assist the requesting Party in addressing a

settlement (but not price) correction or a settlement-related dispute between the requesting Party and one or more of its Market Participants regarding the settlement of CTS transactions.

If an erroneous price is determined at a CTS Enabled External Proxy Bus, independent of any price correction process ISO-NE may utilize, the NYISO shall follow the price correction process set forth in Attachment E to its Market Administration and Control Area Services Tariff.

If an erroneous price is determined at a CTS Enabled External Proxy Bus, independent of any price correction process NYISO may utilize, ISO-NE shall follow the price correction process set forth in the ISO-NE Tariff.

ARTICLE VII

7.0 NON-STANDARD CTS OPERATION

7.1 Permitted Modifications to ISO-NE Supply Price Points

In the event NYISO does not receive the ISO-NE Supply Price Points before it commences the RTC optimization, then the last set of ISO-NE Supply Price Points used to perform an RTC optimization will be used in the RTC optimization to determine the net interchange schedule until the NYISO receives and successfully validates a new set of ISO-NE Supply Price Points.

If one or more quarter-hour intervals within the ISO-NE Supply Price Points fail the NYISO's input checks, the last set of ISO-NE Supply Price Points used to perform an RTC optimization will be used in the RTC optimization.

When ISO-NE Supply Price Points do not cover the full quantity (in MWs) of bids that are evaluated by RTC, then the last pricing point on either end of the ISO-NE Supply Price Points will be extended by NYISO to cover all the bids and offers that are evaluated by RTC.

7.2 Permitted Modifications to ISO-NE Transfer Limits

In the event NYISO does not receive ISO-NE Transfer Limits or operator override values have not been entered before an RTC optimization commences, then the last set of ISO-NE Transfer Limits used to perform an RTC optimization will be used in the current RTC optimization.

If one or more quarter-hour intervals within the ISO-NE Transfer Limits fail any of the NYISO's input checks, including the input checks listed below, the last set of ISO-NE Transfer Limits used to perform an RTC optimization will be used in the RTC optimization.

- A Minimum Generation Transfer Limit and Operating Reserve Transfer Limits will not be sent at the same time.
- The Minimum Generation Transfer Limit will be less than or equal to zero.
- If an ISO-NE 10-minute Operating Reserve Transfer Limit is provided, an ISO-NE 30-minute Operating Reserve Transfer Limit will also be provided.
- The ISO-NE 30-minute Operating Reserve Transfer Limit will be less than the ISO-NE 10-minute Operating Reserve Transfer Limit.

7.3 Hourly Scheduling Under CTS

The Parties may agree to temporarily employ hourly scheduling in RTC on a CTS Enabled Interface when necessary to ensure or preserve system reliability or when not able to implement schedules as expected due to software or communication issues.

ARTICLE VIII

8.0 JOINT ENERGY SCHEDULING SYSTEM CUSTOMER SERVICE; MAINTENANCE; SUSPENSION OF CTS; COOPERATION

8.1 Joint Energy Scheduling System Customer Service

The NYISO developed and maintains the Joint Energy Scheduling System ("JESS") platform that both New York RSPs and New England RSPs use to submit bids at CTS Enabled Interfaces.

1. Each Party is the primary customer service contact for its respective Market Participants.

2. ISO-NE will have read-only access to bids associated with New England Market Participants at CTS Enabled Interfaces on the JESS platform.

8.2 Maintenance

Subject to reasonable expectations, it is the Parties' goal that the data links, software, and other systems necessary to implement CTS are available continuously. The Parties agree to employ regular maintenance, including scheduled maintenance outages when needed, to meet that goal.

In the event of a problem with a data link, software, computational system or data system, the responsible Party will use reasonable efforts to promptly address the problem. The Parties shall work together and shall keep each other informed regarding the problem and its resolution.

The Parties shall inform each other in advance of any scheduled testing activities or maintenance outages that will affect a CTS Enabled Interface. Notice shall be provided sufficiently in advance to allow each ISO to inform its Market Participants of any impacts on the operation of CTS.

8.3 Suspension of CTS

The Parties may suspend the scheduling of CTS transactions at CTS Enabled Interfaces due to: (1) the inability of the NYISO to receive bids for a CTS Enabled Interface; (2) a failure or outage of the data link between the Parties that prevents the timely exchange of information necessary to implement CTS transactions; (3) the actual or suspected failure of any software, computational, or data system that is necessary to implement CTS transactions; (4) the need to verify the functionality of the tools that are necessary to implement CTS; or (5) when necessary to ensure or preserve NYISO or ISO-NE system reliability.

A Party that determines that any of the foregoing conditions have occurred shall, as soon as practicable, notify the other Party.

The Parties shall resolve issues causing the failure or outage of the data link, software, computational systems, or data systems as soon as possible, and will use reasonable efforts to promptly address the problem. The Parties shall work together and shall keep each other informed regarding the problem and its resolution. The Parties shall resume implementation of CTS following, as applicable, the successful

testing of the data link or relevant system(s) after the inability to receive offers or bids, failure, or condition is resolved, or after the resolution of the system reliability issue.

When CTS is suspended the Parties shall mutually agree to interchange schedules at CTS Enabled Interfaces.

8.4 Cooperation

The Parties will cooperate to review the data and mutually identify or resolve errors and anomalies. If one Party determines that it is required to self-report a potential violation to the Commission's Office of Enforcement regarding its compliance with this Schedule D, the reporting Party shall inform, and provide a copy of the self-report to the other Party. Any such report provided by one Party to the other shall be Confidential Information.

ARTICLE IX

9.0 CTS CHANGE MANAGEMENT PROCESS

9.1 Notice

Prior to materially changing any tariff language, software or process that is directly involved in implementing this Schedule D, the Party desiring the change shall notify the other Party's data exchange contact appointed under the Coordination Agreement, in writing or via email, of the proposed change. The notice shall include a complete and detailed description of the proposed change, the reason for the proposed change, and the impacts the proposed change is expected to have on the implementation of CTS.

9.2 Opportunity to Request Additional Information

Following receipt of the Notice described in Section 9.1, the receiving Party may make reasonable requests for additional information/documentation from the other Party. This may include a request by a Party to be involved in the testing of the changes. Absent mutual agreement of the Parties, the submission of a request for additional information under this Section shall not delay the obligation to timely note any objection pursuant to Section 9.3, below.

9.3 Objection to Change

Within ten business days after receipt of the Notice described in Section 9.1 (or within such longer period of time as the Parties mutually agree), the receiving Party may notify in writing or via email the other Party of its disagreement with the proposed change. Any such notice must specifically identify and describe the concern(s) that required the receiving Party to object to the described change.

9.4 Implementation of Change

The Party proposing a change to a process that is directly involved in implementing this Schedule D shall not implement such change until (a) it receives written or email notification from the other Party that the other Party concurs with the change, or (b) the receiving Party fails to notify in writing or via email the other Party of its disagreement with the proposed change within the notice period specified in Section 9.3, or (c) completion of any dispute resolution process initiated pursuant to this Agreement.

ARTICLE X

10.0 AUDITS, CERTIFICATION AND TESTING

Each Party shall provide to the other Party the results of any certification or audit it procures regarding CTS-related software functions, subject to the following conditions: (1) the disclosure may be limited to the portions of the certification or audit that addresses the CTS-related software, and need only include the portions of the certification or audit that address the CTS-related functioning of the software; (2) if the providing Party indicates that the certification or audit is Confidential Information it shall be treated as such by the receiving party; and (3) this provision does not require a Party to disclose information that is subject to a legal privilege.

Before CTS is implemented, and upon any material changes to any components thereof, the Parties shall test the processes and component software.

Each Party shall, at its sole expense, take appropriate actions to address any actual or apparent breach of cyber security related to CTS, and shall provide prompt notification to the other Party of any such incident.

Each party will undertake an annual Service Organization Controls report that covers CTS process-related controls prepared and opined by its external auditors in accordance with Statement on Standards for Attestation Engagements No. 16 or AICPA/CICA Principles and Criterion for System Reliability (SSAE 16 engagement). The NYISO report will include controls related to the Joint Energy Scheduling System bidding platform.

Each Party shall promptly provide to the other Party the results of its annual Service Organization Controls report, subject to the following conditions: (1) the disclosure may be limited to the portions of the report or audit that address CTS, and need only include the portions of the report or audit that address CTS; (2) if the providing Party indicates that the certification or audit is Confidential Information it shall be treated as such by the receiving party; and (3) this provision does not require a Party to disclose information that is subject to a legal privilege.

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